Appendix B: Capital expenditure forecasts for Standard Control Services

Introduction and summary of changes

Our capital expenditure forecasts are focused on continuing to give our customers a safe, dependable service, and increasingly greater choice and control as our industry and the marketplace evolves. Our challenge is to deliver this while taking the pressure off electricity prices.

In considering our investment plans, we have looked at our cost drivers and the other challenges our people face in meeting our customers' expectations – both those that are unique to Ergon Energy and common to the industry.

Due to a very different growth profile to what was forecast at the time of the last distribution determination, and the low growth economic scenario we are using for our forward planning, our capital expenditure will be lower in 2015-20 – totalling $3.4 billion.

Customer benefits

Our capital expenditure program is critical to delivering on our service commitments to regional Queensland – most importantly to our safety and reliability commitments. It is also core to our disaster management and storm/outage response capability and to evolving the network to best support customer choice in economic electricity supply solutions.

Our goal for our safety performance is to stand with the best in our industry… to always be SAFE.

We'll maintain recent overall improvements in power supply reliability… and continue to improve the experience of customers who are suffering outages well outside our standards.

Getting our new connection forecasts right is also vital to us playing our part in powering economic growth – and making it easier to connect to the network.

Appendix B: Capital expenditure forecasts for Standard Control Services

1 Overview

Our total proposed capital expenditure for the regulatory control period 2015-20 is lower than the actual capital expenditure we expect to incur in the regulatory control period 2010-15 and lower than our October Regulatory Proposal. The total capital expenditure Ergon Energy requires to meet the capital expenditure objectives in the regulatory control period 2015-20 is provided below.

Table 44: Forecast capital expenditure, 2015-20[102]

$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Capital expenditure	779,006	716,381	666,324	643,423	636,128	**3,441,260**

This appendix outlines:

- why Ergon Energy incurs this level of capital expenditure, and the various categories of expenditure that make up Ergon Energy's capital program
- our level of capital expenditure in the regulatory control period 2010-15 and how it compares to the efficient level of capital expenditure set by the AER for that period
- factors influencing our capital expenditure in the regulatory control period 2015-20, including the move to new security criteria
- our methodology, approach and assumptions underpinning our forecasts
- outcomes for customers as a result of our forecasts
- how our capital expenditure forecasts satisfy the capital expenditure criteria, having regard to the factors outlined in the NER.

Appendix E separately details our proposal in relation to the need for the AER to apply a transition path in the scenario where the AER rejects our proposal and substitutes it with a much lower forecast.

2 Components of our capital expenditure requirement

We distinguish between two types of capital expenditure – system and non-system capital expenditure. The components of each one are illustrated in Figure 14 and discussed further below.

[102] Reflects the total gross capital expenditure for Standard Control Services, including customer contributions related to connection services classified as standard control (small customer connections).

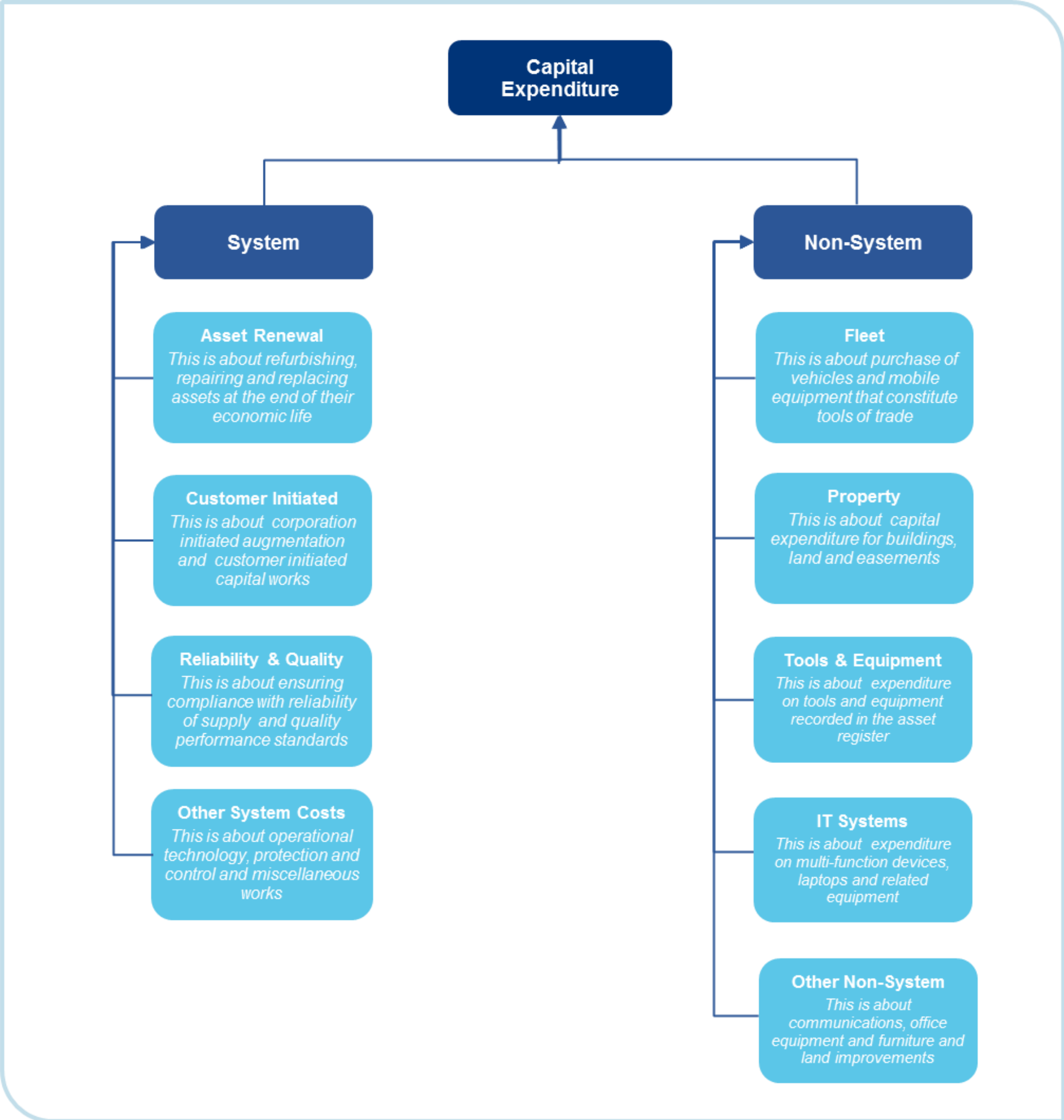

Figure 14: Components of our capital expenditure requirement

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 our service performance, and to maintain the reliability and quality of supply required by technical standards. Asset Renewal capital expenditure therefore 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 work. Our *Asset Renewal Expenditure Forecast Summary* supporting document[103] is an important reference document which explains this category of expenditure in more detail.

Corporation Initiated Augmentation (CIA) capital expenditure is expenditure that is required to augment or reinforce capacity on our shared subtransmission and distribution network in response to increased customer demand. Without this expenditure, or non-network alternatives, we can

[103] *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*.

exceed our network's existing capacity and fail to comply with our security of supply requirements, MSS and requirements of the NER and *Electricity Act 1994 (Qld).* Our *CIA Expenditure Forecast Summary* supporting document[104] is an important reference document which explains this category of expenditure in more detail.

Customer Connection Initiated Capital Works relates to works to service new or upgraded customer connections requested by our customers. We have a legislative obligation, as far as is technically and economically practicable, to connect customers to our distribution network. This expenditure involves work that is to be undertaken by us, someone acting on our behalf or by real estate developers or other service providers, where the assets are subsequently gifted to Ergon Energy. Our *Customer Connection Initiated Capital Works Expenditure Forecast Summary* supporting document[105] is an important reference document which explains this category of expenditure in more detail.

Reliability and Quality of Supply capital expenditure involves two parts. Our reliability capital expenditure relates to works directly targeted at addressing reliability of supply issues in order to meet mandated reliability obligations and to improve the performance experienced by customers supplied by a consistently poor performing feeder or feeder section. Our quality improvement capital expenditure relates to works to comply with mandatory quality of supply obligations in accordance with existing statutory requirements and future regulatory performance standards and targets. Our *Reliability and Quality of Supply Expenditure Forecast Summary* supporting document[106] is an important reference document which explains this category of expenditure in more detail.

Other System capital expenditure encompasses capital expenditure that does not conventionally align to the above capital expenditure categories and their drivers. We break our other system capital expenditure down into the three sub-categories: operational technology; protection and control; and miscellaneous works. Our *Other System and Enabling Technologies Expenditure Forecast Summary* supporting document[107] is an important reference document which explains this category of expenditure in more detail.

Our non-system capital expenditure comprises the following categories:

- **Fleet capital expenditure –** purchases of vehicles and mobile equipment that constitute tools of trade (refer to our *Fleet Expenditure Forecast Summary* supporting document[108])
- **IT System capital expenditure –** expenditure on multi-function devices, laptops and related equipment that are not provided by SPARQ (refer to our *ICT Expenditure Forecast Summary* supporting document[109])
- **Property capital expenditure –** non-system capital expenditure for buildings, land and easements (refer to our *Property Expenditure Forecast Summary* supporting document[110]).

