Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 7-3

Forecast capital expenditure report for the 2016 regulatory period

Public

30 April 2015

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GLOSSARY

AER	Australian Energy Regulator
AIS	Air Insulated Switchgear
AMI	Advanced Metering Infrastructure
ANCAP	Australasian New Car Assessment Program
AW	Airport West zone sub-station
BY	Braybrook zone sub-station
Capex	Capital expenditure
CBRM	Condition Based Risk Management
CESS	Capital Expenditure Sharing Scheme
CIC	Customer Initiated Capital
CN	Coburg North zone sub-station
COO	Coolaroo zone sub-station
COWP	Capital and Operating Works Plan
CS	Coburg South zone sub-station
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
DSA	Distribution Substation Augmentation
ECP	Easy Cost Planner
EDPR	Electricity Distribution Price Review
EP	East Preston zone sub-station
ES	Essendon zone sub-station
ESMS	Electrical Safety Management Scheme
ESV	Energy Safe Victoria
FE	Footscray East zone sub-station
FF	Fairfield zone sub-station
FT	Flemington zone sub-station
GIS	Geospatial Information Systems
HB	Heidelberg zone sub-station
HBRA	Hazardous Bushfire Risk Area
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
KLO	Kalkallo zone sub-station
KTS	Keilor Terminal Station
LBRA	Low Bushfire Risk Area

LGA	Local Government Area
MPA	Metropolitan Planning Authority
NER	National Electricity Rules
NS	North Essendon zone sub-station
OH	Overhead
POE	Probability of Exceedence
PTRM	Post Tax Revenue Model
RAB	Regulated Asset Base
REFCLs	Rapid Earth Fault Current Limiter
RFM	Roll Forward Model
RIN	Regulatory Information Notices
RIT-D	Regulatory Investment Test – Distribution
SBY	Sunbury zone sub-station
SEPP	State Environment Protection Policy
SHM	Sydenham zone sub-station
ST	Somerton zone sub-station
SWER	Single Wire Earth Return
UG	Underground
VCR	Value of Customer Reliability

1. OVERVIEW

1. The purpose of this document is to identify and explain the following elements of Jemena Electricity Networks' (Vic) Ltd (**JEN's**) capital expenditure (**capex**) forecast for the 2016-20 Electricity Distribution Price Review (**EDPR**):

- The key messages that relate to each capital expenditure category
- The drivers of our forecast capital expenditure by category
- The key projects included in our capital expenditure forecast by category
- How we plan and forecast capital expenditure for each of the capital expenditure categories
- In the case of replacement and augmentation, how we have calibrated our own forecasts using the AER's REPEX and AUGEX predictive models and how they compare to our own forecasts
- How our underlying unit rates for projects and programs have been derived and assessed against independent benchmark rates for reasonableness, and
- How our capital expenditure forecast meets the requirements of rule 6.5.7 of the National Electricity Rules (**NER**).

2. All amounts are presented in 2015 dollar value unless otherwise stated.

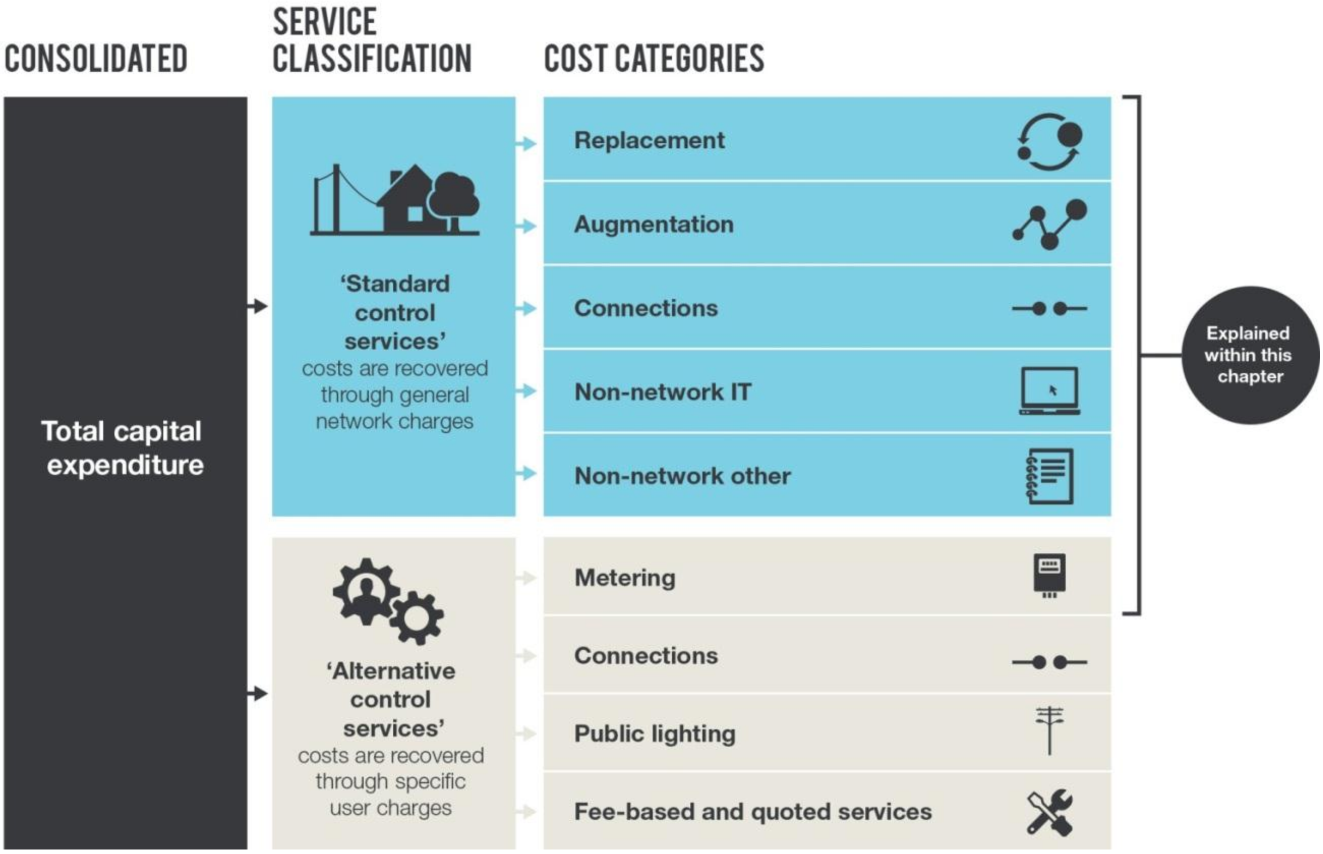
3. The capital expenditure forecast, tables and figures explained within this report reconciles to JEN's capital expenditure forecast model (see Attachment 7-4) and the expenditure is reported inclusive of real cost escalators (unless noted otherwise)(see Attachment 7-13).

1.1 SCOPE OF OUR CAPITAL PROGRAM

4. Our proposed services classification (shown in Box 5-1 of the regulatory proposal) is consistent with the AER's intended classification set out in its Framework and Approach paper. Our proposed classification is also broadly in line with the classification that applied in the 2011 regulatory period[1].

Our standard control services—core distribution network services and new connection services requiring augmentation (including customer initiated connections below 160 MWh annually)—are referred to within this document, (and in the regulatory proposal and attachments) as distribution services. The scope of this attachment is limited to our distribution services (standard control services) and alternative control metering services—referred to within this document, (and in the regulatory proposal and attachments) as metering services (see Figure 1–1).

Figure 1–1: JEN's capital expenditure categories



5. Our regulatory proposal defines alternative control services as 'user pays services'. The expenditure relating to our user pays services is explained in chapter 11 of our regulatory proposal and the associated attachments.

1.2 SUPPORTING CAPITAL EXPENDITURE DOCUMENTS

6. As part of our standard governance process, we have developed a framework of processes and controls to justify our capital expenditure programs to management. These documents are provided as part of our response to the EDPR RIN.[2] The scope and objective of the varying classes of capital supporting documents are explained:

- **Asset class strategies**: explain the approach and principal methods by which each asset class contributes to delivering the Asset Management Objectives as stated in relevant Asset Management Plans, considering the age, criticality and condition profile of the class.

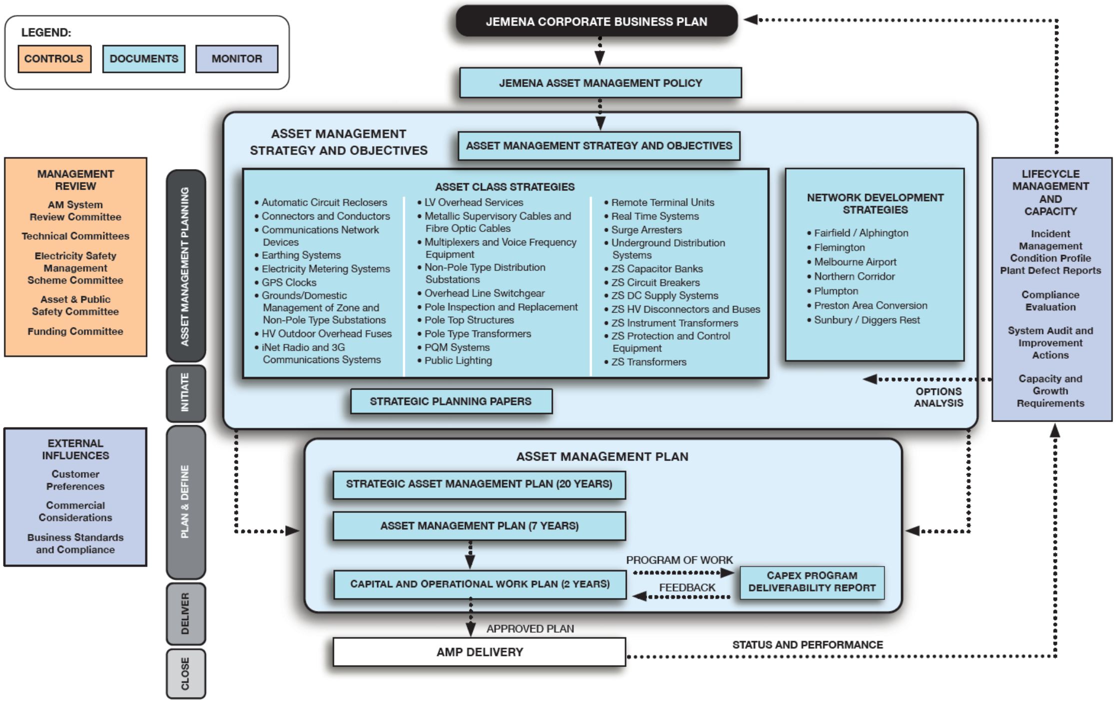
1. In addition to chapter 7 of our regulatory proposal and the corresponding attachments, the end of each sub-section within this attachment includes a table with the reference material for all our corresponding capital expenditure supporting documents provided in response to the EDPR RIN.

The strategies seek to optimise the lifecycle management of the assets and include scenario analysis (e.g. replacement vs. refurbishment, non-network solutions, etc), and demonstrate how the asset management activities for the asset class are to be prioritised or optimised to achieve the Asset Management Objectives.

- **Network development strategies**: present an overview of regional supply capacity risks, outline possible options for economically mitigating these supply risks, and identify the preferred option to manage the forecast risk. These strategies guide the development of our major augmentation capital expenditure and large connection projects.
- **Strategic planning papers**: are capital expenditure governance procedures for managing proposed programs of work in situations where material, incremental increase in expenditure from historical trends. These documents complement the relevant asset class strategy and provide a case to management to understand the drivers for 'above trend' expenditure.
- **Business cases**: substantiate the need and prudency of an investment. A business case is typically created for projects within a two year investment horizon, includes a well-defined scope and determines the strengths and weaknesses of a proposal, in comparison with its alternatives. A business case seeks endorsement and funding for the project from the appropriate JEN stakeholders and approval from the relevant delegated financial authority.
- **IT project investment documents**: these documents present the outline business case for the IT systems lifecycle management on a category by category basis. They detail the nature of the investment, the business needs that it will address and the options that are to be considered at the time the full business case for the project is developed.

7. Figure 1–2 summarises a robust and integrated capital expenditure framework to control and manage expenditure prudently and efficiently.

Figure 1–2: JEN asset management framework



Source: JEN 7-year asset management plan (Attachment 7-5)

2. OVERVIEW OF OUR TOTAL FORECAST CAPITAL EXPENDITURE

8. This section provides:

- an overview of our forecast total gross capital expenditure for the 2016-2020 regulatory control period (**2016 regulatory period**)
- our forecast program of capital works by category
- details of our forecast new major network assets
- context of the overall program of capital works.

Total forecast gross capital expenditure by category ($2015, $millions)

Distribution services

In the 2016 regulatory period we propose to spend $841.2m in total gross capital expenditure to provide distribution services, 20% more in real terms than we expect to spend in the 2011 regulatory period. Of that amount, we propose to spend:

- $293.5m replacing the assets that are in poor condition and have exceeded their useful life
- a gross amount (before reducing for contributions) of $227.8m to connect new customers, augment existing connection sites
- $182.7m to augment areas of the network that are forecast to experience above trend peak demand growth and where the asset is over-utilised
- $101.9m on maintaining the lifecycle management of our IT systems, programs and software. Our IT expenditure includes some capex associated with AMI being re-categorised into distribution services, and
- $35.3m to maintain our fleet, property and tools and equipment.

Metering services

We incur metering expenditure to provide distribution network and user-requested services for customers consuming less than 160 MWh annually (see chapter 5 for detail on service classification). We have allocated metering expenditure to either standard control or alternate control services using an activity based method.

Now that we have completed our smart meter rollout program, we have forecast total capital expenditure for metering services of only $15.3m for the 2016 regulatory period, which is 90% lower than we expect to incur in the 2011 regulatory period.

2.1 TOTAL FORECAST CAPITAL EXPENDITURE

2.1.1 THE PROGRAM

9. Capital expenditure investments are costly and the impacts are enduring. Therefore it is important to make the right investment decisions because they affect the level of services, costs and our prices our customers receive over a long period. We have developed a capex program necessary to deliver the service levels that our customers expect now, and into the future.

10. Our proposed capex for the 2016 regulatory period is $841.2m ($2015). This is an increase of $138m, or 20% relative to the amount of capital expenditure we expect to spend in the current 2011 regulatory period and reflects an increase of 52% relative to the amount that the AER approved for that period (see attachment 7-1).

11. Table 2–1 and Figure 2–1 provide our total forecast gross capital expenditure for the 2011-2015 regulatory control period (**2011 regulatory period**) and 2016 regulatory periods, compared against our allowance, including the amount of metering capital expenditure reclassified to distribution services.

Table 2–1: Actual and forecast distribution services gross capital expenditure over the 2011 and 2016 regulatory periods ($2015, $millions)

Distribution services gross capex	2011 and 2016 regulatory periods											
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total EDPR 11	Total EDPR 16
Actual / forecast capex	148.2	133.0	129.5	137.9	154.6	157.6	182.4	176.3	164.8	149.7	703.2	830.8
Regulatory allowance	112.0	109.7	109.8	115.3	105.8	n/a	n/a	n/a	n/a	n/a	552.6	-
Service reclassification	-	-	-	-	-	0.6	1.2	0.8	2.8	4.8	-	10.3

Figure 2–1: JEN gross capital expenditure – 2016-20 forecast vs 2011-15 actual/estimate ($2015, $millions)

(1) Service reclassification refers to the portion of metering IT capital expenditure allocated to standard control services

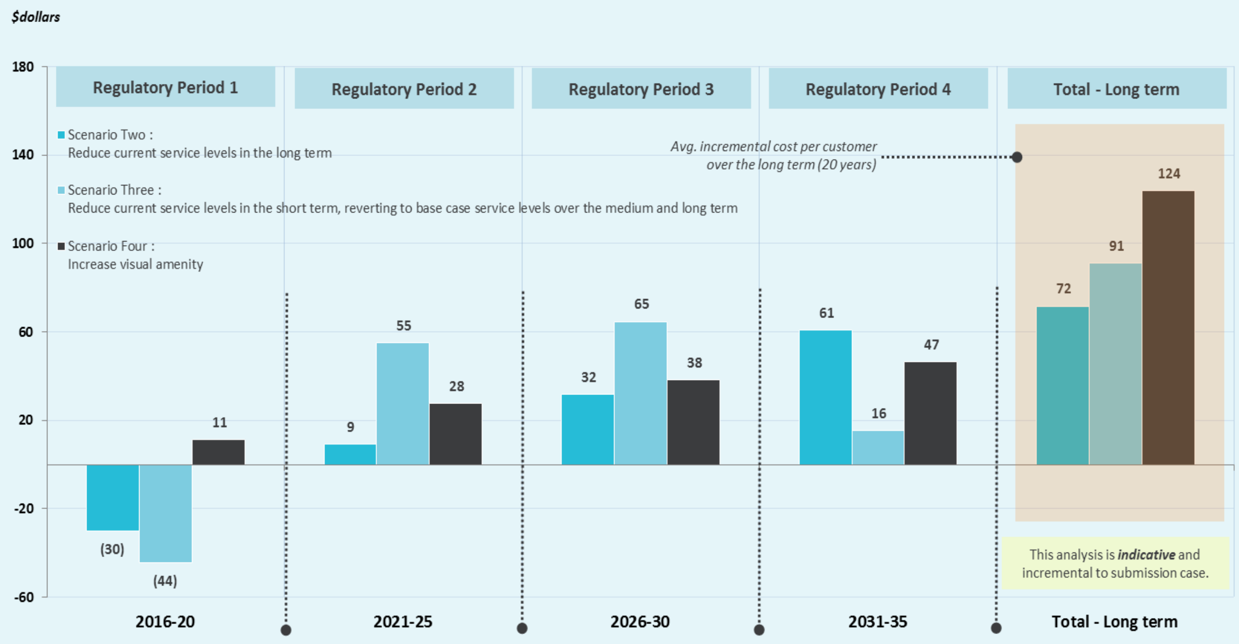
12. We have carefully prioritised our proposed investments to ensure the optimal timing of each investment is planned, in order to deliver services at the lowest sustainable cost to our customers over the long term.

13. As described in our proposal and summarised in our 20-year strategic asset management plan (**SAMP**) (see Attachment 7-6), we have analysed a number of alternative scenarios relative to the one that forms the basis of our proposal which concludes that our proposed program delivers the most preferable long-term outcome for our customers—see Box 2-1. The customers and customer representatives that have engaged with us on our forecasts support this view by seeking to maintain high safety standards and maintaining service and performance levels (see Attachment 4-1).

Box 2-1 Scenario analysis for our 20 year strategic asset management plan

Attachment 7-6 of our proposal presents our SAMP. Section 10.2 includes scenario analysis where we assessed changes in operational and capital expenditure and the impacts on JEN's average cost per customer over the long term. The scenarios used to assess the approach were based on varying service levels or investments in visual amenity. See Figure 2-2.

Figure 2–2: Incremental cost per customer $2015, $dollars relative to scenario one



Source: *Attachment 7-6, 20 year Strategic Asset Management Plan, p93*

Figure 2-2 indicates that despite some reductions in the short term only, all the scenarios tested lead to increases in average cost per customer over the long term, relative to scenario one—capital and operating expenditure balanced to maintain current service levels.

This demonstrates that we have optimised our program design having considered the long term effect of our investments on our customers.

2.2 THE KEY AREAS OF OUR CAPITAL EXPENDITURE PROPOSAL

14. In this section we outline our forecast total gross capital expenditure by category.

2.2.1 CAPITAL EXPENDITURE CATEGORIES

15. Our proposed capital program for the 2016 regulatory period aligns with the capital expenditure categories set out in the AER's category analysis and EDPR RINs. Our forecast is provided by the following expenditure categories:

- Replacement expenditure
- Augmentation expenditure
- Connections expenditure
- Non-network IT expenditure
- Non-network other expenditure.

16. Table 2–2 summarises our 2016 regulatory period forecast gross capital expenditure by expenditure category by year.

Table 2–2: Forecast capital expenditure by category ($2015, $millions)

Gross distribution services capex	2016	2017	2018	2019	2020	Total
Replacement expenditure	49.26	51.76	50.30	69.00	73.16	293.48
Augmentation expenditure	25.44	60.64	52.40	30.64	13.58	182.69
Connections expenditure	45.07	44.24	48.07	43.60	46.83	227.80
Non-network IT expenditure	21.36	22.98	22.28	18.44	16.84	101.90
Non-network other expenditure	17.12	4.03	4.07	5.93	4.15	35.29
Total distribution services expenditure	**158.24**	**183.64**	**177.13**	**167.60**	**154.56**	**841.17**

17. Our forecast metering services capital expenditure represents the prudent and efficient costs required to provide ongoing advanced metering infrastructure (**AMI**) services to our customers. Table 2–3 sets out our proposed forecast metering services capital expenditure for the 2016 regulatory period.

Table 2–3: Metering services capital expenditure ($2015, $millions)

Metering services expenditure	2016	2017	2018	2019	2020	Total
Metering services expenditure	2.41	2.54	2.80	2.94	4.60	15.29

2.3 JEN FORECAST SUPPLY AREA: NEW MAJOR NETWORK ASSETS

18. Table 2–4 provides descriptions of major network developments proposed within the 2016 regulatory period. We have categorised major network developments as individual projects with an estimated total capital expenditure of $2m or greater. The major network developments we have proposed for the 2016 regulatory period are shown on Figure 2–3, the JEN Forecast Supply Area: 2016-2020 map, with the location of works depicted by the Project Reference Number presented in Table 2–4.

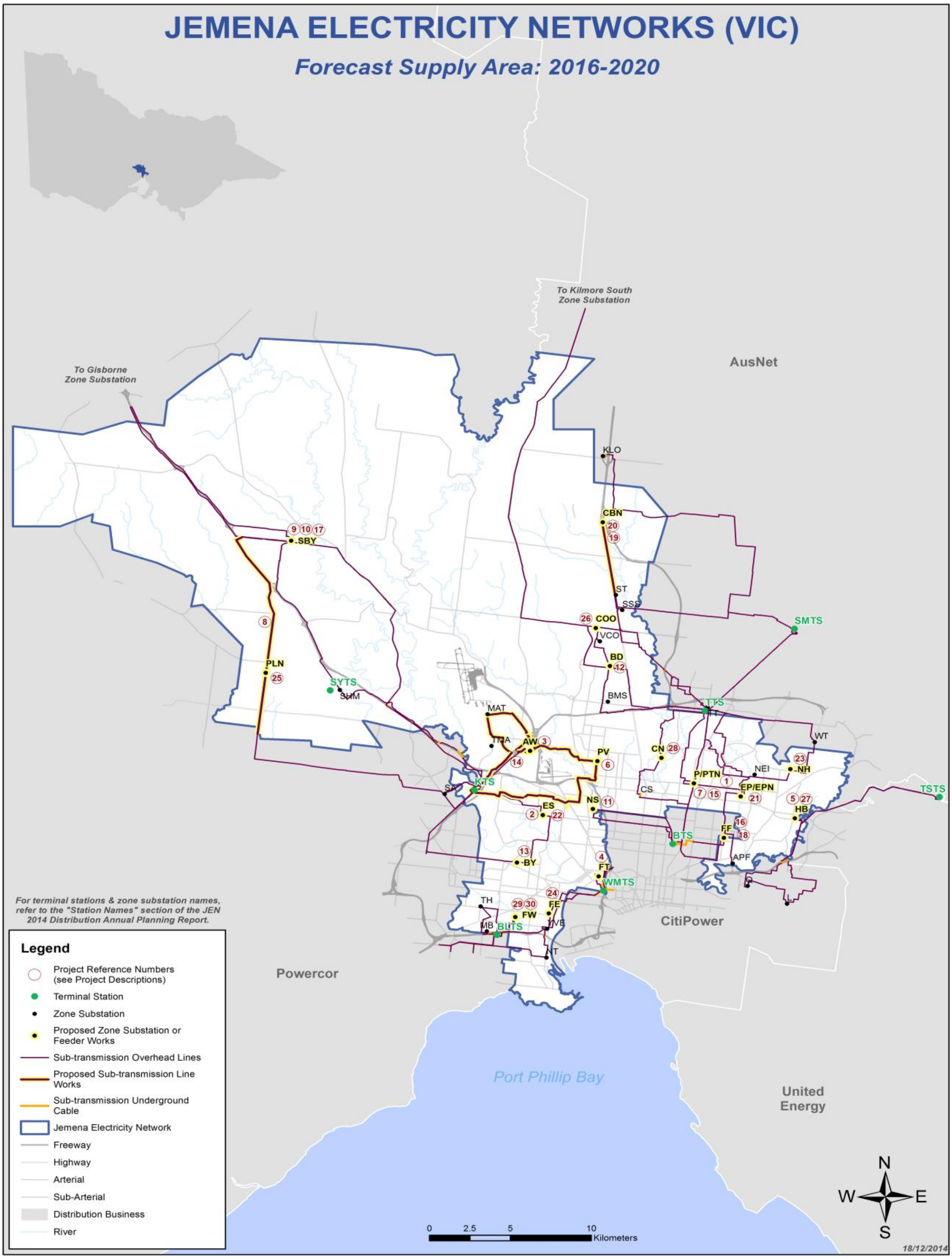
Table 2–4: Project descriptions for JEN forecast major projects

Project Reference Number[3]	Project Description	2014 DAPR section reference
Major network developments proposed in 2016		
1	Stage 4 of Preston area and East Preston area conversions	5.4.8 and 5.4.20
2	Reconfigure ES-23 feeder loads	5.4.9
3	Replace relays at Airport West (**AW**) zone substation	5.4.1
Major network developments proposed in 2017		
4	Redevelop Flemington (**FT**) zone substation by replacing FT 11kV transformer	5.4.11

3 See map JEN Forecast Supply Area: 2016-2020

Project Reference Number[3]	Project Description	2014 DAPR section reference
	cables and installing three new 11kV buses at FT	
5	Install a new Heidelberg feeder (HB-21)	5.4.14
6	Install a new Pascoe Vale feeder (PV-11)	5.4.19
7	Stage 5 Preston area conversion	5.4.20
8	Purchase No.2 Keilor Terminal Station (**KTS**)-Melton-Sunbury 66kV line	5.5.8
9	Purchase Sunbury zone substation site land	5.4.22
10	Install Rapid Earth Fault Current Limiter (**REFCL**) at Sunbury	5.4.22
11	Replace North Essendon zone substation transformers	5.4.17
12	Replace relays at Broadmeadows	5.4.3
Major network developments proposed in 2018		
13	Install two 8 MVAR capacitor bank at Braybrook	5.4.2
14	Split KTS-Melbourne Airport-AW-Pascoe Vale-KTS 66kV loop	5.5.7
15	Stage 6 Preston area conversion (establish PTN)	5.4.20
16	Increase Fairfield (**FF**) thermal capacity	5.4.10
17	Redevelop Sunbury zone substation	5.4.22
18	Replace FF transformers	5.4.10
Major network developments proposed in 2019		
19	Establish a new zone substation in the Craigieburn area (**CBN**). Includes establishing an Somerton-CBN 66kV double circuit line and four CBN feeders	5.4.7 and 5.4.21
20	Install REFCL at CBN	5.4.7 and 5.4.21
21	Stage 5 East Preston area conversion	5.4.8
22	Replace Essendon zone substation transformers	5.4.9
23	Replace relays at NH	5.4.18
24	Replace 22kV switchgear at FE	5.4.12
Major network developments proposed in 2020		
25	Purchase land for future establishment of Plumpton Zone Substation (PLN). Note that a specific site is yet to be identified and map location is therefore indicative only	5.4.23
26	Install REFCL at COO	5.4.7
27	Replace HB transformers	5.4.14
28	Replace relays at CN	5.4.5
29	Replace relays at FW	5.4.13
30	Replace 22kV switchgear at FW	5.4.13

Figure 2–3: JEN forecast supply area – new major network assets



Source: JEN's geospatial information system (February 2015)

3. FORECAST CAPITAL EXPENDITURE BY CATEGORY

19. For each of the forecast capital expenditure categories listed in 2.2.1, this section explains:

- The drivers of our forecast capital expenditure
- How we plan or forecast capital expenditure
- Details of the key projects included in the forecast capital expenditure category
- In the case of augmentation and replacement, how our forecast aligns with the AER's predictive modelling techniques of required capital expenditure, and
- Provides a reference list of confidential internal capital expenditure supporting documents, provided in response to our EDPR Regulatory Information Notice (**RIN**).

3.1 REPLACEMENT CAPITAL EXPENDITURE

20. Replacement capex is the largest component of our forecast capital expenditure for the 2106 regulatory period and relates to replacing existing network assets with their modern equivalent.

3.1.1 KEY MESSAGES

Key messages for our replacement capital expenditure are:

- Our network is aging. A large proportion of our assets were installed in the 1960's and so with our assets coming to the end of their technical and economic lives we are entering the initial phase of a long term replacement cycle that we expect to extend across the next three regulatory control periods.
- Our replacement capital expenditure forecast has been developed with detailed knowledge of our asset base, including the condition of the existing assets through actual condition monitoring and lifecycle optimisation.
- Our forecast volumes are those required to maintain reliability at current levels and to arrest the trend in increasing asset failure rates. Our decisions to invest in asset replacement activities affect the level of services, cost and prices over a long time
- We have developed our replacement capital forecasts by optimising our replacement expenditures and ensuring there is no overlap and duplication between expenditure proposed under other capital expenditure categories (particularly between replacement and augmentation)
- We apply best practice techniques to accurately assess the replacement needs of our network including Condition Based Risk Management (**CBRM**) asset health modelling and net economic cost benefit analysis—in addition to industry standard condition assessment tools.

21. Our total forecast replacement capital expenditure for the 2016 regulatory period is provided in Table 3–1.

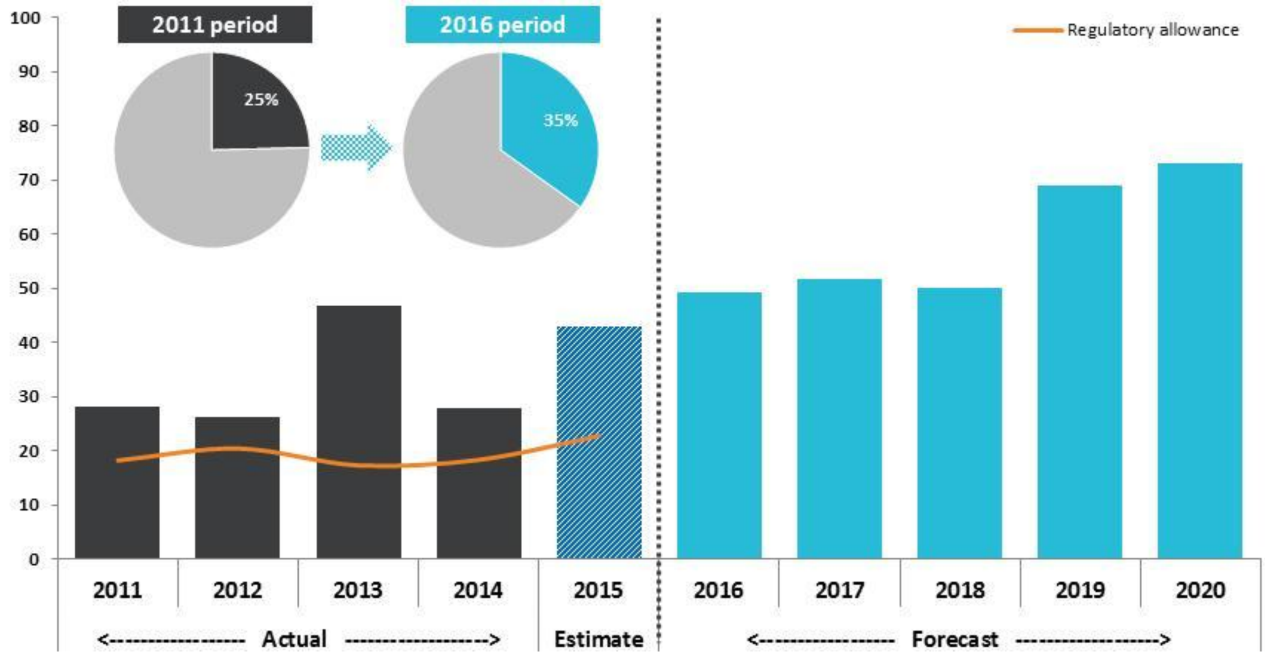
Table 3–1: Total forecast replacement capex 2016-2020 ($2015, $millions)

Total replacement capex	Forecast regulatory period				
	2016	2017	2018	2019	2020
Total replacement capex	49.26	51.76	50.30	69.00	73.16

(1) Replacement capital expenditure excludes public lighting

Figure 3–1 shows the increasing profile in replacement capital expenditure relative to the current 2011 regulatory period. In the context of deteriorating and aging assets that will eventually fail, we propose a 70% increase in replacement capital expenditure to maintain safety and service levels in the 2016 regulatory period, relative to our expenditure in the 2011 regulatory period.

Figure 3–1: Replacement capital expenditure 2011 to 2020



22. Replacement works are planned and undertaken typically by asset class so the lifecycle management of a class of assets can be optimised and planned into programs of work. Below is a list of the asset classes that make up our proposed replacement expenditure. These asset classes reconcile with those in our 7-year asset management plan (see Attachment 7-5) and in our response to the category analysis and EDPR RINs:

- Poles
- Pole top structures
- Service lines
- Overhead (**OH**) conductors
- Underground (**UG**) cables
- Transformers
- Switchgear
- SCADA / Network control and protection systems

- Other.

23. The timing of required replacement expenditure is an important decision and is influenced by:

- The maintenance and operating costs of the asset
- Its performance (e.g. asset reliability)
- The risks associated with its failure (e.g. safety, environmental)
- The associated network performance (e.g. power quality, network reliability), and issues associated with the management of the asset.

The prudence and efficiency of our expenditure program is supported by our proposed timing ('not too early and not too late')(see Box 2-1), ensuring that we are able to mobilise our resources, provide appropriate lead times for planning and communication, and enabling effective and efficient delivery. We have considered how best to optimise the timing of our proposed replacement expenditure with targeted investments, guided by our detailed delivery strategy (see Attachment 7-8).

3.1.2 DRIVERS OF FORECAST REPLACEMENT EXPENDITURE

24. There are two key drivers underpinning the increase in our forecast replacement capital expenditure:

1. **Network condition and safety** – A number of our asset classes have recorded an increase in the number of asset failures during the 2011 regulatory period—this is to be expected given we are entering a replacement phase of our asset base lifecycle. However, this trend has increased the safety risk and so we must increase replacement expenditure in these areas in accordance with our Electricity Safety Management Scheme (**ESMS**) to arrest this degradation and address issues raised by ESV. We are also continuing to deliver our bushfire mitigation programs.
2. **Network performance** – Our network is aging and consequently we will need to increase replacement capital expenditure to ensure reliability, security and safety is maintained and does not degrade over the 2016 regulatory period.

25. In this section, we discuss these key drivers and explain why an increase in our forecast replacement expenditure is necessary.

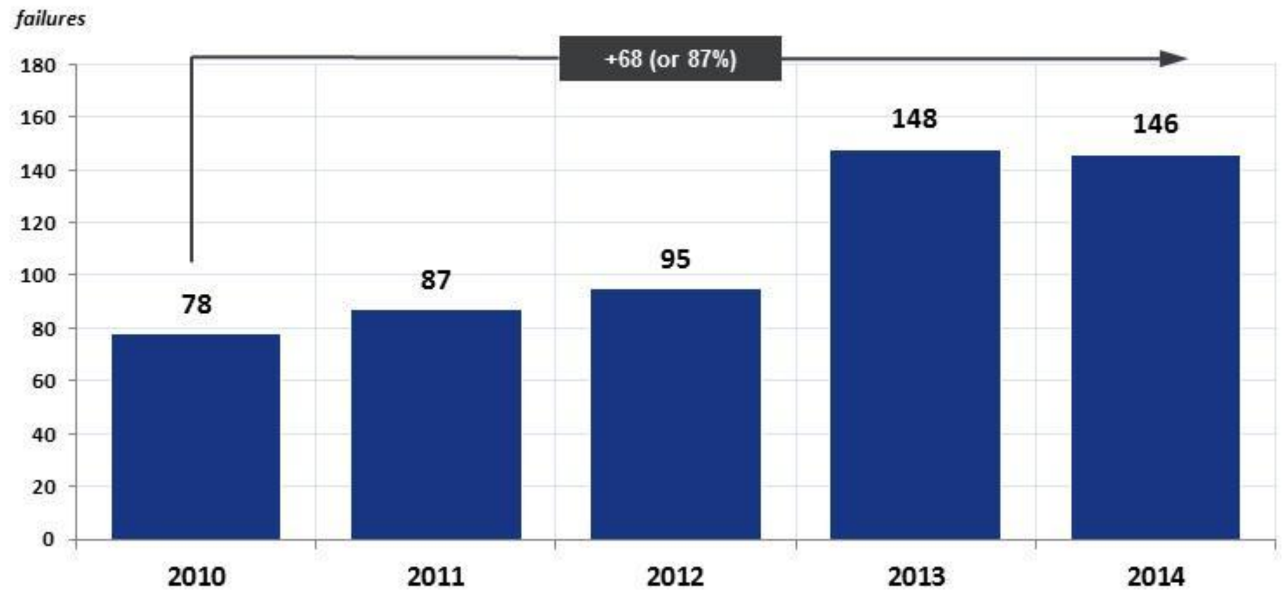
3.1.2.1 Network condition and safety

26. To understand the need to increase replacement capex, it is important to first understand what has been achieved by our historical replacement levels. This indicates whether these levels represent an appropriate base from which changes should be considered i.e. did historical levels of capital expenditure improve, maintain or degrade performance.

