Distribution Annual Planning Report
2017-18 to 2021-22

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DAPR 2017_Assignment Table

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Further Information

Further information on Ergon Energy’s network management is available on our website:


Disclaimer

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Executive Summary

Ergon Energy’s Distribution Annual Planning Report 2017-18 to 2021-22 (DAPR) details the corporation’s future direction and intentions for the next five years in an energy landscape increasingly dominated by distributed generation and a record peak demand. Ergon Energy’s vision as part of the Energy Queensland Limited Group, “we energise Queensland communities”, balances security, affordability and sustainability for our customers and shareholders.

This year’s DAPR is delivered with a focus on safety of our staff, customers and the community, drawing on the capability of a skilled workforce to meet the energy needs of our customers. We look to build capability, leverage technology and optimise our investments while enabling renewable generation and the connection of batteries and electric vehicles to the network platform.

The DAPR provides the community and stakeholders with an insight into the key challenges we face and our responses to them. Many solutions seek customer and industry participation in addressing network challenges. The addition of photovoltaic penetration rates to this year’s DAPR online map increases the transparency of our network planning, asset management and investment decision making processes providing guidance to stakeholders for solutions.

This planning report coincides with the third year of the Australian Energy Regulator’s (AER) five-year determination on our revenue allowance, for which the final Distribution Determination was published in October 2015.

Ergon Energy and Energex are currently in the advanced stages of implementing the Queensland Government’s electricity industry reforms. The centrepiece of this reform has been the creation of Energy Queensland Limited through the merger of Ergon Energy, Energex and SPARQ Solutions. Consequently; increasingly collaborative development of network practices and reporting formats are evidenced in this DAPR.

Key outcomes of the planning process this year are:

Demand fluctuation:

- The network peak demand and energy delivered this year featured fluctuations from previous years. Record sustained warm temperatures across Queensland over the summer months resulted in the system-wide peak of 2,637 MW at 7.30 pm on Monday 13 February 2017, an all-time record. This peak demand was aligned with a 10PoE peak (one in 10 year event). The additional destructive effects of Tropical Cyclone Debbie to the network and state infrastructure overall, resulted in a reduction in energy delivered which otherwise would have been expected.

- The take up of residential solar energy or solar photovoltaic (PV) systems is changing feeder level load shapes and we are responding in a range of ways to help meet customer needs.

Reductions in planned augmentation investment:

- No new limitations subject to RIT-D have been identified under the current forecast.

- Of the 1,185 distribution feeders in the Ergon Energy network, there are 110 that currently experience seasonal limitation and 119 that are forecast to be limited in the next two years. The limitation on these feeders may be resolved through operational response.
Executive Summary

This lower level of network limitation from previous years reflects; network improvements, overall steady demand forecast and changing customer energy usage profiles.

Sustained replacement and refurbishment investment:

- Investment in the refurbishment of assets continues to be our most significant investment category.
- Inspection and condition monitoring work has provided the driver behind more than 20 specific component renewal programs.
- There are a number of large discrete projects with an estimated capital cost of $2 million or more that are in planning or concept stage. These have not yet achieved approval and therefore are not considered to be committed projects at this point in time.

Strong reliability performance:

- In 2016-17 we met all six Minimum Service Standards (MSS) for network reliability. In 2018 Ergon Energy customers are forecast to experience better than Minimum Service Standard reliability performance. This has resulted from Ergon Energy’s focus on continuous improvement and application of information and technology to support reduced interruption duration.
- Unplanned outage duration and frequency have improved by 17% and 11% respectively in the last five years. A number of targeted initiatives have contributed to improve our outage management and fault restoration outcomes. These include; the increased adoption and functionality of field ‘Toughpads’, the automatic circuit recloser (ACR) and remote controlled gas switch strategies, and the implementation of new ‘smart’ technologies such as communications capable line fault indicators and Fuse Savers.
- Favourable unplanned outage performance against the AER’s Service Target Performance Incentive Scheme (STPIS) targets has additionally provided a positive financial benefit for the business.

Supporting solar penetration and managing the impact:

- Solar PV connections continue to increase across Ergon Energy’s network, with 26% of detached houses currently having a solar PV system connected. Over the past 12 months the rate of connections has increased by 20%.
- Strategic planning initiatives such as the Feeder of the Future Program and the trial of the 230 Volt LV Standard will help us manage network voltages for all customers and enable further uptake of solar PV.

Collaborative approach to new technologies:

- The Ergon Energy and Energex joint standard for micro embedded generation units up to 30 kVA has been modified to enable greater customer opportunity to connect Battery Energy Storage Systems BESSs to new or existing installations.
- We are currently managing 118 active large scale embedded generation projects of which three include BESSs as part of their proposed designs.
• We are working with industry partners and the Queensland Government to enable an Electric Vehicle charging highway from Coolangatta to Cairns.

Increase in Large Scale Renewables:

• Ergon Energy is collaborating on a large number of major renewable energy projects and is anticipating investments that could provide up to 5.5 GW of solar sourced energy in the coming years. Projects such as those at Barcaldine, Normanton, Longreach and Collinsville represent initiatives that will form a key part of our future business and that will enhance economic growth across Queensland.

Our planning and response capability has been demonstrated in the recent response to Tropical Cyclone Debbie where more than 67,000 customers were reconnected to the grid after the catastrophic storm event. Ergon Energy’s mobile high voltage generation fleet was expanded from three to five units late last year with the construction of an additional two units. Four of the units were deployed to the Tropical Cyclone Debbie response effort.

Ergon Energy will continue to engage our customers in developing strategies that provide greater choice and control and that help us to make better use of the existing infrastructure. Developing our role as a market enabler of new energy solutions, especially those that support demand management and network utilisation, is fundamental to delivering on our best possible price commitment.

We believe our customers are part of the solution to the challenges we face together, and trust that this DAPR provides our stakeholders with the opportunity to review our plans and engage with us on the path forward. It is only through collaboration that we will best target our future investments and be able to work together to deliver the best outcome for regional Queensland.
1.1  Foreword
1.2  Reporting Requirements
1.3  Electricity Network Overview
1.4  Significant Changes from Previous Year’s DAPR
1.5  DAPR Enquiries
1. Introduction

1.1 Foreword

This Distribution Annual Planning Report (DAPR) details Ergon Energy’s intentions for the next five years in relation to: load forecasting, demand management, new capacity investments, asset renewals, reliability and supply quality in operating and managing the network.

The DAPR is intended to support our commitment to open, transparent stakeholder engagement. It presents the outcomes from our distribution planning carried out in 2016-17 for the forward planning period 2017-18 to 2021-22 and is also a requirement under the National Electricity Rules (NER).

The DAPR provides information for interested parties on:

- our network and operating environment and customer engagement
- key emerging network challenges and opportunities that we are facing
- our approach to asset management and investment governance
- the trend in network demand and our forecasting methodology (energy and load)
- our planning framework, including our planning criteria and other methodologies
- the network’s current and emerging limitations and our risk mitigation strategies
- an overview of our demand and energy management activities
- our approach to asset life-cycle management and asset renewal
- the network’s reliability performance, including details on our worst performing feeders
- the quality of supply being experienced and the network’s power quality performance
- our metering strategy and other associated technology investments.

The investment plans outlined in this DAPR continue to reflect the strategies presented in our Regulatory Proposal for 2015-16 to 2019-20 in line with the AER’s Distribution Determination.

Ergon Energy and Energex are now operating under our parent company Energy Queensland Limited. This new company structure was created through a merger on 30 June 2016. Collaboration has been undertaken in an effort to progress as much as possible towards the development of a common DAPR format. However, as we are maintaining separate Distribution Authorities, we will continue to present separate DAPRs.

Ergon Energy’s planning maps and forecast load and capacity information are now presented via an Environmental Systems Research Institute (ESRI) Graphical Information System (GIS) portal. This provides an interactive experience, with sub-transmission and distribution limitations now highlighted and tables presented in their geospatial context. The ESRI GIS Portal is accessible via the following weblink:

Chapter 1. Introduction

1.2 Reporting Requirements

As a Distribution Network Service Provider (DNSP), Ergon Energy is required to publish a DAPR under Rule 5.13 and Schedule 5.8 of the NER and clause 2.2 of the Electricity Distribution Network Code. Specifically, Ergon Energy is required to:

- publish the DAPR by 30 September each year\(^1\), setting out the results of the distribution annual planning review for the forward planning period
- include the information specified in Schedule 5.8 in its DAPR
- as soon as practicable after it publishes a DAPR, publish on its website contact details for queries on the DAPR.

In addition to the above, Ergon Energy also has DAPR reporting requirements under its Distribution Authority issued under the *Electricity Act 1994* (Qld). Specifically, Ergon Energy is required to:

- report on its economic customer-value based approach to reliability
- provide an overview of the program to improve the reliability on the worst-performing distribution feeders, and report on the outcome for the worst-performing feeders
- report on the measures taken to achieve its Safety Net targets (base level network security in the new network planning criteria) and report on performance against the Safety Net targets.

These requirements are cross-referenced in Appendix D of this report.

New Reporting Requirement – Distribution System Limitation Template

On the 1 July 2017 a National Electricity Rule (Rule) change came into effect requiring DNSPs to submit a Distribution System Limitation template (DAPR template) at the same time of publishing the DAPR. The DAPR template is aimed at improving the consistency and usability of DAPRs across the National Electricity Market (NEM) and improving the ability for non-network providers to identify and propose solutions to addressed identified network needs.

At the time the final rule was issued the AER consulted with DNSPs concerning delivery timeframes for the 2017 reporting period. As Ergon Energy and Energex are bound to an earlier DAPR delivery date a formal request was made to the AER to extend the delivery date of the DAPR template to the 31 December 2017 to align with other DNSP DAPR publishing dates.

The AER have agreed to this request and in accordance with this agreement Ergon Energy will complete and publish the DAPR template before the 31 December 2017 and provide a supplementary document explaining the link between this information and our DAPR.

1.3 Network Overview

Electricity is a commodity that underpins our modern society, providing energy to domestic, commercial, industrial, agricultural and mining sectors, supporting lifestyle and prosperity of individuals and our state as a whole.

\(^1\) Electricity Distribution Network Code (EDNC), cl 2.2.1(b)
The electricity grid, including transmission and distribution networks, connects and facilitates the distribution of electrical energy between generators and users. The bulk of electricity is generated on demand at locations remote to the point of supply. The State’s largest generators typically connect to the State’s transmission network, which is owned and operated by Powerlink Queensland. The transmission network supplies bulk electricity to Ergon Energy’s distribution network, which in turn supplies regional Queensland’s industries, homes and businesses. However, in recent times an increasing number of generators, including renewable energy providers such as solar farms, are supplying directly into our distribution network.

Figure 1 illustrates how electricity is generated, transmitted and distributed to customers. The electricity carried over Powerlink’s network is delivered in bulk to substations that connect to overhead or underground sub-transmission feeders to supply zone substations. Zone substations connect to overhead or underground distribution feeders. Distribution feeders distribute electricity to transformers that supply the low voltage lines at the voltage level required by the end user. Customers use the network to obtain electricity, and to export electricity when excess power is generated.

The capacity of a network at each step along the supply chain is the amount of electricity it can carry at any point in time. The network must have enough capacity to handle the diversified network demand of every customer at any point in time. Peak demand occurs at different times in different parts of the network. Transmission levels must have enough capacity to meet the global peak demand for the region serviced, whereas distribution levels of the network must have enough capacity to meet peak demand in the local area.

With the increase in embedded generation (EG) systems being connected to the network, including small and large scale solar PV and other renewable energy sources, electricity is now being generated and exported into the grid from customers’ premises. Depending on the size and number of these systems, parts of the conventional supply chain are now at times operating in reverse, creating both challenges and opportunities for the network.
Chapter 1. Introduction

1.4 Significant Changes from Previous Year’s DAPR

The following are the key changes to this year’s DAPR, as compared to the 2016 DAPR:

- Ergon Energy is currently in the advanced stages of implementing the Queensland Government’s electricity industry reform with the creation of Energy Queensland Limited. The Corporate Overview, Vision and Purpose described in Chapter 2 are now aligned to Energy Queensland Limited.

- Review and improve the methods of forecasting methodology over the next five years to include system level, regional level and selected metered points across the network, both

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2 This figure is simplified. Ergon Energy owns and operates assets at a wide variety of voltages, including:
- Sub-transmission lines at 220 kV, 132 kV, 110 kV, 66 kV and some 33 kV not classified as distribution feeders
- Bulk Supply and/or Zone Substations at 220/11 kV, 132/66 kV, 132/33 kV, 132/22 kV, 132/11 kV, 110/33 kV, 110/11 kV, 66/33 kV, 66/22 kV, 66/11 kV, 33/22 kV, 33/11 kV, 33/6.6 kV, 22/11 kV
- MV distribution network, including SWER lines, at 33 kV, 22 kV, 19.1 kV, 12.7 kV, 11 kV and 6.6 kV.

Asset boundaries between Ergon Energy and other parties also vary.
Chapter 1. Introduction

upstream and downstream. Significant variations to the methods are anticipated for peak demand and energy forecasting using those metered points, as enabling and disruptive technology shifts the time of peak-demand and shape of the load curves within our network.

- Economic growth has improved slightly over last year estimates as commodities gained ground in 2016-17, particularly iron ore, thermal coal, and coking coal. This will be reflected in the GSP 2017-18 figures where a better than 1% improvement is expected for the year.
- One network limitation was addressed through regulatory investment test consultation and no new Regulatory Investment Test for Distribution (RIT-D) projects were identified to address emerging network limitations.
- There are currently three large committed refurbishment or replacement projects scheduled for completion within the forward planning period. These projects are described in Section 10.5. There is a significant ongoing volume of work related to many small scale renewal and refurbishment investments. These are described in Section 10.4.
- A reduced capital expenditure (capex) program underpinned by further implementation of our risk-based planning criteria rather than the former deterministic criteria.
- 119 distribution feeders will exceed the capacity planning levels (but not necessarily asset capability thresholds) within the next two years; this compares to 123 last year. This reduction is largely due to:
  - network improvements such as augmentation, load transfers and demand management; and
  - improved data accuracy and analysis.
- Update of Asset Management Overview chapter to align with Energy Queensland Limited strategy, including the implementation of a Strategic Asset Management Plan (SAMP) that articulates how organisational objectives are converted into asset management objectives.
- The inclusion of distributed solar PV generation data at the distribution feeder level on the geospatial interface (ESRI mapping tool).

1.5 DAPR Enquiries

We welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au
Chapter 2 – Ergon Energy
Network Overview

2.1 Corporate Overview
2.2 The Electricity Distribution Network
2.3 Network Customers
2.4 Network Operating Environment
2. Ergon Energy Overview

2.1 Corporate Overview

Ergon Energy is a subsidiary of Energy Queensland Limited, a State government owned corporation. Energy Queensland Limited was created through the merger of Ergon Energy, Energex and SPARQ Solutions on 30 June 2016.

2.1.1 Vision

Energy Queensland Limited’s vision is to energise Queensland communities.

Energy Queensland Limited provides an opportunity to deliver better outcomes for customers, employees and all Queenslanders. Energy Queensland Limited will effectively manage Queensland’s electricity networks and respond to the future needs of the energy market.

In the current environment, the Energy Queensland Limited’s vision underpins the provision of a safe, reliable and cost effective electricity distribution network.

2.1.2 Purpose

To achieve the vision, our core purpose is to deliver secure, affordable and sustainable energy solutions with our communities and customers as shown in Figure 2.

Figure 2: Energy Queensland Limited Vision, Purpose and Values
Chapter 2. Ergon Energy Overview

2.1.3 Business Function

The principal operating companies in the Ergon Energy group are; Ergon Energy our distribution business, and its subsidiary Ergon Energy Queensland Pty Ltd (EEQ) our electricity retailer.

Ergon Energy’s core function is to operate, maintain (including to repair and replace as necessary) and protect its supply network to ensure the adequate, economic, reliable and safe connection and supply of electricity to its customers. This includes, under Ergon Energy’s Distribution Authority and the Electricity Act 1994 (Qld), allowing a person to connect supply to its supply network or take electricity from its supply network on fair and reasonable terms as far as technically and economically practicable, and subject to certain conditions specified in the Act.

EEQ buys electricity from generators, both through the market and in direct negotiations. It on-sells to customers in our distribution area, at the Queensland Government’s Notified Prices. Through this subsidiary, Ergon Energy also owns and operates a gas-fired power station in Barcaldine that supplies power into the national electricity grid.

2.2 Ergon Energy Electricity Distribution Network

Around 70% of our electricity network runs through rural Queensland, a vast service area with large distances between communities.

Our service area is by far the largest in the NEM, with the second lowest customer density per network kilometre – see Table 1.

We have a proportionately high investment in sub-transmission assets, compared to our urban counterparts, and one of the largest Single Wire Earth Return (SWER) networks in the world. Compared to a meshed or interconnected urban network, the radial design of our rural network and the limited capacity of the SWER lines limits what we can do when responding to peaks in demand or outages.

Our 65,000 kilometres of SWER lines (the longest is approximately 1,000 kilometres in length) supply around 26,000 customers predominantly located in western areas of regional Queensland. This section of the network operates at three voltage levels: 11 kV, 12.7 kV and 19.1 kV in configurations as conventional, duplex, triplex and non-isolated SWERs. These systems...
are supplied by isolated transformers in the size range between 50 kVA and 200 kVA. The technology was an ideal solution in the early years of the electrification of our vast state. However, today the way we use electricity in our modern lives is increasingly seeing these lines become constrained.

Ergon Energy also has 33 stand-alone diesel-fired power stations with total installed capacity of 46 MW and small amount of solar, wind and geothermal energy sources. Our isolated systems operate on 33 kV, 22 kV, 11 kV, 6.6 kVA, SWER and LV with peaks ranging between 68 kW and 4.2 MW. Ergon Energy's isolated systems supply 39 communities (approximately 7,000 customers) isolated from the main grid. These are located in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands and Palm Island.

A summary of our network assets is provided below.

Table 1: Network Statistics (at year end)

<table>
<thead>
<tr>
<th>Network Statistics</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Area Serviced</td>
<td>1.7 million sq. km</td>
</tr>
<tr>
<td>Power Stations (isolated)</td>
<td>33</td>
</tr>
<tr>
<td>Bulk Supply Substations</td>
<td>30</td>
</tr>
<tr>
<td>Zone Substations (ZS)</td>
<td>323</td>
</tr>
<tr>
<td>Major Power Transformers (33 kV to 132 kV)</td>
<td>610</td>
</tr>
<tr>
<td>Distribution Transformers</td>
<td>101,000</td>
</tr>
<tr>
<td>Power Poles</td>
<td>1 million</td>
</tr>
<tr>
<td>Overhead Powerlines - Sub-transmission</td>
<td>15,600 km</td>
</tr>
<tr>
<td>- High Voltage Distribution</td>
<td>117,500 km</td>
</tr>
<tr>
<td>- Low Voltage Distribution</td>
<td>24,000 km</td>
</tr>
<tr>
<td>Underground Power Cable</td>
<td>9,200 km</td>
</tr>
<tr>
<td>Number of Feeders - Sub-transmission</td>
<td>298</td>
</tr>
<tr>
<td>- Distribution feeders(^3)</td>
<td>1,185</td>
</tr>
</tbody>
</table>

Figure 4 shows our distribution service area, including isolated community generation sites and stand-alone power supply systems.

\(^3\) Includes island feeders
Chapter 2. Ergon Energy Overview

Figure 4: Ergon Energy Distribution Service Area

Key Administration Centre
- Distribution Network (regulated by the AER)
- Depot/Workshop
- Barcaldine Power Station
- Isolated Supply

160,000 km of powerlines
2 network control centres
69 service depot locations
2 customer solutions centres
2.3 Network Customers

Ergon Energy’s network supplies the full range of end users as shown in Table 2. The bulk of the customers connected to the network use less than 100 MWh of electricity a year – about 86% of these are residential customers and the remaining 14% are small to medium businesses. The network also supplies the majority of the State’s largest energy users.

Table 2: Connected Electricity Users

<table>
<thead>
<tr>
<th>Customer Groups</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard Asset Customers – Small: Residential (&lt;100 MWh a year)</td>
<td>636,940</td>
</tr>
<tr>
<td>Standard Asset Customers – Small: Business (&lt;100 MWh a year)</td>
<td>101,119</td>
</tr>
<tr>
<td>Standard Asset Customers – Large (100 MWh to 4 GWh a year)</td>
<td>8,207</td>
</tr>
<tr>
<td>Connection Asset Customers (4 GWh to 40 GWh a year)</td>
<td>160</td>
</tr>
<tr>
<td>Individually Calculated Customers (&gt;40 GWh a year)</td>
<td>74</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>746,500</strong></td>
</tr>
</tbody>
</table>

The network is being increasingly used as a platform for renewable and other distributed energy resources. We now have over 1.1 GW of distributed energy resources connected to our networks. This includes 646.5 MW of major embedded and cogeneration capacity, and an additional 127,000 connected micro EG units, which are nearly all solar photovoltaic (PV) systems. Table 3 and Figure 3 show where the renewable energy resources are being enabled by the network across regional Queensland. The micro EG units represent a total solar array capacity of 494 MW.

Table 3: Known Embedded Generation Capacity

<table>
<thead>
<tr>
<th>Region</th>
<th>Embedded and cogeneration capacity*</th>
<th>Micro Embedded Generating Units (including solar energy systems)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capacity (MW)</td>
<td>Units (MW)</td>
</tr>
<tr>
<td>Far North</td>
<td>44.7</td>
<td>18,556</td>
</tr>
<tr>
<td>North Queensland</td>
<td>158.0</td>
<td>24,858</td>
</tr>
<tr>
<td>Mackay</td>
<td>158.0</td>
<td>11,557</td>
</tr>
<tr>
<td>Capricornia</td>
<td>100.2</td>
<td>20,105</td>
</tr>
<tr>
<td>Wide Bay</td>
<td>36.3</td>
<td>30,431</td>
</tr>
<tr>
<td>South West</td>
<td>149.3</td>
<td>21,916</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>646.5</strong></td>
<td><strong>127,425</strong></td>
</tr>
</tbody>
</table>

*Authorised export capacity as at June 2016.