Separate to these categories of expenditure are purchases of tools and equipment necessary for providing Standard Control Services that are over $1,000 and are recorded in the asset register in

[104] *07.00.02 – (Revised) Ergon Energy CIA Expenditure Forecast Summary.*
[105] *07.00.03 – (Revised) Ergon Energy Customer Connection Initiated Capital Works Expenditure Forecast Summary.*
[106] *07.00.05 – (Revised) Ergon Energy Reliability and Quality of Supply Expenditure Forecast Summary.*
[107] *07.00.04 – (Revised) Ergon Energy Other System and Enabling Technologies Expenditure Forecast Summary.*
[108] *07.00.06 – (Revised) Ergon Energy Fleet Expenditure Forecast Summary.*
[109] *07.00.07 – (Revised) Ergon Energy ICT Expenditure Forecast Summary.*
[110] *07.00.08 – Ergon Energy Property Expenditure Forecast Summary.*

the categories of tools and ladders. Expenditure on communications, office equipment and furniture as well as land improvements which are not allocated to a specific category of expenditure are also included in the overall forecast.

Table 45 provides Ergon Energy's forecast capital expenditure for each year of the regulatory control period 2015-20, disaggregated by program of expenditure.

Table 45: Proposed capital expenditure, 2015-20

$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset Renewal	305,512	289,124	253,566	278,571	277,071	1,403,845
Corporation Initiated Augmentation	166,167	169,345	170,606	125,573	128,922	760,613
Customer Connection Initiated Capital Works	216,795	227,608	238,744	246,730	253,990	1,183,868
Reliability and Quality of Supply	3,133	3,235	3,317	3,347	3,365	16,396
Other System	40,966	29,994	19,192	26,714	23,679	140,544
Non-System	144,433	101,095	91,179	77,618	68,641	482,965
Gross capital expenditure	**877,006**	**820,401**	**776,604**	**758,553**	**755,668**	**3,988,230**
less Alternative Control Services customer contributions	*(98,000)*	*(104,020)*	*(110,280)*	*(115,130)*	*(119,540)*	*(546,970)*
Standard Control Services gross capital expenditure	**779,006**	**716,381**	**666,324**	**643,423**	**636,128**	**3,441,260**
less Standard Control Services customer contributions	*(29,620)*	*(30,810)*	*(32,030)*	*(32,820)*	*(33,520)*	*(158,800)*
Standard Control Services net capital expenditure	**749,386**	**685,571**	**634,294**	**610,603**	**602,608**	**3,282,460**

Note the forecast annual capital expenditures have been adjusted to reflect the following:

- some of the Standard Control Service non-system assets are also used in the provision of services other than Standard Control Services
- Customer Connection Initiated Capital Works includes customer contributed assets, which provide Standard Control Services (once commissioned and energised). Contributed assets may be in the form of:
  - cash or gifted assets arising out of connection services classified as Standard Control Services (such as small customer connections)
  - assets gifted to or constructed by Ergon Energy relating to connection services classified as Alternative Control Services (such as major customer and real estate development connections).

The 'net capital expenditure' above reflects our forecast of capital expenditure that is not otherwise funded through customer contributions, and is therefore required to be funded through our revenue cap and DUOS charges.

Table 46 shows that our total net capital expenditure over the regulatory control period 2015-20 is expected to be 3.37% lower than our October Regulatory Proposal.

Table 46: Comparison between October and revised Regulatory Proposals, capital expenditure, 2015-20

$'000 (real 2014-15)	October Regulatory Proposal	Revised Regulatory Proposal	% difference
Asset Renewal	1,358,064	1,403,845	3.37%
Corporation Initiated Augmentation	790,490	760,613	(3.78%)
Customer Connection Initiated Capital Works	1,188,935	1,183,868	(0.43%)
Reliability and Quality of Supply	17,528	16,396	(6.46%)
Other System	148,872	140,544	(5.59%)
Non-System	603,341	482,965	(19.95%)
Gross capital expenditure	**4,107,231**	**3,988,230**	**(2.90%)**
less Alternative Control Services customer contributions	(551,940)	(546,970)	(0.90%)
Standard Control Services gross capital expenditure	**3,555,291**	**3,441,260**	**(3.21%)**
less Standard Control Services customer contributions	(158,260)	(158,800)	0.34%
Standard Control Services net capital expenditure	**3,397,031**	**3,282,460**	**(3.37%)**

2.1 Summaries of our expenditure by category

Our Regulatory Proposal suite includes a series of summary documents which provide sufficient detail around the basis of the forecasts for each capital expenditure category. We also provide further supporting evidence to meet the necessary requirements under the NER. Figure 15 below outlines the relationship between this appendix and other supporting documentation.

The remainder of this appendix covers expenditure at the total level.

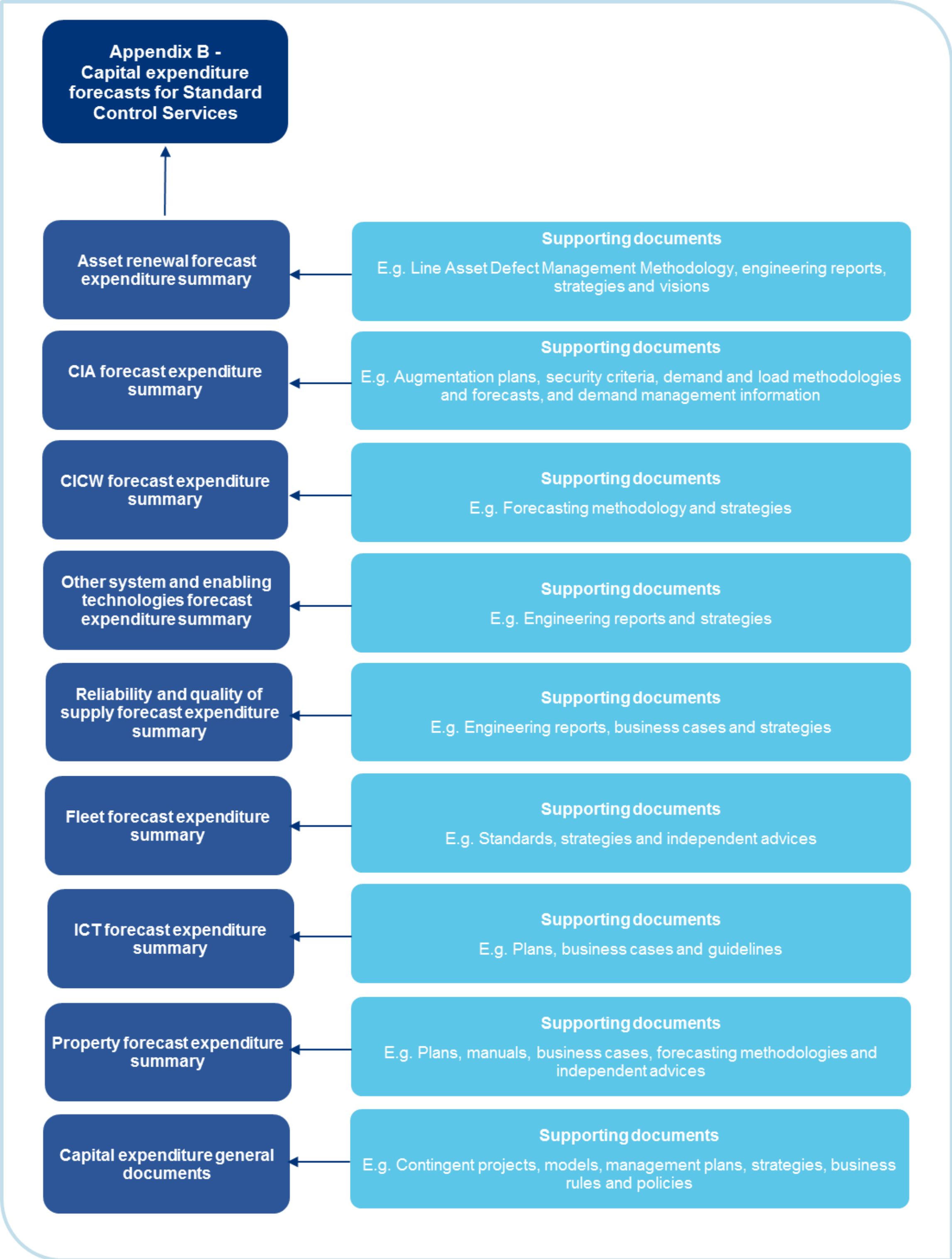

Figure 15: Capital expenditure documentation suite

3 Prior period performance

Table 47 and Table 48 provide Ergon Energy's actual expenditure for each year of the previous two regulatory control periods, disaggregated by program of expenditure.[111]

For comparison purposes, we have categorised this information in the same way as the capital expenditure forecast set out in Table 45. Information provided for both regulatory control periods are based on the CAM applying in the regulatory control period 2010-15.

Table 47: Capital expenditure by category, 2005-10[112]

$'000 (real 2014-15)	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Asset Renewal	202,072	169,549	126,560	147,830	159,968	805,979
Corporation Initiated Augmentation	149,886	218,522	293,104	290,949	222,628	1,175,088
Customer Connection Initiated Capital Works	249,460	349,158	331,307	323,686	270,155	1,523,766
Reliability and Quality of Supply	8,797	13,225	16,076	9,467	12,452	60,017
Other System	24,823	13,359	33,491	56,320	22,659	150,653
Non-System	186,312	169,571	143,591	106,764	102,286	708,526
Gross capital expenditure	**821,350**	**933,384**	**944,129**	**935,016**	**790,148**	**4,424,028**
less Alternative Control Services customer contributions	*0*	*0*	*0*	*0*	*0*	*0*
Standard Control Services gross capital expenditure	**821,350**	**933,384**	**944,129**	**935,016**	**790,148**	**4,424,028**
less Standard Control Services customer contributions	*(45,692)*	*(51,887)*	*(83,333)*	*(107,879)*	*(67,290)*	*(356,080)*
Standard Control Services net capital expenditure	**775,659**	**881,497**	**860,796**	**827,137**	**722,859**	**4,067,948**

[111] NER, S6.1.1(6).