27. A useful measure here is condition-related asset failures and the consequences of these failures. Figure 3–2 shows the historical profile of condition-related asset failures[4]. The chart suggests that condition-related asset failures have been trending upwards, particularly in the latter half of the 2011 regulatory period.

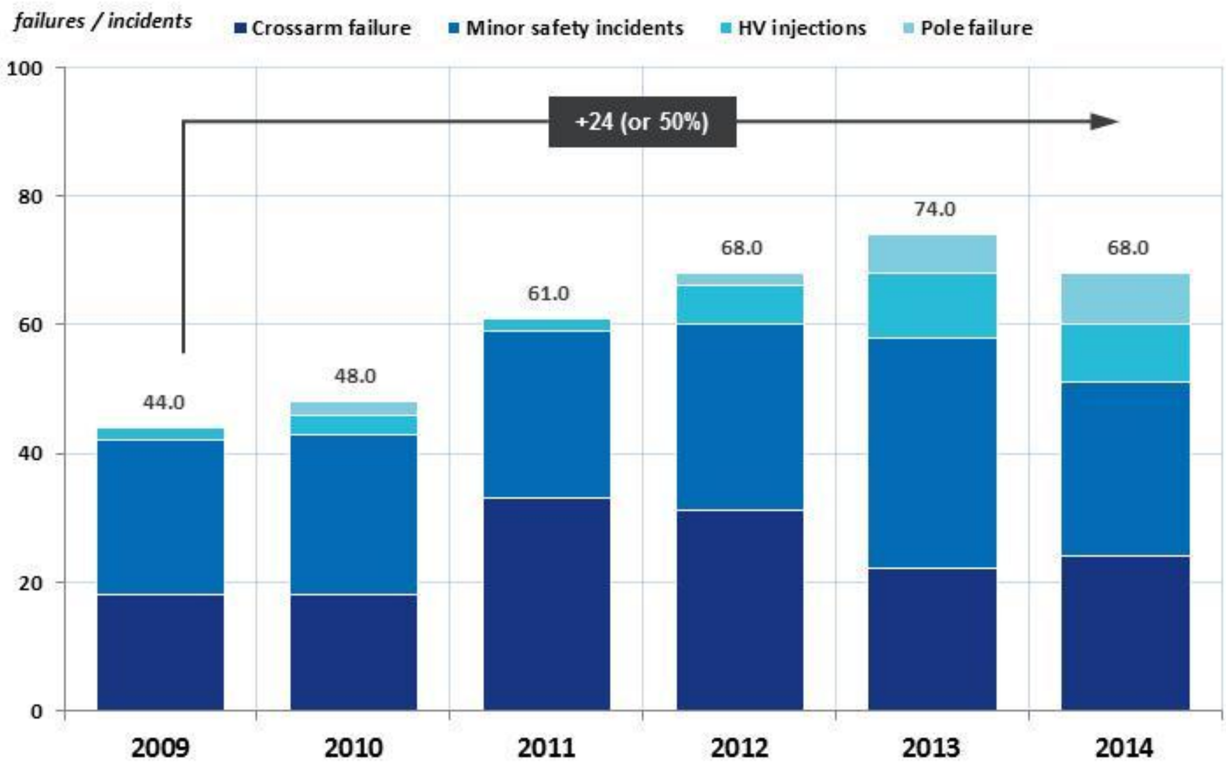
[4] RP-RC-JLA-2014-153, Jemena Electricity Networks 11 Year Incident Analysis 2003-2014, August 2014

Figure 3–2: Condition-related asset failures and incidents



28. Importantly, these failures tend to correlate more to safety hazards rather than reliability incidents. The areas where the safety hazards are most notable are pole and crossarm failures, pole top fires and safety incidents due to failed service lines. The profile of these three failure types is shown in Figure 3–3.

Figure 3–3: Condition-related asset failures by asset type



29. In its latest electrical safety report into 2013 performance, ESV noted this trend and raised its concerns. It has stated that the "number of pole top structure failures needs to be reduced if the Victorian distribution network is to achieve world's best practice".[5]

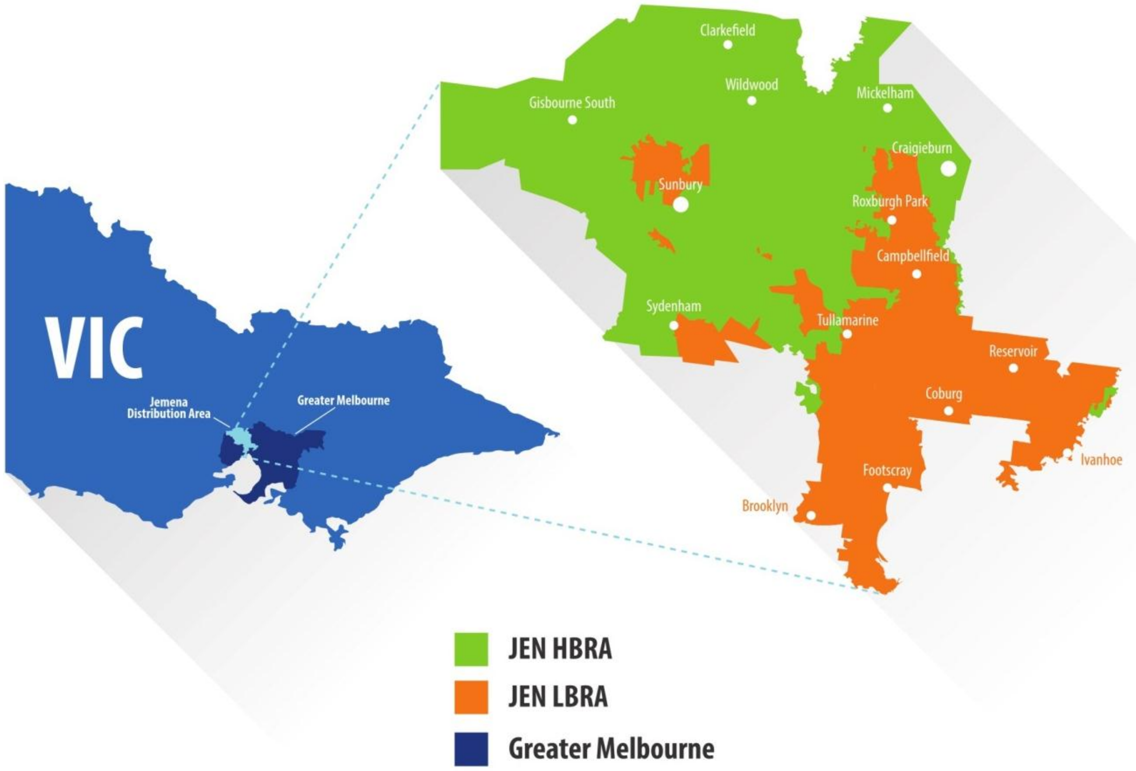
30. This suggests that historical replacement levels have not been sufficient to maintain the integrity of our network. Therefore, even if the effects of asset aging were relatively static, we still need to increase our asset replacement expenditure compared with historical levels to arrest a further decline.

Bushfire mitigation

31. Many of our key safety based replacement programs are related to our bushfire mitigation programs. Figure 3–4 reveals the proportion of our network that is considered a hazardous bushfire risk area (**HBRA**), relative to the rest of the network—low bushfire risk area (**LBRA**).

5 Energy Safe Victoria, *Safety Performance Report on Victorian Electricity Networks* 2013, p8

Figure 3–4: Bushfire risk areas of our network



Source: JEN

32. The HBRA (highlighted in green) is predominantly rural and covers approximately 63% of our distribution network service area. The key bushfire mitigation capital replacement (excluding operating expenditure) programs[6] that have been completed in the 2011 regulatory period are:

- Installing vibration dampers and armour rods in the HBRA
- Retiring all the Single Wire Earth Return (**SWER**)
- Replacing steel conductor
- Replacing neutral screened service lines
- Replacing non-tension connectors and surge diverters
- Replacing all HV wooden cross-arms
- Installing animal proofing of structures; and
- Replacing HV fuse units.

33. In the 2016 regulatory period the key bushfire mitigation replacement programs include:

- Removing LV open wire mains

6 These programs include those mandated by the Victorian Bushfire Royal Commission (removing SWER and installing vibration dampers and armour rods) and recommended by the Victorian Bushfire Safety Taskforce and ESV.

- Replacing steel conductor;
- Installing Rapid Earth Fault Current Limiters (REFCL); and
- Redeveloping Sunbury zone substation.

34. These targeted programs seek to minimise the fire risk associated with our assets and will ensure we continue to maintain the safety of our customers, community and staff and the reliability of our services.

3.1.2.2 Performance of the network

> *"…age is rarely the sole basis for any of our replacement decisions; the actual condition of the asset is far more important to us…"*
>
> ***JEN's Electricity Asset Investment Manager***

35. Assisted by the fact we are a relatively small network, we have a detailed understanding of the most important driver of our replacement capital expenditure—the actual condition of our assets. Some useful asset performance measures we apply that link to the condition of our assets are asset age and the trend in asset failures.

36. The need for this type of replacement activity is typically due to aging mechanisms that wear and degrade the condition of our assets.

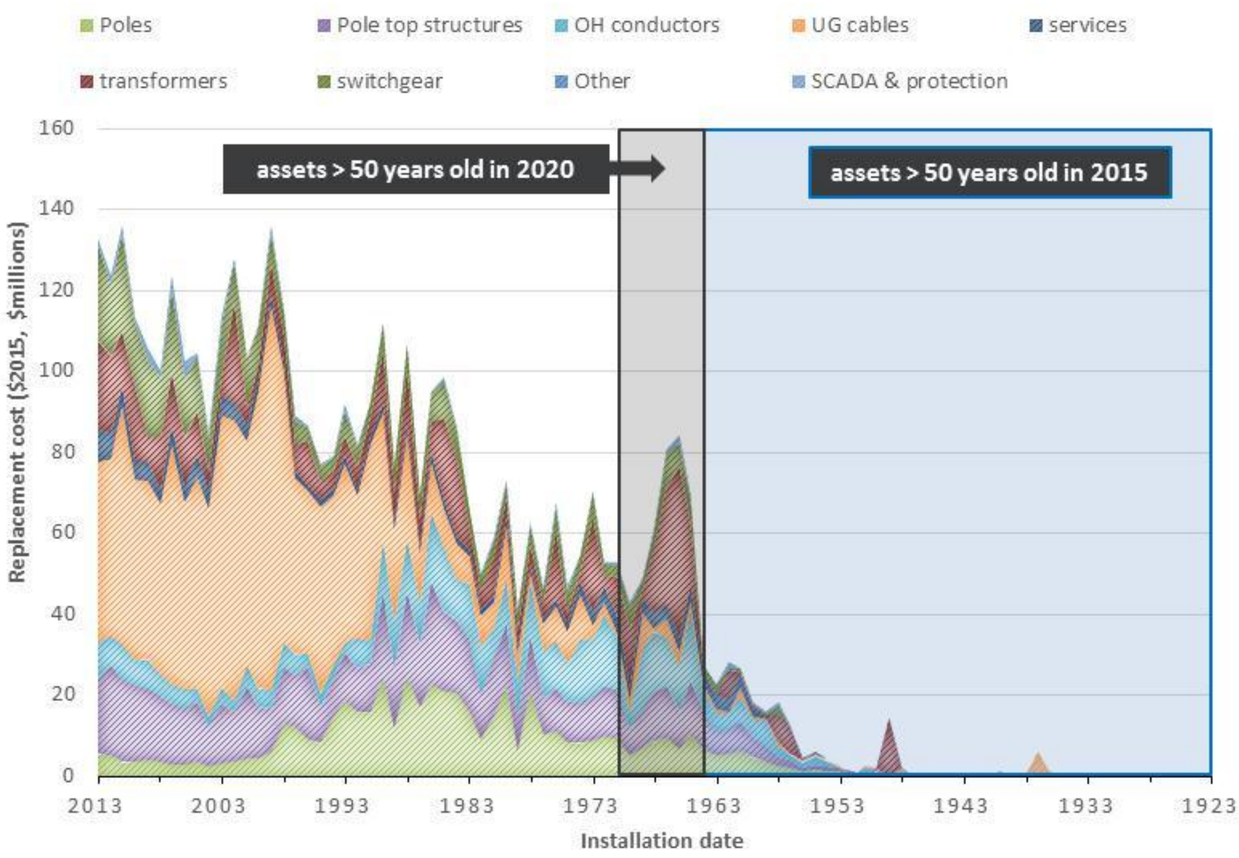
37. If an asset fails, then depending on its role the reliability of our services often reduces (e.g. our customers may lose supply). Until the asset is replaced, the security of these services will also be reduced, as any further failure could result in a more widespread disruption of services. But, more importantly, depending on the mode of failure or the role of the asset, a major failure can result in safety hazards to the public and our personnel. For example, much of our network is overhead and so a major failure of an asset (e.g. a pole failing and falling to the ground) could injure the public or start fires. Because of these safety issues, many of our replacement programs form critical components of our ESMS (which is overseen by ESV).

38. Age is rarely the sole basis for any of our replacement decisions; the actual condition of the asset is far more important. Nonetheless, the age of the asset base is still a useful indicator of the likely condition of assets, and so, changes in the age of our assets suggest the likely changes in future condition-related replacement needs. Accordingly, asset age is used as an indicator for our own replacement planning purposes.

39. It is therefore useful to consider the age and condition of the network moving forward to gauge how this is driving the necessary changes to current replacement levels in order to maintain reliability, security and safety.

40. Figure 3–5 shows the age profile of our network. This profile reflects the undepreciated replacement cost of the network. The chart reveals a steeply rising profile from around the early 1950s, which indicates that the cost to replace our assets as they age is also increasing sharply. Figure 3–5 also indicates the proportion of our network that will surpass 50 years old by 2020, which includes a spike in transformer replacements (represented by the red shaded area).

Figure 3–5: Network replacement cost vs asset age profile



Source: *JEN analysis* (March 2015*)*

(1) This age profile has been developed from the REPEX templates within our Category Analysis RIN which were submitted to the AER on 26 August 2014.

41. The network age profile in Figure 3–5 indicates that due to the a sharp increase in the number of assets that will exceed 50 years old within the 2016 regulatory period, an increase in replacement expenditure is required and should not be unexpected.

42. This supports our claim that we are in the initial phase of a significant long-term replacement cycle. The fact that our 2011 regulatory period replacement capex is only around $35-$40m per year also supports the proposition that we are only in the early stages of this replacement cycle. Therefore, it is not surprising that the aging of our network is driving increasing levels of replacement. Although we may expect some smoothing of this profile as assets reach the end of their life, and some reduction through the need to replace due to other drivers (e.g. augmentation), the shape of the profile at this leading edge indicates that an increase over the 2016 regulatory period from current levels is reasonable.

Box 3-1 Condition Based Risk Management (CBRM)

We apply Condition Based Risk Management (**CBRM**) assessments to ten classes of our primary assets which provide helpful forward-looking measures of asset condition, via a ‘health index’ metric, expected numbers of failures, and economic risk values, which are relatively comparable between asset classes.

CBRM models provide a useful tool to both demonstrate the effects of aging and to assess how our replacement forecasts will affect the reliability, security and safety of the network.

A useful output measure from these models is the expected number of major asset failures in the population. That is, if the expected number of asset failures predicted by the model is decreasing (or increasing) then it is reasonable to conclude that the replacement program will improve (or worsen) reliability, security and safety (as these are all linked to the number of failures).

We provide further detail of our CBRM modelling in section 3.1.3.

3.1.3 REPLACEMENT EXPENDITURE EXPLAINED

43. In the following sections we present our forecast replacement expenditure by **capex category**[7] and compare the forecast expenditure to actual expenditure in the 2011 regulatory period. Expenditure in sections 3.1.3 to 3.1.5 includes forecast labour and material price changes and excludes overhead cost which is consistent with how expenditure is reported in the Category Analysis RINs[8].

Table 3–2: Total replacement expenditure 2016-2020 by sub-category ($2015, $millions)

Total replacement expenditure	2016	2017	2018	2019	2020	Total
Poles	2.24	4.30	5.95	8.47	9.60	30.56
Pole top structures	9.39	8.84	9.05	9.49	10.04	46.82
Overhead conductors	2.80	3.22	2.66	2.75	2.93	14.35
Underground cables	2.34	2.48	2.52	3.21	4.04	14.60
Service lines	3.33	4.18	4.34	6.62	9.31	27.79
Transformers	6.23	10.68	12.30	8.99	5.82	44.04
Switchgear	2.03	1.52	2.31	7.05	8.09	21.00
SCADA, network control & protection systems	9.27	6.54	2.17	11.62	12.07	41.67
Other	11.62	10.00	8.99	10.79	11.25	52.65
Total	**49.26**	**51.76**	**50.30**	**69.00**	**73.16**	**293.48**

(1) values include forecast labour and material price changes and exclude overheads

44. Figure 3–6 shows the total aggregate forecast in each asset class over the 2016 regulatory period compared to our estimate for the 2011 regulatory period. Importantly:

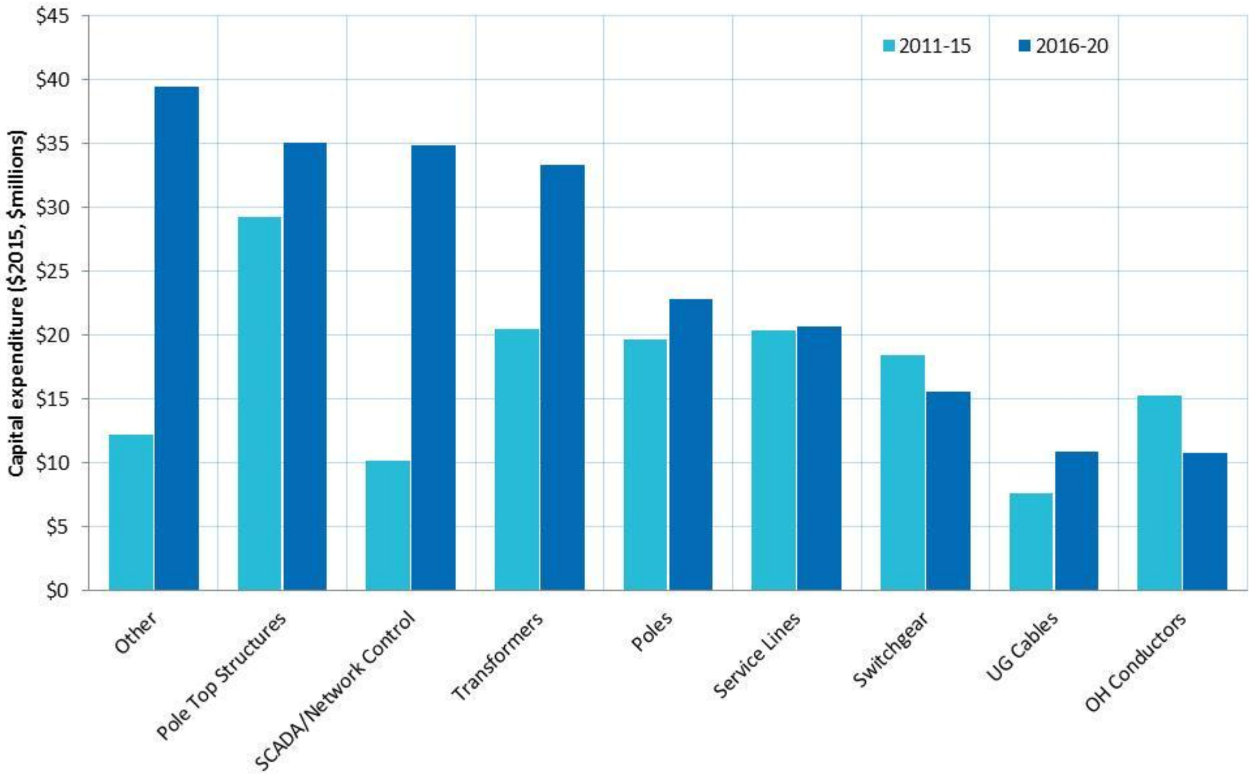
- We have forecast increases in pole top structures, SCADA/network control, transformers and other asset classes, relative to the expenditure we expect to spend in the 2011 regulatory period. Our asset condition monitoring and age profiling indicate these asset classes require an incremental increase in expenditure to ensure the safety of our system and our services are maintained.

7 As outlined in the RIN served on JEN dated 2 Feb 15

8 As outlined in the RIN served on JEN dated 7 Mar 14

- 64% of the 'other' asset class relates to services which have been reclassified[9] and grouped by JEN under other asset classes.

Figure 3–6: Replacement forecast – AER asset classes (values exclude overheads)



45. A logical grouping of these cost categories based on drivers is as follows:

- poles (excluding public lighting) and pole top structure classes—many of the issues behind these programs are similar;
- service lines, transformers, SCADA/protection/control, switchgear and other asset classes—these classes have increases driven by different factors; and
- overhead conductors and underground cables—focus only on the major projects within these classes, as these are forecasting less significant increases

3.1.3.1 Poles and pole top structures (excluding public lighting poles)

46. The poles and pole top structures classes represent the largest component (by expenditure) of our replacement capex over the 2016 regulatory period, at 26% or $58 million of our total REPEX. This forecast represents an 18% increase in REPEX from the 2011 regulatory period - see Figure 3–7.

47. Pole and pole top structures forecast replacement capex for the 2016 regulatory period is provided in Table 3–3.

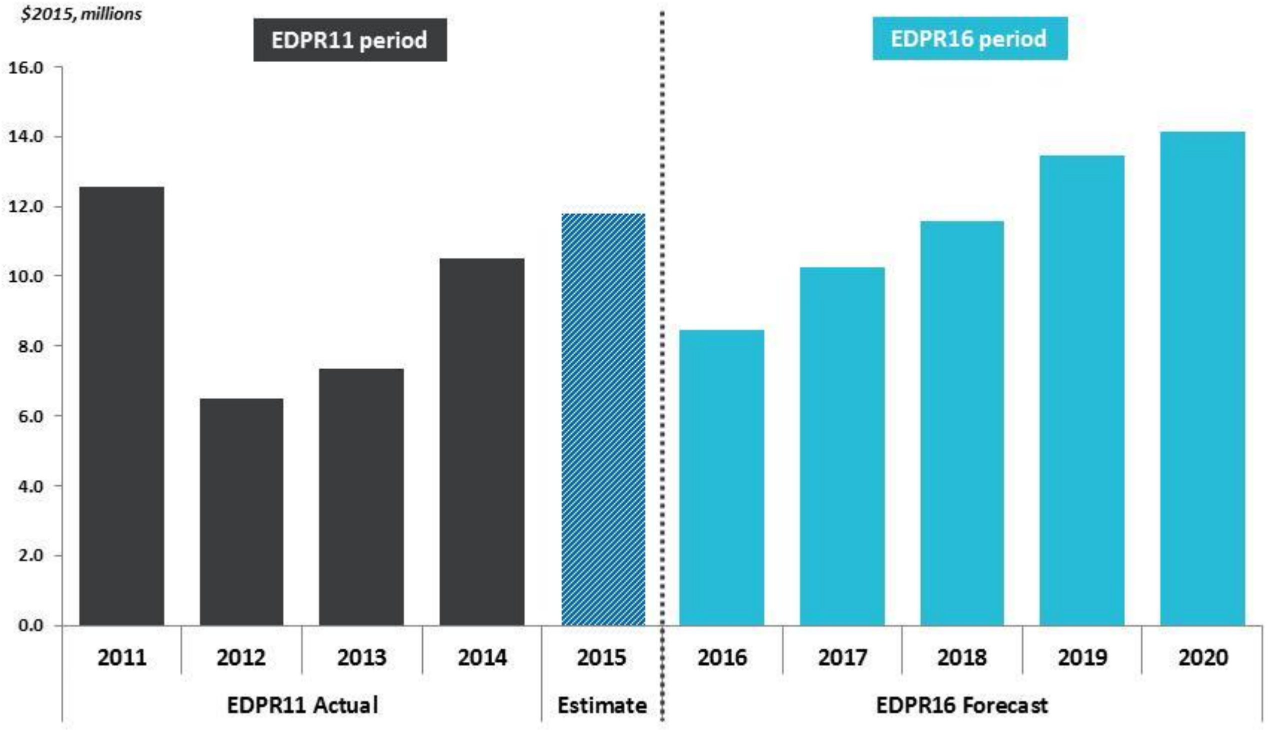
[9] Refer to Attachment 5-1.

Table 3–3: Capex for poles (excluding public lighting poles) and pole top structures asset classes 2016-20 ($M, real $2015)

Poles and pole top structures	Forecast regulatory period				
	2016	2017	2018	2019	2020
Replacement capex	8.46	10.28	11.60	13.46	14.15

(1) values include forecast labour and material price changes and exclude overheads

Figure 3–7: Capital expenditure for poles (excluding public lighting) and pole top structures 2011-20 ($2015, $millions)



48. These two categories cover the replacement of the poles, pole top structures and the associated hardware that supports the overhead conductors of our LV, HV and sub-transmission network.

49. Poles and pole top structures represent two of our highest volume asset classes and are also two of our most critical. The failure of a pole or pole top structure can cause serious safety hazards due to the risk of injuring the public and starting fires. Therefore, all failures of poles and pole top structures are reported to ESV and our replacement plans for these two categories form an important element of our ESMS.

50. Since the 2009 bushfires, the subsequent Royal Commission and in accordance with the enhanced requirements that came from that review, we have increased our inspection and replacement activities for poles and pole top structures which have contributed to the increase in capital expenditure for this category in the 2011 regulatory period. However, as indicated in Figure 3–3, our increased investment in these areas has not yet arrested the increasing trend in failures.

51. The following sections provide further details of these asset populations, the replacement programs, and the key drivers of the planned increases.

Poles

52. We own approximately 98,000 poles. The majority of these are wooden (60,000). We also have approximately 17,000 steel poles, which are typically used for public lighting and the remainder are concrete. Our replacement programs are aimed at the proactive replacement (or reinforcement) of wood and steel poles and does not cover public lighting.[10]

53. There are two sets of replacement programs that are aimed at addressing two different issues with our poles:

- Condition-based replacement (and reinforcement); and
- Non-standard design replacements (and reinforcement).

Condition-based replacement (and reinforcement) programs

54. The first, and most significant set of programs, concerns our ongoing programs to address poles that have reached the end of life and can no longer be maintained economically. These are typically identified though our routine pole inspections. These programs account for 74% of our replacement capex in the poles category (excluding public lighting categories) program.

55. The need for this set of programs is due to the aging mechanism of poles, whereby poles will deteriorate or corrode over time because of the environment that they are located in (e.g. wood poles rot). We have treatment processes to slow these affects, but ultimately the condition of a pole will deteriorate to a point where it no longer meets our minimum mechanical loading standards.[11]

56. Poles in this condition pose significant safety hazards to the public as they may fail under reasonably common conditions (e.g. wind loadings). Therefore, poles identified in this condition are planned for replacement or reinforcement within set timeframes. The reinforcement of a pole, via pole staking, is our preferred method of addressing this issue as it provides a much more cost effective method of extending the service life of a pole.[12] However, reinforcement is not always possible, and in some cases a pole must be replaced.[13]

57. The condition-based replacement programs are ongoing. The key driver underlying the need for increases in these programs is the continuous aging of our pole population. A large volume of poles installed in the 1960's are entering their end of life, which is causing greater volumes of poles to be found to be below the minimum standards. This situation is compounding as the size of the network has grown over time increasing the number of poles that require replacement.

58. With regard to the ongoing aging of the population, there are a range of factors that support a view that there will be significant increases in the volume of poles to be found to be in an unserviceable condition.

59. An analysis of the age of wooden poles that have been replaced due to being unserviceable has identified that the average age of a wood pole when replaced is 39.4 years. It is therefore likely that the average age of a wooden pole at the end of its useful life is considerably lower than the nominal lives shown in Figure 3–10 and used by the CBRM model.

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10 At this time, we do not need to replace significant volumes of our concrete poles.

11 Pole condition is assessed in accordance with the criteria detailed in JEN MA 0900 Asset Inspection Manual.

12 For example, staking a pole may cost 20% of the cost of replacing a pole, but may extend its life from 54 years to 80 years.

13 For example, if the pole rot is above where the pole would be staked or is unable to be physically staked due to access restrictions.

60. The proportion of wood poles that exceed their useful life is shown in Figure 3–8 (assuming typical useful life of a wood pole is 54 years and the life of a reinforced wood pole is 80 years). If no asset replacements occur, over the next 5 years the proportion of wood poles older than their useful life will increase from 8% of the asset population to 20%. If historical replacement rates were continued, the proportion of assets older than their useful life still increases significantly from 8% to almost 18%. With forecast replacement rates, the increase will bring the percentage to 17%. This trend shows an increasing bow-wave of required investment if our proposed volumes are not delivered in the 2016 regulatory period, significantly affecting safety and reliability.

61. Furthermore, the profile of historical condemnation rates outlines an increasing trend (see Figure 3–9), demonstrates that we are already in this phase of increasing volumes.

Figure 3–8: Proportion of poles older than typical life (percent)

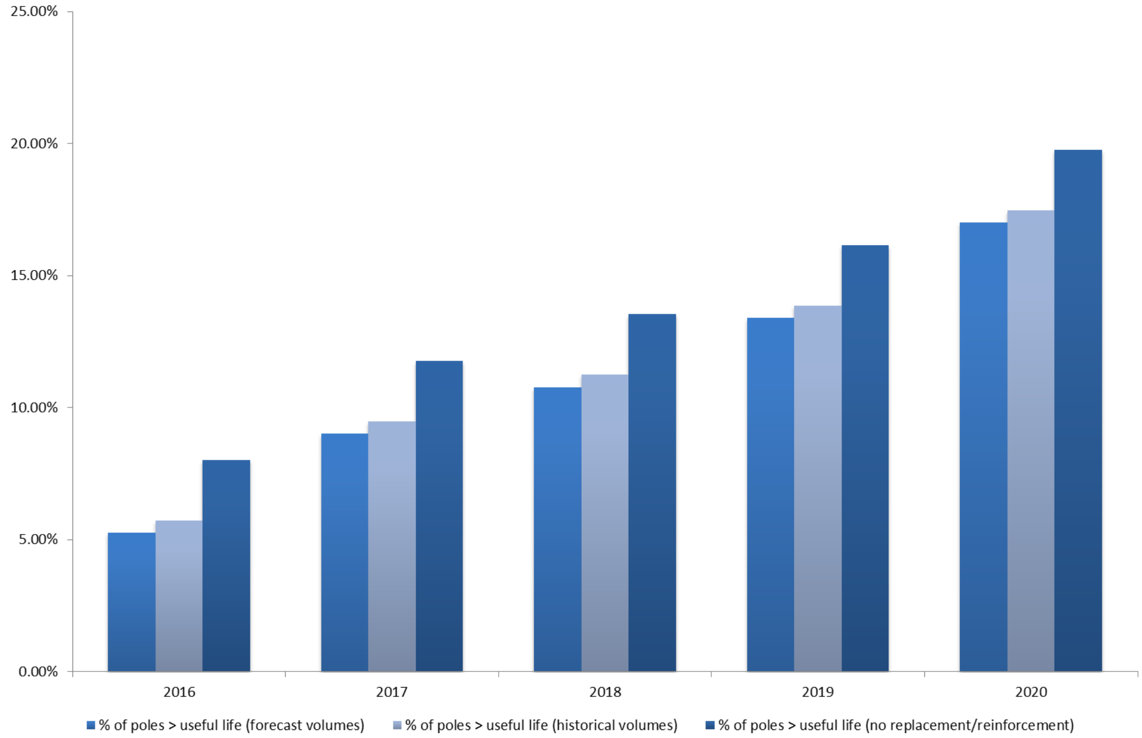
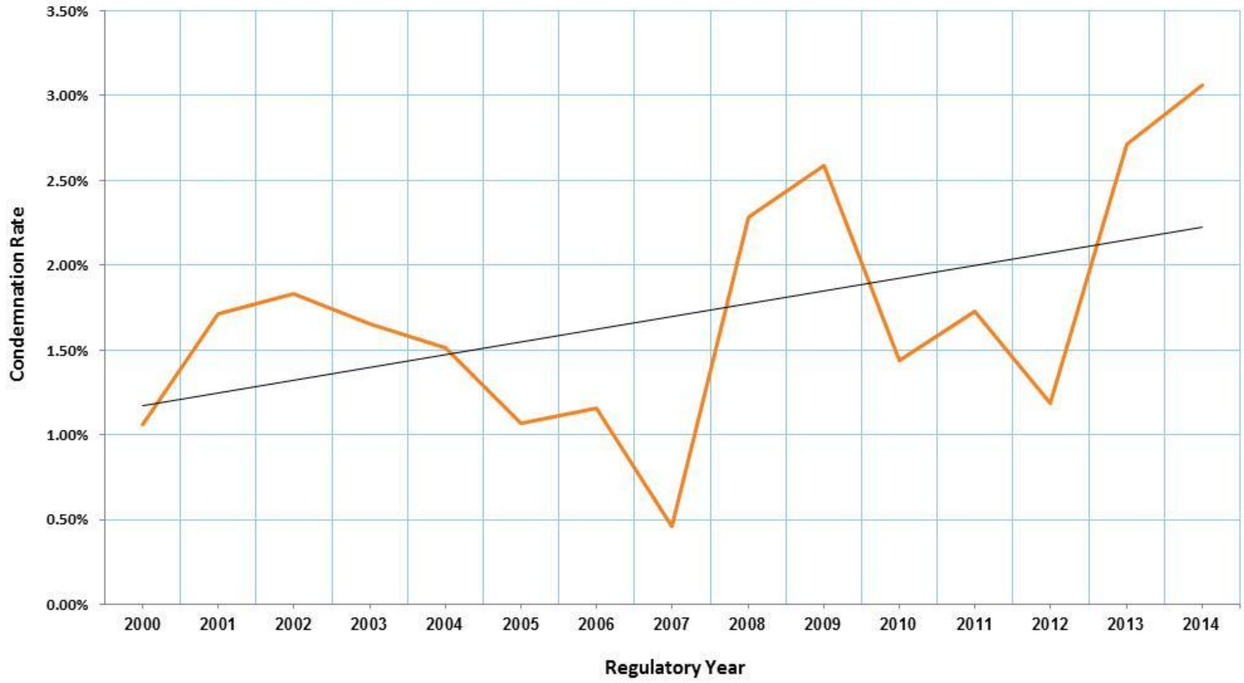
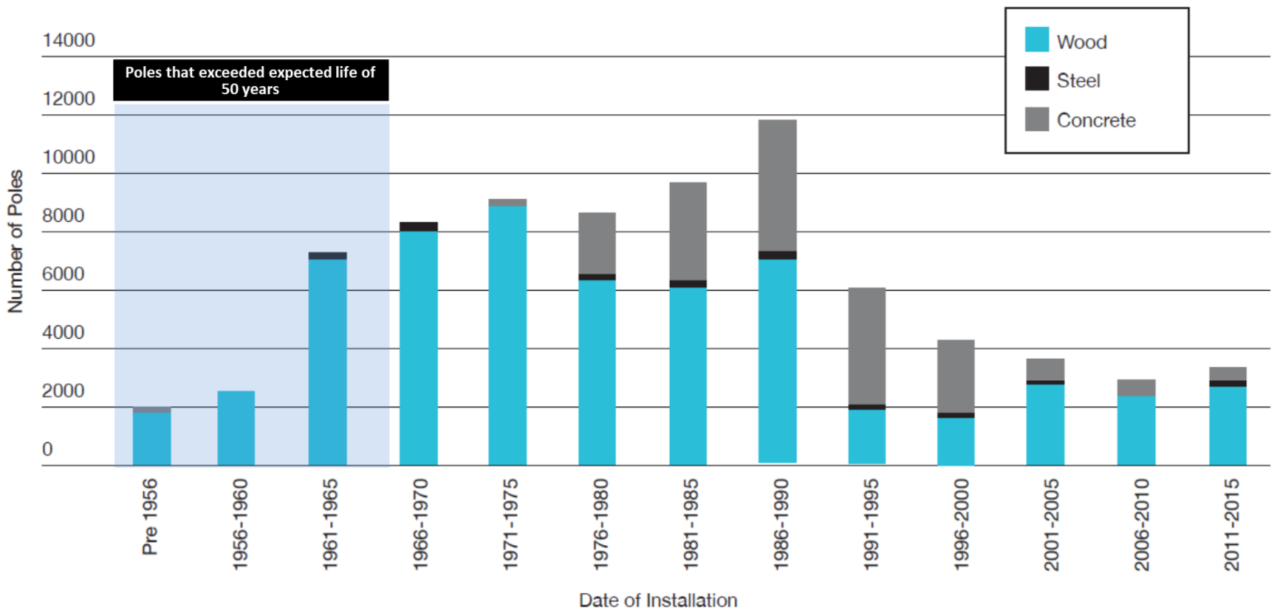


Figure 3–9: Pole condemnation rates (percent)



62. The scale and timing for this increase can also be supported by reference to the age profile of our poles (see Figure 3–10). The age profile suggests a significant portion of our poles have reached the end of expected life, and this portion will increase significantly if replacement rates are not increased.

Figure 3–10: Poles age profile



63. As previously discussed, we have developed CBRM models to validate our forecasts. As we show in Figure 3–32, our replacement volumes have been set to maintain the pole failure volumes as predicted by the poles' CBRM model. To demonstrate this further—and show the anticipated effect of aging of the poles—Figure 3–12 presents the distribution of the Health Index (**HI**) for poles across our pole population.

Box 3-2 Health Index Explained

The HI of an asset is a means of combining information that relates to its age, environment and duty, as well as specific condition and performance information to give a comparable measure of condition for individual assets in terms of proximity to end of life (**EOL**) and probability of failure.

Figure 3–11 illustrates how HI relates to asset remaining life and probability of failure.