In addition, Ergon Energy is collaborating on a number of large-scale renewable energy projects to harness the sun and the wind to drive a new wave of economic prosperity for Queensland. Based on the uplift in enquiries for the connection of large-scale renewable generation, we believe there could be up to 5.5 GW of renewable energy investment in the pipeline for regional Queensland.
2.4 Network Operating Environment

This section describes the external factors that underpin our planning decisions in an operating environment increasingly dominated by distributed generation. While customer demand is still the main trigger in our planning decisions, bi-directional energy flow throughout the network is presenting new challenges particularly with respect to maintaining statutory voltage limits.

2.4.1 Technological Change

As customer technology develops it is influencing the way our customers use our network and source electricity. We have already seen Queensland integrate the highest penetration of residential solar in Australia, and there is significant discussion around the development and deployment of complementary battery technology as the next potential wave. These technologies change customers’ interaction with the grid, in terms of their energy and demand profiles. The dominant role of renewables exacerbates this issue with generation intermittency being another variable that this technology introduces.

Customers will continue to evolve and seek new forms of technology within their home and work, and we will continue to evolve our grid to meet these changing demands. Regardless of the type of technology, our strategy is to create a network that can operate as a platform and interconnector for this technology and our customers.

We expect continued growth in solar PV both in residential and other customer classes. Over the last year we have seen a significant increase in applications to connect large-scale solar, particularly in our rural areas. In future, batteries and electric vehicles are likely to be the next technologies to emerge as the costs of these fall and customers are able to benefit from these technologies.

The AER’s Distribution Determination supported the targeted deployment of light emitting diode public lights in a number of areas and meter capability continues to develop and provide additional network and customer functionality.

2.4.2 Social and Demographic Change

As the Australian population ages our customer base across regional Queensland is changing. We are not only seeing an increasing proportion of people aged 65 years and over retiring, we are also seeing a new generation of primary income earners that have different electricity usage patterns than previous generations. Components of Queensland’s population annual increase to December 2016 comprise; 51.2% from the State itself, 28.9% from overseas and 18.0% from interstate migration. The total annual population state grew by 1.3%, the same as the previous year. Cairns and Mareeba replaced Gladstone as the highest regional growth areas over 1%, in the year to 30 June 2016.4

We track social and demographic change around the way the community is using electricity in the annual Queensland Household Energy Survey (Section 3.2.3). There is significant change on the domestic front. In the commercial space, the use of electrical and digital equipment is also only expected to increase and impact our customers’ energy use and expectations. The increase in

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4 Australian Government Statistician Office-personal communications.
e-commerce, the ability to work remotely, and accessibility to the internet generally, will potentially see an even greater focus from customers on power supply reliability and quality.

Social expectations are also growing around the pace of change in the Queensland electricity market from non-renewable to renewable energy.

These changes in society’s expectations and needs are likely to occur in much shorter timeframes than what we have typically had to respond to in our network investment planning and with regards to asset lifespans.

2.4.3 Government Policy and Reforms

Ergon Energy and Energex are currently in the advanced stages of implementing the Queensland Government’s electricity industry reforms. The centrepiece of this reform has been the creation of Energy Queensland Limited through the merger of Ergon Energy, Energex and SPARQ Solutions.

Merging Queensland’s electricity distribution assets places Energy Queensland Limited in the best position to adapt to industry changes as a customer-oriented, efficient business. These reforms aim to deliver positive price outcomes for the State’s electricity consumers as well as sustainable business returns to the Queensland Government and ultimately the people of Queensland.

The structural reforms continue our focus on developing a competitive cost base. They also build on the significant joint working activity undertaken to date with Energex.

The Queensland Government also continues with its policy commitment to increasing the contribution of renewable energy to Queensland’s energy mix. This includes setting a target for one million rooftops or 3,000 MW of solar PV in Queensland by 2020, and a commitment to providing long-term financial support to parties installing large-scale solar generation.

Similarly, with the support of the Queensland Government, the Energy Queensland Limited is working on Battery Energy Storage System (BESS) trials investigating how this emerging technology can best benefit the State’s power distribution network and wider community.

Energy Queensland Limited is also working to implement further industry reforms driven by the Federal Government. The Power of Choice program is being implemented in Queensland with objectives of providing power users with additional options in the way they use electricity and better access to power consumption data. This program will also expand competition in metering and related services.

In June 2017 The Finkel Review was handed down with some 50 recommendations for reforming the NEM. The Federal Government is currently considering these recommendations. Additionally, the Queensland Competition Authority is currently consulting on a time-varying solar price for regional Queensland which could potentially encourage generation output.

Moving forward, Energy Queensland Limited will continue to work closely with Government from both a regulatory and network planning perspective to ensure secure, affordable and sustainable outcomes for our customers and shareholders.

2.4.4 Economic Activity

Queensland State Product is expected to remain above the national average, although Tropical Cyclone Debbie did take its toll on infrastructure, commerce and agricultural output. Loss of around 10 million tonnes of coal exports due to damaged rail infrastructure and around $300 million of sugar export losses in addition to substantial hits to tourism in the Whitsunday region were experienced. The aggregate of loss from this weather event is estimated at $2 billion or ¾ percentage point reduction in State Product.

The ongoing success of gas exports will continue to benefit the State and coupled with rising export earnings will continue to provide strength to the State’s product from 2018 onwards. Commodity price movements in the later part of 2016 resulted in good returns from coking coal exports although these high returns are unlikely to remain. Tourism is expected to remain solid at just over 7% from the next three years as the Australian dollar remains soft compared to previous years. Continued dampening on wage growth will, however, see an ongoing weaker pace of consumer spending and therefore only modest household consumption growth.

Customers continue to behave cautiously in response to the current economic conditions and business outlook. The electricity sector, in particular, is seeing residential customers and businesses respond to electricity prices, adopting more energy-efficient behaviours. Economic considerations are also impacting the increased uptake of solar PV in the residential sector and more recently the commercial sector. These are likely to be key considerations in the future uptake of electric vehicles and batteries.

The traditional positive relationship between economic growth and electricity demand from the network is changing.

2.4.5 Physical Environment

The physical environment across regional Queensland creates challenges in the operation of an electricity distribution network.

Due to the size of our service area the list of environmental impacts is extensive. The variation in environmental conditions across the State influences our costs and outage times relative to more dense, urban networks. It also influences infrastructure design criteria, as well as our strategies to respond to incidents on the distribution system; we can’t adopt a one-size-fits-all approach.

The environmental aspects impacting the network include:

- high probability of, and high exposure to cyclones in the northern and far north regions
- high storm and lightning activity
- significant summer-winter and day-night temperature variations
- high rainfall areas (e.g. increases pole-top rot in Far North Queensland)
- other weather impacts (e.g. the Channel Country is flooded by rains falling hundreds of kilometres away) causing floods that take weeks to pass creating extended delays in accessing and repairing damaged assets
- significant termite populations affecting power pole integrity

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6 Queensland Budget 2017-18, Budget Strategy and Outlook, Budget Paper No. 2, P4
• unstable soil types (e.g. Darling Downs).

2.4.6 Community Safety

Safety is a high priority for Ergon Energy; for our employees, our customers and our community. Safety is at the core of our network planning and investment decisions.

Section 10 details how Ergon Energy’s asset life cycle management achieves a focus and drive to ensure safety of staff and the community as they interact with our assets. For example, we are actively replacing small diameter aged copper conductor approaching end-of-economic-life to mitigate the safety risks related to breaking and falling conductors. We also maintain a comprehensive vegetation management program to reduce community and field staff safety risk caused by physical impact and electrical conductivity issues.

The Community Electrical Safety Awareness Plan (CESAP) demonstrates our commitment to community safety and outlines the initiatives and actions we implement to deliver this commitment.

The strategies within the CESAP focus on activities that:

• engage with members of the community and key industry groups
• educate at-risk groups and industries about electrical safety
• enable individuals and industries to take ownership for their own electrical safety.

Key activities include the continuation of the “Look Up and Live” campaign, engagement with regulator and other entities, safety awareness presentations, Safety Heroes primary school education program and participation in major industry events and agricultural shows. In 2017 the Community Safety Think Tank was held bringing together key internal and external stakeholders to generate and explore new ideas to further reduce the risk of the community and industry inadvertently contacting our network. For further information or a copy of the plan, go to the Ergon Energy website: https://www.ergon.com.au/network/safety

2.4.7 Environmental Commitment

Ergon Energy’s vision is to be among the top companies in Australia for environment and cultural heritage performance. This is reflected in the Health, Safety, Environment and Cultural Heritage Policy. The policy commits to progress beyond compliance to innovation and excellence and to drive continual improvement in management of environment and cultural heritage.

To support this environmental targets have been established across our priority focus areas of waste, biodiversity and land contamination. The implementation of these targets is assisting our business to; reduce waste volumes to landfill across Regional Queensland, minimise clearing of regulated/protected vegetation, reduce the number of environmental incidents, and reduce the contamination risk of Ergon Energy managed land. Strategic priorities now include looking at ways to reduce our carbon emissions.

Our electricity network traverses numerous environmentally and culturally significant areas across regional Queensland, from coastal and rural areas to the remote communities of western Queensland and the Torres Strait. We are actively involving employees, the community, our customers and the regulatory authorities in the planning and assessment of infrastructure projects to ensure that together we best manage all interests.
2.4.8 Legislative Compliance

Prior to the establishment of Energy Queensland Limited, Ergon Energy was a Queensland Government Owned Corporation (GOC), with shareholding Ministers to whom the Board reported. Ergon Energy is now a subsidiary of the GOC Energy Queensland Limited and remains subject to the same level of regulation as it did as a GOC.

Ergon Energy holds a Distribution Authority, administered by the Queensland Department of Natural Resources, Mines and Energy (DNMRE), to supply electricity using its distribution system throughout regional Queensland. Ergon Energy operates in accordance with all relevant legislative and regulatory obligations, including the following laws:

- *Electricity Act 1994* (Qld), the *Electricity Regulation 2006* (Qld) (the Queensland Electricity Regulation) and the Electricity Distribution Network Code (EDNC, previously the Electricity Industry Code) under the Act
- National Electricity Law (NEL) and National Electricity Rules (NER), as in force in Queensland pursuant to the *Electricity – National Scheme (Queensland) Act 1997* (Qld) and the *Electricity - National Scheme (Queensland) Regulation 2014* (Qld)
- National Energy Retail Law (NERL) and National Energy Retail Rules (NERR), as in force in Queensland pursuant to the *National Energy Retail Law (Queensland) Act 2014* (Qld) and the *National Energy Retail Law (Queensland) Regulation 2014* (Qld)
- *Electrical Safety Act 2002* (Qld) and *Electrical Safety Regulation 2013* (Qld)
- *Aboriginal Cultural Heritage Act 2003* (Qld) and *Torres Strait Islander Cultural Heritage Act 2003* (Qld)
- *Environmental Protection Act 1994* (Qld)
- *Sustainable Planning Act 2009* (Qld) and subsidiary and related planning and environment legislation, such as the *Vegetation Management Act 1999* (Qld), the *Nature Conservation Act 1992* (Qld), the *Coastal Protection and Management Act 1995* (Qld) and subsidiary regulations, and the *Environment Protection and Biodiversity Conservation Act 1999* (Cth)
- *Government Owned Corporations Act 1993* (Qld) and *Government Owned Corporation (Energy Consolidation) Regulation 2016*.

Ergon Energy is subject to periodic (annual and quarterly) and incident-based reporting to verify compliance with these obligations and to ensure issues are identified and resolved at an early stage.

2.4.9 Economic Regulatory Environment

In accordance with the requirements of the NER and NEL, Ergon Energy is subject to economic regulation by the AER. The AER determines maximum allowable revenues or prices that we can earn or charge during each five year regulatory control period.

Our distribution business operates under a five-year revenue cap framework for the provision of Standard Control Services (SCS), whereby we recover the revenue allowed in the AER's

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7 All customers supplied by Ergon Energy’s isolated generation assets are excluded from the jurisdiction of the AER. The isolated generation zone is regulated by DNMRE.
Chapter 2. Ergon Energy Overview

Distribution Determination\(^8\) through charges for the use of the network (otherwise known as Distribution Use of System charges – ‘DUOS’). These charges are billed to a customer’s retailer and form a component of the retail bill.

In addition to this revenue allowance the AER’s Distribution Determination sets out pricing arrangements for our provision of Alternative Control Services (ACS). For the regulatory control period 2015-20, the AER reclassified a number of distribution services as ACS. This affects how Ergon Energy recovers the costs of providing these services.

The most significant change for the period was the reclassification of our Default Metering Services, related to Type 5 and 6 meters, as ACS. These changes mean that customers are now charged upfront when they request a new meter to be installed or upgraded. There are also separate ongoing charges to recover the capital cost of the existing Type 5 and 6 meters, and charges to cover the cost of reading, maintaining and operating each meter. Previously, these costs were spread across all customers and contained in the DUOS charge component in the retail bill. ACS charges are now segmented into four broad categories: Public Lighting Services, Fee Based Services, Default Metering Services and Quoted Services\(^9\).

Alongside this Distribution Determination Ergon Energy is subject to a number of nationally consistent guidelines, models and schemes including the Efficiency Benefit Sharing Scheme (EBSS), the Capital Expenditure Sharing Scheme (CESS), the STPIS and the Demand Management Incentive Scheme (DMIS).

More information regarding Ergon Energy’s allowed revenues and network prices can be found on the AER’s website: [www.aer.gov.au](http://www.aer.gov.au)

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\(^8\) Plus any annual adjustments approved by the AER in the relevant annual Pricing Proposal.

\(^9\) Quoted and fee-based services are generally those services provided in response to a specific request from a customer and include such services as temporary connections; design and construction of large customer connection assets; and de-energisations and re-energisations.
Chapter 3 – Customer Engagement

3.1 Overview

3.2 Our Engagement Program
3. Customer Engagement

3.1 Overview

Energy Queensland Limited’s vision is to energise Queensland communities providing opportunities to deliver better outcomes for customers and all Queenslanders. We believe that to be a truly customer-driven business we need to put our customers at the heart of everything we do. This means listening to our customers, understanding their needs, and working together to deliver value to both customers and the business. We strive for balanced outcomes that meet customer expectations without increasing business costs that ultimately push up energy prices.

We also believe we need to measure and monitor our performance against customer expectations, rather than just meeting legislated minimum service targets or internal measures. This is how we determine if we are progressing towards our vision.

We have a coordinated, multi-channel customer engagement and performance measurement program. This focuses on aligning our investment plans with the long-term interests of our customers, and ensures we are meeting customer expectations. This chapter provides an overview of these programs and describes how they enable us to put customers at the heart of everything we do.

3.2 Our Engagement Program

3.2.1 Customer Commitments Inform Investments

To ensure our investment plans were aligned with the long-term interests of our customers, preparations for our regulatory proposal included significant customer and stakeholder engagement. This led to us refreshing our service commitments to regional Queensland. These service commitments continue to inform our network investment plans.

We see the future of the network business being about enabling distributed energy and other energy-related solutions. This will require us to move our customer value proposition from being one of an essential service to being a provider of essential infrastructure that connects buyers and sellers of energy services. This includes enabling a market from which participants can trade demand management and energy service products.

3.2.2 Voice of the Customer Program

While it is important that Ergon Energy’s network meets network performance criteria, such as outage frequency, duration and quality of supply, we recognise that this alone is not a true reflection of customer satisfaction levels.

As a result, we have implemented a Voice of the Customer program to track customer satisfaction levels in ‘real time’ across all eight customer groups and all major touchpoints with our business. This program enables us to measure the impact of our improvement initiatives, drive accountability for customer outcomes and keep on top of the priority areas for improvement.

We are able to measure the key drivers of customer satisfaction at each touchpoint and have developed a corporate KPI; the Customer Index, to ensure delivering the best customer experience remains front and centre in our focus. As a corporate KPI, our entire organisation from the
Chapter 3. Customer Engagement

Executive to front line personnel are exposed to current customer satisfaction levels. As such, the customer experience is always prioritised within the business.

As a part of this program we have also developed the Customer Enablement Index which measures the internal capability of Ergon Energy to become a customer-driven energy business. This corporate KPI drives the focus of customer-centricity to become an integral part of our business, as we serve each other as well as delivering for customers.

3.2.3 Queensland Household Energy Survey

For the seventh consecutive year Ergon Energy, in conjunction with Powerlink and Energex, conducted the annual Queensland Household Energy Survey. This was the most popular survey since inception and gathered feedback from more than 4,500 individual Queensland households.

Topics covered off in the survey include residential customers’ current energy needs, their future energy intentions (including solar, battery and electric vehicle uptake), their current household appliances and future appliance uptake, tariff awareness and understanding as well as overall attitudes that households have towards electricity consumption and prices. This information allows Ergon Energy to more efficiently plan and utilise the network.

Key findings from the 2016-17 survey include:

- Customers are replacing appliances with newer technology and owning fewer of the same appliances. In the last five years the biggest ownership increases have been in LED or LED/LCD televisions, LED light bulbs, tablet computers, 3D televisions and instantaneous hot water systems. Over the same period the largest decreases in ownership have been in desktop computers, stereos, compact fluorescent light bulbs, LCD televisions and electric heaters.

- Changes in the way customers use entertainment devices may shift electricity consumption away from the lounge room. Ownership of multiple tablet devices continues to increase while ownership of at least one television has decreased by 4% (to 93%) since 2013.

- Air-conditioner penetration has slightly increased across regional Queensland. Air-conditioners are found in 94% of households in the Central and Northern regions; however are found in only 73% of households in the Southern regions of Queensland. Split systems remain the most popular - with 79% of regional Queensland households owning at least one split system.

- Despite the decreasing level of concern regarding electricity costs in South East Queensland over the past twelve months; concern remains high in regional Queensland with 42% stating it is as ‘high’ (compared to 33% in South East Queensland). Concern is particularly high for those without solar panels.

- Interest in solar panels has remained unchanged in the last three years, with 15% of regional Queensland households intending to install solar panels in the next two years. Intention is predicted to remain at these levels until battery storage becomes more widely available.

Customer knowledge and understanding of battery storage has increased significantly across regional Queensland, with 62% of households indicating awareness (up from 38% in 2013). ‘Likelihood to purchase’ in the next three years sits at 8% across Queensland; however this is at customer assumption of an approximate $6,500 price point for battery storage in regional Queensland - which is currently unlikely to be realistic for the average household over the next three years.
Chapter 3. Customer Engagement

Further information is available in the Queensland Household Energy Survey:

3.2.4 Customer Representative Forums

We are continuing to engage with our stakeholders through a range of targeted forums.

Our Customer Council remains our ‘umbrella’ listening forum, comprising representatives from seven peak organisations representing regional Queensland in the community services, primary industry and business sectors. The forum provides these organisations with the ability to influence our decisions, facilitate wider community consultation, and pass on information to their members. The group meets quarterly with a focus on our performance against our customer commitments.

Ergon Energy also hosts a number of regular forums with targeted customer groups to look at issues relevant to their specific needs. Key stakeholder groups include; real estate developers, electrical contractors, the agricultural industry and peak community and industry bodies. We also continue to connect with our ‘local faces’ active in their communities, participating in business community forums and local community events.

3.2.5 Major Customer Engagement

The major customer connection process is regularly reviewed and improved as we balance customer needs, amidst an evolving regulatory environment and complex network technical challenges. We continue to strive to make our business more transparent to our customers, to improve the information and assistance we provide and to streamline connection processes. Ergon Energy has a dedicated team to assist major customers with their connections to the network. This team actively manages our relationships with designated major customers, government agencies and industry groups, and builds our business intelligence on future major customer projects, expansions and modifications that could potentially impact on our network or require resources.

Ergon Energy continues to make proactive efforts to improve our service to this customer segment. As well as planned individual catch up sessions with customers, Major Customer open forums are held where results are shared and improvement opportunities discussed. We understand that major customers require timely and transparent turnaround times for project enquiries, assessments and the processing of applications. Improvement opportunities are centred on:

- reviewing the resourcing and management framework for design and construction of customer initiated capital works
- placing a priority on reducing turnaround times
- developing policies and processes to ensure greater efficiencies within our business and communicating those with connecting customers.

For major customers with connected loads, reliability of supply remains the foremost priority. In current market conditions, mining resources sector customers remain focused on maximising output from existing sites. Some resources sector customers are forecasting increased load and usage; however hesitation towards developing new mine sites remains.

As the major mines operate 24 hours a day, any lost production time and related revenue cannot be regained. As a result, our customer focus remains squarely on outage restoration and ensuring the ongoing continuity of supply.
Chapter 4 – Emerging Network Challenges and Opportunities

4.1 Solar PV
4.2 Battery Energy Storage Systems
4.3 Electric Vehicles
4.4 Strategic Response
4.5 Large Scale Renewable Projects
4.6 Land and Easement Acquisition Timeframes
4.7 Impact of Climate Change on the Network
4. Emerging Network Challenges and Opportunities

Ergon Energy faces a number of specific network challenges and opportunities as it seeks to balance customer service and cost. These include the continuing impact of solar PV, battery energy storage systems, electric vehicles, land and easement acquisition and climate change.

4.1 Solar PV

4.1.1 Solar PV Emerging Issue and Statistics

Queensland has the highest penetration of solar PV systems on detached houses not only in Australia\(^\text{10}\), but compared with any country. In our network, 26% of detached houses have a solar PV system connected. The rapid uptake of solar PV has changed the way power travels through the network; from a purely one-way to a bi-directional energy flow. The impact is greatest in the LV network and creates a number of system design and operation challenges. Ergon Energy is on the leading edge of responding to these issues in the industry and is deploying a range of projects and initiatives to ensure; safe operation of the network, a secure and high-quality supply, and economically viable solutions for customers both with and without solar PV.

Figure 5 shows the increase in installed capacity associated with solar PV. Over the past 12 months, the rate of connections has increased by 20% compared with the previous 12 month period.

Figure 5: Grid Connected Solar PV System Installed Capacity by Tariff as at June 2017

The relatively new issue of reverse power flow occurs where generation exceeds demand on a

network element such as a feeder. Ergon Energy estimates that there are over 450 feeders on which generation during the middle of the day is exceeding the demand of the feeder.