[112] Figures may not directly reconcile to figures set out in supporting documents due to differences in source data and assumptions.

Table 48: Capital expenditure by category, 2010-15

$'000 (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Asset Renewal	228,371	266,667	289,671	229,834	281,047	1,295,590
Corporation Initiated Augmentation	148,225	175,096	152,173	165,888	146,671	788,054
Customer Connection Initiated Capital Works	204,234	197,787	209,593	207,267	159,499	978,381
Reliability and Quality of Supply	22,327	28,275	24,577	32,868	53,545	161,592
Other System	84,657	56,464	37,934	35,932	45,356	260,344
Non-System	156,394	149,502	135,604	95,125	124,965	661,590
Gross capital expenditure	**844,208**	**873,792**	**849,552**	**766,915**	**811,083**	**4,145,551**
less Alternative Control Services customer contributions	*0*	*(2,248)*	*(8,914)*	*(27,729)*	*(17,950)*	*(56,841)*
Standard Control Services gross capital expenditure	**844,208**	**871,544**	**840,638**	**739,187**	**793,133**	**4,088,710**
less Standard Control Services customer contributions	*(75,854)*	*(59,023)*	*(71,117)*	*(61,340)*	*(58,720)*	*(326,053)*
Standard Control Services net capital expenditure	**768,354**	**812,521**	**769,521**	**677,846**	**734,413**	**3,762,656**

Figure 16 compares Ergon Energy's actual and estimated capital expenditure for the regulatory control period 2010-15 with the AER's allowance for this period.

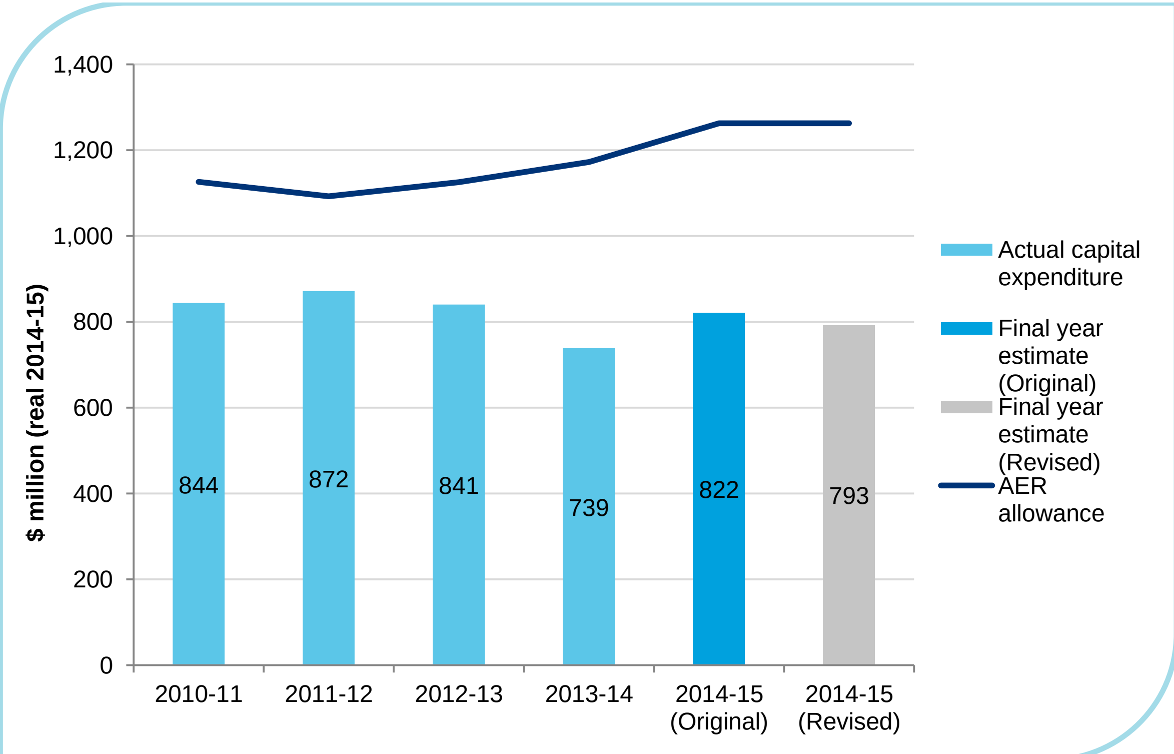

Figure 16: Comparison of capital expenditure, 2010-15

3.1 Expenditure outcomes in 2005-10

Our expenditure profile reflects that from early 2000 Ergon Energy was investing heavily in the network in response to population growth and in an effort to meet our customer's changing expectations around reliability and quality of supply; driven by the uptake of lifestyle appliances.[113] Additional network investment was required from 2004, to meet the higher reliability standards introduced in response to the Electricity Distribution Service Delivery (EDSD) Review.[114]

To achieve the higher reliability standards, each of the Queensland DNSPs had to undertake a number of measures. For Ergon Energy, this meant the obligation to achieve N-1 security on bulk supply substations and large zone substations (5MVA and above) and sub-transmission feeders. Steps also needed to be taken to improve network planning processes, improve maintenance programs and to better communicate with customers on network outages. While it was acknowledged by the EDSD Panel at the time that these recommendations would result in significant capital and operating expenditure, the impact of these reforms on price was not fully understood.

At the time of Ergon Energy's Regulatory Proposal for the regulatory control period 2010-15, the key drivers for Ergon Energy were expected to be continued growth in peak demand driven by economic and population growth in regional Queensland, continued investment to meet increasing reliability obligations and reasonable customer expectations for the safety, quality and reliability of their power supply. Further, our customers had just started to develop an interest in energy supply alternatives, both to procure and use electricity and the introduction of new government initiatives were unclear.

3.2 Expenditure outcomes in 2010-15

As outlined in earlier sections of this appendix, we expect our total capital expenditure for the regulatory control period 2010-15 to be considerably lower than the approved AER allowance.

This outcome has been driven by:

- our responsiveness to changing market and economic conditions to prudently avoid or defer unnecessary and costly capital investment in the network
- successful deferment of considerable network investment due to our demand management initiatives.

Our aim has been to ensure that our investment program did not further exacerbate affordability issues and to avoid incurring cost for work that was not required due to the lack of associated load or demand drivers.

We have also passed on to customers a series of network revenue reductions as a result of the 2011 Electricity Network Capital Program (ENCAP) Review, and absorbed costs associated with Cyclones Yasi, Oswald and Marcia.

During the regulatory control period 2010-15, Ergon Energy also worked closely with Energex and our Queensland Government shareholders to enable the distribution networks in Queensland to transition away from the deterministic EDSD Review N-1 security standards. This will help deliver

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[113] Ergon Energy (2007), *Annual Report 2006-07,* p19.

[114] Our supporting document *0A.01.02 – (Revised) Ergon Energy's Journey to the Best Possible Price* provides further detail.

improved pricing outcomes for customers and reduce the level of network capital investment required in the long-term.

Non-network capital expenditure (especially in the areas of fleet and property) was also subject to significant scrutiny to ensure the levels of expenditure in these areas were kept to an absolute minimum level. Expenditure levels in these areas were reduced during the regulatory control period 2010-15 relative to the approved AER allowance, without compromising on safety, reliability or our ability to deliver services to our customers and to respond effectively to outages or weather driven disruption events.

Based on the latest available assessment of the impacts of the changes in our security and network planning criteria contained in our new Distribution Authority (effective from 1 July 2014) and our forward planning for non-network expenditure, we expect that our overall capital expenditure for this period will be approximately $1.69 billion (real $2014-15) less than the AER approved total capital expenditure allowance.

We have continued to position our expenditure in 2014-15 to ensure we deliver on our customer commitments for the regulatory control period 2010-15 and to deliver the best possible price outcome for the start of the regulatory control period 2015-20. Our expenditure profiles have shifted as we make efficient capital and operating expenditure trade-offs and update key project and program delivery milestones as we address priority investment needs and safety and compliance requirements.

Consistent with our gated governance investment framework, we have continually reviewed and scrutinised the quantum and timing of our future investment needs and priorities for the 2014-15 year. Investments were reviewed against a range of criteria including NER requirements, transitioning to our new security criteria, safety net and Value of Customer Reliability approach, significant weather events (e.g. Cyclone Marcia), safety, compliance and applicable external factors and market conditions.

The following parts of this Section 3 contain greater detail on our performance during the regulatory control period 2010-15 and the challenges we faced.

3.3 Changes to the external environment from 2010

Within 12-18 months of the regulatory control period 2010-15 many of these drivers and assumptions had materially changed due to one or more of the following factors acting independently or collectively:

- weaker global economic conditions. While both Queensland and the rest of Australia have experienced slower economic growth in recent years, the moderation in growth has been more pronounced in Queensland.
- the effect of severe weather in 2010-11, which flooded mining operations, also had a specific effect in Queensland (and was not replicated in the rest of Australia).[115]
- the subsequent high Australian dollar dampened trade-exposed economic activity, particularly in the manufacturing sector.

