Forecast Expenditure Summary

Asset Renewal

2015 to 2020

Contents

1. About this summary document

This section explains the purpose and structure of this summary document.

1.1 Purpose

The purpose of this summary document is to explain and justify Ergon Energy's asset renewal capital expenditure for its standard control services for the next regulatory control period, 1 July 2015 to 30 June 2020.

It aims to provide the reader with a full understanding of Ergon Energy's asset renewal capital expenditure forecasts. However, because it is a summary document, it necessarily addresses some matters at a relatively high level and refers to other documents for further detail.

This summary document provides details of actual, estimated and forecast asset renewal capital expenditure for the previous (1 July 2005 to 30 June 2010), current (1 July 2010 to 30 June 2015), and next (1 July 2015 to 30 June 2020) regulatory control periods.

All capital expenditure presented in this document is in real 2014-15 dollars, except where otherwise stated.

Importantly, this summary document only explains and justifies Ergon Energy's direct costs for its asset renewal capital expenditure. Ergon Energy applies real cost escalations and shared costs (overheads) to these direct costs to determine its total asset renewal capital expenditure. Ergon Energy has prepared, and provided to the Australian Energy Regulator (AER), separate documents that explain and justify – for all of its capital expenditure categories – how it applies these real cost escalations and shared costs (overheads).

Readers should take care in examining the (unescalated) direct costs in this summary document to ensure that they do not confuse them with Ergon Energy's:

- Direct costs, inclusive of real cost escalations
- Total costs, inclusive of direct costs, real cost escalations and shared costs (overheads).

1.2 Structure

The remainder of this summary document is structured as follows:

- Section 2 details Ergon Energy's asset renewal capital expenditure for the previous, current and next regulatory control periods. This is intended to provide the reader, at the outset, with a clear view of the profile of Ergon Energy's actual, estimated, and forecast asset renewal capital expenditure that will be explained and justified in the remainder of this summary document.
- Section 3 describes the conceptual nature of Ergon Energy's asset renewal capital expenditure. It explains why it is necessary, including having regard for customer expectations, as well as Ergon Energy's legislative and regulatory obligations.
- Section 4 examines why Ergon Energy's asset renewal capital expenditure in the current regulatory control period differed from the forecasts that it presented to the AER in its regulatory proposal (and revised regulatory proposal), as well as the AER's own capital expenditure allowance in its distribution determination. It also explains how Ergon Energy has incorporated learnings about these differences into its capital expenditure forecasts for the next period.

- Section 5 explains Ergon Energy's expenditure forecasting methodology for its asset renewal capital expenditure for the next regulatory control period. It does this by reference to its actual practices for undertaking asset renewal capital expenditure.
- Section 6 details Ergon Energy's forecasts for its asset renewal capital expenditure for the next regulatory control period that it is proposing the AER approve. It also details the network, risk and customer outcomes associated with these capital expenditure forecasts, and assesses its forecasts against the results of the AER's replacement expenditure model.
- Section 7 draws on the material in the previous sections to explain and justify Ergon Energy's forecast asset renewal capital expenditure against the capital expenditure objectives and criteria in clause 6.5.7 of the National Electricity Rules (NER). It therefore outlines why the AER should approve this capital expenditure forecast as part of its distribution determination for Ergon Energy's next regulatory control period.

2. Expenditure profile

This section details Ergon Energy's asset renewal capital expenditure for the previous, current and next regulatory control periods. This is intended to provide the reader with a clear understanding of the profile of Ergon Energy's actual, estimated, and forecast asset renewal capital expenditure that will be explained and justified in the remainder of this summary document.

Importantly, this section distinguishes between direct and total costs for Asset Renewal capital expenditure for both SCS (Standard Control Service) and ACS (Alternative Control Service).

2.1 Direct costs

Table 1 details the following information about Ergon Energy's Asset Renewal capital expenditure, for its SCS only, in direct costs, for the previous, current, and next regulatory control periods:

- the Renewal capital expenditure forecast that Ergon Energy:
    - presented in its regulatory proposals, and revised regulatory proposals, to the Queensland Competition Authority (QCA) for the previous regulatory control period (2005-10) and to the AER for the current regulatory control period (2010-15)
    - is now presenting in its regulatory proposal to the AER for the next regulatory control period (2015-20).
- the QCA's and the AER's renewal capital expenditure allowance for the previous and current regulatory control periods respectively
- Ergon Energy's actual and estimated renewal capital expenditure for the previous and current regulatory control periods.

All costs have been converted into real 2014-15 dollars.[1]

Table 2 details the Asset Renewal expenditure in the past, current and next regulatory control periods which is predominantly related to metering and street lighting renewal activities and which the AER classifies as ACS.

[1] Indexation is based on the Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI.

Table 1: Asset renewal capital expenditure – Standard Control Services (Direct costs, $m real 2014-15[2])

Regulatory Review process	2005-06	2006-07	2007-08	2008-09	2009-10	Total	2010-11	2011-12	2012-13	2013-14	2014-15	Total	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Regulatory Proposal	121	115	120	116	112	**584**	145	177	209	232	259	**1,022**[3]	176	193	165	177	172	883[7]
Revised Regulatory Proposal	127	120	126	121	118	**612**	149	185	219	242	264	**1,058**[4]	n/a	n/a	n/a	n/a	n/a	**n/a**
QCA/AER Determination	111	121	132	132	132	**629**	133	155	179	203	227	**897**[5]	n/a	n/a	n/a	n/a	n/a	**n/a**
Actual/Estimate	148	123	87	101	113	**571**	160[6]	187[6]	195[6]	146[6]	166[7]	**853**	n/a	n/a	n/a	n/a	n/a	**n/a**
Variance – Actual v Determination	**33%**	**2%**	**-34%**	**-23%**	**-14%**	**-9%**	**20%**	**21%**	**9%**	**-28%**	**-27%**	**-5%**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

Table 2: Asset renewal capital expenditure – Alternative Control Services (Direct costs, $m real 2014-15)

Regulatory Review Process	2005-06	2006-07	2007-08	2008-09	2009-10	Total	2010-11	2011-12	2012-13	2013-14	2014-15	Total	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Regulatory Proposal	n/a	n/a	n/a	n/a	n/a	**n/a**	2	3	3	4	4	**16**	10	10	10	10	10	**50**[7]
Actual/Estimate	n/a	n/a	n/a	n/a	n/a	**n/a**	1	2	3	4	2	**2**	n/a	n/a	n/a	n/a	n/a	**n/a**

[2] Indexation based on Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI

[3] Regulatory Proposal to AER – Distribution Services for period – 1 July 2010 to 30 June 2015 – 1 July 2009, Page 31, Table 6 (and converted into direct costs)

[4] Revised Regulatory Proposal to AER – Distribution Services for period – 1st July 2010 to 30 June 2015 – 14 Jan 2010, Page 11, Table 1-1 (and converted as above)

[5] AER Final decision, Queensland distribution determination 2010-11 to 2014-15, Page xxxiii, Table 12 (allocated by Ergon Energy into the capex categories and converted as above)

[6] 2010-11 to 2013-14 Ergon Energy Annual Performance RINs, Table 2.4 (2010-11 to 2011-12), Table 1 (2012-13 to 2013-14) (and converted as above)

[7] Network Capital Expenditure Forecast Model (for Ergon Energy 2015-20 regulatory proposal), escalated for CPI only to 2014-15 dollars and excludes non-CPI input price escalations and overhead as per the Cost Allocation Method (CAM)

To provide context for the proposed asset renewal expenditure in the 2015-20 regulatory control period, the reasons for the variances in past expenditure shown in Table 1 are set out below.

Over the 2005-10 regulatory control period, Ergon Energy underspent its allowance for renewals expenditure by $57 million, or 9%. The main drivers for the year-on-year variances and overall reduction were:

- Prior to the Global Financial Crisis (GFC), Queensland was in an economic boom, and afterwards continued to experience strong mining growth and residential property growth. Meeting the demand for customer connections required expenditure significantly above the regulatory determination.
- Significant weather events led to a re-prioritisation of resources/expenditure. For example, in March 2006 Cyclone Larry crossed the North Tropical Coast near Innisfail. Road and rail access was disrupted for several days due to flooding and, at times, prevented road access to the Babinda-Innisfail area from both the north and south. Cyclone recovery works resulted in the deferral of some asset replacement programs.
- Parts of the work program were deferred by industrial action and decisions to reduce overtime.
- In response to upward pressures on customer prices being driven by increased customer initiated capital works and resource limitations, Ergon Energy made a decision to defer some replacement works. Deferral of asset renewal expenditure does not have immediate impacts on reliability and safety but leads to increasing asset failure rates over time.

For the 2010-15 regulatory control period, the AER's allowance for renewals expenditure increased by $268 million (direct). The deferral of renewal works in 2005-10 gave rise to a need for increased renewal expenditure from 2010 onwards to maintain failure rates within acceptable levels. As a result Ergon Energy forecast changes in defect related renewal expenditure including:

- increased conductor, cables, services, pole top and transformer renewal allowances
- a number of subtransmission line rebuilds
- increased earthing remediation allowance.

Over the four years to 2013-14, Ergon Energy exceeded its allowance by $10 million, or 1.5%. The key drivers for this change were:

- major restoration works associated with Cyclones Anthony (2012), Yasi (2011), Oswald (2012), and the flooding around the Bundaberg and Southern regions of Ergon Energy. The Queensland Government directed that Ergon Energy could not seek recovery of the associated costs via pass-through mechanisms available under the NER. Ergon Energy absorbed the costs incurred from Yasi within its existing allowances, as well as trying to complete and/or reprioritise other programs to maintain and/or replace network assets as needed
- the acceleration of replacement programs in response to emerging high risk safety issues (e.g. 7/064 Hard Drawn Bare Copper (HDBC) high voltage (HV) conductors) and the replacement of assets that were threatening minimum service standards (e.g. specific types of Air Break Switches).

Despite exceeding the renewal allowance in each of the first three years of the current regulatory control period, it is forecast that Ergon Energy will materially meet the total renewal allowance for the period. This is driven predominantly by:

- more focused risk assessments and targeted outcomes for various maintenance and defect refurbishment expenditure. These have been achieved through more prescriptive definitions of inspection requirements and benchmarks, a move towards open market tenders for service contracts, improvements in work bundling arrangements and tightening of audit processes of inspection and maintenance tasks
- a reassessment of the need to rebuild the ageing subtransmission feeder population. Condition data for subtransmission feeder assets has progressively improved in quality and coverage since Ergon Energy implemented the Asset Inspection and Defect Management (AIDM) program in 2002, and the Ellipse Asset Management System in 2006. This enabled Ergon Energy to re-assess the need for the program on the basis of more reliable information. At the same time, investment in refurbishing subtransmission feeder assets during the same period led to better than expected improvements in feeder performance. In 2013, Ergon Energy concluded that to continue with most of the subtransmission feeder rebuilding projects would be imprudent, and chose instead to prioritise less expensive pole top refurbishments.

These factors are described in more detail in Section 4.

Renewals capital expenditure for the upcoming 2015-20 regulatory control period is forecast to be $883.2 million, $16 million less than the allowance for the 2010-15 period. Forecast expenditure during this period is driven predominantly by:

- compliance requirements related to Ergon Energy's obligations under section 29 of the *Electrical Safety Act 2002* (Qld), Section 21 of the *Work Health and Safety Act 2002* (Qld), the Queensland Electrical Safety Code of Practice 2010 – Works and the replacement of assets that are reaching the end of useful life eg. (meters, radio network, operational technology and Static VAR Compensators (SVCs)).
- safety requirements driven by the risk of asset failure (e.g. copper conductors)
- replacing assets that have reached the end of useful life.

It is noted that the $883.2 million excludes an amount of $49 million for metering and street lighting related renewal activities which were previously classified as SCS, but which the AER has classified as ACS in the 2015-20 regulatory control period.

Section 6 of this summary document provides further detail of the reasons for the trend in asset renewal capital expenditure in the next regulatory control period.

2.2 Total costs

Table 3 and Table 4 below provide the same information as is in Table 1 and Table 2 but, instead of presenting the asset renewal capital expenditure in direct costs, they present it in total costs (i.e. inclusive of real cost escalations and shared costs (overheads)).

This total cost information is provided for comparative purposes only should readers seek to compare Ergon Energy's total costs with those in other documents. As discussed in Section 1, the remainder of this document explains and justifies Ergon Energy's direct costs only (i.e. the costs in Table 1 and Table 2 above).

Table 3: Asset renewal capital expenditure – Standard Control Services (Total costs, $m real 2014-15[8])

Regulatory Review process	2005-06	2006-07	2007-08	2008-09	2009-10	Total	2010-11	2011-12	2012-13	2013-14	2014-15	Total	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Regulatory Proposal	182	174	176	172	173	**876**	201	240	283	311	338	**1,372**[9]	256	286	256	282	278	**1,358**[13]
Revised Regulatory Proposal	190	183	184	180	181	**917**	205	252	296	323	345	**1,420**[10]	n/a	n/a	n/a	n/a	n/a	**n/a**
QCA/AER Determination	173	189	207	213	217	**999**	188	221	252	283	311	**1,255**[11]	n/a	n/a	n/a	n/a	n/a	**n/a**
Actual/Estimate	205	171	130	148	166	**820**	228[12]	267[12]	290[12]	230[12]	241[13]	**1,256**	n/a	n/a	n/a	n/a	n/a	**n/a**
Variance – Actual v Determination	**18%**	**-10%**	**-37%**	**-31%**	**-24%**	**-18%**	**21%**	**21%**	**15%**	**-19%**	**-23%**	**0%**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

Table 4: Asset renewal capital expenditure – Alternative Control Services (Total costs, $m real 2014-15)

Regulatory Review Process	2005-06	2006-07	2007-08	2008-09	2009-10	Total	2010-11	2011-12	2012-13	2013-14	2014-15	Total	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Regulatory Proposal	n/a	n/a	n/a	n/a	n/a	**n/a**	3	4	4	5	6	**21**	15	15	15	16	16	**76**[13]
Actual/Estimate	n/a	n/a	n/a	n/a	n/a	**n/a**	1	2	4	5	2[13]	**14**	n/a	n/a	n/a	n/a	n/a	**n/a**

[8] Indexation based on Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI

[9] Regulatory Proposal to AER – Distribution Services for period – 1st July 2010 to 30th June 2015 – 1st July 2009, Page 31, Table 6

[10] Revised Regulatory Proposal to AER – Distribution Services for period –1st July 2010 to 30th June 2015 –14th Jan 2010, Page 11, Table 1-1

[11] AER Final decision Queensland distribution determination 2010-11 to 2014-15, Page xxxiii, Table 12 (allocated by Ergon Energy into the capex categories)

[12] 2010-11 to 2013-14 Ergon Energy Annual Performance RINs, Table 2.4 (2010-11 to 2011-12), Table 1 (2012-13 to 2013-14)

[13] System Capital Expenditure Escalation Model escalated for Ergon Energy 2015-20 regulatory proposal in accordance with Ergon Energy Forecasting Methodology, i.e. applying CPI indexation to 2014-15 dollars, non-CPI input price escalations, overhead as per Ergon Energy CAM

Overheads are allocated to direct costs incurred in all expenditure categories internally within Ergon using a Cost Allocation Methodology approved by the AER. Overheads are applied to all direct operating and capital expenditure in the business on a per dollar basis. This allows Ergon Energy to manage its overheads and direct costs through business-as-usual financial management and reporting processes.

As shown in Table 1 and Table 3, asset renewal expenditure is expected to be 5% lower than the AER's allowance for the 2010-15 regulatory control period in direct cost terms, while it is expected to meet the AER's allowance for the period in total cost terms. The variance is due to the way in which direct costs themselves vary over time and the way in which overheads are applied to those direct costs. From time to time Ergon Energy varies the allocation of overheads within the business and as a result, the proportion of direct costs to total costs for each expenditure category will not remain constant over time. As a result, Ergon Energy's actual and expected performance in 2010-15 varies in terms of direct and total costs.

3. Nature of expenditure

This section describes the conceptual nature of Ergon Energy's asset renewal capital expenditure. It explains why it is necessary, including having regard for customer expectations, as well as Ergon Energy's legislative and regulatory obligations.

Asset renewal capital expenditure is recurrent, non-demand driven capital expenditure. It arises from the need to maintain Ergon Energy's distribution asset base in order to continue efficiently delivering its service performance, and to maintain the safety, reliability, and quality of supply required by technical standards. Whenever renewal works are proposed, they are always reviewed against security criteria to ensure that renewal of the asset is necessary to maintain current levels of security of supply.

Asset renewal capital expenditure involves refurbishing, repairing and replacing asset components that reach the end of their economic lives, as determined by their age, condition, technology or environment. This capital expenditure involves both proactive and reactive renewals.

3.1 Customer engagement

To ensure Ergon Energy's Regulatory Proposal is aligned with the long-term interests of its customers and communities, Ergon Energy has undertaken significant customer and community engagement. Through listening to its customers, Ergon Energy was able to refresh its service commitments, which in turn has helped inform the expenditure forecasts outlined in this summary. A comprehensive description of the customer engagement process, and how its outcomes have informed Ergon Energy's decision-making process, is presented in the document, 'Informing Our Plans, Our Engagement Program'.

Ergon Energy's commitment to delivering the best possible price has provided the framework for the forecast. In every way, Ergon Energy has aimed to be as prudent and efficient as possible in its investment plans. In formulating asset renewal plans, Ergon Energy has also considered its commitments around delivering peace of mind, by way of a safe, dependable electricity service. Ergon Energy's continued investment in asset renewal is in line with its customers' expectations to maintain recent improvements in power supply reliability, as described in the 'Forecast Expenditure Summary Reliability and Quality of Supply 2015 to 2020'.

3.2 Legislative requirements

The Queensland *Work Health and Safety Act 2011* requires Ergon Energy to:

- ensure, so far as is reasonably practicable, that the fixtures, fittings and plant are without risks to the health and safety of any person.[14]

Under the Queensland *Electrical Safety Act 2002*, Ergon Energy has a duty to ensure that its works –

- are electrically safe
- are operated in a way that is electrically safe.[15]

Further, the Queensland *Electrical Safety Act 2002* requires Ergon Energy to:

- 'inspect, test and maintain the works'[16].

Both Acts define what is 'reasonably practical' for Ergon Energy to do in meeting its safety obligations.[17] The effect of these definitions is to require suitably-knowledgeable persons to assess the relevant hazards or risks and to eliminate or mitigate the risks having regard, amongst other things, for whether the associated costs of doing so are 'grossly disproportionate' to the risks.[18] Accordingly, Ergon Energy aims to strike a balance between managing acceptable levels of risk and maintaining a level of renewal expenditure that is not grossly disproportionate to the risks the expenditure is intended to address.

The Acts do not provide significant assistance in defining the meaning of 'grossly disproportionate'. The 'value of statistical life' is often used to estimate the benefits of reducing the risk of death. This is the estimated financial value society places on reducing the average number of deaths by one. The Australian Government's Office of Best Practice Regulation has issued a 'Best Practice Regulation Guidance Note'[19] that estimated the 'value of statistical life' at $3.75 million in 2007. Adjusted for CPI, this equates to approximately $4.5 million in 2014.

Expenditure below this value, which is intended to mitigate an identified safety issue with a demonstrable likelihood of death, is therefore deemed to be prudent and hence required under the Acts. While this value provides some guidance on whether the cost of undertaking a project is proportionate to the benefit it provides, this prudency test is only an indication of the bare minimum required of Ergon Energy. Where the costs of a project do not satisfy this test, Ergon Energy conducts a full risk assessment to determine whether the expenditure is not grossly disproportionate to the risk identified and is therefore justified.

Recent amendments to statutory instruments, such as the national harmonisation of Work Health and Safety laws and changes to the Queensland Electrical Safety Codes of Practice, have changed how Ergon Energy performs its duties. These amendments, which took effect in December 2012 and January 2014 respectively, affect risk assessment criterion, statutory performance benchmarks and other obligations, and therefore have influenced Ergon Energy's forecasts for the 2015-20 regulatory control period. Given the widespread impact of Work Health and Safety activities within the business the effect of these changes on forecast capital expenditure is difficult to quantify.

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[14] Section 21(2) of Queensland Work Health and Safety Act 2002

[15] Section 29(1) of Queensland Electrical Safety Act 2002

[16] Section 29(2) of Queensland Electrical Safety Act 2002

[17] Section 18 of Queensland Work Health and Safety Act and section 28 of Queensland Electrical Safety Act 2002

[18] Section 18 of Queensland Work Health and Safety Act and section 28 of Queensland Electrical Safety Act 2002

[19] Australian Government, Department of Finance and Deregulation, Office of Best Practice Regulation, Best Practice Regulation Guidance Note – Value of a Statistical Life

3.3 General philosophical approach to asset renewal capital expenditure

Ergon Energy believes it has an obligation to maintain and manage its assets in accordance with legislation and regulation, to a standard that achieves satisfactory performance into the long term for the community at large and the economic benefit of the state of Queensland. Asset renewal is an essential part of this obligation.

The prime intention of asset renewal is to replace assets, refurbish assets, or extend asset life to achieve the same functional design intent of the original asset. This renewal process requires capital expenditure sufficient only to maintain functional standards of service and regulatory benchmarks.

To this end, Ergon Energy distinguishes between asset renewal and asset augmentation. The latter is related to improving network functionality, and discussed in detail in the documents 'Forecast Expenditure Summary Corporation Initiated Augmentation 2015 to 2020' and 'Forecast Expenditure Summary Customer Initiated Capital Works 2015 to 2020'.

In concept, system level asset renewal should be just sufficient to offset the natural ageing and deterioration process, so that average asset performance and hence system performance and risk remain relatively constant. Except for identified Workplace Health and Safety risks, Ergon Energy has targeted its renewal capital expenditure proposals with this intent. Where Workplace Health and Safety risks have become significant, Ergon Energy has proposed asset renewal capital expenditure programs that effectively bring forward end of economic life for specific assets to mitigate the identified risks.