Another significant network issue resulting from increased solar PV connections is voltage rise on LV networks. Voltage rises when demand is lower and solar PV reduces demand. At some points in the network, the voltage is raised to the limits of statutory requirements, at which point solar inverters are programmed to trip.

Ergon Energy had approximately 670 Quality of Supply (QoS) complaints in the past 12 months related to solar PV, predominantly resulting from high voltages. As the number of solar PV systems increases, managing the voltage within statutory limits will become more challenging. We are undertaking a range of initiatives to minimise the impact of solar PV on the network and reduce the cost to resolve limitations, including; a trial of a 230V network standard, tariff review, LV statcom and energy storage trials.

As a result of our industry-leading responses, the rest of the world is looking to leverage our experience.

From a customer perspective Ergon Energy has improved the application process yet has reduced network risks by enabling minimal and partial-export connections. Minimal-export embedded generating (EG) units don’t permit export of generated electricity to the distribution network. Applications for export-limited inverters now account for around 19% of new micro EG unit applications. Ergon Energy and Energex have jointly released an updated connection standard covering solar PV systems and are undertaking a trial of the 230V standard, as discussed in Sections 4.4.2 and 4.4.3 respectively.

Statistics of distributed micro EG is shown in the ESRI GIS Portal detailing percentage of connections with micro EG, total installed volume of micro EG per feeder and the average size of installed micro EG units per feeder. Available at https://www.ergon.com.au/daprmmap2017

4.1.2 Impacts of Solar PV on Load Profiles

Solar PV is impacting load profiles, asset utilisation, load forecasting and load volatility.

Traditionally, the total aggregated demand of our network peaks between mid-afternoon and early evening during summer, generally on the hottest days of the year. The impact of solar on the shape of our network load profile is evident in peak load statistics. While the 2016-17 demand peak was recorded at 7.30pm in the evening, the actual peak in consumption would have occurred mid-afternoon. However, on that day in February 2017, solar generation was at one point meeting almost 10% of the total network demand. While this changed the shape of the network demand during the afternoon hours, the evening peak remained relatively unaffected.

The change in load pattern as the penetration of solar PV systems on a feeder has increased is illustrated in Figure 6. This figure shows the daily load pattern on a residential feeder in Burrum Heads over six consecutive years for the first week in September. The daytime generation of solar has increased to the point that the feeder back feeds through the zone substation.

The peak demand for the feeder is still occurring at the same time of night in 2016 as it did in 2010. While the night peak demand has seen only slight variances over the years, the midday demand has reduced by over 1 MW. The daily variance on the feeder was previously just over 0.8 MW in 2010, while in 2016 the daily variance was approximately 2.2 MW. This increase in daily variance
makes it more challenging to keep the network voltage within statutory limits, and can also result in decreased asset life of equipment as voltage regulation devices operate more frequently.

*Figure 6: Burrum Heads Feeder Profile: Annual changes observed for September 2010 – 2016*

The increase in embedded generation on our feeders makes it challenging to identify underlying load growth, as additional daytime load can be offset by local generation. Variation to energy use patterns or growth in load only becomes apparent when an unexpected event causes the solar PV systems to stop generating.

*Figure 7 highlights that on the occasions when the solar PV generation is not available, such as during an afternoon thunderstorm, the full customer load is supplied from the network, which can result in large and rapid variations in energy flows.*

In this instance the demand on the feeder was extremely volatile; low during the day with consumers generating and also consuming energy, then rapidly peaking when the storm clouds rolled in. The solar PV generation fell away completely for a short time while the customer load did not. The net result was a peak demand event in the early afternoon that was higher than the feeder’s usual evening peak.

As networks are designed for supplying the maximum demand required by our customers, increasing penetrations of intermittent embedded generating units will significantly increase the complexity of planning and operating networks. Network volatility events, such as the peak seen in Figure 7, could result in excessive voltage drops, overloading of components, protection operation issues and loss of supply if not appropriately managed.
4.2 Battery Energy Storage Systems

Ergon Energy has continued to monitor developments in the residential and commercial sized Battery Energy Storage System (BESS) market. We have built on our previous trials and extended the testing of BESSs to a real world environment in customers’ premises. The trials and tests we have performed in this area have enabled us to continue to engage with the energy storage market on standards, safety and connection requirements. We recognise the potential for BESSs to provide network benefits (peak demand and/or power quality issues); however, we also recognise the barriers to effectively utilising this developing resource.

As highlighted in Section 4.4.2, Ergon Energy and Energex have made changes to their joint standard for micro EG units up to 30 kVA which enables greater customer opportunity to connect BESSs to new or existing installations. This move has heralded the Queensland utilities as leaders in enabling this technology and industry has called on other distributors to do the same11.

Ergon Energy is currently managing 118 active large scale embedded generation projects of which three include BESSs as part of their proposed designs for their installation. We are continuing to deploy our Grid Utility Support System (GUSS) comprising energy storage in SWER networks where these units provide an economically efficient alternative to network augmentation. We will also investigate how we may use customer-side BESSs to achieve the same result in the future.

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Chapter 4. Emerging Network Challenges and Opportunities

4.3 Electric Vehicles

Ergon Energy wishes to remove as many barriers to electric vehicle ownership as possible. This will enable our customers’ choice in transport fuels and will also enhance network utilisation and place downward pressure on electricity prices. Electric vehicles, which are still an emerging industry in Australia, are already popular overseas and their numbers are expected to grow in Queensland as their life-cycle costs decrease.

Ergon Energy is working with industry partners and the Queensland Government to enable an EV charging highway from Cairns to Gold Coast including Toowoomba. In mapping our network against these locations we have considered the expected driving range of fast-charge capable vehicles and the corresponding available network capacity along the route. While the charging highway will not be delivered by Ergon Energy we have a role to play in enabling access to our network for companies wishing to deploy such charging infrastructure to support this emerging technology.

4.4 Strategic Response

4.4.1 Feeder of the Future Program

The distribution feeder network is undergoing rapid change due to new technologies such as residential solar PV, battery storage and electric vehicles. In order to ensure an outcome that is beneficial for customers, the grid and ultimately the State of Queensland; Ergon Energy has embarked upon a collaborative journey. We seek to develop strong relationships with customers, retailers and market participants to ensure that solutions do not disadvantage, and ideally benefit the grid. We particularly recognise that we can benefit from working more closely with customers who are willing to invest in energy solutions on their side of the meter.

In order to understand the most optimal way of designing and operating the network in the current and future environment, a two-pronged approach has been undertaken.

The first is the Feeder of the Future Strategy: a major future planning study aimed at determining the best technologies and operating methodologies available to provide the lowest cost solutions for emerging constraints. This work has redefined our planning processes to change the way we; develop the network, partner with customers to create beneficial beyond-the-meter solutions, and create staff and network capability to embed these solutions. The strategy was advanced this year following detailed technical studies and analysis. It articulates a set of principles to guide our decisions.

Throughout 2017-18 we will explore which of the Feeder of the Future strategic options provide the lowest risk adoption path. We will also perform a review of other DNSP research to identify learnings that can be used within our network.

4.4.2 Revised 0-30 kVA Micro Embedded Generating Unit Connection Standard

In order to ensure that Ergon Energy continues to develop collaborative and mutually beneficial stakeholder relationships we have continued to engage with the solar PV and battery industries to evolve the 0-30 kVA micro EG unit connection standard. Version 4 of the standard, released in May 2017 has further streamlined our connection approach. Key changes include:
Chapter 4. Emerging Network Challenges and Opportunities

- Raising the maximum installed capacity permitted on single phase installs to 10 kVA, but limiting maximum export to 5 kVA, in order to facilitate AC coupled batteries and second systems
- Bringing Ergon Energy assessment threshold on the main grid into alignment with Energex (i.e. >15 kVA 3phase), in response to anticipated state adoption of 230 V (as discussed further in Section 4.4.3)
- Alignment of Export Limiting functional requirements to Section 3.4.8.3 of AS4777.1-2016 soft limit export control.

4.4.3 Trial of 230 Volt Low Voltage Standard

In 2015, Ergon Energy obtained Queensland Government approval to undertake a trial of the 230 V LV standard to bring us into line with the Australian Standards AS60038 and AS61000.3.100.

While the upper supply limit of the 230 V Australian Standards is similar (253.0 V versus Queensland’s existing limit 254.4 V), the lower end of the Australian Standard is only 216.2 V (versus the existing 225.6 V). Australian Standards guide the importing/manufacturing of new appliances and electronic equipment.

The introduction of the 230 V standard is about moving to the national standard. It will provide greater flexibility to manage voltage and help to mitigate the growth in voltage related issues. This will enable more solar PV to be connected to the network.

The trial involves detailed analysis, modelling and implementation on seven feeders across the network. The feeders chosen were; one urban and one rural feeder from the Central, Northern and Southern regions, and one on an isolated generation network. The selected feeders have a high number of monitors or meters available along the feeder to provide voltage data.

During 2016-17, Ergon Energy implemented changes to three feeders through tap plans, regulator settings and/or bus voltage set points to monitor for the 230 V criteria. Preliminary analysis of these feeders so far confirms the technical assumptions made in the network-wide business case and the impact to customers.

Ergon Energy has been providing Energex with updates on the trial, as any change in the current Queensland Electricity Regulation would apply throughout the State. The anticipated future transition plan is predicted to deliver savings upwards of $25 million in network augmentation costs for regional Queensland.

More information on the 230 V trial is available at:

In March 2016 the Queensland Government went out for public comment on a Regulatory Impact Statement regarding a state-wide move to 230 Volts12. Ergon Energy and Energex have provided the backing and support on the proposed change, and provided detailed feedback on the options considered for transition.

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12 Further details about the review can be found on the Queensland Government’s website here:
4.5 Large Scale Renewable Projects

Ergon Energy is currently actively managing more than 100 enquiries for major embedded generation projects that are expected to come online over the next five years to export renewable energy into the grid. Additionally we are aware of numerous other opportunities being explored; we believe there could be up to 5.5 GW of renewable energy investment in the pipeline for regional Queensland. Our support for these projects has the potential to provide a major economic windfall for regional Queensland as we move towards a renewable energy future.

Figure 8: Active Renewable Energy Projects 2013-2017

Supporting utility-scale renewable generation

In a first for the State, in May 2017, the new utility-scale solar farm in Barcaldine began exporting its 20 MW electricity output onto the grid. Throughout the rigorous commissioning process we worked with the owners and their inverter manufacturer to test for any quality of supply issues or network stability risks.

This is now paving the way for future solar farm connections. The size of these systems requires significant technical assessment; to address any potential impacts on network performance, assess any capacity limitations and apply rigorous testing at the commissioning stage.

Barcaldine, in the centre of Queensland, laid claim this year to being home to the State’s first fully-functioning, large-scale solar farm, made up of 78,400 solar panel modules, totalling 20 MW.

During the year the 5 MW Normanton Solar Farm in the State’s remote northwest Gulf country, which has been developed collaboratively by Scouller Energy, Canadian Solar and Ergon Energy, also moved into its final stage of commissioning.

Also in the final stages is the 15 MW Sunshine Coast Solar Farm at Valdora, the largest utility scale projects of its type built by a local government in Australia. It will allow the Sunshine Coast Regional Council to offset 100% of its electricity use across all its facilities, from its administration buildings to its sporting grounds.
Chapter 4. Emerging Network Challenges and Opportunities

In other fringe-of-grid projects, we are also collaborating on Conenergy’s 13.5 MW solar and battery storage project at Lakeland in Far North Queensland and the first phase of the Kidston Solar Project (50 MW), in North Queensland at the site of the historical Kidston Gold Mine. Also progressing are Canadian Solar’s 15 MW Longreach Solar Farm and RATCH Australia Corporation’s 42 MW Collinsville Solar Photovoltaic Project.

These projects, along with others in the pipeline, represent a rapidly evolving area of the industry and one where we are investing significant effort to support customer outcomes while maintaining network security and performance.

Purchasing green energy for our customers

EEQ entered into a new Power Purchasing Agreement with Fotowatio Renewable Ventures for the output of its proposed 100 MW Lilyvale Solar Farm to be built north-east of Emerald. This 12-year contract will provide a significant new source of clean energy for our customers.

Earlier agreements of this type have supported the viability of the Normanton Solar Project (above) and the 170 MW Mount Emerald Wind Farm in Far North Queensland. Construction works are now underway for the wind farm – once operational the 53 wind turbines will supply around a third of the Far North’s power needs.

We are already the largest purchaser of renewable energy in Queensland. These new systems will build on the existing distributed energy resources already connected to the grid, which currently includes 39 MW large-scale renewables and 444 MW of rooftop solar. Our agreements with Queensland’s sugar mills, which generate electricity from bagasse a by-product of sugar refining, contributes 56% to the renewables we purchase for the main grid. Our support for the generation of renewable energy by the Queensland sugar mills saw a $31.3 million economic contribution to this industry over the past year.

Further information on proposed renewable energy projects in Queensland is available at: https://www.nationalmap.gov.au/renewables/

4.6 Land and Easement Acquisition Timeframes

In order to ensure we can operate within the land and easement acquisition timeframes and meet community expectations for engagement, Ergon Energy needs to secure land in strategic areas before urban expansion has occurred and demand has increased. It can take many years to finalise land acquisition, therefore the need to commence these activities early in the process is vital.

The land and easement acquisition process must be completed well ahead of finalisation of design and construction of new infrastructure. It is managed in conjunction with proactive community engagement activities to ensure community expectations are balanced with the technical requirements, environmental outcomes, and the time and cost constraints of the project.

Strategic land acquisition is based on current forecasting. We are, however, in a challenging environment with the potential risk of project scope changes as new technologies or non-network alternatives (NNA) become available. Changes to project scope of this nature, may result in land or easement stranding if the changes are significant by the time the solution is required. During this time, there may also be changes to State planning policies, statutory compliance requirements and changes to Federal and State acts of legislation that may affect the project scope and delivery.
Despite the changes in demand and a reduction in the capital works program, the need to identify future network constraint areas or areas flagged for future urban or commercial development will need to continue.

4.7 Impact of Climate Change on the Network

Climate change projections indicate increased storm and rainfall intensity, greater variations in wet and dry weather patterns, significant sea level rise as well as the potential for an increase in severity of tropical cyclones. This suggests that there may be the likelihood of inundation of some low lying Ergon Energy assets and some associated maintenance and replacement expenditure in the long term future.

Ergon Energy proposes to address the impacts of climate change by the following measures:

- gradually increase the resilience of overhead line assets by the addition of LV conductor spreaders and installing LV fuses on distribution transformers in all cases
- changing HV expulsion drop out fuses in high risk bush fire areas to ‘spark-less design types’
- replacing small aged copper conductor (7/064 and smaller) at end of life
- reviewing pole top inspection regimes to account for longer periods of high rainfall in some areas
- using Fugro Roames™ data to facilitate improved storm surge flood planning for areas which are likely to be impacted by storm surges.

Ergon Energy will continue to adapt network assets to mitigate the risks of severe environmental events (cyclone, storm, flood, bushfire) and has budgetary allowance in a range of programs to facilitate this work.
Chapter 5 – Asset Management

Overview

5.1 Best Practice Asset Management
5.2 Asset Management Policy
5.3 Strategic Asset Management Plan
5.4 Asset Management System
5.5 Network Investment Process
5.6 Further Information
5. Asset Management Overview

Management of Ergon Energy’s current and future assets is core business. Underpinning our approach to asset management are a number of key principles, including making networks safe for employees and the community, delivering on customer promises, ensuring network performance meets required standards, and maintaining a competitive cost structure.

This section provides an overview of Ergon Energy’s:

- Best Practice Asset Management
- Asset Management Policy
- Strategic Asset Management Plan (SAMP)
- Asset Management System and
- Asset Management Investment Process

5.1 Best Practice Asset Management

Ergon Energy recognises the importance of maximising value from assets as a key contributor to realising its strategic intent of achieving balanced commercial outcomes for a sustainable future. To deliver this, our asset management practice must be effective in gaining optimal value from assets.

Ergon Energy is continuing to reshape its asset management practice to align with the ISO 55000 standard. This transition is a significant undertaking and will span several years, so a phased approach has been initiated that will focus on building capability across all seven major categories covered by the standard (i.e. Organisational Context, Leadership, Planning, Support, Operation, Performance Evaluation and Improvement).

5.2 Asset Management Policy

The Asset Management Policy provides the direction and broad framework for the content and implementation of Ergon Energy’s asset management objectives, strategies and plans. The policy directs us to undertake requirements associated with safety, people, meeting customer needs. It describes the commitment to ensure asset management enablers and decision making capability meets the current and future needs.

This policy together with the strategic asset management plan are the primary documents in the asset management documentation hierarchy and influence subordinate asset management strategies, plans, standards and processes.

5.3 Strategic Asset Management Plan

Ergon Energy’s Strategic Asset Management Plan (SAMP) is the interface that articulates how organisational objectives are converted into asset management objectives as shown in Figure 9. The SAMP also sets the approach for developing asset management plans and the role of the asset management system in supporting achievement of the asset management objectives.
5.3.1 Asset Management Key Objectives

The Ergon Energy strategic agenda is translated into the asset management objectives via the SAMP. These objectives, as shown in Figure 10 establish the direction and desired outcomes that asset management strategies, plans and initiatives will target.
5.3.2 Asset Management Plans and Initiatives

As part of Ergon Energy’s transition to align with ISO 55000, a suite of asset management plans have been developed for key network asset categories which enhance asset lifecycle management decision making and ultimately the value realised from assets. These plans document our approach cognisant of legislation, regulatory obligations, standards (internal and external) and asset management strategies.

5.4 Asset Management System

The Asset Management System supports achievement of Ergon Energy’s asset management objectives by ensuring the key system elements are operationalised as part of our asset management practice.

The system also ensures the asset management planning process, capabilities and decision making, take into account the inter-relationships and interdependencies between the system elements. Effective integration of these elements ultimately determines the success with which Ergon Energy maximises value from its assets. The asset management system depicted in Figure 11, conceptualised by the Institute of Asset Management and adopted by Ergon Energy, is a revised version of the system published in 2014-15 to ensure alignment with the ISO 55000 standard.

Figure 11: Ergon Energy’s Asset Management System
Chapter 5. Asset Management Overview

5.5 Network Investment Process

The Network Investment Process is the execution of the Network Asset Management Policy, Network Asset Management Strategy and Plans via the development and delivery of investments and projects.

5.5.1 Corporate Governance

Ergon Energy has a five-tier governance process to oversee future planning and expenditure on the distribution network as shown in Figure 12. Our corporate governance is guided by and structured around legislative compliance.

Figure 12: Program of Work Governance

The five tiers include:

1. **Network Asset Management Policy, Strategy & Objectives**: Alignment of future network development and operational management with the Ergon Energy policy, strategic direction and management plans to ensure implementation of asset management best practice.

2. **Program of Work (PoW) Strategy & Plan**: High level expenditure targets and forecasts,
approved by the Energy Queensland Limited Board and presented to our shareholding Ministers, reflecting the current estimate of five-year expenditure forecast required to deliver the asset management objectives and consequently the corporate plan.

3. **Network Investment Portfolio**: Development of five year rolling expenditure programs and a 12-month detailed program of work which is established through the annual planning review process; (including individual projects approved by the Energy Queensland Limited Board). The Risk and Compliance Committee, a subcommittee of the Energy Queensland Limited Board, oversees the fulfilment of Ergon Energy’s compliance commitments and ensures the network risk profile is managed and aligned to the corporate risk appetite.

4. **Projects and Programs Approval**: Network projects and programs are overseen by senior management and subject to an investment approval process, requiring business cases to be approved by an appropriate financial delegate. The monitoring of all programs and projects is undertaken by the PoW senior management in compliance with the relevant Energy Queensland Limited policy, protocols and standards.

5. **Program of Work Performance Monitoring**: Ergon Energy has Key Performance Indicators (KPIs) to ensure the PoW is being effectively delivered while maintaining performance standards and customer commitments. The Network Operations and Steering Committee meets on a monthly basis to review operational and financial performance to resolve issues.

5.5.2 **Network Risk Management and Program Optimisation**

Management of risk is an integral part of effective asset management frameworks. Our network risk framework provides a consistent approach to the assessment of network risks and is aligned with AS/NZS ISO 31000:2009 Risk Management – Principles and Guidelines.

Five risk categories are defined by which network risks are assessed:

- safety
- environment
- legislated requirements
- customer impacts and
- business impacts.

Projects and programs are assessed against the above risk categories If required, projects and programs of work are then considered and addressed on a priority basis, according to risk and investment maturity, to optimise the PoW to deliver tolerable risk outcomes with regard to funding constraints.

5.5.3 **Investment Guidance**

Ergon Energy prepares its work programs in compliance with its obligations and corporate objectives. The capex, opex and efficiency objectives that we must satisfy are defined in the NER. Achieving the corporate objectives requires the balancing of cost, risk and performance outcomes to gain optimal value from assets, combined with new business models and investments in new technologies.

The efficient use of electrical infrastructure is key to Ergon Energy’s prudent and efficient asset management practice and central to the assessment of expenditure options. The benefits that flow
from capex include modern assets with increased performance and low maintenance costs. These are assessed against the benefits of opex.

In addition to network risks, age and condition of existing assets, Ergon Energy considers capex and opex in the following ways:

- compliance with NER and regulations.
- compliance with Ergon Energy’s Distribution Authority:
  - Minimum Service Standard (MSS) – measures based on outage frequency and duration of feeder performance across the supply network in each given financial year.
  - Worst Performing Feeder Improvement Program – where prudent opportunities exist, to improve reliability outcomes for customers on the network’s worst performing feeders.
  - Safety Net – effective mitigation of the risk of low probability/high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption. Safety Net targets for power restoration times are prescribed for different locations and energy loads at risk.
  - requirement to plan and develop the supply network in accordance with good electricity industry practice.
- assessing the Value of Customer Reliability (VCR) impact for certain proposed investments to assess their economic efficiency.
- application of the RIT-D where applicable to ensure alternative solutions (such as demand management) are considered.
- demand management schemes implemented in targeted areas where they are economically efficient and can defer projects identified over longer term planning horizons.
- investment in assets that will improve efficiency and deliver long term sustainability.

