



**Forecast Expenditure Summary**  
**Other System and**  
**Enabling Technology**  
**2015 to 2020**



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## About this summary document

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

### 1.1 Nature of Other System capital expenditure

Other System and Enabling Technology (Other System) capital expenditure encompasses capital expenditure that does not conventionally align to the other capital expenditure categories and their drivers. The forecasts address specific issues observed throughout the network and with operation of the network. It also forecasts expenditure required for data and communications networks. Other System capital expenditure is broken down into the three sub-categories:

- Operational Technology (including Control)
- Protection
- Miscellaneous.

### 1.2 Purpose

The purpose of this summary document is to explain and justify Ergon Energy's Other System capital expenditure for its Standard Control Services (SCS) and Alternative Control Services (ACS) 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 Other System capital expenditure forecasts. However, because it is a summary document, it necessarily addresses some matters at a relatively high level and refers out to other documents for further detail.

This summary document provides details of actual, estimated and forecast Other System capital expenditure for the previous (1 July 2005 to 30 June 2010), current (1 July 2010 to 30 June 2015) and next regulatory control periods. All capital expenditure presented in this document is in real 2014-15 dollars, except if stated otherwise.

Importantly, this summary document only explains and justifies Ergon Energy's direct costs for its other system and enabling technologies capital expenditure. Ergon Energy applies real cost escalations and shared costs (overheads) to these direct costs to determine its total other system and enabling technologies 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).

## 1.3 Structure

The remainder of this summary document is structured as follows:

- Section 2 details Ergon Energy's Other System 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 Other System capital expenditure that will be explained and justified in the remainder of this summary document.
- Section 3 focuses on Ergon Energy's Other System capital expenditure in the current period and the performance against the AER's allowance.
  - Sub-sections 3.1 to 3.5 examines why Ergon Energy's Other System 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 4 focuses on Ergon Energy's Operational Technology (including Control) Capital expenditure.
  - Sub-section 4.1 describes the conceptual nature of Ergon Energy's Operational Technology Capital expenditure. Sub-section 4.2 explains and justifies Ergon Energy's forecasts for its Operational Technology Capital expenditure for the next regulatory control period that it is proposing the AER approve.
- Section 5 focuses on Ergon Energy's Protection Capital expenditure. Sub-sections 5.1 and 5.2 provide the equivalent detail for Protection Capital expenditure as what is provided in sub-sections 4.1 and 4.2 for Operational Technology Capital expenditure.
- Section 6 focuses on Ergon Energy's Miscellaneous Capital expenditure. Sub-sections 6.1 and 6.2 provide the equivalent detail for Ergon Energy's Miscellaneous Capital expenditure as what is provided in sub-sections 4.1 and 4.2 for Operational Technology Capital expenditure.

## Expenditure Profile

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

### 2.1 Direct costs

Table 1 details the following information about Ergon Energy's Other System capital expenditure, in direct costs, for the previous, current, and next regulatory control periods:

- the Other System 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 and to the AER for the current regulatory control period
  - is now presenting in its regulatory proposal to the AER for the next regulatory control period
- the QCA's and the AER's Other System capital expenditure allowance for the previous and current regulatory control periods respectively
- Ergon Energy's actual and estimated Other System capital expenditure for the previous and current regulatory control periods.

**Table 1: Other System capital expenditure – Standard Control Services (Direct costs, \$m real 2014-15<sup>1</sup>)**

	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	8	9	9	8	8	41	86	61	42	43	45	277 <sup>2</sup>	29	21	13	19	16	99 <sup>6</sup>
Revised Regulatory Proposal	9	11	11	11	10	52	91	62	44	45	46	288 <sup>3</sup>	n/a	n/a	n/a	n/a	n/a	n/a
QCA/AER Determination	9	10	11	11	11	54	85	60	42	43	44	274 <sup>4</sup>	n/a	n/a	n/a	n/a	n/a	n/a
Actual/Estimate	18	10	23	38	59	148	59 <sup>5</sup>	40	26	28	31 <sup>6</sup>	183	n/a	n/a	n/a	n/a	n/a	n/a
Variance – Actual v Determination	100%	0%	109%	245%	436%	174%	-31%	-33%	-38%	-35%	-30%	-33%	n/a	n/a	n/a	n/a	n/a	n/a

**Table 2: Other System capital expenditure – Alternative Control Services (Direct costs, \$m real 2014-15)**

	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	n/a	n/a	n/a	n/a	n/a	n/a	1	1	1	0	0	3 <sup>6</sup>
Actual/Estimate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0 <sup>6</sup>	n/a	n/a	n/a	n/a	n/a	n/a	n/a

<sup>1</sup> Indexation based on Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI.

<sup>2</sup> Regulatory Proposal to AER – Distribution Services for period - 1<sup>st</sup> July 2010 to 30th June 2015 - 1<sup>st</sup> July 2009, Page 31, Table 6 (converted into direct costs).

<sup>3</sup> Revised Regulatory Proposal to AER – Distribution Services for period - 1st July 2010 to 30th June 2015 - 14<sup>th</sup> Jan 2010, Page 11, Table 1-1 (converted as above).

<sup>4</sup> 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).

<sup>5</sup> 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) (converted as above).

<sup>6</sup> 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).

In the 2010-15 regulatory control period, Ergon Energy is expected to underspend the AER's allowance for Other System capital expenditure by \$91 million or 33%. The following factors contribute to the expected variance in Ergon Energy's actual and estimated expenditure when compared with the AER's allowance:

- The accounting reclassification by Ergon Energy of some communications-related costs as non-network costs, based on Ergon Energy's interpretation of AER Regulatory Information Notices (RINs). This appears as a \$65 million underspend in Other System capital expenditure. However the costs have been expended and instead appear in the non-network category of Ergon Energy's Annual Performance RINs.
- Lower than expected maximum demand eventuating, reducing the need to undertake several projects
- The findings of the 2011 Electricity Network Capital Program (ENCAP) Review, Ergon Energy's own internal reviews of capital expenditure, the changing expectations of shareholding Ministers and increasing consumer concerns about the rising cost of electricity, which together led to an overall reduction in Ergon Energy's capital expenditure
- Delivery constraints due to the impact of several cyclones in Queensland over the period and the consequent reprioritisation of resources to perform recovery works.

In the 2015-20 regulatory control period, Ergon Energy is forecast to spend \$99 million, which is \$84 million or 46% less than Ergon Energy's actual/estimated expenditure for the current regulatory control period. Several projects which contributed to capital expenditure in the current regulatory control period will not form part of the forecast capital expenditure in the 2015-20 regulatory control period. These include:

- the Ubiquitous Network (Ubinet) project, Stage 1 of which was successfully delivered in the current period at a cost of approximately \$80 million
- projects to improve the performance of the Single Wire Earth Return (SWER) network, which accounted for approximately \$30 million in the current regulatory control period
- the Cyclone Area Reliability Enhancement (CARE) program, which was discontinued in 2012-13 and will not form part of the proposed capital expenditure in the next period. The project was valued at approximately \$35 million in the 2010-15 regulatory control period.

As a result, no capital expenditure is proposed for these projects in the Other System capital expenditure category in the 2015-20 regulatory control period leading to a decrease in forecast capital expenditure.

Capital expenditure to extend the telecommunications system is not proposed for the 2015-20 regulatory control period. However, Ergon Energy proposes expenditure to replace the existing two-way analog radio system with the P25 mobile radio system, which comprises radios, mobile base stations and repeaters. This project is set out in the 'Forecast Expenditure Summary Asset Renewal 2015-2020' document.

The reasons for the variance in Ergon Energy's current period expenditure compared with the AER's allowance are explained in further detail in Section 3 of this summary document.

To meet its Other System needs in the next period, Ergon Energy has forecast expenditure for projects within the following categories:

- **Operational Technology (including Control)** – Ergon Energy is committed to giving customers greater choices about how they manage their power and take advantage of local generation sources (such as photovoltaics and batteries). Expenditure is proposed to support the transition to a smart network to facilitate consumer choices, improve the utilisation of the existing power network and to defer capital intensive augmentation projects. This is a new capital expenditure requirement in the 2015-20 regulatory control period.
- **Protection** – protection assets are critical to the safety and reliability of the distribution network. Expenditure is proposed to address known issues in protection asset operations and to remedy safety risks arising from earth faults on distribution feeders by installing a Sensitive Earth Fault (SEF) protection scheme.
- **Miscellaneous** – expenditure is proposed for several projects that do not fall into a generic expenditure category.

Ergon Energy's forecast capital expenditure for the 2015-20 regulatory control period is broken down by Operation Technology, Protection, and Miscellaneous and is described in the following sections of this summary document:

- Section 4 – Operational Technology (including Control)
- Section 5 – Protection
- Section 6 – Miscellaneous.

## 2.2 Total costs

Table 3 and Table 4 provide the same information as is in Table 1 and Table 2 but, instead of presenting the Other System 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 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).



**Table 3: Other System capital expenditure – Standard Control Services (Total costs, \$m real 2014-15<sup>7</sup>)**

	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	11	13	13	12	12	<b>61</b>	119	82	57	57	58	<b>375<sup>8</sup></b>	42	31	21	29	26	<b>149</b>
Revised Regulatory Proposal	14	16	16	16	15	<b>78</b>	126	85	60	60	60	<b>390<sup>9</sup></b>	n/a	n/a	n/a	n/a	n/a	<b>n/a</b>
QCA/AER Determination	15	16	18	18	18	<b>85</b>	121	85	59	60	61	<b>386<sup>10</sup></b>	n/a	n/a	n/a	n/a	n/a	<b>n/a</b>
Actual/Estimate	25	13	34	56	86	<b>216</b>	85 <sup>11</sup>	56	38	36	44 <sup>12</sup>	<b>259</b>	n/a	n/a	n/a	n/a	n/a	<b>n/a</b>
Variance – Actual v Determination	<b>67%</b>	<b>-19%</b>	<b>89%</b>	<b>211%</b>	<b>378%</b>	<b>154%</b>	<b>-30%</b>	<b>-34%</b>	<b>-36%</b>	<b>-40%</b>	<b>-28%</b>	<b>-33%</b>	<b>n/a</b>	<b>n/a</b>	<b>n/a</b>	<b>n/a</b>	<b>n/a</b>	<b>n/a</b>

**Table 4: Other System capital expenditure - Alternative Control Services (Total costs, \$m real 2014-15)**

	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	n/a	n/a	n/a	n/a	n/a	n/a	1	2	1	0	0	<b>4</b>
Actual/Estimate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	n/a	<b>n/a</b>

<sup>7</sup> Indexation based on Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI.