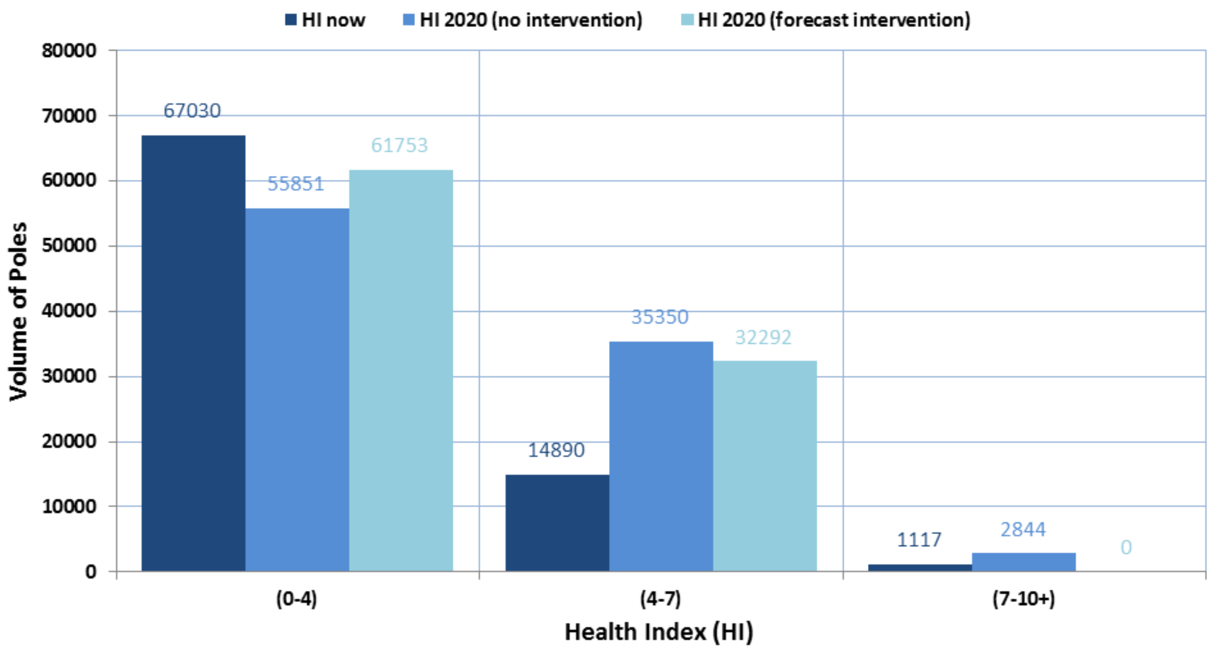
Figure 3–11: Concept of CBRM Health Index (HI)

Condition		Health Index		Remnant Life		Probability of Failure
Bad	10			At EOL (<5 years)		High
Poor				5 - 10 years		Medium
Fair				10 - 20 years		Low
Good	0			>20 years		Very low

The HI represents the extent of degradation as follows:

- Low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal aging, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the Probability of Failure (PoF) remains very low and the condition and PoF would not be expected to change significantly for some time.
- Medium values of health index, in the range 4 to 7, represent significant deterioration, with degradation processes starting to move from normal aging to processes that potentially threaten failure. In this condition, the PoF, although still low, is just starting to rise and the rate of further degradation is increasing.
- High values of health index (>7) represent serious deterioration; i.e. advanced degradation processes now reach the point that they actually threaten failure. In this condition the PoF is now significantly raised and the rate of further degradation.

Figure 3–12: Poles CBRM Health Index (HI) chart



64. Having no assets in the range (7-10+) after forecast interventions (forecast replacements) are delivered (light blue bars) does not imply that we are improving network reliability. The spread of health indices must be considered in the context of overall asset population. The results show that over the 2016 regulatory period we will remove assets that are in worst condition however many assets that were in a healthy range (dark blue bars) would be showing worsening condition with 32,292 poles falling in the range (4-7) by 2020 (blue bars). The important point is that current failure rates are being maintained (Figure 3–32) and the resulting spread of health indices will be reflective of the current risk profile.

Non-standard design replacement programs

65. The second program, which is smaller in volume, is aimed at two groups of our wood pole population that were constructed to the design standards of the day but no longer meet the new requirements nor standards:

- The first relates to a group of wood poles that are undersized; that is, their original design diameter is less than that required to meet our minimum mechanical loading standards. Consequently, these poles could fail under loading conditions that are considered normal, and therefore, they pose significant safety hazards to the public.
- The second concerns a group of our LV wood poles that had HV raiser brackets added (later in their life) to allow them to carry HV circuits above the LV circuits. These raiser brackets use steel crossarms, which are no longer considered acceptable in Victoria under current health and safety standards[14], as they pose significant safety hazard to personnel working on the LV lines.

66. These are both ongoing programs which commenced in 2011. We have identified the location of these groups and have undertaken risk assessments to program their replacement. Our forecasts are aimed at addressing

[14] Electricity Safety (Installations) Regulations 2009 and Electricity Safety (Management) Regulations 2009

these two matters by the end of the 2016 regulatory period, in line with an undertaking to ESV[15]. Our forecasts allow for pole staking of undersized poles, where this is considered feasible.

Pole top structures

67. Pole top structures consist of the crossarms, insulators and associated hardware. We own approximately 117,000 crossarms. Historically, the majority of our crossarms were wood. However, since 1980 we have used steel crossarms in our HV and sub-transmission overhead networks to reduce the possibility of pole top fires. We still use and deploy wooden crossarms for our LV network to ensure safe working practices for personnel working on our LV network.

68. Our replacement programs are aimed at replacing these crossarms, insulators and associated hardware. There are two sets of replacement programs that are aimed at addressing two different issues with our pole top structures:

- condition-based replacement program for the wooden crossarms; and
- a risk based program associated with replacement of HV and sub-transmission wooden crossarms in geographical areas that have been assessed as prone to pole top fires.

Condition-based replacement programs

69. The first and most significant set of programs, concerns our ongoing programs to address crossarms in poor condition, which are typically identified though our routine pole inspections. These programs account for 67% of our replacement capex in the pole top structure category.

70. The need for this set of programs is caused by the aging mechanism of wooden crossarms, which (like wood poles) will deteriorate over time because of the environment that they are located in (e.g. through rot). Crossarms in poor condition pose significant safety hazards to the public as their failure can result in injury, high voltage injections and fire ignition. Crossarms identified to be in poor condition are planned for replacement within set timeframes and in large programs of work. Our proposed replacement program for pole top structures has been considered in our delivery plan (see Attachment 7-8) to ensure that we can optimise our resources, provide appropriate lead times for planning and communication, enabling effective, efficient delivery.

71. The condition-based replacement programs are ongoing. The key drivers underlying the increases in these programs over the 2016 regulatory period are:

- the ongoing aging of our crossarm population, which is causing greater volumes of crossarms to be below the minimum standards; and
- the need to reduce the backlog of crossarm replacement that has been growing over the 2011 regulatory period.

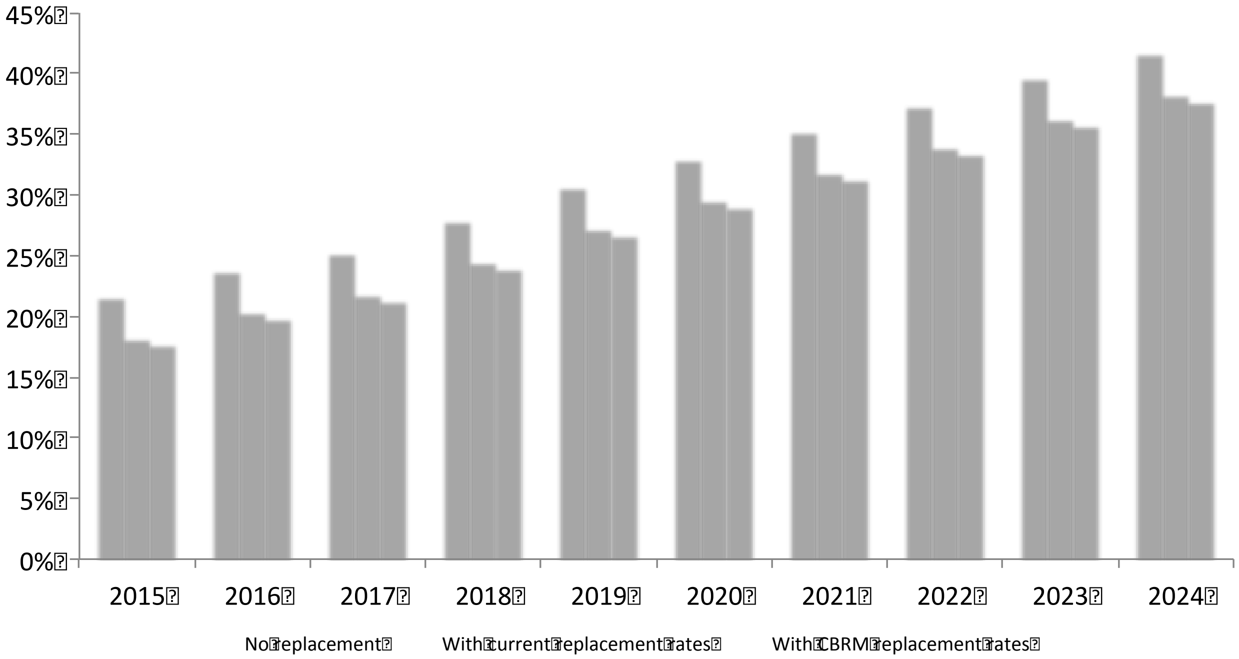
72. With regard to the ongoing aging of the population, the factors supporting the view that we need to significantly increase our forecast volume of replacements are similar to those for poles.

73. The analysis of the age of replaced wooden crossarms suggests that the wear-out phase commences before 40 years (as 50% of replaced crossarms are less than 38 years old). The analysis indicates that the 'wear-out' phase for the majority of wooden crossarms commences around 30 years and ends around 55 years. JEN has adopted 45 years as the useful life of assets for developing forecast replacement volumes in CBRM.

15 Final decision - appendices, Victorian electricity distribution network service providers - Distribution determination 2011-2015, Australian Energy Regulator (AER), October 2010, p670

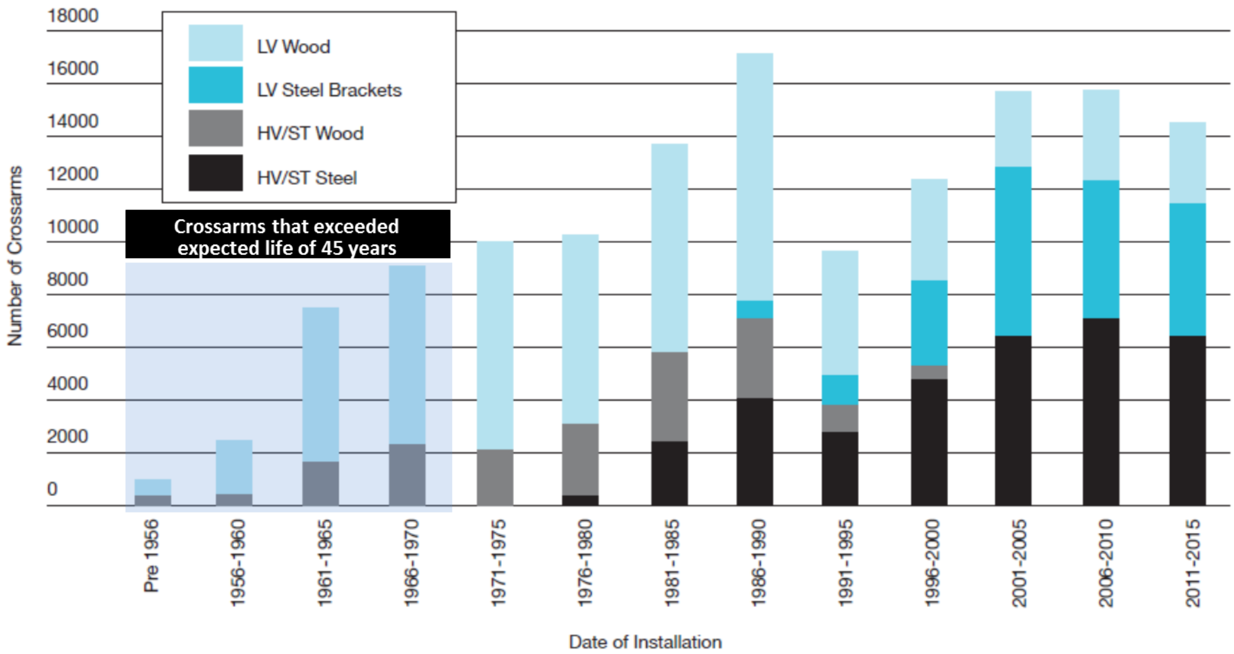
74. The condition of pole top structure assets is deteriorating. Figure 3–13 shows the proportion of the assets over 45 years old. If no asset replacements occur over the next 10 years the proportion of crossarms older than their useful life will increase from 22% of the asset population to over 40%. If historical replacement rates were continued, the proportion of crossarms older than their useful life still increases significantly from 18% to 38%. With forecast replacement rates, the increase will bring the percentage to 37%.

Figure 3–13: Proportion of crossarms older than typical life



75. The scale and timing for this increase can also be supported by reference to the age profile of our crossarms (see Figure 3–14). Analysis of the age of our crossarms at the time they are replaced suggests they typically last 45 years. Comparing this against the age profile suggests a significant proportion of our crossarms are already beyond that age, and this portion will increase significantly if replacement rates are not increased—which similarly to poles—is indicative of the bow-wave of required replacement investments in this asset class in the 2016 regulatory period. If we were to defer expenditure in pole top structures (or poles) the higher cost associated with replacing these assets would not be in the long term interests of our customers.

Figure 3–14: Crossarms age profile

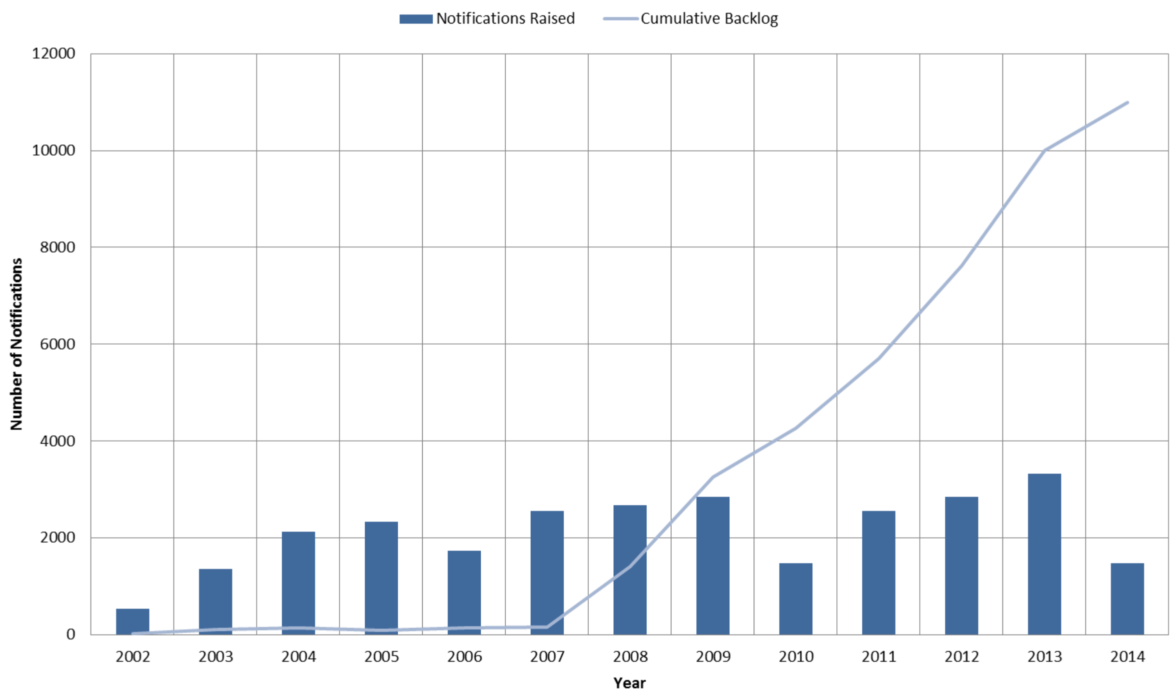


76. With regard to the growing backlog, Figure 3–15 shows the profile of crossarms identified as requiring replacement against actual replacements in each year, since 2003. This figure shows that replacements have not kept track with identified replacements, such that the backlog has doubled over the 2011 regulatory period. We now carry 10,000 defective crossarms on our network, compared to 5,000 in 2011.

77. The high level of necessary crossarm replacements arises due to increasing level of crossarms reaching their end of life and showing poor condition. We manage this backlog by prioritising replacement of crossarms that show greatest level of structural deterioration and therefore carry the greatest risk of failure.

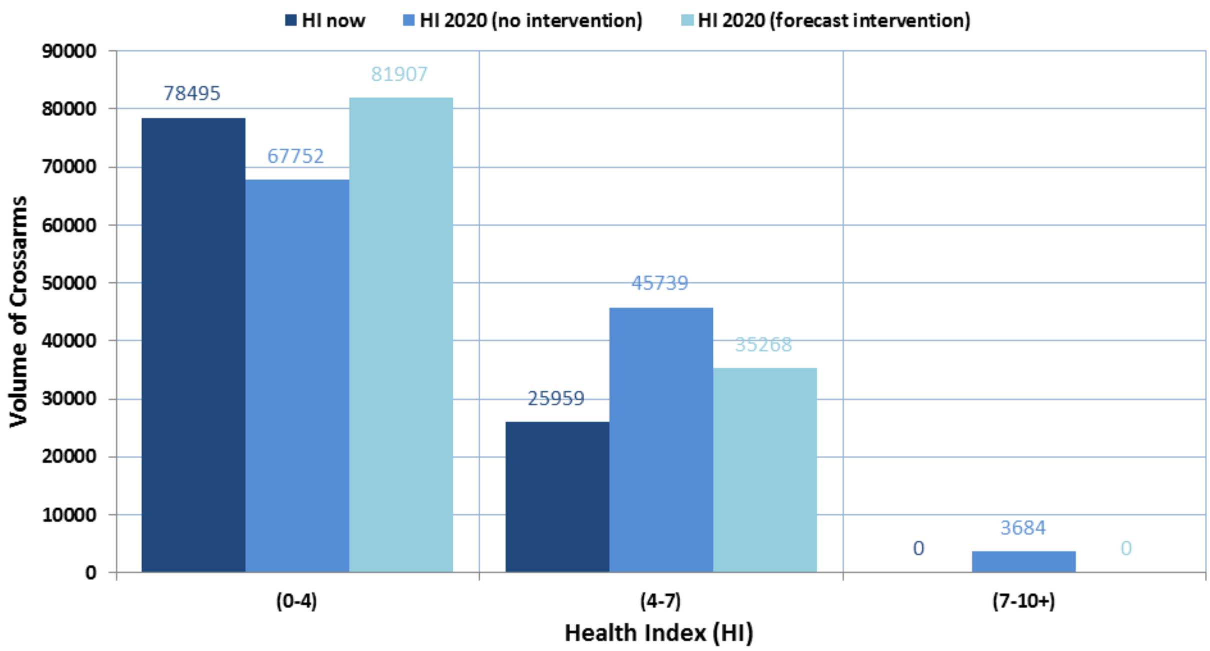
78. This backlog will need to be addressed by increasing crossarm replacement volumes in the 2016 regulatory period to arrest the declining performance that has occurred.

Figure 3–15: Crossarm replacement backlog



79. We have also developed a CBRM model of our crossarm population. As we showed in Figure 3–32, our replacement volumes have been set to reflect the maintenance of the crossarm failure volumes as predicted by the crossarm CBRM model. To demonstrate this further, and show the anticipated effect of aging, Figure 3–16 shows the distribution of the HI for crossarms across the population.

Figure 3–16: Crossarm CBRM Health Index (HI) chart



Risk-based replacement programs (pole top fire mitigation program)

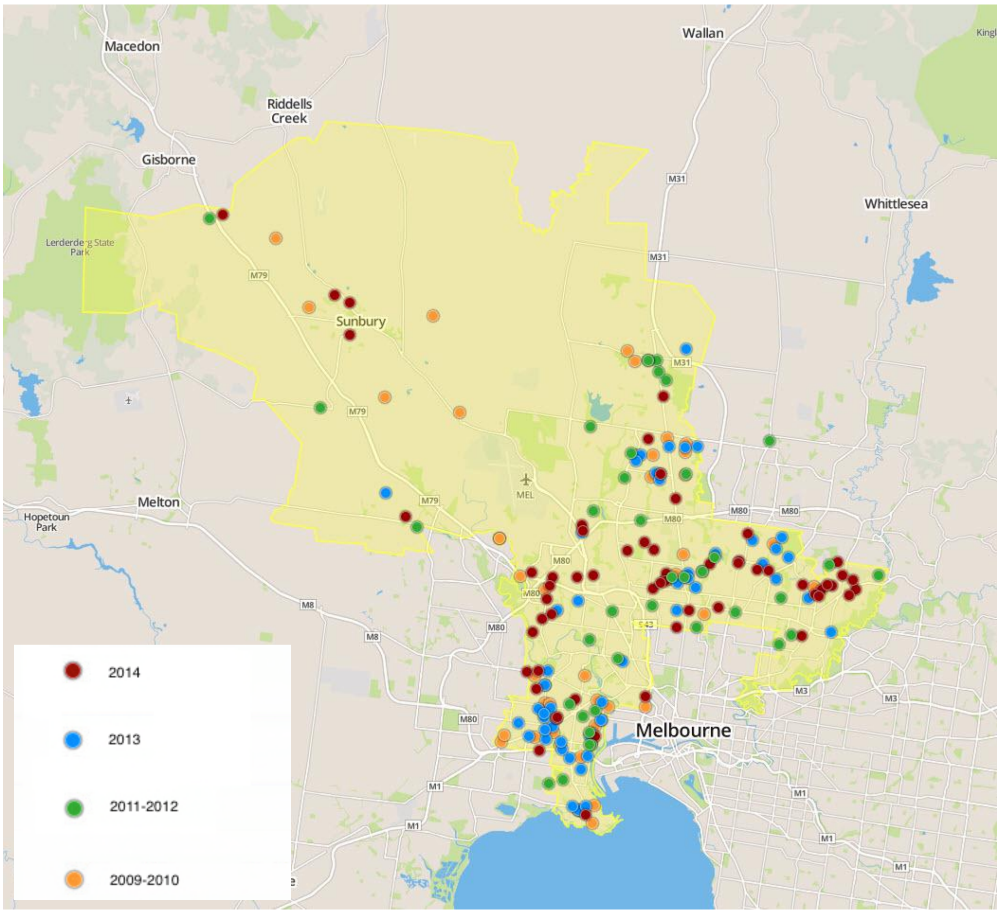
80. The second program is aimed at replacing our highest risk wooden HV and sub-transmission crossarms. This replacement program, together with an enhanced inspection program, represents our pole top fire mitigation program, which has been verbally endorsed by ESV[16]. This is an ongoing program, which commenced in 2000.

81. The pole top fires of concern here are caused by the build-up of particles (e.g. dust) on insulators during sustained dry periods. If this occurs, subsequent moisture (due to light rain or fog) can lead to these particles conducting electricity, which can cause arcing between components of the pole top and in turn result in a fire ignition. This has been identified as most likely when wooden crossarms in poor condition combined with specific types of insulator (e.g. brown and grey pin insulators) are used in high pollution locations (e.g. along major roads or at industrial locations).

82. We will replace 2,835 crossarms under this program in the 2011 regulatory period, and have forecast that this will need to rise to 3,250 in the 2016 regulatory period. We are proposing this increase to arrest the rising trend in pole top fires that has emerged over the 2011 regulatory period.

83. To develop this forecast, we have analysed the recent pole top fires to identify the areas in our network most prone to pole top fires. This analysis has found two specific geographic areas: Yarraville and Footscray in the south; and Coburg and Reservoir in the north (see Figure 3–17).

Figure 3–17: Pole top fire locations



16 Meeting between Jemena, ESV and Worley Parsons at Jemena Offices, 29 September 2014. Refer to Jemena's response to ESV request CM-1179 dated 3 March 2014.

84. We have cross referenced these areas with detailed knowledge of our crossarm and insulator types to develop an optimised replacement program for the 2011 regulatory period to maintain our current reliability levels and conduct the required replacement activities at the least sustainable cost to our customers.

Further detail

85. Table 3–4 provides references to Asset Class Strategies and Strategic Planning Papers that provide further analysis and more detail around the need for investment in pole and pole top structures replacements.

Table 3–4: Document evidence – Poles and Pole Top Structures

Document name	Document reference	Document type
Poles	JEN PL 0024	Asset Class Strategy
Pole Top Structures	JEN PL 0025	Asset Class Strategy
Pole Replacement and Reinforcement	ELE PL 0011	Strategic Planning Paper
Pole Top Structure Replacement	ELE PL 0012	Strategic Planning Paper
Pole Top Fire Mitigation	ELE PL 0015	Strategic Planning Paper
Environmental, Safety and Legal Programs	ELE PL 0020	Strategic Planning Paper

Service lines

86. The service line asset class is another significant component of replacement capex, representing 9% of our total replacement capital expenditure over the 2016 regulatory period or $21m. This forecast represents a 2% increase in replacement capital expenditure from the level in the 2011 regulatory period (values include forecast labour and material price changes and exclude overheads

87.

88. Figure 3–18).

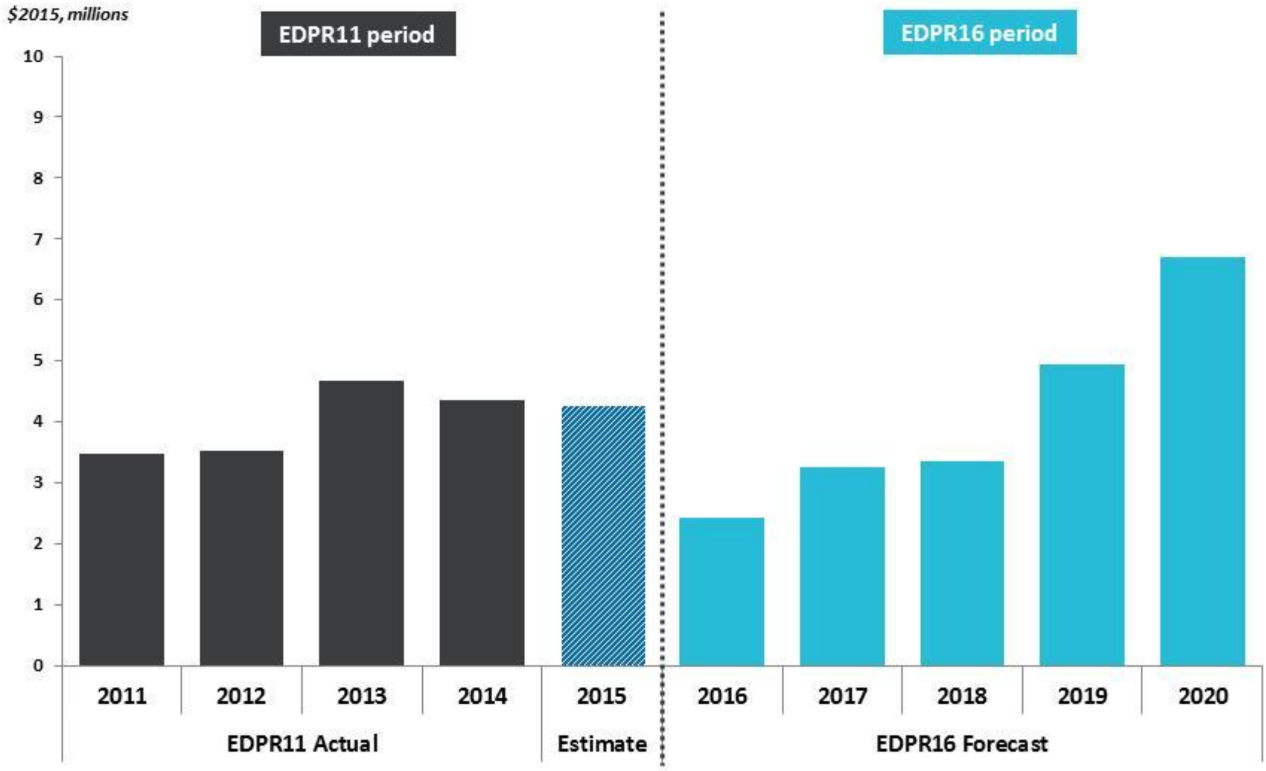
89. Service line forecast expenditure for 2016-2020 is presented in Table 3–5.

Table 3–5: Capital expenditure for service lines 2016-20 ($2015, $millions)

Service Lines	Forecast regulatory period				
	2016	2017	2018	2019	2020
Replacement capital expenditure	2.43	3.27	3.36	4.96	6.71

(1) values include forecast labour and material price changes and exclude overheads

Figure 3–18: Capital expenditure for service lines 2011-20 ($2015, $millions)



90. This category of costs covers the replacement of the service lines and associated hardware that we use to connect individual customers to our network (typically the LV network). We have approximately 179,000 overhead service lines and terminations.

91. We have been using Aerial Bundled Cable (**ABC**) as the preferred type of overhead service line since 1989. ABC has proven to be a reliable material and type of construction.

92. However, we have approximately 64% of our overhead service lines that were constructed using what are now considered to be obsolete approaches (non-preferred service lines), mainly neutral screened conductors (45%) which we used from the early-60s to mid-70s, and twisted wire (16%) which we used from the mid-70s until the introduction of ABC.

93. The main risks with these older types of service connection relate to significant public safety hazards including safety incidences, fires and lack of ground clearance (as older overhead service lines are more likely to be below current ground clearance limits than recently installed service lines). Given the seriousness of these issues, regulations were introduced in Victoria in 1999 to routinely test overhead and underground services on a 10-year cycle.[17] These testing and replacement programs form an important part of our ESMS.

94. In 2011, we commenced a program to replace non-preferred service lines. The initial phase of the program was included in our ESMS safety plan and endorsed by ESV; we are on target to deliver the proposed program.

95. We will continue this program in the 2016 regulatory period which equates to 75% of the expenditure in the service lines asset classes.

[17] Electricity Safety (Management) Regulations 2009

96. The key drivers of the increase in non-preferred service line replacement program are:

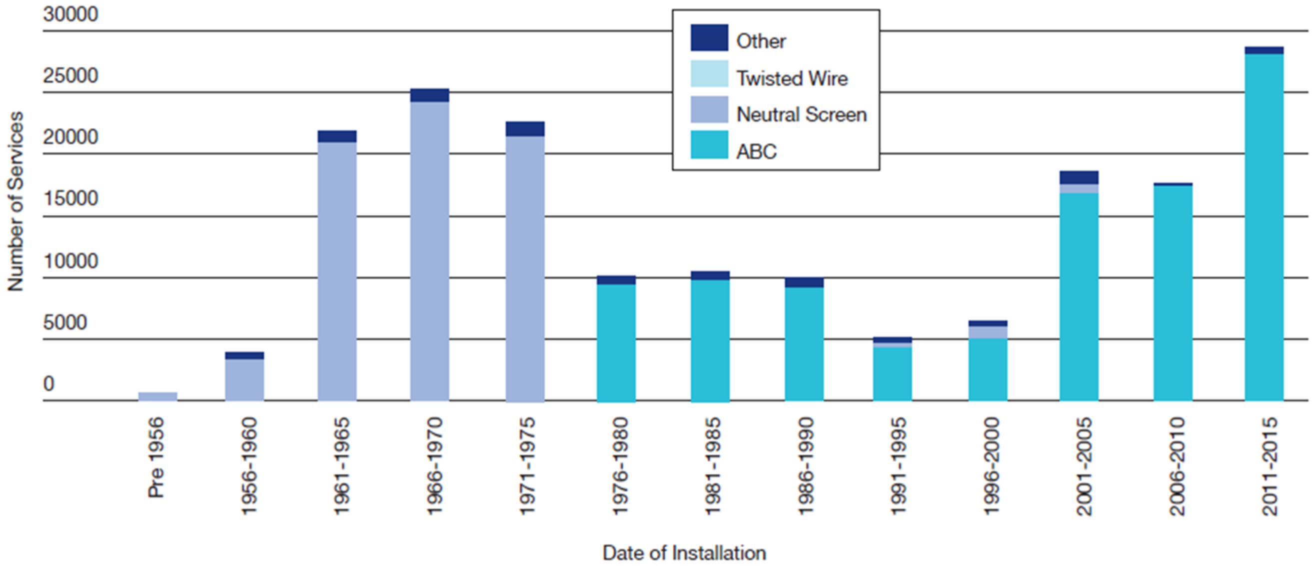
- The increasing rate of safety incidences as a result of service related failures in the 2011 regulatory period; and
- The ongoing deterioration of the condition of the non-preferred service population.

97. We have analysed these incidents and found that a significant portion of these safety incidences (87%) and test failures (71%) are related to our non-preferred, neutral screen and twisted wire service types.[18] Additionally, we have reported three ground fire starts due to the failure of non-preferred service lines since 2011.

98. Overhead services continue to deteriorate and reach end of life at a greater rate than they are currently being replaced. This will remain the case over the 2016 regulatory period if current replacement volumes are not increased.

99. Analysis of the age profile of service lines reinforces the need to accelerate the replacement of non-preferred service lines. Figure 3–19 provides the age profile of our service lines. Analysis of the age of our failed service lines suggests the useful life of a service is around 40 years. Therefore, the majority of our neutral screened service line population is already beyond this life. By the end of the 2016 regulatory period, our oldest neutral screen service lines will be 60 years and our youngest will be 54 years. Therefore, we also need to increase the volume of replacements to arrest the effect that the further deterioration of the population's conditions will have on failures.

Figure 3–19: Age profile of non-preferred service lines



100. To develop our replacement plans, we have prioritised suburbs based on the greatest risk of service line failures. To perform this risk assessment we have identified the suburbs where safety incidences and failures are most prevalent and have correlated these safety incidences and failures to the type of service line.

101. We have also analysed our other replacement programs where service line replacements will occur (e.g. pole and pole top replacements) to ensure we are not double counting service line replacements in these increased volumes.

18 JEN *Service Neutral Testing and Electrical Shocks Report*, December 2014

Further detail

102. Table 3–6 provides references to Asset Class Strategies and Strategic Planning Papers that provide more detail of the need for targeted investments in service line replacements

Table 3–6: Document evidence – Service lines asset class

Document name	Document number	Document type
Low Voltage Overhead Services	JEN PL 0036	Asset Class Strategy
Non Preferred Service Replacement	ELE PL 0010	Strategic Planning Paper
Environmental, Safety and Legal Programs	ELE PL 0020	Strategic Planning Paper

3.1.3.2 Zone Substation and Distribution Transformers

103. The transformer asset class represents 15% of our total replacement capex over the 2016 regulatory period or $33m. This forecast represents 63% increase in replacement capex from the level in the 2011 regulatory period (Figure 3–20). This asset class covers both zone substation (72%) and distribution transformers (28%).

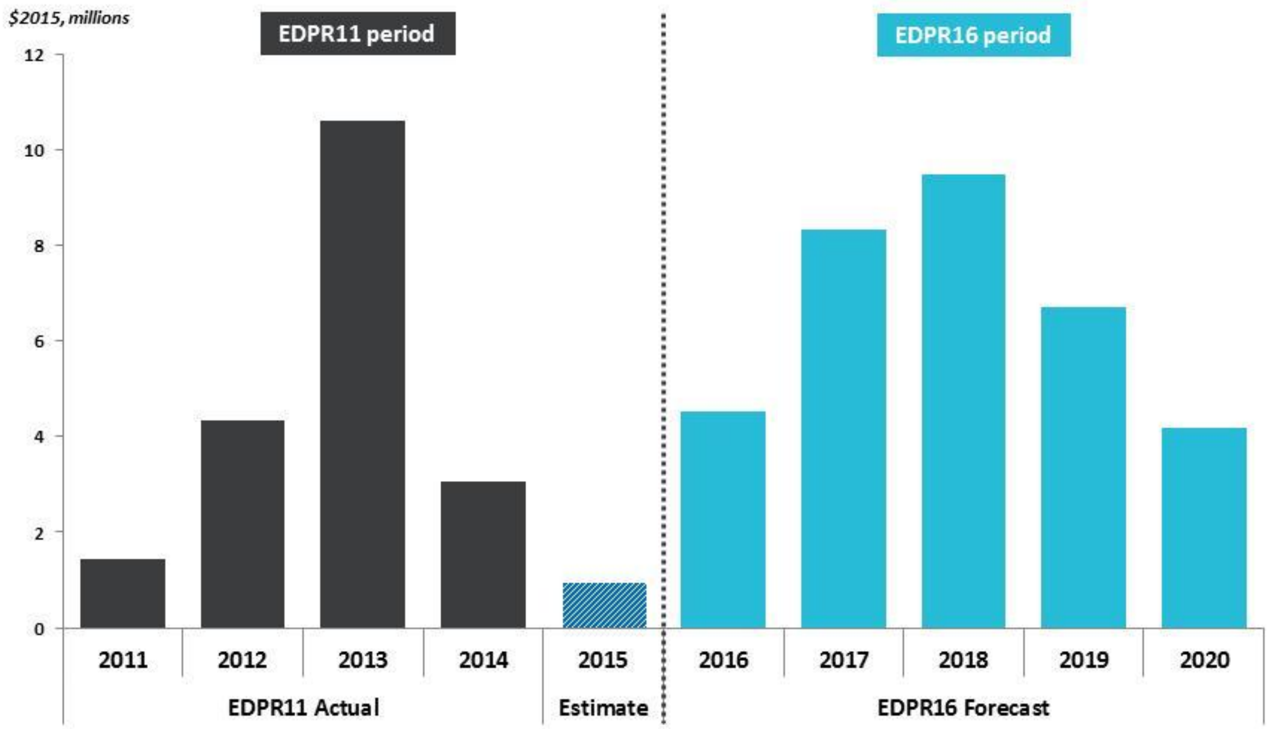
104. Transformers capital expenditure is presented in Table 3–7 and Figure 3–20.