5.5.4 Network Investment Process

The Network Investment Process considers the portfolio of projects and programs proposed for inclusion in the future PoW on a consistent basis by:

- reviewing programs and projects to assess the justification relative to drivers, risks, cost and performance targets.
- reviewing the risks if the proposed programs and projects were not to proceed, and how the untreated risk could be otherwise managed to tolerable levels.
- optimising the portfolio of the PoW to deliver the appropriate balance between risks, resources (including cost) and achievement of performance targets.

Ergon Energy’s gated governance approach is a staged process broadly including planning, risk validation and final approval to implement.

The gated governance approach subjects an investment to a suitable level of management review at up to three predetermined points (Gates 1, 2 and 3) in its life cycle, to ensure the investment’s continuing need, suitability and readiness to proceed.

5.5.5 Program of Work Implementation

Once individual projects/programs are approved they progress through the design, construction
Chapter 5. Asset Management Overview

and commissioning phases as part of program delivery.

Depending on the extent of the scope, proposed projects range from minor projects to significant infrastructure works. Therefore, projects can take between one and three years (with some extending to 5-7 years) from approval to final commissioning. This can vary significantly depending upon jurisdictional (i.e. community consultation and environmental) approval processes.

5.6 Further Information

Further information on our network management, including asset management strategy and methodology, is available on the Ergon Energy website on the following link:

Chapter 6 – Network Forecasting

6.1 Forecast Assumptions
6.2 Energy Sales Forecasts
6.3 Substation and Feeder Maximum Demand Forecasts
6.4 System Maximum Demand Forecast Methodology
6. Network Forecasting

Forecasting is a critical element of our network planning. The demand for electricity at the point in time when electricity use is at its highest is known as peak demand. Although energy is the amount of electricity delivered to customers, it is the growth in peak demand, at the local and regional level, that is the key driver of our augmentation investment.

The local growth in peak demand and the point in time that the peak occurs at any given location can vary from the overall system-wide growth rate and time of peak demand. Further, within a local area, a section of the network that is largely residential has peak loading typically in the evening, whereas for a commercial area, it occurs during the day and early evening.

This means that while we are continuing to forecast that energy consumption and overall demand will remain steady, some areas are continuing to see localised pockets of demand growth where there is potentially insufficient network capacity.

To ensure we respond to this, we undertake both demand and energy forecasting across all areas of the supply chain. We use a combination of multivariate and economic techniques to produce ten-year forecasts for energy and peak demand.

For peak demand forecasts, Ergon Energy uses a ‘bottom-up’ and ‘top-down’ approach to provide a robust forecast methodology. The ‘bottom-up’ forecasts provide a local forecast for each substation across the network based on local climate and weather conditions, customer mix, and localised demographic growth. The ‘top-down’ forecast is an econometric ten-year system maximum demand forecast based on identified factors which affect the load at a system-wide level. Reconciliation between the two is used to introduce the macro-economic factors to the local area forecast.

6.1 Forecast Assumptions

The energy consumption and demand forecasting assumptions are detailed in the following sections.

6.1.1 Customer Behaviour

In making our energy and peak demand forecasts, we consider the impact of customer behaviour, from the take up of energy efficient appliances and solar PV to the choices customers are making about their use of electricity. This is supported by Queensland Household Energy Survey 2016, which tracks appliance penetration, air conditioner use, purchase intentions (e.g. of solar PV systems, etc.) and general behavioural elements. We are also monitoring the market’s response to emerging technologies (e.g. batteries and smart grids). Customer behaviour is dynamic; it changes in response to new emerging technologies and customer adoption rates.

6.1.2 Solar PV Systems

Micro embedded generating (EG) units are customer-owned generators with capacities under 30 kVA, most of which supply power to our network. Solar photovoltaic (PV) systems currently comprise the vast majority of this class of generators. This class does not include large-scale generators or solar farms, and only micro EG class solar PV is discussed in this section.
Growth in the volume of micro EG units is expected to continue as shown in Figure 13 and Figure 14. By the end of June 2022, it is predicted there will be between 150,000 and 250,000 PV systems with a total capacity of between 611 MW and 1161 MW.

**Figure 13: Cumulative Installed Micro EG Units**

**Figure 14: Cumulative Installed Inverter Capacity**
The forecasts assume that solar feed-in tariffs remain constant, no major government incentive programs are implemented during the forecast period, there are minimal ongoing cost reductions for PV systems, and the residential PV market approaches some degree of saturation.

Generation from micro EG solar PV systems significantly reduces demand during daylight hours, but the effect on overall seasonal or peak demand is variable. In recent years, the system peak demand on our network has been in the late afternoon or early evening, when solar PV systems generate little energy. This is demonstrated in Figure 15 which shows the total demand on the peak day of the year (13 February 2017) and the days preceding and following.

Figure 15: Total System Load with and without PV Contribution in Summer 2016-2017

The effect of solar PV on overall peak demand is reflected in the system-wide demand forecast. It is treated as a component of demand management, which is included as a variable in the system equation, and currently represents around 60 MW of system peak demand.

By evening, when solar PV is no longer generating and other residential loads have switched on, daily peaks are generally lower than afternoon peaks were without the effect of solar PV.

Figure 16 shows the estimated reduction in overall seasonal peak demand due to solar PV each summer season, along with the time the actual metered peak occurred. The demand reduction was calculated by comparing the estimated peak demand without PV (normally occurring in the early afternoon) to the actual metered peak demand (normally occurring in the evening). These are shown as the light blue and green lines in Figure 15.
The large difference between the 2014-15 peak and peaks observed in other years can be attributed to the fact that the 2014-15 system peak occurred around 3:00pm when solar PV systems were still generating. In 2015-16 and 2016-17 the peak occurred in the evening when solar was not generating. From 2011-12 to 2014-15, the peak was in the late afternoon, rather than mid-afternoon as in previous years, but there were less PV systems installed, creating a smaller network impact. It is expected that the increasing volume of PV systems will ensure most system demand peaks occur in the evening for the foreseeable future.

Although solar PV affects the peak demand at a system level, it has a varying and lessening effect at lower network elements and as shown in Section 4.1.2 solar PV generation can also mask the daily total electricity demand on each feeder. Due to the combination of load coincidence and intermittency Solar PV generation cannot be relied upon to consistently reduce network demand, so currently plays no role in deferring network augmentation. The impact of PV generation on feeder and substation demand, and its potential to defer augmentation expenditure into the future, is continually being reviewed.

Figure 16: Estimated Reduction in Peak Demand from Solar PV

6.1.3 Electric Vehicles

The purchase of an electric vehicle has the potential to significantly change a customers’ demand profile. However, at this stage the number of electric vehicles in regional Queensland is minimal. The proliferation of electric vehicles is not explicitly included in the current forecasts, but their uptake is being monitored and will be considered for future forecasts if relevant.

6.1.4 Battery Storage

Battery storage (particularly when combined with solar PV) has a great potential to impact how
Ergon Energy’s customers use energy, with effects on both total energy consumption from the grid and peak demand. The uptake of battery storage is being monitored, but at this stage there are not enough customers with battery storage to determine its effects, or a long enough history to calculate a robust forecast. Likely future energy regulations and government policy changes will see improved capabilities and effective monitoring as the uptake of batteries increases.

### 6.1.5 Temperature Sensitive Load and Air Conditioning Growth

Air conditioning is one of the major drivers in peak demand load on the network. There has been constant and linear growth in peak demand load from air conditioners. Air conditioner data is sourced annually from an independent consultancy. This data set is complete with no data adjustments required. The modelling process requires the use of a suitable weather series to relate daily movements in system maximum demand to weather variation.

Daily minimum and maximum temperature data is employed in the models. Weather data is used in the methodology both as part of the regression model used to relate system maximum demand to weather drivers, as well as part of the long run weather series used to derive the 10 Probability of Exceedance (PoE) and 50 PoE demands.

Weather time series are obtained from the Bureau of Meteorology (BOM). The process requires a 50-year history, which restricts the available data somewhat as not all weather stations have 50 years of reliable data. The weather data series used as input to the system maximum demand model is based on a selection of weather data from several points in the Ergon Energy coverage area:

- 039123 Gladstone Radar
- 032040 Townsville Aero
- 031011 Cairns Aero
- 04004 Amberley

Amberley weather station has been chosen as the weather station to represent data in the South Eastern region of Ergon Energy’s distribution area. Other weather stations either did not have the necessary 50 year history or had substantial numbers of missing values.

Although data from these stations proved to be very reliable, there were some missing data values. In order to calibrate the models using the daily maximum demand data, values for missing observations were imputed by either substituting data from a nearby weather station or by utilising linear regression of temperature against time. The choice of reliable weather data meant this imputation process involved only a small number of adjustments.

Weather data used for temperature correction of individual zone substation forecasts was sourced in a similar manner from the BOM but the selected weather station was the closest to the substation being forecast, with reliable weather data.

The recently launched Himawari-8 satellite and further enhanced satellite spectral recording capability will add value to the temperature records we currently have and those we wish to add to. Further applications include more accurate knowledge of solar PV production based on cloud

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13 This reduced set of all possible weather stations result from selection of all possible weather stations for statistical significance with seasonal peak demand together with data integrity.
Chapter 6. Network Forecasting

cover, more precise temperature information and instantaneous weather data which could be used for operational purposes during floods or storms.

6.1.6 Economic and Population Growth

Economic and demographic changes significantly affect the energy and peak demand forecasts in customer and tariff type together with the amount of power consumed.

In terms of future population movements, the main economic institutions such as the Australian Bureau of Statistics (ABS), the Australian Energy Market Operator (AEMO), National Institute of Economic and Industry Research (NIEIR) and Office of Economic and Statistical Research (OESR) project that the population growth is expected across the tourism industry over the next few years, boosted by a commensurate growth in the State economy. Net Inter-state Migration (NIM) and Net Overseas Migration (NOM) as well as a relatively competitive Australian currency (which in turn, will attract more overseas students and tourist arrivals) will result in Queensland population growth of 1.5% in the 2017-18 year. Gross State Product (GSP) data is sourced from the ABS website. Estimated GSP values for forecasting years are obtained from consultants and Queensland Treasury.

6.2 Energy Sales Forecasts

6.2.1 Energy Sales Forecast Methodology

Ergon Energy uses a combination of statistically based time series analysis, multi-factor regression analysis and the application of extensive customer knowledge and industry experience to determine energy sales forecasts. Regression models and consultant reviews are used to substantiate the forecasts, which are separately formulated for each of the following:

- Domestic
- Commercial
- Industrial
- Rural
- Network tariffs

For each of the categories listed above, forecasts are produced for the total customer numbers and the amount of energy usage per connection or customer. The forecasts of customer numbers and average usage per customer are then multiplied together to obtain total energy delivered for each segment. Total system energy is the summation of each of the components. This is a market category or bottom-up approach and provides a reasonable basis for constructing forecasts for total system energy use.

Each category is affected by different underlying drivers for growth. For example, population and income growth are generally of greater significance in driving energy use in the domestic category, whereas GSP growth is of more importance in the commercial category. An understanding of these sensitivities gives Ergon Energy the flexibility to treat the different categories independently, rather than taking a more generalised approach that results in some loss of useful information. This methodology results in a more robust forecast.

Total energy per category is modelled by multiplying energy per category with the number of
customers. Energy per tariff type is obtained from the historical market share of that tariff and projected forward.

6.2.2 Energy Sales History and Forecast

In 2016-17 the total usage across the regulated network decreased by an estimated 245 GWh (2%). The decrease has been attributed to disruptions caused by Tropical Cyclone Debbie. Energy delivered together with customer numbers for historical build up and forecast are shown in Figure 17: Number of Customers and Energy Delivered.

Figure 17: Number of Customers and Energy Delivered

6.3 Substation and Feeder Maximum Demand Forecasts

Ergon Energy reviews and updates its temperature corrected system summer peak demand forecasts after each summer season. Each new forecast is then used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency, the system level peak demand forecast is reconciled with the bottom-up substation peak demand forecast after allowances for network losses and diversity of peak loads.

In recent years, there has been considerable volatility in Queensland economic conditions, weather patterns and customer behaviour, all of which have affected total system peak demand.

Customer reaction to recent electricity price increases, and the fall in prices for solar PV, has contributed to a reduced customer load at temperature corrected conditions, well below long-term average trends. The take up of solar PV is continuing and customers are consciously trying to minimise their electricity costs and energy consumption. Customer behaviour drivers are currently

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14 2017 Energy and customer numbers are estimated as 2017 actual and forecast figures are currently being produced. Historical values include transfer of major customers to and from the Ergon Energy network.
being incorporated into models used for system and substation demand forecasting. The forecasts are being developed using: ABS data, Queensland Government data, AEMO data, an independently produced Queensland air conditioning forecast, solar PV connection data, historical peak demand data, and through regional, local demographic and economic behaviour as provided by consultancy models.

6.3.1 Substation Forecasting Methodology

Ergon Energy employs a bottom-up approach to develop the 10 year zone substation peak demand forecasts using validated historical peak demands and expected load growth, and a feedback process with regional planning engineers. Block loads fulfilling a peak demand criteria on size are included separately after passing a probability of proceeding criteria. The zone substation peak demand forecasts are aggregated up to the 10 year bulk supply point and transmission connection point demand forecasts and take into account diversity of individual zone substation peak demands and network losses. This aggregated forecast is then reconciled with the independent system demand forecast and adjusted as required.

The process used to develop the 10 year substation demand forecast is briefly described as follows:

- Validated uncompensated substation peak demands are determined for summer
- Minimum and maximum temperatures at five BOM weather stations are regressed against substation daily maximum demand to assess the impact of each set of weather data on substation demand. The best fit relationship is used to determine the temperature adjustment
- Industrial substations tend not to be sensitive to temperature and the 50 PoE and 10 PoE adjustments are based on sets of business rules chosen to reflect demand variation
- Previous substation peak demand forecasts are reviewed against temperature adjusted results and causes of forecast error are identified
- Starting values for apparent power, real power, and reactive power are calculated for two periods – summer day and winter day
- Year-on-year peak demand growth rates are determined from, historical growth trends and local knowledge from Asset Managers using a panel review (Delphi) process
- Size and timing of new block loads are reviewed and validated before inclusion in the forecast
- Size and timing of load transfers are also reviewed before inclusion in the forecast
- The growth rates, block loads, transfers are applied to the starting values to determine the forecast demand for each of the 10 years starting from a coincident demand basis
- Zone substation forecast peak demands are aggregated up to transmission connection point demands through the bulk supply substations using appropriate coincidence factors and losses
- Reconciliation of the total aggregated demand with the independently produced system demand forecast ensures consistency for the 10 year forecast period.

Substation peak demand forecasts including growths and temperature corrected starting points are reviewed by forecasting analysts and planning engineers through a feedback discussion (Delphi)
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...process to represent the best forecast outcome in the absence of well-defined substation economic and demographic drivers for each substation.

Peak demand forecasts are produced for each of Ergon Energy's zone substations for summer and winter seasons. The forecasts are calculated at the 10 PoE and 50 PoE levels and are projected forward for 10 years from the most recently completed season.

Zone substation forecasts are based on a probabilistic approach using a multiple regression estimation methodology. This approach has the advantage of incorporating uncertainty relating to weather events into the forecasting methodology.

A Monte Carlo simulation using BOM daily minimum and maximum temperature history is used to calculate the 10 PoE and 50 PoE maximum demands for each zone substation. Growth rates are then calculated using a separate regression for summer and winter going back as far as the limit of available data. Growth rates, load transfers and new major customer loads are then used to simulate the future load at each zone substation 10 years in advance.

Bulk supply substations and transmission connection point forecasts are produced by the aggregation of zone substation forecasts, taking into account losses and coincidence factors.

6.3.2 Sub-transmission Feeder Forecasting Methodology

Forecasts for sub-transmission feeders in Ergon Energy are produced for a five-year window, which aligns with the capital works program. The forecasts identify the anticipated maximum loadings on each of the sub-transmission feeders in the network under a normal network configuration.

Ergon Energy has adopted a modelling approach to produce forecasts for the sub-transmission feeders. The traditional forecasting approach of linear regression of the historical loads at substations is not applicable, since it does not accommodate the intra-day variation. The modelling approach enables identification of the loading at different times of day to equate to the line rating in that period.

The sub-transmission feeder methodology approach takes the substation maximum demand forecasts and the daily load profiles of each individual substation to produce a forecast half hour load profile for the maximum demand day at that substation. This is produced for each substation in the network. A series of load flows are then performed for each half hour period of the day using these loadings. The forecast feeder load for each period is the maximum current experienced by the feeder in any half hour interval during that period.

6.3.3 Distribution Feeder Forecasting Methodology

Distribution feeder forecast analyses carry additional complexities compared to sub-transmission forecasting. This is mainly due to the more intensive network dynamics, impact of block loads, variety of loading and voltage profiles, lower power factors, peak loads tending to peak at different times and dates and the presence of phase imbalance. Also, the relationship between demand and average temperature is more sensitive at the distribution feeder levels.

On the macro level, the forecasting drivers are similar to those related to substations, such as economic and population growth, consumer preferences, solar PV systems, etc. Accordingly, Ergon Energy uses a combination of trending of normalised historic load data and inputs including known future loads, economic growth, weather, local government development plans, etc. to arrive
at load forecasts.

Filtering is performed to remove short-term effects or abnormal situations. An example could be that the feeder may have been operated abnormally for some time in order to supply other load during extended contingency conditions or during prolonged maintenance works. The additional load and demand would then have to be normalised out of the forecast in order to arrive at a baseline forecast.

In summary, the sources used to generate distribution feeder forecasts are as follows:

- the historic maximum demand values have been used to determine historical demand growths. These historical maximum demands have been extracted from feeder metering and/or Supervisory Control and Data Acquisition (SCADA) systems and filtered/normalised to remove any abnormal switching events on the feeder network. Where metering/SCADA system data is not available, maximum demands are estimated using After Diversity Maximum Demand (ADMD) estimates or calculations using the feeder consumption and appropriate load factors.
- the historical customer numbers on the feeder have been used to determine historical customer growth rates. The historical customer numbers are calculated by combining network topology information with customer record sources to count the total historic numbers of customers on each feeder.
- the temperature and humidity data at the time of historical maximum demands, when taking into account weather impacts (extracted from the BOM website); have been used to determine approximate 10 and 50 PoE load levels.
- further forecast information has been obtained from discussions with current and future customers, local councils and government.

6.4 System Maximum Demand Forecast Methodology

Ergon Energy reviews and updates its 10 year 50 PoE and 10 PoE system summer peak demand forecasts after each summer season. We use a combination of ‘top-down’ and ‘bottom-up’ approaches to provide a robust forecast methodology.

The ‘top-down’ forecast is an econometric ten-year system maximum demand forecast based on identified factors which affect the load at a system-wide level. Inputs for the System Maximum Demand forecast include:

- economic growth through the Gross State Product (source: ABS website)
- temperature (source: BOM)
- air conditioning sales (source: independent consultancy)
- solar PV penetration (source: Ergon Energy customer data)
- load history (source: Ergon Energy metering database).
The System Maximum Demand forecast provides a benchmark, against which the aggregated spatial forecasts ‘bottom-up’ are reconciled.

Further to the System Maximum Demand, Ergon Energy also produces a ten-year maximum demand forecast for all zone substations (also described as ‘spatial forecasts’) which are aggregated to bulk supply substations and transmission connection points. Forecasts are also aggregated to a System Total and reconciled to the econometrically derived System Maximum Demand. Zone substation forecasts are based upon a number of inputs, including:

- network topology (source: Ergon Energy equipment register)
- load history (source: Ergon Energy metering database)
- known future developments (new major customers, network augmentation, etc.) (source: Ergon Energy Major Customer Group database)
- customer demographics – consumption
- temperature corrected start values (calculated by SIFT forecasting system)
- forecast growth rates for organic growth (calculated by SIFT forecasting system)
- System Maximum Demand forecasts.

The nature of the System Maximum Demand methodology and the resulting forecast is such that it is considered the most accurate and reliable indicator of future demand in the network.

An overview of this process is illustrated in Figure 18.
There is a level of uncertainty in predicting future values. To accommodate the uncertainty, forecasts at differing levels of probability have been made using the PoE statistic. In practical planning terms for an electricity distribution network, planning for a 90 PoE level would leave the network far too vulnerable to under-capacity issues, so only the 10 PoE and 50 PoE values are significant.
6.4.1 System Demand Forecast Methodology

The methodology used to develop the system demand forecast comprises:

- 50% PoE level - This best estimate level is obtained from a Maximum demand distribution such that 50% of the values are each side of this value.
- 10% PoE level - This highest level is obtained from a Maximum demand distribution such that 10% of the values exceed this.
- The actual Maximum coincident demand at the network level for historical years is extracted from the Ergon Energy System Demand data set from system daily maximum demand loads. Temperature correction for 90%, 50% and 10% PoE system maximum demand is made using the past 50 years of daily temperature from selected weather stations throughout the State.
- Weather normalised data is derived using the past 50 years of temperatures.
- System forecasts are obtained from modelling a temperature-corrected multivariate regression model using economic, demand management, air-conditioning and solar PV uptakes.

6.4.2 System Maximum Demand Forecast Results

In 2016-17 there was low level overall demand growth, as shown in Figure 19, in line with our own forecasts and those of AEMO. The system-wide 2016-17 peak was 2,637 MW at 7.30pm on Monday 13 February 2017 an all-time record as a result of the extreme hot summer weather extending across Queensland. This was aligned with a 10 PoE peak demand (one in 10 year event).

With the global and domestic economy remaining subdued, we are continuing to forecast that energy consumption and overall demand will remain steady. However, some areas are continuing to see localised growth. With investment in the resource industry down, and the LNG industry moving from project construction to production, this growth is being driven from outside of the mining sector, from industries like tourism and from residential housing investment.

System forecast accuracy analysis, obtained by comparing forecast peak demand with actual peak demand, results in the mean absolute percentage error at 4% and consistent with the value of the forecast model’s standard error and given that 2017 aligned with a 10PoE event. Forecast values have been revised down for each subsequent year as economic conditions measured by actual and estimated Gross State Product (GSP) have softened, over the same period.
Figure 19: Trend in System-wide Peak Demand

- 50POE [MW]-Medium
- 50POE-Low
- 50 POE-High
- Actual
Chapter 7 – Network Planning

7.1 Background
7.2 Planning Methodology
7.3 Key Drivers of Augmentation
7.4 Network Planning Criteria
7.5 Voltage Limits
7.6 Fault Level Analysis
7.7 Ratings Methodology
7.8 Customer Initiated Capital Works
7.9 Major Customer Connections and Embedded Generators
7.10 Joint Planning
7.11 DAPR Reporting Methodology
7. Network Planning

7.1 Background

Network Planning strikes a balance between customers’ need for a safe, secure, reliable, and high quality electricity supply, and their desire for this service to be provided at minimal cost. A key part of the network planning process is to optimise the economic benefits of network augmentation, and so should consider facilitating actions beyond the boundaries of the network, such as demand management, embedded generation solutions and other non-traditional approaches.