[115] Queensland Commission of Audit (2013), *Final Report – Volume 2,* February 2013, p5.

3.4 Affordability, customer concerns and how it resulted in reduced expenditure in the previous period

The full cost of the capital investment programs to address the EDSD recommendations was passed through to customers and this began to have a significant impact on network prices and, ultimately retail prices. This impact on network prices was greater than initially anticipated at the time the standards were introduced. Other policy changes such as the one-off effects of moving to the network plus retail (N+R) framework for setting regulated retail prices[116] and renewable energy policies (e.g. Solar Bonus Scheme) also contributed to higher electricity prices.

Climate change policies and subsidies for rooftop solar photovoltaic (PV) installations have led to a rapid increase in the number of households and businesses with solar PV. The installation of solar PV had a twofold effect on the network:

- It introduced an additional source of power for which, in the main, the networks were not designed for. This created immediate engineering, policy and regulatory issues.
- The pattern of solar generation is such that the peak demand has not significantly dropped, whereas overall consumption has. The net effect was that Ergon Energy was still investing in some parts of the network to cater for the peak, yet there was substantially less units of electricity being distributed.

Consumption patterns have therefore changed markedly since 2010, as a result of higher prices for electricity, the adoption of strategies to enhance energy efficiency and broad take-up of demand management initiatives. As customers have become more concerned about the cost of electricity they adopted measures to reduce usage. While these measures have resulted in an overall fall in consumption they have not necessarily resulted in reduced retail bills. Queensland households therefore became increasingly price sensitive as a result of substantial ongoing electricity price rises, seeking alternatives to consuming more energy which only lead to frustration as energy bills rose further to counter for global reductions in consumption.

In response to this, Ergon Energy realised that an immediate and proactive response was required to address the electricity affordability issue rather than wait until the end of the regulatory control period 2010-15.

In recognition of the cost pressures created by the higher reliability standards introduced following the EDSD Review, we investigated alternative methods for achieving security of supply on the distribution network that may be more cost effective and efficient in the long-term. Based on this work and our belief that greater flexibility was required to adapt to change and deliver value and choice to our customers, we commenced discussions with the Queensland Government and made submissions for a change in the policy settings.[117] The ENCAP Review ultimately recommended a relaxation of the security criteria (N-1) and changes to MSS which resulted in around $709 million in capital expenditure reductions compared to the original AER allowance for 2010-15.[118]

In response to the ENCAP Review, Ergon Energy received a direction notice on 11 February 2012 from the Queensland Government to not recover the capital expenditure savings identified in the

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[116] Notified Prices for 2012-13 were the first set of retail tariffs that had been determined on the basis of the N+R methodology.

[117] Ergon Energy (2011), *Submission to the Electricity Network Capital Program Review – Somerville Review Panel*, 31 October.

[118] Ergon Energy identified capital savings totalling $930 million over the regulatory control period 2010-15 although the total saving is offset by $220 million in additional costs, resulting in a net saving of around $709 million. Queensland Government (2011), *Electricity Network Capital Program Review 2011: Detailed report of the independent pane,* p73, http://www.business.qld.gov.au/__data/assets/pdf_file/0018/9117/ENCAP_Review_Final_Report_3_new.pdf.

ENCAP Review. As a result, Ergon Energy reduced our network charges by $99.18 million in 2012-13 and 2013-14.

In May 2012, the Queensland Government established an Interdepartmental Committee on Electricity Sector Reform with a view to ensuring:

- electricity in Queensland is delivered in a cost-effective manner to customers
- Queensland has a viable, sustainable and competitive electricity industry
- electricity is delivered in a financially sustainable manner from the Queensland Government's perspective.

In response, we undertook an additional review of our program of works and further reduced our capital expenditure.

3.5 Our performance outcomes

Maximum (or peak) demand

Our maximum demand during the regulatory control period 2010-15 has remained steady – significantly less than either we or the AER anticipated. Figure 17 shows the trend in our monthly maximum demand since 2001 in total and across our northern, central and southern regions.

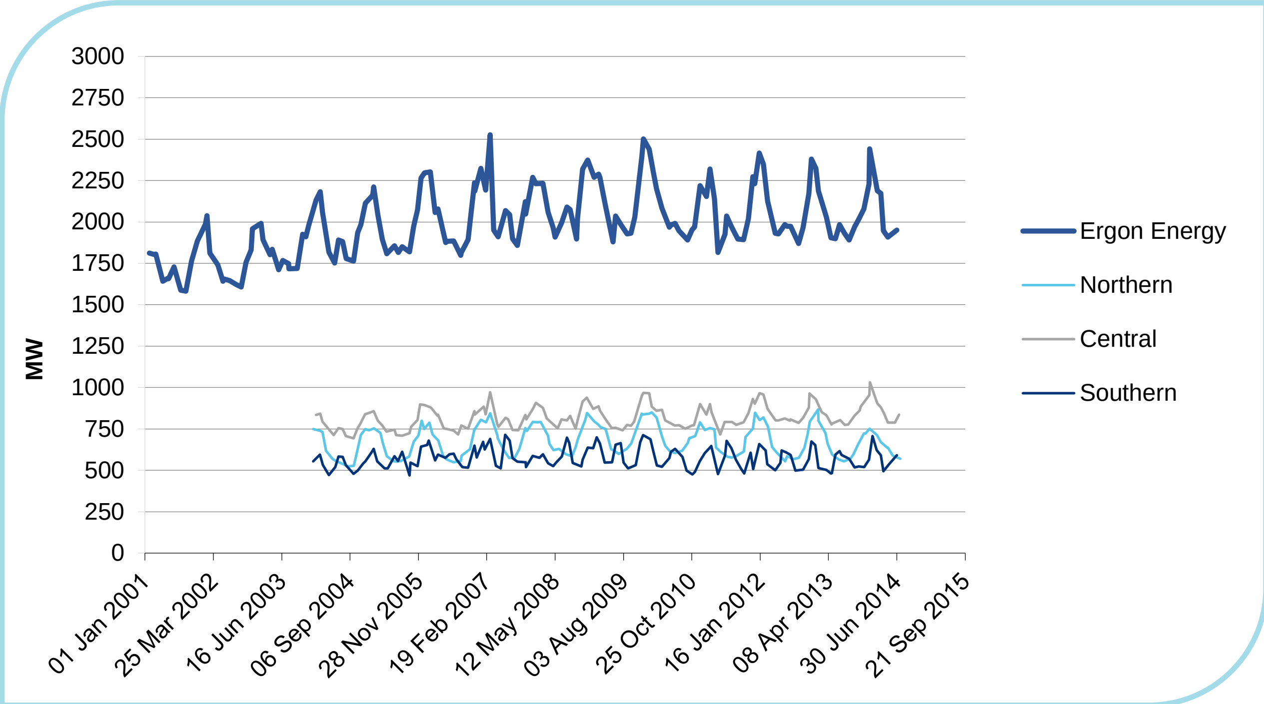


Figure 17: Monthly maximum demand

In the regulatory control period 2010-15, our aggregate maximum demand peaked in 2013-14 at 2,441MW. This represents a 5.3% increase on 2010-11 levels but a 3.4% decrease on 2008-09 levels, which was the peak of the previous regulatory control period. Due to a combination of factors, including the impact of the global financial crisis on the Queensland economy, the rate of growth in electricity demand slowed significantly over 2010 and 2011. Peak demand at this time was also impacted by cyclone events, milder summer temperatures and changes to energy consumption.

Customer connection numbers

Table 49 shows that our customer connection numbers have increased by 1.62% per annum for the four years of the regulatory control period 2010-15 to date. Residential customer connections have increased on average by 1.41% per annum and non-residential customer connections have increased on average by 2.72% per annum.

Table 49: Customer numbers, 2010-14

	2010-11	2011-12	2012-13	2013-14
Residential customer numbers	577,958	585,538	595,439	607,276
Annual residential customer growth rate	1.24%	1.31%	1.69%	1.99%
Non-residential customer numbers	111,001	113,726	114,992	114,654
Annual non-residential customer growth rate	4.61%	2.45%	1.11%	(0.29%)
Total customer numbers	688,959	699,264	710,431	721,930
Annual growth rate	1.77%	1.50%	1.60%	1.62%

The actual average annual growth rate of 1.62% is slightly higher than our forecast annual total customer growth rate for the regulatory control period 2010-15 of 1.58%, which we detailed in our Regulatory Proposal for 2010-15.[119]

Asset age

Our assets age at different rates, depending on their components, location, use, exposure to climatic conditions and history. While our average asset lives are within reasonable averages, we do face significant ongoing expenditure on assets that are approaching or have reached the limits of their viable lives.

Reliability

Over the last five years the performance of the network has significantly improved. While weather conditions always play a part in reliability outcomes, this significant achievement is a result of a substantial investment in network improvements over the past decade, and the dedication of our people.

With the cost of electricity now such a significant issue for our customers, and given our improved performance, we no longer consider reliability improvement investment of this scale warranted. Our customers are now generally satisfied with the supply standards they receive.

We now see our challenge is to maintain reliability standards overall, while continuing to address areas of the network that are underperforming. Around 7% of our customers are supplied by sections of the network that are well outside the performance standards.

Our position also reflects changes to our Distribution Authority, which was modified in line with our customers' expectations in July 2014.

[119] Refer Table 39. Ergon Energy (2009), *Regulatory Proposal to the Australian Energy Regulator, Distribution services for period 1 July 2010 to 30 June 2015*, 1 July 2009, p150.