3.4 Asset Management Strategy and associated models

Ergon Energy has developed an overarching 'Network Optimisation Asset Strategy'. In relation to asset renewals, the strategy details Ergon Energy's approach to lifecycle optimisation and the key enabling strategies to achieve this.

Ergon Energy has established Condition Based Risk Management (CBRM) models for its major substation assets as well as condition monitoring tools and processes to identify the balance between proactive and reactive asset replacement. The CBRM models document the trade-offs between ongoing maintenance costs and risks, versus replacement costs and risks, and recommends optimum and prudent replacement times. The CBRM models have been calibrated with Ergon Energy asset failure history. Unlike the Replacement Expenditure (Repex) models, which assume that historical maintenance and refurbishment strategies and practices continue substantially unchanged, the CBRM models have been used to evaluate different renewal strategies and calculate the potential failure rates and consequences that arise from each of the different strategies.

Where CBRM models have not yet been developed (such as for lines), Ergon Energy uses net present value analysis and risk assessments that consider the safety, history, performance, cost, and other business delivery factors, in order to inform its decisions about proactive end-of-economic-life replacement and life-extension refurbishment works.

The CBRM models used by Ergon Energy are based on principles similar to those used across Australia and the world generally. Several Australian network service providers use the CBRM approach including Energex, and there are 12 Australian network service providers represented in the CBRM Users Group industry body.

In late 2014, Ergon Energy developed Repex models based upon data collected for the Regulatory Information Notices (RINs). The overall renewal volume and costs predicted by the Repex models (which assume the asset management strategies used in the past will be equally used in the future) appear to compare favourably with Ergon Energy's proposed expenditure for the 2015-2020 regulatory control period. This is not unexpected as Ergon Energy has actively improved its asset management (impacting both maintenance and renewal) strategies and processes in the current (2010-2015) regulatory control period. CBRM models represent a significant demonstration of this improvement.

3.5 Approach to asset renewal capital expenditure

As discussed in Section 3.3, Ergon Energy's approach to asset renewal capital expenditure is to replace components as needed to maintain the assets' intended functional performance. The primary focus is to maintain intended or expected service performance levels and only to improve performance where it is mandated by safety obligations.

All assets have the potential to fail in service. Ergon Energy's approach to managing the risk of asset failures is consistent with Queensland legislation and good asset management practice.

In relation to its high cost assets, Ergon Energy through its CBRM modelling, has expressed service performance outcomes as risk elements, and actively sought to maintain the same level of overall risk currently experienced in the current regulatory control period (2010-2015). This has dictated the different asset class forecast replacement volumes and expenditure.

In relation to its low cost assets, Ergon Energy has assumed reasonably constant service outcomes based upon its maintenance framework of processes, standards, and work practices. This has dictated the overall defect repair and renewal strategy, and associated renewal forecast expenditure.

Given this approach to maintain service level outcomes, total renewal expenditure forecasts for 2015-2020 regulatory control period are reasonably consistent with actual outcomes of the 2010-2015 regulatory control period.

Ergon Energy distinguishes between expenditure for:

- proactive refurbishment and replacement, where the objective is to renew assets before they fail in service by predicting the assets' end-of-life based on condition
- run-to-failure refurbishment and replacement, which includes replacing assets that have failed in service or replacing those that are believed will fail before the next inspection.

A proactive approach is undertaken typically for high-value assets such as transformers, where Ergon Energy holds plant information and condition data. This information is used where analysis shows that proactive replacement or refurbishment capital expenditure is the most prudent and efficient approach to achieve required quality, reliability, safety and environmental performance outcomes, having regard for the whole-of-life equipment cost. The consequence of failure impacts the priority for replacement of the asset in the program.

Low-value assets where it is not economic to collect and analyse trends in condition data are allowed to run-to-failure, with minimal or no intervention. These assets are managed generally through an inspection regime required under legislation. The objective of this regime is to identify and replace assets that are expected to fail before their next inspection. However, low-value assets that have higher than expected failure rates, or high levels of risk upon failure, may generate targeted replacement programs.

Both of these asset management approaches will result in some assets failing in service, necessitating more reactive responses. Finding the optimum balance between proactive and reactive asset renewal is not straight forward and varies for each asset class over time. Ergon Energy actively seeks to identify the right balance in order to support prudent expenditure.

Ergon Energy's risk management approach also recognises that for high cost assets, intrusive maintenance is relatively expensive and that lifecycle cost reductions can be achieved by non-intrusive condition monitoring and testing, collecting data, and analysing and reacting proactively. For low-cost assets, routine maintenance and/or obtaining and maintaining condition data are relatively expensive and therefore not prudent to pursue.

Table 5 provides an indicative list of asset classes that Ergon Energy includes in the two categories – proactive and run-to-failure. Some specific types within an asset class may have a proactive-replacement approach while the remainder of the asset class is run-to-failure. These specific types are reflected in the budget forecasts and are supported by specific 'engineering reports'.

Table 5: Asset type and associated asset management approach

Proactive refurbishment/replacement based on significant inspection and testing program or systemic study of failure modes
Subtransmission pole top structures
Power transformers
Circuit breakers and switchboards
Instrument transformers
Substation isolators and Earth switches
Capacitors
Protection assets
Substation DC power supplies
Revenue metering
Reactors
Streetlight lamps
Run-to-failure – Minimised inspection and testing undertaken to minimise life-cycle costs
Poles
Overhead conductor
Fuses
Distribution pole top structures
Distribution transformers
Regulators
Reclosers
Underground cables
Supervisory Control and Data Acquisition (SCADA)
Remote terminal units
Communication assets not associated with protection functions
Air break switches
Ring main units
Services
All assets that have actually failed in service regardless of value and/or impact

3.6 Improved asset management practices within the current regulatory control period

Ergon Energy is committed to aligning its asset management practices with the *ISO 55000 Asset Management Standard* principles and to undertaking good engineering practice.

Ergon Energy has made considerable improvements during the current regulatory control period, including to its data and information systems, inspection and condition monitoring regimes, understanding of many asset failure modes and its asset management processes. These improvements have resulted in Ergon Energy making better maintenance and renewal forecasts during the current regulatory control period. Ergon Energy has built on these improvements in its regulatory proposal for the next regulatory control period, using factors such as risk, ongoing maintenance cost, replacement cost, age and asset condition, to inform its renewal decisions.

Collation and use of condition-monitoring data is an area of continuous improvement for Ergon Energy. Where condition data is not yet available en-masse such as for substation isolators, Ergon Energy will continue to use age as an indicator of condition. Ergon Energy intends to continue to increase its reliance upon condition data as it becomes available for more asset classes.

For example, in its regulatory proposal for the 2010-15 regulatory control period, a lack of condition data meant that Ergon Energy used the age of assets as an indicator of asset condition to form the basis for renewal forecasts for substation and lines asset classes. Since then, the improvement of Ergon Energy’s asset information and processes has enabled Ergon Energy to reassess and defer or cancel a considerable number of refurbishment driven capital expenditure projects in the current regulatory control period. Additionally, Ergon Energy now specifically uses dissolved gas analysis from oil sampling to inform its modelling about asset condition for several asset classes such as transformers and circuit breakers.

Ergon Energy has steadily improved its AIDM program across a number of areas including identification, definition, application, and work maintenance planning. In 2010, Ergon Energy significantly enhanced its ‘Lines Defect Classification Manual’ to remove the subjectivity in lines inspection processes. This improved Ergon Energy’s ability to ensure component replacements are prudent. The information has allowed consequential maintenance and renewal works processes to be packaged, to improve works efficiency and so reduce costs.

In 2013, Ergon Energy’s testing criteria for all of its assets was reviewed and documented in the *Standard for Maintenance Acceptance Criteria (MAC),* developed from a joint workings program with Energex. This document has removed a significant level of subjectivity in condition monitoring and substation maintenance expectations. Ergon Energy also improved its standards for inspection and maintenance tasks, extending to all substation assets. This has improved asset condition data and enabled better and more cost-effective maintenance strategies. It has also supported life extension and plant rating decisions.

These asset management improvements are reflected in unit costs and quantities that underpin Ergon Energy’s asset renewal capital expenditure forecasts for the next regulatory control period.

4. Current regulatory control period performance

This section examines why Ergon Energy's asset renewal capital expenditure in the current regulatory control period differed from the forecasts that it presented to the AER in its regulatory proposal (and revised regulatory proposal) as well as the AER's own capital expenditure allowance in its distribution determination. It also explains how Ergon Energy has incorporated learnings about these differences into its capital expenditure forecasts for the next regulatory control period.

4.1 Ergon Energy's regulatory proposal and AER's distribution determination

For the current regulatory control period, Ergon Energy's asset renewal forecasts in its regulatory proposal (and revised regulatory proposal) were split into a defect program and a condition based program.

Ergon Energy forecast its defect renewal program based on its asset population, historical defect rates and its asset inspection program. Ergon Energy forecast its condition based program using asset condition information obtained from age, maintenance and testing programs, subject matter expertise, analysis of network performance and dangerous electrical events.

In its determination of Ergon Energy's asset renewals capital expenditure forecast, the AER determined a business-as-usual level of expenditure, by calculating a historic growth rate (2001-02 to 2005-06) and applying this to the replacement capital expenditure in the last year of the (then) current regulatory control period. Table 6 compares Ergon Energy's asset renewal forecasts that it submitted in its regulatory proposal and revised regulatory proposal, with what the AER approved in its distribution determination.

Table 6: Current period asset renewal capital expenditure proposed and allowed (Direct costs, $m real 2014-15)

Regulatory Review Process	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Regulatory Proposal	145	177	209	232	259	**1,022**
Revised Regulatory Proposal	149	185	219	242	264	**1,058**
QCA/AER Determination	133	155	179	203	227	**897**

4.2 Performance against the AER's asset renewal allowance

Ergon Energy expects that by the end of the current regulatory control period it will have achieved delivery of its asset renewal capital expenditure, close to the AER's allowance. As shown in Table 7, Ergon Energy's actual expenditure to the end of 2013-14 was $10 million more than was allowed. Ergon Energy expects that its capital expenditure in the last year of the regulatory control period will be $66 million below the AER's allowance for 2014-15, materially meeting the direct renewal capital expenditure allowance for the period.

Table 7: Current period asset renewal capital expenditure compared to the AER's allowance (Direct costs, $m 2014-15)

Regulatory Review Process	2010-11	2011-12	2012-13	2013-14	2014-15	Total
AER Determination	133	155	179	203	227	**897**
Actual/Estimate	160	187	195	146	166	853
Variance – Actual v Determination	**20%**	**21%**	**9%**	**-28%**	**-27%**	**-5%**

4.3 Reasons for variance from AER's asset renewal allowance

The following section expands on Section 2.1.

4.3.1 Exogenous factors and emerging safety risks

There were a number of exogenous, or external, factors resulting in variations between Ergon Energy's actual renewal costs when compared to the AER's determination during the current regulatory control period. The material drivers underpinning these variations are described below.

Yasi in February 2011 was the largest and most severe cyclone to affect Queensland for decades. The restoration effort required substantial resources from Energex and interstate and required the capitalisation of approximately $50 million of expenditure, which was absorbed by Ergon Energy within its existing expenditure allowance.

This significant outlay in resources exacerbated an existing backlog in the asset inspection program. After Yasi, asset inspections were ramped up to achieve program targets, leading to an increase in the number of observed defects and hence an increase in expenditure to address those defects. Compounding this increased expenditure was the emergence of resource constraints in the central Queensland region due to the on-going resources boom. This increased the cost of performing work as high demand for contractors placed upward pressure on contract prices. Together, these combined impacts contributed to Ergon Energy exceeding its allowed renewal expenditure in 2011-12 and 2012-13.

Early in the regulatory control period, several high-risk safety issues emerged that required higher levels of expenditure to mitigate risks to employees and the public. These were:

- The replacement of specific type of Air Break Switches – Ergon Energy identified a systemic failure mode that caused the switches to fail prematurely and resulted in porcelain shards falling onto operating staff. This created a significant safety risk for staff and threatened compliance with minimum service standards. As a result, the ABS maintenance program was suspended to focus on replacement only to remove the risk and the reliability impact. This was a higher expenditure than forecast and was brought forward in the period between 2010 to 2013 to remove the safety risk as soon as practicable and achieve delivery efficiency from external contracts.

- The 7/.064 Hard Drawn Bare Copper (HDBC) High Voltage conductor replacement program – by 2011, it was recognised that the proposed replacement rate was insufficient to arrest the increasing rate of conductor failures, and hence the failures continued to dominate as a leading cause of Dangerous Electrical Events in some locations such as the Burdekin area in northern Queensland. As a result, the program was accelerated early in the regulatory control period to manage the risk of failure and in response to formal requests for improvement from the Queensland Electrical Safety Office.
- The replacement of open wire services. Services are the connections between the ‘pole’ and customer premises. Open wire services are services with uninsulated conductors. Ergon Energy had a steady rate replacement program in place, but accelerated the replacement of remaining open wire services with insulated wire services to manage an emerging risk as a result of several customer shock incidents.

To manage these safety risks in a prudent manner Ergon Energy re-allocated expenditure from other programs. At the same time, Ergon Energy implemented processes to improve the efficiency of works to be delivered in the remainder of the period to maintain expenditure within the AER’s allowance. These processes are described below.

4.3.2 Improvement in asset management techniques

In response to the overspend that occurred in the first three years of the regulatory control period, in late 2012 Ergon Energy conducted a series of efficiency and effectiveness reviews to improve asset management techniques and processes, to better manage overall risk while containing expenditure within the allowance for the remainder of the period. This resulted in more focused risk assessments and targeted outcomes for various maintenance and defect refurbishment expenditure. These endogenous, or internal changes, are described below.

Recognising an increasing volume of defects identified in the current regulatory control period, Ergon Energy sought and initiated targeted improvements in the efficiency of defect rectification works to remain within its expenditure allowance. These efficiencies were realised in both operating and capital expenditure and will continue to be realised in the next period. They include:

- joint design and maintenance standards (developed in conjunction with Energex) achieving improved objectivity in benchmark pass/fail levels
- more prescriptive definitions of inspection requirements and benchmarks, used in Service Delivery contracts and internally resourced inspections (e.g. Lines and Substation Defect Classification Manuals)
- re-establishment of major Inspection and Refurbishment Service Contracts with significant efficiencies established. Open-market tenders have achieved cost reductions and performance efficiencies for this work
- improvements in work-bundling arrangements for defect refurbishment tasks
- tightening of audit processes for inspection and maintenance tasks, reducing rework and improving overall efficiency
- facilitating repair and inspection urgency level amendments following prescribed risk assessments.

Condition data for subtransmission feeder assets has progressively improved in quality and coverage since Ergon Energy implemented the AIDM program in 2002 and the Ellipse Asset Management System in 2006. AIDM was the first systemic attempt by Ergon Energy to inspect and monitor condition data for every line asset. Over the same period, the increase in observed defects generated substantial activity and investment, targeted towards refurbishment of subtransmission feeder assets.

The improvement in performance of the feeders, in terms of both safety and reliability, was significantly better than anticipated at the time of Ergon Energy's Regulatory Submission for 2010-2015. As a result, and on the basis of improved asset condition data from the AIDM program, Ergon Energy concluded that to continue with most of the subtransmission lines rebuilding projects would be imprudent. In response, this program was significantly reduced in scope, leading to a significant reduction in associated expenditure over the entire period. This is expected to result in a larger subtransmission pole-topping program in 2015-20 as pole top refurbishment is a less expensive alternative to rebuilding entire feeders.

Ergon Energy has developed a new 'Security Criteria' document (refer to the 'Forecast Expenditure Summary Corporation Initiated Augmentation 2015 to 2020' for more details). This was incorporated into the prudency check related to asset renewal justifications, and resulted in some changed project risk assessment outcomes leading to the deferral and/or cancellation of some renewal projects. Additionally, Ergon Energy has begun to use improved assessment tools to identify and target the most appropriate assets for refurbishment (e.g. CBRM, used on major substation assets classes). The subsequent improvement in asset-condition reports has led to the deferral of major substation condition-based refurbishment projects such as the Charters Towers Substation refurbishment project.

4.4 Effect of current regulatory control period expenditure on the next period

As described in Section 3.3, finding the optimum balance between proactive and reactive asset renewal is not straight forward and varies for each asset class over time. Ergon Energy actively seeks to identify the right balance in order to support prudent expenditure. As safety, reliability, or security of supply risks are identified, expenditure may be reprioritised in order to make prudent decisions, especially where emerging risks require a proactive, short-term response. As assets are managed over a long period spanning multiple regulatory control periods, the reprioritisation of expenditure in one period often defers the expenditure to the subsequent period.

Several activities in the current period are likely to have an impact on proposed expenditure in the 2015-20 regulatory control period. These factors are summarised below and are described in further detail in Section 6:

- Changes to the network planning criteria made in early 2012 and in 2014, lower than forecast maximum demand growth, and demand management have reduced the need for augmentation in the 2010-15 regulatory control period. The deferral of augmentation has meant that older, existing assets have remained in service rather than being replaced by newer, higher-capacity assets. These assets will be subject to continued inspection and maintenance commensurate with their aged condition and result in higher levels of expenditure to replace, refurbish or maintain them, than they would otherwise require. Details of the impact of the planning criteria changes are discussed in detail in the 'Forecast Expenditure Summary Corporation Initiated Augmentation 2015 to 2020'.
- The reduction in the capital intensive subtransmission feeder rebuilding program that occurred in 2010-15 will be replaced by a more targeted shift to subtransmission pole top refurbishments in the 2015-20 regulatory control period.
- The 7/.064 HDBC HV conductor replacement program identified that HDBC Low Voltage (LV) conductors were also at risk of failure. As a result the replacement of HDBC conductors is proposed to be accelerated in the 2015-20 regulatory control period and beyond.

- Ergon Energy conducted investigations in the 2010-15 regulatory control period into specific failure risks for the following asset types:
    - Current Transformer (CT) replacements (specific types only) – occurred between 2011 and 2013, following an investigation that revealed an insulating oil additive resulted in solidification of the oil and subsequent explosive failure of the unit.
    - 66kV Circuit Breaker (CB) refurbishment (specific models only) – occurred between 2011 and 2014, to address partial discharge and significant moisture ingress leading to catastrophic failure.

Because expenditure was directed towards proactive replacement of specific models within a broader asset category, work to renew other models within the same category were deferred as a result. The resultant deterioration in the age profile of the broader CT and CB asset categories gave rise to a need for increased expenditure in the 2015-20 regulatory control period. Additionally, refurbishment of the 66kV CBs was undertaken in line with manufacturer recommendations, but generally unsuccessful. Further work to replace the most severely degraded units is expected in the 2015-20 regulatory control period.

Ergon Energy has worked with Energex to standardise processes and benchmarks to achieve a more appropriate level of maintenance performance across the industry. As asset management history has accumulated and systemic failure impacts understood, Ergon Energy has developed and improved essential maintenance standards and benchmarks, resulting in higher than expected defect quantities to be resolved. These improved standards have been reflected in revisions to the 'Lines Defect Classification Manual' in 2010 and 2013 and the publication of the 'Substation Defect Classification Manual' in 2011 and revision in 2012. Generally, a 'new' benchmark or identified defect class will directly impact renewal expenditure, appearing as a 'bow wave' expenditure impact lasting typically for one complete inspection cycle, before settling back to a new constant level that reflects ongoing assets degradation rates for the specific defect.

5. Expenditure forecasting methodology

This section explains Ergon Energy's expenditure forecasting methodology for its asset renewal capital expenditure for the next regulatory control period. It does this by reference to its actual practices for undertaking asset renewal capital expenditure.

5.1 Broad approach

Ergon Energy uses two broadly based asset management approaches to make asset replacement decisions, discussed in Section 3:

- a proactive refurbishment and replacement approach
- a run-to-failure refurbishment and replacement approach

Preparing forecasts of replacement expenditure that replicate these approaches can provide unique challenges. Most notably:

- predictability – it can be difficult to infer the future condition from knowledge of the current condition
- scale – replacement programs may cover the replacement of high volumes of asset components, many of which are not specifically recorded in Ergon Energy's asset management systems, and therefore, it can be difficult to identify specific future requirements.

Consequently, it is usual in the industry to use a range of methods to prepare the medium term replacement forecasts that are necessary for regulatory purposes. These methods tend to be specific to the asset and its management approach.

The following sections will:

- explain how Ergon Energy make actual replacement decisions
- explain the various methods Ergon Energy have used to prepare asset replacement forecasts
- set out how these methods are appropriate.

5.2 Making asset replacement decisions

Figure 1 describes in general how asset replacement decisions are made, with key emphasis upon the proactive and replace on fail approaches used at Ergon Energy.