The selection of the optimal network and business solution is achieved by:

- Determining and critically assessing key network limitations
- Developing and evaluating a broad range of network and non-network solutions
- Seeking to integrate and optimise outcomes using a variety of planning inputs
- Staging of project phases to ensure prudent expenditure.

This section outlines the network planning criteria, process, and framework that underpins our network planning approach.

To support discussion in this section, Figure 20 below illustrates a traditional simplified DNSP network which typically consists of sub-transmission, HV distribution, and LV networks supplying customers at all voltage levels. It should be noted, as highlighted in other areas of this document, this traditional network topology is changing as we see greater numbers of embedded generators (and storage technology) at all voltage levels. This increased complexity and diversity at all levels within the network is both creating opportunity and challenge in the planning of the network.

Figure 20: Traditional Simplified DNSP Network
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7.2 Planning Methodology

7.2.1 Strategic Planning

Ergon Energy’s planning process involves production of short, medium and long-term strategic network development plans. These plans assess the electricity supply infrastructure requirements for defined areas based on the most probable forecast load growth projections. Where appropriate, scenario planning is also used to obtain alternative development plans for a range of possible outcomes (e.g. high growth, more intense weather patterns, etc.). Demographic studies based on local government plans are carried out to help indicate the likely long-term demand for electricity across a development area. These include scenario modelling to test various outcomes, such as high or low customer response to demand management and energy efficiency initiatives.

The strategic planning process is an iterative and analytical process that provides an overall direction for the network development of a region. The purpose of strategic network development plans is to ensure the prudent management and investment for network infrastructure in both the short and long term, and to coordinate developments to address limitations and meet utilisation targets.

Strategic network development plans detail the results of the information and studies that produce the set of recommendations for proposed works over the study period. This includes:

- details of all proposed works over the study period, including variations and dependence on different trigger factors
- recommendations for easement and site acquisitions required in advance of any proposed works, including variations and dependence on trigger factors
- details of all technical and financial analysis performed.

The long-term nature of strategic planning means that there is significant uncertainty around the estimations of load growth and location of load. The output of the strategic planning process gives direction to the short and medium-term recommendations, while allowing land and easement acquisition and approvals to proceed. Specific outcomes of strategic network development plans are to identify areas where non-network solutions may be feasible to defer or avoid network augmentation.

7.2.2 Detailed Planning Studies

As the works identified within each strategic network development plan draw closer or where unforeseen customer initiated development changes occur, more detailed localised studies are performed. The shorter term detailed planning studies are conducted to identify all existing and anticipated network limitations within a five-year horizon. Ergon Energy is using area plans that encompass sub-transmission, distribution, non-network and, where significant, asset renewal planning functions.

These planning studies are conducted at the sub-transmission and distribution level to consolidate and assess any other factors that may have a material impact on the studied network. This usually includes an assessment of:
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- non-network alternatives NNA
- fault levels
- voltage levels
- security of supply requirements
- quality of supply considerations
- asset renewal (where significant)
- new connection applications
- local, state and federal government decisions and directions.

Proposals are then developed to address the various issues.

7.3 Key Drivers of Augmentation

Network augmentation can be the result of customer activity, upstream augmentation works, network reconfiguration or major customer works that impact the shared network.

There are four general types of customer activity that can cause limitations in Ergon Energy’s distribution system and prompt the need to invest:

(i) organic growth that occurs when existing customers increase or change the profile of their electricity usage in a particular part of the network, or across the network
(ii) increases in the number of residential or small commercial customers in a particular part of the network due to population growth
(iii) block loads connecting to a particular part of the network, such as new large commercial or industrial customers
(iv) changes/installation of small/medium scale embedded generators and/or storage technology.

Without network or non-network investment, customers’ increased demand can result in us exceeding our existing planning limits (including component capacity/ratings, voltage regulation constraints and protection limit encroachment) and/or the security criteria of the network.

Augmentation works within our network can also be driven by Powerlink, as the Transmission Network Service Provider (TNSP) or other related DNSPs. Work on Powerlink’s network may require complementary activity within our network in order to ensure the transmission capacity can be delivered to the distribution network. Such complementary activity could be the result of increased fault levels or plant rating constraints. These types of augmentation activities are analysed and reviewed as part of the Joint Planning process conducted between Ergon Energy and Powerlink (or other DNSPs) as required by the NER.

Network reconfiguration, due to decommissioning of plant or through load shifting, can also contribute to the requirement for network or non-network works as can the impact of significant customer connections on the shared network. In these cases, there could be a combination of drivers for augmentation which may result in a combination of network or non-network responses to resolve limitations.
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7.4 Network Planning Criteria

Network planning criteria are a set of rules that guide how future network risk is to be managed or planned for and under what conditions network augmentation or other related expenditure (such as demand management) should be undertaken.

There are two widely recognised methodologies for the development of planning criteria for power systems:

- deterministic approaches (e.g. N-1, N-2, etc.)
- probabilistic (risk-based) approaches.

In September 2014, the network planning requirements under Ergon Energy’s Distribution Authority changed from a deterministic approach to a probabilistic approach. The changes removed the requirement for specific levels of network redundancy, allowing for full consideration of the network risk at each location, including operational capability, plant condition and network meshing.

The criteria gives consideration to many factors including the capability of the existing network asset, the regulated supply standards (such as voltage, quality, reliability, etc.), the regulatory framework around investment decision making, the magnitude and type of load at risk, outage response capability and good electricity industry practice. Consideration is also given to the complexity of the planning process versus the level of risk, allowing for simpler criteria to apply where lower risks exist and where the cost of potential investments is smaller.

While the new planning criteria are far more complex in application, the change has resulted in a significantly reduced augmentation program across the network, which in turn applies downward pressure on future electricity prices.

The new criteria adopted by Ergon Energy increase the focus on customer service levels and comprise two parts:

- **customer value investment**: predominantly driven by the benefits gained from a reduction in unplanned outages (i.e. VCR), but also including (where applicable) other classes of market benefits, and;
- **mandatory investment**: this includes the regulated standards for the quality of supply as per the NER, the MSS and Safety Net requirements in the Distribution Authority and any other regulatory obligations, to the limit that those requirements are applicable.

To avoid doubt, proposed investments that are not mandatory investments must have a positive Net Present Value (NPV) when all significant costs and benefits are accounted for, over a reasonable evaluation period (usually 20 years). This approach ensures that investment occurs only where the benefits outweigh the costs. Mandatory investments need not be NPV positive, however, where the benefits from different options may have an appreciable effect upon which option is selected; those benefits should be taken into account.

7.4.1 Value of Customer Reliability

In September 2014, AEMO published the results of an investigation into the value that NEM customers place upon reliability. AEMO also published an application guide in December of that year.
According to the AEMO Review\textsuperscript{15}, the VCR:

```
"… represents, in dollar terms, the estimated aggregated value that customers place on
the reliable supply of electricity. The actual value will vary by the type of customer and
the characteristics of the outages being considered. The VCR at different points on the
grid would then vary based on the mix of customer types at that point. As customers
cannot directly specify the value they place on reliability, the VCR plays an important role
in determining the efficient level of investment in, and efficient operation and use of,
electricity services required by customers in the National Electricity Market (NEM)."
```

Components in the calculation of VCR include:

- Energy at Risk (EaR): the average amount of energy that would be unserved following a
  contingency event, having regard to levels of redundancy, alternative supply options,
  operational response and repair time
- Probability of the Contingency (PoC) occurring in a given year at a time when there is
  energy at risk
- network losses between the measurement point and the customer
- customer mix, by energy consumption across various customer sectors.

The first three factors are combined to calculate the ‘annualised probability-weighted Unserved
Energy (USE)’ in MWh. The last factor, customer mix, is combined with the AEMO VCR tables to
calculate the ‘energy-weighted locational VCR’ (in $/MWh). Finally, the two are multiplied to
calculate the annual economic cost of unserved energy (VCR) associated with the given
contingency (or contingencies). By also considering load growth and (for example) plant ageing,
estimates of the annual VCR are calculated across the evaluation period (usually 20 years).

Changes in VCR associated with a particular project (or option) represent a benefit (if positive), or
a cost (if otherwise) that is used as a benchmark to assess proposed solutions. To be comparable,
proposed solutions are required to be expressed in terms of annualised costs or annuities. By
balancing the VCR and the cost of supply, a more efficient service can be provided to our
customers.

Research conducted by Ergon Energy clearly indicates that there are distinct differences in
reliability tolerance across various end-use customer segments. Consequently, Ergon Energy uses
a sector-specific (including for example, residential, agricultural, commercial and industrial)
approach to setting VCRs where appropriate.

### 7.4.2 Safety Net

While the probabilistic customer economic value approach described above provides an effective
mechanism for keeping costs low while managing most network risk; high-impact-low-probability
(HILP) events could still cause significant disruption to supply and potentially customer
inconvenience and hardship. These, however, may not be enough to trigger investment.

The Safety Net requirements address this issue by providing a backstop set of “security criteria”
that set an upper limit to the customer consequence (in terms of unsupplied load) for a credible
contingency event on our network. Ergon Energy is required to meet the restoration targets

defined in Schedule 4 of Ergon Energy’s Distribution Authority (shown in Table 4 below) “…to the extent reasonably practicable”.

This acknowledges that regardless of level of preparation, there will always be combinations of circumstances where it is impossible to meet the restoration targets at the time of an event (for example, if it is unsafe to work on a line due to ongoing storm activity), though these should be rare. In addition, during the planning phase, where the risk of failing to meet the target timelines is identified as being not credible, investment to further mitigate the risk would generally not be recommended, as per industry best practice.

### Table 4: Service Safety Net Targets

<table>
<thead>
<tr>
<th>Area</th>
<th>Targets for restoration of supply following an N-1 Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Centre</td>
<td>Following an N-1 Event, load not supplied must be:</td>
</tr>
<tr>
<td></td>
<td>• Less than 20 MVA after 1 hour;</td>
</tr>
<tr>
<td></td>
<td>• Less than 15 MVA after 6 hours;</td>
</tr>
<tr>
<td></td>
<td>• Less than 5 MVA after 12 hours; and</td>
</tr>
<tr>
<td></td>
<td>• Fully restored within 24 hours.</td>
</tr>
<tr>
<td>Rural Areas</td>
<td>Following an N-1 Event, load not supplied must be:</td>
</tr>
<tr>
<td></td>
<td>• Less than 20 MVA after 1 hour;</td>
</tr>
<tr>
<td></td>
<td>• Less 15 MVA after 8 hours;</td>
</tr>
<tr>
<td></td>
<td>• Less 5 MVA after 18 hours; and</td>
</tr>
<tr>
<td></td>
<td>• Fully restored within 48 hours.</td>
</tr>
</tbody>
</table>

Efficient investments under the Safety Net provisions will provide mitigation for credible contingencies that could otherwise result in outages longer than the Safety Net targets.

At the implementation of Safety Net a major review was undertaken of the network’s sub-transmission feeders and zone and bulk supply substations. The capacities of all elements within the applicable networks were examined and network transfer capability confirmed (often requiring extensive network modelling). In many cases transformer cable ratings, bus section capability, breaker capability, network topology and protection schemes were identified as the limiting factor.

Since then, work has continued that includes:

- further liaison with field staff to ensure that local issues such as location of field crews, spares, available equipment, access conditions and fatigue management are taken into account.
- initiation of capital works and other actions as specified in the plans to ensure that Ergon Energy is compliant as far as reasonably practicable.
- reviewing the inventory of mobile substations, skid substations and mobile generation as part of the introduction of the new security criteria including the suitability of this plant for

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16 Regional Centre relates to larger centres with predominantly Urban feeders, whereas Rural Areas relates to areas that are not Regional Centres. Modelling and analysis is benchmarked against 50 PoE loads and based on credible contingencies.
Chapter 7. Network Planning

the sites being assessed. Two extra HV injection units are being added to increase the inventory from three to five units.

- trialling a small number of plans to ensure that they are anticipative, actionable and achieve the desired outcomes.

Ongoing, Ergon Energy continues to review the changing state of the network for Safety Net compliance as part of the normal network planning process, ensuring that care is taken to understand our customers' needs when considering the competing goals of service quality against cost of network.

7.4.3 Consideration of Distribution Losses

Distribution losses refer to the transportation of energy across the distribution network. In 2015-16, network losses equated to 683.6 GWh, which contributed 540.1 kilotonnes (tCO$_2$-e) to Ergon Energy’s carbon footprint.$^{17}$ These losses represent 75% of Ergon Energy’s total greenhouse gas emissions for Scope 1, 2 emissions defined under the National Greenhouse and Energy Reporting Act 2007 (Cth) (NGER).

Ergon Energy values losses by considering the marginal cost of supplying the additional kW and kWh through the distribution and sub-transmission networks. This marginal cost calculation takes into account the average generation pool price ($/kWh) and the network capacity costs ($/kWh). It is rare that this value of losses is ever sufficient to justify a project economically, in isolation. Therefore the value of losses is mostly used in comparing alternative network or non-network augmentation options, which either act to reduce the average current through the network or lower the resistance. The peak demand loss for a particular section of the network is calculated via modelling, and loss load factors are used to estimate the total marginal cost of supplying the losses in that part of the network.

7.5 Voltage Limits

Voltage Levels

Our distribution network consists of numerous different HV levels due to legacy network topologies, various specific customer or sub network requirements, or due to industry best practice for a network configuration. Table 5 below shows the system nominal voltage and the system maximum voltage for the main network voltages. The maximum voltage is generally the operating level that can be sustained without equipment damage.

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$^{17}$ This information is based on available 2015-16 emissions data as the most up to date at the time of publishing.
Table 5: System Operating Voltages

<table>
<thead>
<tr>
<th>System Nominal Voltage</th>
<th>System Maximum Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>132 kV</td>
<td>145 kV</td>
</tr>
<tr>
<td>110 kV</td>
<td>123 kV</td>
</tr>
<tr>
<td>66 kV</td>
<td>72 kV</td>
</tr>
<tr>
<td>33 kV</td>
<td>36 kV</td>
</tr>
<tr>
<td>22 kV</td>
<td>24 kV</td>
</tr>
<tr>
<td>11 kV</td>
<td>12 kV</td>
</tr>
</tbody>
</table>

Maximum Customer Voltage

The NER gives utilities the authority to specify the customer supply voltage range within the connection agreement for HV customers above 22 kV. The NER requires Root Mean Square (RMS) phase voltages to remain between ±5% of the agreed target voltage (determined in consultation with AEMO); provided that at all times the supply voltage remains between ±10% of the system nominal RMS phase to phase voltage except as a consequence of a contingency event.

In Queensland, for customers less than or equal to 22 kV, the Queensland Electricity Regulation specifies supply voltage ranges for LV and HV customers.

Table 6 below details the standard voltages and the maximum allowable variances for each voltage range from the relevant Queensland Electricity Regulation and the NER.

Table 6: Maximum Allowable Voltage

<table>
<thead>
<tr>
<th>Nominal Voltage</th>
<th>Maximum Allowable Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;1,000 V</td>
<td>Nominal voltage +/- 6%</td>
</tr>
<tr>
<td>240 V Phase to Neutral</td>
<td></td>
</tr>
<tr>
<td>415 V Phase to Phase</td>
<td></td>
</tr>
<tr>
<td>1,000 V – 22,000 V</td>
<td>Nominal voltage +/- 5% or as agreed</td>
</tr>
<tr>
<td>&gt;22,000 V</td>
<td>Nominal voltage +/- 10% or as agreed</td>
</tr>
</tbody>
</table>

The values in this table assume a 10 minute aggregated value, and allow for 1% of values to be above this threshold, and 1% of values to be below this threshold.

Transmission and Sub-transmission Voltage Limits

Target voltages on bulk supply substation busbars will be set in conjunction with Powerlink. Unless customers are supplied directly from the transmission or sub-transmission networks, the acceptable voltage regulation on these networks will be set by the ability to meet target voltages on the distribution busbars at the downstream zone substations, considering upstream equipment limitations, under both peak and light load scenarios.
Where customers are supplied directly from these networks, supply voltages must meet the requirements shown in the previous section.

Where it can assist in meeting voltage limits, Line Drop Compensation (LDC) may be applied on zone substation transformers to optimise the voltage regulation on the distribution network. In some instances, issues such as the distribution of load on individual feeders may mean that LDC is not a feasible solution.

**Distribution Voltage Limits**

Target voltages on zone substation busbars are set by Ergon Energy as relevant. These zone substation busbars are operated with either LDC, or with a fixed voltage reference or Automatic Voltage Regulator (AVR) set points. Downstream voltage regulators may also be set with LDC or with a standard set point.

For distribution systems, the network is operated to supply voltage at a customer’s point of connection and considerations are also made to the variable impacts of the different LV network configurations on subsequent LV customers supply voltage.

Augmentation of the distribution network generally occurs when voltage limitations occur on the distribution network under system normal conditions.

Table 7 provides an indicative level of the maximum HV voltage drops in the distribution network, to ensure acceptable supply to LV customers. The drop defined is from the zone substation bus to the regulation zone extremity (which may or may not be the feeder extremity), for steady state conditions.

**Table 7: Steady State Maximum Voltage Drop**

<table>
<thead>
<tr>
<th>Ergon Energy network targets</th>
<th>Maximum voltage drop – fixed voltage</th>
<th>Maximum voltage drop – with LDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urban</td>
<td>5.0%</td>
<td>8.0%</td>
</tr>
<tr>
<td>Short &amp; Long Rural</td>
<td>6.4%</td>
<td>9.4%</td>
</tr>
</tbody>
</table>

**Low Voltage (LV) Limits**

Typically LV network voltage is managed via the On Load Tap-Changer (OLTC) on the zone substation transformer, HV Voltage Regulators and also a fixed buck (reduction) or boost (increase) available from the distribution transformer tap ratio to cater for additional network voltage rise/drop. In addition, LV Regulators (LVR) where installed, enable the LV network voltage to be managed in a similar way to the HV distribution and sub-transmission networks, with an automatic response and voltage set point.

Augmentation of the LV network may occur when voltage limitations occur under system normal conditions and is occurring increasingly as a result of voltage rise due to solar PV compared to historical load based issues.

As per Section 4.4.3, Ergon Energy is considering the implications of a transition from a nominal voltage of 240 V to a 230 V standard.
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7.6 Fault Level Analysis

7.6.1 Fault Level Analysis Methodology

Ergon Energy performs fault level analysis at all bulk supply point and zone substation higher voltage and lower voltage buses in our supply grid. Isolated generation sites are not considered in these studies.

Studies are based on anticipated network configurations for the present and future five years based on Ergon Energy and Powerlink Annual Planning Reports. Simulation studies are carried out for 3-phase, 2-phase to ground and 1-phase to ground faults. A ‘flat start’ method is used to perform the fault level studies in the network modelling package DINIS. This method initialises the voltage applied at all infeed points to 1.0 per unit (p.u) or 1.1 p.u. as outlined below.

The studies are based on two possible network configurations within each study year:

- Network Normal: all normally open bus ties on all buses are open.
- Network Maximum: all normally open bus ties on all buses are closed.

The studies provide results for the sub-transient and synchronous fault levels for each network configuration:

- Sub-transient: a voltage factor of 1.1 is used to create a driving voltage of 1.1 p.u. behind sub-transient reactances.
- Synchronous: a voltage factor of 1.0 is used to create a driving voltage of 1.0 p.u. behind synchronous reactances.

All fault level analysis results are stored in a spreadsheet which is then validated and analysed prior to publishing. Fault level studies are carried out based on the following assumptions:

- major network connected generators are assumed to be in operation.
- all transformers are fixed at nominal tap.

The fault levels are calculated in accordance with Australian Standard AS3851. However, a voltage factor of 1.1 is used for all voltage levels when performing sub-transient analysis. In addition, a voltage factor of 1.0 is used for all voltage levels for synchronous fault level analysis.

7.6.2 Standard Fault Level Limits

Table 8 lists design fault level limits that apply to our network.
Table 8: Design Fault Level Limits

<table>
<thead>
<tr>
<th>Network Type</th>
<th>Voltage (kV)</th>
<th>Existing Installation Current (kA)</th>
<th>New Installation Current (kA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sub-transmission</td>
<td>132/110</td>
<td>25 / 31.5</td>
<td>40 (2s)</td>
</tr>
<tr>
<td>Sub-transmission</td>
<td>66</td>
<td>25</td>
<td>25 (3s)</td>
</tr>
<tr>
<td>Sub-transmission</td>
<td>33</td>
<td>13.1</td>
<td>25 (3s)</td>
</tr>
<tr>
<td>Distribution</td>
<td>22</td>
<td>13.1</td>
<td>25 (3s)</td>
</tr>
<tr>
<td>Distribution</td>
<td>11</td>
<td>13.1</td>
<td>25 (3s)</td>
</tr>
</tbody>
</table>

While Table 8 presents design fault ratings, in some instances the values given for existing installations may not align with standard modern switchgear ratings. Site specific fault levels are considered in planning activities for network augmentations or non-network solutions.

It should be noted that if no fault time duration is specified in the table; then fault levels are quoted with a one-second duration. A faster protection clearing time will be considered where appropriate. This can be further investigated when fault levels approach limits.

Where fault levels are forecast to exceed the allowable fault level limits, then fault level mitigation projects are initiated.

7.6.3 Fault Level Growth Factors

Fault levels on our network are affected by factors arising from within the network or externally, such as the TNSP’s network, generators and customer connections.

Fault level increases due to augmentation within the network are managed by planning policies in place to ensure that augmentation work will maintain short circuit fault levels within allowable limits.

Fault level increases due to external factors are monitored by annual fault level reporting, which estimate the prospective short circuit fault levels at each substation. The results are then compared to the maximum allowable short circuit fault level rating of the switchgear, plant and lines to identify if plant is operated within fault level ratings.