Table 3–7: Capex for transformer asset classes 2016-20 ($M, $2015)

Transformers	Forecast regulatory period				
	2016	2017	2018	2019	2020
Replacement capex	4.53	8.36	9.52	6.74	4.20

(1) values include forecast labour and material price changes and exclude overheads.

Figure 3–20: Capital expenditure for transformers 2011-20 ($2015, $millions)



105. This category of asset cost covers:

- The replacement or refurbishment of the power transformers in our zone substations, and
- The replacement of our distribution transformers that supply our LV network.

106. The major program within this category concerns the condition-based replacement of zone substation transformers, whereas the replacement of distribution transformers follows the historical trend of low volumes of failure and condition based replacement. Our objective is to upgrade those distribution transformers with the highest utilisation before they fail through our network augmentation program.

107. The reason for this difference in approach is that zone substation transformers are one of the most critical assets on our network. They are one of our highest unit cost items and can have long lead times associated with their procurement and installation. A major failure of a transformer can have a range of significant consequences, including:

- Reliability - the loss of supply to a significant number of customers (e.g. around 5,000 customers depending on the zone substation and load at the time of failure)
- Security – the security of supply can be severely compromised while the transformer is out of service as another major outage could result in a far more widespread outage
- Safety – a major failure could injure personnel working in the vicinity and cause fires (this type of failure can also damage other equipment in the zone substation)
- Environmental – a major failure can release oil, which must be contained and disposed.

108. Therefore, we always aim to proactively replace our zone substation transformers prior to such a major failure. Because of their criticality, we manage these assets very carefully to maximise their life. These management practices include:

- Routine monitoring, inspection and testing of all our transformers (and their sub-systems) to determine their condition across a range of measures
- Maintenance and refurbishment practices to address defects and maintain condition where this is feasible.

109. The critical measure of condition that typically drives the need to replace a transformer concerns the winding insulation. This deteriorates as the transformer is used (the rate of deterioration is related to the electrical loading). The condition of the winding insulation is typically expressed in terms of its Degree of Polymerisation (**DP**)[19], where a DP measure of around 700 would represent a new transformer and a DP measure of 200 reflects a transformer at the end of its life.[20] The DP of the insulation can be directly measured from samples taken from the paper insulation medium or estimated from transformer oil or electrical test results.

110. In the 2011 regulatory period, we have replaced four transformers (two at Pascoe Vale zone substation and two at Yarraville zone substation). In the 2016 regulatory period we need to replace 10 transformers:

- Replace three 22/11kV transformers at North Essendon (**NS**) zone substation
- Replace three 22/6.6kV transformer at Fairfield zone substation (**FF**)
- Replace two 66/11kV transformers at Essendon zone substation (**ES**)
- Replace two 66/11kV transformers at Heidelberg zone substation (**HB**).

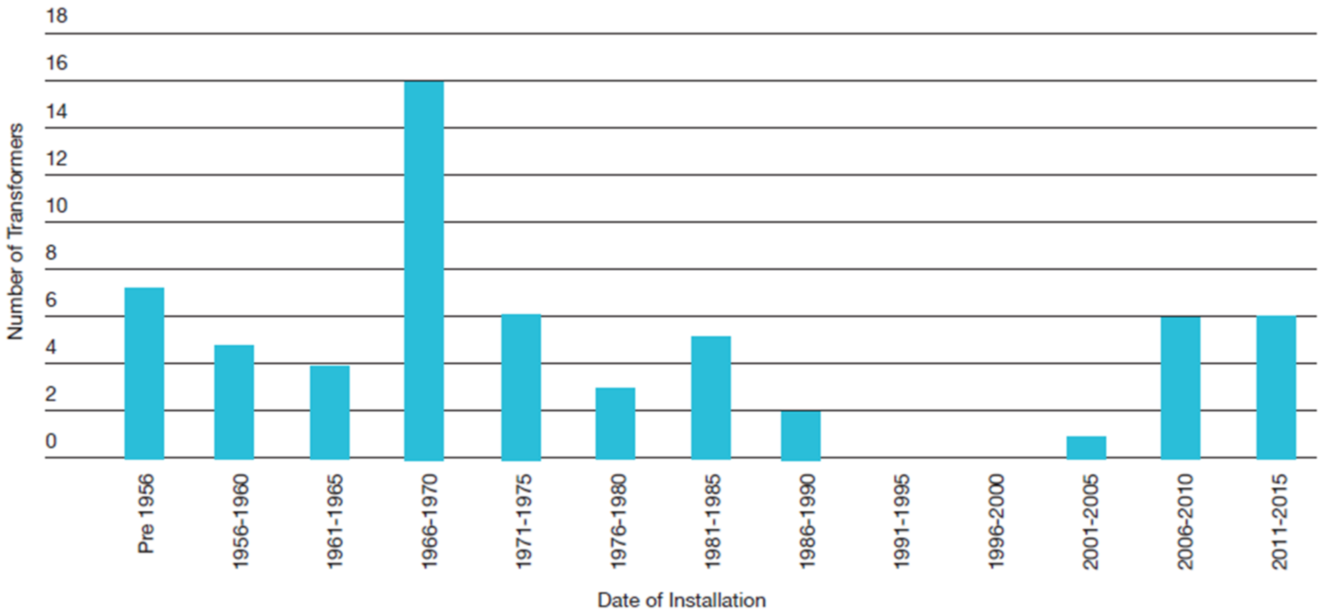
111. The main driver of increased replacements is the poor condition of these transformers, which indicates that their winding insulations are all expected to reach their end-of-life phase during the 2016 regulatory period. In addition, there are other issues with some of these transformers that can be prudently managed through their replacement.

112. The profile of our zone substation transformer population is aging (see Figure 3–21) with a large proportion—24 transformers out of a population of 63—being installed prior to 1970. By the end of the 2016 regulatory period, these would all be older than 50 years and 6 would be older than 60 years. This is not to say they will all be in poor condition, but it does show that we have an emerging population of very old transformers whose condition will drive their replacement over the 2016 regulatory period.

[19] This is a measure of the length of the molecular chains that form the cellulose material of the insulator, and reflects the mechanical strength of the insulation.

[20] End of life here means that the insulation no longer has sufficient strength to withstand the mechanical forces it is likely to receive from a nearby short circuit, and therefore, such an event could lead to the major failure of the winding.

Figure 3–21: Zone substation transformer population



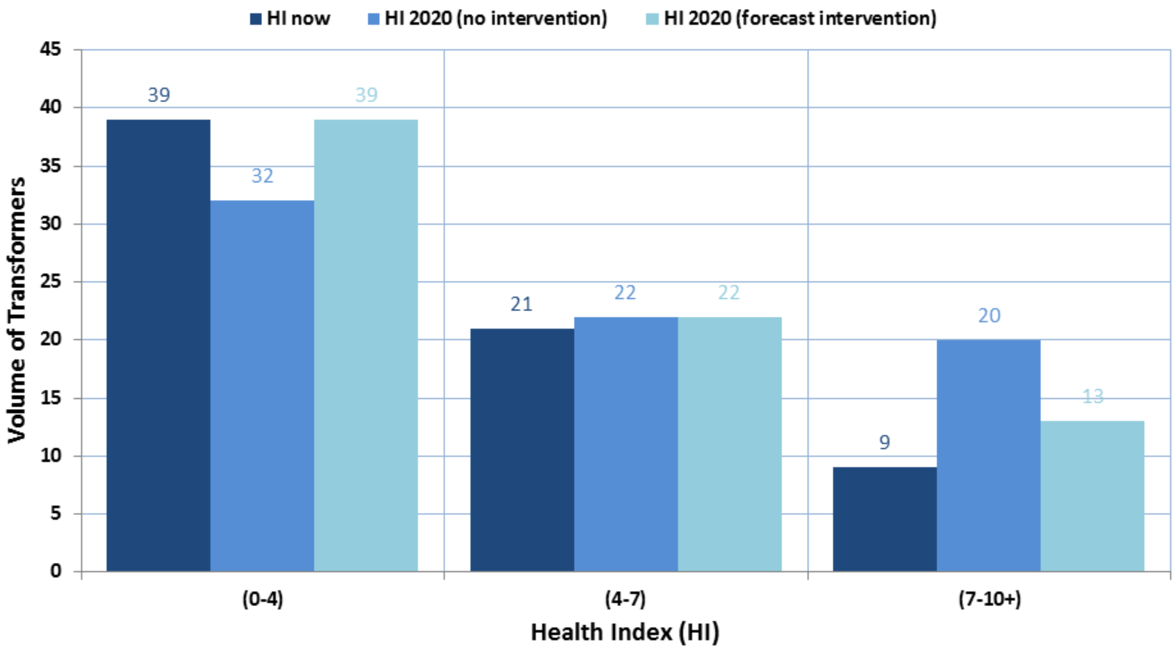
113. We have determined which specific transformers need to be replaced from our detailed knowledge of their condition as provided by our various condition assessment processes. Additionally, a number of transformers have other issues, including:

- Noise levels in residential areas above Environmental Protection Authority (**EPA**) standards
- Poor transformer oil conditions
- Insulation moisture
- Protection issues.

114. The continued operation of these transformers places additional costs and risks which could be addressed through dedicated service programs. Alternatively, the replacement of the transformers provides an opportunity to efficiently address these issues as well as put assets in service for the long term interests of customers.

115. We have also developed a CBRM model of our transformer population. As shown in Figure 3–32 , our forecast replacement volumes reflect a level that should maintain the expected failure volumes as predicted by the CBRM model. To demonstrate this further, and show the anticipated effect of aging of the transformers, Figure 3–22 shows the distribution of the HI (i.e. condition) for transformers across the population. This figure indicates the distribution of the HI of our transformer population will be broadly similar leaving the 2016 regulatory period as it is now, provided we have replaced our forecast number of transformers. If this number of replacements was reduced, the overall condition of our population would deteriorate, and in turn, the expected reliability, security and safety provided by this asset class would deteriorate.

Figure 3–22: Zone Substation Transformer CBRM Health Index (HI) chart



Further detail

116. Table 3–8 provides references to Asset Class Strategies, Strategic Planning Papers and Business Cases that provide more detail around the need for investments into transformer replacements.

Table 3–8: Document evidence – Transformer asset classes

Document name	Document number	Document type
Non Pole Type Distribution Substations	JEN EL 0033	Asset Class Strategy
Pole Type Transformers	JEN EL 0032	Asset Class Strategy
Zone Substation Instrument Transformer	JEN EL 0040	Asset Class Strategy
Zone Substation Transformers	JEN EL 0042	Asset Class Strategy
High Voltage Installations Replacement Program - Transformer Platform Heights Rectification	ELE PL 0018	Strategic Planning Paper
Improve Somerton (ST) Zone Substation Oil Containment	BAA-RSA-000119	Business Case
Replace Footscray West (FW) 66kV Transformer Bushings	BAA-RSA-000060	Business Case
Replace Essendon (ES) Zone Substation Transformers	BAA-RSA-000107	Business Case
Replace Fairfield (FF) Zone Substation Transformers	BAA-RSA-000105	Business Case
Replace Heidelberg (HB) Zone Substation Transformers	BAA-RSA-000109	Business Case

Document name	Document number	Document type
Replace North Essendon (NS) Zone Substation Transformers	BAA-RSA-000079	Business Case

3.1.3.3 SCADA / Network control and protection systems asset classes

117. The SCADA / network control and protection systems asset class represents 16% of our total replacement capex over the 2016 regulatory period or $35m, and reflects a significant increase in replacement capital expenditure from the level in the 2011 regulatory period (see Figure 3–23).

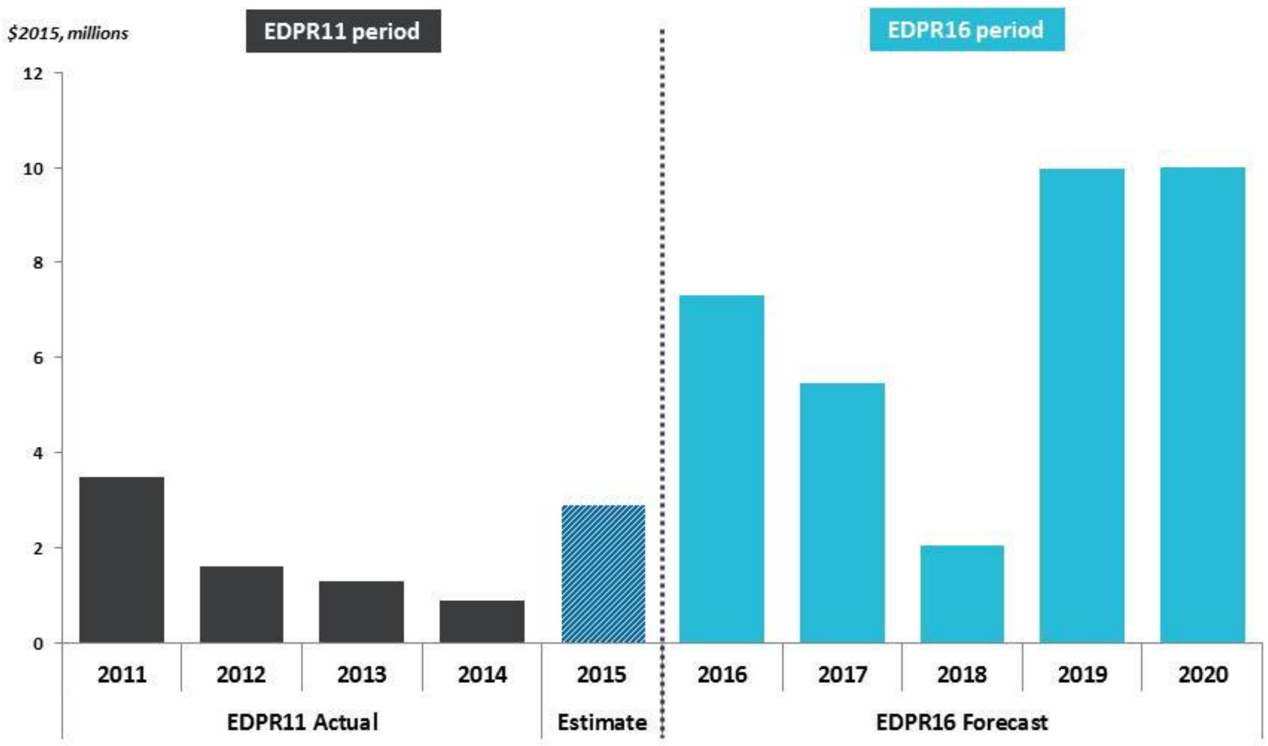
118. Our SCADA and protection capital expenditure for 2016-20 is presented in Table 3–9.

Table 3–9: Capital expenditure for SCADA / network control and protection systems 2016-20 ($2015, $millions)

SCADA/Network Control and Protection Systems	Forecast regulatory period				
	2016	2017	2018	2019	2020
Replacement capital expenditure	7.33	5.48	2.05	10.00	10.00

(1) values include forecast labour and material price changes and exclude overheads

Figure 3–23: Capital expenditure for SCADA / network control and protection systems 2011-20 ($2015, $millions)



119. This category of replacement expenditure covers a range of asset types associated with our SCADA system, Real Time Systems (**RTS**), zone substation protection and control infrastructure (including relays and power supplies) and the associated communication systems used to communicate critical information.

120. The major program within this category concerns the condition-based replacement of our protection and control schemes (50%).

121. A further 30% concerns upgrade or replacement of SCADA systems used to support JEN's real-time network management and operation.

122. We have approximately 1,500 protection and control relays, which consist of around 250 different types of relay.

123. The relays types are grouped into three categories, based upon their technology:

- 36% are electro-mechanical relays, which represent our oldest relays and the oldest technology
- 18% are analogue electronic relays, which we installed from the 1970s and into the 1990s
- 46% are microprocessor-based relays, which we began using in the 1990s.

124. The protection and control schemes within our zone substations are considered critical systems within our network. A correctly functioning scheme ensures the safe and reliable operation of our sub-transmission system and our HV network. Their purpose is to rapidly detect faults in the network and send signals to switchgear to isolate the faults. This action minimises the effect of the fault on customer supplies and ensures dangerous fault currents do not result in safety hazards or damage equipment.

125. It is not possible (or cost effective) to remove the possibility of all failures of this equipment, however, we typically aim to proactively replace our protection schemes, when they exhibit unreliable behaviour and the risks suggest that it is no longer prudent and efficient to continue their use. For this, we monitor the performance of relays types to identify emerging failure trends.

126. In the 2016 regulatory period we have identified a need to replace 234 protection relays in the following locations:

- Replace 14 relays at Brooklyn Terminal Station
- Replace 85 relays at Broadmeadows zone substation
- Replace 5 relays at Braybrook zone substation
- Replace 80 relays at Coburg North zone substation
- Replace 50 relays at Footscray West zone substation.

127. There will also be expenditure associated with completing replacements associated with the zone substation at Airport West (**AW**) project (52 protection schemes replaced), which commenced in the 2011 regulatory period.

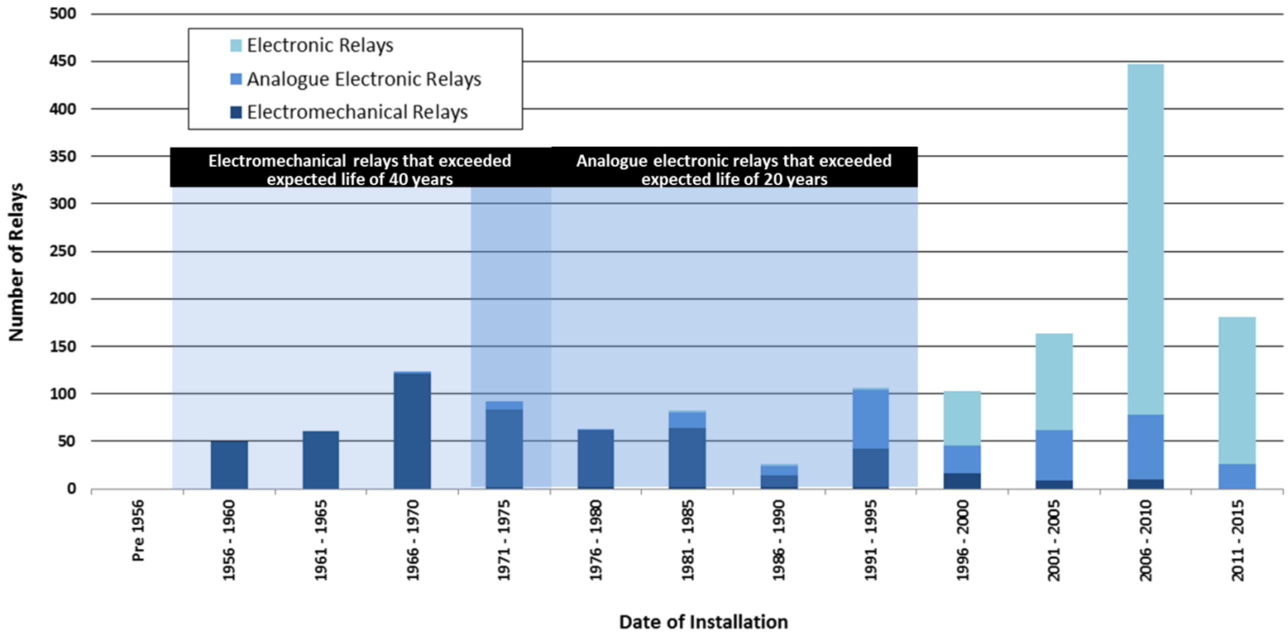
128. The main driver of increased replacements is the poor operation and therefore undesired performance of a number of types of relays. In addition, there are other limitations with some of these protection systems and the control rooms that they are housed that can be efficiently addressed through their replacement.

129. To appreciate the need for this increase in replacement volumes it is worth first considering the age profile of our relay population, by technology (see Figure 3–24):

- We expect lives of 40 years for our electro-mechanical relays. The age profile indicates we have 315 relays older than 40, and this will increase to 377 by 2020 without further replacements.
- Similarly, we expect lives of 20 years for our electronic and analogue electronic relays. The age profile indicates we have 106 relays older than 20, and this will increase to 193 by 2020 without further replacements.

130. This suggests an increase in replacement levels is required to maintain reliability, security and safety.

Figure 3–24: Population of relays



131. To identify which relays will need replacing, we have analysed the failure history of relays. We have identified three groups of relays with deteriorating performance.

132. We have also conducted risk assessments, based upon the location of failures, performance of the relays, and the scale of possible disruptions to supply to identify the most appropriate location for the replacement of these relay types in the 2016 regulatory period. We have structured our replacement program at specific zone substations to ensure cost effective implementation through the replacement of a group of relays at one time (ie. economies of scale and other efficiencies are achieved by replacing a set of relays at a zone substation together).

Further detail

133. Figure 3–15 provides references to Asset Class Strategies and Business Cases that provide more detail around the need for investments into SCADA/protection replacements.

Table 3–10: Document evidence – SCADA / network control and protection systems

Document name	Document number	Document type
Communications Network Devices	JEN PL 0009	Asset Class Strategy
GPS Clocks	JEN PL 0010	Asset Class Strategy
Metallic Supervisory Cables and Fibre Optic Cables	JEN PL 0004	Asset Class Strategy
Multiplexers and Voice Frequency Equipment	JEN PL 0006	Asset Class Strategy
Remote Terminal Unit	JEN PL 0007	Asset Class Strategy
iNet Radio and 3G Communications Systems	JEN PL 0005	Asset Class Strategy
Zone Substation DC Supply System	JEN PL 0023	Asset Class Strategy
Zone Substation Protection and Control	JEN PL 0021	Asset Class Strategy

Document name	Document number	Document type
Equipment		
Replace Brooklyn Terminal Station to Melbourne Water (BLTS-MB) 22kV Feeder Relays	BAA-RCA-000020	Business Case
Replace North Heidelberg (NH) Zone Substation and Nielsen Electrical Industries (NEI) Relays (including Thomastown Terminal Station)	BAA-RCA-000035	Business Case
Replace Broadmeadows (BD) Relays and Control Building	BAA-RCA-000004 & BAA-RSA-000039	Business Case
Replace Braybrook (BY) Zone Substation 22kV Feeder Relays	BAA-RCA-000037	Business Case
Replace Coburg North (CN) Zone Substation Relays	BAA-RCA-000039	Business Case
Replace Footscray West (FW) Zone Substation Relays	BAA-RCA-000041	Business Case
Replace Pascoe Vale (PV) Zone Substation Battery Bank and Charger and Replace East Preston (EP), Footscray East (FE), North Heidelberg (NH) and Sunbury (SBY) Zone Substation Chargers	BAA-RCA-000025	Business Case
Replace East Preston (EP), Footscray East (FE), Flemington (FT), North Heidelberg (NH) Zone Substation Battery Banks and Coburg South (CS) Zone Substation Chargers	BAA-RCA-000045	Business Case
Replace Essendon (ES) and Sunbury (SBY) Zone Substation Battery Banks	BAA-RCA-000047	Business Case
Replace Braybrook (BY) Zone Substation Battery Banks and Chargers and Coburg South (CS) Zone Substation Battery Banks	BAA-RCA-000049	Business Case
Replace Coburg North (CN), North Essendon (NS) and Newport (NT) Zone Substation BUEF Relays	BAA-RCA-000012	Business Case

3.1.3.4 Zone substation and distribution switchgear

134. The switchgear asset class represents 7% of our total replacement capital expenditure over the 2016 regulatory period or $16m, representing a 15% reduction in replacement capex from the level in the 2011 regulatory period (see Figure 3–25).

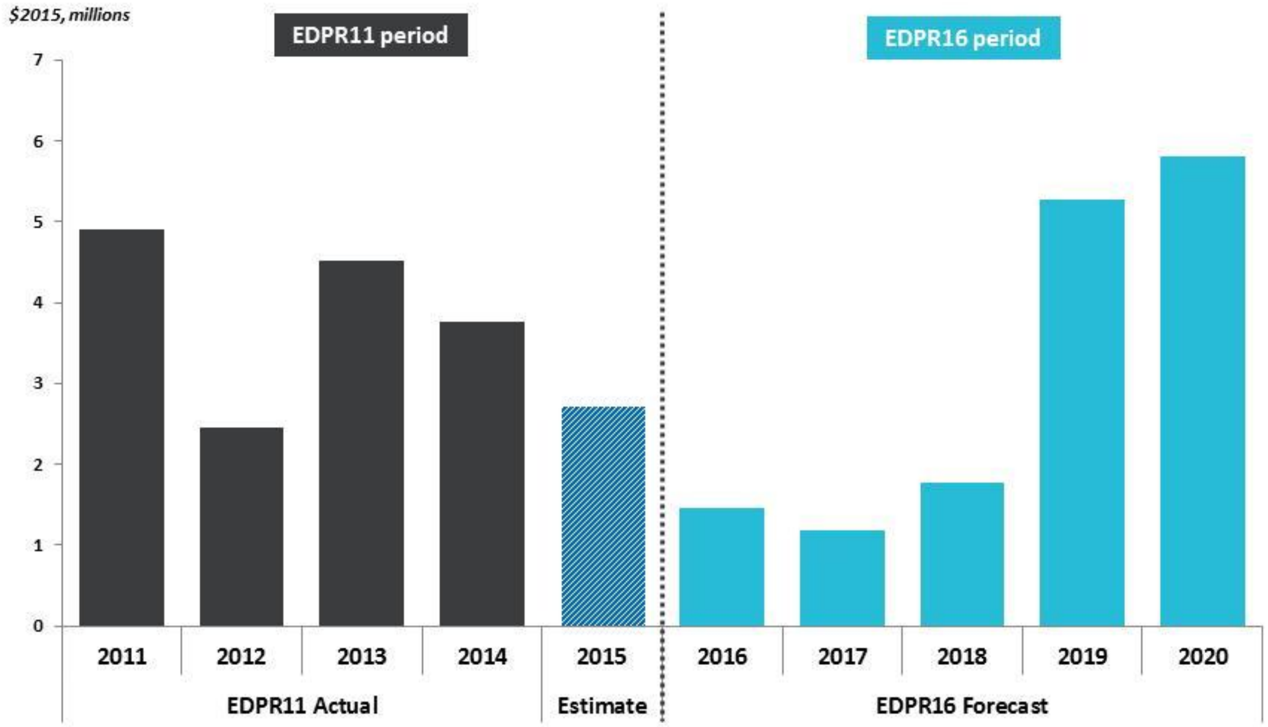
135. This asset class covers both zone substation (60%) and distribution switchgear (40%). Switchgear forecast capital expenditure for 2016-20 is presented in Table 3–11.

Table 3–11: Capital expenditure for switchgear 2016-20 ($2015, $millions)

Switchgear	Forecast regulatory period				
	2016	2017	2018	2019	2020
Switchgear replacement capital expenditure	1.47	1.19	1.79	5.28	5.83

(1) values include forecast labour and material price changes and exclude overheads

Figure 3–25: Capital expenditure for switchgear 2011-20 ($2015, $millions)



Distribution switchgear

136. Distribution switchgear covers a broad range of asset types associated with distribution substations and the distribution overhead network including fuses, ring main units, overhead switches, and automatic circuit reclosers (**ACR**). Replacement capex on distribution switchgear is set to increase in the 2016 regulatory period, increasing by 4% from levels in the 2011 regulatory period. However, the replacement capex is spread across a range of minor programs, associated with the various switchgear types.

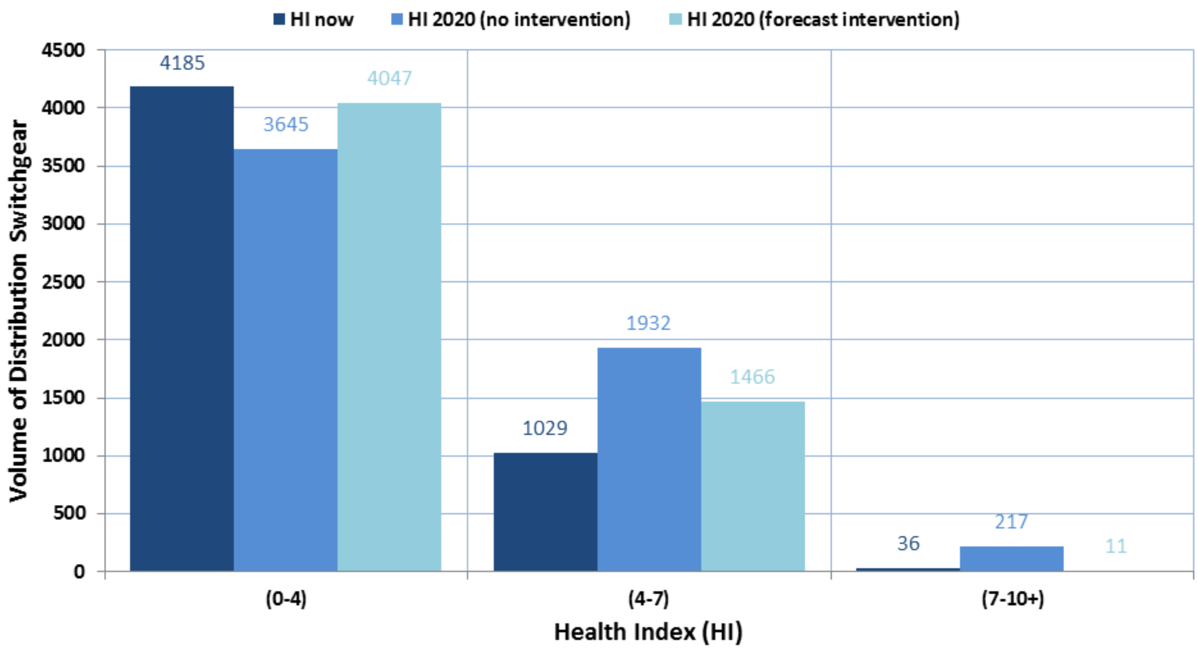
137. These are ongoing replacement programs, but the increases are necessary to address emerging issues, associated with the deteriorating condition of these assets. Without these increases, the deteriorating condition of these assets over the 2016 regulatory period will increase our safety and performance risks from levels in the 2011 regulatory period. Our high voltage installation replacement program addresses the need to replace a group of assets that are related to operating the high voltage network and includes the following:

- High voltage overhead switchgear – including air break switchgear, HV isolators and HV gas switches
- High voltage indoor switchgear – including metal clad ring-main-unit switchgear, wall mounted arc chute switchgear and fuses, cubicle enclosed air insulated isolating switches, bulk oil circuit breakers etc.

- Surge diverters
- Auto circuit reclosers
- High voltage overhead fuses and mounts

138. We have also developed a number of CBRM models covering our distribution switchgear. These models cover gas switches, ACRs, air break switches, isolators, and ring main units. As we showed in Figure 3–32, our forecast replacement volumes reflect a level that should maintain the expected failure volumes as predicted by the CBRM model. To demonstrate this further—and show the anticipated effect of aging of distribution switches—Figure 3–26 shows the distribution of the Health Index (i.e. condition) across the population of modelled switches. This figure indicates the distribution of the Health Index of our switches will be broadly similar leaving the 2016 regulatory period as it is now, provided we replaced our forecast number of switches. If this number of replacements was reduced the overall condition of our population would deteriorate, and in turn, the expected reliability, security and safety provided by this asset class would deteriorate.

Figure 3–26: Distribution switchgear CBRM Health Index (HI) chart



Zone substation switchgear

139. Zone substation switchgear includes circuit breakers and associated isolators, disconnectors, and related plant. We have 415 circuit breakers operating on our network. The majority of these are HV circuit breakers (85%), with the remainder 66kV.

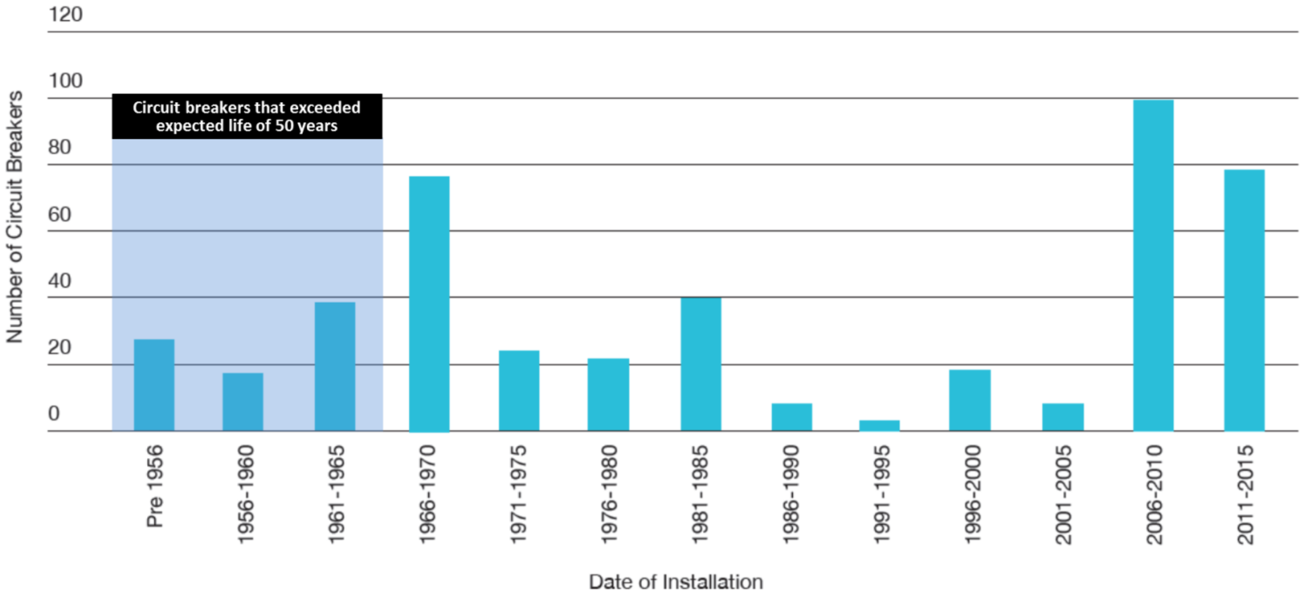
140. Replacement capex on zone substation switchgear is set to decrease in the 2016 regulatory period, decreasing by 25% from levels in the 2011 regulatory period.

141. Our zone substation circuit breakers are considered critical assets. In tandem with the protection systems, their correct functioning provides for the safe and reliable operation of our sub-transmission system and our HV feeders. Their mal-operation can result in similar consequences on protection schemes. Because of this, we proactively replace our circuit breakers when they exhibit unreliable behaviour and the costs and risks suggest it is no longer prudent and efficient to continue their use. For this, we perform various tests to assess their

condition (e.g. partial discharge tests), we conduct routine maintenance and we monitor the performance of circuit breaker types to see emerging trends in failures.

142. It is worth first considering the age profile of our circuit breaker population (see Figure 3–27). We expect useful economic lives of around 50 years for our circuit breakers. The age profile indicates we have approximately 50 circuit breakers older than 50 years, and this will nearly triple by 2020 to 135, without further replacements. This suggests we need to replace circuit breakers in the medium term to ensure reliability, security and safety is maintained.

Figure 3–27: Age profile of circuit breakers



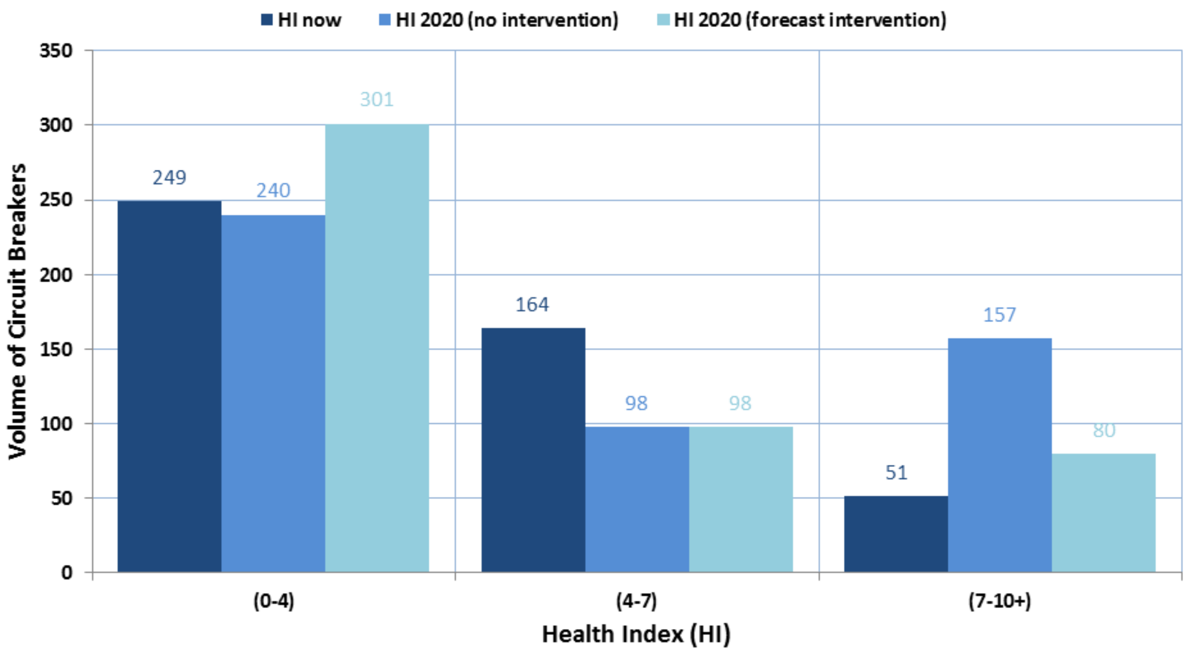
143. Our condition monitoring and failure analysis assists us to identify a number of our older circuit breaker types that are in poor condition. We have been progressively replacing these based upon their risk of failure.