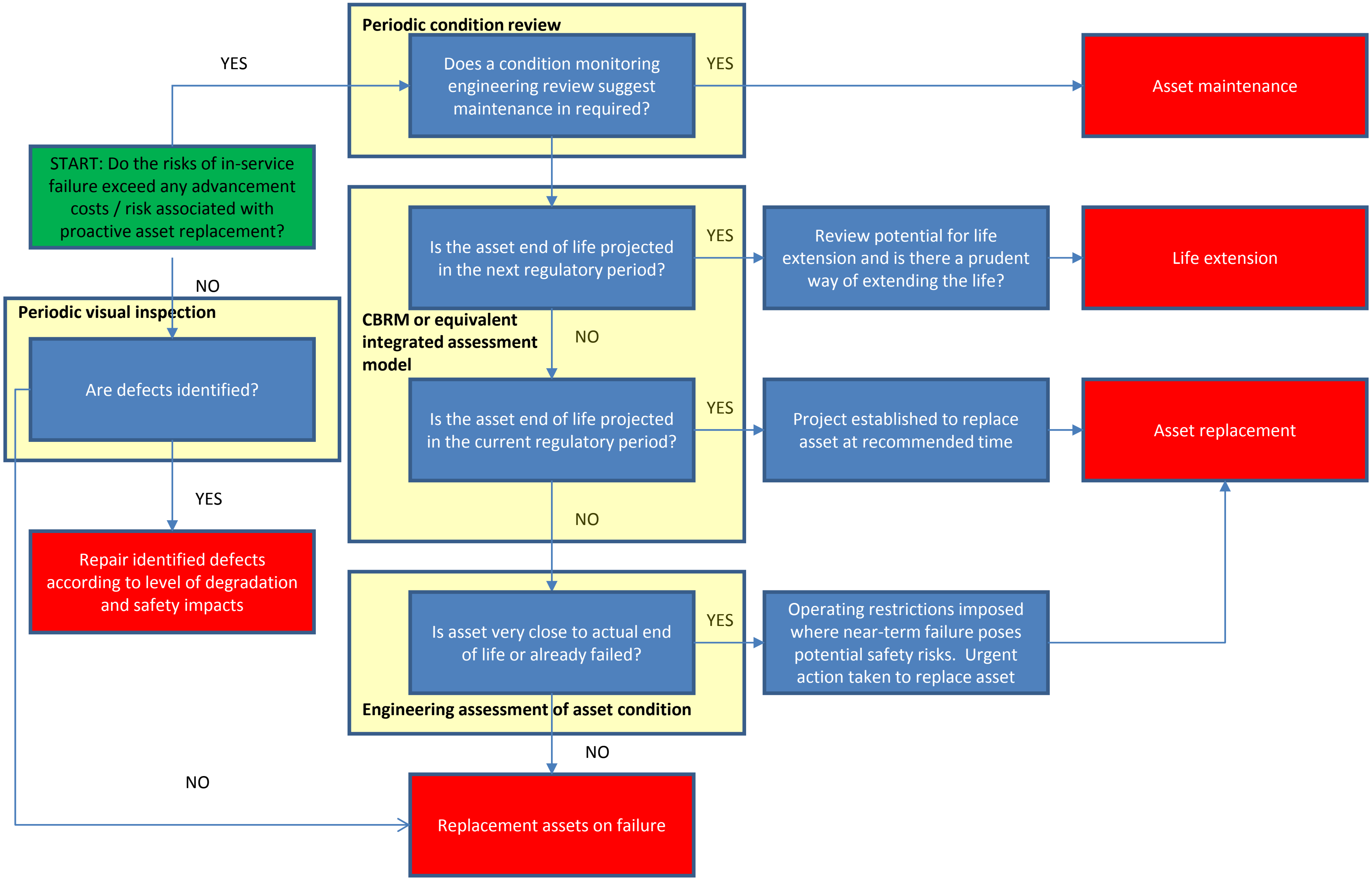


Figure 1: Asset replacement decision-making process

5.2.1 Proactive replacement

Ergon Energy replaces assets proactively where the risks (consequence and cost) of an in-service failure exceed any advancement cost associated with its replacement. These risks typically relate to:

- public and company safety risks associated with a catastrophic failure of an asset
- extended customer interruptions due to the failure, or an increased risk of extensive interruption while the asset is out of service
- increased operating and capital costs associated with unplanned and emergency outages and replacements.

Ergon Energy does not make decisions to proactively replace an asset lightly. Before a decision to replace any specific asset is made, Ergon Energy reviews condition history to determine whether it has an imminent likelihood of failing.

For example:

- The power transformers within zone substations are low-volume high-cost assets. These assets have a number of subcomponents (e.g. tap changers) that can themselves fail independent of the main transformer. Depending on its size and location, there can be significant safety and reliability costs associated with major transformer failures.
- Ergon Energy regularly inspects and performs a range of tests on every transformer and its subcomponents, providing information on their condition. There are criteria associated with these tests that inform Ergon Energy as to whether the transformer or its subcomponents close to failure and may require some form of refurbishment or replacement.
- Due to the higher value of transformers, Ergon Energy typically performs further analysis before deciding to replace a transformer. This analysis improves the understanding of the likelihood and consequence of immediate and medium failure of the transformer, and informs the decision on whether or not, or when to replace it. Should a decision be made to replace the transformer, the analysis enables Ergon Energy to optimise the replacement with other operational needs at that substation.

5.2.2 Run-to-failure

A run-to-failure approach is used where Ergon Energy believe the types of risk, noted above, would not justify the advancement cost of the replacement or where it is not feasible to make a reasonable estimate of the likelihood of failure.

Following the failure of an asset (even the unanticipated failure of an asset under the proactive replacement approach), Ergon Energy will inspect and investigate the failed asset. The asset will be replaced with an identical or similar asset (allowing for standards changes over the years, stores inventories and spare component availability).

Importantly, because Ergon Energy has a duty to inspect, test, and maintain the assets under their control, they have developed inspection and condition monitoring programs to identify the degradation of all assets.

Asset replacement responses to the assessed degradation are defined through documented processes, pre-determined risk assessments, and defect repair standards. These matters are set out in key documents, including:

- the ‘Lines and Substation Defect Classification Manuals’
- the *Standard for Maintenance Acceptance Criteria*

These documents have been approved and certified by Registered Professional Engineers Queensland (RPEQ).

For example:

- Wood poles are a high-volume low-cost asset. Wood poles are subject to degradation from lightning and weather, wood rot, termites and other external influences. The pole deterioration rates vary dramatically depending upon the cause. For example, termites can completely eat a wood pole within a few short months. Regular (four or six yearly) inspection and testing of every pole is undertaken to determine the amount of structurally 'good' wood. The 'Lines Defect Classification Manual' provides visual criteria to assist in the determination of pole serviceability and the pole inspection standards define the criteria that determine whether the amount of 'good' wood has reduced to a level where the pole is at significant risk of structural failure. When that criterion is exceeded, the pole is classified as unserviceable, and tasks initiated for replacement or reinstatement (pole nailing).

5.3 Replacement forecasting methods

5.3.1 Overview

Ergon Energy has used a number of methods to develop individual project and program forecasts. These methods can be classified as follows:

- Discrete Analysis – this method reflects the detailed analysis applied in usual business processes to develop individual projects that address specific known needs. This method is used in situations where Ergon Energy has significant information associated with specific asset issues, and the planned project is material enough to justify its own discrete analysis.
- Condition Based Risk Management (CBRM) – this method uses a series of asset-specific predictive models that Ergon Energy has developed, based upon the proprietary framework developed by EA Technology Pty Ltd. These complex models use available asset information and incorporate ageing models to predict asset-failure probabilities and associated risks. These types of models have been used for asset classes where Ergon Energy has good asset information across a population; a good understanding of the ageing mechanism and failure modes; a good understanding of the locational and operational risks involved; asset condition information; and the resulting modelling effort is justified by the greater accuracy of the prediction.
- Simple Predictive modelling – this method uses models that simplify the real underlying replacement dynamics. These models treat the asset class as a population, and assume simple relationships between some known asset information and future replacement needs. Due to their simplicity, the models produce forecasts at an aggregate program level. The AER's Repex model is an example of such a model. Models that also rely upon historical trends also fit into this category. Ergon Energy has used these methods to prepare forecasts for many of the high volume recurrent programs, where it would be too onerous or even impossible, to attempt to make accurate predictions of discrete replacement needs.

Selection of the appropriate forecasting methodology is dependent on how well suited it is to the project or program, based upon the available asset information and the trade-off between the forecasting effort and accuracy.

Table 8 summarises Ergon Energy's approach to asset management and forecasting the replacement profile of each asset type, documenting the usual approach to managing the asset (the asset replacement approach) and the approach used for specific asset classes or subclasses that are seeking special directed renewal works during the 2015-20 regulatory control period.

Table 8: Asset management approach and forecasting methodology

Asset type	Usual asset replacement approach	Replacement forecasting approach for 2015-20 Capex works
Air Break Switches	Run-to-failure	Simple Predictive
Capacitor Banks	Proactive	CBRM
Communications (backbone system)	Proactive	Discrete Engineering Review
Communications(Other)	Run-to-failure	Simple Predictive
Conductors	Run-to-failure	Simple Predictive
Current Transformers	Proactive	CBRM
DC System	Proactive	Discrete Engineering Review
Distribution Transformers	Run-to-failure	Simple Predictive
Distribution Other Assets (Fuses and Spreaders)	Run-to-failure	Simple Predictive
Gas Break Switches	Run-to-failure	Simple Predictive
Lighting	Proactive	Simple Predictive
Pole Tops (Distribution)	Run-to-failure	Simple Predictive
Pole Tops (Subtransmission)	Proactive	Discrete Engineering review
Poles	Run-to-failure	Simple Predictive
Protection	Proactive	Discrete engineering review
SCADA	Proactive	Discrete Engineering Review
Reclosers	Run-to-failure	Simple Predictive
Revenue Meters (ACS)	Proactive	Simple Predictive
Services	Run-to-failure	Simple Predictive
Static VAR Compensators	Proactive	CBRM
Underground Cables	Replace on fail	Simple Predictive
Voltage Transformers	Proactive	CBRM
Zone Substation Circuit Breakers	Proactive	CBRM
Zone Substation Isolators	Proactive	CBRM
Zone Transformers and Reactors	Proactive	CBRM

Figure 2 sets out the decision-making process Ergon Energy uses to adopt an expenditure forecasting methodology for each asset category.

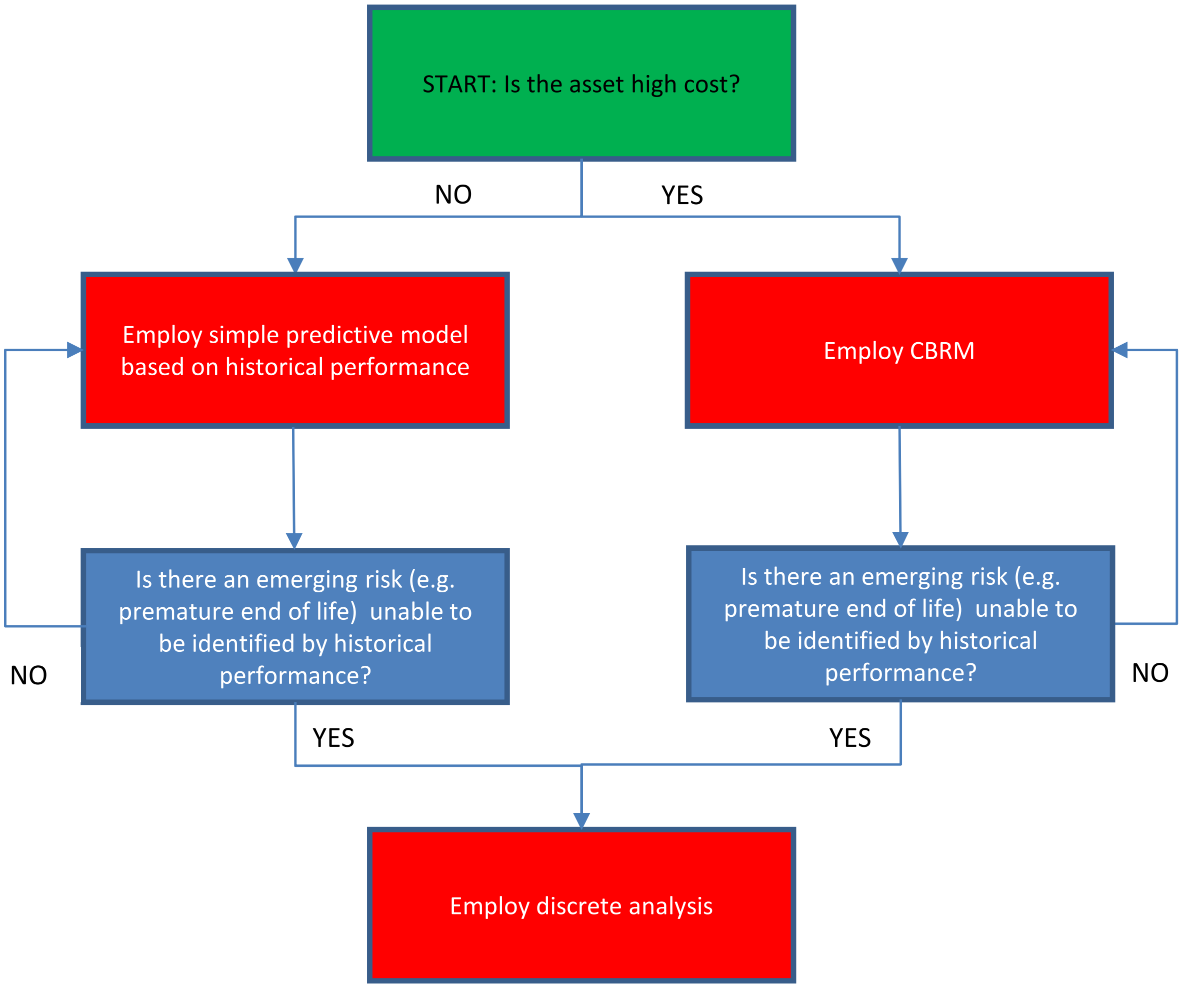


Figure 2: The decision making process for determining the appropriate forecasting methodology.

Each of these forecasting methods and their underlying models are described in Sections 5.3.2, 5.3.3, and 5.3.4 below.

5.3.2 Discrete analysis

Ergon Energy has used discrete analysis to prepare the forecasts for a number of significant proactive replacement projects and programs. Where systemic failure modes emerge, it becomes clear that historical performance of the asset class is not an indicator of future performance. CBRM type models, based upon specific sets of condition monitoring data, and using formula derived ageing and degradation algorithms will not reflect the impact of the identified failure mode. Simple predictive modelling based on historical population performance also becomes inappropriate. Under these circumstances, the performance of the type of asset must then be analysed and necessary remedial action established. Outcomes of such discrete analysis may include process change, additional maintenance, additional component renewal, or complete asset replacement.

Systemic issues are often identified by multiple occurrences of similar Dangerous Electrical Events (DEE). Formal investigations follow the ICAM (Incident Cause Analysis Method) methodology[20] and

[20] ICAM is copywritten by SafetyWise Solutions

documentation system. The nature of discrete analysis is such that each assessment is conducted differently, depending on the issue at hand, assets affected, the modes of failure and the technical risks identified. As a result, the inputs and assumptions for each discrete analysis task will vary, as will outcomes, detailing the appropriate and prudent solution set. 'Engineering Reports' and Network Optimisation Management Plans', many of which form part of the suite of justification documents for asset renewals for the 2015-20 regulatory control period, are used to record the process, issues, risks, options considered and preferred solution.

For example, a customer received a shock while working near Ergon Energy's assets. An investigation revealed degraded insulation due to insufficient UV protection, leading to an emerging safety and reliability issue with degradation accelerating at a greater rate than average historical performance. As a result, Ergon Energy undertook a technical analysis of the risks and legislative obligations and proposed an asset renewal program to remediate this issue (Refer to 'Colour Coded Service Cable Replacement Engineering Report'). The typical process involves recognition of a systemic issue, followed by engineering investigation(s), risk assessments, option consideration and recommendations, approval and outworking the solution. Risk assessments align with Ergon Energy's corporate Risk Assessment methodology. Work Health and Electrical Safety legislation firmly embed risk assessment and management as a necessary obligation of Ergon Energy in the performance of its duties.

The Queensland Electrical Safety Office (ESO) is responsible for reviewing Ergon Energy's performance in relation to the *Electrical Safety Act 2002* (Qld) on an annual basis. This includes reviewing Ergon Energy's safety systems, investigating DEEs and reviewing Ergon Energy's response to such events. Where the ESO makes a finding in relation to Ergon Energy's performance, they have the right to make requests for information, conduct investigations and otherwise enforce Ergon Energy's compliance with the Act. In these instances, Ergon Energy may use discrete analysis in relation to specific asset types to respond to issues raised by the ESO.

Figure 3 outlines the decision making process for discrete analysis. Appendix B lists documentation that details the discrete analysis associated with the replacement programs proposed for the 2015-20 regulatory control period.

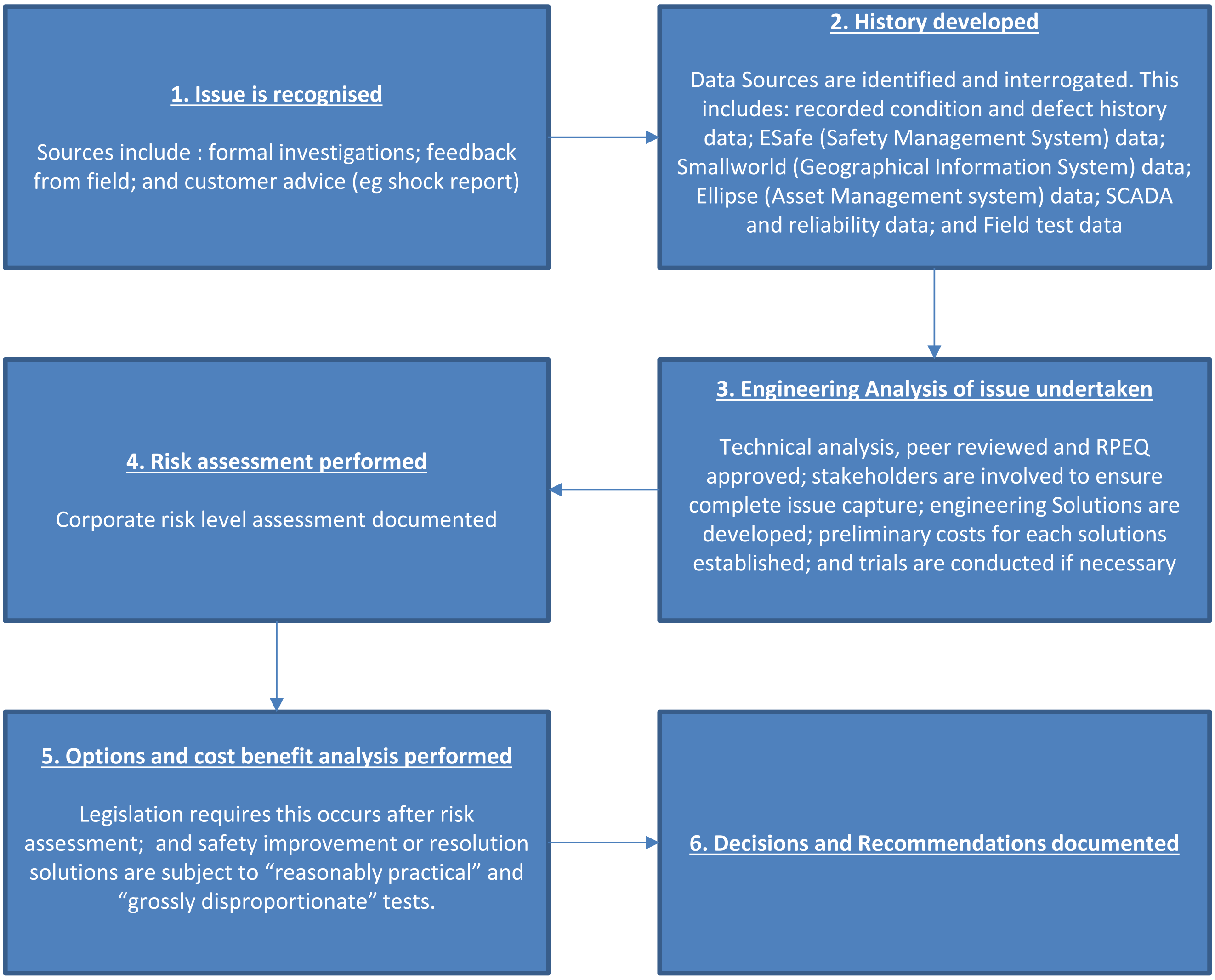


Figure 3: Discrete analysis asset replacement decision-making process.

As discussed in section 5.3.1, where an emerging safety or reliability issue is identified in a specific type of asset, such as 7/.064 Copper Conductor, discrete analysis may be used to identify the failure mode and prepare a program of works to remedy the defect. This is the case even where the replacement volumes in the broader asset category (i.e. conductors) are generally forecast using a simple predictive model. The existence of specific failure risks, such as insulation degradation or conductors falling pose unacceptable risks to safety or reliability that cannot be managed using a simple predictive approach.

Replacement programs have been developed for the following assets using discrete analysis. Supporting documents are listed in Appendix B.5:

- Distribution Feeder Reconductoring Program
- XLPE Service Cable Replacement
- Colour Coded Services Cable Replacement
- Neutral Screen Service Cable Replacement
- Connector and Splice Replacement
- EDO Fuse Replacement in High Bush Fire Risk Areas
- Replacement of Non-ceramic Fuses
- Cast Iron Cable Pot Head Replacement
- Laminated Crossarm Replacement
- Modifications to Distribution Earth Defect Thresholds
- Subtransmission Pole Topping program
- DC System Upgrades

Section 6.2 describes these programs in more detail.

5.3.3 Condition based risk modelling

CBRM is a proprietary methodology developed by EA Technology UK. Electricity utilities throughout the world, including Australia, use it to support their long-term asset management strategies. The methodology combines asset information, engineering knowledge and practical experience to define the current and future condition, performance, and risk for network assets. CBRM, implemented in a manner that is consistent with the principles of Ergon Energy's risk management framework, is the preferred method for evaluating condition related risk for asset classes with high replacement costs or high consequences due to unexpected failure. Importantly, Ergon Energy's transition to the CBRM methodology represents a significant improvement to the replacement forecasting methods used during the last submission to the AER, which were developed largely from simpler age-based models.

The CBRM method forecasts quantitative risk profiles for the individual assets being modelled. The risk associated with any asset is a function of the probability of failure and the consequences of failure. CBRM establishes this for each asset and expresses it as a financial value. It is therefore possible to make a direct assessment of the 'value' obtained from different proposed investment programs. Ergon Energy believes that CBRM modelling can be used for some asset types to predict the most cost efficient life cycle with more accuracy than the other methods, resulting in an overall lower cost to consumers.

Ergon Energy has developed CBRM models for the following high value zone substation assets, which are replaced proactively. These models cover:

- power transformer
- circuit breakers and switchboards
- instrument transformers
- outdoor isolators and earth switches
- capacitor banks

For each asset class, Ergon Energy has developed a CBRM model to reflect the population of assets within that class. The asset class model is developed to allow for:

- the various failure modes and relationship to various measures of asset condition
- a forecast rate of deterioration/change in condition over time
- maintenance, refurbishments and replacement requirements and relationships to asset condition
- asset criticality and failure consequences.