Up until 1 July 2014, the Queensland Electricity Industry Code set out the MSS levels that we must meet for our reliability performance.[120] These are expressed as annual limits for our urban, short rural and long rural feeders for the duration and frequency of interruptions (expressed as SAIDI and SAIFI).

Table 50 shows that we met five of our six MSS limits in 2010-11 to 2012-13, and all six MSS limits in 2013-14. In 2014-15, we are expecting to meet five of our six MSS limits, with the long rural SAIDI performance likely to exceed the limit as a result of an unusually active summer storm season across much of western Queensland. Specifically, over the 2014-15 summer storm season the long rural feeders were subjected to a significantly higher number of lightning strikes compared to the past five storm seasons, with 70 per cent more strikes in close proximity to long rural feeders compared to the historical average.

Table 50: Reliability performance, 2010-15

		2010-11	2011-12	2012-13	2013-14	2014-15 (estimate)
SAIDI						
Urban	MSS	149	148	147	146	149
	Actual	148.88	136.28	135.12	118.49	130.69
Short rural	MSS	424	418	412	406	424
	Actual	425.74	391.95	341.44	291.91	371.07
Long rural	MSS	964	948	932	916	964
	Actual	827.35	1,041.58	951.53	798.42	1,078.54
SAIFI						
Urban	MSS	1.98	1.96	1.94	1.92	1.98
	Actual	1.628	1.413	1.493	1.394	1.471
Short rural	MSS	3.95	3.9	3.85	3.8	3.95
	Actual	3.532	3.549	2.977	2.767	3.286
Long rural	MSS	7.4	7.3	7.2	7.1	7.4
	Actual	5.266	7.019	6.246	6.118	7.006

Quality of supply

In the previous regulatory control period 2005-10, Ergon Energy initiated a strategic program of power quality monitoring device installations across the distribution network. The investment in this program continued into the regulatory control period 2010-15 and has to date resulted in the installation of 1,790 monitors across the network.

Consequently, 823 distribution feeders or approximately 67% of the network feeders are now monitored for Quality of Supply disturbances.

The customer outcomes resulting from the improved awareness and response to emerging issues can be demonstrated by the reduction in customer initiated quality of supply complaints received by Ergon Energy since the inception of this strategic program.

Table 51 below provides the annual network asset event records based on customer complaints that relate to quality of supply issues, and breaks this down to show the solar installation initiated

[120] The MSS levels are currently prescribed in our Distribution Authority.

complaints, and the non-solar installation related complaints received by Ergon Energy in the past five years. The early identification and proactive response provided to address emerging quality of supply problems is considered to have been a significant contributor to the improvement across the five-year period.

Table 51: Quality of supply complaints, 2010-15

Year	Quality of Supply complaints	Solar issue complaints	Non-solar complaints
2010-11	950	71	879
2011-12	975	147	828
2012-13	1,398	592	806
2013-14	817	307	510
2014-15 (estimate)	1,260	510	750

Our commitment to seeking alternatives to augmentation investment

We reduced demand management through customer-side initiatives aimed at constrained areas of the network. In the regulatory control period 2010-15, we surpassed our five-year demand management target of 122MVA and are forecast to deliver 135MVA in demand reductions, deferring or avoiding $664 million in capital investment.

Necessary emergency response for significant weather events

A number of significant weather events affected expenditure in the regulatory control period 2010-15. Major restoration works were associated with Tropical Cyclones Yasi (2011), Anthony (2012), Oswald (2012), Ita (2014), Marcia (2015) and the flooding around the Bundaberg and Southern regions of Ergon Energy.

Over this period we have been investing in our network and people to uphold our commitment to “being there after the storm”. These initiatives include hardening the asset base (e.g. undergrounding assets, cost effective elevation of substations), developing advanced monitoring and real time data collection capabilities, and ensuring we have a strong on the ground emergency response and recovery/reconstitution capability. To better target our response, our people are also now supported by the Remote Observation Automated Modelling Economic Simulation technology, which can provide a rapid aerial damage assessment following a major event.

Not only did we respond to these significant weather events, but we did not seek to raise electricity prices as a result of the unforeseen costs we had to incur in responding to these events. Going forward, we are considering financial products to ensure our customers are not exposed to what could potentially be a significant price shock impact, if one or more of Queensland’s coastal population centres were devastated by a major cyclone.

Necessary response to solar uptake

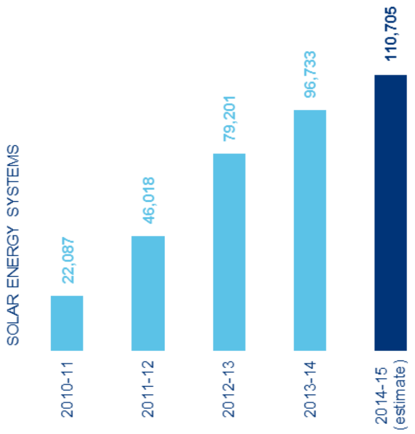
By and large, today’s electricity network is currently geared to a one-way supply from the power station through the ‘poles and wires’ into the customer’s premise.

Increasing the amount of two-way supply, such as when a customer with solar energy feeds energy back into the grid, requires us to invest to modernise the distribution network, and to manage the growing volume of data involved efficiently.

More than one in five households now have solar and, despite declines in government incentives, our customers' intent to purchase or expand on their current solar energy system remains high. Solar energy exports, together with renewable energy from the sugar industry (bagasse) and other sources, are already contributing over 10% of the electricity for our main grid. Twenty-six per cent of Queenslanders have indicated they are looking to either purchase more panels or acquire solar PV in the next two years.

We have already begun to respond to these technical challenges by integrating operational technology with our more traditional network management capabilities in order to optimise business processes, enhance decision-making, reduce costs and lower risks.

CUSTOMER TAKE UP OF SOLAR IS CONTINUING



Over recent years there has been a dramatic jump in customers choosing solar as part of their electricity supply solution; 19.2% of homes now have solar, and support for this technology is continuing.

4 Factors influencing forecasts in 2015-20

There are many factors influencing our capital expenditure forecast requirement for the regulatory control period 2015-20:

- our inherent network area, design, environment and customer base
- existing obligations, rules requirements, plans policies and procedures
- our current performance in key drivers of expenditure for each of our expenditure categories
- our commitments to customers based on our ongoing conversation on what they are looking for from Ergon Energy in the regulatory control period 2015-20.

4.1 Our inherent network area, design, environment and customer base

Our network area

Our distribution network covers 97% of the area of Queensland. Our focus is on customers who live in rural and regional Queensland. There are two specific features that set our distribution network apart from other DNSPs operating in the National Electricity Market (NEM). The first of these is the relatively large amount of sub-transmission network that Ergon Energy has had to build and manage. The second factor is the relatively large proportion of the network that is radial (rather than meshed) in design.

With such a large network area it is inevitable that we experience varying levels of customer density and must distribute electricity across large distances. This has clear implications for both the investment required per customer, and the way we operate. It can make network and non-network costs look higher than other distributors in areas like property and fleet, which are needed to access the assets (for emergency response, pole inspections and vegetation management etc.).

Our network environment

Our network is built, maintained, operated and supported within an area that has a harsh environment and climate. Ergon Energy is seen to exhibit the highest temperature, largest annual rainfall and rainfall variability, as well as the third highest average relative humidity of the Australian DNSPs. We also have high bushfire risks for a large portion of our network area and are unique compared to DNSPs in the NEM with respect to our exposure to cyclones. Further, our network contains the areas that are subject to the most intense (from a wood pole degradation perspective) environment.

The variability of environmental effects within the network presents Ergon Energy with a set of challenges for efficient maintenance of physical assets. Specifically, when a broad range of conditions is to be considered, significant complexity is introduced for development of optimal maintenance schedules and resource allocation.

The climatic conditions while harsh for our network infrastructure can have positive outcomes for customers in the area of alternative energy sources. Queensland has had the greatest uptake of solar power in Australia. Over the period from 2006 to 2013, Ergon Energy experienced a relatively significant decrease in energy density, and the highest increase in peak demand, but (to a greater extent than other DNSPs) is in the position of still having to build, maintain, operate and support a growing peak demand because the overall demand density and energy delivered is increasing.

Our network design

Our network design is also a significant outlier on many metrics, because of our network area. Ergon Energy has more overhead sub-transmission lines than any other Australian DNSP; this is because of the significant potential for voltage drop over the vast distances to be covered, and the boundaries of the Powerlink transmission network. We have the highest line capacity (KVA-kms) per customer and the second lowest percentage of underground network. Huegin's analysis of AER benchmarking data suggests Ergon Energy has a significant number of cost disadvantages, particularly at the inherent and inherited end of the cost driver.[121]

Existing obligations, rules requirements, plans, policies and procedures

Our capital expenditure forecasts for the regulatory control period 2015-20 are developed by applying a series of plans, policies, procedures and strategies that, taken together, achieve the capital expenditure objectives in the NER.

This is because these plans, policies, procedures and strategies ensure that our capital expenditure forecasts have regard for:

- our and our customers' capital expenditure-related outcomes and goals
- our relevant regulatory obligations
- the service standards that we must deliver.

Our supporting document *07.09.17 – Our Capital Governance and our plans, policies and procedures* outlines Ergon Energy's framework for the development and prioritisation of our capital and operational expenditure investment program to meet the expenditure objectives, criteria and factors set out in the NER, supported by a hierarchy of governance bodies and approval authorities

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[121] *0A.02.01 – Ergon Energy Expenditure Benchmarking*.

and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- *01.01.01 – (Revised) Legislative and Regulatory Obligations and Policy Requirements*
- response to the RIN, Templates 7.1 and 7.3.