<sup>8</sup> Regulatory Proposal to AER – Distribution Services for period - 1st July 2010 to 30th June 2015 - 1st July 2009, Page 31, Table 6.

<sup>9</sup> Revised Regulatory Proposal to AER – Distribution Services for period -1st July 2010 to 30th June 2015 - 14th Jan 2010, Page 11, Table 1-1.

<sup>10</sup> AER Final decision Queensland distribution determination 2010-11 to 2014-15, Page xxxiii, Table 12 (allocated by Ergon Energy into the capex categories).

<sup>11</sup> 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).

<sup>12</sup> 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.

## Current period expenditure and performance against the AER's allowance

This section compares, in direct costs:

- Ergon Energy's Other System capital expenditure forecast from its regulatory proposal and revised regulatory proposals
- the AER's Other System capital expenditure allowance from its distribution determination and
- Ergon Energy's actual and estimated Other System capital expenditure.

**Table 5: Other System capital expenditure forecast (Direct costs, \$m real 2014-15)**

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Regulatory Proposal	86	61	42	43	45	<b>277</b>
Revised Regulatory Proposal	91	62	44	45	46	<b>288</b>
AER Determination	85	60	42	43	44	<b>274</b>
Actual/Estimate	59	40	26	28	31	<b>183</b>
Variance – Actual v Determination	<b>-31%</b>	<b>-33%</b>	<b>-38%</b>	<b>-35%</b>	<b>-30%</b>	<b>-33%</b>

In the 2010-15 Regulatory Proposal, Ergon Energy proposed five sub-categories of Other System capital expenditure:

- Communications
- Protection
- Single Wire Earth Return (SWER)
- Undergrounding
- Other programs, which comprise low voltage fuse retrofits, low voltage spreaders, substation security, oil containment bunding, and alternate substation alternative current (AC) supplies.

Ergon Energy's actual and estimated expenditure within each of these categories in the 2010-15 regulatory control period is explained below:

### 3.1 Communications

Communications expenditure in the Other System category in the 2010-15 regulatory control period was predominantly related to the UbiNet project. In May 2008, Ergon Energy developed a UbiNet Business Case, comprising three stages, to upgrade Ergon Energy's core communications capability across its distribution area.

As forecast in the 2010-15 Regulatory Proposal, Ergon Energy delivered Stage 1 of the UbiNet communication project, which involved new or upgraded equipment at 248 sites (128 of these required an infrastructure upgrade) across the distribution network to support a mix of fibre optic and radio infrastructure. The project was completed in 2014 at a cost of approximately \$80 million over the 2010-15 regulatory control period (in direct costs), which was approximately 5% greater than forecast. This variance was in part due to the emergence of newer and more effective telecommunication technologies that highlighted the potential for a significant improvement in project outcomes at a low additional cost. These technologies were subsequently brought within the scope of

the project and have enabled Ergon Energy to remotely operate protection systems at 25% more substations than initially specified in the project design.

At the time of submission of the Regulatory Proposal for the 2010-15 regulatory control period, Ergon Energy proposed to account for communications expenditure in network-related asset classes. Since then, based on Ergon Energy's interpretation of the AER's Annual Performance and Reset RINs, Ergon Energy has reclassified communications expenditure as non-network expenditure in its subsequent annual reporting to the AER. As a result, Ergon Energy's reported Other System expenditure set out in Table 1 excludes approximately \$65 million of expenditure to deliver the UbiNet project. This expenditure instead appears in the non-network category of Ergon Energy's Annual Performance RINs. This expenditure instead appears in the non-network category of Ergon Energy's Annual Performance RINs. For the purposes of this Regulatory Proposal, this should be taken into account when assessing Ergon Energy's performance to ensure an appropriate comparison with the AER's allowance for the 2015-20 regulatory control period.

## 3.2 Protection

The purpose of protection expenditure is to ensure that existing and new protection systems reliably detect and operate for faults that may occur on the distribution network in accordance with the legislative requirements of the National Electricity Rules (NER) and the *Electrical Safety Act 2002 (Qld)*. Where a need is identified, expenditure is proposed to upgrade, replace or install new equipment for protection purposes.

In the 2010-15 Regulatory Proposal, Ergon Energy proposed expenditure of approximately \$30 million to maintain protection performance on the distribution system and delivered the following outcomes:

- Identified and initiated auto-reclose functionality on 12 existing feeders
- Identified and initiated sensitive earth fault protection on 37 existing overhead feeders
- Undertook desktop substation protection reviews and ensured protection systems comply with statutory obligations. This included an allowance for new primary plant such as current transformers and circuit breakers to address performance gaps identified through desktop reviews. Ergon Energy conducted reviews of several 11/22 kiloVolt distribution feeders.

Capital expenditure for protection works in 2015-20 is expected to be lower than the AER's allowance due to several factors. Fewer protection reviews were conducted than anticipated due to the reprioritisation of existing protection resources and concerns about data quality. For those that progressed to the detailed design phase, the scope and justification of each project was reviewed and refined on the basis of field investigations which were performed to validate the results of the initial desktop reviews. Due to these field investigations, the scope of some projects were reduced and accordingly the associated capital expenditure.

Additionally, the lower than expected demand that eventuated in Queensland from 2012 onwards had the effect of minimising the risk of fault current exceedances within Ergon Energy's distribution system. This reduced the need for Ergon Energy to undertake protection works to accommodate higher fault currents originating both from the distribution system and from the upstream Powerlink transmission system. At the same time, in response to heightened stakeholder and consumer concerns about the price of electricity, from 2012 onwards protection works were limited to only projects necessary to address protection issues deemed as high risk.

As a result of these factors, protection works actual/estimated capital expenditure (for the current regulatory period) is expected to be approximately \$10 million, \$20 million or an approximately 66% less than forecast expenditure.

### 3.3 Single Wire Earth Return

The SWER project and supporting strategy were developed in response to the findings of the Electricity Distribution and Service Delivery (EDSD) review in 2004. The purpose of the SWER project was to improve the reliability of Ergon Energy's SWER network, which had been experiencing poor performance in terms of both capacity and voltage. The project involved conductor upgrades, isolator upgrades, and the installation of voltage regulators to improve SWER performance by reducing imbalance on SWER feeders and isolating un-isolated sections of the network.

Ergon Energy's ability to deliver planned programs of work during this regulatory control period has been severely impacted by sustained levels of cyclonic activity:

- Cyclone Tasha in 2010 resulted in flooding and a disaster declaration for Dalby, Theodore, Emerald, Bundaberg, Central Highlands, Northern Burnett and Woorabinda.
- Cyclones Anthony and Yasi in early 2011 impacted on over 600,000 square kms of our service area from the Cassowary Coast to Mt Isa and resulted in loss of supply to some 220,000 customers.
- Cyclone Oswald caused extensive flooding in the Burnett River region and on the Darling Downs in January 2013.
- Cyclones Dylan (January 2014) and Ida (April 2014) both impacted coastal areas of northern Queensland.

Significant resources needed to be redeployed from the normal works program to perform repairs in the affected areas following these major disasters.

As a result, lower priority projects such as the SWER program were deferred and resources re-allocated to address higher risk safety and reliability issues. At the same time, in response to heightened stakeholder and consumer concerns about the price of electricity, from 2012 onwards the SWER program was limited to only projects deemed as high risk.

As a result of these factors, SWER actual/estimated capital expenditure (for the current regulatory period) is expected to be approximately \$20 million, \$5 million or 20% less than the \$25 million forecast.

### 3.4 Undergrounding

In the 2010-15 regulatory control period Ergon Energy proposed several projects related to undergrounding overhead conductors, the largest of which was the CARE project. The objective of the CARE project was to underground critical high voltage infrastructure in cyclone prone areas and provide an important enhancement to the ability of the network to withstand cyclonic forces. Since 2001 the program has established secure underground connections to over 150 essential services such as hospitals, disaster-control centres, aged-care facilities (e.g. 24 hour nursing care), category five cyclone shelters and evacuation centres (e.g. schools) in the high-risk cyclone region from Mackay to the far north of Queensland.

CARE projects are prioritised based on the results of a risk assessment or 'value index' to identify facilities that would experience severe adverse health, social or economic outcomes in the event of a catastrophic weather event, and the projects' potential to defer planned augmentation works, and thereby improve local reliability outcomes. On this basis, there were ten projects proposed in the 2010-15 regulatory control period at a cost of approximately \$30 million.

In 2012-13, the CARE program was reviewed in response to the findings of the 2011 ENCAP Review, Ergon Energy's own internal reviews of capital expenditure, the changing expectations of shareholding Ministers and increasing consumer concerns about the rising cost of electricity. The

review found that the program had succeeded at delivering significant benefits to improve the resilience of local communities to catastrophic weather events in the Far North region and to continue to perform targeted works would not be prudent. This is supported by Ergon Energy's customer engagement process, which is described in detail in the 'Informing Our Plans, Our Engagement Program' document, in which customers recognised that reliability of supply has improved and are no longer looking for higher reliability standards.

Of the approximately \$30 million of projects proposed in the 2010-15 Regulatory Proposal, approximately \$15 million was delivered prior to the closure of the program. The decision to wind back the CARE program is expected to result in a reduction of approximately \$15 million in direct costs for the remainder of the regulatory control period.

### 3.5 Other programs

Resource constraints affected the progress of other programs in this asset category such as the installation of low voltage regulators.

The wire alert program did not proceed in April 2011 resulting in a reduction of around \$1.5 million to the capital plan. While the technology was validated, a trial set was provided to all Ergon Energy employees. It was found that of almost 5000 units issued, a very low number of problems with neutral connections were identified when first installed, but the units quickly fell into disuse as the users found other needs for the power points employed. The trial concluded there was little benefit in proceeding to full distribution as planned, and the program was closed.

The effect of these factors is that Ergon Energy spent less than the AER's allowance for other programs in the 2010-15 regulatory control period.

## Operational technology (including control)

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

### 4.1 Nature of expenditure

Ergon Energy is committed to giving customers greater choices about how they manage their power and take advantage of local generation sources (such as photovoltaics and batteries). During the customer engagement process, customers increasingly said they want greater choice and control around their energy supply solutions. In response to this engagement, Ergon Energy is giving a commitment to empowering customers with new technologies and options for their electricity supply solutions. To do this, Ergon Energy needs to transition to a Smart Network. This will not only benefit the customer, it will also improve the utilisation of the existing power network to use existing network assets more effectively and to defer capital-intensive augmentation projects.