Each asset class model takes various inputs specific to the asset class, such as:

- specifications and duty
- historical faults, failures, and maintenance records
- environmental information
- test and inspection results
- financial failure consequence data
- intervention costs, including refurbishment and replacement costs.

Each asset class model provides a number of outputs covering the state of the existing asset and forecasts, including:

- measures of the asset condition/performance of the assets (termed its 'health' in the CBRM approach)
- probability of failure and failure rates
- the quantification of risks.

Probability of failure method

To forecast the probability of failure for any asset, a metric, specific to EA Technology's CBRM approach, is used. This is called the Health Index (HI). The higher the HI for an asset, the higher the probability of failure. See Figure 4 below.

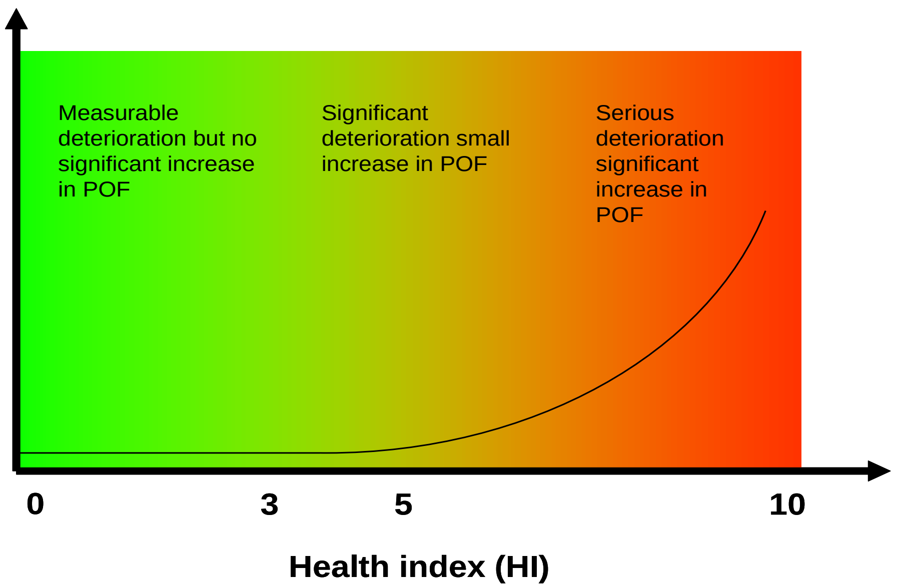


Figure 4: Relationship between Asset Condition and Probability of Failure (POF)

The current HI of an asset is developed from knowledge of the asset, the systems that make up the asset, and recorded asset data such as condition test results. The asset condition data is a very important input to this calculation, with actual test results being the preferred input to CBRM modelling. For example, dissolved gas analysis, and other test results from routine oil testing from oil filled substation plant is used in the power transformer model.

The initial HI is calibrated by reference to EA Technology's global asset performance history (establishing the shape of the typical HI curves), actual failure rates experienced by Ergon Energy (establishing the specific average locations of Ergon Energy asset fleet on this curve) and actual condition data (establishing a 'spread' around the average). Ergon Energy believes this is a reasonable approach because it has been proven to provide a reasonable correlation between prediction and actual performance in jurisdictions also using the CBRM approach.

To forecast the HI of an asset in the future, the model uses a simple ageing function to transform the initial HI into a future HI. The function used varies for the different asset types. Ergon Energy believes this ageing function is appropriate because it has been proven to provide a reasonable correlation between prediction and actual performance in businesses also using the CBRM approach.

Finally, to transform the HI metric (for any year – current or forecast) into a probability of failure, the model uses another function. The function used varies for the different asset types. Ergon Energy believes this ageing function is appropriate because it has been proven to provide a reasonable correlation between prediction and actual performance in businesses also using the CBRM approach. In addition, the combined probability of failure compares similarly with the forecasts of failure derived from Ergon Energy's Repex modelling.

Consequence of failure

The consequence of an asset failure is also developed from knowledge of the asset, the systems that make up the asset, the role the asset plays in supplying customers, and our knowledge of the environment of the asset. Based upon this information, an economic consequence of the asset failure (in $ terms) is calculated. This calculation splits the consequence into various factors that reflect our risk management framework, such as safety, operational, and reliability. For each of these factors CBRM calculates a consequence value from the available information. These calculations use a number of assumptions, the most sensitive of which are costs to replace the asset, and costs to maintain and retain the asset in service.

Developing the replacement forecast

EA Technology's CBRM models have a number of features that aid in the development of replacement forecast.

Intervention plans, in the form of maintenance, refurbishments, and replacement, can be direct inputs. These inputs reflect the physical intervention and their costs. These intervention plans adjust the assets or their condition, and in turn, the HI and probability of failure of the assets.

In addition, the models allow scenario analysis and optimisation to occur around the intervention plans, using discounted cash flow techniques. In this way, intervention plans can be developed in the model to achieve a specific outcome; for example, to set the risk value to a specific level over time.

Ergon Energy has used this feature to develop our replacement forecasts. In this regard, the models are used to identify the renewal strategy that delivers present best improvement in overall risk at least cost.

The costs used in these intervention plans are developed from Ergon Energy standard estimates process, which documents actual recent historical average costs for replacement of the particular asset type. Ergon Energy believes these costs are appropriate because the recent actual history provides best indication of total costs for future, similar projects.

Ergon Energy believes this approach is appropriate because it reflects the NER expenditure objectives to maintain reliability, security and safety levels and the NER expenditure criteria of the forecast reflecting efficient levels.

Ergon Energy also believes that this approach is in line with AER's desires expressed in its expenditure assessment guidelines.

5.3.4 Simple Predictive models

Ergon Energy has a well-established defect classification process, jointly developed with Energex, to identify assets that have failed or are expected to fail before the next scheduled inspection. The 'Lines and Substation Defect Classification Manuals' describe the observed common failure modes for the many high volume components within each asset category. These manuals are reviewed regularly as new common failure modes, solutions, and materials become evident over time. Generic risk assessments have been conducted on each failure mode leading to documented expectations of response, urgency level and timeframes. These are used by field staff to achieve the intended risk mitigation. The objective of the Simple Predictive model is to establish budgets and resources for this defect management work.

Due to the high volume and low unit cost nature of these programs, Ergon Energy has used a simple projection of the trends in historical failures to forecast future failure levels, and consequently replacement volumes, using five-year recent performance history. This is described in detail in the document 'Line Asset Defect Management Methodology'.

Similarly, Ergon Energy uses minor asset replacement unit cost rates for each asset class, to produce an expenditure forecast from the volume forecast. The following assumptions are inherent in this methodology.

- Observed asset deterioration and failure rates continue at the forecast rates
- Statutory and regulatory obligations remain unchanged
- Project and construction resources will continue to be available
- Material costs, especially of assembled components, and service contract/ staffing costs will increase by CPI rather than other economic indices such as the Commodity Metals Price Index.

A model shown in Figure 5 has been used to prepare forecasts of routine defect remediation programs. This model is designed to reflect the application of Ergon Energy's current AIDM processes. It produces forecasts of the defect remediation quantities of specific programs and their associated expenditure. The model uses:

- Historical defect data associated with our overhead lines – AIDM data is accumulated, resulting in a record of every defect found in Ergon Energy's asset management system. Over time, this provides extensive performance data.
- Future preventive maintenance plans – these are formulated using the historical defect data as an indicator of future degradation rates and therefore informs requirements for refurbishment.

The model assumes that defects related to common failure modes will be identified as the network is inspected, with frequency rates based upon historical rates of occurrence. Scaling factors are applied to specific defect types in the model and are based on factors including:

- historical data
- expected impacts of any recently implemented changes to AIDM processes or Ergon Energy's maintenance framework, which covers regular visual and/or intrusive testing of assets
- inspection cycle changes.

The model details are documented in the supporting document ‘Line Asset Defect Management Methodology’, and presented in Figure 5.

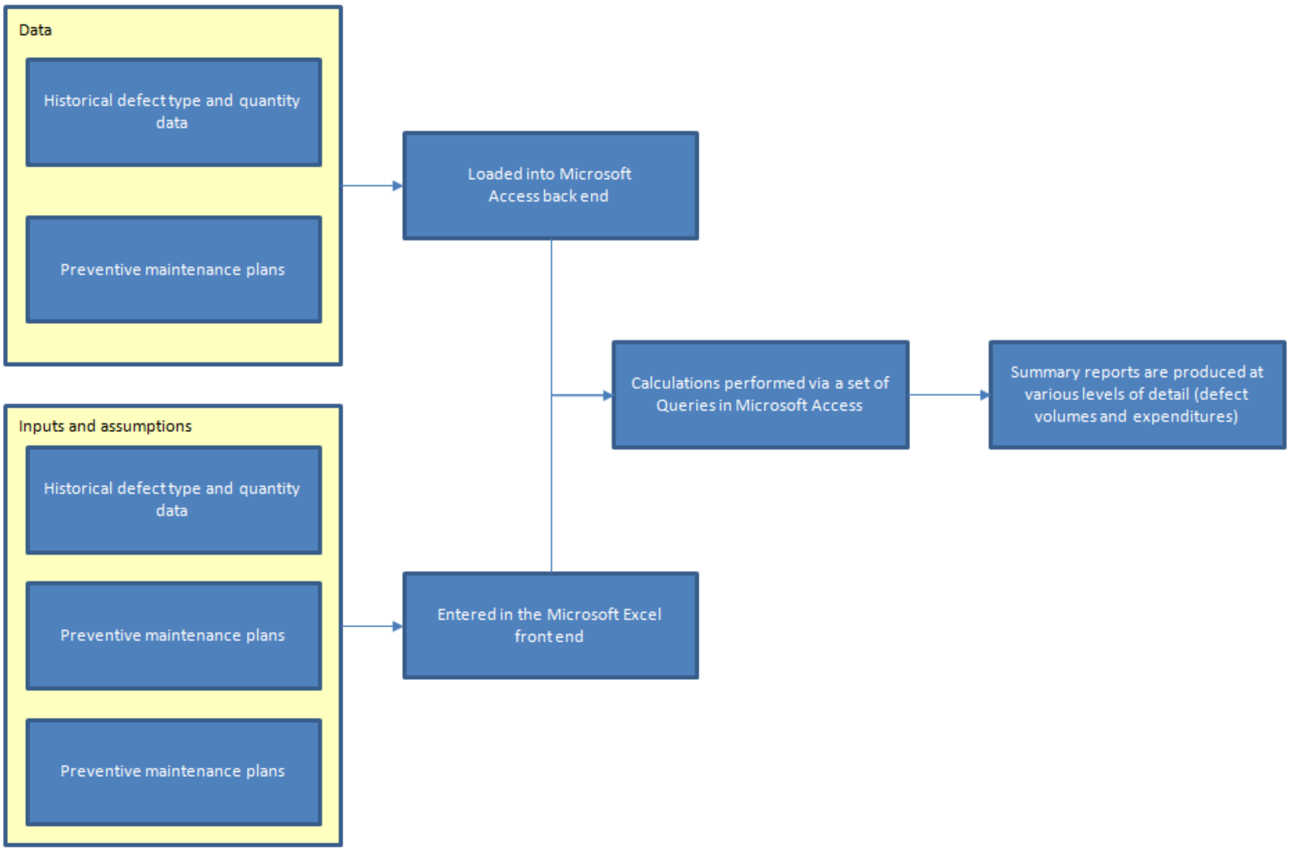


Figure 5: Defect refurbishment modelling process

Minor asset replacement defect occurrence rates are based on historical population performance. Minor asset replacement unit cost rates use (appropriately escalated) historical averages as recorded for the various replacement tasks or market contract rates defined for each task. The expenditure forecast is calculated from the summation of the product of the various defect occurrence rates derived from the model, with the minor asset replacement unit cost rates. Ergon Energy believes this is a reasonable approach because inspection rates and minor replacement cost rates are defined by contract terms, and other costs reflect recent asset management history of actual similar works.

Ergon Energy has established insurance to provide cover against the financial impact (both capital expenditure and operating expenditure) of restoration resulting from the most severe cyclonic wind events, such as a cyclone similar to Yasi. This insurance does not provide cover for the small to medium size cyclonic situations such as experienced with Oswald. Some of the very low level tropical storms have had almost no impact upon Ergon Energy’s assets. The Department of Meteorology advice suggests the order of four to six cyclones of various strengths will impact Ergon Energy’s assets during the 2015-2020 regulatory control period. This is consistent with that experienced during the current regulatory control period (2010-2015). The costs of the insurance cover is discussed elsewhere and included in the operational cost forecast. Ergon Energy has included an asset renewal capital expenditure allowance for the 2015-2020 regulatory control period based on two small to medium size cyclones and using the historical costs associated with Oswald of $8.6 million per event. These costs are allocated nominally to 2016-17 and 2018-19 corresponding to the two expected events.

Obsolescence initiated refurbishment

Over time, Ergon Energy's suppliers improve their equipment and components. This includes new and/or improved standards, design modifications to eliminate safety or premature failure modes, changes in materials and changes in technology. While suppliers generally support superseded equipment and asset components, availability of equipment, components, active design knowledge, and spare parts become problematic over time. Figure 6 presents the obsolescence decision-making process.

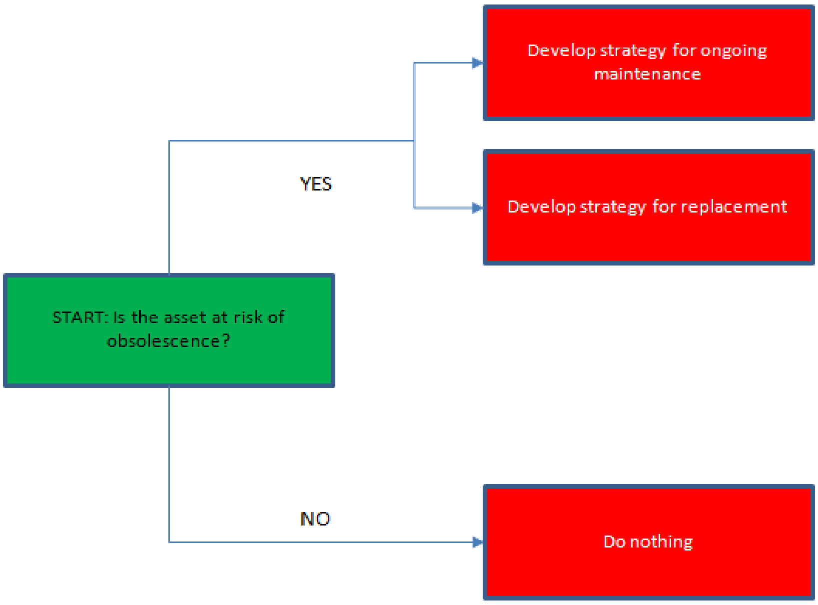


Figure 6: Obsolescence decision making process

Ergon Energy does not automatically replace assets as quickly as suppliers advance and develop their equipment/component model fleet. Suppliers continue to support earlier revisions of their product fleet items for a period. However, inevitably they eventually decide it is uneconomic to continue to support these earlier versions. In-service assets become obsolete when suppliers and manufacturers no longer provide components, expertise or service capability. With prudent care and maintenance, in-service assets can become obsolete well before projected end-of-life. The issue is particularly common with electronic and processor based assets.

Because obsolescence is effectively driven by business decisions by other companies, accurate long-term prediction of obsolescence is not generally possible. Ergon Energy does not remove assets from service simply because they are obsolete. However, Ergon Energy must eventually replace obsolescent assets as spare components or maintenance expertise become less available and asset failure rates increase. Management strategies that eventually lead to replacement must be implemented.

Ergon Energy has identified these obsolescent asset classes, and established appropriate management and replacement strategies in response. This has led to renewal programs for some classes of protection relays, reclosers, remote terminal units (RTU), two-way radios, CoreNet site infrastructure, CoreNet activities, revenue meters (ACS) and audio frequency load controls (AFLC). These programs are described in detail in Section 6.2.

5.4 The appropriateness of Ergon Energy's methodologies

Ergon Energy believes that the methods used to prepare asset replacement forecasts are appropriate and represent a reasonable approach, and are consistent with best practice industry approaches. For example:

- CBRM is undertaken by many other Distribution Network Service Providers (DNSPs) in Australia and Great Britain. Twelve Australian DNSPs are represented in the CBRM Users Group industry body. It reflects good asset management practice and supports the *ISO55000 Asset Management Standard* strategies. Application of this approach at Ergon Energy is consistent with CBRM application at other DNSPs.
- Discrete analysis has been used on a number of programs, and is in principle, similar to the analysis methods routinely used in the industry to develop replacement projects and programs.
- Simplified predictive approaches have been used where historical performance that underpins these models provides an appropriate guide for future performance, given the recurrent nature of these programs.

In addition, validation of these models and many of their key inputs has been completed by Ergon Energy. For example:

- In 2010, Ergon Energy contracted EA Technology to develop CBRM models for most of their high value zone substation assets, which are replaced proactively. Subsequently, in 2013, Ergon Energy employed EA Technology to review the implementation of these models.
- Asset failure rates used in the CBRM models predate but are consistent with the AER Annual Performance and Category Analysis Regulatory Information Notices (RIN). Initial comparison of the data has produced similar results to actual outcomes, and provides assurance that the forecasts are appropriate.
- Ergon Energy has also backcast expenditure, using the defect remediation model at the sub-category level using known historical quantities and job cost estimates to historical expenditures, in order to verify the accuracy of the estimates and the model. Ergon Energy has used this and recently renewed contract rates to calibrate its forecasts against its historical expenditure. The findings of this analysis are documented in detail in the 'Lines Defect Management Methodology'.
- In February 2013, Ergon Energy commissioned Parsons Brinckerhoff consultants to undertake a review and validate the lines defect management model to support the current regulatory proposal. Forecast volumes are based upon recent historical performances.

All proposed investments leading to asset renewal programs of work are subjected to a rigorous internal review process. This includes approval by senior management levels, Ergon Energy's Network Investment Review Committee for all investments, as well as the corporate Investment Review Committee for investments greater than $10 million.

Each of the investment committees,' the Network Investment Review Committee (NIRC) and the Investment Review Committee (IRC), have charters that govern the process, the meeting and the delegation approvals. Refer to the 'Network Investment Review Committee (NIRC) Charter dated July 2014' and the 'Investment Review Committee Charter dated July 2014'

The AER has recently published a benchmark comparison of DNSPs in relation to expenditure. Ergon Energy believes that its overall historical expenditure, which is consistent with and very similar to its proposed forecast expenditure, compares favourably with other DNSPs. This is based upon comparisons of Repex normalised for network size and considering line route length. Ergon Energy believes this is indicative of historical prudent and efficient performance. In the light that Ergon Energy embraces continuous improvement practices, and has established its forecasts with significant reference to historical outcomes, the DNSP comparisons represent a lag indicator that Ergon Energy's proposals represent prudent and efficient practice.

Ergon Energy's recent Repex modelling is consistent with its total renewal expenditure forecasts. This represents a lead indicator that Ergon Energy's renewal expenditure proposals represent prudent and efficient practice.

5.5 Case studies

The following section provides examples of how these forecasting methodologies underpin forecast expenditure programs for the next regulatory control period. The intention is to describe the information relating to a particular asset, how that information is processed, and how the outputs of that analysis inform the forecast expenditure program.

5.5.1 Case study – Discrete Analysis

On 18 July 2012, a member of the public climbed the roof of a house and sustained burns and an electric shock from contact with a deteriorated 'figure 8' Colour Coded Service line. Figure 7 shows two sections of the service involved in this incident. Early observations indicated that the insulation was directly exposed to UV radiation, and deteriorated approximately 600mm from the point of attachment (POA). As shown in the picture, the identification stripe of this cable is positioned on the side of the cable and covers about 25% of the circumference of the core.

Figure 7: Deteriorated Colour Coded Service wire

As an outcome of the investigation, the following service cable audits were conducted in early 2013. A number were found deteriorated or had been replaced. The last metre or so (the tails) of the original colour coded service had been left in place connecting between the mains box and the tensioned service. Table 9 summarises the results of these audits.

Table 9: Summary of Service Audit Results

Service type	Inspected	Deteriorated	Colour Coded Tails Only
Twisted	130	0	32
'Figure 8'	30	10	0
Total	160	10	32

An engineering assessment was undertaken, reviewing the defect classification system, the inspection process, and all available samples. Advice from other DNSPs was sought for similar occurrences. The findings of the assessment indicated the minor changes were required to tighten up inspection processes, which were duly initiated. A risk assessment of the asset deterioration concluded that a high risk remained and further risk mitigation was required.

A series of engineering options were considered, including:

- do nothing
- replace all colour coded services
- replace only all 'Figure 8' colour coded services
- replace only 50% of the 'Figure 8' colour coded services.

Based upon the analysis of the sampled serviced inspected and summarised in Table 9, there is a clear and substantial risk associated with "Figure 8" colour coded services (around one third were deteriorated) while similar problems are yet to be manifested in the twisted colour coded services.

The final recommendation was to replace only all 'Figure 8' colour coded services over five years, for $9.1 million of capital expenditure, which satisfies the grossly disproportionate test detailed in Section 3.2; and to monitor the twisted colour coded services for further deterioration.

The detail of this case study can be found in the 'Colour Coded Service Replacement Engineering Report'.

5.5.2 Case study – Simple Predictive modelling

Ergon Energy defines a periodic inspection regime for ground level distribution asset inspection. A periodic task list is generated automatically via Ergon Energy's asset management system for each defined maintenance zone. Each maintenance zone consists of a number of a specific asset classes, for example, all poles on a particular feeder. The task is presented to an Ergon Energy inspection crew, who visit each asset defined in the maintenance zone and perform a prescribed inspection task, using the 'Lines Defect Classification Manual' as the benchmark for defining acceptable asset condition. Records from the inspection are recorded automatically into Ergon Energy's asset management system. Repair work orders appropriate for the recorded defects are subsequently and automatically generated.