144. The majority of the replacement capital expenditure for this asset class in the 2016 regulatory period is associated with two significant projects, replacing the switchboards at two zone substations that contain these circuit breaker types. These projects are:

- Footscray East, where we propose to replace 20 circuit breakers
- Footscray West, where we propose to replace 14 circuit breakers.

145. We have also developed a CBRM model of our zone substation circuit breakers. As we showed in Figure 3–32 our forecast replacement volumes reflect a level that should maintain the expected failure volumes as predicted by the CBRM model. To demonstrate this further, and show the anticipated effect of aging of the breakers, Figure 3–28 shows the distribution of the Health Index (i.e. condition) across the population. This figure indicates the distribution of the HI of our breaker population will be broadly similar leaving the 2016 regulatory period as it is now, provided we replace our forecast number of circuit breakers. If we replaced fewer breakers, the overall condition of our population would deteriorate, and in turn, our reliability, security and safety could deteriorate.

Figure 3–28: Zone substation circuit breaker CBRM HI chart



Further detail

146. Table 3–12 provides references to Asset Class Strategies, Strategic Planning Papers and Business Cases that provide more detail around the need for investments in switchgear.

Table 3–12: Document evidence – Switchgear asset classes

Document name	Document number	Document type
Automatic Circuit Recloser	JEN PL 0028	Asset Class Strategy
High Voltage Outdoor Overhead Fuse	JEN PL 0030	Asset Class Strategy
Overhead Line Switchgear	JEN PL 0027	Asset Class Strategy
Distribution Surge Arresters	JEN PL 0031	Asset Class Strategy
Zone Substation Circuit Breakers	JEN PL 0039	Asset Class Strategy
Zone Substation Disconnectors and Buses	JEN PL 0041	Asset Class Strategy
High Voltage Installations Replacement Program - Enclosed Switches	ELE PL 0052	Strategic Planning Paper
High Voltage Installations Replacement Program - Overhead Switches	ELE PL 0053	Strategic Planning Paper
Replace Broadmeadows (BD) Zone Substation 66kV HKEYC Circuit Breakers	BAA-RSA-000059	Business Case
Replace Coburg North (CN) Zone Substation 66kV 1-2 Bus-Tie Circuit Breaker	BAA-RSA-000067	Business Case
Replace Footscray East (FE) Zone Substation Switchgear	BAA-RSA-000111	Business Case

Document name	Document number	Document type
Replace Footscray West (FW) Zone Substation Switchgear	BAA-RSA-000085	Business Case

3.1.3.5 Overhead conductor and underground cables

147. This asset class represents 10% of our total replacement capital expenditure over the 2016 regulatory period or $22m, representing a 5% reduction in replacement capital expenditure from the level in the 2011 regulatory period (Figure 3–29).

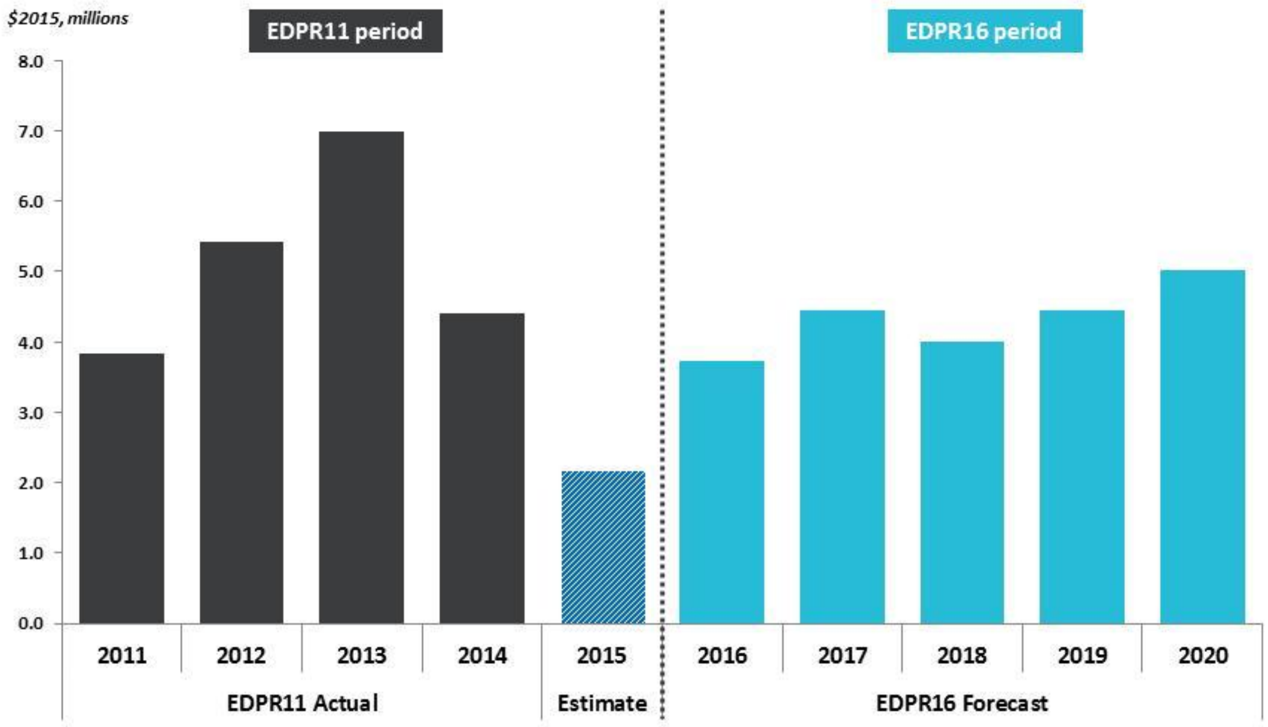
148. Overhead conductor (OH conductor) and underground cables (UG cables) asset classes forecast expenditure for 2016-20 is presented in Table 3–13.

Table 3–13: Capital expenditure for OH conductors and UG cables 2016-20 ($2015, $millions)

OH conductors and UG cables	Forecast regulatory period				
	2016	2017	2018	2019	2020
Replacement capital expenditure	3.74	4.46	4.01	4.46	5.02

(1) values include forecast labour and material price changes and exclude overheads

Figure 3–29: Capital expenditure for OH conductors and UG cables 2011-20 ($2015, $millions)



UG Cables

149. UG cables covers a broad range of asset types associated with underground distribution systems including cables and terminations.

150. The forecast replacement capex for UG cables is set to increase by 43% from levels in the 2011 regulatory period. The replacement capital expenditure is spread across a range of programs, associated with the various UG systems.

151. The main program contributing to the increase is in the underground cable asset class, and concerns the replacement of metal trifurcating boxes. These boxes are located on our poles and connect our underground cables to our overhead network. These terminations were installed on the 6.6kV, 11kV and 22kV networks. We have 133 pitch-filled trifurcating boxes on our network and the majority of these are over 40 years old. We have two types of pitch-filled trifurcating boxes: one uses a cast iron box to contain the pitch whilst the other uses a fabricated metal box.

152. We have experienced major failures of both types of boxes in recent years. The failure of the cast iron type is the most serious as the box fails explosively, spreading shards of cast iron and molten pitch some distance. The fabricated metal boxes, still exhibit a major failure, however the metal box tends to split expelling molten pitch and other debris in a more localised area.

153. Since 2007 we have had 10 failures of trifurcating boxes. We have an ongoing condition based program to replace these trifurcating boxes. The replacement of the metal trifurcating boxes has been prioritized based on the voltage and fault levels. As of 2014 all of the metal trifurcating boxes operating at 22kV have been replaced as these were more susceptible to failure due to their exposure to higher voltage stresses.

154. The remaining metal trifurcating boxes are 6.6kV or 11kV. There are 22 of 6.6kV boxes which are not targeted for replacement by this program as these are in the Preston supply area and will be retired as part of the Preston supply upgrade project. The remaining 111, 11kV boxes have been prioritised based on high fault levels and proximity to zone substations, i.e. the closer the boxes are to the zone substation the greater the fault level.

OH conductors

155. OH conductor includes assets associated with OH distribution systems including conductors and connectors.

156. The forecast replacement capital expenditure for OH conductors is set to reduce by 29% from levels in the 2011 regulatory period. The replacement capital expenditure is spread across a range of programs, associated with the various OH conductors. The main condition related replacement programs involve replacing our LV and HV OH conductors (50%).

157. We will also propose to remove LV mains in the HBRA and replace them with alternative solutions such as servicing customers directly from the distribution substation pole or by installing LV ABC. The forecast capital expenditure for this program is 25% of the overall OH conductor capital expenditure.

Further detail

158. Table 3–14 provides references to Asset Class Strategies and a Business Case that provide more detail of the need to invest in overhead conductors and underground distribution systems.

Table 3–14: Document evidence – Overhead conductors, Underground cables and zone other asset classes

Document name	Document number	Document type
Conductors and Connectors	JEN PL 0035	Asset Class Strategy
Underground Distribution Systems	JEN PL 0035	Asset Class Strategy
Replacement of Metal Trifurcating Boxes	BAA-RUA-000002	Business Case

3.1.3.6 Other asset classes

159. Other asset classes represent 18% of our total replacement capital expenditure over the 2016 regulatory period or $39m, representing a significant increase in replacement capital expenditure from current levels (see Figure 3–30).

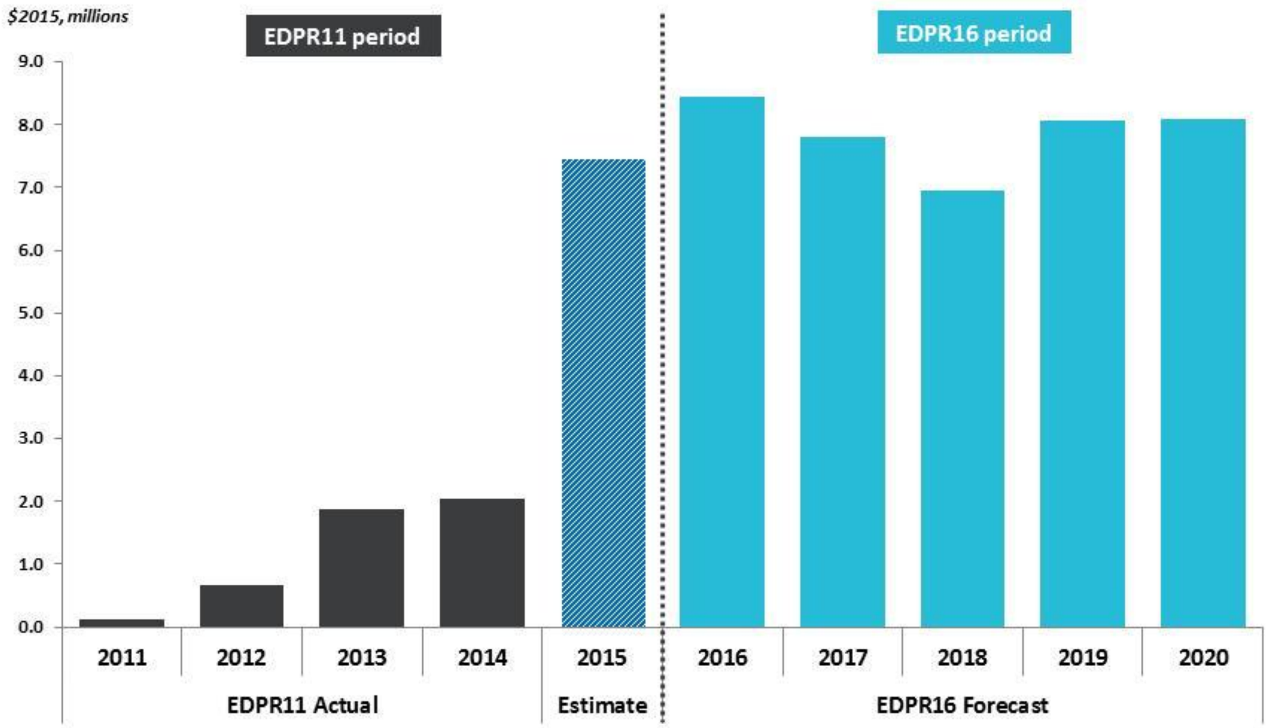
160. Other asset classes forecast replacement expenditure for 2016-20 is presented in Table 3–15.

Table 3–15: Capital expenditure for other asset classes 2016-20 ($2015, $millions)

Other asset classes	Forecast regulatory period				
	2016	2017	2018	2019	2020
Replacement capital expenditure	8.46	7.82	6.95	8.09	8.10

(1) values include forecast labour and material price changes and exclude overheads

Figure 3–30: Capex for other asset classes 2011-20

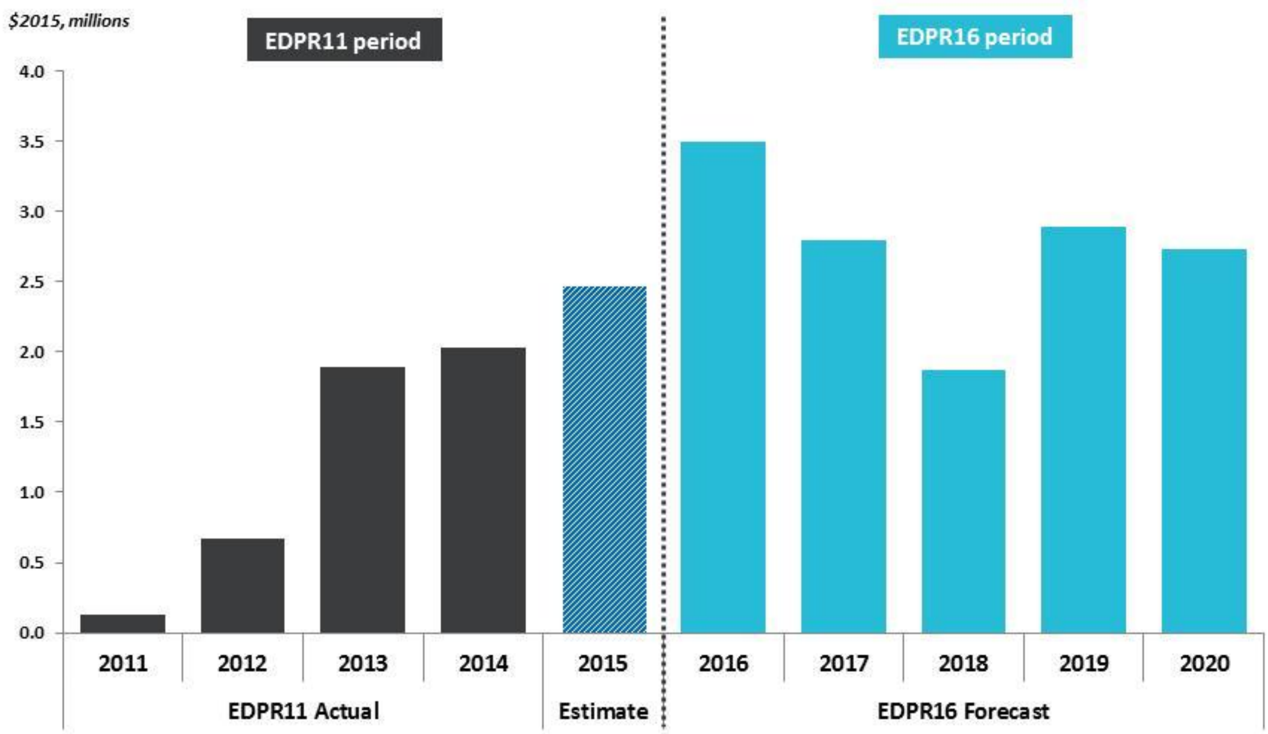


161. This category covers a broad range of asset types that don't specifically fit to any of the remaining asset classes. Examples include zone substation land, capacitor banks and battery chargers.

162. As we propose (see Attachment 5-1), 'Other assets' now includes projects classified as special capital works (e.g. elective undergrounding and asset relocation) and recoverable works (e.g. replacement of damaged assets), forming 64% of the overall capex in this category. As these activities relate to replacing assets on JEN's network we have classified these as 'replacement capex - other'.

163. Apart from special capital works and recoverable works, 'Other assets' capex is relatively on trend, representing 4% increase from expenditure in the 2011 regulatory period. We have reproduced Figure 3–30 above to exclude special capital works and recoverable works—see Figure 3–31 below.

Figure 3–31: Capital expenditure for other asset classes (no special projects) 2011-20 ($2015, $millions)



(1) Figure 3–31 excludes special capital works and recoverable works

3.1.4 KEY REPLACEMENT PROJECTS AND PROGRAMS

3.1.4.1 Condition related replacements

164. The key condition based replacement programs we are proposing include:

165. **Pole top fire mitigation** – this program will:

- Replace 3,249 vulnerable or high risk cross-arms in the 2016 regulatory period
- Reduce our customers' exposure to the risk of fire starts and associated interruptions (including high voltage injection (**HVI**)).

166. **Service Line replacement** – this program will:

- Replace 46,000 service lines of the non-preferred type and 4,531 replacements due to height (a total of 50,531)
- Address the increasing trend of electrical shocks caused by deteriorated overhead service neutrals
- Address the instance of fire starts due to failure of overhead service lines.

167. **Pole top (crossarm) replacement** – this program will:

- Replace 16,344 crossarms (when pole top fire mitigation is taken into account)
- Address the increasing risk of failure associated with a deteriorating population of crossarms.

168. **Pole replacement -** this program will:

- Replace 4,092 poles (including public lighting) and reinforce 2,460 poles
- Replace or reinforce 2,150 wood poles which are deemed 'undersized' or are LV poles fitted with HV raiser brackets
- Address the increasing risk of failure associated with a deteriorating population of poles.

169. **Underground cable trifurcating boxes** - this program will:

- Replace 72 trifurcating boxes
- Address the population of underground cable metal trifurcating boxes that have a history of major failures which could result in damage to public property or public safety.

170. **Electric line clearance engineering solutions** – this program will:

- Address 64 project locations in order to meet the updated Electricity Safety (Electric Line Clearance) Regulations by applying engineering solutions in non-compliant locations where tree removal/trimming is not possible
- Reduce our exposure to risk of fire starts, outage events, asset damage and electric shocks.

171. **Bare LV mains removal in the HBRA** - this program will:

- Progressively remove 40km of bare LV mains conductors and substitute them with alternative LV distribution solutions such as servicing customers from the pole substations or installation of LV ABC
- Be a cost effective way of reducing our customer's exposure to bushfire risk.

172. Implementing this program will further reduce the risk of fire ignition associated with electricity assets in the HBRA, therefore enhancing customer safety and avoiding damage to customer property.

173. **Zone substation switchgear replacement** - this program will:

- Replace 20 circuit breakers at Footscray East (**FE**) zone substation
- Replace 14 circuit breakers at Footscray West (**FW**) zone substation

174. **Zone substation transformer replacement** – this program will:

- Replace three 22/11kV transformers at NS zone substation
- Replace three 22/6.6kV transformer at FF zone substation
- Replace two 66/11kV transformers at ES zone substation
- Replace two 66/11kV transformers at HB zone substation.

175. Implementing this program will mitigate the risk associated with one of the most critical assets on our network. Zone substation transformers are one of our highest unit cost items and a major failure can have a range of significant consequences, including the extended loss of supply to up to 5,000 customers, loss of security of supply, potential for personal injury, risk of fire damage to equipment and environmental impacts due to oil release.

176. **SCADA/protection and control replacement** - this program will:

- Replace 14 relays at Brooklyn Terminal Station (**BLTS**)
- Replace 85 relays at Broadmeadows (**BD**) zone substation
- Replace five relays at Braybrook (**BY**) zone substation
- Replace 80 relays at Coburg North (**CN**) zone substation
- Replace 50 relays at Footscray West (**FW**) zone substation

177. The implementation of this program will reduce the risk associated with protection schemes at these zone substations not initiating a trip as intended, which will typically mean slower backup protection will operate to isolate the fault resulting in a larger part of the network being isolated, and so, customer reliability and security of supply will be reduced. In addition, there is also the possibility that backup protection will fail, which will greatly increase the likelihood of equipment damage.

3.1.5 HOW WE PLAN THE REPLACEMENT NEEDS OF OUR NETWORK

178. Our replacement capital expenditure forecast has been developed from expert engineering skills having detailed knowledge of our asset base, including the condition of the existing assets, their aging mechanisms, and their risk of failure. We have tested our investment proposal with our customers in a transparent way and to verify that our plans meet their expectations (see Attachment 4-1) with the intention of:

- Maintaining reliability and security of supply of standard control services
- Maintaining safety of the network through the supply of standard control services
- Complying with statutory obligations, including compliance with our approved ESMS.

179. More generally our replacement capital expenditure forecast will allow us to comply with our broader obligations associated with owning and operating a safe electricity network within Victoria.[21]

180. We implement asset inspection, testing, and maintenance programs across our asset base to maximise the economic life of an asset. These programs form part of our operating expenditure forecast. However, most assets, or their components, will fail at some stage due to the effects of aging on their condition. We apply two broad condition based approaches to replacing our assets:

- Replace-before-fail – proactively replace the asset, in anticipation of an unrepairable failure
- Replace-on-fail – replace the asset following an unrepairable failure.

181. Deciding which method is the most appropriate for an asset type depends on the possible consequences of a failure and the criticality of the asset in supplying services. Because of the significant consequences of failures, many of our assets are proactively replaced i.e. replaced-before-fail. In fact, an important element of our ESMS is to ensure we proactively replace critical assets and do not allow them to fail while in service to avoid safety issues.

21 Electricity Distribution Code – Section 3.1 – Good Asset Management

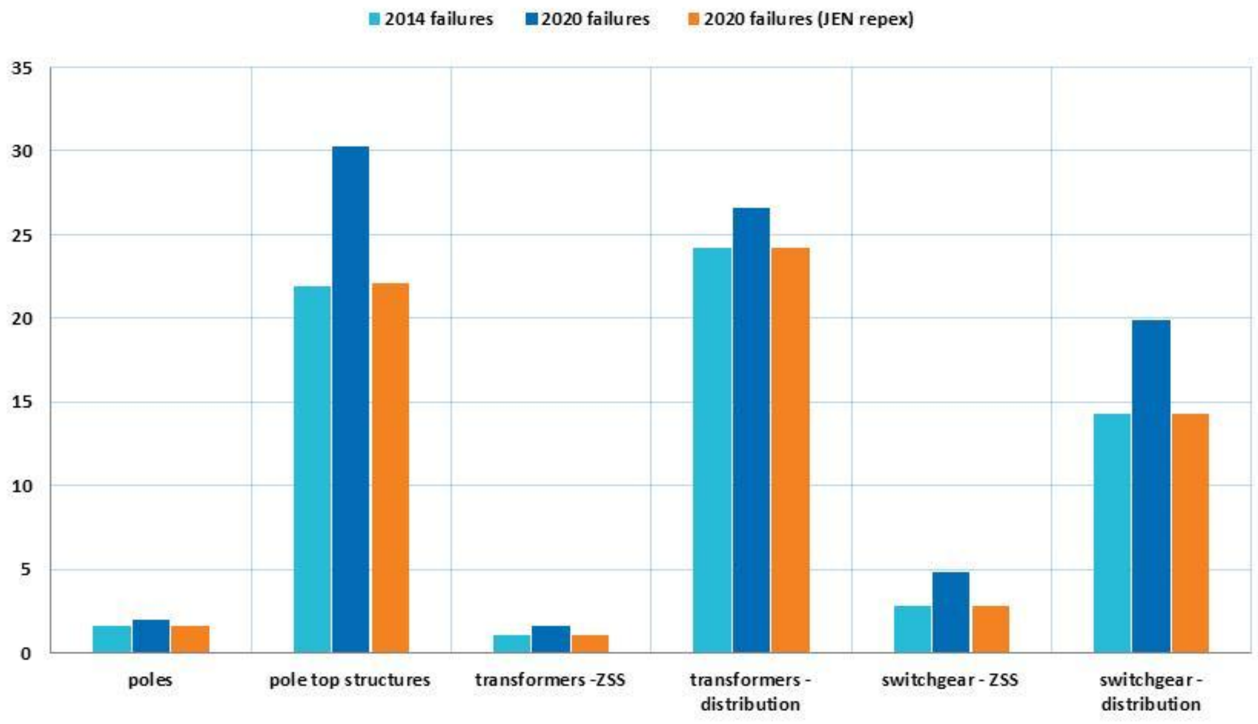
182. Importantly, we assess the condition of the assets in order to time this replacement to ensure that assets are replaced just in anticipation of their failure. We apply a number of methods to ensure this timing is optimal, including:

- assessing the condition of assets via field inspections and testing; and
- analysing failure history to identify emerging trends.

183. We also perform risk assessments to determine whether it is appropriate to replace an asset or seek to further optimise its useful life with further maintenance—evidence that we actively manage trade-offs in capital and operating expenditure as part of our business as usual processes. More recently, we apply CBRM models to aid this assessment for a number of our important assets including poles, crossarms, transformers, and switchgear. CBRM is a proprietary model[22] that uses information on the assets being modelled to provide a quantitative risk evaluation across the asset population. We have used these models to verify the reasonableness of our forecast replacement plans and assist us in ensure we are continuing to maintain reliability, security and safety at current levels.

184. Figure 3–32 summarises the asset failures as predicted by our various CBRM models. This figure shows the models' prediction of failures in 2014 (noting the models are calibrated such that 2014 reflects the actual volume of failures in that year) and 2020.[23] For 2020, the figure shows the number of failures if no replacement occurs and the number assuming a replacement rate that reflects our condition-based forecast.

Figure 3–32: CBRM model predicted number of failures



185. This figure shows that without any replacements, the number of failures would increase significantly across all the asset classes, ranging from around a 10% increase in distribution transformers to just over a 50% increase

[22] Owned by EA Technologies

[23] This measure of failure excludes the CBRM model's prediction of minor failures, which would typically be repairable.

for zone substation transformers. The total increase in failures across all the assets will be almost 30% compared with 2014 levels. Importantly, the expected number of failures in 2020, determined by considering our REPEX proposal, approximately matches the 2014 levels. That is, our forecasts can be assumed to be sufficient to maintain reliability, security and safety at 2014 levels.

Asset lives and replacement forecasting

186. We have developed a set of asset lives for the asset categories that we use to manage our network. These lives provide an indication of likely replacement age and have formed an important input into our replacement forecasting methods, particularly the various CBRM models. But it is important to stress that these lives are typically only one input, and other factors—such as the known condition of an asset—are a more significant determinant of the need to replace.[24]

187. This set of asset lives has been developed from a review conducted during the current 2011 regulatory period, and reflect a more accurate and complete set of asset lives than we have previously had available.

188. This review has considered the lives from a range of sources, which bring together independent views of good industry practice and our experience. These sources have included:

- Previous independent advice we have commissioned on the appropriate asset lives that reflect good industry practice, including advice we received in 2007 from GHD Australia and advice we received in 2010 from Parsons Brinckerhoff (**PB**)[25]
- Workshops held with AusNet Services in 2012 on the lives we could expect from our assets
- Asset lives based on JEN's previous experience.

189. The range of asset lives for the various asset classes are summarised in Table 3–16. These asset lives are used to derive the standard asset lives for the Regulatory Asset Base (**RAB**) asset classes. These calculations are undertaken within the JEN capex forecast model (see Attachment 7-4).

Table 3–16: Summary of asset lives

Asset class	Comments on range of lives
Poles	• wood poles - 54 years for unreinforced poles and 80 years for reinforced poles • concrete poles – 70 years • steel towers –70 years
Pole top structures	• wood poles tops – 45 years • steel pole tops – 70 years
Overhead conductors	• LV and HV overhead conductor – 60 years • Sub-transmission overhead conductor – 65 years
Underground cable	• Oil filled (sub-transmission only) – 70 years

24 It is also important to note that these lives are different to those that we have advised in our 2013 category analysis RIN. These lives simply reflect the lives derived from the population of assets that were replaced over the reported period.

25 JEN Forecast Asset Replacement Volumes, PB Power. 1 July 2010 and Report on the 2006 Valuation of AGL NSW Gas Distribution Network and the AGL Victorian Electricity Distribution Network, GHD. 2007.

Asset class	Comments on range of lives
	• Paper insulated (HV and LV only) – 70 years • XLPE – 55 years for LV and 40 years for HV and sub-transmission
Service lines	• Overhead service – 40 years • Underground service – 50 years
Transformers	• Zone substation transformers – 60 years • Distribution transformers – 50 years
Switchgear	• Zone substation circuit breakers – 50 years • Zone substation switchyard equipment – 55 years • HV and LV switchgear – 50 years
Public lighting	• Public lighting poles – 30 years • Streetlights – 30 years
SCADA, protection and control	• Relays – 40 years (electro-mechanical) to 20 years (digital) • Supervisory cable – 50 years • Other electronic/ digital assets – 15 to 20 years
Other	• Zone substation CTs, VTs, and buses – 50 years • Reactive plant and neutral earthing resistors – 40 years • Zone substation buildings and earth grids – 70 years

190. The methodologies we use to develop the forecast of replacement volumes do not require an explicit representation of the distribution of the asset life (i.e. via the parameterisation of a normal distribution or some other function, as is required by the AER's repex model). However, our CBRM approach does implicitly allow for the variability in the life of across the asset population, via the input of other data that represents the condition and service environment of assets. In addition, as part of the cost-benefit analysis we have applied to some of our major projects, we have used the Perks' equation[26] to represent the failure probability of an asset, and in turn, calculate the risks of asset failure over the analysis period.

191. Our replacement forecasting methods are summarised in the JEN forecasting methodology paper[27]. More detailed explanations are provided in the business cases and strategic planning papers that support the specific projects and programs that underpin our replacement forecast.

192. Further details of our process to develop detailed cost estimates that underpin our replacement expenditure forecast is provided in section 4 of this Attachment and in Attachment 7-10: cost estimation methodology, to our regulatory proposal.

Further detail

193. Table 3–17 provides references to supporting capital expenditure documents that provide more detail around the CBRM modelling, process of calculating asset age and determining useful life.

26 Perks' equation is an accepted equation for representing the hazard function in mortality studies.

27 Jemena Electricity Networks (VIC) Ltd, *Expenditure forecast methodology, May 2014*

Table 3–17: Document evidence – CBRM Modelling, Network Asset Useful Lives and Age Profiling Method

Document name	Document number	Document type
Condition Based Risk Management (CBRM)	ELE GU 0005	Supporting procedure document
Network Asset Useful Lives Procedure	ELE PR 0012	Supporting procedure document
Age Profiling Methodology	ELE PR 0011	Supporting methodology document

3.1.6 PREDICTIVE MODELLING: REPEX

194. In assessing the reasonableness of our replacement forecasts, we have developed an alternative replacement forecast using the AER's assessment tool that it calls the REPEX model.[28] This forecast provides an alternative high-level assessment that supports the validity of our own replacement forecast.

195. We have followed the method indicated by the AER, to construct a model of our network using the REPEX model and calibrate it to reflect our actual replacement outcomes (volumes and expenditure) over the 2010 to 2014 period. To do this, we used the data supplied to the AER in response to the category analysis RIN.[29]

196. As explained in the addendum to Attachment 7-11, for the NSW/ACT draft determinations the AER calculated a 'reasonable range' for each of the distribution network service provider's (**DNSP**) replacement capital expenditure forecasts. Importantly, the range presented the aggregate REPEX over the forecast regulatory period (not a year on year or asset class assessment).

197. The reasonable range was determined from a set of model scenarios. Each scenario reflected a forecast prepared by the model using a different set of the model's planning parameters (i.e. asset lives and unit costs).

198. For our own REPEX calibration, we have applied the same three scenarios that the AER would apply if we assumed they applied the same rationale as they did for the NSW/ACT businesses:

- **Scenario 1** – uses our historical replacement capital expenditure unit costs from the 2010-2014 data reported in our category analysis RIN response
- **Scenario 2** – uses our forecast replacement capital expenditure unit costs for 2016-20 reported in our response to the EDPR RIN, and

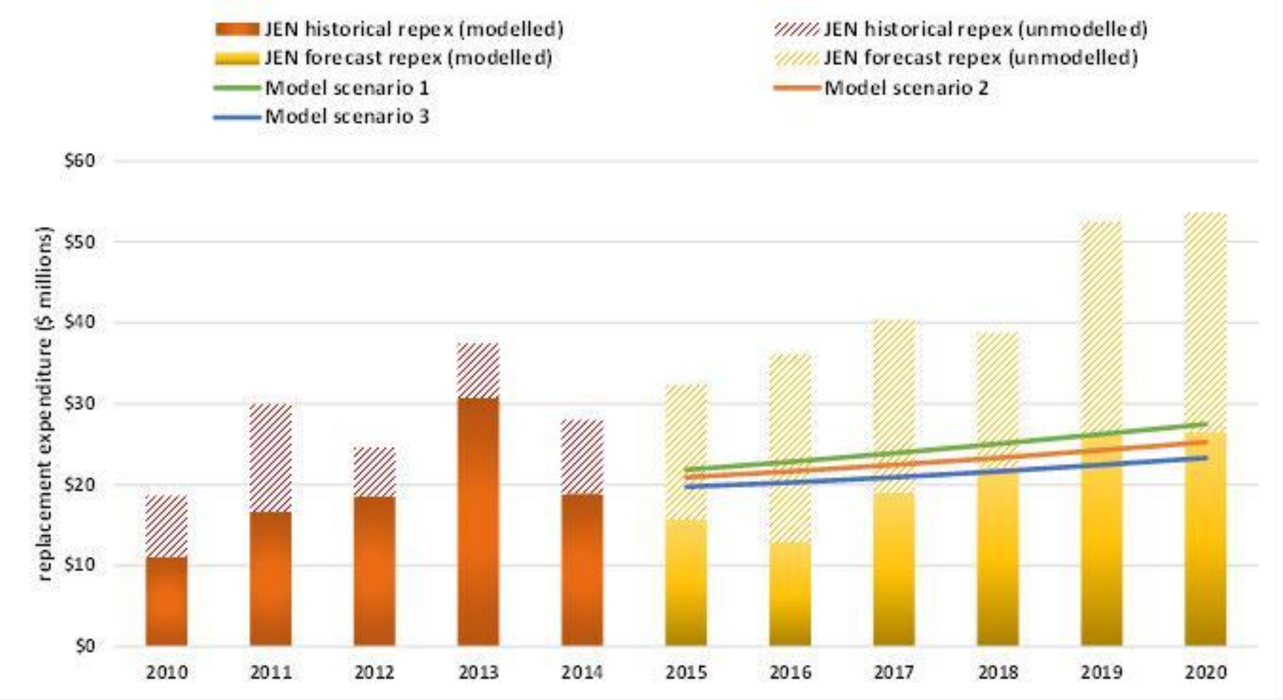
199. **Scenario 3** – uses the AER's benchmark unit costs that are an average of the historical unit costs (like Scenario 1) from all the DNSPs in the National Electricity Market.

200. Figure 3–33 shows the results of our REPEX modelling, indicating the alternative forecasts for each of the three scenarios produced by the REPEX model, compared to our own replacement forecast.

28 AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013

29 Our calibration of the REPEX model was prepared by Dr Brian Nuttall who originally developed the model for the AER. Dr Nuttall has prepared an expert report with further detail of how the model was calibrated, see Attachment 7-11: Nuttall Consulting – Independent analysis of replacement expenditure.

Figure 3–33: JEN REPEX predictive model results ($nominal, $millions)



Source: Attachment 7-11: Independent analysis of replacement expenditure (Nuttall Consulting), Addendum

201. This figure shows that the AER REPEX model predicts a ‘reasonable range’ 2% above the component of our own replacement capital expenditure forecast covered by this model. This suggests that the AER would accept this component[30] of our replacement capital expenditure forecast if it applied the same modelling approach as it did for the NSW/ACT DNSPs.

202. Attachment 7-11 further explains how the forecast increase in replacement capital expenditure should be expected for at least the next 20 years—which supports our claim that the network is entering the initial phase of a long term replacement cycle and replacement levels will need to continue to increase from historical levels if we are to maintain the reliability, security and safety of our network in light of the further aging of our network assets. This message is also clearly explained within Attachment 7-6.

203. Given the analysis summarised above, we believe it is reasonable to conclude that our forecast is well supported by the alternative forecast prepared using the AER’s REPEX model. See Attachment 7-11 for further detail.

3.2 CONNECTIONS CAPITAL EXPENDITURE

We plan and construct customer connections, new and upgraded, at our customers request.

204. Connections expenditure explained in this section is gross customer initiated connections capital expenditure which has not been reduced by forecast customer contributions.

30 In determining a reasonable range, the AER noted that some replacement capital expenditure categories should not be assessed with the REPEX model and were consequently excluded from its modelling. These categories were also excluded from the analysis above in Figure 3–33 and include the SCADA/ network control, other, pole top structures and public lighting categories. We have also ran a scenario in Attachment 7-11 which includes the pole top structures category for reasons outlined in the attachment.

3.2.1 KEY MESSAGES

Key messages for our connection capex are:

- Customer connections investment is expected to continue at similar levels in the 2016 regulatory period to what occurred in the 2011 regulatory period, except for the one-off major connection project to upgrade the supply capacity to the commercial precinct in and around Melbourne Airport.
- Continued changes in our customer mix are expected into the 2016 regulatory period. These changes are characterised by large industrial customers in decline and substituted with significant growth in residential and commercial customer connections.