In order to meet these goals, Ergon Energy requires more data to operate the network closer to its technical limits before augmentation is needed. More monitoring and control is needed throughout the high voltage and low voltage networks to effectively manage two-way power flows. This will be achieved by better managing data of existing systems such as Supervisory Control and Data Acquisition (SCADA) and protection, and by increasing in network metering and monitoring and control through Intelligent Electronic Devices (IEDs). Protection assets are further described in Section 5 of this document.

Ergon Energy has developed a 'Network Control Strategy' and an 'Operational Technology Architecture and Environment Strategy 2020' that examines the dynamics motivating operational technology systems growth, the key strategies that it needs to embrace, and its vision for the Operational Technology environment in 2020. Ergon Energy's key strategies include:

- separating the collection, storage and governance of data functions from the users of the data so that users can focus on using and interpreting the data
- applying a common, decoupled standard systems integration approach so that they can be managed cost effectively
- promoting reliable operational independence to promote stability and resilience
- managing the technology environment independent of the underlying telecommunications environment, so that they can develop independently without affecting upon each other
- centrally managing support and maintenance of intelligent electronic devices through an integrated Network Operations Centre (iNOC)
- using advanced information management to improve power network operation and control
- the need for greater security and resilience as part of the overall design of the operational technology environment given the increased exposure to cyber and physical security threats.

Operational Technology capital expenditure responds to these key strategies. It includes the systems and infrastructure required to collect, manage and control data for asset management purposes as well as to provide for remote monitoring and operation of the power network. The Operational Technology capital expenditure includes telecommunications, Distribution Management System (DMS), SCADA and other real time data collection systems, and support for the Operational Technology environment, such as data centres, data and systems security and other support services.

The predominant benefit of all proposed Operational Technology investments is to constrain the growth of future staffing costs through the proactive, coordinated, and centralised management of Operational Technologies solutions at a business level. An approach in which individual functions of the business deploy technology solutions leads to duplication and inefficiency as technologies are scaled up in an ad-hoc manner to accommodate new and unanticipated business requirements that emerge over time. This leads to increased staff costs in the form of additional staff or contractors or significant amounts of overtime to manage unexpected issues that arise.

A secondary but equally important benefit of Operational Technology is to adopt a proactive approach to collecting and managing data from the field and hence deliver useful and timely information to all areas of the business. This information can then be used to make more informed decisions about future expenditure at a corporate level, such as maintenance and augmentation planning, based on information about the state of the network that is objective, complete, and reliable. This has a direct impact on the efficiency of future capital expenditure.

While the benefits of Operational Technology are known, the benefits only become apparent as the scale of the technology grows and the efficiencies arising from a centralised deployment are realised. Ergon Energy expects that savings to operational expenditure resulting from the introduction of new Operational Technology will begin to accrue after the 2015-20 regulatory control period as the technologies gradually embed into business-as-usual processes.

## 4.2 Expenditure forecasts for next period

This sub-section details Ergon Energy's Operational Technology capital expenditure forecasts for the next regulatory control period. It details the total capital expenditure forecasts for the period and the seven operational technology projects that comprise this total. These projects should be seen as an integrated series of responses to the key strategies detailed in Ergon Energy's 'Operational Technology Architecture and Environment Strategy 2020' and 'Network Control Strategy'.

### 4.2.1 Total Operational Technology capital expenditure

Table 6 provides a detailed breakdown of Ergon Energy's Operational Technology capital expenditure forecasts for the next regulatory control period, expressed in direct costs.

**Table 6: Operational Technology capital expenditure forecast (Direct costs, \$m real 2012-13)**

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Integrated Network Operations Centre	0.6	0.1	0.2	0.3	0.5	2
Alternative Data Acquisition Service	1.6	-	1.2	-	1.2	4
Distribution Management System	8.6	4.4	-	-	-	13
Master Station SCADA Strategy	2.6	2.7	1.8	4.4	1.6	13
Operational Network Security	3.1	1.4	-	-	-	5
Regulator Remote Communications Strategy	1.1	1.1	0.7	1.2	1.1	5
Meter Configuration Management System (evenly split between SCS and ACS)	1.0	2.2	1.9	0.4	-	5
<b>Total</b>	<b>19</b>	<b>12</b>	<b>6</b>	<b>6</b>	<b>4</b>	<b>47</b>

These projects are described in the following sections.

## 4.2.2 Project 1 – Integrated Network Operations Centre

Modern distribution networks are increasingly installing active terminal equipment to allow for real-time monitoring and remote control. This equipment includes the control of network elements such as reclosers and switches, plus monitoring devices, which will provide real-time data on network status. Based on a survey of business requirements conducted in 2012, and known technology available today, Ergon Energy expects the number of devices to continue to grow, and the rate of deployment to increase, over the coming years. This is detailed further in the Ergon Energy 'Integrated Network Operations Centre Strategy' supporting document that has been developed to support this project.

It will become increasingly important to monitor active device assets to ensure that they function correctly and are available to perform when required. It considered four potential options:

- No active monitoring (business-as-usual) – this is the current approach. Ergon Energy does not actively monitor IEDs and there are an unknown number of devices not functioning
- Establish a dedicated IED operation centre – this involves establishing a new dedicated group to monitor and manage IEDs throughout the network
- Implement within the Communications Network Operation Centre Environment – this involves extending the functionality of the communication network operation centre to also monitor and manage IEDs
- Business Group management of IEDs – this involves managing and monitoring the IEDs within the group within Ergon Energy that is responsible for the installed device.

Ergon Energy's preferred option is to establish a dedicated IED operation centre, or iNOC. This is a centralised support model for the growing number of intelligent electronic devices installed in the power network. Rather than have multiple operational groups monitor the health of these devices independently, the iNOC provides a common and consistent way to monitor, log, track and resolve issues with intelligent devices in the network. The iNOC would be a capability within the business resourced with sufficient staff to support the twenty-four/seven operation. The group would provide device activation, management, monitoring, and support for IEDs within the network.

This investment is necessary because there is an organic growth in intelligent devices due to the integration of technology into power equipment. If Ergon Energy fails to manage the devices appropriately, there will be a reduction in the quality, reliability, and security of the power network. Centralised resources will be more cost effective than employing additional staff in multiple operational groups across the business. The introduction of the iNOC will reduce potential overtime and on-call allowances incurred by business functions, as they will no longer need to respond to an increasing number of IED operational issues outside of business hours.

Ergon Energy has based its expenditure forecast on vendor pricing and the use of standard labour rates based on number of devices monitored.

The iNOC costs consist of a software component, based on previous experience and costs obtained from recent related upgrade costs at the Communications Network Operations Centre. Further information about the build-up of these costs is detailed in the 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

The costs to develop the iNOC capability have been assessed as the most prudent and efficient to deliver the support of the future IEDs as they are implemented. Retaining the current business-as-usual approach would require regular growth in, and training of, field operational staff at multiple locations to monitor and support the devices.

An alternative ad-hoc approach would require an inefficient process of regular reviews to determine if equipment is functioning correctly. As such, the iNOC project focuses around reducing future cost growth with the addition of IEDs in the network.



The organic growth of IEDs is part of the standard control services being provided to customers in terms of power delivery. In the long term, the data from these devices will improve the operational and maintenance strategies for the network. The implementation of the iNOC will enable Ergon Energy to begin on-going analysis and maintenance of IEDs in a centralised manner. Ergon Energy expects potential savings in this area to occur in the next AER regulatory control period, once efficiencies arising from the implementation of the iNOC can be realised. For further details, refer to the 'Integrated Network Operations Centre (iNOC) Strategy'.

### 4.2.3 Project 2 – Alternative Data Acquisition Service

Ergon Energy needs to collect data from the growing number of IEDs in the field in order to understand how the distribution network is performing, and apply this data to enhance network performance planning and strategies.

The SCADA system is currently the main interface that is used to collect data from IEDs. The SCADA system enables the control centres to remotely operate and monitor the performance of the power network. This is a critical capability for the business. The SCADA system is designed to be highly available and Ergon Energy carefully considers what data it collects to ensure the control room operators only receive relevant information.

The SCADA system is the only system that Ergon Energy has to interface to power network IEDs in the required communications protocols. However, the SCADA system has not been designed to collect and manage this type of new information. Stretching the boundaries of what the SCADA system collects will 'clutter' the system, which may impair control room operators' ability to make quick and informed decisions.

There could be as many as 200,000 IEDs on the power network by 2025 with the potential to provide valuable data to Ergon Energy, which is not relevant to a control-room operator.

Ergon Energy needs a way to effectively collect data from IEDs. It considered potential options:

- continue with business-as-usual
- expand the SCADA system to collect data from all IEDs
- allow the growth of vendor supplied data collection systems as part of the IED installation, such as by allowing each IED product family installed on the network to have its own manufacturer supplied data collection and management system
- implement an Alternative Data Acquisition Service (ADAS).

Ergon Energy has assessed that the ADAS is the most cost effective infrastructure to manage the collection and storage of information from IEDs as supported by the detailed information in the 'Alternative Data Acquisition Strategy 2020' supporting document. This option involves procuring and installing software on the Operational Communications Network to act as an ADAS. The ADAS will be a repository for data in the operational environment; interfacing with the wide variety of IEDs to make their data available to the business.

The ADAS solution will allow Ergon Energy to collect condition monitoring and network performance data and to make them available across the business to improve maintenance and planning activities. Condition based risk monitoring is discussed further in the 'Forecast Expenditure Summary Asset Renewal 2015 to 2020' document. Currently control room remote monitoring activities are limited to substation assets. ADAS will provide visibility to the business for IEDs in the low voltage network to ensure they are operating effectively.

The ADAS will have the capability to scale-up to collect data from as many as 200,000 devices. However, initially only licensing for 5,000 devices will be procured, growing to 21,000 devices by 2020. In this way, if the forecast growth rates of devices connecting to the network do not become a

reality, there is no risk of over investing in the ADAS as it will start as a small-scale solution, and will be expanded on an as-required basis. Under this approach, data will be stored in a central repository, making it easier to integrate to other operational or corporate systems and databases.

Ergon Energy has based its expenditure forecast on vendor pricing and the system has been sized based upon expected IED growth rates. Ergon Energy proposes using an off-the-shelf system for industrial applications, so the cost proposed by the vendors is considered appropriate. The implementation costs are based on standard labour rates, and an estimate of the hours required for Ergon Energy's Subject Matter Experts (SMEs) to undertake the work. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

The cost for the ADAS has been assessed as being the most prudent and efficient way of managing data associated with the IEDs in the network. The alternative approaches would require either significant growth with risk to the SCADA infrastructure, or an ad-hoc approach with multiple groups within Ergon Energy managing the data locally. As the ADAS will cater for future IED growth, it will minimise future costs associated with this capability rather than replacing existing infrastructure. This is further detailed in the 'Alternative Data Acquisition Service Strategy' document.