Over time, the quantity and types of specific defect repair work orders provides sufficient history as to allow long-term performance trending to be developed, allowing reasonable estimates of defects per asset per annum to be established. In addition, as these defects represent relatively repetitive repair tasks, costs and resources associated with those tasks, average labour, material and resource usages can be derived.

Ergon Energy has associated every asset with a maintenance zone in the asset management system.

Simple Predictive modelling combines all of these numbers into a simple formula for each maintenance zone:

- Forecast defects expected per maintenance zone = quantity of defects per asset type experienced in the same maintenance zone at the previous inspection; scaled by SME knowledge about intended targeted projects or procedural practice changes.
- Forecast costs per maintenance zone = sum of current rates for (labour, material, resources) multiplied by the associated forecast defects per maintenance zone.
- Costs per year = sum of costs of each forecast cost per maintenance zone schedule to be inspected in each particular year.
- Costs for the regulatory control period = sum of costs per year between 2015 and 2020.

The method described above ignores escalation and on-costs. The model easily accounts for changes to the periodic inspection rates. Ergon Energy is now into its fourth complete inspection cycle since program initiation, and the forecast method has proven to be both reliable and accurate in terms of overall defect quantities and costs.

The example below, details how simple predictive modelling is applied.

In June of 2012, a new defect was introduced for live line clamps connected to a conductor without a stirrup. The absence causes rapid and premature deterioration of the conductor. As a result, asset inspectors will record defects for all clamps that were installed this way. Such installations are likely to be limited to particular areas due to legacy practices.

P2	
Object	Live Line Clamp
Damage	Incorrect Use
Cause	Incorrect Installation
Task	Replace
Priority	**P2**
Description Live Line Clamp is directly connected to a conductor under tension without a connector stirrup.	

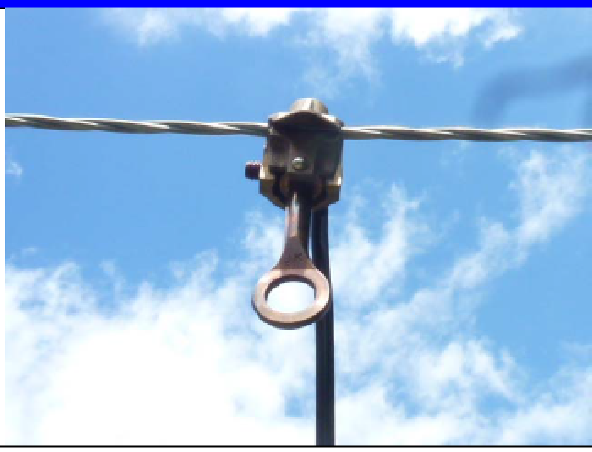


Figure 8: New P2 defect classification from Defect Point of Reference #58 – 1 June 2012

To model the likely number of live line clamp defects it was assumed that the number of such defects will remain at the 2012-13 level for four years to 2015-16. Once the majority of these defects are addressed, the number of defects can be expected to reduce to around 32 per year in the consequent inspection cycle (essentially covering those missed in the previous inspection). Based on these assumptions, the model produced the following live line clamp defect forecasts shown in Table 10. Variation in the numbers of defects is due to variations in preventive maintenance and inspection plans year on year.

Table 10: Live line clamp defect forecast (cyclic asset inspection, AIP3X only)

Defect Group	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Live Line Clamps – Incorrect Use	244	229						
Live Line Clamps – Incorrect Use (Future)			214	272	260	67	32	32

For further details on this case study, refer to the ‘Asset Defect Management Methodology’.

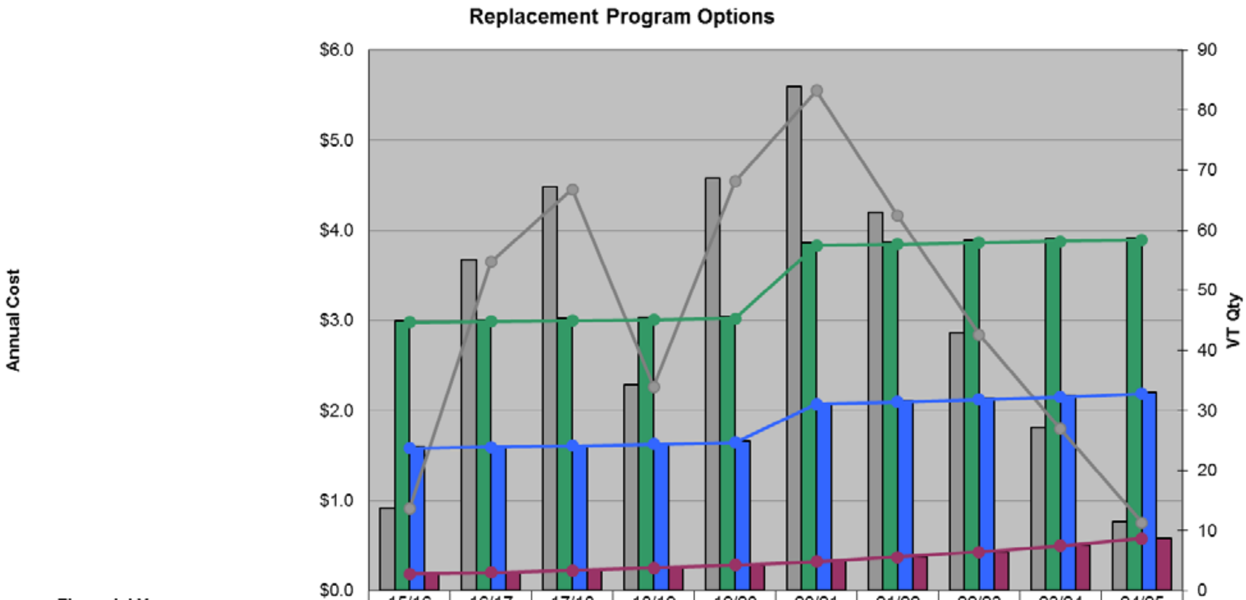
5.5.3 Case Study – CBRM

The following example demonstrates the results of CBRM modelling for voltage transformers (VT). Similar detail can be found in the ‘Engineering Report Instrument Transformer Replacement and Refurbishment’.

A model is created listing each VT, detailing its brand and type, voltage level, condition, performance history, age, location in the network, failure consequence in terms of customer and operational impact, current maintenance costs, both planned and forced, and present day replacement cost estimates.

A calibrated health Index (HI) was developed for each asset, and CBRM ageing modelling applied to establish an optimised least cost compromise between the risks and costs to retain the asset in service, versus the risks and costs to replace each asset. This is designated as the theoretical optimum model. The model is theoretical because it does not accommodate practical implementation issues such as resourcing constraints.

The theoretical optimum model was used to generate a replacement list, prioritised according to a risk-reduction impact and ideal time to replace. Several practical replacement strategies, based upon different replacement rates and using the prioritised replacement list priority order, were compared with the theoretical optimum CBRM model output. The potential strategies (Option A and B) have been smoothed to support efficient resource management across the years. An additional strategy (Option D), which is essentially run-to-failure is also evaluated. The four options are presented graphically in Figure 9.



Financial Year	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Optimum Program Cost $	$0.9	$3.7	$4.5	$2.3	$4.6	$5.6	$4.2	$2.9	$1.8	$0.8
Option A Program Total Cost $	$3.0	$3.0	$3.0	$3.0	$3.0	$3.9	$3.9	$3.9	$3.9	$3.9
Option B Program Total Cost $	$1.6	$1.6	$1.6	$1.6	$1.7	$2.1	$2.1	$2.1	$2.2	$2.2
Optiion D Program Cost $	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.4	$0.4	$0.5	$0.6
Optimum from CBRM Replace qty + FIS	14	55	67	34	68	83	62	43	27	11
Option A program Replace qty + FIS	45	45	45	45	45	57	58	58	58	58
Option B program Replace qty + FIS	24	24	24	24	25	31	31	32	32	33
Option D program qty + FIS	3	3	3	4	4	5	6	6	7	9

Figure 9: Voltage transformer program options

The CBRM approach quantifies risk in dollar terms, allowing conventional NPV analysis and comparison of risk at the end of each year for any proposed replacement program.

The current (2014-15) risk profile of the populations of VTs (the model Year 0 Risk) as well as the risk profile of each option at model Year 10 (2024-25) in the future, has been evaluated for each of the potential strategies and is presented graphically in Figure 10 and Figure 11.

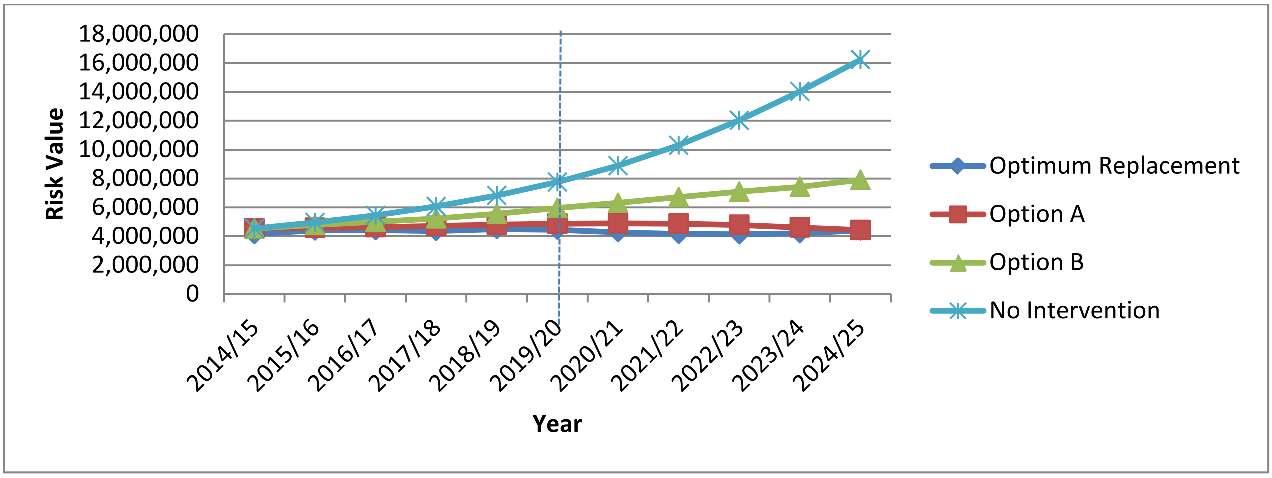


Figure 10: Voltage transformer replacement program options – change in risk

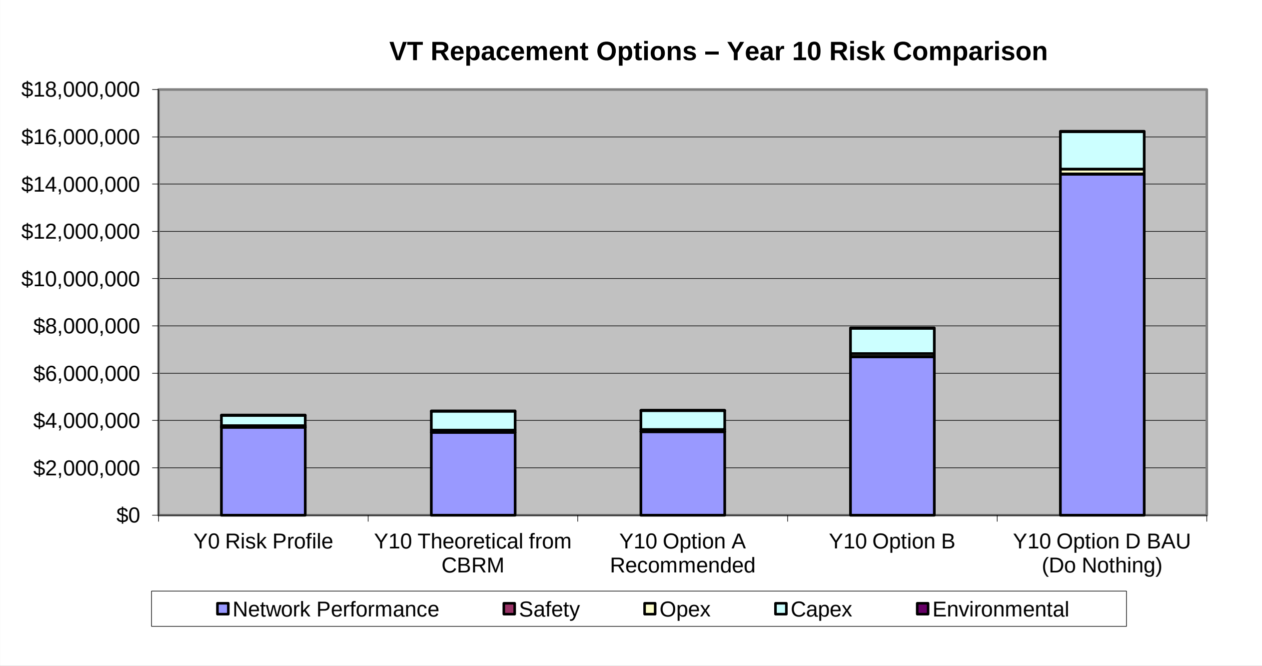


Figure 11: Voltage transformer replacement options – risk comparison

The modelling clearly demonstrates that a run-to-failure approach (Option D) is not prudent or efficient.

The modelling also demonstrates that:

1. workload levelling (Option A model) of the theoretically optimum model has little long term effect on overall risk. This is the recommended option, being both demonstrably prudent and efficient.
2. generally deferring the replacement program (Option B model) increases corporation risk and cost significantly and is not prudent.

6. Expenditure forecasts and outcomes for next period

6.1 Primary drivers for renewal capital expenditure forecasts

This section details Ergon Energy's forecasts for its Asset Renewal capital expenditure for the next regulatory control period that it is proposing the AER approve. It also details the network, risk and customer outcomes associated with these capital expenditure forecasts. Asset Renewal capital expenditure is forecast to be $883.2 million for the 2015-20 regulatory control period, $16 million or 1.8% lower than the AER's determination for the current 2010-15 regulatory control period. This is comprised of expenditure to mitigate safety risks and to renew assets that are at the end of their economic lives. It is noted that the $883.2 million excludes an amount of $49 million for metering and street lighting related renewal activities which were previously classified as SCS but which the AER has classified as ACS in the 2015-20 regulatory control period.

Table 11 summarises the programs where the primary driver involves safety risk mitigation. Each of these capital expenditure investments proposed for the 2015-20 regulatory control period have been subjected to the 'grossly disproportionate' test required under Queensland legislation and discussed in Section 3.2.

A substantial volume of this investment is related to resolving the risk of preventing live LV copper conductor falling to the ground and exposing the public to electrical shock. In 2014, Ergon Energy recognised this emerging risk and formulated extensive mitigating programs in response. This program is described in Section 6.2, and in detail in the 'Engineering Report Distribution Feeder Reconductoring Program'.

A total of $263.7 million or 30% of all renewals costs are driven by safety issues identified in the current regulatory control period, giving rise to a need for significant investment in the 2015-20 regulatory control period.

Table 11: Renewal Program Expenditure driven primarily by safety obligations

Program/project
Cast Iron Pot Head Replacement
Colour Coded Service Cable Replacement
Connector and Splice Replacement
DC System Upgrade
Distribution Feeder Reconductoring Program
EDO Replacement in High Bushfire Risk Areas
Laminated Cross-arm Replacement
XLPE Service Cable Replacement
Modifications to Distribution Earth Defect Thresholds
Neutral Screen Service Cable Replacement
Protection Relay Replacement
Replacement of Non-ceramic Fuses

Table 12 summarises the programs where the primary driver involves end-of-life risk mitigation. Section 5 discusses how the scope of these programs was established.

A total of $619.6 million or 70% of all renewals costs are driven by essential end-of-life renewal decisions, using forecasting methods discussed in Section 5.

The most significant component of this expenditure involves basic lines based component replacement of high-volume, low-cost components identified from mandated periodic asset inspection processes as required under the *Queensland Electrical Safety Act (2002)* and the *Queensland Electrical Safety Code of Practice (Works) 2010* (Line and Substation Defect Remediation program).

Table 12: Renewal Program Expenditure driven primarily by end-of-life renewal obligations

Program/project
Aged Remote Terminal Units Replacement
AFLC Replacement
Capacitor Bank Replacement
Circuit Breaker And Switchboard Replacement
CoreNet Active network Replacement
CoreNet Infrastructure Replacement
Instrument Transformer Replacement and Refurbishment
Isolator Replacement
Lines Defect Remediation
Revenue Meter Replacement
Radio Refurbishment – Mackay – Maryborough
Radio Refurbishment – Western Queensland
Subtransmission Pole topping program
Static VAR Compensators Replacement
Transformer renewal

The recent change to security of supply criteria has reduced the volume of forecast augmentation investment. Assets originally projected to be replaced for augmentation reasons are now expected to remain in service longer. While this security criteria change has not substantially impacted the immediate need for asset renewal investment, the change is likely to be reflected as increased renewal need in the regulatory control periods beyond 2020. Ergon Energy believes that current Repex modelling, reflecting current historical performance, is therefore likely to underestimate failure rates in the long term. Therefore, Ergon Energy strongly believes that it is prudent to maintain at least current levels of renewal investment for the 2015-20 regulatory control period, and is likely to require increased renewal investment beyond 2020.

6.2 Asset renewal programs for the next regulatory control period and key outcomes

Ergon Energy has established high-level focus documentation for various assets, identified as ‘Network Optimisation Management Plans’. These plans provide tactical focus upon specific asset classes and subclasses, and will be used to record significant technical decisions and direction. This will support Ergon Energy’s continuous improvement journey in asset management, consistent with *ISO 55000 Asset Management Standard*. The plans cover all aspects of asset operation, including operations and maintenance, renewal, data systems, condition monitoring approaches and risk.

While the ‘Network Optimisation Management Plans’ represent intent and tactics to manage ongoing asset issues, not all of them require material capital expenditure. Ergon Energy renewal capital expenditure proposals identify the most prudent and efficient expenditure programs considered necessary to maintain its distribution asset base in order to continue efficiently delivering its service performance, and to maintain the reliability and quality of supply required by technical standards.

The following sections detail each capital expenditure program/project by asset management plan, identifying the relevant primary driver for that expenditure, the expected outcome/risk mitigated, and the program/project's cost.

All expenditure stated in this section is shown in 2012-13 dollars.

6.2.1 Overhead Feeder Circuits

The proposed renewal capital expenditure programs expenditure for 2015-20 that relates to overhead feeder circuits and related assets, and which are supported by the document 'Management Plan Overhead Feeder Circuits', are detailed in Table 13.

This Management Plan sets out, at a high level, Ergon Energy's approach to maintaining conductor and connector assets. The plan explains how Ergon Energy's legislative obligations and strategic vision aligns with proposed conductor and connector replacement activities. Engineering reports analyse the current state of conductor and connector assets based on historical data and presents a risk-based approach to identifying and prioritising expenditure initiatives.

Table 13: Renewal capital expenditure for overhead feeder circuit assets (2012-13 dollars)

Program/project	Forecast $ next period
Colour Coded Service Cable Replacement	$9.1 million
Connector and Splice Replacement	$3.6 million
Distribution Feeder Reconductoring Program	$150.2 million
XLPE Service Cable Replacement	$2.1 million
Neutral Screen Service Cable Replacement	$4.1 million
Laminated Crossarm Replacement	$2.1 million
Subtransmission Pole topping program	$49.7 million
Lines Defect Remediation (Part)	$314.3 million (part)

These programs are described in detail below:

- Colour Coded Service Cable Replacement ($9.1 million) – there is a considerable safety risk as a result of the deterioration of insulation on 'Figure 8' colour coded services, exposing bare conductors. Ergon Energy had a near fatality as a result of this deterioration, and there was a subsequent 'Request for Improvement' from the Queensland Electrical Safety Office. This risk will be mitigated through replacement of these assets. The five-year failure rate between 2007 and 2012 was an average of 122 per annum. Refer to 'Engineering Report Colour Coded Low Voltage Overhead Customer Services' for further details.
- Connector and Splice Replacement ($3.6 million) – connectors and splices are failing, resulting in conductors on the ground, creating a safety risk. Ergon Energy has committed to the Queensland Electrical Safety Office to replace the highest risk components. Defective connectors and splices are identified through thermal surveying. This risk is mitigated by replacing defective connectors/splices within one kilometre of zone substations (highest fault level, and therefore at

highest risk of experiencing heavy current flow through high-resistance connections). In 2011-13, average defects per annum were approximately 650. This program will reduce this number by approximately 10%, and directly reduce the number of DEEs. Refer to ‘Engineering Report Defective Connector and Splice Replacement’ for further details.