Ergon Energy obtains upstream fault level information from TNSPs annually. Changes throughout the year are communicated through joint planning activities as described in Section 7.10.1

New connections of distributed generation and embedded generation which increase fault levels are assessed for each new connection to ensure limits are not infringed. Known embedded generators are added to simulation models so that the impacts of these generators on the system fault levels are determined.
# 7.7 Ratings Methodology

Plant ratings are determined using Ergon Energy’s Plant Rating Guidelines and encompass primary current carrying items of all primary plant including overhead lines, underground cables, power transformers and substation HV equipment.

## 7.7.1 Feeder Capacity and Ratings

To determine the feeder capacity for planning purposes the following methodology has been applied.

- **Overhead lines** – current carrying capacities are aligned to BOM Climate zones design ratings that are based on Joint Workings studies. The default overhead rating parameters used are listed in Section 7.7.2. Where the feeder backbone conductor decreases in size, the smaller conductor has been used in cases where there is minimal load upstream of the smaller conductor.

- **Alignment to the feeder load profile** where available (otherwise summer noon is assumed).

- **Loads caused by abnormal network configurations** have been discounted when determining the peak demands.

- **Where the existing conductor operating temperature is not known**, a thermal rating of 50°C has been used. This is the typical overhead conductor thermal design temperature rating used in Ergon Energy regions.

- **Where the existing underground cable laying conditions are not known**, the following typical conditions have been used:
  - 30°C ground temperature
  - ducted installation
  - double point (solid) bonded
  - one of two cables in the vicinity that are buried 300mm apart
  - ground thermal resistivity of 2°C.m/W
  - software (CymCap) simulations of cable rating where completed.

## 7.7.2 Overhead Line Ratings

The overhead line rating is the maximum allowable current flow through the line without exceeding the maximum design temperature.

Overhead line ratings are based on environmental conditions, such as minimum wind speed and maximum ambient temperature, wind angle, conductor material properties, conductor emissivity and absorptivity, reflectance and solar radiation which are detailed further in this section. The wind speed, ambient temperature and wind angle have the most significant effect on the line rating.

Default parameter values used by Ergon Energy to calculate the overhead line ratings are shown in Table 10 to Table 15 below.
Weather study

In 2010, Ergon Energy undertook a climate study in partnership with the BOM and Aurecon to develop new overhead line rating weather parameters for the State. This study produced four major climate zones and several smaller special climate zones as shown in the Plant Rating Guidelines.

Time of day

In the context of static ratings, a day is split into day, evening, night/morning for both summer and winter as shown in Table 9. The shoulder seasonal months of April, May, September, October and November are generally rated with summer parameters.

Table 9: Time of Day Definition

<table>
<thead>
<tr>
<th>Description</th>
<th>Abbreviation</th>
<th>Indicative time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer Day</td>
<td>SD</td>
<td>Dec-Mar, 9am to 5pm</td>
</tr>
<tr>
<td>Summer Evening</td>
<td>SE</td>
<td>Dec-Mar, 5pm to 10pm</td>
</tr>
<tr>
<td>Summer Night/Morning</td>
<td>SN/M</td>
<td>Dec-Mar, 10pm to 9am</td>
</tr>
<tr>
<td>Winter Day</td>
<td>WD</td>
<td>Jun-Aug, 9am to 5pm</td>
</tr>
<tr>
<td>Winter Evening</td>
<td>WE</td>
<td>Jun-Aug, 5pm to 10pm</td>
</tr>
<tr>
<td>Winter Night/Morning</td>
<td>WN/M</td>
<td>Jun-Aug, 10pm to 9am</td>
</tr>
</tbody>
</table>
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Climate zones

The climate study produced the overhead line rating weather parameters for the State shown in Table 10. These nine climate zones are shown in Figure 21.

Table 10: Climate Zone Parameters

<table>
<thead>
<tr>
<th>Region</th>
<th>SD Wind (m/s)</th>
<th>SE Wind (m/s)</th>
<th>SN/M Wind (m/s)</th>
<th>WD Wind (m/s)</th>
<th>WE Wind (m/s)</th>
<th>WN/M Wind (m/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Far North</td>
<td>0.8</td>
<td>0.4</td>
<td>0.2</td>
<td>1.4</td>
<td>0.7</td>
<td>0.3</td>
</tr>
<tr>
<td></td>
<td>38</td>
<td>34</td>
<td>30</td>
<td>32</td>
<td>28</td>
<td>24</td>
</tr>
<tr>
<td>Eastern &amp; Coastal</td>
<td>1.3</td>
<td>0.8</td>
<td>0.3</td>
<td>1.2</td>
<td>0.5</td>
<td>0.3</td>
</tr>
<tr>
<td></td>
<td>35</td>
<td>31</td>
<td>27</td>
<td>28</td>
<td>23</td>
<td>23</td>
</tr>
<tr>
<td>Mackay</td>
<td>1.9</td>
<td>1.5</td>
<td>1.2</td>
<td>1.8</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>33</td>
<td>27</td>
<td>27</td>
<td>24</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Eastern &amp; Central Special</td>
<td>1.7</td>
<td>1.3</td>
<td>0.4</td>
<td>1.2</td>
<td>0.4</td>
<td>0.4</td>
</tr>
<tr>
<td></td>
<td>33</td>
<td>27</td>
<td>27</td>
<td>25</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Toowoomba</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.5</td>
<td>1.3</td>
</tr>
<tr>
<td></td>
<td>33</td>
<td>27</td>
<td>21</td>
<td>19</td>
<td>14</td>
<td>11</td>
</tr>
<tr>
<td>Central Tablelands - North</td>
<td>1.3</td>
<td>0.7</td>
<td>0.2</td>
<td>0.8</td>
<td>0.4</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>37</td>
<td>34</td>
<td>29</td>
<td>30</td>
<td>26</td>
<td>20</td>
</tr>
<tr>
<td>Central Tablelands - South</td>
<td>1.3</td>
<td>0.7</td>
<td>0.2</td>
<td>0.8</td>
<td>0.4</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>37</td>
<td>34</td>
<td>29</td>
<td>25</td>
<td>22</td>
<td>15</td>
</tr>
<tr>
<td>Western</td>
<td>1.7</td>
<td>1.4</td>
<td>1.4</td>
<td>1.4</td>
<td>1.2</td>
<td>0.7</td>
</tr>
<tr>
<td></td>
<td>42</td>
<td>40</td>
<td>36</td>
<td>32</td>
<td>29</td>
<td>20</td>
</tr>
<tr>
<td>Western Special</td>
<td>1.5</td>
<td>0.8</td>
<td>0.3</td>
<td>1.1</td>
<td>0.4</td>
<td>0.3</td>
</tr>
<tr>
<td></td>
<td>41</td>
<td>37</td>
<td>32</td>
<td>32</td>
<td>28</td>
<td>20</td>
</tr>
</tbody>
</table>
Figure 21: Visualisation of Ergon Energy Climate Zones

Wind Angle

This is the angle of airflow across the conductor and is the next most important factor in determining the line ratings. Table 11 shows the wind angle and turbulence parameters. In practice these will vary over the full range from axial to traverse as the line changes direction and the wind direction changes.

Table 11: Wind Angle and Turbulence Parameters

<table>
<thead>
<tr>
<th>Wind Angle and Turbulence Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Yaw Angle</td>
</tr>
<tr>
<td>45° to the line</td>
</tr>
<tr>
<td>Wind Turbulence</td>
</tr>
<tr>
<td>0.1%</td>
</tr>
</tbody>
</table>
Ground reflectivity factor

The reflectivity of the ground beneath an overhead line, shown in Table 12, is based on the most appropriate ground cover.

Table 12: Ground Reflection Factor Values

<table>
<thead>
<tr>
<th>Ground Cover</th>
<th>Ground Reflectivity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grass, Crops</td>
<td>0.2</td>
</tr>
<tr>
<td>Water</td>
<td>0.05</td>
</tr>
<tr>
<td>Forest</td>
<td>0.1</td>
</tr>
<tr>
<td>Urban Areas</td>
<td>0.15</td>
</tr>
<tr>
<td>Sand</td>
<td>0.3</td>
</tr>
<tr>
<td>Ice</td>
<td>0.5</td>
</tr>
<tr>
<td>Snow</td>
<td>0.75</td>
</tr>
</tbody>
</table>

Conductor Emissivity and Absorptivity

Radiation emitted and absorbed from a conductor, is based on assessment of surface condition as shown in Table 13.

Table 13: Conductor Emissivity and Absorptivity

<table>
<thead>
<tr>
<th>Conductor Surface</th>
<th>Conductor Emissivity</th>
<th>Solar Absorptivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rural Weathered</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Industrial</td>
<td>0.85</td>
<td>0.85</td>
</tr>
<tr>
<td>New Bright</td>
<td>0.3</td>
<td>0.6</td>
</tr>
<tr>
<td>Black</td>
<td>1.0</td>
<td>1.0</td>
</tr>
</tbody>
</table>

The Ground Air Differential

Ground air temperature differential is based on season and time of day as shown in Table 14.

Table 14: Ground Air Temperature Differential Default Values

<table>
<thead>
<tr>
<th>Time of Day</th>
<th>SD</th>
<th>SE</th>
<th>SN/M</th>
<th>WD</th>
<th>WE</th>
<th>WN/M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ground Air (with respect to Ambient) (°C)</td>
<td>+5</td>
<td>+4</td>
<td>-5</td>
<td>+5</td>
<td>+2</td>
<td>-5</td>
</tr>
</tbody>
</table>
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Solar radiation

The solar radiation is based on season and time of day as shown in Table 15.

Table 15: Solar Radiation Parameters

<table>
<thead>
<tr>
<th>Time of Day</th>
<th>SD</th>
<th>SE</th>
<th>SN/M</th>
<th>WD</th>
<th>WE</th>
<th>WN/M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Radiation</td>
<td>910</td>
<td>200</td>
<td>0</td>
<td>728</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Diffuse Radiation</td>
<td>210</td>
<td>20</td>
<td>0</td>
<td>156</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

7.7.3 Real Time Capacity Monitoring Ratings

Real time capacity monitoring has been trialled in the network to monitor feeder limitations that rely on environmental parameters and thermal limits to determine their capacity. Measuring actual conditions using real time data, from field devices and weather stations, gives us greater flexibility in our load management response, which can be critical when responding to asset failure.

The type of monitoring used is dependent on whether it is an overhead line or underground cable constraint. The type of sensors used can be overhead line temperature sensors mounted on the limiting section of line or Resistive Temperature Devices (RTDs) attached to the outer jacket of the underground cable. For some specially constructed cables there is the capability for Distributed Temperature Sensor (DTS) measurement which can provide multiple temperature measurements along the length of the cable using an optical fibre embedded in the cable.

Overhead line temperature sensors measure the actual conductor temperature, which is used as an input to calculate available line capacity. Weather parameters such as ambient air temperature, wind speed and solar radiation are also input to provide 15 minute line ratings.

The results of real time capacity monitoring are used to compare to probabilistic ratings and reveal capacity in the network.

7.7.4 Transformer Ratings

Transformer ratings have been determined using Ergon Energy’s Plant Rating Guidelines. The Normal Cyclic Capacity (NCC) rating determines the upper limit to which zone substation transformers should be loaded under normal cyclic operating conditions.

The NCC rating is dependent on the transformer condition, nameplate rating, applied loading profile, historical ambient temperatures and allowable loss of life. Transformer rate of ageing is limited to ‘one day per day’ loss of life when calculating the NCC rating.

The rating methodology takes into account the present condition of a transformer when applying a thermal rating. Ratings are not fixed for the duration of the transformer life, but rather ratings are published periodically. A fundamental process is the evaluation of transformer condition by means of oil sampling and analysis for dissolved gases, moisture content, oxygen content, oil acidity and degree of polymerisation.
7.8 Customer Initiated Capital Works

Customer Initiated Capital Works (CICW) are defined as works to service new or upgraded customer connections that are requested by Ergon Energy’s customers. As a condition of our Distribution Authority, we must operate, maintain and protect its supply network in a manner that ensures the adequate, economic, reliable and safe connection and supply of electricity to our customers. It is also a condition that it allows, as far as technically and economically practicable, its customers to connect to its distribution network on fair and reasonable terms.

Ergon Energy has a Connection Policy that details the circumstances in which a customer must contribute towards the cost of its connection and how it is to be treated for regulatory purposes. This Policy came into effect in July 2015.

Subject to certain exceptions prescribed in the policy, including where the shared network augmentation threshold is not exceeded, a capital contribution is generally required when the incremental costs of providing a connection exceed the incremental revenue expected to be received from the new or altered connection over a period of 30 years for residential customers. For commercial and industrial premises, the period will vary depending on the nature of the premises and will be defined in the connection offer. For Major Customer Connections, where dedicated network assets are required to enable the load or generation to connect to the Network, those assets are funded fully by the Connecting Customer. For large scale Embedded Generation, fully funded works also include works to remove a network limitation from the existing shared network.

CICW undertaken are generally of the following types:

- designing and constructing shared network assets that are directly relevant to customer connections
- designing and constructing connection assets
- commissioning and energising connection assets
- installing assets as part of a real estate development
- installing assets to remove a network limitation for an embedded generator
- providing and installing metering assets
- providing and constructing public lighting.

Not all CICW are undertaken by Ergon Energy. Depending on the type of work, services can be undertaken by one of three parties:

- Ergon Energy
- someone acting on Ergon Energy’s behalf (i.e. a contractor), or
- real estate developers, major customers, or other service providers, where the assets are subsequently gifted to Ergon Energy.

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18 *Electricity Act 1994* (Qld) s 42(c).
19 Ibid, s 43.
Depending on the nature of the work being undertaken, CICW can be funded by:

- Ergon Energy, where it, or someone acting on its behalf, undertakes the works
- a customer paying a capital contribution, an ACS fee, or both to Ergon Energy, where Ergon Energy or someone acting on its behalf, undertakes the works
- a real estate developer paying an ACS fee to Ergon Energy, or
- a real estate developer, major customer, or another service provider, where after the assets are built, they are ‘gifted’ to Ergon Energy.

For contestable works, the real estate developer, major customer, or another service provider may construct and continue to own and operate the works at their cost. There may still be some costs for the works Ergon Energy needs to undertake. The way in which CICW is progressed affects both how the cost of the works is recovered and from whom they are recovered.

### 7.9 Major Customer Connections and Embedded Generators

Ergon Energy is committed to ensuring that, where technically viable, major customers are able to connect to the network. We have a clear Major Customer Connection (MCC) process available on our website[^20] that aligns with the connection processes in Chapters 5 and 5A of the NER. The process generally applies to proposed connections where the intended Authorised Demand (AD) or load, on our network exceeds 1,500 kVA (1.5 MVA) or where power usage is typically above 4 GWh per annum at a single site.

Ergon Energy also has clear processes for the connection of EG units, which applies to embedded generating systems 30 kVA and above. The processes may vary depending on the size of the generating unit and whether the system is exporting into our network. These processes are also listed on our website.[^21]

The connection of any Major Customer or EG systems requires various levels of technical review. An assessment into the effect that the connection will have on existing planning and capacity limitations (including component capacity/ratings, voltage regulation constraints and protection limit encroachment, system stability and reliability, fault level impacts and the security criteria) is necessary to ensure that Ergon Energy continues to operate the network in a manner that ensures the adequate, economic, reliable and safe connection and supply of electricity to its customers.

Further information on the Major Customer connection process is available on the Ergon Energy website at:


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7.10 Joint Planning

7.10.1 Joint Planning Methodology

Rule 5.14 of the NER requires Ergon Energy to undertake joint planning with any TNSP and DNSP with which Ergon Energy is interconnected.

In Queensland, Powerlink owns the State’s 275 kV and 330 kV network, as the TNSP, as well as some of the 110 kV and 132 kV network. Energex operates the distribution network in south-east Queensland.

Powerlink and Ergon Energy undertake formal annual joint planning meetings. These meetings are used to review known or emerging network limitations at the connection points or on either network where the other party is affected or has the potential to be affected in the forward planning period.

As part of these discussions, both parties openly discuss the solutions that are technically and economically viable, the network security risks of the potential options and the customer impact of the consequences. Once the two companies have settled upon a potentially effective non-network or network approach, the normal Regulatory Investment Test for Transmission (RIT-T) and RIT-D conditions and processes apply. Subsequently, the market is informed and opportunities provided for input. Formal meeting minutes are recorded and accepted by both organisations. Between formal joint planning meetings, Powerlink and Ergon Energy participate in specific project based discussions where they are relevant to both organisations. Specific joint planning investments are detailed in Section 7.10.4.

In addition, Ergon Energy also meets with Energex to discuss the interface between the two business’ distribution (11 kV) and sub-transmission (33 kV and 110 kV) networks. As there are very few interface points between Energex and our networks, these meetings are more irregular and are spaced at approximately 18 months apart with discussions held between formal meetings as required.

Ergon Energy also has formal discussions with Essential Energy (a DNSP operating in New South Wales), particularly in regards to the negotiation of the applicable connection agreement at Waggamba substation located in Goondiwindi. Further discussions, due to the nature of the interconnection, are irregular and hinge around projects that may affect either organisation.

Ergon Energy also has interfaces with service providers in the mining sector, and power stations in the North Queensland Western Region. Joint planning with these parties is held on an as needs basis.

7.10.2 Role of Ergon Energy in Joint Planning

The joint planning process (except in the cases of CICW) is conducted strategically, with a long term view to address a specific emerging network limitation. Timings of any emerging network limitations are reviewed annually by all parties involved in the joint planning. In this process, there is a steady increase in the intensity of joint planning activities, which may lead to a regulatory test consultation.
Chapter 7. Network Planning

Through this process Ergon Energy is tasked with:

- ensuring that its network is operated with sufficient capability, and augmented if necessary, to provide network services to customers as per the planning criteria identified in Section 7.2.
- conducting annual planning reviews with TNSPs and DNSPs whose networks are connected to our network. This includes but is not limited to Powerlink, Energex, Essential Energy, service providers in the mining sector and generators in the North Queensland Western Region.
- developing recommendations to address emerging network limitations through joint planning with DNSPs, TNSPs and consultation with Registered Participants and interested parties as defined by the NER.
- advising Registered Participants and interested parties of any emerging network limitations within the time required for action.

7.10.3 Emerging Joint Planning Limitations

During the joint planning process, the network capacities are assessed and analysed to ensure that they are not exceeded. The key capacity limitations relate to:

- thermal plant under normal and contingency conditions
- overhead line ratings under normal climatic conditions (dynamic rating where appropriate)
- fault ratings of plant under fault conditions
- network voltage to remain within acceptable operating thresholds
- aged asset replacement or replacement of unreliable assets resulting in network risk.

7.10.4 Joint Planning Results

Table 16 presents the outcomes of Ergon Energy’s joint planning investments undertaken with Powerlink as described in Section 7.10.1 and 7.10.2 in 2016-17.

Table 16: Ergon Energy– Powerlink Joint Planning Investments

<table>
<thead>
<tr>
<th>Region</th>
<th>Brief description</th>
<th>Est. Capital Cost*</th>
<th>Est. Timing</th>
<th>Lead NSP</th>
</tr>
</thead>
<tbody>
<tr>
<td>FN</td>
<td><strong>T53 Kamerunga</strong> – Ergon Energy work associated with Powerlink replacement of 132 kV plant.</td>
<td>$0.5M</td>
<td>Aug-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>NQ</td>
<td><strong>Garbutt bulk supply substation</strong> – Ergon Energy work related to Powerlink's replacement of Transformer 1 and Transformer 2 with a new 100 MVA transformers.</td>
<td>$1.25M</td>
<td>Aug-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>MK</td>
<td><strong>T34 Moranbah</strong> – Ergon Energy work related to Powerlink's replacement of Transformer 2 and Transformer 3 with a new 100 MVA transformer.</td>
<td>$8.04M</td>
<td>Jun-2018</td>
<td>Powerlink</td>
</tr>
<tr>
<td>CA</td>
<td><strong>Dysart substation</strong> – Install two 66/22 kV 20 MVA transformers to supply the Dysart area distribution network once Powerlink remove the existing 2 x 70 MVA 132/66/22 kV.</td>
<td>$15M</td>
<td>Dec-18</td>
<td>Ergon Energy</td>
</tr>
</tbody>
</table>

*Ergon Energy component (including overheads)
Chapter 7. Network Planning

There were no investments resulting from joint planning in 2016-17 with Essential Energy, Energex, mining sector service providers or generators in the North Queensland Western Region.

7.10.5 Further Information on Joint Planning

Further information on Joint Planning outcomes requiring a RIT-T led by Powerlink is available on the Powerlink website at:


Alternatively we welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au
7.11 DAPR Reporting Methodology

The methodology shown in Figure 22 below is used in the preparation of the DAPR to report on sub-transmission network and primary distribution feeder limitations and solutions, joint planning projects, and RIT-D projects.

Figure 22: DAPR Methodology
Chapter 7. Network Planning

7.11.1 Joint Approach to Demand Forecasting
With the forecasting function of Ergon Energy and Energex merging work will continue on developing common tools, techniques and processes to support the production of accurate and reliable forecasts. These forecasts include energy, peak demand, load customers, EV’s, solar and other network parameters at various points within the electrical distribution, sub-transmission and transmission network. Forecasts are developed with consideration of the impact of emerging technologies and demographic, economic and regulatory factors and community expectations. Forecast outcomes are then used for the determination of an optimised network capital program of work, determination of network capacity limitations, determination of contingency plans, determination of network pricing and Regulatory submissions.

7.11.2 Substation Analysis Methodology Assumptions
Bulk and zone substation analysis is a build-up of multiple pieces of data. Much of the analysis is specified in Section 6.3.1 and also takes into account Ergon Energy’s Plant Rating Guidelines. Ergon Energy has a program of assessing plant rating capabilities within substations, with a focus on critical substation assets.

Further analysis is also conducted, as discussed in Section 7.4.2, around the Safety Net compliance of a substation. This analysis involves evaluation to determine whether efficient investments under the Safety Net provisions will provide mitigation for credible contingencies that could otherwise result in outages longer than the Safety Net targets.