The ADAS's functionality is similar to that of SCADA, except at a lower cost per point, as the information collected supports but does not control the network. As such, it is part of standard control services.

#### 4.2.4 Project 3 – Distribution Management System

The challenges faced by Ergon Energy in its network operations are common to many network businesses around the world. They include:

- increased pressure from regulatory bodies to improve operational efficiency and workforce productivity, especially to deliver higher quality and reliable power
- the uptake of renewable generation and distributed resources is increasing the complexity of the operating environment, requiring the management of a bi-directional, less predictable network
- new entrants and disruptive technologies are causing implications for the assumptions about network design and power flow. This is occurring both internally, as the operational technology and information technology domains continue to converge, and externally, through the use, for example, of distributed generation and electric vehicles
- the universal focus on climate change and the environment, and the increasing desire of consumers to participate in energy management and conservation.

A DMS can assist to relieve these pressures by automating many of the manual processes in operating a distribution network and supporting new technologies in the network. Specifically, a DMS can deliver:

- enhanced operating efficiency
- improved business continuity
- smarter network operations
- improved quality of supply
- improved safety outcomes
- enhanced customer interaction

The DMS is the foundation information and decision support system for the deployment of intelligence in a distribution network.

The DMS is a suite of applications underpinned by an electronic model of the electricity distribution network incorporating electrical connectivity information. The current state of each element in the model network is updated either in real-time from SCADA or in near real-time by manual updates by Network Controllers. A DMS uses complex mathematical algorithms to analyse and predict how to optimise power flow through a utility's distribution power system and to assist with network switching. It is the foundational information and decision support system for the deployment of intelligence in a distribution network, providing the distribution power system operator with tools allowing them to make faster and better informed decisions and improving the efficiency of the network minimizing outage times. The functions performed by a full DMS implementation include: switching management; outage management; network analysis; network optimisation; and support for distribution system automation.

Investing in a DMS provides the ability to deliver a range of benefits, including:

- limiting the need for Ergon Energy to increase staff in the Operations Control Centre, particularly in the area of switch plan production and validation checks
- streamlining interaction between the Operations Control Centre and field staff with all information at the network controller's desk and electronic transfer of information between the Operations Control Centre and field staff
- enabling Ergon Energy to better meet regulatory requirements relating to service reliability, quality and reporting, through avoided alternative reliability investments and/or avoided Service Target Performance Incentive Scheme penalty through reducing Customer Average Interruption Duration Index
- providing more up-to-date and granular outage data and more efficient access by customers (and staff) to outage data to keep them informed and for regulatory reporting and incident analysis. It will also help to improve customer information on restoration times and to prioritise restoration of customers.
- supporting Ergon Energy's investment in Smart Grid technologies. Implementing a DMS is both a key enabler for Smart Grid investment and a key component in providing agility for dealing with emerging trends and technologies (such as electric vehicles) .
- improving ability to operate assets to capacity and perform load-transfer decisions through greater accuracy, in real-time, of load calculations on the network, while also improving business continuity and disaster recovery responses.
- improving safety through improved data integrity on the status of the network, enhanced decision making through the ability to simulate network scenarios, better communication between control room and field staff, and the removal of the need for manual handling of pinboards in the control room.

The proposed project will deliver core DMS capability and efficiency improvements in Ergon Energy's control room and in its outage management. Base-level data is required to provide an accurate representation of the electrical network from a network connectivity and customer information perspective. The data is essential to deliver most Smart Grid applications. Accurate engineering data such as conductor impedances, lengths, and load data are not essential to deliver the identified benefits. The project will deliver software capability in most smart grid areas. It will test and demonstrate this where possible in a pilot area. However, it is not in the project scope to fully deploy Smart Grid capability.

Ergon Energy commenced its DMS project in the current period and estimates that the total project cost will be \$35.3 million. This estimate has been determined using a total-cost-of-ownership model based on the contractor's tendered price, and Ergon Energy and Sparq Solutions implementation costs.

An allowance for a DMS of \$22.8 million was included in Ergon Energy's regulatory proposal for the current period. There were delays in commencing the project, which Ergon Energy expects to result in a \$14.3 million underspend in the current regulatory control period. Ergon Energy is including an amount of \$13 million (\$ real 2012-13 direct cost) in its expenditure forecast for the next period, which represents the gap between the total forecast project cost and the amount approved in the current period. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

The DMS project is focused on improving efficiency in the Operations Control Centres. Currently, the volume of switching sheets being used to manage the network is growing at a steady rate. To manage the safety of customers and Ergon Energy staff, this will mean staff increases in both Operations Control Centres. This additional cost would need to be reflected both in system operating expenditure and in property capital expenditure, as the Operations Control Centres would need to be expanded. However, the DMS provides a more cost-effective method to increase productivity. This will avoid the need for additional Operations Control Centre staff and expansion of existing facilities. The DMS is a core system used to manage and operate the power network and is fundamental to providing Standard Control Services. For further details refer to the 'Distribution Management Strategy'.

#### **4.2.5 Project 4 – Master Station SCADA Strategy**

The drive to build smarter, more efficient distribution grids in recent years has seen the increased development of new technology. This technology includes both an increase in IEDs on the distribution network as well as more intelligent centralised control systems. Ergon Energy expects that, over the coming years, the uptake of this technology will push the device numbers directly scanned by the SCADA centralised control system, from just over 1,500 to over 20,000. The SCADA system will go from being the only centralised control system with minimal intelligence, to a component of a greater operational system with more advanced capabilities.

Ergon Energy's SCADA system needs to evolve in response to these changes into a system that:

- has components with the flexibility to change without a full system upgrade
- easily interfaces with other systems
- can be supported by Ergon Energy with minimal dependence on the vendor
- uses software that is not dependent on the type of underlying hardware resources
- can accommodate mapping of devices to multiple or alternative back-end systems
- will be secure in the changing operational technology environment.

The master station is a necessary tool for the Operations Control Centre to perform its daily duties, as well as providing Ergon Energy with critical asset data. If the master station was neither maintained nor developed, there would be a greater need for field staff at depots, and at the call centre, to allow manual operation of equipment in substations. This increases the costs to the business and introduces additional safety risks.

The '10 year 2015 – 2025 Master Station SCADA Strategy' sets out the programs required for maintaining the existing SCADA master station infrastructure and developing the capabilities of the master station to meet Ergon Energy's future network monitoring and control requirements. Ergon Energy's Master Station SCADA strategy promotes:

- open interfaces and components – open architecture will allow Ergon Energy to be less dependent on a single vendor and create less susceptibility to the costs or risks of total system upgrades. Ergon Energy will examine existing components and supported protocols. Non-replicable components that require full-system upgrades will have alternative open architecture solutions examined. Ergon Energy will drive towards adopting an open standard International Electrotechnical Commission standard design of electrical substation automation (IEC61850).
- facilities and technology that enable the capability to provide in-house support – Ergon Energy will move towards a system that is predominantly supported internally. It will develop internal resources and investigate the feasibility of establishing a local QAS. The move to an open architecture will assist in making the system more transparent and easier for Ergon Energy to support
- virtualisation of servers – virtualisation will be adopted over parts of the SCADA hardware, removing the dependence on hardware from the control system software. Virtualisation allows the physical infrastructure to be shared by many virtual machines, consolidating hardware requirements. This removes the dependence on hardware such that Ergon Energy is not locked into purchasing hardware as dictated by the software vendors
- an Internet Protocol (IP) based architecture – migrating to an IP-based infrastructure will enable flexibility for the control infrastructure to change and a wider range of devices can be integrated. An IP-based architecture reduces the number of physical wires in the substation, reducing deployment times and paving the way for a move to an open standard IEC61850.
- more stringent security processes – new technologies such as Smart Grid and the increasing number of applications interfacing to the system require Ergon Energy to evolve its security practices. Ergon Energy will address policies and processes in key areas of network access, security audits, change management, and network documentation. Ergon Energy will work towards a network intrusion detection system and consider host intrusion detection systems.

The proposed project of maintaining and developing the master station involves a number of solutions to get Ergon Energy's operating environment to industry best practice to protect against cyber-security threats and incidents. It is based upon an independent security review carried out in 2010 of Ergon Energy's operating technology environment and its risk exposure.

Ergon Energy has based its expenditure forecast on a combination of standard labour rates, materials costs recorded in Ellipse for previous projects, and vendor pricing of software costs. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

The SCADA system project is an on-going program of work to keep the system operating as efficiently and effectively as possible. The SCADA system is the 'heart' of the power network, providing operation and control of the substations. These costs relate to maintaining capability as the do nothing case would put the support of the system at risk, and therefore the operation of the power network at risk. The growth in automation of the substations means that increased capacity in SCADA is also needed.

SCADA provides the fundamental regulation and control of high voltage power (substations) that enable Standard Control Services.

#### 4.2.6 Project 5 – Operational Network Security

The emergence of new technologies such as smart meters, transformer monitoring, and low voltage network automation will enable Ergon Energy to better utilise existing network distribution assets and provide self-healing capabilities in the network. By 2025, it is estimated that approximately 800,000 smart devices will connect to the network with associated requirements around data collection, storage, security and management of the devices themselves.

These changes in the technology environment bring new challenges around the security of data and intelligent devices connecting to the operational network, in particular the threat of a cyber-attack.

Major drivers for Ergon Energy to invest in security infrastructure in its operational networks include:

- increasing use of ubiquitous information technology protocols/systems – without the use of these protocols and systems, Ergon Energy’s network is exposed to external and internal threats, which have the potential to cause damage to computer networks
- increasing interconnectivity – greater interconnectivity with third-party distributed energy supplies, such as renewable and distributed generation, and device vendors for support and maintenance purposes, increases the exposure of the network to malicious or unintentional damage. Appropriate IT security infrastructure and resourcing is required to ensure secure connectivity and flow of data between vendors and partners
- greater awareness of threats – there has been significant recent media exposure to the growth of cyber risks and globally utilities are facing increasing difficulty in obtaining cyber-risk insurance.

Ergon Energy identified and evaluated three options to address security infrastructure and resourcing:

- Business-as-usual – this means treating security with a ‘best-effort’ model. There is no dedicated security capability currently within Ergon Energy. Although current systems have security features these are not always used or incorporated into the design and operation
- Option A – the implementation of ‘best-practice’ security for the Ergon Energy Operational Network to secure the operational network against external and internal cyber threats
- Option B – the implementation of ‘edge-only’ security to secure the operational network against external cyber threats.