205. JEN is responsible for providing connection and supply services to customers and generators, undergrounding or asset relocation services, public lighting services, distribution services to other distributors and other services. Forecasts of gross connections capital expenditure presented in this section only relate to services classified as standard control services (or distribution services as we have defined it in section 1.1 of this attachment) (see Attachment 5-1).

206. Customer connections investment is driven by customers and is outside our direct control. The level of customer investment on our network is generally correlated with the level of economic activities in Melbourne and as such, we derive our forecast connections capital expenditure using externally sourced macro-economic forecasts.

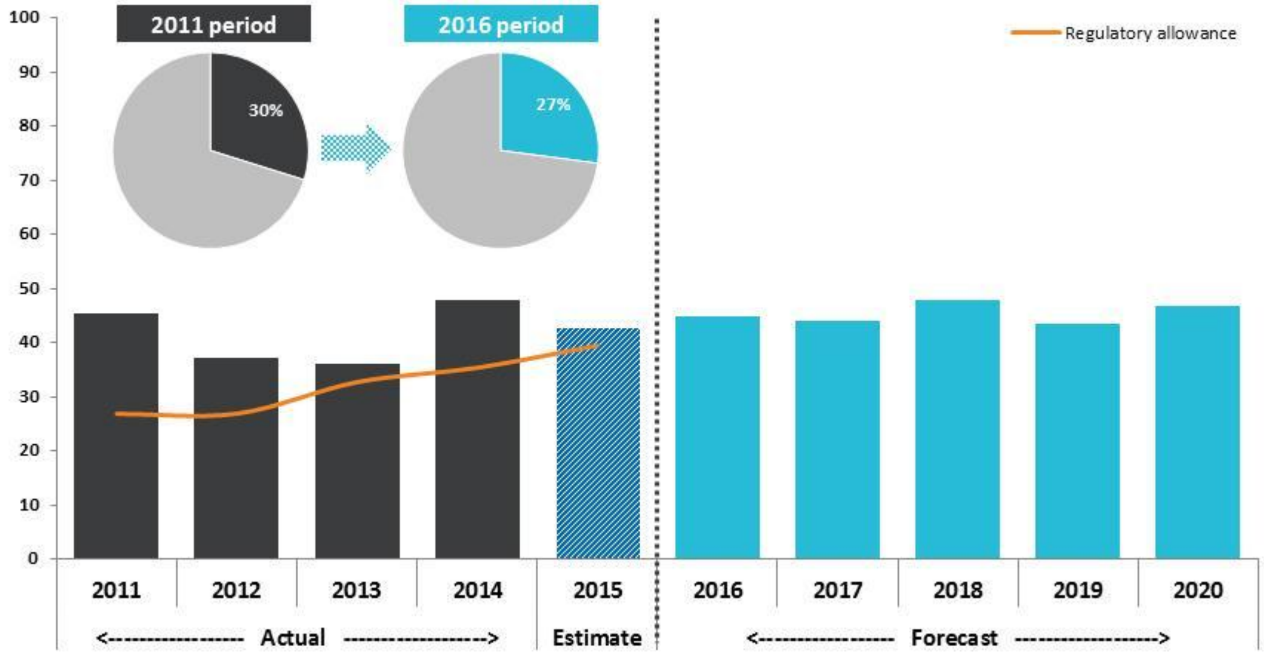
207. Table 3–18 provides the total gross distribution services connections capital expenditure for the 2016 regulatory period.

Table 3–18: Total gross distribution services connections capex 2016-2020 ($2015, $millions)

Total gross connections capital expenditure	Forecast regulatory period					
	2016	2017	2018	2019	2020	Total
Total gross connections capex	48.2	47.8	50.3	46.3	48.8	241.4

(1) Gross connections has not been reduced for forecast customer contributions
(2) Distributions services is defined as standard control services in this report

Figure 3–34: Connections capital expenditure 2011-2020 ($2015, $millions)



3.2.2 DRIVERS OF FORECAST GROSS CONNECTIONS EXPENDITURE

208. JEN derives its forecast capital expenditure using macro-economic growth forecasts consistent with the expected level of economic activities in Melbourne.

209. We engaged ACIL Allen and utilise forecasts from the Construction Forecasting Council (**CFC**) to inform our volume forecasts for each of our connections activities. These macro-economic sources are used as a basis to establish annual volume growth rates for forecasting customer connections investment:

- ACIL Allen residential customer number forecasts are used to derive forecast volume growth rates for residential connection activities (dual and multiple occupancy, and medium density housing)—see Attachment 3-3 and 3-4.
- CFC non-residential sector (industrial, other commercial & miscellaneous) expenditure forecasts are used to derive forecast volume growth rates for business connection activities (businesses with usage greater than 10kVA, and low density / small business supplies)
- CFC engineering sector (roads, bridges, railways and harbours) expenditure forecasts are used to derive forecast volume growth rates for special capital or recoverable works.

210. In addition to developing a trend model to forecast the majority of customer connections capital, significant one-off projects, such as the capital investment required to supply the commercial precinct in and around Melbourne Airport, are included as individual project forecasts.

211. The macro-economic forecasts we used to develop our customer connections investment are presented in Table 3–19 and Table 3–20.

Table 3–19: ACIL Allen forecast of JEN residential customers

Year	JEN residential customers	Residential customers added	Annual growth rate
2011 (actual)	274,983		
2012 (actual)	279,065	4,082	1.46%
2013 (actual)	283,007	3,942	1.39%
2014 (actual)	287,018	4,011	1.40%
2015	291,012	3,994	1.37%
2016	295,081	4,068	1.38%
2017	298,974	3,894	1.30%
2018	302,685	3,711	1.23%
2019	306,456	3,771	1.23%
2020	310,289	3,832	1.23%

Table 3–20: CFC forecast of non-residential sector expenditure

Year	Non-residential sector (Industrial, Other Commercial & miscellaneous) expenditure [$2014, $millions]	Expenditure ratio to previous year
2011 (actual)	$1,730	
2012 (actual)	$1,828	106%
2013 (actual)	$1,764	96%
2014 (actual)	$2,232	127%
2015	$2,447	110%
2016	$2,691	110%
2017	$2,701	100%
2018	$2,689	100%
2019	$2,731	102%
2020	$2,745	101%

Table 3–21: CFC forecast of engineering sector expenditure

Year	CFC engineering sector (Roads & Bridges Railways Harbours) expenditure [$2014, $millions]	Expenditure ratio to previous year
2011 (actual)	$3,839	
2012 (actual)	$4,228	110%
2013 (actual)	$3,860	91%
2014 (actual)	$3,566	92%
2015	$3,468	97%
2016	$3,371	97%
2017	$3,371	100%
2018	$3,363	100%
2019	$3,391	101%
2020	$3,399	100%

3.2.3 GROSS CONNECTIONS EXPENDITURE EXPLAINED

212. Table 3–22 provides our year-on-year connections capital expenditure forecasts by common connection activity. We've generated detailed forecasts for each of the connection activities by applying a rolling three yearly weighted average volume of work and unit rate for each activity based on actual historical data. Our total connections capital expenditure proposed for the 2016 regulatory period is on trend with our historical expenditure, except for the incremental expenditure associated with the significant development (and associated connection activities) at Melbourne Airport.

Table 3–22: Total forecast connection activity capital expenditure 2016-20 ($2015, $millions)

Connections expenditure (SCS) by category	2016	2017	2018	2019	2020	Total
New KTS to MAT 66kV line	0.93	3.49	6.67	-	-	11.08
Business supply > 10kVA	25.16	23.69	24.29	25.55	27.32	126.02
Dual and multiple occupancy	11.85	10.67	10.71	11.35	12.24	56.81
Medium density housing	7.04	6.30	6.31	6.59	7.16	33.39
Low density/small business supplies < 10kVA	0.10	0.09	0.10	0.10	0.11	0.50
Total	**45.07**	**44.24**	**48.07**	**43.60**	**46.83**	**227.80**

(1) Numbers may not add due to rounding

3.2.4 KEY GROSS CONNECTIONS PROJECTS

3.2.4.1 [C-I-C Melbourne Airport Expansion]

213. [C-I-C Melbourne Airport is investing more than $1 billion in capital development projects. Their program is part of Melbourne Airport's biggest transformation since it opened more than 40 years ago. Over the next 10 years, Melbourne Airport expects to triple the required load from our network from 30 MVA to 90 MVA.

214. As Melbourne Airport is a sub-transmission customer, augmenting the sub-transmission loop (66kV lines) that supplies Melbourne Airport is our responsibility and so we have been working closely with Melbourne Airport to ensure the network can meet its future electricity supply needs.

215. Under normal network conditions, our sub-transmission (66kV) line from the Keilor Terminal Station (KTS)-Airport West (AW) would be overloaded by summer 2017-18 and the KTS-Tullamarine (TMA) 66kV line would be overloaded by summer 2019-20. Customer supply risk in the event of a single line outage (an N-1 event) already exists for customers supplied from this 66kV sub-transmission loop.

216. Additional details of this project can be found in the 'Melbourne Airport – Network Development Strategy, which identifies the need to construct a new 66kV sub-transmission line from KTS to Melbourne Airport prior to summer 2018/19 at an estimated cost of $10.4m].

3.2.5 HOW WE FORECAST NEW CONNECTIONS ON OUR NETWORK

217. This section provides a summary of how we forecast customer connection investment. Additional detail can be found in our Customer Connections Capital Forecasting Methodology, provided with the capital expenditure supporting documents in response to the EDPR RIN.

218. Consistent with the capital expenditure objectives set out in Clause 6.5.7 (a) of the NER, this methodology is aimed at providing a consistent, transparent and auditable approach underpinning the forecast capital expenditure that is required to meet the expected demand for customer connections.

219. Our customer connections capital expenditure is grouped under the activities in Table 3–23 with the following proposed service classification proposed in Attachment 5-1.

Table 3–23: JEN Customer Connections Service Classifications

Service Classification	Activity Description
Business supply >10kVA	Capital works associated with the provision of new or increased supply to all projects that require network augmentation and negotiated using the Industrial/ Commercial extension procedures, using low, medium and high density network methods.
Dual and multiple occupancy living	Capital works associated with the provision of additional supply points to existing lots from roadside mains including any minor upgrading of the roadside low voltage mains and installation of service cables and pits.
Medium density housing (URD/PURD)	Capital works associated with High Voltage and Low Voltage underground and partial underground works (URD/PURD), service pits and kiosks to provide supply to new medium density residential subdivisions, neighbourhood extensions both specific and general as well as minor low voltage extensions in medium density areas, supplied by extending or upgrading the network system.

Service Classification	Activity Description
Special Capital or Recoverable Works[31] (Customer Contribution of a Non Supply nature)	Capital works carried out for customers or other authorities in which actual costs are externally financed and for which the prime purpose is to satisfy a requirement other than new or increased supply. It also includes minor pole relocations that have been requested by customers or developers. The amount of work required varies annually, depending on the volume of customer requests.
Low Density/Small Business Supplies <10kVA	Capital works associated with the provision of new or increased overhead or underground supply to low density subdivisions and single/ small group extensions.

220. The methodology used for customer connections capital forecasting is divided into three phases:

- Data Analysis
  - Historical capital expenditure data (by financial years) for each activity is broken down for analysis into: material and labour; unit rates; unit volumes; and number of projects
  - Unit volumes and rates are derived for each activity to form the basis for the Module Forecasting phase; this is known as 'Base Volume' and 'Base Unit Rate'. Base Unit Rate is then escalated using historical CPI index so that it represents current year dollar ($real).
- Module Forecasting
  - Volume Forecasts are derived from macro-economic forecasts sourced from ACIL Allen and CFC.
- Forecast and Reporting
  - The forecast for each activity is derived from the product of Volume Forecast for each activity, its corresponding 'Unit Rate Forecast' and its 'Unit Price Escalation'. Any major projects identified are also included in the forecast for each activity. The forecasts for each activity are then seasonalised using a historical monthly expenditure profile taking into account the actual expenditure to date, to produce monthly forecast for each activity.

3.3 AUGMENTATION CAPITAL EXPENDITURE

We propose to deliver targeted augmentation investments required to meet the capacity needs of our customers.

221. Augmentation expenditure is required to ensure that our network can meet customer expectations regarding demand and reliability. Our augmentation expenditure is primarily driven by forecast changes in our customers' demand for electricity.

[31] These services have historically been treated as ACS, however reclassified to SCS from the 2016 regulatory period

3.3.1 KEY MESSAGES

Key messages for our augmentation capex are:

- Growth in demand across JEN is slowing but remains positive overall, with the network-wide summer maximum demand forecast to grow at an average rate of 1.36% per annum between 2014-15 and 2020-21. This compares to a historical average growth rate of 2.44% per annum over the past nine years.
- Network averages mask significant spatial differences in demand and network utilisation. Despite the general slowing in demand growth at the total network level, there are areas within the network where maximum demand is forecast to grow well beyond the network average level. On the other hand, some parts of the network are forecast to experience a decline in maximum demand due to manufacturing closures. As a part of our augmentation forecast we prudently analysed these local network conditions to identify and address emerging constraints on the network to ensure we are acting efficiently in meeting our capital expenditure objectives.
- Similar levels of augmentation expenditure are forecast in the 2016 regulatory period, relative to the 2011 regulatory period, are required to service the growing residential and small business population in three of the Victorian Government's identified metropolitan growth corridors:
  - The Northern growth corridor, encompassing Craigieburn and the Somerton supply region
  - The Sunbury growth corridor, covering the region around Sunbury and Diggers Rest
  - The Western growth corridor, including some of the Western perimeter of our network around Sydenham.
- We engaged a consultant to conduct econometric modelling to forecast demand on JEN, using the same forecasting methodology as it developed for AEMO[32]; our internally developed spatial demand forecasts were calibrated to these macro forecasts to ensure we have a robust forecast on which to develop our augmentation capex program of works.
- We adopt a probabilistic approach to network planning; this method takes a risk based assessment of not serving energy to determine growth and therefore augmentation investment. For a particular feeder, zone substation or subtransmission line an assessment is made of the available capacity (maximum asset loading), and the risk that customer demand will exceed the available capacity, leading to unserved energy. This approach results in significant customer savings when compared to a deterministic planning approach.
- We continually seek out opportunities to deliver prudent and efficient outcomes for our customers by exploring non-network (e.g. demand management) solutions to customer supply constraints, including Regulatory Investment Tests for Distribution (**RIT-D**) for our major augmentation projects in the 2016 regulatory period, assessing opportunities to align augmentation and replacement projects (ensuring no duplication); and engaging with customers to better understand how they value reliability[33].

222. Table 3–24 provides our total forecast augmentation capital expenditure for the 2016 regulatory period.

[32] AEMO*, Transmission connection point forecasting approach, for Victoria*, September 2014

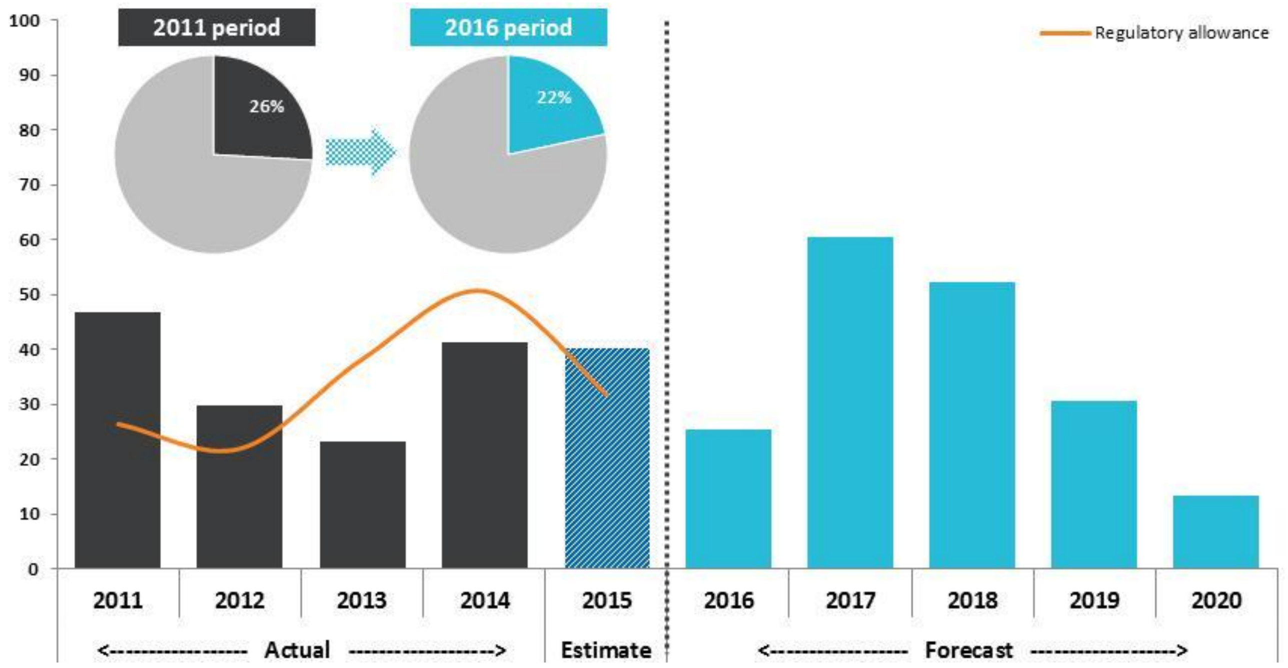
[33] Options are evaluated using economic cost benefit analysis to consider the broader costs and benefits of various options. Key inputs to this analysis are our customers' expected unserved energy and the value of customer reliability (**VCR**). The VCR is determined by AEMO and reviewed periodically. We have applied the updated (lower) VCR in all our planning assessments, augmentation forecasts and economic cost benefit analyses for the 2016 regulatory period.

Table 3–24: Total augmentation capital expenditure 2016-2020 ($2015, $millions)

Total augmentation capital expenditure	Forecast regulatory period					
	2016	2017	2018	2019	2020	Total
Total augmentation capex	25.44	60.64	52.40	30.64	13.58	182.69

(1) Capital expenditure includes real cost escalators, capitalised overheads however excludes equity raising costs

Figure 3–35: Augmentation capital expenditure 2011 to 2020 ($2015, $millions)



3.3.2 DRIVERS OF FORECAST AUGMENTATION EXPENDITURE

223. The key driver for determining augmentation expenditure on our network is customer supply risk. We have been using the same approach for determining augmentation expenditure for over a decade.

224. Forecast customer supply risk and our plans for augmenting the network are reviewed each year as part of the annual network planning cycle. This annual planning review results in the publication of our Distribution Annual Planning Report (**DAPR**).[34] The DAPR is provided as a capital expenditure supporting document with our response to the EDPR RIN.

225. The DAPR presents customer supply risk by comparing forecast customer demand against the existing capability of the network (sub-transmission lines, zone substations and high-voltage feeders). The outcome of this comparison results in a number of scenarios:

- Demand is increasing or decreasing but is always less than the capability of the network → no augmentation
- Demand is increasing and exceeds network capability → identify augmentation options

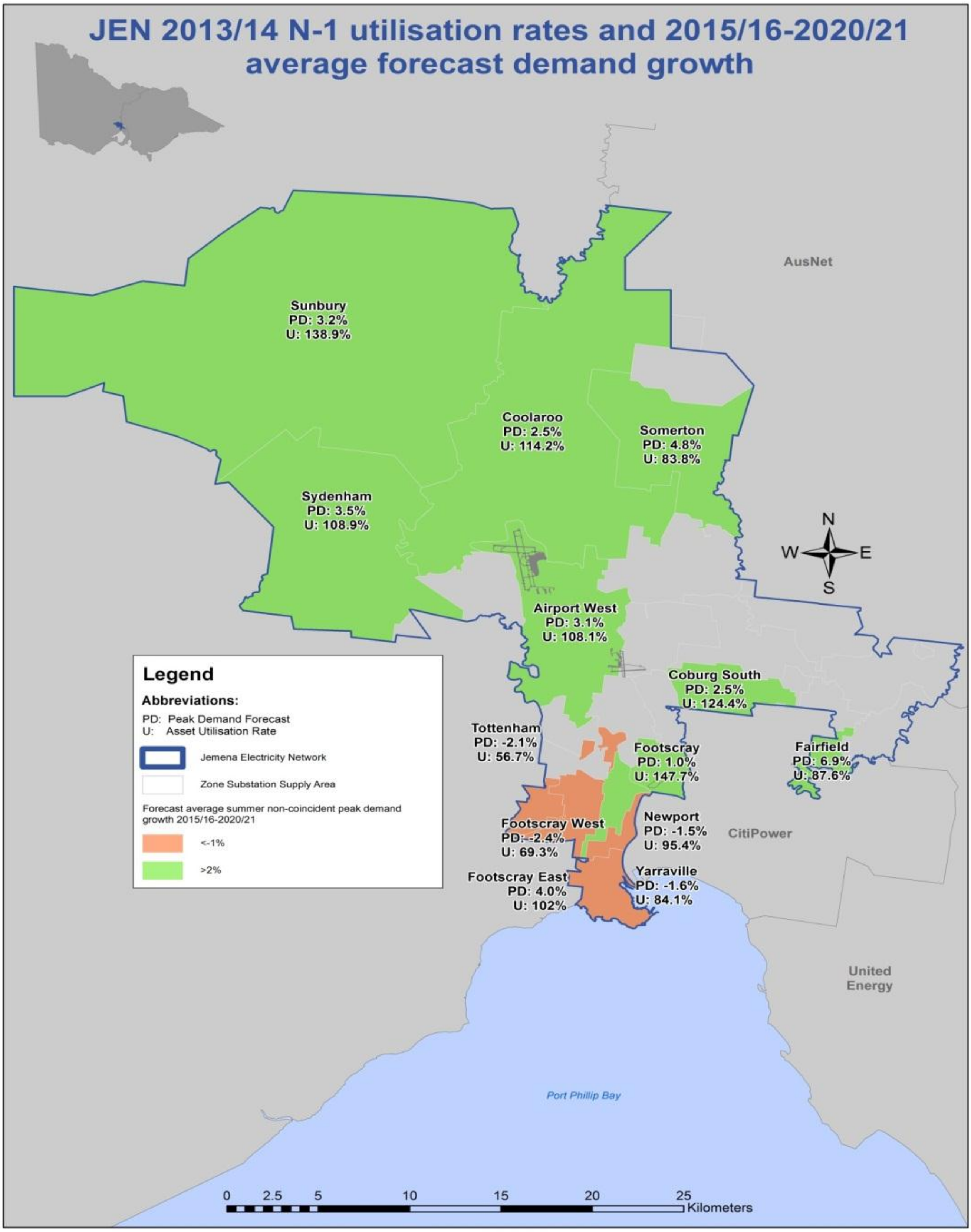
34 NER cl 5.13

- Demand is decreasing but already exceeds network capability → identify short-term non-network augmentation options
- Demand is only slightly above network capability → continue to monitor where there is insufficient customer risk to justify augmentation

226. Figure 3–36 is a map of the JEN area, by zone-substation distribution regions. The areas of the map highlighted in green represent those where we are forecasting strong (>2% per annum) peak demand growth[35] over the 2016 regulatory period, conversely areas in orange are locations where we are forecasting negative growth greater than -1% per annum peak demand.

35 Average Summer non-coincident peak demand growth over 2015/16-2020/21 (50% probability of exceedence)

Figure 3–36: JEN growth areas by distribution sub-station region (per annum)



227. Note: Each zone sub-station region has the actual average forecast peak demand growth rate denoted by the acronym 'PD'. Each zone sub-station region also has the 2014 actual asset utilisation rate denoted with the acronym 'U'—representing the current Summer cyclic capacity of the zone-substation (at N-1)[36].

228. Our approach to determine the need for electricity network augmentation is summarised further in section 3.3.5, documented in our 2014 DAPR (Section 2.4) and is in Attachment 3-5.

3.3.3 AUGMENTATION EXPENDITURE EXPLAINED

229. Table 3–25 provides our forecast augmentation expenditure by sub-category over the 2016 regulatory period.

Table 3–25: Total augmentation expenditure 2016-20 by sub-category ($2015, $millions)

Total augmentation expenditure	2016	2017	2018	2019	2020	Total
Subtransmission augmentation	0.03	10.90	5.65	2.82	0.0	19.40
Zone substation augmentation	6.36	21.09	35.64	10.34	4.31	77.74
High voltage feeder augmentation	5.51	12.92	3.79	3.89	2.68	28.79
Distribution substation & Low Voltage network augmentation	5.24	4.45	4.50	4.62	4.94	23.75
Other augmentation	8.29	11.28	2.81	8.97	1.65	33.01
Total	**25.44**	**60.64**	**52.40**	**30.64**	**13.58**	**182.69**

230. Approximately two-thirds of JEN's proposed augmentation expenditure over the 2016 regulatory period relates to the seven largest projects/programs listed in Table 3–26.

Table 3–26: Proposed augmentation capex by major project / program ($2015, $millions)

Augmentation capital expenditure by major project	2016	2017	2018	2019	2020	Total
Preston conversion	8.15	8.42	12.66	6.95	-	36.17
New zone substation at Craigieburn	-	-	9.22	10.24	-	19.47
Upgrade zone substation at Flemington	3.22	7.46	-	-	-	10.68
Upgrade zone substation at Sunbury	-	5.99	11.08	-	-	17.07
High voltage distribution feeder works	5.51	12.92	3.79	3.89	2.68	28.79
Distribution substation	5.24	4.45	4.50	4.62	4.94	23.75
Other projects	3.32	21.40	11.15	4.93	5.96	46.77
Total	**25.44**	**60.64**	**52.40**	**30.64**	**13.58**	**182.69**

231. We provide a summary of the seven largest augmentation projects/programs we must undertake in the 2016 regulatory period to ensure we maintain our current service levels and meet increased demand in various areas of the network. The following projects contribute about 67% of our total proposed augmentation costs.

[36] N-1 zone substation capacity refers to capability of the zone substation to supply power with one critical asset out of service.

3.3.4 KEY AUGMENTATION PROJECTS

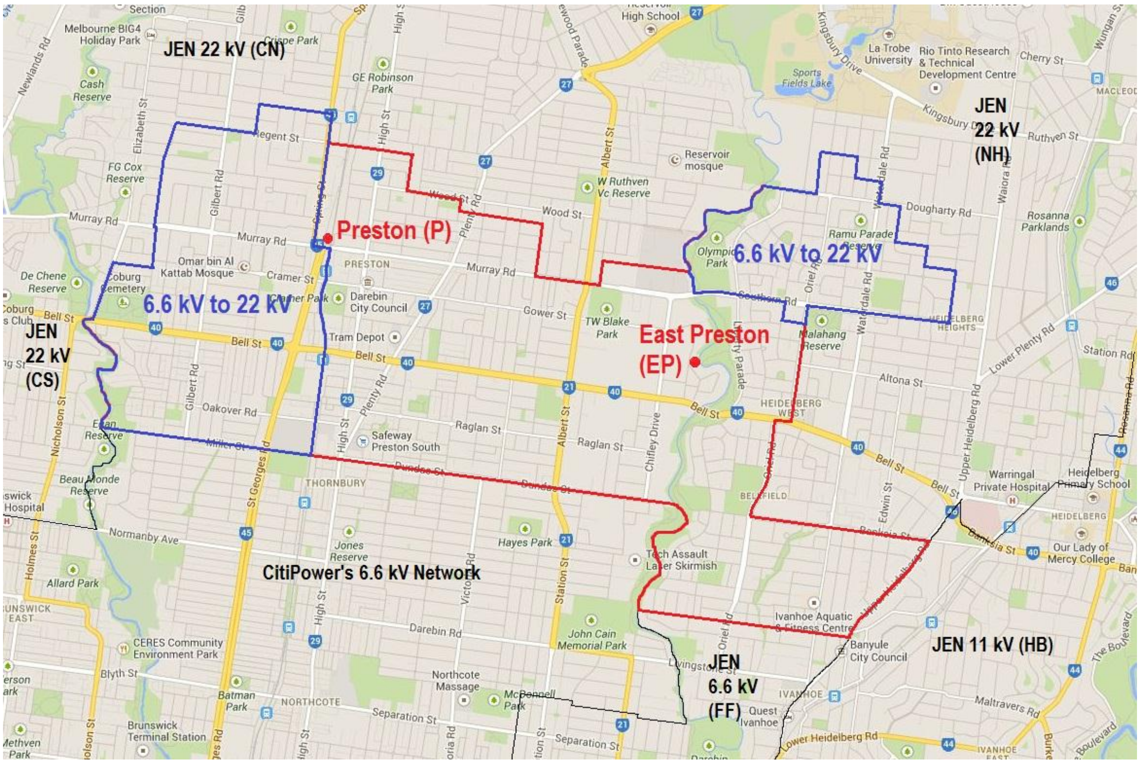
3.3.4.1 Preston Conversion Program

232. Prior to the Preston conversion project commencing in 2008, the Preston area was entirely supplied by the Preston (**P**) and East Preston (**EP**) zone substations which operate at 6.6kV distribution voltage. These assets were established in the 1920s and underwent refurbishment in the 1950s and 1960s.

233. Our condition based assessments of the equipment at P and EP predicts the assets will reach the end of useful life in 2014 and 2020 respectively. In combination with the actual condition constraints of these assets, urban revitalisation in the area has also led to demand constraints on the 6.6kV system. This lack of capacity will result in deteriorated service to customers due to us being unable to restore supply within a reasonable time frame during outages and would also require major 6.6kV feeder augmentation at considerably higher costs than the conversion program.

- In 2008, a Preston area network development strategy was developed which recommended converting the 6.6kV distribution assets—a voltage standard from the 1920s—to 22kV, rather than a like-for-like replacement. At December 2014, we had completed five of the fourteen stages of the conversion program, which will in total span the length of four regulatory control periods.
- Total expenditure for the conversion program between 2008 and 2023 is estimated at $83m, as opposed to approximately $105m if the 6.6kV network was retained, replaced and expanded for customer growth.
- Figure 3–37 provides an image of the Preston conversion network augmentation already undertaken, with areas in blue already converted from 6.6kV to 22kV and areas in red still being supplied by the 6.6kV distribution assets.

Figure 3–37: Preston area conversion program



Source: *JEN analysis, January 2014*

234. The planned works in 2016 and 2017 (P Stages 4 and 5, and EP Stage 4) enable the Preston zone substation to be removed from service. By 2017, once P has been removed from service, the load that has been transferred to neighbouring 22kV zone substations places a larger number of customers at risk of losing supply as a result of network outages. With the additional load, previously supplied from P, being supplied from Coburg South (CS) and Coburg North (CN) zone substations, the supply capacity of these stations is forecast to be exceeded by summer 2018-19.

235. The need for additional 22kV supply into the area is planned to be achieved by constructing a new Preston (PTN) zone substation on the existing P site, once all of the existing assets are decommissioned and removed. This new PTN zone substation is planned to be in-service by November 2018, before the capacity of CS and CN is exceeded.

236. The remaining stages of the Preston conversion program had originally been planned to be completed by 2020 to align with the end of useful life of assets at EP. Given that we have extended the life of the Preston zone substation by 3 years, the conversion strategy has been updated to complete the conversion program by 2023. As such, the final three stages of the conversion program have shifted from the 2016-20 period to the 2021-25 period. Our economic cost benefit analysis indicates that this deferral will provide our customers with the greatest net economic benefit.

3.3.4.2 New zone substation at Craigieburn

237. JEN's network is experiencing rapid load growth in the areas around Craigieburn and Greenvale—within the Northern Growth Corridor—and augmentation of the distribution network is required to meet the increased demand arising in the coming years.

238. The area around Craigieburn is expected to increase its population by approximately 20,000 people over the next ten years, and two suburbs (Kalkallo and Mickleham) to the north of Craigieburn are expected to experience rapid population growth following this. Kalkallo and Mickleham are forecast to increase their population tenfold to about 50,000 between 2021 and 2036.

239. In the short term, the load at risk (i.e. customer supply risk) on the five critical HV feeders supplying the area around Craigieburn is managed by load transfers to the distribution zone substation at Kalkallo (**KLO**) and a feeder reconfiguration project planned for completion by November 2016. However, even with these reconfigurations, we forecast that the HV feeders supplying the area will be over capacity by summer 2019/20.

240. The three zone substations currently supplying the northern growth corridor region, Somerton (**ST**), KLO and Coolaroo (**COO**), are also forecast to reach capacity over the next ten years and are all a significant distance from the centre of the current load growth, making further HV supplies to the area difficult and costly. ST zone substation, which is the closest and most logical point to supply additional HV feeders to the growth area, is a fully developed zone substation with no spare 22kV circuit breakers for additional feeders.

241. We considered six different options of how best to meet our safety and reliability obligations to our customers while minimising the cost of this investment on our customers' bills. The outcome of our analysis was that building a new Craigieburn zone substation is the optimal solution as it will augment the distribution network in the Craigieburn, Somerton, Roxburgh Park and surrounding areas and provide sufficient capacity to meet our forecast load growth and will maintain supply reliability at adequate levels. We have undertaken detailed economic cost benefit analysis associated with this project to ensure that the broader benefits and costs to the network and our customers have been considered and that the project (and associated costs) is in the long term interests of our customers.

242. The recommendation from this analysis was to build a new Craigieburn zone sub-station and the optimal timing to invest is to deliver the project by November 2019 in time to meet the forecast summer 2019-20 peak demand.

3.3.4.3 Upgrade Flemington zone substation

243. The Flemington zone substation (**FT**) supplies close to 15,000 domestic, commercial and industrial customers in the Flemington, Kensington, Ascot Vale and surrounding areas, with major customers including Flemington Race Course and the Melbourne Showgrounds.

244. FT is a multi-level indoor zone substation that was originally commissioned in the 1960s using air insulated switchgear (**AIS**). Due to its age and condition, many of the primary assets and the protection and control assets will require replacement over the next five to ten years to maintain current levels of supply reliability. The zone substation building is also beginning to degrade and is in need of repair.

245. The FT zone substation capacity is limited during summer and winter peak demand periods, by the inadequate 11kV ratings of the transformer cables and circuit breakers.

246. An augmentation project to address these capacity constraints was planned to occur during the 2011 regulatory period, however the condition of the zone substation building and safety concerns regarding working in close proximity to the 66kV indoor roof-suspended assets, resulted in the project being deferred and alternative solutions being investigated.

247. With the Flemington Racecourse and Showgrounds both contributing to increased demand in the area, and new housing developments in and around the racecourse, additional capacity out of the FT zone substation is needed immediately. As such, the RIT-D for this project commenced in early 2015, with the expectation that augmentation can be achieved by late 2017.

248. Detailed economic cost benefit analysis of the options considered in this augmentation has concluded that advancing the replacement of the 11kV switchgear and transformer cables, and the addition of a new 11kV bus to enable more HV feeders into the supply area, provides the greatest net economic benefit to our customers.

3.3.4.4 Upgrade Sunbury zone substation

249. Sunbury and the area around Diggers Rest has developed from a rural country area to a large suburban area with a mixture of commercial and medium density housing as significant new housing estates and land developments have been made. The Sunbury and Diggers Rest area is located within the Victorian Government's urban growth boundary, and the Metropolitan Planning Authority is currently preparing five Precinct Structure Plans for development of the areas surrounding the Sunbury CBD. With these developments expected to lead to significant population growth in the area and electricity demand is expected to grow at a rate of 4% per annum over the next 15 years.

250. Established in 1964, the Sunbury zone substation (**SBY**) now supplies 14,500 customers, has reached full capacity and is of low reliability due to an inferior design that is no longer appropriate for the amount of load the substation now provides.

251. The capacity of SBY is provided by two 16MVA transformers and one 10 MVA transformer. The overall station transformers' normal rating (N rating) is effectively 32 MVA (instead of 42MVA)—due to the uneven load sharing of the three transformers. The 10 MVA transformer reaches its limit before the other two transformers are fully utilised.

252. Since the summer of 2012, we've managed the overload risk under system normal conditions by conducting load transfers to the nearby Sydenham (**SHM**) zone substation. Contingency transfer under system normal condition is only used as a temporary measure rather than a permanent solution, as this places additional risks on the adjacent Sydenham zone substation and its feeder where the transfer was made. From summer 2017-18 onwards, under system normal conditions, there will be insufficient capacity at SBY over the summer peak load period (including contingent load transfer to SHM) to supply the forecast customer demands.

253. Therefore, the risk of significant supply interruptions at SBY is very high for summer 2017/18 and so we propose to redevelop the SBY zone substation (including transformer replacement) in 2017. In alignment with the RIT-D methodology, our preferred and recommended strategy is the option (five were considered) that maximises the net economic benefit to our customers.

254. The preferred option includes redeveloping the station in accordance with current zone substation standards by replacing the outdoor 22kV switchyard with an indoor 22kV assets in a new zone substation building, and augmenting the station capacity by replacing the existing 10 MVA transformer with a new 20/33 MVA unit.

3.3.4.5 High Voltage (HV) distribution feeder augmentation program

255. JEN has a total of 221 high voltage electricity distribution feeders, of which 22 feeders are forecast to exceed their maximum safe loading limit by summer 2020-21 under 10% probability of exceedence (**POE**) demand conditions. There are also additional feeders which have downstream capacity limitations, transfer capacity limitations for planned or unplanned outages, or quality of supply issues.

256. A feeder project may include feeder upgrade, reconfiguration, extension or construction of a new feeder. This includes modification or addition as required of associated in-line equipment (e.g. switches, voltage regulators) and secondary systems.

257. In order to maintain a safe and reliable electricity supply to customers, Jemena proposes a total capital expenditure of $25.6m across 25 projects during the 2016 regulatory period to address high voltage electricity distribution feeder capacity constraints.

258. This level of expenditure is comparable to the HV feeder augmentation expenditure during the 2011 regulatory period.