- Distribution Feeder Reconductoring Program ($150.2 million) – due to aged and annealed cooper conductors breaking and falling, all are considered at or beyond practical end-of-life. There was a fatality in 2009 due to a member of the public making contact with energised low voltage conductor on the ground, and several similar close-call events since then. There was also a subsequent ‘Request for Improvement’ from the Queensland Electrical Safety Office. These assets are considered a significant safety risk, and renewals works have been identified to reduce the number of high-risk safety incidents due to failure of 7/.064 LV Copper Conductor. The expected reduction in the number of incidents is based on historic rates of similar incidents that occurred in 2012-13. This program will replace the entire population of small LV Copper (7/.064 and similar) conductors of approximately 1400 circuit kilometres. While this project is expected to mitigate a substantial public safety risk, it will not make an appreciable impact to the overall population ageing profile, as this program will only affect approximately 1% of Ergon Energy’s LV conductor assets (over 117,000 circuit kilometres). The proposed program will also replace a small amount of HV copper conductor in similar condition. Refer to ‘Engineering Report Distribution Feeder Reconductoring Program’ for further details.
- XLPE Service Cable Replacement ($2.1 million) – a medium level safety risk has been identified by other DNSPs. Ergon Energy performed a trial replacement to obtain samples for chemical analysis, which suggests that the insulation is not adequately protected against UV, and failures and degradation are expected to occur and escalate. The expected outcome of this expenditure program is identification, removal and replacement of the highest risk XLPE service cables, preventing public-shock incidents. Normal defect monitoring and management will apply thereafter, resulting in significantly reduced ongoing numbers of defects. Refer to ‘Engineering Report XLPE Service Cable Insulation Degradation’ for further details.
- Neutral Screen Service Cable Replacement ($4.1 million) – a public safety risk currently exists, as aged neutral screen cable, insulation is deteriorating, resulting in a number of public shocks. A series of identified defects with insulating degradation prompted Ergon Energy to investigate further. It has been identified that the insulation does not have adequate UV protection, which will advance normal expected end-of-life and introduce significant public safety risks. The expected outcome of this expenditure program is identification and removal of the most deteriorated service cables, and prevention of public shock incidents. Normal defect monitoring and management will apply thereafter resulting in significantly reduced ongoing numbers of defects. The average annual failure rate between 2007 and 2012 was 100 per annum. Of these 100 defects per annum, it is expected 80% will be resolved after the program is complete.
- Laminated Crossarm Replacement ($2.1 million) – there is a material safety risk due to a loss of strength of crossarms resulting from Alkaline Copper Quaternary (ACQ) preservative leeching and subsequent fungus development. Most crossarm failures result in DEEs and introduce a significant public safety risk. This program will remove laminated crossarms in special and high-risk locations (expected to be high rainfall/humidity and high pedestrian traffic locations) from service, to mitigate those public safety risks. Going forward, monitoring programs will be established to determine degradation patterns. Without removal of these crossarms, Ergon Energy will experience an increasing number of crossarm failures per annum and associated DEEs as the laminations deteriorate further. Refer to ‘Engineering Report ACQ Treated Laminated Veneer Crossarms’ for further details.

- Subtransmission Pole Topping Program ($49.7 million) – in substantially reducing its subtransmission rebuilding expenditure, Ergon Energy has shifted its focus to pole top renewal, to manage the asset degradation issues. The renewal targets those subtransmission lines that have recent history of relatively poor performance in terms of forced maintenance costs, customer outage impact and numbers of DEEs. The renewal process is not expected to improve overall network performance, as the replacement quantity rate remains lower than the overall ageing rate. Refer to 'Engineering Report Subtransmission Lines Refurbishment' for further details.
- Lines Defect Remediation (part of $314.3 million routine defect remediation budget) – Ergon Energy has an obligation to meet the requirements of the *Queensland Electrical Safety Act (2002)* to inspect, test and maintain all assets. Ergon Energy is not expecting any legislative change, and except for specifically targeted safety risks, defect repair rates are generally expected to continue at historical levels, except where detailed at each asset sub-category in the document 'Line Asset Defect Management Methodology'.

6.2.2 Overhead and underground plant and equipment

The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to overhead and underground plant and equipment and related assets, and which are supported by the 'Management Plan Overhead Feeder Circuits', are detailed in Table 14.

Table 14: Renewal capital expenditure for overhead and underground plant and equipment (2012-13 dollars)

Program/project	Forecast $ next period
EDO Fuse Replacement in High Bushfire Risk Areas	$1.0 million
Replacement of Non-ceramic Fuses	$0.7 million
Lines Defect Remediation (Part)	$314.3 million (part)

These programs are described in detail below:

- Expulsion Drop Out (EDO) Fuse Replacement in High Bushfire Areas ($1.0 million) – operation of EDOs produces sparks and molten metal that fall to the ground. In dry tinder locations, this has been demonstrated to initiate bushfires. This presents public safety, material public asset, and significant legal and corporate risks for Ergon Energy. A recent settlement relating to the Victorian bushfires is publically touted as $500 million, with the DNSP portion of this around $380 million and the Victorian Government portion $120 million. Even though Ergon Energy has a low volume of bushfire areas, and the annual fire season tends to occur during more moist conditions when compared to Victoria, Ergon Energy intends to mitigate these risks by replacing EDOs with current limiting fuses. Replacement of these assets represents a significant risk mitigation strategy for Ergon Energy. Refer to the 'Engineering Report EDO Fuse Replacement in High Fire Risk Areas' for further details.
- Replacement of Non-ceramic Fuses ($0.7 million) – these are obsolete LV fuse installations owned by Ergon Energy and mounted on customer premises. A failure mode has been identified that results in overheating, and there is considerable risk of initiating fire on the premises, classed as a DEE. This program includes the removal of Sicame fuse holders from house fascia boards, removing the fire risk and potential for a DEE. Refer to the 'Engineering Report Replacement of Non-Ceramic Fuses' for further details.

- Lines Defect Remediation (part of $314.3 million routine defect remediation budget) – Ergon Energy has an obligation to meet the requirements of the *Queensland Electrical Safety Act (2002)* to inspect, test and maintain all assets. Ergon Energy is not expecting any legislative change, and except for specifically-targeted safety risks, defect repair rates are generally expected to continue at historical levels, except where detailed at each asset sub-category in the document ‘Line Asset Defect Management Methodology’.

  This component of the Lines Defect Remediation covers high and low voltage switches and fuses, switches, surge arrestors, pole mounted capacitor banks, RMUs, autoreclosers and sectionalisers, distribution transformers, regulators and reactors, SWER isolating transformers and padmounted distribution substations.

6.2.3 Zone and bulk supply plant and equipment

The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to overhead feeder circuits and related assets, and which are supported by the ‘Management Plan Zone and Bulk Supply Plant and Equipment’, are detailed in Table 15. The indicated forecasts include an allowance for failed in service replacement.

Table 15: Renewal capital expenditure for zone and bulk supply plant and equipment (2012-13 dollars)

Program/project	Forecast $ next period
Transformer Renewal	$73.5 million
Static VAR Compensators Replacement	$9.5 million
Isolator Replacement	$12.2 million
Instrument Transformer Replacement and Refurbishment	$21.4 million
Capacitor Bank Replacement	$8.4 million
Circuit Breaker and Switchboard Replacement	$28.1 million

These programs are described in detail below:

- Transformer Renewal ($73.5 million) – transformers are condition monitored and require regular tap-changer maintenance. The failure consequences are related to safety impacts for staff in the vicinity at the time of failure, reliability impacts related to technical ability to meet supply demand, environmental damage from the quantities of oil involved, and high costs of replacement. Due to the potential high replacement costs and high consequence of unexpected failure, Ergon Energy has adopted a CBRM approach to define the highest priority and economic end-of-life of these assets, optimised for overall least cost and least risk increase. Very wet and badly deteriorated transformers (prioritised by CBRM) undergo major overhauls and gain life extension where practical. Refer to the ‘Engineering Report Power Transformer Replacement and Refurbishment Program’ for further details.
- Static VAR Compensators (SVC) replacement ($9.5 million) – the Charleville system exceeds statutory and asset voltage design limits without the SVC in service. The system appears marginally stable when the SVC is in service, but the SVC is at its maintenance end-of-life. Spare parts are no longer available from the manufacturer, and technical expertise has become difficult to procure. Water cooling systems are severely rusted and almost unrepairable. The system has become almost unmaintainable. This creates a reliability-of-supply and quality-of-supply risk. Replacement of these assets will stabilise power system operation within statutory voltage limits

into the future. The SVC is incurring considerable maintenance costs to keep it in service. As a result of replacement, these costs should be reduced considerably. Refer to the ‘Engineering Report Static VAR Compensator (SVC) Refurbishment & Replacement’ for further details.

- Isolator Replacement ($12.2 million) – isolators are used to allow access to primary plant for planned operational and maintenance work. They require minimal maintenance themselves. The failure consequences are generally related to delays in performing other maintenance on high consequence failure assets. Replacement within substations involves extensive planning due to a need for extensive plant outages and results in significant impacts on service delivery. As a result of the potential high consequence of unexpected failure, Ergon Energy has adopted a CBRM approach to define the highest priority economic end-of-life of isolators, optimised for overall least cost and least risk increase. A slight increase in failure risk is expected, with consequences generally related to longer planned outages. Refer to ‘Engineering Report Outdoor Isolators and Earth Switches Replacement and Refurbishment’ for further details.
- Instrument Transformer Replacement and Refurbishment ($21.4 million) – CT and VTs are maintained to a serviceable level to avoid the consequences of premature failure including loss of supply, damage to other substation equipment and the environment, and to mitigate hazards to personnel in the substation and the public. The failure consequences are related to delays in performing other maintenance. As a result of the potential high replacement costs and high consequence of unexpected failure, Ergon Energy has adopted a CBRM approach to define the highest priority economic end-of-life of current and voltage transformers, optimised for overall least cost and least risk increase. Refer to ‘Engineering Report Instrument Transformer Replacement and Refurbishment’ for further details.
- Capacitor Bank Replacement ($8.4 million) – capacitor banks provide harmonic absorption and local voltage support. They also act to support the ability to supply load under N-1 transformer contingency situations and contribute to overall power system stability in the Far North under Powerlink contingency situations. As a result of the potential high-replacement costs and high consequence of unexpected failure, Ergon Energy has adopted a CBRM approach to define the highest priority economic end-of-life of capacitor banks, optimised for overall least cost and least risk increase. Recent changes to security of supply policy have resulted in a higher dependence on capacitor banks to reduce effective transformer and line loading, delaying potential augmentation expenditure. Refer to the ’Engineering Report Capacitor Banks Replacement and Refurbishment’ for further details.
- Circuit Breaker and Switchboard Replacement ($28.1 million) – circuit breakers and switchboards are maintained to a serviceable level to avoid the consequences of premature failure including loss of supply, damage to other substation equipment and the environment, and to mitigate hazards to personnel in the substation and the public. The failure consequences are related to delays in performing other maintenance. As a result of the potential high-replacement costs and high consequence of unexpected failure, Ergon Energy has adopted a CBRM approach to define the highest priority economic end-of-life of circuit breakers, optimised for overall least cost and least risk increase. Refer to the ‘Engineering Report Circuit Breakers and Switchboards Replacement and Refurbishment’ for further details.

6.2.4 Earthing systems

The proposed Renewal capital expenditure programs expenditure for 2015-20 that relate to earthing systems and related assets, and which are supported by the 'Management Plan Earthing Systems', are detailed in Table 16.

Table 16: Renewal capital expenditure for earthing systems (2012-13 dollars)

Program/project	Forecast $ next period
Modifications to Distribution Earth Defect Thresholds	$41.5 million

This program is described in detail below:

- Modifications to Distribution Earth Defect Thresholds ($41.5 million) – Ergon Energy is required under its obligations to meet the *Queensland Electrical Safety Code of practice (Works) 2010* to undertake these works. Stage 2 of a three-stage compliance benchmark program is substantially complete. Refer to 'Engineering Report Modifications to Distribution Earth Defect Thresholds' for further details.

6.2.5 Protection and control

The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to protection and control systems and related assets, and which are supported by the 'Management Plan Protection and Control', are detailed in Table 17.

Table 17: Renewal capital expenditure for protection and control systems (2012-13 dollars)

Program/project	Forecast $ next period
Protection Relay Replacement	$24.6 million
Aged Remote Terminal Units (RTU) Replacement	$7.6 million

These programs are described in detail below:

- Protection Relay Replacement ($24.6 million) – there is a substantial safety risk to staff and the public due to the loss of protection for substations and with lines assets when protection assets fail. Many of the older sites and assets are in situations where backup protection does not completely compensate for initial protection asset failure. As a result, this replacement program will ameliorate most failure prone relays. Overall performance of loss of protection statistics will be marginally improved. Refer to the 'Protection Relay Replacement Engineering Report' for further details.
- Aged Remote Terminal Units Replacement ($7.6 million) – older RTU technology deployed in Ergon Energy's network has become obsolescent. This is due to the lengthy service lives (15 years upwards) of the older legacy technology, lack of spare parts, loss of supplier expertise, and loss of internal expertise and knowledge as the ageing workforce slowly changes. Failure consequences include loss of remote control of the power system, loss of monitoring capability of the power system, increase in public safety risks, particularly for low voltage incidents, extended reliability issues relating to supply restoration. Due to the extensive secondary system monitoring, and associated wiring, replacement is time and resource intensive, and a high-cost exercise. Replacement of these ageing and obsolescent assets will support ongoing safety and reliability obligations. Refer to the 'Engineering Report RTU Replacement Program' for further details.

6.2.6 Underground feeder circuits

The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to underground feeder circuits and related assets, and which are supported by the 'Management Plan Underground Feeder Circuits', are detailed in Table 18.

Table 18: Renewal capital expenditure for underground feeder circuits (2012-13 dollars)

Program/project	Forecast $ next period
Cast Iron Pot Head Replacement	$2.3 million

This program is described in detail below:

- Cast Iron Pot Head Replacement ($2.3 million) – all cast iron pot heads are very old type cable terminations, rusted and allow moisture ingress. They cannot be condition monitored for oil degradation (and it would be uneconomic to do so if it were possible). Eventually the water/oil combination degrade will result in flashover, with catastrophic and sometimes explosive failure. The potheads are typically in urban and business centre locations frequented by the general population. These situations can present significant public safety risks. This replacement program will result in no further asset failures of this type. Refer to the 'Engineering Report Cast Iron Cable Pot Head Replacement' for further details.

6.2.7 Auxiliary substation components

The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to auxiliary substation components and related assets, and which are supported by the 'Management Plan Auxiliary Substation Components', are detailed in Table 19.

Table 19: Renewal capital expenditure for auxiliary substation components (2012-13 dollars)

Program/project	Forecast $ next period
DC System Upgrades	$12.5 million
Audio Frequency Load Control (AFLC) Replacement	$9.3 million

These programs are described in detail below:

- DC System Upgrades ($12.5 million) – DC battery systems are condition monitored and require regular maintenance. Failure consequences include loss of all substation protection, loss of remote and local control, loss of substation communications and loss of the ability to switch load and fault currents. These directly result in loss of ability to ensure public safety under fault conditions, and extensive asset failures due to inability to restrain and curtail network fault energy. Improved monitoring will assist to identify imminent failure situations. Condition monitoring has been used to identify and prioritise those assets at end of economic life. Refer to the 'Engineering Report Substation DC System Renewal' for further details.
- Audio Frequency Load Control (AFLC) Replacement ($9.3 million) – AFLC equipment serves to perform customer demand management by facilitating peak load lopping of hot water systems, pool pumps and other large fixed installation loads. Failure consequences include higher than expected customer energy usage (bill shock), loss of remote peak load switching capability, increased load peaks experienced by regional assets, overloading of distribution assets and overload tripping of assets in some cases. Demand management strategies present significant

potential to delay augmentation expenditure. AFLC asset failure limits Ergon Energy's immediate ability to perform active demand management. Because is it not yet possible to distinguish demand load impact from historical load records, load increases due to loss of demand management ability arising from failed AFLC assets are recognised as additional network load. This has the consequential effect of increasing statistical load forecasts, which acts to promote bringing augmentation expenditure forward. Condition monitoring has identified near end-of-life of some assets. This program will reduce those assets at end-of-life, and reduce the risk of excessive plant overload across the distribution network. Refer to the 'Audio Frequency Load Control Strategy' for further details.

6.2.8 Telecommunications

The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to telecommunications and related assets, and which are supported by the 'Telecommunications Network Strategy 2014-2020' and the 'Management Plan Network Communications Infrastructure', are detailed in Table 20.

Table 20: Renewal capital expenditure for telecommunications (2012-13 dollars)

Program/project	Forecast $ next period
Radio Refurbishment – Mackay to Maryborough	$15.5 million
Radio Refurbishment – Western Queensland	$12.4 million
CoreNet Infrastructure Replacement	$7.9 million
CoreNet Active Network Replacement	$17.5 million

These programs are described in detail below:

- Radio Refurbishment – Mackay to Maryborough ($15.5 million) – refurbishment in the Mackay to Maryborough area needs to be undertaken due to the potential loss of mobile communications resulting from asset end-of-life. Failure consequences involve safety risks for staff working in remote locations, reliability risks due to extended communications issues, and service risks due to inability to manage network operations. Proactive asset replacement will be undertaken to mitigate these risks.
- Radio Refurbishment – Western Queensland ($12.4 million) – refurbishment in the Western Queensland area due to the loss of mobile communications as a result of asset end-of-life. Failure consequences involve safety risks for staff working in remote locations, reliability risks due to extended communications issues, and service risks due to inability to manage network operations. Proactive asset replacement will be undertaken to mitigate these risks.
- CoreNet Infrastructure Replacement ($7.9 million) – equipment contained at core layer sites has greater size and capacity, is significantly more expensive to repair, will require specialised skills to repair and material ordering lead times may be longer than those found in 'lower' classified sites. The equipment has become obsolescent, and the failure risks include significant loss of corporate business and operational communication facilities, with ongoing business capability and staff safety issues. Due to the obsolescence, there are increased costs associated with expected escalating maintenance and repair requirements as asset replacement is deferred beyond condition-assessed recommended replacement. As a result of the potential high replacement costs and high consequence of unexpected failure, Ergon Energy has adopted a discrete analysis approach. This defines the highest priority economic end-of-life of CoreNet

infrastructure, optimised for overall least-cost and least-risk increase. Replacement of this infrastructure reduces the risk of increased capital expenditure costs, business disruption, and safety issues associated with unplanned replacement of equipment when unrepairable failure occurs.

- CoreNet Active Network Replacement ($17.5 million) – Ergon Energy has identified obsolescence and/or reliability risks for piecemeal communication asset types and systems relating to loss of main trunk communications between offices and substations. This directly impacts the ability to operate as a business (Office), substation protection and SCADA signalling. Timely replacement of these assets will mitigate these risks.

6.2.9 Metering

The AER has established that provision of metering is an Alternate Control Service for the 2015-20 regulatory control period. The proposed renewal capital expenditure programs expenditure for 2015-20 that relate to metering and related assets, and which are supported by the 'Network Optimisation Metering Management Plan', are detailed in Table 21.

Table 21: Renewal capital expenditure for metering (2012-13 dollars)

Program/project	Forecast $ next period
Revenue Meter Replacement	$36.27 million

This program is comprised of three elements which are described in detail below:

- Replace Meters end-of-life ($13.2 million) – the *Standard for End-of-life Meter Equipment* is based on the principals of the AER's Repex Replacement Model handbook. Metering equipment will be classified as end-of-life metering where they are twice their recommended economic life and display characteristics of failure.
- Replace Meters in Situ ($19.4 million) – the replacement of non-compliant meters is non-discretionary and required to meet regulatory obligations under 'Ergon Energy's Meter Asset Management Plan'. Non-compliant meter families are allocated the highest priority for replacement and must be replaced as soon as practical.
- Replace Meters Obsolete ($3.7 million) – the *Standard for Obsolete Metering Equipment* will be used to support replacement of non-compliant and end-of-life meter equipment. The allowance for obsolete meter equipment is based on a percentage of the number of targeted meter replacements. The percentage allowance for meters is 15% and for control equipment is 5%.

Refer to the 'Engineering Report Meter Replacement Program' for further details.

6.3 AER's replacement expenditure model

6.3.1 Purpose of the AER's replacement expenditure model

The 'AER's Expenditure Forecast Assessment Guideline for Electricity Distribution', published in November 2013, states that the AER has developed, and intends to use a replacement expenditure model (Repex model) to help determine the expected efficient costs over the regulatory control period to forecast non-demand driven, condition based asset replacement activities.[21] The Repex

[21] AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, http://www.aer.gov.au/node/18864, November 2013, accessed 14 October 2014.

model developed by the AER takes as inputs the age profile for several asset categories, the mean life and standard deviation and the average unit replacement cost, and outputs the estimated replacement volumes and expenditure for the following 20 years, by asset category. The model relies upon average historical replacement volumes and costs, and the age profile of existing assets to forecast future replacement volumes, and hence future replacement expenditure.

The 'Repex Model Mark III Report 2013–14' provides a detailed analysis, which is summarised below.

6.3.2 Replacement expenditure modelling methodology

In preparing its expenditure forecast for the 2015-20 regulatory control period, Ergon Energy has assessed its forecast expenditure against the outcomes of the Repex model. This satisfies Ergon Energy's obligations under clause 6.5.7(e)(4) of the NER to demonstrate the efficiency of its costs of meeting the demand for standard control services by having regard for the benchmark capital expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period.

The Repex model parameters were calibrated based on historical expenditure levels and replacement volumes drawn from data submitted by Ergon Energy in tables 2.2.1 (replacement volumes and unit costs) and 5.2.1 (asset age profile) of the 2013-14 Category Analysis RIN. In turn this data is extracted from Ergon Energy's corporate asset management database. Replacement volumes and unit costs are calculated based on volumes and cost of assets installed since 2008-09, while the age profile represents the quantity of the assets installed in a particular year as far back as 1920-21. However, the accuracy of the age profile is limited by the availability of data about the date of installation of a given asset. Where no such data is available, Ergon Energy uses several methods to infer the age of an asset based on their knowledge of the distribution network. For more details on the preparation of the model refer to the 2015-20 Reset RIN Template 5.2 Basis of Preparation and Schedule 1 Section 6 of the Reset RIN Response.

The Repex model has been calibrated to historical expenditure, in accordance with the 'AER's Replacement Expenditure Model Handbook', published November 2013.[22] Average costs are escalated to 2013-14 dollars by applying published CPI rates to past expenditures. To prepare the Repex model, Ergon Energy has used two scenarios to represent the historical averages of replacement volume and average unit cost rate for each of the asset categories in table 2.2.1. The two scenarios for each asset category are:

(i). A five year average comprising 2009-10, which was the final year of the previous regulatory control period, and the current regulatory control period up to the end of 2013-14

(ii). A four year average comprising the current regulatory control period up to the end of 2013-14.

The 'Replacement Expenditure Model Handbook' states that the model should be calibrated based on 'the actual historical replacement volumes over the most recent duration that reflects the regulatory control period (e.g. 5 years of the most recent actuals)'.[23] Accordingly, Ergon Energy has produced scenario (i) above, which encompasses five years of historical data. However, the beginning of the current regulatory control period in 2010-15 saw a significant change in asset management practices and a corresponding increase in asset renewal expenditure compared with 2009-10. As a result, to identify historical cost that reflect consistent asset management practice, scenario (ii) was developed and is limited to the past four years of historical data.