These assessments, deterministic ratings and data collection provides the input data required for Ergon Energy’s Substation Investment Forecast Tool (SIFT). The SIFT tool utilises the data from the forecast coupled with this rating data to provide an overview of a substation’s limitation.

7.11.3 Sub-transmission Feeder Analysis Methodology Assumptions
The sub-transmission feeder methodology approach takes the substation maximum demand forecasts and the daily load profiles of each individual substation to produce a forecast half hour load profile for the maximum demand day at that substation. This is produced for each substation in the network and a series of load flows are then performed for each half hour period of the day using these loadings. The forecast feeder load for each period is the maximum current experienced by the feeder in any half hour interval during that period. These forecast load flows are then compared against the feeder ratings resulting from ratings methodology detailed in Section 7.7. The outcome of this methodology, as per the planning process discussed is Section 7.2, could be the creation of a project, data verification or load transfers. In these cases, these outcomes would be transferred to future forecasts and load flows.

7.11.4 Distribution Feeder Analysis Methodology Assumptions
Methodology and assumptions used for calculating the distribution feeder limitations are as follows:

- The previous maximum demands are determined from the historical metering/SCADA data for each feeder. These maximum demands are filtered to remove any temporary switching events.
- The future forecast demands for each feeder are then calculated based on the historical and current customer growth rate and other localised factors.
Chapter 7. Network Planning

- The worst utilisation period (summer day, summer night, winter day or winter night) are calculated by dividing the period maximum demand by the period rating. This is the determining period which will trigger an exceedance.
- The period rating is determined from the underground exit cable and first section of overhead line capacities only.
- The maximum utilisation is forecast out two years. The year and season (i.e. summer or winter) is recorded where the maximum utilisation exceeded either (see Appendix B):
  - the three into four 75% nominal distribution feeder security criteria for urban planning area designated feeders (sufficient interties between feeders); or
  - the 90% criteria for rural planning area designated feeders (sparse or no interties between feeders).

  Note: the above criteria is only a planning level, which triggers further detailed analysis based on a number of factors. Not all breaches of these criteria will trigger augmentation.
- The amount of exceedance of the relevant planning utilisation level is calculated after the two forecast years (in MVA), and the amount of MW required to reduce the feeder below the required planning utilisation level is calculated (with an assumed power factor of 0.9).

We also analyse ‘downstream’ limitations using load flow analysis; however, these studies are done on a case by case basis and are therefore not included in this methodology. Similarly, limitations on SWER and LV systems are also excluded.
Chapter 8 – Network Limitations and Mitigation Strategies

8.1 Emerging Network Limitation Maps
8.2 Substation and Sub-transmission Limitations and Mitigation Strategies
8.3 Distribution Feeder Limitations
8.4 Distribution Feeder Potential Solutions
8.5 Regulatory Investment Test Projects
8. Network Limitations and Mitigation Strategies

8.1 Emerging Network Limitation Maps

Maps and emerging network limitations for substations, sub-transmission lines, and distribution feeders are presented via the ESRI GIS Portal accessible via the following link:


Forecast load and capacity information is also made available in spreadsheet format via the hyperlinks in Appendix B.

All files can also be downloaded directly from the Ergon Energy website at this location:

8.2 Substation and Sub-transmission Limitations and Mitigation Strategies

Table 17 outlines a summary of system limitations within our network for sub-transmission and zone substations.

Table 17: Substation and Sub-transmission Limitations Summary (at June 2016)

<table>
<thead>
<tr>
<th>Location</th>
<th>Timing of limitation</th>
<th>Load transfer capability</th>
<th>Load reduction to defer 12 mths</th>
<th>Load reduction connection point</th>
<th>Impact on bulk connection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Malchi 66/11 kV substation</td>
<td>Dec 2016 – Feb 2017</td>
<td>1.5 MVA</td>
<td>0.6 MW</td>
<td>11 kV</td>
<td>Nil</td>
</tr>
</tbody>
</table>

Limitation:
Safety Net standard not met for outage to radial 66 kV sub-transmission line feeding Malchi substation or for a transformer failure at Malchi substation.

Options Considered:
1) NNA (standby generation during summer period)
2) new 1x10 MVA transformer substation at Gracemere site and 66 kV line from Egans Hill (Recommended)
3) new 1x20 MVA transformer substation at Gracemere site and 66 kV line from Egans Hill
4) new 2x20 MVA transformer substation at Gracemere site and 66 kV line from Egans Hill
5) upgrade Malchi substation from 2x10 MVA to 2x32 MVA transformers.

The RIT-D was finalised in 2015-16. Option 2 is the recommended option.
### Chapter 8. Network Limitations and Mitigation Strategies

<table>
<thead>
<tr>
<th>Location</th>
<th>Timing of limitation</th>
<th>Load transfer capability</th>
<th>Load reduction to defer 12 mths</th>
<th>Load reduction connection point</th>
<th>Impact on bulk connection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emerald 66/22 kV Substation</td>
<td>Already exists</td>
<td>1 MVA</td>
<td>15 MW</td>
<td>66 kV or 22 kV</td>
<td>Nil</td>
</tr>
</tbody>
</table>

**Limitation:**
1) The existing 66 kV network supplying Emerald Substation has insufficient capacity to supply statutory voltage for the forecast load at Emerald under system normal conditions.
2) For an outage of the Lilyvale to Emerald 66 kV feeder, there is load at risk of breaching Safety Net restoration timeframes.

**Options:**
1) Install additional 11 MVars of reactive compensation at Emerald Substation and Upgrade of the Blackwater to Emerald feeder to a maximum operating temperature of 100°C.
2) Construct 66 kV feeder bays at Blackwater and Emerald substations and construct a new 66kV feeder from Blackwater to Emerald

Non-network option to Defer Option 1 by 10 years – 5 MVA Diesel Power Station – External Submission. A RIT-D was finalised in 2016-17.

Option 1 is the recommended option. Refer to Section 8.5 Regulatory Investment Test Projects

<table>
<thead>
<tr>
<th>Location</th>
<th>Timing of limitation</th>
<th>Load transfer capability</th>
<th>Load reduction to defer 12 mths</th>
<th>Load reduction connection point</th>
<th>Impact on bulk connection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planella 33/11 kV substation</td>
<td>Already exists</td>
<td>2.3 MVA</td>
<td>N/A</td>
<td>11 kV</td>
<td>Nil</td>
</tr>
</tbody>
</table>

**Limitation:**
Safety Net standard not met for outage to radial 33 kV sub-transmission line supplying Planella substation.

**Options:**
1) 11 kV tie augmentation to increase transfer capacity to North Mackay and Glenella substations
2) NNA (standby generation during summer period).

Option 1 is proceeding.

Note: There is no credible option with an augmentation component >$5M, and so this project is not subject to the RIT-D process.
Chapter 8. Network Limitations and Mitigation Strategies

<table>
<thead>
<tr>
<th>Location</th>
<th>Timing of limitation</th>
<th>Load transfer capability</th>
<th>Load reduction to defer 12 mths</th>
<th>Load reduction connection point</th>
<th>Impact on bulk connection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Guthalungra 66/11 kV substation</td>
<td>Already exists</td>
<td>0.0 MVA</td>
<td>0.1 MW</td>
<td>11 kV</td>
<td>Nil</td>
</tr>
</tbody>
</table>

Limitation:
One phase of the 0.5 MVA 66/11 kV transformer is overloaded during peak load times under system normal conditions due to the predominance of a SWER load on the substation. Investigations have shown that this overload occurs during the peak holiday times over December/January, and during the Easter period.

Options:
1) Seek an inverter technology load balancing solution
2) Replace 0.5MVA transformer with a larger transformer
3) Do nothing and accept the premature aging of the transformer

An NNA has been in place for some time with a major customer on this substation to minimise transformer overload and imbalance during peak times.

While Option 1 is the preferred option, a suitable solution has not yet been identified.

Table 18 outlines a summary of system limitations within our network for sub-transmission lines.

Table 18: Subtransmission Line Limitations Summary

<table>
<thead>
<tr>
<th>Region</th>
<th>Season of Limitation</th>
<th>Asset ID</th>
<th>Asset Description</th>
<th>Line Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Queensland</td>
<td>Summer</td>
<td>82962655</td>
<td><strong>Clare South – Mona Park</strong></td>
<td>66 kV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>This feeder is limited to 50°C design temperature. To be investigated further as the load is forecast to be within 5amps of the feeder rating.</td>
<td></td>
</tr>
<tr>
<td>Wide Bay</td>
<td>Summer</td>
<td>50000079</td>
<td><strong>Isis – Childers</strong></td>
<td>66 kV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>This feeder requires further investigation. Preliminary review indicates a possible data error.</td>
<td></td>
</tr>
</tbody>
</table>

For detailed discussion and assessment of the considered options to address each network limitation, please visit Ergon Energy’s regulatory test consultation page at:


8.3 Distribution Feeder Limitations

Of the 1,185 distribution feeders in our network, there are a 110 that are currently seasonally constrained and 119 forecast to be constrained in the next two years based on utilisation against the distribution planning/security criteria. These capacity limitations have been assessed against the security criteria loading of 75% for Urban feeders and 90% for all feeder categories. For further
Chapter 8. Network Limitations and Mitigation Strategies

details on the methodology used, refer to Section 7.11.4. Note that identification of an asset as ‘constrained’ does not necessarily imply that the integrity or capability threshold of the asset has been compromised. Potential solutions to these limitations are described in Section 8.4.

Table 19: Distribution Feeder Summary Report

<table>
<thead>
<tr>
<th>Region</th>
<th>Total feeder numbers**</th>
<th>Total capacity limitations* (current)</th>
<th>Total forecast capacity limitations* (after 2 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Far North</td>
<td>148</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>North Queensland</td>
<td>305</td>
<td>27</td>
<td>30</td>
</tr>
<tr>
<td>Mackay</td>
<td>149</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Capricornia</td>
<td>203</td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td>Wide Bay</td>
<td>169</td>
<td>16</td>
<td>17</td>
</tr>
<tr>
<td>South West</td>
<td>211</td>
<td>40</td>
<td>44</td>
</tr>
<tr>
<td>All Regions</td>
<td>1,185</td>
<td>110</td>
<td>119</td>
</tr>
</tbody>
</table>

*Capacity limitation against the Security Criteria loading (75% for Urban Feeders and 90% for all feeder categories. For more details see Section 7.11.4.)

**Note dedicated customer connection assets are excluded from the analysis.

8.4 Distribution Feeder Potential Solutions

Distribution feeder capacity problems can be solved in a number of ways, depending on the local characteristics of the distribution feeder. In each instance, actual solutions are subject to a detailed study and business case. Possible solutions to feeder limitations include (in approximate order of preference based on network cost):

- **Network reconfiguration:**
  - transferring existing load to adjacent feeders if capacity is available
  - re-rating or dynamic rating of the underground exit cable or overhead feeder.

- **Demand management initiatives that reduce customer loading:**
  - energy efficient appliances
  - power factor correction
  - shift loads (e.g. pool pumps, hot water storage etc.) to a controlled load tariff
  - shift loads to a time-of-use tariff
  - air conditioning ‘Peak Smart’
  - customer micro EG units
  - call off load
  - commercial and industrial demand management
Chapter 8. Network Limitations and Mitigation Strategies

- customer embedded generation to ‘peak lop’
- network embedded generation to ‘peak lop’
- energy storage.

- Network augmentation:
  - replacing the underground exit cable or overhead feeder
  - creating new substations and/or feeders and transferring existing load

8.5 Regulatory Investment Test Projects

8.5.1 Regulatory Investment Test Projects - In Progress and Completed

In accordance with clause 5.17.3 of the National Electricity Rules there are no projects approved (with credible options having an estimate cost of the augmentation component greater than $5 million) for which RIT-Ds are required. Table 20 lists projects for which the regulatory tests have now been completed.

Table 20: Regulatory Test Investments – Completed

<table>
<thead>
<tr>
<th>Project Need, Credible Options and Conclusion</th>
<th>Preferred option</th>
<th>Impact on Network Users (Preferred Option)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cost*</td>
<td>Est. Delivery.</td>
</tr>
<tr>
<td>Emerald 66 kV Network</td>
<td>$6.5M</td>
<td>Construction Commencing</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Est. June 2018</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Commissioning</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Est. June 2020</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Nil impact beyond regulated revenue.</td>
</tr>
</tbody>
</table>

Project need:
1) The existing 66 kV network supplying Emerald Substation has insufficient capacity to supply statutory voltage for the forecast load at Emerald under system normal conditions.
2) For an outage of the Lilyvale to Emerald 66 kV feeder, there is load at risk of breaching Safety Net restoration timeframes.

Credible Options:
3) Install additional 11 MVars of reactive compensation at Emerald Substation and Upgrade of the Blackwater to Emerald feeder to a maximum operating temperature of 100°C. (NPV = -$3.57M)
4) Construct 66 kV feeder bays at Blackwater and Emerald substations and construct a new 66kV feeder from Blackwater to Emerald (NPV = -$23.83M)
5) Non-network option to Defer Option 1 by 10 years – 5 MVA Diesel Power Station – External Submission (NPV = -$6.66M).

Conclusion: Final Recommendation is Option 1, $6.5M, June 2020

Status: Final Project Assessment Report completed.
1) Ergon Energy has issued an Expression of Interest for external parties to provide the reactive support requirements of Option 1. This closed 21/03/2017.
2) Ergon Energy received four submissions to the Expression of Interest and is currently working through Due Diligence. Once an agreement has been met with one of the proponents this outcome will be publicly published.

* Includes overheads.
Further information on augmentation planning requiring RIT-D is available on the Ergon Energy website at:

8.5.2 Foreseeable RIT-D Projects
There are currently no emerging network limitations that Ergon Energy foresees that would trigger a new RIT-D.

8.5.3 Urgent and Unforeseen Projects
During the year, there have been no urgent or unforeseen investments by Ergon Energy that would trigger the RIT-D exclusion conditions for the application of regulatory investment testing.
Chapter 9 – Demand Management Activities

9.1 Non-Network Options Considered in 2016-17

9.2 Key Issues Arising from Embedded Generation Applications

9.3 Actions Promoting Non-Network Solutions

9.4 Demand Management Results for 2016-17

9.5 Demand Management Programs for 2017-22

9.6 Other Demand Side Participation Activities
9. Demand Management Activities

Demand management has long been seen as a key tool to managing our costs by engaging our customers in opportunities to work proactively to reduce network risks and therefore reduce investment in the network. Ergon Energy produces a Demand Management Plan on an annual basis and publishes this plan on our website.

Ergon Energy Demand Management Plan 2017-18

Our demand management program continues to look holistically at the issues facing our network and the options we have for utilising demand side options as a solution for peak demand, reverse power flows and voltage management. We have continued to evolve and improve our demand management program to respond to customer and market needs.

In 2016-17 Ergon Energy developed a range of innovations that are now in production including:

- implementing the Optimal Incremental Pricing method for pricing demand based on network risk across our network
- mapping our demand constraints on an interactive map so as to further engage with the market and our service providers
- enhancing the Ergon Incentives branding and developing a range of new market offers; and
- expanding our Trade Ally Network range of delivery partners.

Full details on these activities are provided in our demand management plan.

9.1 Non-Network Options Considered in 2016-17

Our non-network program is market led and involves informing the market of the opportunity including value, location and requirements. In this way we enable all technologies and provide customers and aggregators an opportunity to participate in our program and support network risk reduction at the lowest possible cost.

Several non-network options were considered in the past year for mitigating network risks, as listed in Table 21. These were in addition to the projects that are currently operational as listed in Table 22.

Core technologies available for funding under the demand management programs include:

- embedded diesel generations
- commercial energy management (e.g. lighting, HVAC, pumps and motors)
- embedded renewable generation (mainly solar PV)
- residential consumer products including direct load control and peak smart air conditioning
- power factor correction
- call off load, whereby a customer shuts down part of their plant at peak times
- permanent load shifting
- tariff switching opportunities.
## Chapter 9. Demand Management Activities

### Table 21: Non-Network Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Sub-programs</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Optimal Incremental Pricing (OIP) Program</strong></td>
<td>Geographical based feeder demand management program utilising a program delivery approach leveraging the OIP valuation methodology. OIP provides a variable demand and pricing based on the network risk which changes dependent on forecasts and program success.</td>
<td><strong>Cairns North</strong></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Peak demand period: 4pm - 9:30pm, Mon to Friday, November to March</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Up to $290 per kVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cairns South</strong></td>
<td>Peak demand period: 4pm - 9:30pm, Mon to Friday, November to March</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Up to $272 per kVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cannonvale</strong></td>
<td>Peak demand period: 12pm - 8pm, Mon to Friday, November to April</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Up to $350 per kVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Chinchilla</strong></td>
<td>Peak demand period: 9am - 8 pm, Mon to Saturday, November to April</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Up to $200 per kVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Emerald</strong></td>
<td>Peak demand period: 1pm - 9pm, Mon to Sunday, November to March</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Up to $225 per kVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hervey Bay</strong></td>
<td></td>
<td></td>
<td>Pending</td>
</tr>
<tr>
<td><strong>Mackay Northern Beaches</strong></td>
<td></td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Peak demand period: 4pm - 8pm, Mon to Sunday, November to April</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Up to $200 per kVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Mackay South</strong></td>
<td></td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td>Peak demand period: 10am - 2 pm, Mon to Friday, October to April</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Up to $300 per kVA</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
# Chapter 9. Demand Management Activities

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Sub-programs</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Roma</td>
<td></td>
<td></td>
<td>Pending</td>
</tr>
<tr>
<td>Townsville North-West 1</td>
<td>Peak demand period: 8am - 5pm, Mon to Friday, November to April, Up to $350 per kVA</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td>Townsville North-West 2</td>
<td>Peak demand period: 4pm - 9pm, Mon to Friday, November to April, Up to $350 per kVA</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td>Safety Net Program</td>
<td>Develop the practices, contracts and products to support Safety Net risk mitigation in conjunction with network operations.</td>
<td>The Safety Net program has progressed targeting the priority network initiatives, this year we will review the action reports to determine where demand management may be appropriate, estimated at three sites totalling 2MVA.</td>
<td>Pending</td>
</tr>
<tr>
<td>Voltage Program</td>
<td>Develop and implement a product that enables business-as-usual demand side responses to voltage risks as an alternative to network augmentation. These programs will include: Local programs, specific to individual customers and Large scale programs, leveraging solar farm inverters to provide network voltage support.</td>
<td>Develop appropriate systems, procedures and products to enable field crews to respond quickly to voltage issues. Develop a valuation methodology to ensure that the demand side solution provides overall cost benefit. Quantify inverter capabilities for using power factor settings for managing local voltage issues.</td>
<td>Development</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Continue to explore the opportunity around leveraging customer side solutions for supporting Static Var Compensators (SVC).</td>
<td>Investigation</td>
</tr>
</tbody>
</table>
Table 22: Operational Non-Network Projects

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Maintain availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gordonvale</td>
<td>Contracted demand at the sugar mill in the Gordonvale-Mt Peter area to support peak demand and load growth in the southern Cairns growth corridor.</td>
<td></td>
</tr>
<tr>
<td>Dingo</td>
<td>Support of voltage constraints on the Dingo network derived from customer contracted embedded generation.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Mt Isa</td>
<td>Network support for the Mt Isa network derived from customer and network embedded generators.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Alpha</td>
<td>The Alpha network from Barcaldine has voltage constraints and is supported by an integrated network embedded generator.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Malanda</td>
<td>Customer embedded generator contracted to support the reduction of load in the Malanda area for network contingency requirements.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Barcaldine</td>
<td>Network embedded generator enabled to support the Barcaldine area during network outages.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Dajarra</td>
<td>Network embedded generator in the Dajarra area for supporting voltage and outages.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Kajabbi</td>
<td>Network embedded generator in the Kajabbi area for supporting voltage and outages.</td>
<td>Maintain availability</td>
</tr>
<tr>
<td>Renewable energy investigations</td>
<td>Investigations for voltage complaints from renewable energy systems.</td>
<td>Transition to BAU – seek efficiency</td>
</tr>
</tbody>
</table>

9.2 Key Issues Arising from Embedded Generation Applications

In a number of substation locations, Ergon Energy is managing multiple enquiries seeking to connect large scale embedded generation in the same area of the network at the same time. The complex network impacts are made more challenging by the speculative nature of these enquires. Further, we are obliged to keep customer information confidential which can result in issues around disclosure to customers with competing enquiries.

Network information and analysis provided to customers enquiring on the feasibility of an EG project is based on the configuration of the network at the time of the response; however, the technical assessments and reports may need to be reviewed and recalculated once any one of the customers’ projects becomes committed.

Ergon Energy’s current approach is to work with generation proponents to manage this complex issue. We alert them to the risks and formally advise if another project has become committed and to encourage customers to seek a review of any technical assessments or reports already received in this instance.
9.3 Actions Promoting Non-Network Solutions

Our plans for promoting non-network options for the coming years are detailed on our website in several places. An overarching view of our actions in promoting non-network solutions and how we work with our partners and customers to enable greater choice can be found on our website at the link below:


A summary of these activities is detailed below.

**INFORMING THE MARKET**

As the Ergon Energy network covers a very large geographical area it is important that we work with our customers and partners to offer incentives to encourage participation in our demand reduction or utilisation programs.

Moving forward our approach will be to focus on the most efficient and effective methods to support our customer and manage our network risks. We will continue to leverage the value of the network incentive map in conjunction with offers and information that support all regional Queenslanders.

**ENGAGING THE ENERGY SERVICES MARKET**

We are leveraging the energy services market to help us deliver demand reductions and engage directly with end-user customers. We have also established a [Trade Ally Network](https://www.ergon.com.au) (TAN) registry of local, state-wide and national businesses to help customers explore energy efficiency and demand management opportunities, and the associated incentives being offered. The registry is evolving as we roll out new programs in new areas across our network. Third parties who work with us to deliver demand management initiatives to customers can apply to use the Ergon Incentives logo on their
We have continued to evolve our communications and advisory information under the banner of Manage Your Energy on our website, enabling access to a range of customer centric information sources.

9.4 Demand Management Results for 2016-17

The financial year 2016-17 ended with the results shown in Table 23 and Table 24 for demand management activities and embedded generation connections, which are largely forecast to remain in place to 2021.