The best-practice business case proved to be the least-cost solution when compared both to the total cost of the program and the value-at-risk. This option is in line with the United States of America National Security Agency’s recommendations on technology contained in its guideline *Defence in Depth – A practical strategy for achieving Information Assurance in today’s highly networked environment*.<sup>13</sup> Through this option, Ergon Energy will be able to significantly reduce the size of attack surfaces open to internal threats, reduce the resulting damage and to mitigate the impacts and losses from potential cyber-attacks as quickly as possible. This is further detailed in the supporting document ‘Operational Network Security Strategy’.

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<sup>13</sup> National Security Agency, *Defence in Depth – A practical strategy for achieving Information Assurance in today’s highly networked environment*, <https://www.nsa.gov/ia/files/support/defenseindepth.pdf>, 2012, accessed 13 October 2014.

Under this option, the operational network will be secured against external and internal cyber threats through the following initiatives:

- implement an information assurance office within Ergon Energy – this office will be responsible for the development, maintenance and enforcement of the information-assurance policy. It would have oversight of security for Ergon Energy’s operational facilities, ensuring the entities providing security services are accountable for delivering information-assurance services in line with Ergon Energy policies and guidelines
- segment operational network into zones and enforce point-to-point connectivity within zones using Multiprotocol Label Switching virtual private networks – separating devices into security zones based on common functions and security requirements allows security controls to traffic flows within and between the zones. Enforcing point-to-point connectivity between devices within zones allows damage caused by any rogue device connected to the network to be limited
- segment operational network boundaries – the likelihood of an intruder gaining access to the operational network can be greatly reduced by tightly controlling access to the operational network for users and applications
- implement a centralised operational-device authentication and audit system – this will allow users connecting to all devices within the operational network to be authenticated using a single set of active directory credentials and for that access to be centrally audited
- implement an Intrusion Detection/Prevention System– such devices or software applications will monitor networks or systems for malicious activities or policy violations, with the ability to detect abnormal behaviour/attacks at all layers of the Open Systems Interconnection model
- implement a Security Information Event Management System – this system will correlate security data from multiple sources within the Operational Network, streamlining the task of identifying and responding to security incidents.

The proposed investment consists of both operational expenditure and capital expenditure components, with the capital expenditure component costing \$4.6 million (\$ real 2012-13 direct cost) in implementation costs to Ergon Energy. Individual assets have been costed using a vendor-pricing tool and standard labour rates were applied. Further information about the build-up of these costs is detailed in Ergon Energy’s ‘Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020’.

Ergon Energy has determined that the risk to the power network is ‘high’ and that the items in this Regulatory Proposal reduce that risk to ‘medium’. Should a well-planned cyber event occur, the key risk to Ergon Energy would be the destruction of one or more substation assets such as power transformers and switchgear. This would have a significant financial and operational impact on Ergon Energy as the customer minutes’ outage would last until the substation(s) is repaired. Damage to assets such as power transformers have the potential to result in lengthy outages. The impacts to Ergon Energy’s assets are outlined in the ‘Operational Network Security Strategy’.

This objective of this project is to provide new security capability to support Ergon Energy’s operational environment and as such there are no opportunities to save elsewhere. These costs therefore mitigate the evolving threat to the power network and Ergon Energy’s ability to deliver standard control services.

#### 4.2.7 Project 6 – Regulator Remote Communications Strategy

Ergon Energy has approximately 584 high voltage (HV) regulator sites, none of which has remote communications. Ergon Energy's goal by 2030 is for all HV regulators to have remote communications for engineering access and SCADA/DMS data. It expects that 75% of the regulators will have communications in place by 2020.

Enabling remote communications to regulator sites will:

- make it easier for operators and planners to maintain the network, including by undertaking some maintenance remotely, saving field staff travel and labour
- give operators and planners enhanced visibility and control by giving remote access to data to determine if plant is suitable for its current use. Voltage profiles will be more accurate so the network could be better utilised
- allow potentially for deferred augmentation work.

Ergon Energy intends that regulator remote communications will become part of the business-as-usual process for new and replacement HV regulators. It will replace existing regulators across four phases:

- Phase 1 (2015-16 to 2016-17) addresses the existing regulators that have communications capability and only require minimal communications hardware and configuration work – these cover approximately 40% of existing HV regulator sites.
- Phase 2 (2017-18 to 2018-19) addresses regulators that require an auxiliary power supply as well as minimal communications hardware and configuration work – these cover approximately 16% of existing HV regulator sites.
- Phase 3 (2018-19 to 2019-20) addresses regulators that require a controller replacement as well as auxiliary power supply and communications hardware and configuration work – these cover approximately 16% of existing HV regulator sites.
- Phase 4 (2015-16 to 2029-30) addresses the remaining 28% of existing HV regulator sites. No cost has been included for this phase as these regulators will be replaced with communications added as they fail-in-service.

The project costs have been developed based on standard labour rates and internal knowledge of labour and materials. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

When this project is 70% complete (i.e. at the end of Phase 3) it has the potential to adjust maintenance expenditure on regulators during 2020-25 once the collected information has been analysed and turned into new field-staff processes and procedures. There are no additional cost savings in the current regulatory control period. The document 'Regulator Remote Communications Strategy' provides more detail on this proposed project.

The regulators provide an important voltage quality and support role as part of Standard Control Services.



#### 4.2.8 Project 7 - Meter Configuration Management System

Historically, meters used to measure energy usage were mechanical devices that could not be altered to suit different tariff applications. Electronic meters and ripple receivers that are now being installed can be configured (programmed) to suit a wide range of tariff structures and list of features and functionality that can be used to deliver:

- customer benefits,
- provide useful information to help manage the distribution network, and
- addressed retail (business-to business) service requests for Type 6 Metering.

Ergon Energy proposes to implement a Meter Configuration Management System (CMS) to provide ongoing supply chain cost reductions and improvements in work process efficiency and customer service. This report promotes the use of a state of the art generic handheld unit to configure electronic meters and ripple receivers via their communications optical port. The in-field configuration system will permit customer tariff requirements to be programmed into the meter equipment and applied on site where electronic meters and ripple receivers are installed for new and changed tariff applications. The system will permit direct uploading of details to host asset management and Customer Information Systems to improve data quality and validation for market operations.

The use of electronic meters was mandated in Queensland from 1 July 2007 at the commencement of Full Retail Competition. Prior to this date, electronic meters were used in small quantities, mainly for large three phase customers. The need for a meter CMS becomes more critical to manage electronic meters and ripple receivers as the quantity of electronic meters increases as a percentage of the total meter asset population, (currently at 17.7% with an approximate growth rate of 4 –5% per annum<sup>14</sup>. The need for a meter CMS is based on an assumption that remote communications or an AMI metering platform for metering applications will not be mandated in Queensland for a rollout in the foreseeable future.

Ripple receiver device management is quite complex for Ergon Energy due to the large number of injection frequencies and different telegram systems deployed by each of the six historical regions prior to Ergon Energy's formation. The use of ripple receivers associated with special control tariffs is an essential part of Ergon Energy's demand control strategy. Configuration management is an important tool to simplify ripple receiver management and avoid costs.

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<sup>14</sup> This is based on new and customer driven meter growth excluding other meter capital replacement programs.

Implementing a CMS will generate the following benefits:

- a metering solution that will support customer's tariff selections and multidirectional flows of energy and additional choice in electricity supply solutions, consistent with the customer expectations described in 'Informing Our Plans, Our Engagement Program'.
- A reduction in on site costs of approximately 65% where electronic meters and ripple receivers are reconfigured through the optical interface, prolonging the service life and avoiding the need to replace an electronic meter or ripple receiver to accommodate the change in tariffs.
- A more efficient processing and customer satisfaction by avoiding interruption to supply.
- A simplified installation by having equipment that can be configured on site, thereby avoiding the need for field staff to arrange and carry multiple stock items in vehicles to suit installations requirements.
- The procurement of generic stock, rather than multiple preconfigured items which will reduce stock management, stock holding and supply chain costs.
- The elimination of refurbishment, testing and restocking costs where meter or ripple receiver replacement is avoided.

Failure to implement a CMS will lead to cost increases over time in logistics, supply chain, stock, field staff and refurbishment costs as the electronic meter population grows.

The project estimate is based on costings provided by meter vendors, estimates of labour and similar past costings. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

For further details refer to the 'Engineering Report Meter Configuration Management System', supported by the 'Management Plan Metering'.

## Protection

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

### 5.1 Nature of expenditure

Protection assets are critical to the safety and reliability of the distribution network. These assets monitor and operate plant, detect network faults and operate circuit breakers in substations and downstream distribution feeders. All of these asset types have a natural physical life, as well as an economic and technological support life.

### 5.2 Expenditure forecasts for next period

This sub-section details Ergon Energy's Protection capital expenditure forecasts for the next regulatory control period. It details the total capital expenditure forecasts for the period and the two protection projects that comprise this total.

#### 5.2.1 Total Protection capital expenditure

Table 7 provides a detailed breakdown of Ergon Energy's Protection capital expenditure forecasts for the next regulatory control period, expressed in direct costs.

**Table 7: Protection capital expenditure forecast (Direct costs, \$m real 2012-13)**

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Protection Review Program Rectification	3.2	3.2	3.3	3.4	3.4	17
Sensitive Earth Fault Protection Program	0.4	0.8	0.4	0.9	0.5	3
Total	4	4	4	4	4	20

#### 5.2.2 Project 1 – Protection Review Program Rectification

The purpose of this project is to undertake protection augmentation of substations and distribution feeders in order to ensure that protection equipment adequately protects the public, staff, environment and plant from network faults. It will address the recommendations of periodic desktop protection reviews.

Other drivers for this work include catering for network load changes, new lines and substations, network configuration changes, as well as compliance with the NER, and internal company standards with respect to protection and substation requirements.

Specific NER compliance requirements for protection schemes are detailed in Schedule 5.1.9 (c) and (f) of the NER:

*(c) Subject to clauses S5.1.9(k) and S5.1.9(l), a Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault of any fault type anywhere on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f).*

*(f) The fault clearance time of each breaker fail protection system or similar back-up protection system of a Network Service Provider must be such that a short circuit fault of any fault type that*

*is cleared in that time would not damage any part of the power system (other than the faulted element) while the fault current is flowing or being interrupted.*<sup>15</sup>

The Substation Protection Reviews undertaken assess existing protection schemes against these criteria. Where existing protection schemes do not meet these criteria and changing existing protection settings/parameters etc. cannot be made to address the gap, then other augmentations need to occur. The document 'Protection Review Rectification Strategy', supported by the broader 'Network Protection Strategy' provides more detail on this proposed program.