Whilst both scenarios (i) and (ii) above have been prepared for comparison with Ergon Energy's forecast renewal expenditure, for the reasons described above it is Ergon Energy's view that

[22] AER, Replacement Expenditure Model Handbook, http://www.aer.gov.au/node/18864, November 2013, accessed 14 October 2014.

scenario (ii) better represents contemporary levels of replacement volumes and average unit cost rates. For the purposes of this discussion, all references to the Repex model outputs are based upon the outputs of scenario (ii).

Nevertheless, as explained in the following section, a simplistic calibration of replacement expenditure produced by the Repex model to Ergon Energy's historical expenditure for a four or five year historic period does not take into account significant variances in historical expenditure, which are often due not to age-based replacement but rather to safety or reliability concerns. Even without those historical variances, to generate accurate and robust outputs, the Repex model relies on several assumptions, of which the most material are:

- the asset age profile for each asset category is accurate
- the mean life of assets will remain the same over time
- historical and future replacement expenditure is predominantly driven by age-related replacement (not safety, or obsolescence, which are also drivers of asset renewal expenditure).

These assumptions do not necessarily hold true for all asset categories and this has flow-on effects on the accuracy of the expenditure forecasts produced by the Repex model, which are discussed in the following section.

6.3.3 Replacement expenditure modelling results

Ergon Energy's historic and forecast replacement capital expenditure by category and the results of the Repex model are shown in Figure 12 and Table 22.

[23] AER, Replacement Expenditure Model Handbook, http://www.aer.gov.au/node/18864, November 2013, accessed 14 October 2014, p20

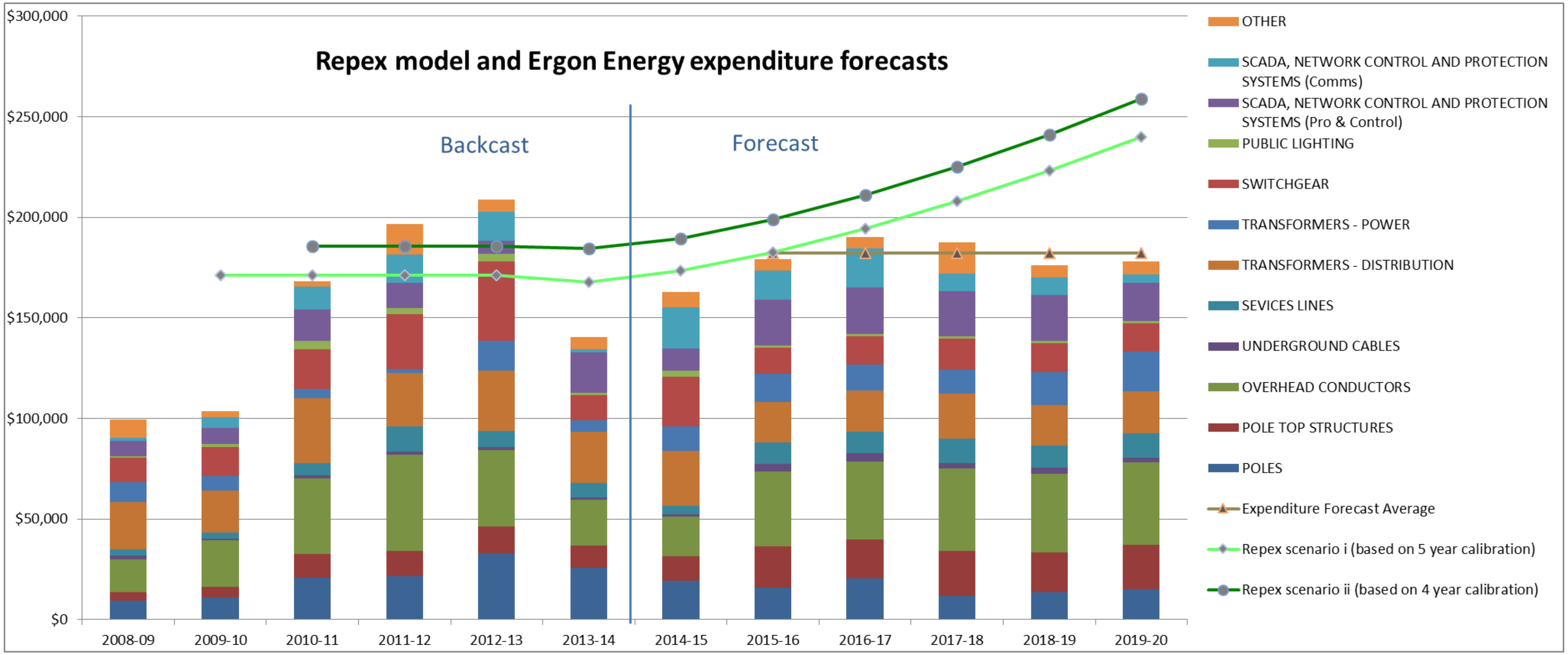


Figure 12: Comparison of Repex model and Ergon Energy's forecast expenditure by asset category (in 2013-14 real dollars)

Table 22: Comparison of Repex model (4 year average scenario) and Ergon Energy forecast expenditure (in 2013-14 real dollars)[24]

Year	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Repex Model (‘4 year average’ scenario)	199	211	225	241	259	**1,135**
Ergon Energy	179	190	187	176	178	**911**
Variance	20	21	38	65	81	**224**
Variance (%)	10%	10%	17%	27%	31%	**20%**

It can be seen from Figure 12 that Ergon Energy’s forecast expenditure in the 2015-20 regulatory control period is lower than both scenarios produced by the Repex model. While the Repex model and Ergon Energy’s forecast expenditure increase at the same rate at the beginning of the regulatory control period, the variance between the two increases over time. Table 22 shows that over the 2015-20 regulatory control period Ergon Energy’s forecast expenditure for asset renewal is $224 million or 20% lower than the expenditure forecast by scenario (ii) of the Repex model.

Ergon Energy does not believe that significant weight should be placed on the conclusions that can be drawn from this comparison. There are several factors inherent in the design of the Repex model which mean that the Repex model does not accurately predict the efficient level of Ergon Energy’s forecast asset renewal expenditure in the 2015-20 regulatory control period. These are described in the following sections.

6.3.4 Factors affecting backcast renewal expenditure model outcomes

Over the past, current and next regulatory control periods, Ergon Energy has made and will continue to make significant changes to its asset management strategy, both at a portfolio level and within specific asset categories. The Repex model is more likely to produce realistic outputs where a stable asset management process is adhered to over time, and where replacement is predominantly driven by age related failure. Changes in asset management practices, such as, to address safety risks, or to meet statutory reliability targets, or for maintenance or operational purposes lead to variations in how assets are replaced over time which the Repex model is unable to take into consideration.

The beginning of the 2010-15 regulatory control period was characterised by high levels of asset renewal expenditure compared with historical expenditure. This was predominantly due to increased investment in asset renewal to meet higher reliability standards imposed upon Ergon Energy by legislation. Additionally, Ergon Energy brought forward expenditure to the beginning of the current period to address several emerging high risk safety issues such as Air Break Switch failures, 7/.064 HDBC High Voltage conductor deterioration and open wire service shocks. Where systemic failure modes emerge, it becomes clear that historical performance of the asset class is not an indicator of future performance. As described in Section 5.3.2, where an emerging safety or reliability issue has led to an increase in historical expenditure in an asset category, historical replacement behaviour is not necessarily an indicator of future replacement expenditure levels.

It can be seen from Figure 12 that Ergon Energy’s expenditure in 2013-14 was materially lower compared with the previous three years of the current period. As discussed in Section 4.3.2, several

[24] There is a variance between Ergon Energy’s forecast expenditure as used for Repex modelling purposes and the forecast expenditure set out in Section 6. This is due to differences in the real cost escalations applied to each, and minor variances between the forecast expenditure in Section 6 and the forecast expenditure reported in the Category Analysis RIN, the latter of which has been used to evaluate the results of the Repex model.

factors contributed to this variance, notably improvements in asset management techniques such as consistent maintenance standards for defect classifications, and Ergon Energy's decision not to proceed with capital-intensive line rebuilding in lieu of more targeted subtransmission pole top refurbishment. Combined, these factors have led to a reduction in 2013-14 expenditure. This again calls into question the effectiveness of the backcasting process since it ignores significant recent changes in expenditure and hence replacement volumes.

The effect of these changes is that the backcast expenditure produced by the Repex model is not necessarily reflective of long-run historical levels of asset renewal expenditure. The variability in historical expenditure which comes with changes in asset management practices, introduces uncertainty into the Repex model. This has consequent flow-on effects on the assumed mean economic life of each asset category, which means that the life of assets in real life is unlikely to be normally distributed, as the Repex model assumes. As a result, the historical replacement volume and expenditure data does not provide a robust basis on which to forecast future expenditure.

6.3.5 Factors affecting forecast renewal expenditure model outcomes

The Repex model forecasts year-on-year growth in expenditure throughout the 2015-20 regulatory control period, while Ergon Energy's forecast expenditure remains relatively constant over time. Several factors explain why Ergon Energy's forecast expenditure does not increase over time consistent with the outputs of the Repex model.

Ergon Energy has made significant improvements to its asset inspection processes to remove subjectivity in the identification of defects. As these new standards and processes are embedded, efficiencies will be realised over time, placing downward pressure on forecast renewal expenditure. Similarly, the implementation of new asset management techniques such as CBRM, have had the effect of extending the economic life of high value assets to which they are applied. This results in a reduction in forecast expenditure for asset renewal, since assets which otherwise would have been replaced remain in service.

The accuracy of the Repex model is heavily reliant on the accuracy of the asset age profile for each asset category. For those categories, which have poor historical data on installation date, such as conductors, the asset age profile is only an estimate with a low degree of confidence. For those categories, the results of the Repex model are unlikely to provide any basis for assessing the prudency or efficiency of the expenditure forecast that Ergon Energy proposes.

While the Repex model forecast expenditure is higher than Ergon Energy's forecast expenditure on an aggregate basis across all asset categories, there are variations between Ergon Energy and the Repex model's forecast expenditure within specific asset categories, which can be explained by reference to historic and future asset management decisions within those asset categories.

7. Meeting Rules' requirements

This section draws on the material in the previous sections to explain and justify Ergon Energy's forecast asset renewal capital expenditure against the capital expenditure objectives and criteria in clause 6.5.7 of the NER.

It therefore outlines why the AER should approve this capital expenditure forecast as part of its distribution determination for Ergon Energy's next regulatory control period.

7.1 The capital expenditure objectives

The National Electricity Rules set out the objectives that Ergon Energy must satisfy for its proposed capital expenditure for the next regulatory control period. Clause 6.5.7(a) states:

> *A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):*
>
> *(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> *(i) the quality, reliability or security of supply of standard control services; or*
>
> *(ii) the reliability or security of the distribution system through the supply of standard control services,*
>
> *to the relevant extent:*
>
> *(iii) maintain the quality, reliability and security of supply of standard control services; and*
>
> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services.*

Standard Control Services is the name given to those services that Ergon Energy provides by means of, or in connection with, its distribution system, and for which the costs incurred by Ergon Energy in doing so are generally recovered through distribution use of service tariffs paid by all, or most, customers. SCSs are grouped into five categories: network services, connection services, metering services, ancillary network services and public lighting services. The SCSs that Ergon Energy provides to customers are set out in the 'AER's Framework and Approach – Ergon and Energex 2015-2020' paper.[25] Asset Renewal capital expenditure relates to network services and metering services.

Ergon Energy believes that its proposed capital expenditure for Asset Renewal in the next regulatory control period achieves the objectives as follows:

- Meeting and managing expected demand for standard control services, as required by clause 6.5.7(a)(1), is the predominant objective of Ergon Energy's proposed Asset Renewal capital expenditure, the nature of which is described in Section 3 of this document. Ergon Energy's Asset Renewal activities are driven by the deterioration and failure of assets over time. However, for

[25] AER, Framework and Approach – Ergon and Energex 2015-2020, April 2014, p 51

Ergon Energy's proposed Asset Renewal capital expenditure, Ergon Energy would not be able to meet the expected demand for standard control services over the 2015-20 regulatory control period. The way in which Ergon Energy forecasts its Asset Renewal capital expenditure is based upon condition monitoring, inspections and the historical performance of the existing population of assets. This is in contrast with Corporation Initiated Augmentation and Customer Initiated Capital Works capital expenditure, which are driven by expected levels of demand for electrical load. Ergon Energy's Asset Renewal capital expenditure forecast is not system load demand driven and hence the proposed capital expenditure is not intended to augment the capability of the distribution network to meet any increase over current levels of demand for standard control services.

- The Asset Renewal capital expenditure that Ergon Energy proposes is necessary to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services, as required by clause 6.5.7(a)(2).
- As described in Section 3.2, Ergon Energy is subject to regulatory obligations imposed by several statutory instruments at a state and at a federal level. Key Queensland legislation includes, but is not limited to, the *Work Health and Safety Act 2011* (Qld), the *Electrical Safety Act 2002* (Qld) and enforceable orders issued by the Queensland Electrical Safety Office. These obligations underpin Ergon Energy's asset management strategies, risk management framework, maintenance/inspection activities and associated practices, strategies and policies. The methods that Ergon Energy has developed to forecast its Asset Renewal capital expenditure, which are set out in Section 5.3, are underpinned by the decision making processes to replace assets, which are set out in section 5.2 of this document. The resulting works that Ergon Energy proposes to undertake, are intended to discharge Ergon Energy's obligations under these and other statutory instruments. For further details on specific aspects of the proposed works in the 2015-20 regulatory control period refer to Ergon Energy's supporting strategies, management plans and engineering reports set out in Section 6.2, which in turn form the basis for the Asset Renewal capital expenditure forecast set out in Section 6.1.
- The Asset Renewal capital expenditure that Ergon Energy proposes is necessary to maintain the quality, reliability and security of supply of standard control services, and hence the reliability and security of the distribution system, as required by clause 6.5.7(a)(3).
- The Electrical Safety Act 2002 (Qld), and Ergon Energy's Distribution Authority under the Electricity Act 1994 (Qld), require Ergon Energy to maintain its assets for several purposes, all of which are ultimately directed toward maintaining the quality, reliability and security of supply of standard control services and hence maintain the reliability and security of the distribution network. When considered in the context of Ergon Energy's other obligations under law, to achieve this objective, Ergon Energy must maintain, refurbish and/or replace its assets by having regard for their safety performance, their economic end of life and for the security of supply criteria.
- Independent of these regulatory obligations, Asset Renewal capital expenditure is necessary to manage the effects of asset degradation and failure, which, if left unchecked, would lead to deterioration in the existing levels of quality, reliability, and security of supply of Ergon Energy's standard control services. The works that Ergon Energy proposes to undertake in the 2015-20 regulatory control period are therefore focused at maintaining functional performance of the distribution network and are intended to discharge Ergon Energy's obligations under clause 6.5.7(a)(3) and the statutory instruments described in the preceding paragraph. Ergon Energy forecasts its asset renewal capital expenditure to the extent it is necessary to maintain overall service performance by selecting, for each asset type, the appropriate expenditure forecasting methodology from the methodologies set out in section 5.3. For further details on specific aspects

of the proposed works refer to the supporting strategies, management plans and engineering reports set out in Section 6.2, which in turn form the basis for the Asset Renewal capital expenditure forecast set out in Section 6.1.

- The Asset Renewal capital expenditure that Ergon Energy proposes is required to maintain the safety of the distribution system through the supply of standard control services, in accordance with clause 6.5.7(a)(4). Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld) to inspect, test, and maintain works, and a duty to ensure that its works are electrically safe and are operated in a way that is electrically safe. Under the *Work Health and Safety Act 2011* (Qld), Ergon Energy must ensure, so far as is reasonably practicable, that the fixtures, fittings and plant are without risks to the health and safety of any person. Additionally, Ergon Energy is subject to enforceable orders issued by the Queensland Electrical Safety Office in response to identified safety risks.
- To discharge these obligations, Ergon Energy has implemented a comprehensive Work Health and Safety governance framework that governs the safety, and the safe operation, of the distribution system. These policies are given effect through the Asset Inspection and Defect Maintenance program and other targeted replacement programs. Ergon Energy believes that the works conducted in these programs are therefore necessary to maintain the safety of the distribution system in accordance with Ergon Energy's regulatory obligations. Additionally, where safety risks that are specific to particular assets or classes of assets are identified, Ergon Energy undertakes discrete analyses of the risks and has proposed targeted programs of work to prevent unacceptable deterioration in the safety of its assets. For further details on specific aspects of the proposed works refer to Ergon Energy's supporting strategies, management plans and engineering reports set out in Section 6.2, which in turn form the basis for the asset renewal capital expenditure forecast set out in Section 6.1. In this way, the asset renewal capital expenditure that Ergon Energy proposes is necessary to maintain existing levels of safety of the distribution system.

7.2 The capital expenditure criteria

Clause 6.5.7(c) states:

> *The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (the capital expenditure criteria):*
>
> > *(1) the efficient costs of achieving the capital expenditure objectives;*
> >
> > *(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*
> >
> > *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.*

Clause 6.5.7(e) goes on to state:

> *In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the capital expenditure factors):*
>
> > *(1) – (3) [Deleted]*
> >
> > *(4) 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;*

(5) the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;

(5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4;

(9) the extent the capital expenditure forecast is referable 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;

(9A) 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);

(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s):

(12) any other factor the AER considers 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.

The capital expenditure that Ergon Energy proposes to meet the objectives, in accordance with clause 6.5.7(a), reasonably reflects the criteria set out in clause 6.5.7(c) by reference to the factors in clause 6.5.7(e) as follows.

The efficient and prudent costs of achieving the objectives

Ergon Energy has had regard for the AER's interpretation of prudency and efficiency in assessing whether Ergon Energy's capital expenditure reasonably reflects sub clauses (1) and (2) in this Summary. In the Explanatory Statement to the 'Expenditure Forecast Assessment Guidelines', the AER stated that:

"We consider that efficient costs complement the costs that a prudent operator would require to achieve the expenditure objectives. Prudent expenditure is that which reflects the best course of action, considering available alternatives. Efficient expenditure results in the lowest cost to consumers over the long term. That is, prudent and efficient expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives."[26]

In the context of Ergon Energy's asset renewal capital expenditure, Ergon Energy uses two approaches to make asset replacement decisions – proactive replacement and run-to-failure - which are set out in Section 5.2. By applying these approaches, Ergon Energy determines the most prudent action to be taken, at the most appropriate time, having regard for the objectives, which its expenditure must satisfy. These actions may be in the form of a specified project to address a specific need, or a program of works comprising a volume of activities to be undertaken. Ergon

[26] Australian Energy Regulator, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, p 12.

Energy's decision making processes, and the way in which they achieve prudent outcomes, are demonstrated throughout its corporate policies, protocols, standards, Management Plans, Engineering Reports and associated supporting documentation and business-as-usual governance processes. It is Ergon Energy's stated intention to align generally with the *ISO 55000 Asset Management Standard*, and to promote and support continuous improvement in its overall asset management processes. These represent the actions of a prudent operator.

Ergon Energy has developed objective methodologies to model the need for asset renewal, based upon assessed risk, asset condition, age, actual performance history, and population performance, to establish prudent volumes of asset renewal. These are discussed in detail in its justification documentation and various models provided to the AER in its submission. Ergon Energy applies unit costs to the projects and programs, based on demonstrated efficient costs, to determine an efficient forecast level of asset renewal capital expenditure.

To develop an efficient cost base Ergon Energy has adopted a robust methodology to estimate the unit costs of projects and programs of works, based on a combination of historic and estimated costs. These costs, and how they are developed, are described in the 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'. Ergon Energy considers its capital expenditure to be both prudent and efficient because not only are its unit costs efficient, Ergon Energy applies those efficient costs to the prudent actions it proposes to undertake so that its total Asset Renewal capital expenditure is both prudent and efficient.

A realistic expectation of the demand forecast and cost inputs required to achieve the objectives

Ergon Energy adopts a realistic expectation of the cost inputs required to achieve the objectives by developing unit costs that are based on a reasonable and robust estimation methodology. This methodology excludes inefficient costs when evident, includes only those costs to do the task and presents a transparent set of escalations due to contractor and mobilisation costs in establishing direct costs. For further details refer to the 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

Having regard for the factors

Ergon Energy's proposed capital expenditure reasonably reflects the prudent and efficient costs of achieving the objectives by having regard for the factors in clause 6.5.7(e) as follows:

- In relation to sub clause (4), in September 2014 the AER decided to delay the release of its first benchmarking report under clause 6.27 until late November 2014, one month after the submission of this Regulatory Proposal. As a result, Ergon Energy has not been able to use it to inform its capital expenditure forecasts. Nevertheless, using the same publicly available information that will be used to develop the AER's benchmarking report, Ergon Energy commissioned an independent report to enable it to compare its performance and other network service providers, having regard for the unique qualities of Ergon Energy's network. This is prudent because Ergon Energy has quite unique cost drivers which should be considered when benchmarking performance. For further details refer to the 'How Ergon Energy Compares' document.

  The benchmark capital expenditure that an efficient DNSP would incur over the regulatory control period cannot be observed directly because the expenditure forecast is by its nature concerned with future, rather than historical, events. To improve its ability to assess benchmark capital expenditure for asset replacement, the AER has published a replacement expenditure model (the Repex model) for NSPs to use to forecast the replacement needs of assets on a per category basis. As set out in Section 6.3 Ergon Energy has applied this model to its asset profile and has assessed its proposed Asset Renewal Capital Expenditure (as set out in Section 6.1) in light of the results of the Repex model forecasts.