4.2 Our commitment to customers based on what they told us

The above factors in the regulatory control period 2010-15 have led to our service and price performance to customers. We have asked our customers what they are looking for in the regulatory control period 2015-20. Our commitment to what customers want, in addition to ensuring we can meet relevant requirements of the NER and other regulatory obligations, is largely driving the expenditure program in the regulatory control period 2015-20.

Peace of mind – being always safe

Ergon Energy is committed to ensuring the safety of our customers, the community, employees and contractors. This will see an ongoing investment in control measures around potential life threatening risks, a focus on reducing dangerous electrical events. To maintain the safety (and reliability) of the network we have a significant asset refurbishment and replacement program, including an additional program to address a large volume of conductor clearance issues that have been identified since our October Regulatory Proposal was lodged. Over recent years we've gained a better understanding of the network and addressed significant issues. However, we have more work to do and have proposed a number of specific safety-related asset renewal programs in our Regulatory Proposal. We do not want to risk the network deteriorating unsafely, or safety problems to arise in the future.

We are also planning further investment in the protection and control equipment across our substations and distribution lines, in order to better ensure we adequately protect the community, our people, and the network itself from faults. This will include continuing to add sensitive earth fault protection to our high voltage feeder lines and addressing a safety issue associated with our older zone substations and how the auxiliary power is supplied for use in the substation itself.

The proposals around our operational technology investment will also support network operations in delivering positive safety outcomes.

In our Regulatory Proposal we are also seeking an allowance to help maintain high standards of environmental performance. We are continuing to progressively address transformer sites, which have been found to be without adequate oil containment protection, by installing oil separation and containment measures.

More detail on our renewal investment program can be found in *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*.

Peace of mind – reliability and quality of supply

We have enhanced our demand forecasting, and governance protocols to be as prudent as possible in this area of investment in the network. We will seek to avoid the potential for network limitations that could impact security of supply, and ultimately reliability performance by using the most cost effective way to respond to constraints on the network. Increasingly this is through the use of non-traditional alternatives to system augmentation.

Our areas of Central and Southern Queensland service some of Queensland's largest energy users. Several of these resource companies are developing and proposing to develop LNG fields in the Darling Downs and west of Clermont, and demand is expected to be driven upwards as local service centres grow to supply accommodation and support industries. Port development is also expected to add considerable load.

At the substation level, we are applying new network planning criteria, which consider the customer value of the investment from a reliability perspective and applies a safety net based on the potential impact of a single event. We will continue to assess this approach as we move forward to best balance our customers' expectations around reliability and price.

At the distribution level, in addition to addressing localised demand, we are forecasting augmentation investment to specifically deal with voltage-driven constraints and conductor clearance issues.

We have allocated expenditure to address the performance of up to 45 feeder lines that are consistently underperforming.

To best target efforts towards our customers who are consistently experiencing supply interruption duration well beyond the MSS, we will review reliability outcomes annually, along with the solutions that are most cost effective.

We also plan to continue installing power quality monitors across the network so that we can proactively address momentary outages and voltage issues. Around two thirds of our distribution feeder lines are now monitored for power quality. Our proposal is to invest in a further 1,120 power quality monitors and an additional 100 power quality analysers.

Our asset renewal approach is aimed at reducing the risk of faults (both from a reliability and safety perspective) for the lowest whole-of-life cost. To do this efficiently we are continuing our investment in our condition monitoring capability to give us a better understanding of the state of the network. We are planning a significant replacement or refurbishment investment across our substation and powerline assets as well as for a range of other obsolescent technologies (including our radio communication network.

More information on our plans to ensuring reliability and quality of supply can be found at:

- *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*
- *07.00.02 – (Revised) CIA Expenditure Forecast Summary*
- *07.00.03 – (Revised) Customer Connection Initiated Capital Works Expenditure Summary*
- *07.00.04 – (Revised) Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.05 – (Revised) Reliability and Quality of Supply Expenditure Forecast Summary*.

Peace of Mind – being there after the storm

In preparation for each storm season, we will continue to routinely review our summer preparedness and improve our emergency management response capability. Our summer storm safety communications program will also continue and we will ensure our contact centre has the capacity to handle the call load following a major event when our customers need us the most.

Our expenditure in non-network assets across our vast service area, including our investment program in property, fleet, equipment and tools, remains critical to our people in delivering on our emergency response. They also have access to a significant mobile generation and substation capability.

Our focus on enhancing the resilience of the network to the impact of storms is continuing through our asset refurbishment and replacement programs, and through targeted initiatives. For example, we are installing 'spreaders' (insulated rods) as a cost effective solution to prevent lines clashing during high winds and retrofitting fuses to protect against electrical overload.

More information on our plans to ensuring our resource capability for emergency response can be found at:

- *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*
- *07.00.06 – (Revised) Fleet Expenditure Forecast Summary*
- *07.00.08 – Property Expenditure Forecast Summary.*

Choice and Control

In order to respond to the needs of our customers, and a changing industry and marketplace, we are progressively developing a 'smarter' grid and creating an open access platform that enables distributed energy resources and other applications to easily connect with our network to enhance customer choice.

We plan to be proactive, with investment in improving our real time data on network status, which will support better operational management decisions. This approach is necessary to support the change in the way customers are using the network. It will also allow us to achieve greater network utilisation (and potentially defer or avoid costly network investment), as well as general operational efficiencies. This capability, coupled with other voltage management initiatives, is particularly important in ensuring we can manage the network voltage issues associated with a higher penetration of solar energy systems.

To take advantage of this smart technology, we are targeting investment in new operational technology capabilities. This includes further investment in our distribution and outage management system, our SCADA control system and demand management system, as well as in telecommunications infrastructure.

More information on our plans to future proofing our network and business to give customers more choice and control can be found at:

- *07.00.04 – (Revised) Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.07 – (Revised) ICT Expenditure Forecast Summary*.

Best Possible Price

To support further efficiencies, over the next five-year period, we are implementing new technology-based capabilities, including better information and decision-making tools.

We are currently investing in management systems to enable efficiencies – this covers organisational performance information systems, as well as the systems that manage finance, human resources, safety and procurement. An investment is also continuing to be made in our spatial data and Geographic Information System to enable continued support, while delivering functional improvements.

Technology, and a focus on demand management, has allowed us to move our investment planning approach from being largely based on building more or bigger 'poles and wires' solutions, to a focus on finding the best, most cost-effective solution. Our delivery of 135MVA demand reductions to date over the regulatory control period 2010-15 is a clear demonstration of the capability developed in this area. This is equivalent to removing the demand of 36,000 houses or the demand of a regional city the size of Bundaberg.

We plan to strengthen this capability by progressively expanding the automation within the network. This will enable us to adopt emerging 'smart' technologies in the future that will optimise our ability to efficiently deliver the power supply needs of regional Queensland.

More information on our plans to implement new technology-based capabilities can be found at:

- *07.00.04 – (Revised) Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.07 – (Revised) ICT Expenditure Forecast Summary*.

5 Forecasting method

It is important to outline the methods that we have used to develop our capital expenditure forecasts in order to demonstrate how we meet the capital expenditure objectives set out in the NER. On 29 November 2013, we submitted our Expenditure Forecast Methodology[122] to the AER that detailed how we go about forecasting each of our capital expenditure categories.

This section expands on that methodology. It also briefly explains the AER's approach to determining our expenditure requirement in the regulatory control period 2010-15, and concerns raised by the AER on our previous forecasting approach and how we have addressed them.

5.1 Previous period forecasting

AER approach

In the regulatory control period 2010-15, the AER determined our:

- Asset Renewal capital expenditure based on historical levels
- CIA capital expenditure by adjusting our proposed forecast by applying a lower maximum demand and removing certain projects it considered were not justified
- Customer Connection Initiated Capital Works based on our average historical connection numbers and expenditure levels, escalated by the forecast customer growth rate
- Reliability and Quality of Supply capital expenditure based on historical levels, with an additional allowance for some specific programs
- Non-system capital expenditure by accepting our plant, vehicles, tools and equipment forecasts, removing an IT "change program" and two major property projects, although the Australian Competition Tribunal (the Tribunal) subsequently allowed these property projects to be re-included.

[122] Refer to https://www.ergon.com.au/network/network-management/future-investment/future-direction.

5.2 Our capital expenditure forecasting approach in 2015-20

The process begins with the development of 'category level' expenditure forecasts. The methods that are used for each capital expenditure category are summarised in Section 5.5 below.

Each of the category level forecasts are then consolidated into a total capital expenditure amount and forecast (in nominal $) for the final year of the previous period (i.e. 2014-15) and the five years of the regulatory control period 2015-20. Overheads are applied and allocated at this time. Consistent with the requirements of the NER, the total capital expenditure forecasts are converted into 2014-15 real dollars by applying assumptions about CPI and other cost escalators.

The third step converts the aggregate capital expenditure forecasts (along with other key regulatory inputs) into revenue and pricing outcomes. Both the capital expenditure forecasts and the revenue and pricing outcomes are assessed against a number of factors, including:

- customer expectations regarding pricing and service outcomes, both within the regulatory control period 2015-20 and in future periods
- corporate and stakeholder expectations and commitments in respect of price and service delivery
- compliance with the NER and state imposed regulatory obligations
- current workforce delivery and capacity to deliver works in the regulatory control period 2015-20.