The bottom-up cost estimates are based on standard labour rates and internal knowledge of the cost of materials and equipment. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

### 5.2.3 Project 2 – Sensitive Earth Fault Protection Program

Ergon Energy is legally obliged under the *Electrical Safety Act 2002* (Qld) and associated Regulations and Codes of Practice to maintain a safe and reliable supply of electricity to customers. Phase-to-ground fault currents can be difficult to detect and can vary within a large range, becoming almost negligible in certain situations. Unlike other protection schemes, sensitive earth fault (SEF) protection offers the capability to detect residual currents across three phases and to generate an alarm or trip signal.

Statistical information provided by eSafe, Ergon's incident and safety recording system, identified 43 dangerous electrical events, of varying levels of personal injury, that could have been prevented by an operational SEF protection scheme. SEF protection can also help to prevent bushfires caused by fallen live conductors, which historically in Australia have not only caused significant material losses but have also claimed many lives.

SEF protection is considered an industry standard for protecting high voltage distribution feeders. Protection schemes on all new distribution feeders now include SEF under the Ergon Energy zone substation standards. It is also considered good engineering practice to retrofit SEF protection on existing distribution feeders without this capability. Absence of SEF protection in other jurisdictions has been identified as contributing to fatalities.

This project continues the installation of SEF protection schemes during the next regulatory control period to a target listing of 19 substations (61 feeder schemes) – out of Ergon Energy's existing 500 substations – where SEF protection is not currently in service but is required. Ergon Energy has prioritised targeted substations with feeder-protection relays of electromechanical disc type, which are not capable of providing SEF protection. This work is therefore a continuation of existing work. This is a multi-regulatory control period program because of the quantity of work required and Ergon Energy's capacity to resource the work.

The SEF protection program will where possible, coincide with other secondary system programs, such as the protection relay replacement program and other substation projects. This will minimise travel and labour costs and maximise network reliability and delivery with fewer outages.

Ergon Energy expects that this program will continue beyond the 2015-20 regulatory control period, targeting substation protection schemes lacking SEF protection. The document 'Sensitive Earth Faults (SEF) Protection Strategy', supported by the broader 'Network Protection Strategy' provides more detail on this proposed program.

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<sup>15</sup> Clauses (c) and (f), Schedule 5.1.9, *National Electricity Rules*, Version 65, October 2014, accessed October 2014.

Failing to deliver this SEF protection program may potentially result in:

- adverse impact upon public safety, the environment and service delivery, including environmental damage or bushfires due to the failure to detect fallen live lines starting bush fires
- health and safety risks to employees and the community through exposure to electrical faults
- non-compliance with Ergon Energy's responsibilities under the Electrical Safety Act 2002 (Qld) and the Codes of Practice
- greater costs of completing projects individually as opposed to delivering this program concurrently with other substation projects.

The bottom-up cost estimates are based on standard labour rates and internal knowledge of the cost of materials and equipment. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

## Miscellaneous

This section describes the conceptual nature of Ergon Energy's Miscellaneous capital expenditure.

### 6.1 Nature of expenditure

Miscellaneous capital expenditure refers to other minor programs covered by Ergon Energy's Other System capital expenditure category, which include:

- Low Voltage (LV) spreader and fuse program
- Substation alternating current (AC) system upgrade program
- Substation power transformer bunding.

### 6.2 Expenditure forecasts for next period

This sub-section details Ergon Energy's Miscellaneous capital expenditure forecasts and expected risk mitigation and performance outcomes for the next regulatory control period. It details the total capital expenditure forecasts for the period and then the three projects that comprise this total.

#### 6.2.1 Total Miscellaneous capital expenditure

Table 8 provides a detailed breakdown of Ergon Energy's Miscellaneous capital expenditure forecasts for the next regulatory control period, expressed in direct costs.

**Table 8: Miscellaneous capital expenditure forecast (Direct costs, \$m real 2012-13)**

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
LV Spreader And Fuse program	1.1	1.3	1.1	1.8	2.3	8
Substation AC System Upgrade Program	1.8	1.8	1.8	1.8	1.8	9
Substation Power Transformer Bunding	3.2	2.2	1.4	3.8	2.7	13
<b>Total</b>	<b>6</b>	<b>5</b>	<b>4</b>	<b>7</b>	<b>7</b>	<b>30</b>

#### 6.2.2 Project 1 – LV Spreader and Fuse program

Clashing LV conductors contribute on average 130,462 customer minutes per year over an average 22.1 outages per year. Clashing conductors can cause outages by either blowing LV or HV fuses or burning through the conductor and grounding the wires.

Clashing conductors that blow LV or HV fuses generally occur on long span, medium to larger sized conductors as they are generally less susceptible to burn down due to the larger cross sectional area. Outages that are caused by this mode are contributing on average 125,406 customer minutes per year over an average of 20 outages per year.

Small conductors are most likely to fail due to conductor clashing. This is due to lower inertia making them more likely to be displaced due to impact by adjacent trees or wind-borne impact. The smaller cross section also makes them more susceptible to burn down due to arcing and heating resulting from clashing. Outages that are caused by this mode are contributing 5,056 customer minutes per year over an average of 2.1 outages per year.

With any grounded LV conductor, there is a high risk that the conductor may stay live due to high conductor-to-ground impedances. In such circumstances, the fuses, either HV or LV, will not

experience sufficient fault current to blow, and the conductor will remain live. This represents a significant electrical hazard to the public.

Clashing LV conductors that subsequently fail and fall to ground can also start grass fires. Clashing conductors have been implicated in the starting of a number of large fires across the country, most notably, one of the recent Sydney fires in October 2013, and at least one of Victoria's 'Black Saturday' fires in February 2009.

LV conductor spreaders consist of an insulated rod section attached mid span to LV conductors, with the intended purpose of maintaining mid-span conductor clearances following impact by adjacent vegetation or wind-borne debris during the action of moderate to high winds. LV spreaders have been actively introduced into the network since the year 2000. They were only used on LV open wire mains in cyclonic areas and have been proven to be effective in the recent cyclones in north Queensland.

Because of its demonstrated effectiveness, Ergon Energy has recently extended its approach for application of LV spreaders across its entire network. This has been considered in conjunction with the extensive problem now recognised with aged and annealing 7/0.64 copper. Refer to document 'Engineering Report Distribution Feeder Reconductoring Program'.

LV spreader installation is a straightforward task – it takes around 10 minutes per span by a single person and provides immediate risk mitigation against LV clashing under high wind and fault conditions. LV spreaders are therefore relatively inexpensive to install, at approximately \$350 per spreader, with total cost is considered lower than the grossly disproportionate tests required under legislation. Refer also to the document 'Forecast Expenditure Summary Asset Renewal 2015 to 2020' for discussion about Ergon Energy's approach to this test. Some spans may require two or three spreaders installed.

Ergon Energy proposes retrofitting LV fuses to all of its distribution transformers.

LV transformer fuses attempt to protect transformers and LV conductors against thermal overload and clear fault currents resulting from phase-to-phase or phase-to-neutral short circuits. In some cases, the additional protection LV fuses provide is against transformer overload and against conductor burn down.

The fuse size necessary to cater for normal load currents, results in fuse ratings that have no possibility of clearing all phase-to-earth faults due to the likely earth-fault resistance. The impedance/resistance of structures such as concrete, bitumen, and even gravel is relatively high, which results in lower-fault currents than detectable by the fuse. The LV fuses can generally only clear faults that involve phase-to-phase, or phase-to-neutral conductor contact, and then not necessarily for the entire LV branch. LV fuses are often not able to provide a complete level of protection to sections of the LV network remote from the transformer, but in general they do provide a significantly better level of protection than that provided by HV fuses alone.

In 2002, Ergon Energy established that LV fuses would be fitted to all new installations of distribution transformers, however chose not to retrofit where not already fitted.

As a result of the investigations relating to recent conductor failures, Ergon Energy now believes that retrofitting installation of LV fuses at all distribution transformer locations will mitigate public safety concerns and risk, by reducing the opportunity for lines to fail when they clash.

The proposed program involves Ergon Energy undertaking programmed and targeted installation of LV spreaders on identified spans, and retrofitting LV fuses to distribution transformers to the current standard. Together these approaches will assist to mitigate the high risks arising from live conductors on the ground and being easily accessible to the community. The document 'Engineering Report Low Voltage Spreaders and Fuses', supported by the 'Management Plan Overhead Feeder Circuits', provides more detail on this proposed program.

Ergon Energy's intended outcomes for this program are:

- reduced clashing and grounded conductors in high risk areas
- improved protection on LV networks that do not have LV fuses
- ensured compliance with coronial recommendations in response to a 2007 fatality involving a grounded live line.

Ergon Energy has based its capital expenditure forecasts for this project on its expenditure for the current regulatory control period. The program estimates are based on standard estimates for each asset type requiring replacement. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

### **6.2.3 Project 2 – Substation AC System Upgrade program**

Many of Ergon Energy's substations were designed by legacy organisations and are now up to 50 or 60 years old. The designs were suitable when they were built but are not necessarily suitable for modern day needs.

AC systems installed within zone substations are designed to supply auxiliary power for lighting, power circuits, motors and supply-to-battery chargers for direct current (DC) systems. This AC power is usually supplied from the network via small transformers within the substation and occasionally from an external supply outside the substation. Sites may have one or two AC supply sources.

Ergon Energy manages approximately 451 AC auxiliary systems, roughly equivalent to the number of zone substations.

Under fault conditions, substations experience an earth-potential rise. If customers are supplied from the substation's services transformer, their houses also experience a voltage rise on their equipment. As they have a remote earth point (Common Multiple Earth System), the situation introduces dangerous step-and-touch potentials that could result in electric shocks or worse. The original designs did not contemplate the modern day fault levels. The same problem occurs if a pole-mounted distribution transformer outside the substation supplies customers as well as supply into the substation.

A recent review identified the need, for public safety reasons, to separate customer and substation supplies. This requires new distribution transformers or new substation transformers (depending on situation) to be installed.

The proposed project presents solutions for health and safety hazards, from exporting fault current arising out of some zone substation secondary AC supply systems extending beyond the substation earth grid, or providing secondary supply to a zone substation from outside of the substation earth grid perimeter.

The first solution involves providing an AC supply originating from inside the substation. The potential neutral rise is kept within the substation connected HV and LV earthing system. The solution requires the installation of a local LV distribution transformer inside the perimeter of the substation earth grid. This may also require the installation of a LV switchboard to allow distribution of the LV circuits.