- In relation to sub clause (5), Ergon Energy has set out, in Tables 1 and 2 of this Summary, its actual capital expenditure during the previous regulatory control period (2005-10) and actual and expected capital expenditure in the current regulatory control period (2010-15). To accompany this information, in Section 2.1, Ergon Energy has explained the actual and expected capital expenditure by reference to the allowance approved by the AER (and, for the 2005-10 regulatory control period, the QCA) and the endogenous and exogenous factors that have contributed to any variance from the AER's allowance.

  In doing so Ergon Energy has demonstrated that its proposed Asset Renewal capital expenditure is efficient because it is broadly in line with the level of efficient capital expenditure it has incurred in the current and prior regulatory control periods. Where its current or prior period expenditure has deviated from the AER's allowance, Ergon Energy has explained this by reference to drivers and circumstances that support the prudency and efficiency of the level of capital expenditure that was actually incurred. This demonstrates the robustness of Ergon Energy's system of investment review controls, which ensures that Ergon Energy's capital expenditure is continuously assessed for prudency and efficiency.

- In relation to sub clause (5A), Ergon Energy has conducted a comprehensive program of customer engagement to identify the concerns of electricity consumers and ensure that its proposed capital expenditure addresses those concerns. The results of Ergon Energy's engagement, and how they have informed its proposed capital expenditure, are set out in this summary document and in the document 'Informing Our Plans, Our Engagement Program'. Additionally, Ergon Energy has summarised the outcomes of the customer engagement that are directly relevant to the Asset Renewal expenditure category in Section 3.1.

- In relation to sub clauses (6) and (7), the nature of asset renewal presents some opportunity to consider the relative prices and substitution possibilities of operating and capital expenditure. One of the objectives of Asset Renewal capital expenditure is to maintain the functional performance of the distribution network by maximising the economic life of existing assets. This enables Ergon Energy to meet demand for standard control services as prudently and efficiently as possible. Ergon Energy uses several methods to maximise the economic life of its assets, which are set out in Section 5.3.

  CBRM modelling specifically compares the ongoing costs and risks of keeping an asset in service (operating expenditure) with the replacement cost (capital expenditure) and ongoing costs and risks of an equivalent new asset. By adopting this approach for high cost assets, Ergon Energy determines how to maximise their economic life by either proposing operating expenditure to inspect and maintain the asset, or capital expenditure to refurbish or replace it. Ergon Energy's use of CBRM modelling in support of this trade-off is described in Section 5.3 of this document.

  For asset categories whose asset renewal capital expenditure is forecast using a simple predictive or discrete analysis methodology, Ergon Energy incurs a significant level of operating expenditure, largely arising from the operation of the Asset Inspection and Defect Management (AIDM) program. The purpose of the AIDM program is to inspect, test and maintain all of its assets so as to satisfy its obligations under Queensland legislation.[27] For those (usually low cost) assets that are within the scope of the AIDM program, defects identified by the inspection process generally involve component or complete replacement which incurs capital expenditure.

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[27] Electrical Safety Act 2002 (Qld), s 29(2).

There is little opportunity for substitution of operating for capital expenditure in this process as these assets are managed using a run-tofailure approach.

- In relation to sub clause (8), Ergon Energy notes that none of the schemes set out in clauses 6.5.8A or 6.6.2 to 6.6.4 of the Rules is applicable in the context of its proposed Asset Renewal expenditure for the 2015-20 regulatory control period.
- In relation to sub clause (9), Ergon Energy has robust procurement governance processes in place to ensure that contractual arrangements at all times reflect arm's length terms. These processes are described in detail in the 'Network Deliverability Plan'. It is noted that Ergon Energy's only subsidiary Sparq Solutions does not provide network services for Asset Renewal that would constitute 'direct' costs and which would thus form part of the expenditure proposed in Section 6.1.
- In relation to sub clause (10), as required by clause 5.17.4 of the Rules, Ergon Energy must apply the Regulatory Investment Test (RIT-D) (previously the Regulatory Test) for capital expenditure augmentation projects greater than $5 million or asset renewal projects where there is an augmentation component greater than $5 million. As part of this test, Ergon Energy must consider adopting non-network solutions where it is prudent and efficient to do so. Based on Ergon Energy's functional like-for-like renewal approach, there are very few specific asset renewal projects subject to application of the RIT-D test. Ergon Energy identifies potential projects in the development of its 'Distribution Annual Planning Report' (DAPR).

  Additionally, Ergon Energy has provided an overview of the demand management strategic directions and activities for the control period in the 'Ergon Energy Demand Management Overview 2015-2020'. This document sets out the programs, activities, and capabilities required to capture demand reduction potential and hence avoid network capital expenditure and reduce network risks. How Ergon Energy assesses these non-network alternatives is described in the 'Ergon Energy Demand Management Overview 2015-20' that forms part of this regulatory proposal. Demand management solutions are considered in response to asset renewal needs at an asset's end-of-life by ascertaining if security of supply can be maintained through demand management activities rather than asset replacement. Given the limited emergence of demand management options to meet asset renewal needs to date, proposed capital expenditure is currently based on efficient historical costs incurred as described in the 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.
- In relation to sub clause (11), Ergon Energy is required to develop a final project assessment report under 5.17.4(o), (p) or (s) as part of the Regulatory Investment Test for Distribution (RIT-D). Ergon Energy will apply the RIT-D to applicable projects in the 2015-20 period as required by the Rules. Ergon Energy notes that no capital expenditure projects have been subjected to the RIT-D to date and hence there are no relevant final project assessment reports for Ergon Energy to have in regard to its proposed asset renewal capital expenditure for the 2015-20 period.
- In relation to sub clause (12), Ergon Energy has not been notified of any other factor that the AER considers relevant and has notified Ergon Energy is a capital expenditure factor.

Appendix A. Definitions, acronyms and abbreviations

1. Definitions

Term	Definition
Economic Life	The period over which an asset is expected to be usable, with normal repairs and maintenance, for the purpose it was acquired.

2. Acronyms and abbreviations

Abbreviation or acronym	Definition
ABS	Air Break Switch
ACQ	Alkaline Copper Quaternary
ACS	Alternative Control Services
AER	Australian Energy Regulator
AFLC	Audio Frequency Load Controls
AIDM	Asset Inspection and Defect Management
CB	Circuit Breaker
CBRM	Condition Based Risk Management
CT	Current Transformer
DC	Data centre or direct current
DEE	Dangerous Electrical Event
DNSP	Distribution Network Service Provider
EDO	Expulsion Drop Out
ESO	Electrical Safety Office
GFC	Global Financial Crisis
HDBC	Hard Drawn Bare Copper
HI	Health Index
HV	High voltage
ICAM	Incident Cause Analysis Method
IRC	Investment Review Committee
kV	Kilovolt
LV	Low voltage
MAC	Maintenance Acceptance Criteria
NER	National Electricity Rules
NIRC	Network Investment Review Committee

Abbreviation or acronym	Definition
QCA	Queensland Competition Authority
Repex	Replacement Expenditure
RIN	Regulatory Information Notice
RPEQ	Registered Professional Engineers Queensland
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SVC	Static VAR Compensator
VT	Voltage Transformer

Appendix B. References

1. Compliance documentation

Name	Description
Codes of Practice	Codes of practice provide practical guidance for people who have electrical safety duties about how to achieve the standards required under the Electrical Safety Act 2002 (Qld) and about effective ways to identify and manage electrical safety risks.
Distribution Authority	Licence issued by the Queensland State Government to Ergon Energy pursuant to the Electricity Industry Act 1994 (Qld) to undertake electricity distribution activities in Queensland.
Electrical Safety Act 2002 (Qld)	The *Electrical Safety Act 2002* is the legislative framework for electrical safety in Queensland. The purpose of this Act is to prevent people from being killed or injured and property from being destroyed or damaged by electricity
Electrical Safety Regulation 2013	The Electrical Safety Regulation 2013 identifies specific ways to meet electrical safety duties under the Electrical Safety Act 2002 and establishes requirements for electrical work; licensing; installations; equipment; supply; safety management systems; cathodic protection systems; and incident notification and reporting.
Electricity Act 1994 (Qld)	State legislation governing the supply, distribution, sale and use of electricity in Queensland.
ISO55000 Asset Management Standard	An international suite of standards that provides guidance in asset management best practise and focuses on developing proactive lifecycle asset management system.
National Electricity Rules	Statutory instrument made under the National Electricity (South Australia) Act 1996 governing the National Electricity Market and the regulation of market participants including Ergon Energy.
National Electricity Rules	Statutory instrument made under the National Electricity (South Australia) Act 1996 governing the National Electricity Market and the regulation of market participants including Ergon Energy.
Work Health and Safety Act 2011 (Qld)	State Legislation governing the provision of a balanced and nationally consistent framework to secure the health and safety of workers and workplaces.

2. Strategic documentation

Name	Description
Network Control Strategy	The objective of this document is to outline the requirements and direction of the Network Control Strategy throughout the whole of Ergon Energy and to align the Control Systems business unit's intent with the overarching strategy of the Engineering Standards and Technology Group in which Control Systems resides. This strategy aims to address current issues and provide strategic direction for the future.
Network Optimisation Asset Strategy	The Asset Strategy specifies objectives and outcomes that provide the link between the high-level aspirations and guiding principles articulated in the Asset Management Policy and the operational and tactical aspects within the asset management plans.
Network Protection Strategy	The purpose and scope of this Protection Strategy is to identify the current status and function of Protection business unit's role and future intent with in the overarching strategy of the Asset Management Engineering Standards and Technology group that it resides in.

3. Network Optimisation Management Plans

These documents describe for the stated asset type, Ergon Energy's approach to managing their assets, cognisant of appropriate legislation, regulatory obligations, asset management strategies, and standards, both internal and external.

Further the document details the key projects and programs underpinning activities for the period 2013-14 to 2019-20 in addition to the basis upon which we derive our capital expenditure and operating expenditure forecasts.

Name
Auxiliary Substation Components Management Plan
Earthing Systems Management Plan
Metering Management Plan
Network Communications Infrastructure Management Plan
Network Operations Management Plan
Operational Building and Sites Management Plan
Overhead and Underground Plant and Equipment Management Plan
Overhead Feeder Circuits
Protection and Control Management Plan
Public Lighting Management Plan
Underground Feeder Circuits Management Plan
Vegetation and Access Tracks Management Plan
Zone and Bulk Supply Plant and Equipment Management Plan

4. Supporting documentation

Name	Description
AFLC Strategy	The purpose of this strategy to provide the future direction to address the current issues and continue the development of an effective Ripple Control System throughout Ergon Energy. Supporting Business Case: • AFLC (Audio Frequency Load Control) Equipment Replacement Plan
Defect Classification Manuals	• Line Defect Classification Manual • Substation Defect Classification Manual These manuals define the Ergon Energy defect classification and prioritisation requirements for recording defects during an asset inspection.
Distribution Annual Planning Report (DAPR)	Ergon Energy's Distribution Annual Planning Report 2014-15 to 2018-19 presents the outcomes of a five-year distribution annual planning review, based on strategies and planning processes underpinning our approach and good practices in asset management.
Ergon Energy Demand Management Overview 2015-20	This document comprises an overview of Ergon Energy's proposed demand management activities for the regulatory control period 2015 to 2020. As well as the targets and expenditure forecast, this document contains a summary of activities, strategies, risks, drivers and operation of demand management throughout Ergon Energy's network.
Forecast Expenditure Summary Corporation Initiated Augmentation 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Corporation Initiated Augmentation capital expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
Forecast Expenditure Summary Customer Initiated Capital Works 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Customer Initiated Capital works expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
Forecast Expenditure Summary Reliability and Quality of Supply 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Reliablility and Quality of Supply capital expenditure for its standard control services for the next regulatory control period, 1 July 2015 to 30 June 2020.
How Ergon Compares	This document discusses benchmarking approaches across distribution networks and whether the cost to develop, operate and maintain the Ergon network can easily be compared and contrasted with the industry average and peers. The document provides an appreciation of the way that the design and operation of Ergon network has been shaped, over time, in direct response to both the needs of our customers and the challenges of our network area. Specifically, this documents seeks to highlight those significant drivers of cost that affect Ergon Energy more (or in a different way when compared to) other DNSPs.
Informing Our Plans, Our Engagement Program	The document, Informing Our Plans, Our Engagement Program, details the engagement program and the customer insights used to inform our Regulatory Proposal. It supports the document, An Overview, Our Regulatory Proposal and the main Regulatory Proposal.

Name	Description
Investment Review Committee Charter dated July 2014	The document details the Charter and specifies the terms of reference and strategic and tactical oversight functions of the Investment Review Committee.
Meter Asset Management Plan	The Meter Asset Maintenance Plan (MAMP) is required under Chapter 7 of the National Electricity Rules (NER), as part of Ergon Energy's accreditation as a Meter Provider Category B. The MAMP outlines the meter testing requirements and test periods (as applicable) for revenue meters Types 1 to 6 as approved by AEMO.
Network Deliverability Plan	The purpose of the Deliverability Plan is to summarise how Ergon Energy will ensure an efficient, prudent and successful delivery of the AER Regulatory control period 2015 - 2020 Program of Work
Network Investment Review Committee (NIRC) Charter dated July 2014	The purpose of the NIRC is to facilitate the prudent and efficient management of all network related capital and operating expenditure of Ergon Energy in accordance with the Network Optimisation Plan.
Security Criteria	The purpose of this document is to define Ergon Energy's Security of Supply/Network Planning Criteria. This criteria when combined with Minimum Service Standards (MSS) targets, will underpin prudent capital and operating costs to deliver the appropriate level of service to customers.
Standard for Maintenance Acceptance Criteria	This document sets out objective criteria for testing of assets for condition monitoring purposes.
Telecommunications Network Strategy 2014-2020	The document states Ergon energy's strategy for providing o provide an efficient and reliable telecommunication network which supports the current, and enables the future, operations of Ergon Energy. Supporting Business Cases: • End-of-life Radio Refurbishment Mackay to Maryborough • End-of-life Radio Refurbishment Western Queensland • CoreNet site infrastructure replacement • CoreNet Active Network Replacement

5. Engineering Reports

Name	Description	Supporting Business Case
Capacitor Banks Replacement and Refurbishment	This report presents an analysis of Ergon Energy's capacitor bank assets, identifies asset specific risks and considers remedial actions and asset characteristics in the context of any asset renewal program.	Substation Capacitor Bank Replacement Program
Cast Iron Pot Head Replacement	This report addresses current concerns relating to Cast Iron Cable Pot Heads. It will investigate the current number of Cast Iron Cable Pot Heads still in service across Ergon Energy, what actions have previously been taken to address concerns about them, and what options are available currently to mitigate these issues to Ergon Energy's and other stakeholders satisfaction.	Cast Iron Cable Pot Head Replacement Program
Circuit Breaker And Switchboard Replacement Engineering and Refurbishment	The purpose of this report is to present an analysis of Ergon Energy's Circuit Breaker and Switchboard assets, identify asset specific risks, and consider remedial actions and consider asset characteristics in the context of any asset renewal program.	Substation High Voltage Circuit Breaker and Switchboard Replacement Program
Colour Coded Service Cable Replacement Engineering Report	This Engineering Report outlines available data, incidents and risks associated with colour coded low voltage customer service cables on Ergon Energy's overhead lines. This report examines possible future courses of action to address or mitigate the risks posed by these service cables.	Colour Coded Low Voltage Overhead Customer Services Replacement Program
Substation DC System Renewal	This document presents a position for discussion and recommendations on the continuation of upgrading of DC supplies in zone substations, to continue to address known issues and reduce the risks associated with DC failure.	Substation DC System Upgrade Program
Defective Connector Splice replacement	This Engineering Report examines the need for a connector and splice replacement program on Ergon Energy's network. Analysis and recommendations are based on all major connector types and splices on Ergon Energy's network (listed in section 4.1). It does not include the replacement of dead-ends or attachment ties.	Defective Connector and Splice Replacement Program
Distribution Feeder Reconductoring Program	This engineering report provides an explanation of and rationale behind Ergon Energy's Distribution Feeder Reconductoring Program, which is proposed for the 2015 – 2020 Regulatory control period.	Distribution Feeder Reconductoring Program
EDO Fuse Replacement in High Fire Risk Areas	This engineering report investigates the options available and recommends solutions to reduce the risk of bushfire in high fire risk areas, which are attributable to EDO fuses on Ergon Energy's network.	EDO Fuse Replacement in High Risk Fire Areas
Instrument Transformer Replacement and Refurbishment	The purpose of this report is to present an analysis of Ergon Energy's CT and VT assets, identify asset specific risks, and consider remedial actions and consider asset characteristics in the context of any asset renewal program.	Instrument Transformer Replacement Program
Outdoor Isolators and Earth Switches Replacement and Refurbishment	The purpose of this report is to present an analysis of Ergon Energy's Outdoor Isolator and Earth Switch assets, identify asset specific risks, and consider remedial actions and consider asset characteristics in the context of any asset renewal program.	Substation Isolators Replacement Program

Name	Description	Supporting Business Case
Instrument Transformer Replacement and Refurbishment	The purpose of this report is to present an analysis of Ergon Energy's CT and VT assets, identify asset specific risks, and consider remedial actions and consider asset characteristics in the context of any asset renewal program.	Instrument Transformer Replacement and Refurbishment Program
Outdoor Isolators and Earth Switches Replacement and Refurbishment	The purpose of this report is to present an analysis of Ergon Energy's Outdoor Isolator and Earth Switch assets, identify asset specific risks, and consider remedial actions and consider asset characteristics in the context of any asset renewal program.	Substation Isolators Replacement Program
ACQ Treated Laminated Veneer Crossarms	This document is to assess risks associated with ACQ treated laminated veneer crossarms on Ergon Energy's overhead lines. Data and analysis presented in this document will inform management decisions on the need to initiate replacement programs, implement changes to maintenance programs or practices.	Replace Laminated Crossarms
XLPE Service Cable Insulation Degradation	This Engineering Report outlines the issues associated with the reported deterioration of certain XLPE customer service cables and recommends an approach to managing these issues.	Inspect and Replace Overhead Customer Services
Modifications to Distribution Earth Defect Thresholds	The purpose of this Engineering Report is to manage the process towards compliance with the Code of Practice Works concerning Distribution Earth Defect Thresholds.	Distribution Earthing Remediation
Neutral Screen Service Cable Replacement	This Engineering Report details issues and assesses safety risks associated with low voltage neutral screened service cables on the Ergon Energy network. This report examines the need to change processes or take further action to reduce the risk exposure associated with these services.	Neutral Screened Low Voltage Overhead Customer Services Replacement Program
Replacement of Non-ceramic Fuses	This report addresses current concerns relating to facia mounted non-ceramic fuses. It will investigate the current number of these fuses still in service across Ergon Energy, what actions have previously been taken to address concerns about them, and what options are available currently to mitigate these issues to Ergon Energy's and other stakeholders satisfaction.	Non-Ceramic Customer End Service Fuse Replacement
RTU Replacement Program	This report details the state of Ergon Energy's Substation Remote Terminal Units (RTUs). The number of current units, make/model, age, and known issues are detailed in this report. It will provide a recommendation for an appropriate replacement plan of unsupported RTU assets.	Remote Terminal Unit Replacement Program
Static VAR Compensators (SVC) Replacement and Refurbishment	This report presents an analysis of Ergon Energy's Static VAR Compensators, identifies asset specific risks and considers remedial actions in the context of asset renewal programs.	Substation SVC Replacement Program
Power Transformer Replacement and Refurbishment	The purpose of this report is to present an analysis of Ergon Energy's Power Transformer assets, identify asset specific risks and consider remedial actions and consider asset characteristics in the context of any asset renewal program.	Substation Power Transformer Replacement and Refurbishment Program

Name	Description	Supporting Business Case
Sub transmission Lines Refurbishment	Ergon Energy recognises there is a need to minimise potential failures in the sub-transmission network, which by their nature affect reliability of supply to large customer groups translating into significant impact on the community. The purpose of this report is to present an analysis of Ergon Energy's Sub-Transmission Lines condition, performance, costs, and risks and to consider remedial actions in the context of asset refurbishment and rebuild program options.	Sub Transmission Line Refurbishment Program
Protection Relay Replacement	This engineering report proposes to replace aged and problematic protection relays throughout Ergon Energy's network, improving and securing network reliability and the safety of personnel and the public.	Protection Relay Replacement Program
Meter Replacement Program	This engineering report outlines the meter asset management framework that will be used for the Metering Equipment Asset Replacement program for the next AER regulatory control period from 2015 - 2020.	Replace MT End of Life Replace MT In Situ Replace MT Obsolete
Meter Configuration Management System	This report details the issues and requirements to implement a Meter Configuration Management System to provide ongoing supply chain cost reductions and improvements in work process efficiency and customer service.	Metering Configuration Management

6. Models and Explanatory Documents

Name	Description
CBRM Models	Condition Based Risk Management tool – a proprietary system developed by EA technology Pty Ltd. *Supporting documents provided:* • A CBRM Data Collecting Tool - CB • B CBRM Data Collecting Tool - TX • C1 CBRM Data Collecting Tool - CT • C2 CBRM Data Collecting Tool - VT • D CBRM Data Collecting Tool - Isolator • E CBRM Data Collecting Tool - Capbank
Line Asset Defect Management Methodology	This report sets out the methodology for forecasting expected volumes of asset defects for the 2015-20 regulatory control period based on historical performance. It describes Ergon Energy's practices, plans, and forecasts for the management of defects on the overhead and underground distribution and sub transmission network.
Line Asset Defect Management Model	This purpose of this model is to forecast expected volumes of line asset defects for the 2015-20 regulatory control period based on historical performance. The outcomes of this model are supported by the Replace Defect Management Business Case.
Repex Model	An AER initiative, provides replacement forecasts based upon actual historical performance. *Supporting documents provided:* • Repex Model Mk III Base Case • Repex Model Mk III 5Yr Repl Rate_Cost • Repex Model Mk III 4Yr Repl Rate_Cost • Repex Model Mark III Data Input_Output
Repex Model Mark III Report 2013-14	This report describes the purpose, inputs, workings and outputs of Ergon Energy's Repex model and compares the outputs of the model to Ergon Energy's proposed capital expenditure forecast for the 2015-20 regulatory control period.