Where the aggregate capital expenditure forecasts or the revenue/pricing outcomes are inconsistent with the customer, corporate, workforce capability or regulatory expectations, refinements are made to the forecast volumes and the costs at the category level.

Prior to final internal approval, we assess the category level forecasts using, among other things:

- benchmarking and category based assessment techniques (such as augex and repex modelling) recommended and used by the AER as part of its own assessment processes
- independent verification of the expenditure forecasting methodology, assumptions and inputs
- historical and trend analysis
- detailed project reviews
- technical assessments
- governance and documentation reviews.

These techniques allow us to internally scrutinise category level forecasts, ensuring that the forecasts are prudent and efficient. Based on the outcomes of these assessments, category level forecasts are revised or substantiated with further evidence before the capital expenditure forecast is finalised.

5.3 Key assumptions

Clauses S6.1.1(4) and S6.1.1(5) of the NER require us to detail the key assumptions that underlie our capital expenditure forecasts and for the directors of Ergon Energy to certify the reasonableness of these assumptions. We consider key assumptions to be substitutes for facts or inputs necessary to prepare forecasts, where those facts or inputs are not known with certainty or cannot reasonably be derived from other data. We have therefore developed a key assumption where it does not otherwise have an objectively verifiable factual basis on which to prepare our capital expenditure forecasts.

Table 52 outlines the key assumptions underpinning our capital expenditure forecasts for the regulatory control period 2015-20, consistent with NER requirements.[123] There have been no material changes since our October Regulatory Proposal. In June 2015, the directors of Ergon Energy reviewed the key assumptions and confirmed their continued application for this revised Regulatory Proposal.

Table 52: Capital expenditure assumptions, 2015-20

Assumption	Application
Our current company structure, ownership arrangements and service classification will continue.	The capital expenditure forecasts are based on continuing the current company structure. Any future restructuring could change Ergon Energy's cost structure and would require changes to our CAM.
We will deliver our forecast capital expenditure for 2014-15.	Based on the best estimates contained in the Submission RIN and excluding the impacts of exogenous events that impact works delivery (e.g. severe cyclones and flooding), we have sufficient internal and external resources and capability to deliver the forecast capital expenditure for 2014-15 and we do not expect that there will be any material works delivery issues in undertaking our capital projects and programs in accordance with our forecast capital expenditure for 2014-15.
Our current legislative and regulatory obligations will not change materially.	The capital expenditure forecasts are designed to comply with the current legislative and regulatory obligations. If any material changes occur, they may be treated as a cost pass through event.
We apply an "economic" customer value based approach to reliability, supported by "safety net" measures – this is in response to a Queensland Government Direction.	The capital expenditure forecasts – in particular, for CIA – have been prepared using these security criteria. We no longer apply deterministic security criteria.
Our MSS in our Distribution Authority will remain at 2010-11 levels until 2019-20.	The capital expenditure forecasts – in particular, for Asset Renewal and Reliability – have been designed to comply with the current MSS requirements set out in our 2014 Distribution Authority. Our current Distribution Authority has set our new MSS levels at the 2010-11 levels that had been previously set by the QCA under the *Electricity Act (1994)* and the Electricity Industry Code.
Actual maximum demand and customer connection growth will not vary materially from our forecasts.	The capital expenditure forecasts – in particular, for CIA and Customer Connection Initiated Capital Works – have been prepared to meet our demand forecasts, and have been informed by a range of factors, including our own market intelligence and customer feedback, and by relying on the best available external forecasts of endogenous variables within our forecast models, and the advice of independent experts on various inputs into these models.

[123] For the original directors' certification, refer to supporting document *06.01.06 – Certification of reasonableness – expenditure forecast assumptions*.

Assumption	Application
We will apply a new Connections Policy – this will replace our Capital Contributions Policy, dated April 2005.	In accordance with the requirements of the NER, our cash contributions and gifted assets in our Customer Connection Initiated Capital Works capital expenditure forecasts reflect our contestability arrangements and are based on this new Connections Policy.
Our contestability arrangements that allow capital works to be undertaken by third parties will continue on the current basis.	The proportions of gifted assets and works undertaken by Ergon Energy in our Customer Connection Initiated Capital Works capital expenditure forecasts reflect our contestability arrangements.
Our forecast capital expenditure is based on our efficient costs for specific investments and programs of work, which are explained in this Regulatory Proposal.	Estimates for specified investments progressively undergo review, refinement, and revision as they progress through our Gated Governance Framework. By contrast, estimated unit costs are developed for 'programs of work' where there is uncertainty about their scope or location, or where there are significant volumes of recurrent activity.
Our parametric insurance will cover the financial impact of extreme wind-generated weather events and our works delivery and expenditure requirements will not be materially disrupted by extreme weather events.	Our capital expenditure forecasts have been prepared on the basis that the proposed inclusion of parametric insurance costs is allowed by the AER. Extreme weather events, such as cyclones or major flood events, can interfere with our ability to implement planned capital expenditure programs such as Asset Renewal.
Our labour, material and other cost escalations are realistic and reasonable.	We have based rate of change factors on existing enterprise agreement precedents (if applicable) and the independent expert advice on labour, material and other costs escalations (refer Jacobs (SKM) report).[124] This approach ensures that these escalators appropriately reflect the increases in the cost of materials and other non-labour inputs, as well as the skills required and the market factors driving the demand and supply of labour for the provision of our services.

5.4 We listened and responded to AER criticisms and concerns in 2010

The AER raised a number of issues in its May 2010 Distribution Determination about our capital expenditure forecasts for the regulatory control period 2010-15. We have implemented a range of measures to address these concerns, as shown in Table 53.

Table 53: Addressing AER concerns in relation to our 2010-15 capital expenditure forecasts

Category	AER concern	How Ergon Energy has responded
Asset Renewal	Asset ages overstate capital expenditure requirements	Enhanced defect classification and maintenance acceptability criteria
	Models use outdated data and have internal inconsistencies	Improved condition monitoring processes and systems
	Volumes do not use suitable data	Forecast volumes based on risk, ongoing maintenance cost, replacement cost, age and asset condition

[124] *06.02.02 – Jacobs: Cost Escalation Factors 2015-20* and *06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20*.

Category	AER concern	How Ergon Energy has responded
CIA	Maximum demand forecast too high	Developed new forecasting methodology incorporating top down and bottom up approaches
	Do not demonstrate efficiency of preferred options	Implemented gated governance framework supported by project business cases
	Cannot reconcile capital expenditure forecasts to plans	Developed clear augmentation plans at sub-transmission and distribution levels
Customer Connection Initiated Capital Works	Do not use prudent forecasting approach	Adopted new forecasting approach based on established macroeconomic indicators
Reliability	Do not demonstrate prudence / efficiency of expenditure, including volumes, benefits and timing	Presented clear justification supported by strategies and business cases
	Overlap with other funding allowances	Presented clear explanation of interdependencies with other allowances

5.5 Expenditure forecasting methodologies by category

This section summarises the expenditure forecasting methodologies that we have used for each category of capital expenditure. This expands on the information that we provided in our Expenditure Forecast Methodology. Further detail is contained in the Forecast Expenditure Summaries that we have prepared for each capital expenditure category.

We use a combination of replace on fail and proactive asset replacement approaches to forecast our **Asset Renewal capital expenditure**. We forecast our costs using standard estimates of replacement for each asset type. We forecast volumes using a combination of:

- discrete engineering analysis of individual projects in order to address specific known needs
- Condition Based Risk Modelling that uses available asset information and complex ageing models to predict asset failure probabilities and associated risks
- simplified predictive models that use statistical relationships between known asset information and future replacement needs, including the AER's repex model and historical trend models.

We forecast **CIA capital expenditure** using a combination of:

- detailed engineering analysis that compares forecast demand and capacity in the sub-transmission and distribution systems in order to identify emerging constraints. We then undertake detailed assessments of the least cost options to address the identified constraints
- the AER's augex model, which is a simplified predictive model that uses information on capacity, utilisation and demand patterns in network segments, and unit costs.

We forecast **Customer Connection Initiated Capital Works** using average historical costs and an econometric model that forecasts volumes using the following State macroeconomic variables: final demand; private investment – dwelling; and private investment – non-dwelling. These variables historically demonstrated the greatest causality and correlation to customer connection outcomes. This aligns with the approach that the AER applied to forecast this capital expenditure for the regulatory control period 2010-15.

We forecast **Reliability capital expenditure** using average historical costs for comparable projects and an assumption that we will deliver three reliability projects each year. We forecast **Quality Improvement capital expenditure** on the basis that in the regulatory control period 2015-20 we will complete the installation of power quality monitors across our three phase and Single Wire Earth Return (SWER) distribution feeders and power quality analysers at our zone substations. These forecasts are also based on historical costs.

We forecast **Other System capital expenditure** on a project-by-project basis using a combination of vendor pricing, historical costs and standard labour rates and material costs.

Fleet capital expenditure is forecast using a model that forecasts the replacement date of vehicles and assets which are part of the Ergon Energy fleet. This model applies a set of replacement parameters to individual vehicle categories. The parameters applied take into account age and usage. The results from the model are a vehicle-by-vehicle lifecycle, from procurement through to replacement.