The second solution involves an alternate earthing system. Substations that have their local AC system supplying LV loads beyond the substation earthing system can lead to a potential rise on these cables should a fault occur within the substation. This risk is eliminated by installing a LV distribution transformer outside the substation earthing system and nearby to the anticipated connected load. The transformer can be supplied from any nearby HV distribution circuit. This would facilitate the removal of the outgoing LV circuits from the substation.

The proposed program expenditure is intended to separate substation LV supply systems from customer LV supply systems to mitigate public safety risks due to transfer of earth-potential rise. The



document 'Engineering Report AC Systems', supported by the 'Management Plan Auxiliary Substation Components', provides more detail on this proposed program.

The program estimates are based on standard estimates for each asset type requiring replacement. Further information about the build-up of these costs is detailed in the 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

#### **6.2.4 Project 3 – Substation Power Transformer Bunding**

The principal legislation addressing pollution in Queensland is the *Environmental Protection Act 1994* (Qld). It imposes a general environmental duty on all persons undertaking an activity to take all reasonable and practicable measures to prevent or minimise any environmental harm.

A transformer bund captures any transformer oil spill and prevents its migration to adjacent transformers and other site equipment, and release from the substation, and into the environment.

The nature of the transformer bund is designed to suit the power transformer's requirements – the style of oil facilities depend on the specific risk at the site.

Ergon Energy has conducted a review of its current oil containment program to assess whether sites comply with the Australian standard. It performed a risk assessment of each existing site to determine what oil containment measures are required. Older, and more degraded, transformers have a higher risk of failure and hence oil release. Risks are also substantially increased if the site is uphill of a water supply dam or a river, or if there is potential to leech directly into the ocean.

This proposed program involves progressively addressing sites that have been found to be without adequate oil containment protection, by prioritising identified sites for retrofitting bunding and/or installing oil separation and containment where required. The program is to retrofit oil containment at identified substation sites commencing with those with the highest environmental risk (i.e. sites that have the high probability of an incident and/or high volume of oil that could be released into a sensitive environment). Further details can be found in the document 'Engineering Report Zone Substation Bunding Upgrade Program', supported by the 'Management Plans Operational Building and Sites'.

The key benefit of this program is that Ergon Energy will significantly reduce the probability of environmental contamination as a result of an oil leak from a large power transformer into a sensitive environment. It will enable Ergon Energy to discharge more effectively its environmental duties under the *Environmental Protection Act 1994* (Qld).

The program estimates are based on standard estimates for each asset type requiring replacement. Further information about the build-up of these costs is detailed in Ergon Energy's 'Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020'.

## Meeting Rules' requirements

### 7.1 The capital expenditure objectives

The National Electricity Rules set out the objectives that Ergon Energy's proposed capital expenditure must achieve 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. Standard Control Services are grouped into five categories: network services, connection services, metering services, ancillary network services and public lighting services. The Standard Control Services that Ergon Energy provides to customers are set out in the AER's Framework and Approach – Ergon and Energex 2015-2020 paper.<sup>16</sup> The proposed Other System expenditure for Standard Control Services relates to network services.

Ergon Energy believes that its proposed capital expenditure for Other System and Enabling Technology in the next regulatory control period contributes to achieving the objectives of its total forecast capital expenditure as follows:

- Meeting and managing expected demand for standard control services, as required by clause 6.5.7(a)(1), is one of the objectives of Other System capital expenditure. The nature of Other System expenditure means that there are several objectives that the expenditure will satisfy, depending on the need that has been identified. The expenditure for the projects and programs set out in Section 4 of this Summary is intended to meet or manage expected demand for standard controls services as follows.
- The SCADA system is the fundamental hardware and software system that supports the provision of standard control services as it enables Ergon Energy to monitor and control transformers, switchgear and other primary and secondary systems that control the flow of electricity and hence provides standard control services. The ADAS project is necessary so that

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<sup>16</sup> AER, Framework and Approach – Ergon and Energex 2015-2020, April 2014, p 51.

uncontrolled growth in IEDs does not overburden the SCADA system and compromise Ergon Energy's ability to continue to supply those services. Similarly, the need to invest in Master Station SCADA and associated cyber security protection is necessary, and has been independently assessed as prudent, to mitigate increasing cyber security risks to the SCADA system. Together these projects are necessary for Ergon Energy to continue to meet expected demand for network (standard control) services in the face of exogenous factors.

- Another objective of part of Ergon Energy's proposed Other System expenditure is to improve the efficiency with which Ergon Energy manages future demand for standard control services. Projects such as the Integrated Electronic Device Monitoring and Support (iNOC), DMS and the Regulator Remote Communications Strategy described in Section 4 will enable Ergon Energy to meet the expected demand for standard control services. Completion of this will be in a more efficient manner by automating manual processes, operating the network at higher utilisation reliably and improving network planning information accuracy leading to outcomes that are more cost efficient. Combined, this will enable Ergon Energy to meet the expected demand for standard control services across the network in a cost-effective manner.
- Part of the Other System 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). Specifically, each program and project described in this Summary has been proposed to satisfy Ergon Energy's technical, safety and environmental obligations under the National Electricity Rules, *Electrical Safety Act 2002* (Qld) and *Environmental Protection Act 1994* (Qld) respectively.
- Even without the regulatory obligations described above, part of the Other System expenditure that Ergon Energy proposes is still necessary to maintain the quality, reliability and security of supply of standard control services, and hence the reliability and security of supply of the distribution system, and would therefore satisfy the objective in clause 6.5.7(a)(3). The operational technology investments proposed in Section 4 are directed at the fundamental systems that enable the delivery of standard control services. Exogenous factors such as the growth of IEDs and cyber security threats must be proactively managed to avoid impacting the quality, reliability and security of supply of the distribution system, additionally the this growth if not managed, can adversely affect the communications and control systems that support the delivery of electricity.
- Similarly, the Protection Review Program in Section 5 is needed to manage increases in fault current levels over time that have been caused by increasing demand on the distribution system. Failure to identify and resolve fault current exceedances would impact the safety, quality, reliability and security of supply because network assets may be operated outside of their technical operating limits. This will lead to the malfunction or failure of protection relays to operate as intended, which may potentially result in significant damage to equipment, increased restoration time after an outage or exposure to safety injuries to the public and staff.
- Part of the Other System 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 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.

As discussed in the previous point above to discharge these obligations, Ergon Energy has proposed specific projects and programs to mitigate known safety risks and, in the case of the

Protection Review Program, to address future safety risks as they are identified through periodic desktop reviews.

## 7.2 The capital expenditure criteria and factors

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.*

Therefore, Ergon Energy must demonstrate that its proposed capital expenditure reasonably reflects the criteria in clause 6.5.7(c) by reference to the factors in clause 6.5.7(e).

## **The efficient and prudent costs of achieving the objectives**

The needs that give rise to Other System expenditure vary according to the project or program that Ergon Energy has proposed. The growth in IEDs and the increasing risk of cyber security threats require Ergon Energy to propose several operational technology solutions in Section 5 to enable it to manage the risk of adverse impacts on its ability to deliver standard control services. Where possible these projects have been subjected to independent reviews that support Ergon Energy's proposed actions. The 'Distribution Management System Strategy' and 'Regulator Remote Communications Strategy', also set out in Section 4, represent prudent actions because they are necessary to manage the emergence of a smarter, bi-directional and hence more complex network. A centralised and automated approach to managing the distribution system that these projects have adopted will improve the network's utilisation, enable Ergon to make better operational and planning decisions and constrain growth in future staffing costs that would otherwise arise as the network becomes more complex. Additionally, each project and program proposed in Section 6 and Section 7 is primarily necessary for Ergon Energy to discharge specific technical, safety and environmental statutory obligations under state and federal legislation. Together these projects and programs represent the actions of a prudent operator.

To develop an efficient cost base Ergon Energy has adopted a robust methodology to estimate the costs of projects and programs of works. These costs, and how they are developed, are described in the document titled 'Capital Expenditure Forecast Unit Costs Methodologies 2015 to 2020'.

Depending on the project or program that is proposed, the methodology for forecasting expenditure varies. The Operational Technology projects and programs set out in Section 4 are supported by vendor pricing for off the shelf technologies, contract tender prices for custom technologies, standard labour rates and SME estimates of time to implement and historical costs where relevant.

For every project or program the estimation approach used results in an efficient cost base as the forecast unit costs which are based upon independent costings where possible, or the most recent and therefore realistic cost of similar projects or devices delivered by Ergon Energy in the current regulatory control period. For these reasons Ergon Energy considers its capital expenditure to be 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 Other System 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 reasonable and robust estimation methodologies. These methodologies exclude inefficient costs when evident and includes only those costs to do the task in establishing direct costs. Mobilisation and contractor costs are assessed and applied on a per-program basis based on similar costs incurred by each program in the current period. For further details see the 'Capital Expenditure Forecast Unit Cost Methodologies 2015 to 2020' paper.

## **Having regard for the factors**

Ergon Energy's proposed capital expenditure reasonably reflects the prudent and efficient costs of achieving the objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure 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<sup>17</sup>, 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 Compares' document.

- In relation to sub clause (5), Ergon Energy has set out, in Tables 1 and 3 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 3, 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.
- Where its current period expenditure has deviated from the AER's allowance, Ergon Energy has explained this by reference to drivers and circumstances that support the prudence 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 prudence and efficiency.
- In relation to sub clause (5A), Ergon Energy has conducted a comprehensive program of customer engagement to identify the concerns of its customers 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 throughout this Summary and in the document entitled 'Informing our Plans, Our Engagement Programs'.

This process highlighted that Ergon Energy's customers wish to maintain reliability performance at current levels to reduce upward pressures on retail electricity prices. Accordingly, the majority of Ergon Energy's Other System capital expenditure in Section 4, and specifically the Integrated Electronic Device Monitoring and Support (iNOC), the ADAS, Master SCADA Strategy and the cyber security projects, will maintain reliability performance through managing emerging risks such as the growth in IEDs and cyber security threats that, if left uncontrolled, would otherwise cause an increased risk of reliability impacts on the distribution system.

The process also demonstrated the community's desire for Ergon Energy to operate the network in a way that supports greater customer choice and control in electricity supply solutions. Ergon Energy's Other System capital expenditure in Section 4 does this by proposing systems and technology solutions such as the DMS and Remote Recloser Communications that are necessary to manage demand management, distributed generation and other emerging technologies that facilitate greater choice in consumer energy supply solutions. They also support Ergon Energy's journey to the best possible price by enabling Ergon Energy to make the most effective use of its existing assets. This is achieved by reducing outages, improving network utilisation and improving the accuracy of the data that supports network planning decisions.