3.3.4.6 Distribution substation and Low Voltage (LV) network augmentation program

259. At the beginning of the 2011 regulatory period we estimated that around 17% of our distribution substations could exceed their capacity under 10% POE demand conditions. During the 2011 regulatory period, the distribution substation augmentation (**DSA**) program focused on augmenting the distribution substations with the largest customer supply risk, and it is estimated the substations at risk will have reduced to around 11% of the population by the end of 2015.

260. Although the DSA program during 2011-2015 has focused on substations with the largest risk, there remains a significant number with forecast loading greater than 120% of capability. As such the DSA program for the 2016 regulatory period has been planned with a similar, but slightly lower, level of expenditure of approximately $20m.

Further detail

261. Table 3–27 references to the detailed network development strategies underpinning these proposed augmentation projects.

Table 3–27: Document evidence – augmentation capex

Document title	Document number	Document type
Preston Area Conversion NDS	ELE PL 0029	Network Development Strategy
Northern Growth Corridor NDS	ELE PL 0025	Network Development Strategy
Flemington NDS	ELE PL 0027	Network Development Strategy
Sunbury / Diggers Rest NDS	ELE PL 0030	Network Development Strategy

Document title	Document number	Document type
Distribution Feeders NDS	ELE PL 0006	Network Development Strategy
Distribution Substation Augmentation NDS	ELE PL 0017	Network Development Strategy

3.3.5 HOW WE PLAN THE AUGMENTATION NEEDS OF OUR NETWORK

262. Probabilistic planning—our principal planning method—is a cost-benefit approach to network augmentation which compares the expected amount (and value) of energy that will not be supplied under a 'do nothing' option against the expected cost of feasible network and non-network options that would reduce or eliminate the identified network capacity issue. The option that maximises the net benefit, which includes the 'do nothing' option, is selected.

263. An important aspect of probabilistic planning is that it exposes customers to the risk that network capacity may not be sufficient to meet actual demand. Under this planning approach, action is only taken to address the risk of a capacity shortage if this outcome is less costly to customers than the expected cost of the outage. It should be noted that one source of risk is the demand forecast, especially as weather may have a significant impact on actual demand. For this reason, maximum demand forecasts are reported on a POE basis, to denote the probability that the actual demand will exceed the forecast.

264. Although customers are exposed to higher levels of supply risk than what would occur using a deterministic network planning criteria, they receive the economic benefit (i.e. reduced electricity costs) due to augmentation projects occurring many years later.

265. Table 3–28 provides the current Summer 2014/15 utilisation rates of some of our most heavily loaded zone substations and the forecast utilisation rate for Summer 2019/20 under an **N-1 event**.

Table 3–28: JEN's heavily utilised zone substations

Zone sub-station	Utilisation rates (N-1 Summer cyclic capacity)	
	2014 utilisation rate	2020 utilisation rate
Flemington (**FT**)	147.5%	146.9%
Coburg South (**CS**)	124.4%	131.7%
Sunbury (**SBY)**	138.9%	160.1%
Footscray East (**FE**)	102.0%	128.3%
Coolaroo (**COO**)	114.2%	119.9%
Braybrook (**BY**)	130.2%	118.2%
Sydenham (**SHM**)	108.9%	112.7%
Somerton (**ST**)	83.8%	107.6%
Essendon (**ES**)	119.4%	107.1%
Fairfield (**FF**)	87.6%	98.6%
North Essendon (**NS**)	110.8%	96.2%
Airport West (**AW**)	108.0%	88.7%

Source: JEN internal analysis (March 2015)

(1) The Airport West 2020 utilisation rate is presented with a load transfer to our new Tullamarine zone substation, committed to be completed by the end of 2015.

266. Table 3–28 indicates that at least 12 of our zone sub-stations are facing a significant amount of load at risk (level of customer supply exposed at an N-1 event) which is driving the need to augment the network in these areas. Under a deterministic network planning approach 10 of these 12 stations would have already been augmented.

267. Some of the utilisation rates in Table 3–28 are decreasing between 2014 and 2020 due to decreasing demand. Where this is occurring we are carefully reviewing our augmentation options to ensure we don't over invest in network options that may be underutilised in the future. At some of these stations, a non-network option (i.e. demand management) or HV feeder project to enable load to transferred to a neighbouring zone substation if an outage occurs, are significant less costly than increasing the capacity of the zone substation, and are likely to be better economic options for our customers.

3.3.6 PREDICITIVE MODELLING: AUGEX

268. The required augmentation capital expenditure is robust, based on best practice techniques and innovative designs, and it delivers a network that can meet forecast customer demand and expected levels of reliability. To sense check this forecasting approach we compare against results obtained from predictive models that determine required levels of augmentation.

269. To better understand the AER's predictive AUGEX model[37], JEN engaged Nuttall Consulting to calibrate the model based on historical levels (i.e. 2010 to 2014) of augmentation and forecast the future augmentation needs. The key outcome of this analysis was that the AUGEX model produces a forecast 7% higher than (the modelled component of) JEN's own augmentation forecast, suggesting JEN's augmentation forecast benchmarks favourably compared to its own recent history.

270. A summary of the analysis, by AUGEX category is provided in Table 3–29 and in Table 3–30.

Table 3–29: JEN AUGEX model – network segment summary augmentation expenditure

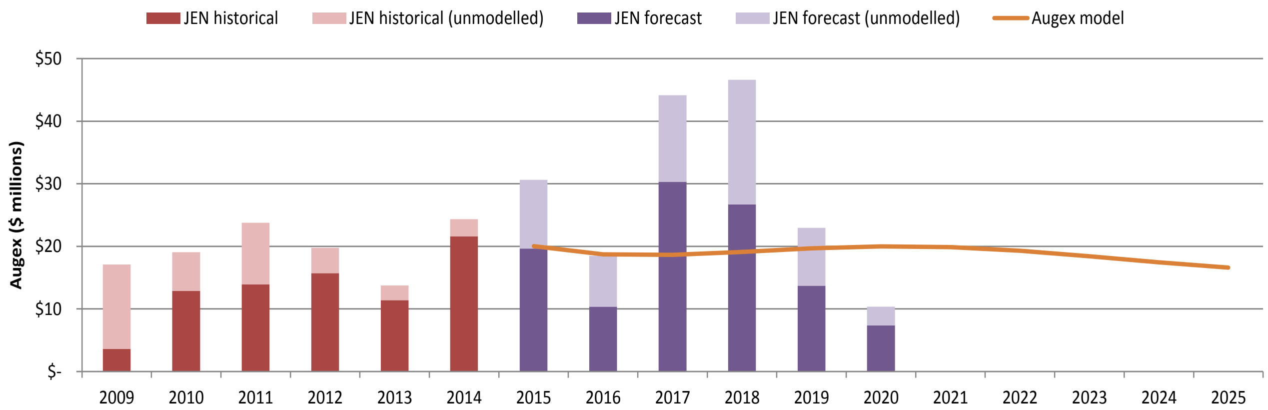
	NSP average per annum			Augex model average per annum			
	historical	forecast	forecast	augex	diff to NSP	augex	diff to NSP
	2011-14	2016-2020	2015-2020	2016-20	forecast	2015-20	forecast
	$ millions	$ millions	$ millions	$ millions	%	$ millions	%
ST lines	0.50	2.22	1.92	0.92	-59%	0.89	-54%
ZSS	8.13	7.36	7.98	11.20	52%	10.98	38%
HV feeders	2.61	4.54	4.51	5.28	16%	5.73	27%
DSS	4.44	3.56	3.60	1.70	-52%	1.65	-54%
Total	**15.68**	**17.68**	**18.01**	**19.11**	**8.1%**	**19.24**	**7%**

[37] AER, *Guidance document, AER augmentation model handbook*, November 2013

Table 3–30: JEN AUGEX model – network segment summary augmentation capacity added

	NSP average per annum			Augex model average per annum			
	historical	forecast	forecast	capacity	diff to NSP	capacity	diff to NSP
	2011-14	2016-2020	2015-2020	2016-20	forecast	2015-20	forecast
	MVA	MVA	MVA	MVA	%	MVA	%
ST lines	22	27	24	41	54%	42	76%
ZSS	25	22	41	34	52%	34	-16%
HV feeders	20	32	47	41	26%	40	-15%
DSS	14	10	10	5	-48%	5	-46%
Total	**81**	**91**	**122**	**120**	**33%**	**122**	**0%**

Figure 3–38: JEN AUGEX model forecast



Source: *Independent analysis of augmentation expenditure (Nuttall Consulting), Attachment 7-12*

271. Figure 3–38 indicates the proportion of our augmentation expenditure, which should not be assessed through the AUGEX model as the primary driver is not due to capacity limits associated with the utilisation of the network assets (light purple bars). Examples of un-modelled augmentation expenditure include projects such as reinforcing earthing across the distribution network or installation of a new bund for oil containment at a zone substation, as these projects do not provide additional supply capacity to the network.

Further detail

272. Table 3–31 provides references to Excel supporting files used to derive our AUGEX forecast, provided in response to our EDPR RIN.

Table 3–31: AUGEX supporting files

Document name	Document type
Augex model report (zip file)	Supporting Excel files

3.4 NON-NETWORK CAPITAL EXPENDITURE

273. Non-network capex relates to expenditure required to replace JEN's IT systems, motor vehicles and plant and buildings and property.

274. Non-network categories are classified as follows:

- Non-network IT[38]
- Non-network Other
  - Motor vehicles and plant
  - Buildings and property (including tools and equipment).

3.4.1 KEY MESSAGES

Key messages for our non-network capex are:

- **IT**: Over the 2016-20 regulatory period we have forecast to broadly maintain our current trend in IT expenditure by proposing lifecycle replacement of some of our systems, including the Outage Management System, Distribution Management System, Geospatial systems and Asset construction and field service systems. To the extent our non-network IT forecast is incremental in real terms to our historical trend, this is mostly due to expenditure attributed to the cost re-categorisation of JEN's Advanced Metering Infrastructure IT expenditure previously regulated under the CROIC but now transferring into standard control service regulation.
- **Buildings and property**: The main property related project JEN proposes to undertake within the 2016-20 regulatory period is to redevelop our Broadmeadows operational depot in 2016 to reduce the size but increase the functionality of the depot.
- **Motor vehicles and plant**: Much of our motor vehicles and plant assets are within a replacement phase of their lifecycle and so we are proposing to replace or rebuild 213 motor vehicles and plant.

275. The non-network expenditure represents 16% of our total capex over the 2016 regulatory period or $137m. This is a 1% reduction in non-network capex from the level in the 2011 regulatory period.

276. Our total forecast non-network capital expenditure for the 2016 regulatory period is presented in Table 3–32.

Table 3–32: Non-network capital expenditure 2016-20 ($2015, $millions)

Non-network capital expenditure	Forecast regulatory period				
	2016	2017	2018	2019	2020
Total non-network capital expenditure	38.48	27.01	26.35	24.37	20.99

(1) No overheads applied to the non-network capex category

277. Table 3–33 provides the non-network IT forecast capital expenditure for the 2016 regulatory period.

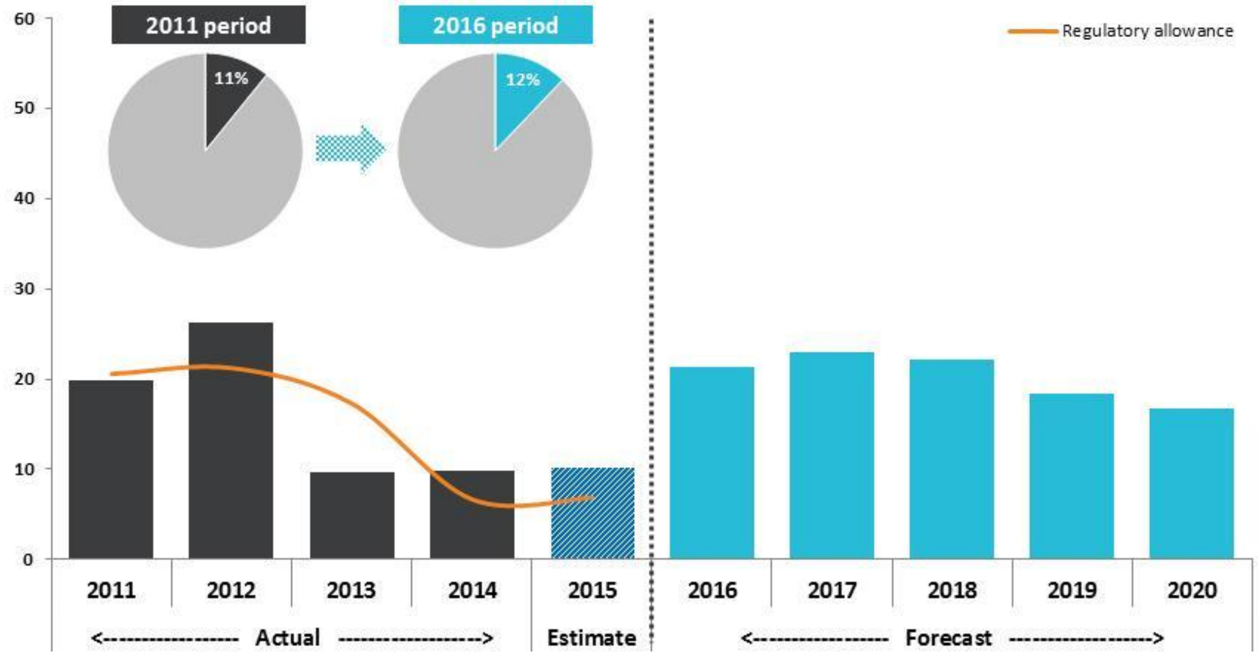
[38] Excludes real time network systems such as SCADA

Table 3–33: Non-network IT capital expenditure 2016-20 ($2015, $millions)

Non-network IT capital expenditure	Forecast regulatory period				
	2016	2017	2018	2019	2020
Total non-network IT capital expenditure	21.36	22.98	22.28	18.44	16.84

(1) No overheads applied to the non-network capex category

Figure 3–39: Non-network IT capital expenditure 2011-20 ($2015, $millions)



278. Our capex in the non-network—other category predominately comprises the following items:

- Motor vehicles and plant
- Buildings and property (including tools and equipment).

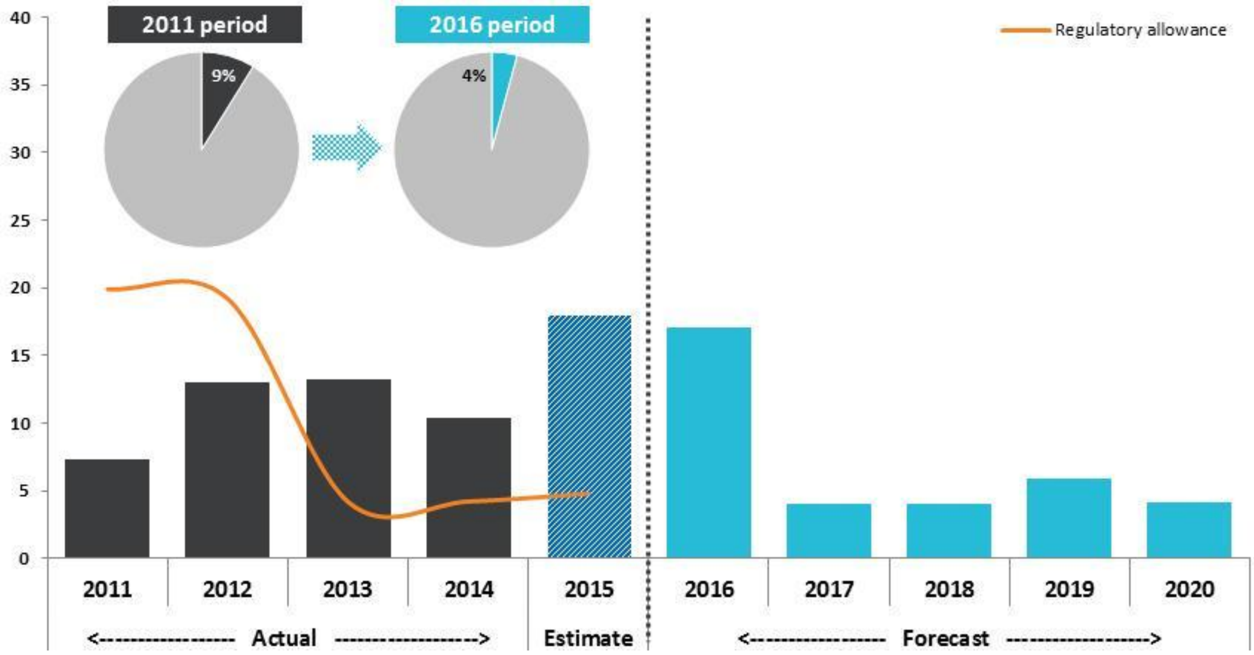
279. The non-network other expenditure represents 4.2% of our total capex over the 2016 regulatory period or $35m, representing a 43% reduction in non-network other capex from the level in the 2011 regulatory period. Table 3–34 provides the non-network other forecast capital expenditure for the 2016 regulatory period.

Table 3–34: Non-network other capital expenditure 2016-20 ($2015, $millions)

Non-network other expenditure	Forecast regulatory period				
	2016	2017	2018	2019	2020
Total non-network other capital expenditure	17.12	4.03	4.07	5.93	4.15

(1) No overheads applied to the non-network capex category

Figure 3–40: Non-network other expenditure 2011-2020 ($2015, $millions)



3.4.2 DRIVERS OF FORECAST NON-NETWORK EXPENDITURE

3.4.2.1 Drivers of forecast IT capital expenditure

280. The objective of our IT capital program is to take advantage of new technologies and capabilities to develop IT solutions which support our operations' efficiency and effectiveness.

281. To prepare our IT capex forecast, projects are sourced from the business to elicit new initiatives and historical activities to sustain systems. When preparing costings for the activities, we use a range of techniques, including top-down analysis and external consultant advice and bottom-up builds based on historical project costs and timings.

282. The capital projects costs are based on two average daily rates, excluding overheads, reflecting two levels of project complexity:

- Highly specialised projects based on solutions such as SAP, Geospatial Information Systems, Business Intelligence, Market Systems and Infrastructure projects are costed at an average daily rate per project team of $1,463 ($2015) per day[39].
- More widely and commonly used and less complex software applications such as Microsoft based systems development, office systems, records management and document management. These projects are costed at an average project team cost of $1,000 ($2015) per day.

283. The daily rates are a mix of in-house employees at a total cost of employment calculation plus external contract and services company staff and the rates used are based on historical expenditure trends. Contract rates for

39 These rates are competitively sourced through market tenders and panel arrangements as detailed in our deliverability report within the IT AMP (see Attachment 7-7)

external staff are obtained through individual tender by project or from a competitively sourced panel of suppliers.

284. JEN's ratio of internal to external, contract staff depends on the nature of the project with a 15% / 85% ratio[40] on complex applications where specialised skills are required and internal resources are not maintained as permanent staff. These are generally also the projects where the higher rate is incurred. The ratio of internal to external staff is 50% / 50% on more standardised and recurrent projects such as infrastructure upgrades and client device updates where internal resources are maintained on a long term basis.

3.4.2.2 Drivers of forecast Motor vehicles and plant capital expenditure

285. There are six drivers for the replacement and rebuild of motor vehicles and plant. The drivers are:

- To ensure that motor vehicles remain fit for purpose
- To ensure that motor vehicles purchased offer the least cents per kilometre vehicle operating costs
- Motor vehicles should meet the latest Australian Standards and Design Rules
- Motor vehicles will be four (4) star or greater safety rating as per the Australasian New Car Assessment Program (**ANCAP**)
- Where a motor vehicle is of low utilization (< 150,000 km), is in presentable condition and is economic to retain, the vehicle may be retained in service
- To ensure that Jemena maintains a good community reputation and that customers are not adversely impacted by inappropriate or unreliable motor vehicles and plant that will in turn impact our network performance.

3.4.2.3 Drivers of forecast buildings and property capital expenditure

286. JEN operates two field depots within the distribution territory, namely:

- The Broadmeadows depot which is a site of approximately 24,000 square meters and provides office accommodation for project management, design, planning and specialised technicians
- The Tullamarine depot which is a site of approximately 7,000 square meters, is located 12 kilometres from the Broadmeadows site, and provides facilities and logistics for field service personnel

287. The following factors are drivers for the redevelopment of the Broadmeadows depot:

- The need to comply with Jemena's OH&S risk management policy. There are existing issues associated with asbestos remediation and non-compliance with building codes
- The relocation of field and office staff from the Broadmeadows depot to the recently completed Tullamarine depot means that there is no longer a requirement to utilise the full capacity of the existing Broadmeadows site.

[40] These ratios demonstrate our preference for elastic resourcing for specialised skills and are aligned with common IT business practice. Further detail is provided in our deliverability report in Attachment 7-7.

3.4.3 NON-NETWORK EXPENDITURE EXPLAINED

3.4.3.1 Non-network IT

288. Table 3–35 provides our year-on-year IT capital expenditure forecasts by IT activity class. We've generated detailed forecasts for each of the connection activities listed by applying a bottom-up forecast for each activity based on actual historical data. Our total IT capital expenditure proposed for 2016 regulatory period is on trend with our historical expenditure and is indicative mostly of lifecycle management.

Table 3–35: Total forecast IT activity expenditure by regulatory year ($2015, $million)

Non-network IT expenditure by category	2016	2017	2018	2019	2020	Total 2016-20
Regulatory & market services systems	0.99	0.44	0.45	0.45	0.46	2.80
Corporate & office systems	1.02	0.18	0.47	2.86	0.19	4.73
Finance & accounting	0.69	0.37	0.14	0.15	0.25	1.60
Human resources, safety & incident management	1.31	0.63	0.27	0.28	0.28	2.77
SAP lifecycle management	1.28	0.39	1.17	0.66	0.76	4.26
Customer systems	2.79	1.19	0.06	0.84	0.16	5.03
Outage Management System (OMS) & Distribution Management System (DMS)	1.68	4.64	6.20	1.07	1.00	14.59
Business intelligence, reporting & data warehouse systems	0.23	0.23	2.45	2.49	0.86	6.27
Document, record and content management systems	1.28	0.92	0.61	1.33	0.92	5.06
Geospatial systems, mapping & asset imaging	0.93	2.06	0.61	2.02	3.45	9.07
Asset Construction & Field Services Systems	3.35	3.90	1.32	0.63	1.17	10.37
IT Infrastructure (Lifecycle Upgrades, Replacement & Retirement)	5.49	7.21	8.01	3.30	2.94	26.96
Metering - Standard Control Systems Metering	0.33	0.81	0.50	2.38	4.39	8.40
Metering – Ongoing advanced metering	-	-	-	-	-	1.91
Total	**23.50**	**24.62**	**23.93**	**23.60**	**23.41**	**103.81**

(1) Expenditure above excludes overheads

289. We explain the type of activities occurring in each of the IT categories and where possible, explain the specific unit rate applied to forecast expenditure in each category.

Regulatory and market services systems - $2.80m

290. The regulatory and market services encompass information systems functions and facilities required to meet regulatory obligations and to comply with all non-energy government regulations.

291. JEN provides a range of service to the electricity energy market via demand and supply and load management systems.

292. The regulatory and market systems encompass information systems, functions and facilities required to:

- Comply with AER regulation and rules
- Provide the services and integration for the energy market to operate via AEMO
- Comply with all non-energy Federal and State Government regulation.

293. Costings are prepared from bottom up project timelines using labour rates for specialised projects based on the high rate for staff.

Corporate and office systems - $4.73m

294. The corporate and office systems encompass the corporate and back office functions of JEN. The enterprise systems cover IT solutions used by the entire business including office systems, intranet and general reference information. The functions supported by the corporate and enterprise systems are:

- Executive and general management
- Operational portal
- Office administration and productivity tools
- Internet and Intranet
- Corporate communications
- Mobility tools

295. Costings are prepared from bottom up project timelines using labour rates on the SAP related projects based on the high rate for staff and the lower rate for other activities. Additional costs are included for licencing and hardware in the desktop tools projects.

Finance and accounting - $1.60m

296. The finance and accounting systems projects encompass the functions used by the entire business including accounting, credit management, capital and asset accounting, treasury management, Business plans, governance, risk and compliance, and labour and cost allocation models and general reference information. The functions supported by the systems are:

- Executive and general management
- Governance and risk management
- Financial management and accounting
- Procurement
- Credit management
- Treasury

297. Costings are prepared from bottom up project timelines using labour rates for SAP projects based on the high rate for staff.

Human resources, safety and incident management - $2.77m

298. The Human Resource systems projects encompass human resource, safety and incident management functions of JEN. The enterprise systems cover IT solutions used by the entire business. The functions supported by the human resource systems are:

- Human capital management
- Managed self service
- Learning management
- Environment health and safety
- Incident management
- Payroll

299. Costings are prepared from bottom up project timelines using labour rates for SAP projects based on the high rate for staff.

SAP lifecycle management - $4.26m

300. The SAP lifecycle projects encompass SAP ERP system and associated modules used by the entire business. The functions supported within the corporate environment are:

- Procurement and logistics
- Works and asset management
- Customer management
- Resource management
- Operations analytics

301. The SAP Lifecycle Management category specifically excludes finance and accounting and human resources which have been described in earlier sections and form part of the integrated SAP ERP system.

302. Costings are prepared from bottom up project timelines using labour rates for SAP projects based on the high rate for staff.

Customer systems - $5.03M

303. The customer systems encompass all interaction with JEN’s customers including the end consumer of energy. The Customer systems consist of those systems required to engage with and service end customers, retailers, providers and transmission businesses.

304. The customer systems projects encompass functionality used by the business to support:

- System based customer relationship management
- Customer engagement solutions
- Customer safety through Dial Before You Dig

305. The customer systems include systems devoted to the protection of assets from third party interaction with the asset.

306. Costings are prepared from bottom up project timelines using labour rates for SAP projects based on the high rate for staff. Additional costs are included for licencing and hardware in the CRM and Dial Before You Dig projects.

Outage (**OMS**), Distribution (**DMS**) and emergency management - $14.59m

307. The distribution network systems for the purposes of this asset class are those systems that manage the network as a physical asset and to distribute electricity. The systems manage the electricity from the point of advice by the retailer to provide the service, to receiving the energy from the transmission businesses and through to the end consumer. The systems assets in this class are:

- Outage Management—Current IT systems that manages the disruption or failure of the network to supply electricity.
- Distribution Management—New capability that improved the routing and load management of electricity through the network.
- Integrity Management Tool—New and replacement technology that monitors the networks condition and ability to distribute electricity.
- Operational Technologies (**OT**)—Outage and phase identification tools.

308. New and replacement technologies to monitor, track and predict outages.

- Demand and emergency load management—Increased capability leveraging advanced metering data to improve the matching and management of demand and supply.

309. Emergency load management is the controlled reduction of energy load to minimise harm to consumer businesses.

- Relay equipment setting information system (**RESIS**)—Provision for ongoing change to an existing system.
- Emergency management—Improved IT systems support for emergencies enabled by new mobility, intelligence and communications technologies.

310. Costings are prepared from bottom up project timelines using labour rates for specialised projects based on the high rate for staff. Additional costs are included for software licencing related to the replacement of the Outage & Distribution Management Systems.

Business intelligence, reporting and data warehouse systems - $6.27m

311. The business intelligence, reporting and data warehouse systems encompass corporate and back office functions of JEN. The systems cover IT solutions used by the entire business to manage data collection, storage and presentation for internal and external requirements

312. The BI, Data Warehouse and Reporting projects encompass functionality used by the business to support:

- Sourcing, management and provision of data.
- Business analytics.
- Executive and management reporting.

313. Costings are prepared from bottom up project timelines using labour rates for specialised projects based on the high rate for staff. Additional costs are included for software licence growth.

Documents, records and content management systems - $5.06m

314. The document, records and content management systems encompass corporate and back office functions of JEN. The systems cover IT solutions used by the entire business to manage, maintain and enable access to documents (be they reports, drawings, photographs or the like) required to manage the business.

315. The document, records and content management projects encompass functionality used by the business to support:

- Content management in terms of information sources, taxonomy, currency and redundancy of information.
- Document and records management including regulatory and certifications compliance records.
- Organised and structured administration and control of all information, data and records.
- Drawings including management of drawing versions and their provision to end users.
- Photographic storage and provision to users.

316. Costings are prepared from bottom up project timelines using labour rates on the drawings management related projects based on the high rate for staff and the lower rate for other activities. Additional costs are included for licencing growth and the new Drawings Management System.

Geospatial systems, mapping and asset imaging - $9.07m

317. The geospatial asset class encompasses all systems solutions that provide functions, information and data for the following services to assist the JEN divisions and business partners to design, construct and manage energy and to develop, extend, maintain and change distribution assets:

- Current systems for:
  - Geospatial Information
  - Mapping
  - Asset imaging and geological imaging
  - Government geospatial and topographic information
  - Geographical information relating to the positioning of the current and future distribution network
  - Integration with asset management systems
  - Integration with geospatial information sources including entities such as State Government services and Google Maps
- New systems and capability for:
  - Common Information Model—To bring together information from disparate sources and consolidate into one common information model for reference, multiple system updating and as a single source of reference for geospatial information and data.
  - Network visualisation tools including:
    - High voltage and sub-transmission schematics

   - Feature manipulation engine tool
   - Network Viewer

318. Costings are prepared from bottom up project timelines using labour rates for specialised projects based on the high rate for staff. Additional costs are included for software licence growth and new Network Analysis and Visualisation tools.

Asset construction and field services systems - $10.37m

319. The asset construction systems assets encompass program, portfolio and project management solutions. The field services assets are those software applications and mobility technologies used by managers, supervisors and workers in the field for planning, construction and for works management including maintenance, inspections, outages and materials management.

320. The asset construction and field services projects encompass functionality used by the business to support:

- Network asset identification location, condition and capacity, for planning and design capabilities
- Asset inspection tools
- Environmental management responsibility component of JEN’s OHS capabilities
- Program and project management
- Mobile management of human and physical assets.

321. Costings are prepared from bottom up project timelines using labour rates for SAP projects based on the high rate for staff. Additional costs are included for software licence growth and new Network Design tools.

IT infrastructure (lifecycle upgrades, replacement and retirement) - $26.96m

322. The IT infrastructure category encompasses all hardware technology platforms, communications, operating environments and data systems needed to operate the application solutions.

323. In the 6-year asset management lifecycle the entire IT infrastructure, with the exception of communications, is planned to be replaced due to the assets becoming unsupported by vendors, uneconomic to retain or overtaken by newer more efficient technologies.

324. The majority of the IT infrastructure investments made during the 2016 regulatory period will be involved in lifecycle replacements of the platforms with some upgrades.

325. The IT Infrastructure program consists of some 160 asset projects that range over small, medium and large scale with the following lifecycles all based on economic efficiency:

- Personal computing and telephony 3-year lifecycle sometimes extended to 4 years due to competing priorities
- Data storage has a 4-year economic cycle and then replacement takes place in the 5th year
- Systems processing and all other technologies have a 5-year cycle except for communications.

- Communications networks are provided as a service by outsourced telecommunications companies selected by competitive tender. The external communications networks are owned by the outsourced service provider or partner organisation. Replacements, higher capacity with growth and upgrades all require capital projects. The lifecycle is determined by the service provider and external asset owner but is typically 7 years or greater.
- Enabling communications technologies such as routers, switches and other network devices are owned and operated by Jemena. The lifecycle is a minimum of 5 years.

326. The program of work has been further broken down into 8 sub categories listed below:

- Data storage and management
- Platforms and processing
- End-user services
- Security Services
- Systems management and operations
- Communications and network services
- Facilities and data centres
- Business and systems growth.

327. Costings are prepared from hardware cost estimates for the platforms and bottom up project timelines using labour rates for the lower rate for staff.

Metering – SCS - $8.40m

328. The metering systems encompass all functions relating to the provision of electricity meters, their operation, maintenance and support and meter data.

329. The standard control metering projects encompass functionality used by the business to support:

- Network management and performance and reporting
- Network and customer growth
- Network billing.

330. Costings are prepared from bottom up project timelines using labour rates for specialised projects based on the high rate for staff. Additional costs are included for software licence growth and additional licences and hardware for the network management system upgrade.

Metering – ACS – ongoing advanced metering $1.91m

331. The advanced metering projects encompass functionality used by the business to support:

- Customer consumption of energy
- Customer growth and change
- Customer and network billing

332. Costings are prepared from bottom up project timelines using labour rates for specialised projects based on the high rate for staff. Additional costs are included for additional licences and hardware for the network management system upgrade.

Box 3-3 Ongoing advanced metering (ACS)

The metering systems encompass all functions relating to the provision of electricity meters, their operation, maintenance and support and meter data in a non-contestable environment.

The derogation granting Victorian distribution network service providers exclusive rights to install, own and operate Advanced Metering Infrastructure under the NER is expected to expire by July 2017, subject to an open rule change application.

Our forecast non-network IT capital expenditure forecast currently excludes the capital expenditure required for incremental systems capability to provide the new contestable metering function. As the rule change is still open we consider the most prudent way to recover our efficient costs are to submit an application for a nominated pass through event ('end of metering derogation rule change event'). For further detail see Attachment 5-4.

333. For more in depth detail of our proposed IT capital expenditure, please refer to our IT Asset Management Plan (see Attachment 7-7).

3.4.3.2 Non-network other

Motor Vehicles and Plant

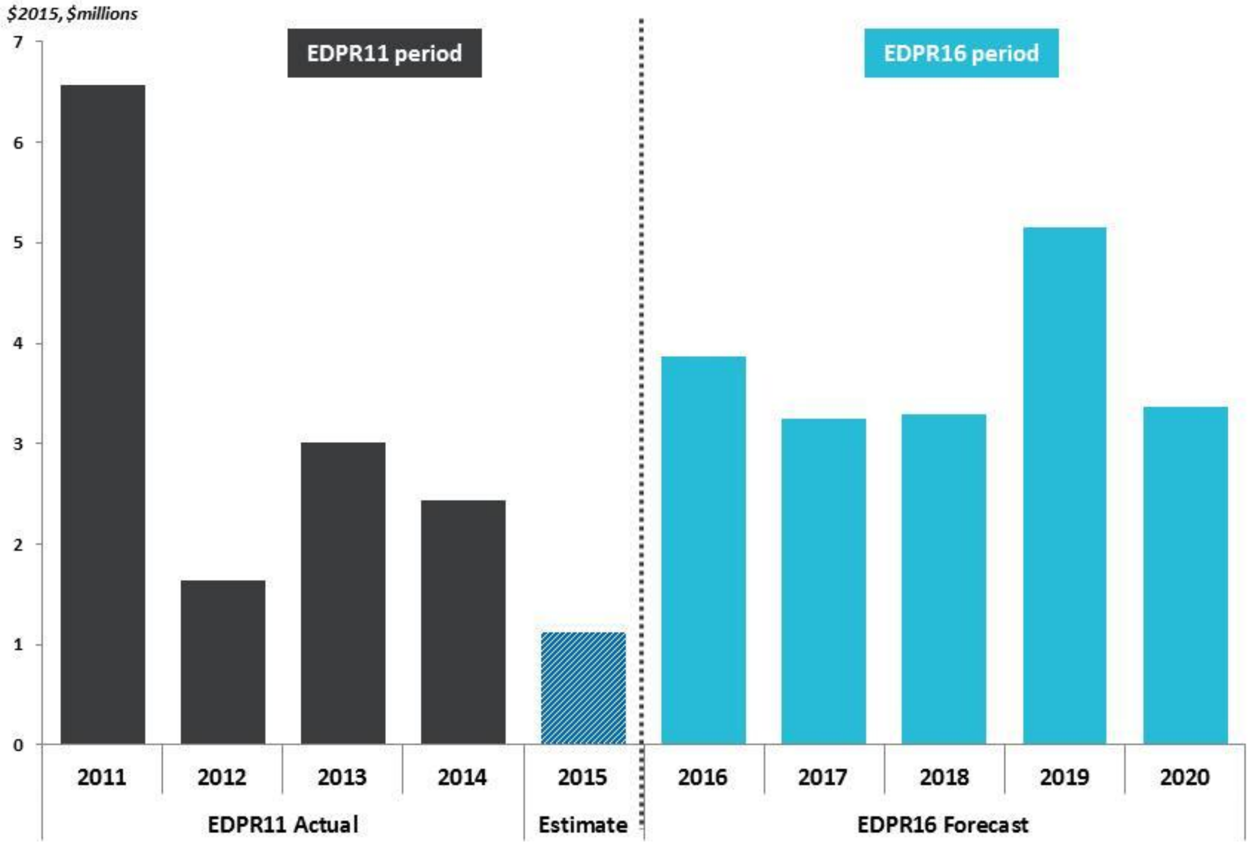
334. We own, lease and operate various motor vehicles and plant that is built specifically to meet the requirements of various business units. Table 3–36 and Figure 3–41 below present our forecast motor vehicles and plant expenditure for the 2016 regulatory period.

Table 3–36: Capital expenditure for motor vehicles and plant 2016-20 ($2015, $millions)

Motor vehicles and plant	Forecast regulatory period				
	2016	2017	2018	2019	2020
Total capital expenditure	3.88	3.26	3.30	5.16	3.38

(1) There are no overheads applied to non-network other capex category

Figure 3–41: Motor vehicles and plant capital expenditure 2011-2020 ($2015, $millions)



335. We outsource the management of our fleet to an external service provider—Zinfra Group, who employ specialists in fleet management. Zinfra have the responsibility of procuring, managing and disposing of our fleet and plant (mobile or fixed).

336. Our current fleet and plant (mobile or fixed) inventory as at April 2015 are presented in Table 3–37.

Table 3–37: Motor vehicle and plant inventory at April 2015

	Elevating Platform Vehicle (EPV)	Heavy Commercial Vehicle (HCV)	Light Commercial Vehicle (LCV)	Plant	Passenger Vehicle (PV)	Trailers	Total
Motor Vehicles and Plant	33	29	104	12	54	51	283

337. Each motor vehicle class is managed via a lifecycle management strategy. This strategy includes information regarding kilometres travelled, asset age and engine hours worked. The actual condition of the asset is the primary driver for replacement of vehicles followed by the asset age as the secondary consideration.