There are two elements to the **Property capital expenditure forecast**; these are the major and the minor programs. The major program is compiled based on using the Hub and Spoke strategy; with each item of expenditure (largely on property 'hubs') then going through the capital governance process to ensure the best value for money solution is achieved. The minor program (focused on 'spokes') uses optimisation to select the most efficient portfolio of works from all the candidate projects. In the case of the minor program, the candidate projects are largely determined as a result of regular inspections of existing properties.

There are other miscellaneous **Non-system capital expenditure** items relating to tools and equipment, mobile generation and IT equipment that are forecast separately.

5.6 Capital expenditure unit costs

Our supporting documents *07.00.09 – (Revised) Unit Cost Methodologies Summary for Ergon Energy* and *07.09.01 – (Revised) Network Capex Summary Model* note that we apply different approaches to developing our capital expenditure forecast for "specified investments" and our "program of works".

We also use standard unit costs in the development of our ICT (e.g. infrastructure renewal)[125] and fleet[126] capital expenditure forecasts. Details of how program and project estimates are developed for our property investments are outlined in our supporting document *07.00.08 – Property Expenditure Forecast Summary.*

Specified investments

Ergon Energy develops a cost estimate for all specified investments when there is certainty around the constraint, scope, location and timing of the investment. Our estimating system is designed such that as each specified investment progresses through Ergon Energy's Gated Governance

[125] *07.07.03 – ICT Forecasting Method and Approach*.
[126] *07.00.06 – (Revised) Ergon Energy Fleet Expenditure Forecast Summary*.

framework (obtaining financial approval for investments) the estimate progressively undergoes review and refinement and is updated accordingly.

These investments begin with one or more standard estimates. Standard estimates are ready-made estimates based on standard designs and drawings. Estimating specialists create the standard estimates and update these when standard designs change. Effectively these estimates are templates that are modified to accommodate the specific requirements of the investment required.

The repository for these estimates is located in internal IT systems. Standard estimates:

- are sufficiently accurate for forecasting several years ahead
- provide a consistent and efficient basis for producing project cost estimates for works repeatedly undertaken
- includes appropriate structures for estimated direct and known costs and on-costs dependent on its intended use
- exclude the cost of borrowings, unknown costs, and uncertainty allowances.

There are a limited number of specified investments that have not utilised a standard estimate. These exceptions occur when the proposed investment is unlikely to be repeatedly undertaken. An example would be a new specific project such as an IT software purchase.

As a specified project progresses, it moves through five different phases and the estimating system supports the management of this progression. The five phases are Pre-Concept, Concept, Development, Implementation and Finalisation.

Program of works

Where there is some uncertainty in the investment scope, location or if the investment involves significant volumes of recurrent work, we develop our expenditure forecast based on a prediction of volumes multiplied by a unit cost.

The approach adopted to develop each program estimate depends on the availability, comparability and granularity of historical data. Broadly, we apply one of the following three approaches:

- *Historical average cost program estimates* – we develop some program estimates based on an average of recorded historical costs. This is the case when future activities and costs are expected to reflect the historical activities and associated costs. These costs include all direct costs related to the investment such as labour, materials, equipment, mobilisation and contractors' costs. The averaging of these historical costs over multiple years provides a robust estimate of future costs and the program estimate applied to our capital expenditure forecast.
- *Bottom up program (product) estimates* – where historical data is not available or where data is not reflective of future activities or costs, we develop bottom-up program estimates using a scope of work that reflects future activity. Specialist estimators then use the scopes to estimate a unit cost. Depending on the nature of the program and the information available, we assess unit costs against at least one of the following to validate the robustness of each estimate: one-off historic costs; market costs; market estimates; and peer review by our subject matter experts. Estimates are updated for variations in labour rates and material costs.

- *Application of uplift factors* – unlike historical average cost estimates, bottom up program estimates are direct lean costs required to perform the intended activity. We apply appropriate mobilisation and cost uplift factors specific to the program activities.

6 Outcomes for customers

As a result of our investments, we are committing to the customer benefits shown in Table 54.

Table 54: Customer benefits and related risks

Customer benefit	Related risks
Our approach to safety	
• Our goal is for our safety performance to stand with the best in our industry… to be Always Safe. • Our expenditure on renewal, maintenance and network operations are all focused on managing safety risks.	• Unforeseen safety related issues or damage caused by weather events may arise during the period that may result in the reprioritising of expenditure towards addressing them or lead to passing on cost increases in the period following.
A reliable, quality electricity supply	
• We'll maintain recent overall improvements to power supply reliability… and continue to improve the experience of customers who are suffering outages well outside our standards.	• Further reductions to the expenditure proposals, seasonal weather conditions or delivery delays (due to significant weather related events/reprioritisation of expenditure) may impact the reliability performance in some areas. • Improvements in the areas of the network currently requiring attention will need to be prioritised based on the level of available funds. • We will be monitoring the impact of the changes to the way we are managing security of supply to ensure they do not impact to reliability in longer-term.
Our disaster response	
• We'll be there after the storm, prepared and with the resources to respond to whatever Mother Nature delivers.	• If approved, the operational resourcing levels outlined in our Regulatory Proposal will maintain our current emergency response capability.
Meeting service expectations	
• We'll meet our guaranteed services commitments. If we don't, we'll pay you.	• As expectations around choice and control evolve, our service standards, especially in the connections and communications area may need to be reviewed.
A future of customer choice	
• We're looking to the future – and evolving the network to best support customer choice in economic electricity supply solutions.	• We have made assumptions on the rate of industry change in our planning, and the market reforms needed to support it. If the market reforms are ineffective, and/or the rate that customers take up new technologies or the type of technology that emerges is significantly different, our ability to respond could be limited.
The best possible price	
• After reducing charges for the use of our network in 2015-16, we're targeting to keep charges overall at 2014-15 levels for the remaining four years out to 2020. • By separating metering service charges from our network charges, we	• Network charges are only one part of a customer's bill. Other costs will also influence what a customer pays. Adjustments to incentive schemes, or rate of return adjustments could increase or decrease revenues requirements. • For customers on regulated retail prices (Notified Prices) the actual price impact of our Regulatory Proposal will depend on the

Customer benefit	Related risks
are supporting customer choice in providers.	approach the QCA takes in setting prices in the future. • The financial target we have set is a challenge. We will require significant reductions in costs in the future. There is a risk that further reductions would not be sustainable, and may affect service delivery and the safety of the network.

7 Meeting Rule requirements

The NER places obligations on Ergon Energy to provide information to assist the AER make a decision on the total capital expenditure for the period. We believe there is sufficient evidence in this proposal and supporting documents to satisfy the AER that our proposed capital expenditure reflects the capital expenditure criteria.

In addition to the information contained in each capital expenditure category summary document, our supporting document *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* provides substantial detail on:

- why the forecasts enable Ergon Energy to achieve each of the capital expenditure objectives
- why Ergon Energy believes there is sufficient evidence to satisfy the AER that the forecasts meet the capital expenditure criteria.

The approach outlined in *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* remains applicable to this revised Regulatory Proposal. Where applicable or necessary, Ergon Energy has supplied updated information regarding any material changes to our forecasts and the application of the relevant NER requirements in the attachments that support this revised Regulatory Proposal.

8 Supporting documentation

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
Ergon Energy Expenditure Benchmarking	0A.02.01	Ergon Benchmarking
(Revised) Legislative and Regulatory Obligations and Policy Requirements	01.01.01	(Revised) Legislative and Regulatory obligations
(Revised) Meeting Rule Requirements for Expenditure Forecasts	06.01.05	(Revised) Meeting the Rules requirements
Certification of reasonableness – expenditure forecast assumptions	06.01.06	Certification of reasonableness – expenditure forecast assumptions
Jacobs: Cost Escalation Factors 2015-20	06.02.02	Cost Escalation Factors 2015-20 SKM
Jacobs: Addendum Cost Escalation Factors 2015-20	06.02.07	Jacobs Addendum Cost Escalation Factors 2015-20
(Revised) Asset Renewal Expenditure Forecast Summary	07.00.01	(Revised) Asset Renewal Expenditure Forecast Summary
(Revised) CIA Expenditure Forecast Summary	07.00.02	(Revised) Corporation Initiated Augmentation Expenditure Forecast Summary

Name	Ref	File name
(Revised) Customer Connection Initiated Capital Works Expenditure Forecast Summary	07.00.03	(Revised) Customer Initiated Capital Works Expenditure Forecast Summary
(Revised) Other System and Enabling Technologies Expenditure Forecast Summary	07.00.04	(Revised) Other System Enabling Technologies Expenditure Forecast Summary
(Revised) Network Reliability and Quality of Supply Expenditure Forecast Summary	07.00.05	(Revised) Reliability and Quality of Supply Forecast expenditure Forecast Summary
(Revised) Fleet Expenditure Forecast Summary	07.00.06	(Revised) Fleet expenditure forecast summary
(Revised) ICT Expenditure Forecast Summary	07.00.07	(Revised) ICT expenditure forecast summary
Property Expenditure Forecast Summary	07.00.08	Property expenditure forecast summary
(Revised) Unit Cost Methodologies for Ergon Energy Summary	07.00.09	(Revised) Unit Cost Methodologies summary
ICT Forecasting Method and Approach	07.07.03	Expend Forecast Method 2015-2020 Indiv Business Unit ICT
(Revised) Network Capex Summary Model	07.09.01	(Revised) Network Capex Summary Model
Our Capital Governance and our plans, policies and procedures	07.09.17	Governance, Plans, Policies and Procedures
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal. Information provided in our RIN is correct as at the time of our October Regulatory Proposal, unless otherwise stated