Finally, as expected by its customers, Ergon Energy is committed to the maintenance of a safe distribution system and the works described in Section 5 and Section 6 that it proposes to undertake are intended to mitigate known and potential safety risks to Ergon Energy employees and to the public.

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<sup>17</sup> Australian Energy Regulator, *Expenditure Forecast Assessment Guideline – Regulatory information notices for category analysis*, <http://www.aer.gov.au/node/21843>, accessed 22 August 2014.

In relation to sub clauses (6) and (7), several of the proposed Other System projects and programs present opportunities for assessing the relative prices and substitution possibilities of operating and capital expenditure. Specifically, the Integrated Electronic Device Monitoring and Support (iNOC) and DMS described in Section 4 are necessary to constrain growth in future staffing costs that would occur if existing operational technology solutions continued to be deployed without intervention. This is because both projects represent a centralised, automated, and coordinated approach to managing expected increases in the complexity of operational technology in the distribution system. In relation to other projects and programs in Section 4, because of their nature, capital rather than operating expenditure has been determined as the most prudent means of addressing the identified need. In relation to the projects and programs described in Section 5 and Section 6, Ergon Energy has an obligation to deliver a capital works solution to satisfy its statutory obligations.

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 Other System 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 ICT subsidiary Sparq Solutions does provide ICT services for Other System expenditure that would constitute 'direct' costs and which would thus form part of the expenditure proposed in Sections 6.1 and 6.2.

When this is the case they procure the ICT portion if requested through their procurement processes but are costed directly to Ergon. Together Ergon and SPARQ Solutions determine if the work required can be sourced inside SPARQ Solutions, or it is put out through a competitive tender process either to existing procurement panels or the open market. All work that is completed by Sparq Solutions must be commercially competitive and is available through Open Book pricing as per the Sparq Solutions shareholders agreement.

In relation to sub clause (10), clause 5.17.4 of the Rules is not applicable to Other System capital expenditure.

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). The outcomes of such reports are not directly relevant to the expenditure Ergon Energy has proposed for Other System and hence Ergon Energy has not had regard for them in developing this expenditure forecast. Nevertheless Ergon Energy notes that no capital expenditure projects have been subjected to the RIT-D to date and as a result there are no relevant final project assessment reports for Ergon Energy to have regard to in proposing its Other System expenditure for the 2015-20 regulatory control period.

In relation to sub clause (12), Ergon Energy has not been notified of any other factor the AER considers relevant and has notified Ergon Energy is a capital expenditure factor.

## Appendices

### Appendix A. Definitions, acronyms and abbreviations

#### 1. Definitions

Term	Definition
IEC61850	International Electrotechnical Commission standard design of electrical substation automation
Other System	Other System and Enabling Technologies
UbiNet	Ubiquitous Network

#### 2. Acronyms and abbreviations

Abbreviation or acronym	Definition
AC	Alternative current
ADAS	Alternative Data Acquisition Service
AER	Australian Energy Regulator
CARE	Cyclone Area Reliability Enhancement
CMS	Meter Configuration Management System
DC	Direct current
DMS	Distribution Management System
EDSD	Electricity Distribution and Service Delivery
ENCAP	Electricity Network Capital Program
HV	High voltage
IED	Intelligent Electronic Device
iNOC	Integrated Network Operations Centre
IP	Internet Protocol
LV	Low voltage
NER	National Electricity Rules
P25	Mobile radio system
QCA	Queensland Competition Authority
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SEF	Sensitive earth fault
SME	Subject Matter Expert





## Appendix B. References

### 3. 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 <i>Electrical Safety Act 2002</i> (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 <i>Electricity Act 1994</i> (Qld) to undertake electricity distribution activities in Queensland.
Electrical Safety Act 2002 (Qld)	State legislation directed at eliminating the human cost to individuals, families and the community of death, injury and destruction that can be caused by electricity.
Electricity Act 1994 (Qld)	State legislation governing the supply, distribution, sale and use of electricity in Queensland.
Environmental Protection Act 1994 (Qld)	State legislation governing the protection of Queensland's environment while allowing for development that improves the total quality of life, both now and in the future, in a way that maintains the ecological processes on which life depends (ecologically sustainable development).
National Electricity Rules	Statutory instrument made under the <i>National Electricity (South Australia) Act 1996</i> 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.

### 4. Strategic documentation

Name	Description
10 Year 2015 – 2025 Master Station SCADA Strategy	This document is a strategy paper for the Ergon Energy SCADA system. It outlines the philosophy for maintaining and developing SCADA capabilities for the business without going into specific detail or timeframes for individual projects. <i>Supporting business case:</i> <ul style="list-style-type: none"> <li>Master Station SCADA Strategy</li> </ul>
Alternative Data Acquisition Service Strategy 2020	This document is to outline the strategy for developing and maintaining an ADAS to meet the data collection requirements of the business without going into specific detail or timeframes for individual projects. <i>Supporting business case:</i> <ul style="list-style-type: none"> <li>Alternative Data Acquisition Service - Phase 2</li> </ul>
Distribution Management Strategy	The purpose of this strategy is to implement an integrated DMS and Outage Management System within Ergon Energy to achieve efficiencies in day to day operations. <i>Supporting business case:</i> <ul style="list-style-type: none"> <li>DMS</li> </ul>

Name	Description
Integrated Network Operations Centre (iNOC) Strategy	<p>This document is a strategy paper for Ergon Energy's iNOC. The intent of this document is to outline the strategy for the implementation and growth phases for an iNOC but without going into specific detail or timeframes for individual projects.</p> <p><i>Supporting business case:</i></p> <ul style="list-style-type: none"> <li>• Integrated Electronic Device Monitoring and Support</li> </ul>
Network Control Strategy	<p>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 control issues and provide strategic direction for the future.</p>
Network Optimisation Asset Strategy	<p>The Network 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.</p>
Network Protection Strategy	<p>The purpose and scope of this Network 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 in which it resides. This strategy aims to address current protection issues and provide strategic direction for the future.</p>
Operational Network Security Strategy	<p>This document outlines a strategy to protect Ergon Energy's operational assets from cyber-attack and covers all network assets connected to the Ergon Energy Operational Communications Network, and SCADA Network</p> <p><i>Supporting business case:</i></p> <ul style="list-style-type: none"> <li>• Operational Network Security</li> </ul>
Operational Technology Architecture and Environment Strategy 2020	<p>This strategy paper will explore the dynamics motivating operational technology systems growth, the key requirements, or strategies that Ergon Energy needs to embrace and from these determine what the OT environment should look like by 2020.</p>
Protection Review Rectification Strategy	<p>This strategy details the requirement to implement the findings of protection reviews of zone substations and associated feeders in order to mitigate protection related risks.</p> <p><i>Supporting business case:</i></p> <ul style="list-style-type: none"> <li>• Protection Review Rectification Program</li> </ul>
Regulator Remote Communications Strategy	<p>The purpose of this strategy is to provide future direction to address HV regulators to have remote communications for engineering access and SCADA/DMS data by 2030 (75% by 2020).</p> <p><i>Supporting business case:</i></p> <ul style="list-style-type: none"> <li>• Regulator Remote Communications Strategy</li> </ul>
Sensitive Earth Faults (SEF) Protection Strategy	<p>This document outlines a strategy for implementing SEF on Ergon Energy feeders for detecting high impedance earth faults.</p> <p><i>Supporting business case:</i></p> <ul style="list-style-type: none"> <li>• Sensitive Earth Fault (SEF) Protection Program</li> </ul>

## 5. Network Optimisation Management Plans

These documents describe, for the stated asset type, Ergon Energy's approach to managing its assets, cognisant of appropriate legislation, regulatory obligations, asset management strategies, and standards, both internal and external. They are developed pursuant to Ergon Energy's broader 'Network Optimisation Asset Strategy'.

Further these documents detail the key projects and programs underpinning activities for the period 2013-14 to 2019-20 in addition to the basis upon which Ergon Energy derives its capital and operating expenditure forecasts.

Name	Description
Management Plan Auxiliary Substation Components	Includes Substation AC System Upgrades
Management Plan Metering	Includes the Meter Configuration Management System
Management Plan Operational Building and Sites	Includes Substation Power Transformer Bunding
Management Plan Overhead Feeder Circuits	Includes LV Spreaders and Fuses
Management Plan Protection and Control	Includes Protection, Control and Operational Technology <ul style="list-style-type: none"> <li>• Sensitive Earth Faults</li> <li>• Protection Review Program Rectification</li> <li>• Master Station SCADA</li> <li>• Regulator Remote Communications</li> <li>• Alternative Data Acquisition Service</li> <li>• Distribution Management System</li> <li>• Integrated Network Operations Centre</li> <li>• Operational Network Security</li> </ul>

## 6. Supporting documentation

Name	Description
Forecast Expenditure Summary Asset Renewal 2015-2020	The purpose of this summary document is to explain and justify Ergon Energy's Asset Renewal capital expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
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.
Forecast Expenditure Summary Unit Cost Methodologies 2015 to 2020	The purpose of this summary document is to explain and justify the methodologies applied by Ergon Energy to develop unit cost estimates for its Standard Control Services (SCS) and Alternative Control Services (ACS) 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.

## 7. Engineering Reports

Name	Description	Supporting Business Case
Engineering Report AC Systems	The purpose of this report is to present an analysis of Ergon Energy's Substation AC Supply System assets, identify asset specific risks and consider remedial actions and consider asset characteristics in the context of any asset upgrade program.	Substation AC System Upgrade Program
Engineering Report 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
Engineering Report Low Voltage Spreaders and Fuses	This report presents an analysis of Ergon Energy's LV network, identifies safety risks and considers remedial actions, to satisfactorily address the recommendations of the coroner's report. This report aims to support the safe and reliable serviceability of the LV network by avoiding the grounding of wires. This report will also take a holistic approach in reviewing LV network protection with an aim to improve the protection and safety of the network and the safety for the public.	LV Spreaders and Fuse Program
Engineering Report Meter Configuration Management System	This report promotes the use of a state of the art generic handheld unit to configure electronic meters and ripple receivers via their communications optical port. This will permit direct uploading of details to host asset management and Customer Information Systems to improve data quality and validation for market operations.	MET EECL NEW Metering Configuration Management

Name	Description	Supporting Business Case
Engineering Report Zone Substation Bunding Upgrade Program	The purpose of this report is to present an analysis of Ergon Energy's environmental risk at sites with large power transformers assets, by and large zone substations, to identify asset specific risks in respect of issue of oil leaking into the environment in the context of developing an upgrade program.	Substation Power Transformer Bunding