338. In some cases, often with EPVs and HCVs for example—the vehicle can be rebuilt after 10 years to extend its asset life and thereby defer incurring the replacement cost until the actual condition of the vehicle warrants replacement.

339. Our forecast for motor vehicle replacement and rebuild for the next regulatory period is provided in Table 3–38.

Table 3–38: Number of motor vehicles and plant to be replaced or rebuilt during the 2016 regulatory period

	Elevating Platform Vehicle (EPV)	Heavy Commercial Vehicle (HCV)	Light Commercial Vehicle (LCV)	Plant	Passenger Vehicle (PV)	Trailers	Total
Motor Vehicles and Plant	29	18	98	6	45	17	213

340. Table 3–39 provides our forecast motor vehicle expenditure for the 2016 regulatory period by vehicle class.

Table 3–39: Forecast motor vehicles and plant expenditure for the 2016 regulatory period ($2015, $millions))

	Elevating Platform Vehicle (EPV)	Heavy Commercial Vehicle (HCV)	Light Commercial Vehicle (LCV)	Plant	Passenger Vehicle (PV)	Trailers	Total
Motor Vehicles and Plant	8.26	2.94	5.57	0.34	1.61	0.26	18.97

341. Below are references to the Asset Class Strategy and Strategic Planning Paper that provide further detail around the need for investments into replacement or rebuild of motor vehicles and plant.

Table 3–40: Document evidence – Motor vehicles and plant

Document name	Document number	Document type
Fleet	JEM ST 0051	Asset Class Strategy
Fleet Replacement and Rebuild	ELE PL 0035	Strategic Planning Paper

Buildings and property (including tools and equipment)

342. Buildings and property (including tools and equipment) represent 46% of our total non-network other capex over the 2016 regulatory period or $16.3m. This forecast represents a 66% reduction in capex from the level in the 2011 regulatory period.

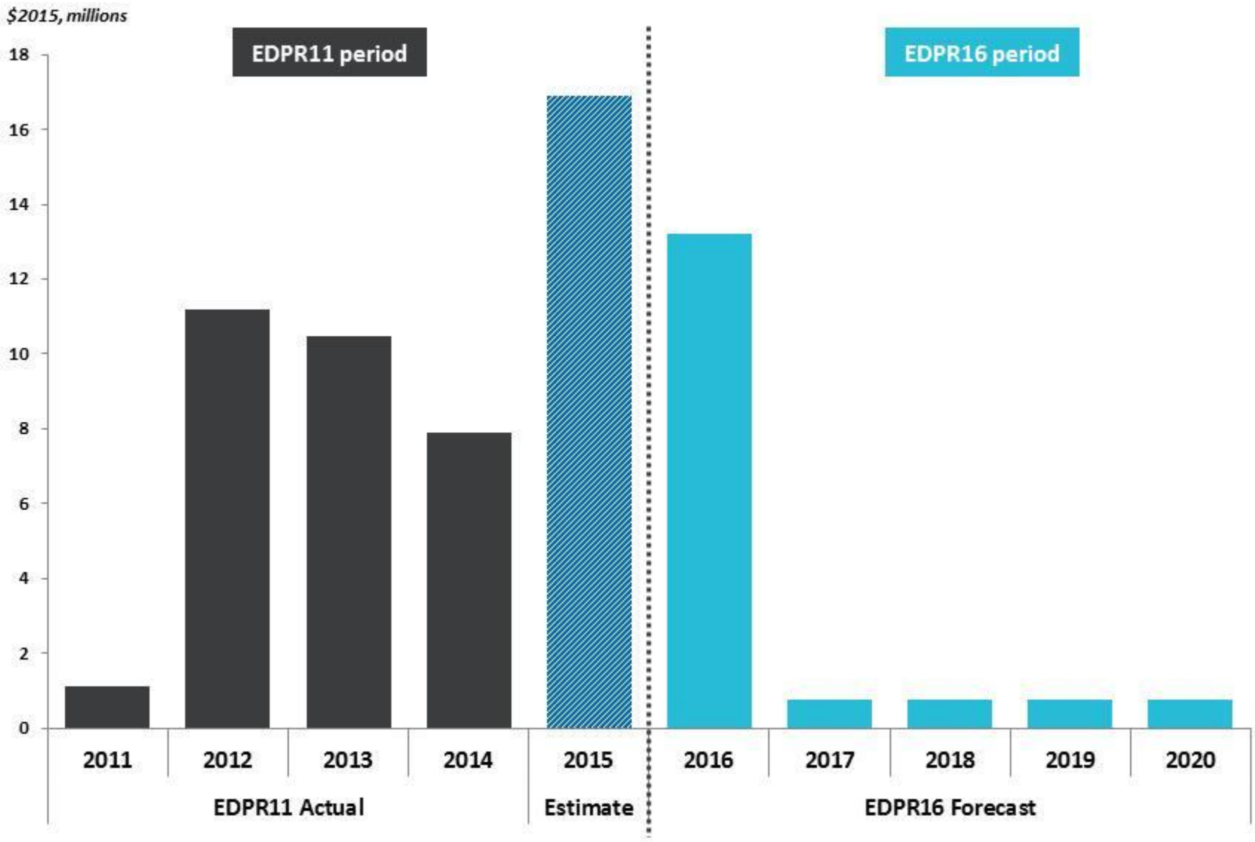
343. Buildings and property (including tools and equipment) forecast expenditure for the 2016 regulatory period is presented in Table 3–41.

Table 3–41: Capital expenditure for buildings and property (including tools and equipment) 2016-20 ($2015, $millions)

Buildings and property (including tools and equipment)	Forecast regulatory period				
	2016	2017	2018	2019	2020
Total capital expenditure	13.24	0.77	0.77	0.77	0.77

(2) No overheads applied to the non-network capex category

Figure 3–42: Buildings and property (including tools and equipment) expenditure 2011-2020 ($2015, $millions)



344. The majority of the building and property expenditure in the 2016 regulatory period relates to redevelopment of our Broadmeadows depot in 2016 ($12.3m). In the remaining years expenditure relates only to the condition based replacement of tools and equipment that are necessary to safely and efficiently deliver construction, maintenance and operational activities on the network ($3.8m).

Broadmeadows Depot Redevelopment

345. We have owned the Broadmeadows site since the 1960's. The site consists of 3 office buildings that were constructed in the 1960's and 70's. It is a large site of over 24,000 square metres and consists of two land titles. This site was the main field service depot for the network until mid-2014 when the new purpose built Tullamarine depot became operational in May 2014. Now that the Tullamarine depot is operational, we propose to redevelop the Broadmeadows depot to be a smaller facility that better meets our business requirements and will facilitate a more efficient operating environment.

346. The Broadmeadows depot redevelopment will involve the demolition of one of the existing buildings and the construction of a new, smaller operational and administration facility on one land title. The second land title will be sold

347. The redevelopment will also allow us to address the issues associated with the age and condition of the site, in accordance with Jemena's Occupational Health and Safety risk management policies. These issues relate to:

- Asbestos monitoring

- Compliance with the Building Code of Australia, and

Compliance with other regulatory requirements.

Tools and Equipment

348. We are required to maintain our inventory of general tools and equipment in a serviceable condition and at optimum levels so as to be able to deliver against our commitments effectively and efficiently.

349. Below are references to an Asset Class Strategy and a Business Case which provide more detail around the need for investment.

Table 3–42: Document evidence – Buildings and property (including tools and equipment)

Document name	Document number	Document type
Broadmeadows Redevelopment	BAA-GPA-000008	Business Case
General Tools and Equipment	JEN ST 0105	Asset Class Strategy

3.4.4 HOW WE PLAN NON-NETWORK NEEDS

3.4.4.1 Non-network IT

350. For detail of our planning approach for non-network IT, refer to our 7 year IT asset management plan at Attachment 7-7.

3.4.4.2 Non-network: Motor vehicles and plant

351. Our fleet replacement plan incorporates the operational requirements to support the ongoing performance of the distribution network and mitigate risk.

352. This will be achieved through the replacement of vehicles based on class type, age of vehicle and condition. As a result, the vehicle replacement plan mitigates the failure rate of the vehicles and maintains the reliability and safety of the motor vehicles and plant.

353. Our fleet strategy is based on three (3) key objectives. These are:

- Vehicles selected are fit for purpose
- Least cents per kilometre
- Preferred purchase approach

Fleet Replacement and Compliance Criteria

354. Our motor vehicle and plant replacement and compliance criteria are based on an age and kilometre travelled criteria. Table 3–43 summarises the replacement criteria.

Table 3–43: Motor Vehicles and Plant compliance criteria by asset class

Vehicle Classification	Standard age based replacement term	Standard km based replacement term
EPV	10	400,000

Forklift	5	not applicable
HCV	10	400,000
LCV	5	150,000
Plant	10	not applicable
PV	5	150,000
Trailer	15	not applicable

3.4.4.3 Non-network: buildings and property

Broadmeadows depot

355. The Broadmeadows depot will be redeveloped as part of our strategy to optimise the size and space requirements of the existing location. In addition it will address safety concerns and poor condition of the existing site.

Tools and equipment

356. Our general tools and equipment strategy is based on the following core principles:

- All general tools and equipment shall be 100% utilised only on our network assets
- All general tools and equipment are identified and managed through an asset register
- The lifecycle of general tools and equipment is managed in accordance with the Tools and Equipment Strategy;

357. For Class 1 and 2 general tools and equipment (<$6,000), the expected life cycle is 2-3 years and 3-5 years respectively. The key considerations for Class 1 and 2 general tools and equipment are:

- The end user is supplied with equipment that is fit for purpose and meets all regulatory and legislative requirements
- The purchase price
- Maintenance
- Lifecycle (asset age).

358. For Class 3 and 4 general tools and equipment (>$6,000), the expected life cycle is 5-10 years. The key considerations for Class 3 and 4 general tools and equipment are:

- The user is supplied with equipment that is fit for purpose and meets all regulatory and legislative requirements
- Available technological advancements
- The purchase price
- Maintenance requirements
- Lifecycle (asset age).

- The estimated lifecycle for each of the asset classes is derived under the assumption of normal use, general wear and tear and we therefore replace items within their estimated useful life. Extending beyond these timeframes may lead to:
- A reduction in the reliability of the asset
- Total failure of the asset
- Excessive repair / maintenance costs (ie. substituting higher operating costs for a lower capital cost)
- Obsolescence in relation to safety features and technology.

3.5 METERING SERVICES CAPITAL EXPENDITURE

359. In the current regulatory control period, the cost for the provision of metering services is separately recovered through the Advanced Metering Infrastructure (**AMI**) Order-in-Council. In the 2016 regulatory control period, metering services will be classified as an alternative control service and the ongoing costs associated with meter provision will be recovered through the EDPR under the NER (see Attachment 5-1).

3.5.1 KEY MESSAGES - METERING

Key messages for our metering capex are:

- The majority of the metering capex relates to the lifecycle management of the metering assets supplying customers that use less than 160MWh pa. It includes addition, alterations, replacements and abolishment based on our forecast requirements. A proportion of the cost for the up-keep of the IT head-end systems, for data collection and metering network management is also included.
- While the discussion on meter contestability is on-going, the level of expenditure necessary to provide regulated metering services during the 2016 regulatory period will not vary materially.

360. Metering capex relates to expenditure required on JEN's metering, associated metering communications technologies and systems so they perform to the required performance specification. The scope relates to metering applied to customers consuming less than 160MWh per annum and includes:

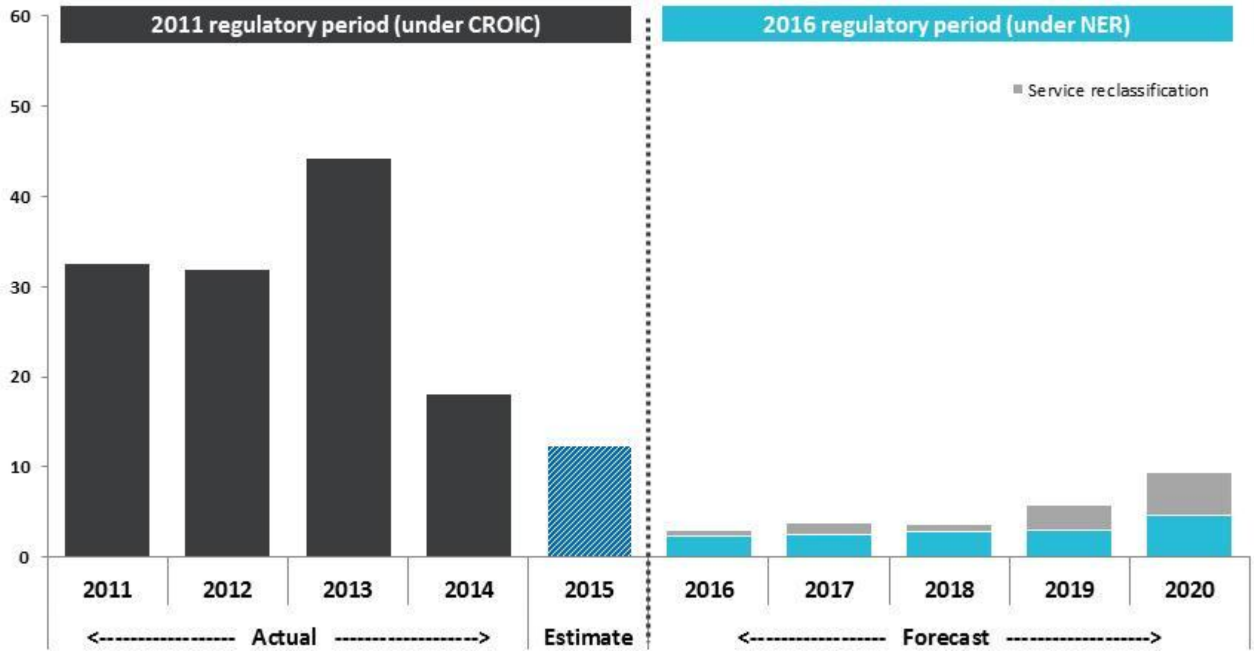
- AMI meters
- Legacy accumulation meters
- Legacy interval meters
- Associated metering accessories (such as time switches)
- Advanced metering communications infrastructure
- Proportion of IT head-end systems that interface with these classes of meters.

361. The metering services forecast capital expenditure for 2016-2020 is presented in Table 3–44, and further below Figure 3–43 reveals the reduction in metering services capital expenditure in the 2016 regulatory period relative to the 2011 regulatory period.

Table 3–44: Total metering services capital expenditure 2016-2020 ($2015, $millions)

Total metering capital expenditure	2016	2017	2018	2019	2020	Total
Metering services capital expenditure	2.41	2.54	2.80	2.94	4.60	15.29

Figure 3–43: Metering services expenditure 2011-2020



3.5.2 DRIVERS OF FORECAST METERING CAPITAL EXPENDITURE

362. Below we individually explain the three main drivers of metering capital expenditure on our network: the lifecycle management costs, our investments in metering technologies and communications and the metering IT infrastructure and systems.

3.5.2.1 Metering asset lifecycle management

363. The forecast metering asset lifecycle expenditure is considerably lower than the 2011 regulatory period as our rollout of the AMI program is complete with 98% of our customers logically converted to AMI by June 2014. The rollout has renewed the majority population of legacy accumulation and interval meters and so we are forecasting for substantial reductions in metering services expenditure in the 2016 regulatory period, relative to the 2011 regulatory period. Details of assumptions used in the metering services expenditure forecast are included within the metering asset class strategy provided in response to the EDPR RIN[41].

364. We do not expect that AMI meter family failures will occur in the 2016 regulatory period and meter renewal will be limited to random failures caused by premature component failure or environmental influence such as water ingress.

41 JEN PL 0045 Electricity metering and associated communications asset class strategy

3.5.2.2 Metering Technology and Communications

365. Our AMI communications network is based on a single private network technology covering the entire distribution territory and meets service levels defined tin the Victorian AMI service level specification. The communications network equipment requires periodic lifecycle renewal of batteries, modems, access points and relay equipment to ensure capacity, performance and reliability are maintained during the 2016 regulatory period. Lifecycle forecasts allow for replacements, augmentation and upgrades of the AMI communications assets through the period.

366. Metering communications infrastructure is shared between the provision of metering services and distribution services. A capex allocation (62.5% ACS and 37.5% SCS) is made in line with the split between metering and advanced network functions as defined in the Victorian AMI functional specification.

3.5.2.3 IT metering (head-end) Infrastructure and Systems

367. The metering head-end IT infrastructure and systems provide the data collection and metering network management functionality as distinct from the back office systems like meter data management, customer relationship management and billing systems (back office systems are included in IT capex).

368. Metering head-end IT system lifecycle replacement / upgrade capex is apportioned between metering functions and network functions in line with the split between metering and advanced network functions as defined in the Victorian AMI functional specification (59% ACS and 41% SCS).

3.5.3 METERING CAPITAL EXPENDITURE EXPLAINED

369. While the discussion on meter contestability is on-going the level of expenditure necessary to provide regulated metering services during the 2016 regulatory period will not vary materially.

370. Contestability is assumed to commence from 1 July 2017 and the existing regulated metering services will continue with the incumbent. It is not expected that existing AMI meters will be replaced by third party providers as the AMI meters are fit for purpose, likely to exceed the minimum service specifications for the forthcoming contestable meter market and subject to exit fees to replace the relatively new AMI meters. We have also assumed that all metering additions and alternations will be carried out by JEN utilising the same AMI meters.

3.5.4 KEY METERING PROJECTS

371. On account of the AMI program of works having reached completion in the current regulatory period; of which included a comprehensive capital replacement program of meters, communications infrastructure and associated IT systems; the age profiles of the metering assets are relatively low (typically less than 5 years). Consequently there is no end-of-life project proposed for meters, communications or metering IT assets. Only one IT lifecycle renewal project is proposed for the AMI head-end system (network management system). All other IT renewal projects for back office systems are included in the IT Capex forecast and excluded from ACS metering services capex.

3.5.4.1 Upgrade of Network Management System

372. Our AMI meters operate from a proprietary head-end system supplied by Silver Spring Networks. This system is commonly known as the Network Management System which collects meter data, supervises the meter communications network and manages advanced network functionality.

373. The network management system is a bespoke system required to support the full 15-year forecast life cycle of our AMI meter types. During the 2016 regulatory control period one major upgrade of the network management system is proposed to ensure the concurrency of the software, supportability and ongoing metering compliance.

374. Apart from this project, due to reasons noted above, no other significant metering services projects are proposed in the 2016 regulatory period.

3.5.5 HOW WE FORECAST METERING CAPITAL EXPENDITURE NEEDS

375. Forecasts for additions and abolishment of metering installation services are based on the net customer growth forecast provided by ACIL Allen (see Attachment 3-3). Historical trends of gross metering activities are used to predict future meter activity volumes which are in turn aligned to the ACIL Allen net growth assumptions. Historic trends are used to forecast volumes of alterations (one for one replacement) and meters refurbished/written-off. Vendor's specification is used to forecast AMI meter failures (like for like replacement).

376. Meter communication infrastructure forecasts are based on a conservative asset replacement strategy with an effective maintenance program for field based radio equipment (including access points, relays, antennas, modems and batteries). Volumes of communications infrastructure activities are driven by augmentation drivers (new additions), failure drivers (replacements) and end-of-life drivers (replacement).

Capital investment in IT infrastructure technology and systems is principally project oriented with some allowance for annualised activities including meter firmware release, communications firmware release, as well as ongoing investment in the technology test lab to support production, development and testing metering technology environments.

4. NETWORK COST ESTIMATION PRINCIPLES

377. The approach we have applied to estimate the costs of all JEN's projects and programs of work is applied with our cost estimating framework and guided by our Project Estimation Methodology—provided at Attachment 7-10.

378. Accurate budgeting depends on the consistent application of a robust estimating framework. Our cost estimation framework uses the best available information to develop project estimates, depending on the nature and proposed timing of the expenditure. The cost estimation process described in Attachment 7-10 promotes consistently accurate budgeting by ensuring that our estimating governance framework:

- Provides accurate and consistent project estimates for all works, recognising the nature of the proposed work and its likely timing
- Ensures that business cases and forecast programs have been estimated using appropriately sourced, realistic and efficient input data
- Provides project estimates that account for safety, environmental and regulatory requirements
- Identifies opportunities for innovation
- Identifies the risks associated with the relevant works and ensure that these are communicated to Project Managers (for example the likelihood of encountering rock during excavations)
- Ensures appropriate estimates are prepared at different stages of the PMM project governance gating process
- Ensures risk is treated appropriately, recognising that JEN undertakes a portfolio of projects and programs of work, and scope adjustment factors should be applied at the portfolio level
- Ensures value for money for our customers
- Ensures there is a formal change process if circumstances change.

4.1 ESTIMATING TECHNIQUES

379. We apply both top down and bottom up estimating techniques in combination to ensure that our project estimates are fit for purpose in the context of the PMM governance gating process and our two-year rolling program of work in the Capital and Operating Works Plan (**COWP**).

4.1.1 TOP DOWN ESTIMATING METHOD

380. The top down estimating technique relies on historical data from completed, similar projects to estimate the costs of the proposed project. Historical data is maintained within our internal databases and includes information sourced from:

- Historical data from past projects
- Recent tender prices (at the time of estimating e.g. within six (6) months)
- Expected labour costs (consistent with Jemena's labour model)
- Period contract prices.

4.1.2 BOTTOM UP ESTIMATING METHOD

381. Bottom up estimating is a thorough estimate of the project by estimating each and every work package.

382. All estimates are developed using the Easy Cost Planning (**ECP**) module of SAP. Estimating templates have been developed within ECP for each of the major categories of work for non-routine and routine network projects. The templates are based on appropriate design and construction standards using Bills of Materials, Standard Task lists and Base Planning Objects to ensure that each estimate is developed in a consistent and comprehensive manner.

4.1.3 INDEPENDENT VERIFICATION OF OUR INTERNALLY PRODUCED ESTIMATES

383. One of the key steps in our business as usual estimating governance process is to seek an independent assessment from a suitably qualified expert, to sense-check our own internally produced estimates to ensure they're reasonable and within acceptable tolerances.

384. Typically, we engage an independent expert every two years to prepare their own, independent project estimates for a cross-section of our forecast projects and programs of works. On this occasion the engagement coincides with the timing of the development of the 2016 regulatory proposal.

385. The next section discusses in detail the approach applied by the independent consultant to establish and maintain independence from JEN's estimates and provides a summary of their findings.

4.2 INDEPENDENT EXPERT ESTIMATES OF JEN'S FORECAST PROGRAMS AND PROJECTS

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5. COMPLIANCE WITH THE NATIONAL ELECTRICITY RULES

396. We have considered whether our planning and forecasting processes are consistent with the capital expenditure objectives and capital expenditure criteria and address the capital expenditure factors specified in the NER, and whether the resultant capital expenditure forecasts met these requirements.

397. Our planning processes explicitly considered the drivers of our forecast capital expenditure set out in the capital expenditure objectives and our analysis and international best practice governance frameworks address the matters raised in the criteria.

398. In relation to the resultant capital expenditure forecasts, our forecast capital program is consistent with the requirements of the NER and that the associated costs are both prudent and efficient.

5.1 WHY THE TOTAL FORECAST CAPEX IS REQUIRED TO ACHIEVE EACH OF THE CAPEX OBJECTIVES IN 6.5.7(A)

399. We have established capital expenditure forecasts that achieve the capital expenditure objectives specified in the NER. We have primarily achieved this by (among other things):

- Conducting detailed analysis of the actual condition and age of our assets
- Assessing the sufficiency of our current compliance with regulatory obligations to identify required investments for corrective actions
- Assessing foreseeable changes in the operating environment that will place upward pressure on our forecast capital expenditure such as changing climate conditions (which are increasingly affecting our network's performance), lengthening and intensifying the bushfire season,[43] and creating conditions conducive to pole fires. In addition, increasingly frequent severe weather events (including wind storms and heat waves) mean we need to undertake programs to minimise the fire risk associated with our assets. Our proposed safety replacement programs in the 2016 regulatory period will ensure we continue to maintain the safety of our customers, community and staff and the reliability of our services
- Identifying new or changed obligations that will affect our forecast capital expenditure program
- Quantifying customer initiated requests to connect to our network as informed by various expert demand reports
- Incorporating real cost escalators to our input costs prepared by industry experts.

400. Table 5–1 summarises how we have complied with the capital expenditure objectives.

Table 5–1: Compliance with the capital expenditure objectives

Capital expenditure objective	NER	Actions to ensure compliance
meets or manages the expected demand for standard control services over the regulatory period	6.5.7(a)(1)	We have forecast our relevant capital expenditure categories to take into account the growth effects of expert peak demand, consumption and customer number reports prepared by ACIL Allen (see Attachment 3-1 and 3-3). These top down forecasts also reconcile to our own bottom up spatial demand forecasts

[43] Climate Council , *Be prepared: Climate change and the Victorian bushfire threat* , 2014

Capital expenditure objective	NER	Actions to ensure compliance
		(see Attachment 3-5) and ensure that are forecasts are allocatively efficient.
complies with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.7(a)(2)	We have assessed our current compliance processes against our obligations as well as assess corrective actions and additional new obligations. Our existing systems and processes—including our international best practice governance framework[44]—ensures that our compliance obligations are well managed. Attachment 8-6 to our regulatory proposal sets out our proposed step changes for new regulatory obligations or requirements associated with the provision of standard control services.
maintain the quality, reliability and security of supply of standard control services,	6.5.7(a)(3)	We have prepared a comprehensive 7 year asset management plan (see Attachment 7-5) for our network assets and also a 7 year IT asset management plan (see Attachment 7-7) to guide our IT expenditure. The associated capital expenditure forecasts within the asset management plans have considered the impact of our changing operating environment, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of supply. We have also provided a copy of our 20 year strategic asset management plan at Attachment 7-6 which includes scenario analysis (see section 10.2) where we assessed changes in the level of capital expenditure (and operating expenditure) and their associated impact on the average cost to our customers over three time horizons. We have also consulted extensively with our customers and interested stakeholders on our forecast capital plan and their preferences around service levels.
Maintain the safety of the distribution system through the supply of standard control services	6.5.7(a)(4)	We have prepared a comprehensive 7 year asset management plan (see Attachment 7-5) for our network assets. The associated capital expenditure forecasts within the asset management plan have considered the impact of our changing operating environment, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of the system. Additional considerations include trends of asset failures and customer reports of safety issues as they impact potential future network safety issues. Safety is our number one priority. We have forecast the required capital expenditure to comply with our Electricity Safety Management Scheme (**ESMS**). Our ESMS, of which Energy Safe Victoria has oversight, assists ensure the safety of the distribution system is maintained.

[44] We attained PAS 55 accreditation in August 2014, and are one of only three Australian businesses to have done so. The accreditation applies to our asset management system, which covers activities relating to the creation, acquisition, operation and maintenance of electricity distribution assets.

5.2 HOW OUR TOTAL CAPEX FORECAST REASONABLY REFLECTS EACH OF THE CAPEX CRITERIA IN 6.5.7(C)

401. We have established our capital expenditure forecasts to comply with the capital expenditure criteria specified in the NER. We have primarily achieved this by:

- Developing our capital expenditure forecasts in accordance with our PAS 55 accredited asset management framework and governance structures that assist ensure that the input costs to our capital expenditure forecasts are the efficient costs of achieving the capital expenditure objectives.
- Developing our forecasts based on our robust cost estimation methodology (see Attachment 7-10) that ensures all the program and project cost estimates within our forecasts have been developed according to our top down assessment approaches (using historical cost data, recent tender prices and contract prices) and bottom up cost estimates (using schedules of rates negotiated under competitive tender and panel arrangements). This process ensures our forecasts are productively efficient.
- Ensuring a cross section of our forecast unit rates for routine capital programs and major projects were costed by an independent expert and assessed for reasonableness—the majority of JEN's programs and projects outperformed the independent expert's benchmark indicating our forecasts are productively efficient and that we have forecast only those costs that a prudent operator would incur to achieve the capital expenditure objectives.
- Updated our procurement approach by establishing new competitive tenders, and refreshed our panel of preferred suppliers to provide us access to an external resource base with specialised expertise at best market rates to achieve productive efficiency (see Attachment 7-8).
- Developing a detailed delivery strategy which ensures that our forecast program of work can be delivered as planned, without exposing JEN to resource constraints and additional costs (see Attachment 7-8). This strategy provides a plan for our forecast program of work to be delivered within an optimal time frame and at efficient cost by utilising our own work force to its optimum capacity and the resources available from service agreements through competitive tenders and long standing supply contracts. This document confirms that our capital expenditure forecast reflects a realistic expectation of our demand forecasts and cost inputs.

5.3 HOW OUR TOTAL FORECAST ACCOUNTS FOR THE CAPEX FACTORS IN 6.5.7(E)

402. The NER set out the capital expenditure factors which the AER must have regard to when deciding whether or not to approve our capital expenditure forecast. In addition to the materials outlined in section 1.2 of this attachment and our RIN response, Table 5–2 summarises points we consider relevant to these factors.

Table 5–2: Compliance with capital expenditure factors

Capital expenditure factors	NER	JEN comments
the most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*	6.5.7(e)(4)	As a first pass assessment of relative efficiency, our performance stands out in the top quartile of efficient businesses for the Multilateral Total Factor Productivity (MTFP) measure (Figure 16) in the AER's first annual benchmarking report[45] and we benchmark as the second most efficient Distribution network service provider in the country for the capital expenditure partial performance indicator (Figure 18). These benchmarks reveal that despite our scale disadvantage, we're managing to produce

[45] AER, *Electricity distribution network service providers, annual benchmarking report*, November 2014

Capital expenditure factors	NER	JEN comments
		more with less, relative to our peers. (See Attachment 8-4 and Attachment 8-5)
the actual and expected capital expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*	6.5.7(e)(5)	JEN has a proven record of accurately forecasting what we require to safely and reliably run our network. We have provided a detailed explanation of our historical capital expenditure incurred by year in Attachment 7-1 and in chapter 7 more broadly.
The extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified in the course of our engagement with our customers	6.5.7(e)(5A)	We have consulted extensively with our customers and broader stakeholders while developing our capital expenditure forecasts (see box 7-2 in our regulatory proposal). Chapters 3 and 4 of our regulatory proposal, and particularly Attachment 4-1 provide an in depth summary of their concerns and how their feedback more broadly, has influenced our capital expenditure forecast.
The relative prices of operating and capital inputs	6.5.7(e)(6)	We rely on lifecycle management planning for each asset class, which considers all the strategies and options over the entire asset life from planning to disposal to deliver the lowest long term sustainable costs to deliver our corporate objectives and business plan. Lifecycle management focusses on ensuring effectiveness and efficiency in maintenance (operating expenditure) and replacement (capital expenditure) of the network assets based on analysis that balances issues relating to safety, cost, risk and reliability. Additionally, we have relied upon the same input cost escalators for capital and operating expenditure (see Attachment 7-13 and Attachment 8-8) respectively.
The substitution possibilities between operating and capital expenditure	6.5.7(e)(7)	Part of business as usual operations include analysing ways to optimise the economic life of our assets, various examples of this analysis are included in our regulatory proposal. Typically, we assess whether asset replacement can be deferred by substituting capital expenditure for further maintenance—where it leads to lower long term average costs to our customers and considering the safety and reliability risks associated with these decisions. We also assess whether network augmentation projects can be deferred by utilising non-network alternatives to defer augmentations—through demand management for example (see box 7-3 of our regulatory proposal). JEN takes its obligations in making expenditure decisions seriously and looks to optimise these on a continual basis. This may result in spending opex instead of planned capex—or vice-versa—depending on the circumstances at the time. JEN is particularly capable of delivering against this trade-off objective being one of the highest ranked electricity distribution businesses for managing the trade-off requirement (see Attachment 2-1, section 4.3). Also, with the introduction of the Capital Expenditure Sharing Scheme (**CESS**) we will face symmetrical incentives across operating and capital expenditure and so we will continue to search for ways to optimise the substitution possibilities between operating and capital expenditure.

Capital expenditure factors	NER	JEN comments
Whether the capital expenditure forecast is consistent with any incentive schemes or schemes that apply under clauses 6.5.8A or 6.6.2 to 6.6.4	6.5.7(e)(8)	Our capital expenditure forecasts are consistent with the CESS, the STPIS and the small-scale incentive scheme. Our forecasts include no capital expenditure to fund improvements to our levels of reliability, only to maintain reliability. The STPIS' self-funding mechanism incentivises us appropriately in this regard. We maintain a rigorous approval process for proposals to commit capital funding that are all subject to financial evaluations. Our augmentation and connection projects apply economic cost benefit analysis as a standard for all significant capital proposals and we have also applied economic cost benefit analysis to some replacement projects that meet an agreed criteria and where costs and benefits can be calculated with respect to the whole supply chain. All realistic options are assessed in these analyses and all costs, savings (both capital and operating) and revenues relevant to each option are included. Our analysis is holistic in that it captures all the incremental marginal benefits and marginal costs and the incremental impact of the relevant incentive schemes are included in our investment analysis. Furthermore, as a privately owned business we have other natural incentives not to overspend our allowance due to bearing the financing costs and depreciation expense for doing so.
the extent the capital expenditure forecast is preferable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms	6.5.7(e)(9)	As discussed in section 19 of our response to Schedule 1 of the EDPR RIN, we have an established outsourcing arrangement that reflect prudent commercial terms with Jemena Asset Management (**JAM**) and Zinfra.
whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b)	6.5.7(e)(9A)	Our proposed forecast capital expenditure does not include an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).
the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives	6.5.7(e)(10)	As stated in our response to 21.2 of Schedule 1 of the EDPR RIN we are proposing to undertake two demand response projects in the 2106 regulatory period with the objective of managing network risk and providing best value solution to our customers. Our 2104 DAPR (provided with the capital expenditure supporting document with our EDPR RIN response) identifies the two locations where we intend to undertake targeted demand response programs.
any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	6.5.7(e)(11)	Our capital expenditure forecast includes a number of projects that are subject to the Regulatory Investment Test-Distribution (**RIT-D**). **RIT-D** processes will be conducted for the major augmentation zone substation projects at Craigieburn, Flemington and Sunbury as identified in 3.3.3 of this Attachment 7-3.
any other factor the AER considers	6.5.7(e)(12)	We have provided information to respond to the assessment

Capital expenditure factors	NER	JEN comments
relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor		techniques spelled out in the AER's expenditure assessment guideline.

5.4 S6.1.1(6) INFORMATION AND MATTERS RELATING TO CAPITAL EXPENDITURE

403. *A building block proposal must contain at least the following information and matters:*

404. *(6) capital expenditure for each of the past regulatory years of the previous and current regulatory control period, and the expected capital expenditure for each of the last two regulatory years of the current regulatory control period, categorised in the same way as for the capital expenditure forecast and separately identifying for each such regulatory year:*

405. *(i) margins paid or expected to be paid by the Distribution Network Service Provider in circumstances where those margins are referable to arrangements that do not reflect arm's length terms; and*

406. *(ii) expenditure that should have been treated as operating expenditure in accordance with the policy submitted under paragraph (8) for that regulatory year;*

5.4.1 JEN'S RESPONSE

407. JEN's capital expenditure for each of the past regulatory years of the previous and current regulatory control periods and the expected capital expenditure for each of the last two regulatory years of the current regulatory control period, categorised in the same way as for the capital expenditure forecast is available by regulated asset base (**RAB**) categories in:

- Our 2010 RAB roll forward model (**RFM**) submitted to the AER, for information relating to 2006-2009
- Our 2016 RAB RFM submitted to the AER with this regulatory proposal, for information relating to 2010-2015, and
- Our 2016 post tax revenue model (**PTRM**) submitted to the AER with this regulatory proposal, for information relating to 2016 to 2020.

408. The margins paid or expected to be paid by JEN in circumstances where those margins are referable to arrangements that do not reflect arm's length terms over the period 2006-2020 were provided to the AER in JEN's response to the category analysis RIN submitted on 30 April 2014 in worksheet 2.12 Input tables (see Excel field CF9:CH80).

409. JEN only paid related party margins to Jemena Asset Management from April 2010 to March 2012. All time series outside this window (ie. 2008-2009 and 2013-2020) have reported zero related party margins.

410. JEN's response to section 22.2 of Schedule 1 of the EDPR RIN submitted on 30 April 2015 with this regulatory proposal identifies that no changes to JEN's (or its parent company's) capitalisation policy had any effect on either forecast or actual historical operating expenditure over the current 2011-15 regulatory control period.

411. JEN has submitted its capitalisation policy with its annual RIN response and completed an audit of our compliance against this policy each year since 2011 (and also with the Regulatory Accounting Statements

provided in accordance with Guideline 3 that applied up until 2010). As per those annual RIN responses, the substance of JEN's capitalisation policy has remained unchanged throughout the 2011-2015 period.

412. With respect to the 2006-2010 period and as we explained in our regulatory proposal for the 2011 regulatory period[46], JEN's capitalisation policy was consistent with the policy underlying the operating expenditure forecasts established by the Essential Services Commission (**ESC**). The only exception to this was the application of a new Jemena group-wide cost allocation methodology in 2008 which resulted in a $4.61m increase in the level of expensed overheads per year from 2008. No other change to the substance of JEN's capitalisation policy has occurred that would have resulted in expenditure being treated as operating expenditure if applied in years before the change.

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46 Jemena Electricity Networks (Vic) Ltd, *Regulatory proposal 2011-15*, 30 November 2009, section 17.2 p207

6. ADDENDUM (CONFIDENTIAL) – INDEPENDENT EXPERT COST ESTIMATES REPORT