Table 23: Demand Under Control

<table>
<thead>
<tr>
<th>Activity</th>
<th>Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand under contractual control available for dispatch (excluding load control tariffs)</td>
<td>41 MVA</td>
</tr>
<tr>
<td>Demand under controlled load tariffs</td>
<td>230 MVA</td>
</tr>
</tbody>
</table>

Table 24: Embedded Generation Connections

<table>
<thead>
<tr>
<th>NER Requirement</th>
<th>No. received since 1 July 2016</th>
<th>Average Time to complete (Business days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Embedded generation connection enquiries received under clause 5.3A.5</td>
<td>78</td>
<td>–</td>
</tr>
<tr>
<td>Embedded generation applications to connect received under clause 5.3A.9</td>
<td>15</td>
<td>–</td>
</tr>
<tr>
<td>Average time to complete embedded generation applications to connect</td>
<td>2</td>
<td>1 years 6 months from Application</td>
</tr>
</tbody>
</table>

---

22 Diversified demand under control
Chapter 9. Demand Management Activities

9.5 Demand Management Programs for 2017-22

Ergon Energy’s demand management programs for 2017-22 are detailed in our annual Demand and Energy Management Plan which can be found on our website at the below link:


A summary of the program’s forecast for the period 2017-18 are detailed in Table 25.

Table 25: Demand Management Programs 2017-18

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Sub-programs</th>
<th>Status</th>
<th>Expenditure Forecast ($'000)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Optimal Incremental Pricing (OIP) Program</strong></td>
<td>Geographical based feeder demand management program utilising a program delivery approach leveraging the OIP valuation methodology. OIP provides a variable demand and pricing based on the network risk which changes dependent on forecasts and program success.</td>
<td><strong>Cairns North</strong>&lt;br&gt;Peak demand period:&lt;br&gt;4pm - 9:30pm, Mon to Friday, November to March&lt;br&gt;Up to $290 per kVA</td>
<td>Active</td>
<td>$1,777</td>
</tr>
<tr>
<td><strong>Cairns South</strong></td>
<td>Peak demand period:&lt;br&gt;4pm - 9:30pm, Mon to Friday, November to March&lt;br&gt;Up to $272 per kVA</td>
<td>Active</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td><strong>Cannonvale</strong></td>
<td>Peak demand period:&lt;br&gt;12pm - 8pm, Mon to Friday, November to April&lt;br&gt;Up to $350 per kVA</td>
<td>Active</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td><strong>Chinchilla</strong></td>
<td>Peak demand period:&lt;br&gt;9am - 8 pm, Mon to Saturday, November to April&lt;br&gt;Up to $200 per kVA</td>
<td>Active</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td><strong>Emerald</strong></td>
<td>Peak demand period:&lt;br&gt;1pm - 9pm, Mon to Sunday, November to March&lt;br&gt;Up to $225 per kVA</td>
<td>Active</td>
<td>Active</td>
<td></td>
</tr>
</tbody>
</table>
## Chapter 9. Demand Management Activities

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Sub-programs</th>
<th>Status</th>
<th>Expenditure Forecast ($’000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hervey Bay</td>
<td></td>
<td></td>
<td>Pending</td>
<td></td>
</tr>
<tr>
<td><strong>Mackay Northern Beaches</strong></td>
<td>Peak demand period: 4pm - 8pm, Mon to Sunday, November to April</td>
<td>Up to $200 per kVA</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td><strong>Mackay South</strong></td>
<td>Peak demand period: 10am - 2 pm, Mon to Friday, October to April</td>
<td>Up to $300 per kVA</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td>Roma</td>
<td></td>
<td></td>
<td>Pending</td>
<td></td>
</tr>
<tr>
<td><strong>Townsville North-West 1</strong></td>
<td>Peak demand period: 8am - 5pm, Mon to Friday, November to April</td>
<td>Up to $350 per kVA</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td><strong>Townsville North-West 2</strong></td>
<td>Peak demand period: 4pm - 9pm, Mon to Friday, November to April</td>
<td>Up to $350 per kVA</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td><strong>Safety Net Program</strong></td>
<td>Develop the practices, contracts and products to support Safety Net risk</td>
<td></td>
<td>Pending</td>
<td>$320</td>
</tr>
<tr>
<td></td>
<td>mitigation in conjunction with network operations.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Voltage Program</strong></td>
<td>Develop and implement a product that enables business-as-usual demand side</td>
<td>Develop appropriate systems, procedures and</td>
<td>Development</td>
<td>$200</td>
</tr>
<tr>
<td></td>
<td>responses to voltage risks as an alternative to network augmentation.</td>
<td>products to enable field crews to respond</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>These programs will include: Local programs, specific to individual</td>
<td>quickly to voltage issues.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>customers and Large scale</td>
<td>Develop a valuation methodolgy to ensure</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>that the demand side solution</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>provides overall cost benefit.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Quantify inverter capabilities</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Ergon Energy Distribution Annual Planning Report 2017-18 to 2021-22
### Chapter 9. Demand Management Activities

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Sub-programs</th>
<th>Status</th>
<th>Expenditure Forecast ($'000)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>programs, leveraging solar farm inverters to provide network voltage support.</td>
<td>for using power factor settings for managing local voltage issues.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Continue to explore the opportunity around levering customer side solutions for supporting Static Var Compensators (SVC).</td>
<td></td>
<td>Investigation</td>
<td>$250</td>
</tr>
</tbody>
</table>

### 9.6 Other Demand Side Participation Activities

Ergon Energy participates in the Australian Energy Market Commission’s (AEMC) Power of Choice market reforms and responds to papers released by the AEMC and AER. We have been an active participant in the Australian Renewable Agency funded development of the National Opportunities Maps to map locations across the NEM where demand side solutions may be applicable. Further information can be found at:


We have been working to expand the information provided to customers regards to the non-network opportunities that may be available as well as provide richer sources of information on our network, including the Available Capacity Map and last years on line mapping of the Distribution Annual Planning Report.

We have been further developing cost reflective pricing as part of the changes to network prices and tariffs and have been actively involved in promoting these new tariffs to our customers.

Finally, Ergon Energy has been actively testing and developing additional demand side products to enable broader customer participation including:

- testing of Home Energy Management Systems, with a view to standardising customer offers
- testing of consumer energy storage systems with a view to offering a standard customer offer for a battery system, and;
- evaluating the opportunity to leverage customer side inverters to supply VARs for network voltage support.
Chapter 10 – Asset Life-Cycle Management

10.1 Approach
10.2 Safety and Compliance
10.3 Asset Condition Management Methodology
10.4 Specific Plant Replacement Programs
10.5 Asset Renewal Project Summaries
10.6 Asset Condition and System Limitations
10. Asset Life-Cycle Management

10.1 Approach

Ergon Energy’s approach to asset life-cycle management, including asset renewal, integrates several key objectives including: providing a safe workplace for staff and safe networks for the community, delivering customer service and network performance to meet the required standards, and maintaining an efficient and sustainable cost structure.

Policies are developed and refined and plans are prepared to provide a safe, reliable network that delivers the quality of supply to legislative compliance requirements and optimum asset life. These policies and plans cover equipment installed in substations, as well as the main components of overhead powerlines, underground cables and other distribution equipment. They define inspection and maintenance requirements for each type of asset. Asset life optimisation takes into consideration equipment degradation and failure modes as well as safety, environmental, operational and economic consequences.

All assets have the potential to fail in service. Ergon Energy’s approach to managing the risk of asset failures is consistent with regulatory requirements including the Electricity Act 1994 (Qld), Electrical Safety Regulation 2002 and the Electricity Safety Code of Practice 2010 – Works and good asset management practice. We distinguish between expenditure for:

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

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

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

Potential equipment failures are addressed by a number of approaches depending on the nature of the equipment and failure modes. They include on-condition replacement, bulk replacement, risk based refurbishment/replacement and run to failure.

Detailed programs are developed for key asset classes as follows:

- Substation Plant Replacement
Chapter 10. Asset Life-Cycle Management

- Substation Secondary System Replacement
- Distribution Line and Equipment.

The safety and reliability performance of assets is monitored to identify emerging equipment performance issues. This information is analysed, along with the age, condition and obsolescence of assets, to develop maintenance, refurbishment and replacement programs. These activities also facilitate negotiated delivery commitments from service providers and the prudent physical and financial delivery of programs.

Ergon Energy and Energex are currently working together to review and align our asset lifecycle approaches. We will endeavour to consolidate planning activities and align the processes associated with addressing limitations. This will drive efficient outcomes across both across Repex and Augex investment programs.

10.2 Safety and Compliance

Ergon Energy manages safety and compliance requirements through established plans. A number of high profile risks are explained in the following sections.

10.2.1 Asset Inspections and Condition Based Maintenance

Ergon Energy generally employs condition and risk-based asset inspection, maintenance and replacement strategies in line with its asset management policies and strategies discussed in Section 5. End-of-economic-life replacement and life-extension refurbishment decisions are informed by risk assessments considering safety, history, performance, cost, and other business delivery factors.

Equipment is inspected at scheduled intervals for physical indications of degradation exceeding a threshold that is predictive of an ongoing failure mechanism. Typical examples of inspection and condition monitoring activities include:

- analysis of power transformer oil to monitor for trace gases produced by internal faults
- inspection of service lines
- assessing the extent of decay in wood power poles to determine residual strength
- inspection of timber cross-arms to detect visible signs of degradation
- intrusive condition testing of timber cross-arms in high degradation areas.

In particular, Ergon Energy has a well-established asset inspection program to meet regulatory requirements. All assets are inspected in rolling period inspection programs. Remedial actions identified during inspections are managed using a risk assessed priority code approach.

Pole assets, for example, employ a Priority 1 (P1) coding which requires rectification within thirty (30) days and Priority 2 (P2) unserviceable poles require rectification within six months. This ensures the required actions are completed within the recommended regulatory standards. Ergon Energy has a three year rolling average in-service pole failure rate of 38 failures per annum of the 962,807 pole population, achieving 99.9961% pole reliability, which is better than the code of practice guideline limit of 99.9900%.

Consistent with the principles of ISO 55000 Asset Management, Ergon Energy is further building its spatial data capability with an ongoing investment into its Geographical Information Systems
and the integration of corporate data with Google Earth™. These efforts include utilising data from the aerial asset and vegetation monitoring management technology provided by ‘Fugro Roames™’. This aircraft-based laser and imaging capture system provides annual spatial mapping of the entire overhead line network. The data captured is processed to enable measurement of the network and surrounding objects such as buildings, terrain and vegetation. The system creates a virtual version of the real world to allow the fast and accurate inspection and assessment of the network and the surrounding environment, particularly vegetation, without the need to deploy field crews. The integration of this information into our decision framework and works planning processes is increasingly delivering productivity and efficiency improvements, not only with vegetation management but with other network analytics such as clearance to ground analysis, clearance to structure analysis, pole movement and leaning poles with other innovative identification systems being developed.

10.2.2 Vegetation Management

Vegetation encroaching within minimum clearances of overhead powerlines creates safety risks for the public, Ergon Energy employees and contract workers. Vegetation in the proximity of overhead powerlines is also a major factor in network outages during storms and high winds.

With the technology sourced from ‘Fugro Roames™’, Ergon Energy maintains a comprehensive vegetation management program to reduce the community and field staff safety risk and provide the required network reliability. To manage this risk we employ the following strategies:

- A cyclic program, to cut vegetation on all overhead line routes. Varying cycle times validated using ‘Fugro Roames™’ and whole of network analytics to prioritise risk enabling optimisation of cycle times, are managed by Ergon Energy with its vegetation contractors to ensure the clearance zone is kept clear at all times. Ergon Energy uses a suite of measures to ensure compliance of the contractors.
- Reactive spot activities to address localised instances where vegetation is found to be within clearance requirements by ‘Fugro Roames™’ or has been reported for action by customers.

For some considerable time now, Ergon Energy has worked cooperatively with local councils to reduce future risk of vegetation contacting powerlines. Initiatives include the development of tree planting agreements, specifying requirements for the selection of tree species for use near powerlines and programs to remove existing unsuitable trees and replace with powerline friendly trees. These relationships are now quite mature.

Ergon Energy employs the ‘Fugro Roames™’ technology to annually update its 3D geo-spatial representations of network assets to assist not only with ongoing vegetation management but other aspects of asset inspection. This capability, which includes predictive capability based on vegetation growth rates, is being used wherever possible to reduce maintenance and planning costs, and maintain safety and reliability of supply for our customers and communities.

In terms of disaster management assistance, Fugro Roames™ provides post-disaster data capture flights to give Ergon Energy visibility of the environment and assets for damage assessment and to support efficient creation of restoration plans.
10.3 Asset Condition Management Methodology

The processes for inspection and maintenance of Ergon Energy’s lower cost assets are well established and constantly reviewed. The results of these programs are regularly monitored with inspection and maintenance strategies improved accordingly. Renewal forecast expenditure is based on these strategies and forecasted data.

In relation to its high cost assets, Ergon Energy has recently implemented Intelligent Process Solutions’ condition monitoring and management software, to collect and analyse asset condition data. In addition, Ergon Energy employs EA Technology’s Condition Based Risk Management (CBRM) modelling methodology which combines current asset condition information, engineering knowledge and practical experience to predict future asset condition, performance and risk of failure of network assets.

For other lower cost asset classes a formal asset class risk assessment is conducted that documents the risks associated with asset failure and mitigation measures to be implemented.

The CBRM process has been progressively applied for those asset classes where sufficient information is available to produce a Health Index, probability of failure and value of risk for an individual asset.

Essentially, the Health Index of an asset is a means of combining information that relates to its age, environment, duty, and specific condition and performance information to give a comparable measure of condition for individual assets in terms of proximity to retirement age and probability of failure. The concept is illustrated schematically in Figure 23.

**Figure 23: Concept of Health Index**

<table>
<thead>
<tr>
<th>Condition</th>
<th>Health Index</th>
<th>Remnant Life</th>
<th>Probability of Failure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bad</td>
<td>10</td>
<td>At retirement age (&lt;5 years)</td>
<td>High</td>
</tr>
<tr>
<td>Poor</td>
<td>7</td>
<td>5–10 years</td>
<td>Medium</td>
</tr>
<tr>
<td>Fair</td>
<td>4</td>
<td>10–20 years</td>
<td>Low</td>
</tr>
<tr>
<td>Good</td>
<td>0</td>
<td>&gt;20 years</td>
<td>Very low</td>
</tr>
</tbody>
</table>

The Health Index represents the extent of degradation as follows:

- Low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal ageing, that is the difference between a new asset and one that has been in service for some time but is still in good condition.
- Medium values of Health Index, in the range 4 to 7, represent significant deterioration, degradation processes starting to move from normal ageing to processes that potentially threaten failure.
- High values of Health Index (>7) represent serious deterioration, advanced degradation processes now reaching the point that they actually threaten failure.

The detail of the CBRM Health Index formulation is inevitably different for each asset group,
reflecting the different information and the different types of degradation processes. There is, however, an underlying structure for all asset groups as outlined below:

(i) For a specific asset, an initial age related Health Index is calculated using knowledge and experience of its performance and expected lifetime, taking account of factors such as original specification, manufacturer, operational experience and operating conditions (e.g. duty, proximity to coast); and

(ii) Where condition information relating to specific degradation processes can be used to identify potential end of life conditions or retirement age (e.g. oil test results for transformers), a separate factor is derived for each degradation process, calibrated by linking a defined condition to a specific Health Index value. This gives rise to a number of multipliers, one for each potential end of life condition. These are then combined to give a combined condition factor.

The relationship between the Health Index and the condition-related probability of failure is not linear. An asset can accommodate some level of degradation with very little effect on the risk of failure. However, once the degradation becomes significant or widespread, the risk of failure rapidly increases. This relationship is shown in Figure 24.

Figure 24: CBRM Health Index and Probability of Asset Failure

The present Health Index profile of a group of assets provides a snapshot of the current condition of those assets. The CBRM methodology is then used to predict how these assets will behave in the future, or how the Health Index will change going forward based on the asset duty and operating environment. The ability to predict the change in Health Index over time enables the determination of future failure rates and development of appropriate intervention strategies.

CBRM has been implemented for the major substation plant asset classes and allowed Ergon Energy to develop a prioritised list of candidate assets for renewal.

Projects are then created from these candidate assets, evaluated in terms of the corporate risk framework to ensure prudent replacement decisions using formal Business Case analysis.
Chapter 10. Asset Life-Cycle Management

Figure 25 below provides a summary of the process for delivering network asset investment planning based on CBRM.

Figure 25: Process to Create Asset Investment Plan

10.4 Specific Plant Replacement Programs

Ergon Energy has a number of specific programs to replace network items that have been identified as a result of the inspection and condition monitoring programs. These are detailed in the following sections.

10.4.1 Substation Plant

Ergon Energy uses modelling and analysis of asset population types to determine condition and risk of each asset relative to similar assets. This allows identification of the most suitable candidates for refurbishment. An additional check of actual condition with maintenance engineers is also made prior to final selection for replacement.

We seek bundling opportunities where the business benefits can be demonstrated. Occasionally, replacing the individual assets in the programs detailed below gives rise to more holistic replacement of larger portions of a substation (or the whole substation) due to project efficiencies and improved technology.

Power Transformer Replacement and Refurbishment

Transformers are condition monitored and require regular tap-changer maintenance. The failure consequences are related to safety impacts for employees in the vicinity at the time of failure, reliability impacts related to technical ability to meet demand, environmental damage from the quantities of oil involved, and high costs of replacement. Due to the failure consequences, Ergon Energy has adopted a CBRM approach to define the highest priority and economic end-of-life replacement of these assets, optimised for overall least cost and least risk increase.

Circuit Breaker and Switchboard Replacement and Refurbishment

Circuit breakers and switchboards are maintained to a serviceable level to avoid the consequences of premature failure including loss of supply, damage to other substation equipment and the environment, and to mitigate hazards to personnel in the substation and the public. As a result of
the potential failure consequences, Ergon Energy has adopted a CBRM approach to define the highest priority economic end-of-life replacement of circuit breakers, optimised for overall least cost and least risk increase.

**Instrument Transformer Replacement and Refurbishment**

Current Transformers (CTs) and Voltage Transformers (VTs) are maintained to a serviceable level to avoid the consequences of premature failure including loss of supply, damage to other substation equipment and the environment, and to mitigate hazards to personnel in the substation and the public. Due to the failure consequences, Ergon Energy has adopted a CBRM approach to identify the highest priority economic end-of-life replacement of current and voltage transformers for replacement, optimised for overall least cost and least risk increase.

**Substation Outdoor Isolator and Earth Switch Replacement and Refurbishment**

Outdoor isolators are used to allow access to primary plant for operational and maintenance work. The failure consequences are generally related to delays in performing other maintenance on other substation assets. Because this is relatively simple equipment which requires minimal regular maintenance, Ergon Energy has adopted a near run-to-failure approach for outdoor isolators and earth switches.

**Capacitor Banks Replacement and Refurbishment**

Capacitor banks provide harmonic absorption and local voltage support. They also support the ability to supply load under contingency situations and contribute to overall power system stability. As these assets are often able to be repaired by the replacement of lower cost internal components, Ergon Energy has adopted a near run-to-failure approach for Capacitor Banks. Prior to replacement, a review is made to confirm the ongoing need for these assets.

**Static VAR Compensators (SVC)**

The Charleville power system exceeds statutory and asset voltage design limits without a Static VAR Compensator (SVC) in service. The system appears marginally stable when the SVC is in service, but the SVC is beyond its economic maintenance end-of-life. Spare parts are no longer available from the manufacturer, and technical expertise has become difficult to procure. Water cooling systems are severely rusted and almost unrepairable. Overall, the SVC has become almost unmaintainable. This creates a reliability and quality of supply risk. Replacement of these assets will stabilise power system operation within statutory voltage limits into the future. The SVC is incurring considerable maintenance costs to keep it in service. As a result of replacement, these maintenance costs should be reduced considerably.

## 10.4.2 Secondary Systems

**Protection Relay Replacement Program**

There is a safety risk to staff and the public due to the loss of protection for substations and with lines assets when protection assets fail. Many of the older sites and assets are in situations where backup protection does not completely compensate for initial protection asset failure. As a result,
Chapter 10. Asset Life-Cycle Management

this replacement program will progressively replace problematic or near end of life relays.

**SCADA Remote Terminal Unit Replacement Program**

Aged Remote Terminal Unit (RTU) technology deployed in our network has become obsolete. This is due to the current asset ages (30 years upwards) of the older legacy technology, lack of spare parts, loss of supplier and internal expertise. Failure consequences include loss of remote control of the power system, loss of monitoring capability of the power system, increase in public safety risks, particularly for LV incidents and extended reliability issues relating to supply restoration. Due to the extensive secondary system monitoring, and associated wiring, replacement is time and resource intensive, and a high-cost exercise. Replacement of these ageing and obsolete assets will support ongoing safety and reliability obligations.

**Audio Frequency Load Control Replacement Program**

AFLC equipment serves to perform customer demand management by facilitating peak load lopping of hot water systems, pool pumps and other large fixed installation loads. Failure consequences include the loss of remote peak load switching capability, increased localised load peaks, overloading of distribution assets and overload tripping of assets in some cases, and the potential for customer outage impacts. In addition, load increases due to loss of demand management ability arising from failed AFLC assets could be recognised as additional network load. This has the consequential effect of increasing load forecasts, which promotes earlier augmentation expenditure. Condition monitoring has identified near end-of-life of some assets and a planned replacement program for this asset class is underway.

**10.4.3 Sub-transmission and Distribution Line Equipment**

**Line Defect Remediation Program**

Ergon Energy has an obligation to meet the requirements of the *Electrical Safety Act (2002) (Qld)* to inspect, test and maintain all assets. This program remediates risk prioritised lines defects found by ground based inspection at every asset location. This achieves incremental renewal of all lines based assets at near end of life, maximising the utility of the assets. Ergon Energy is not expecting any legislative change, and, except for specifically-targeted safety risks, defect repair rates are generally expected to gradually escalate in line with asset age trends.

**Cast Iron Pot Head Replacement Program**

Cast iron pot heads are a very old type of cable termination filled with oil. They are frequently rusted with moisture ingress. They cannot be condition monitored for oil degradation and it would be uneconomic to do so if it were possible. Eventually the water/oil degradation will result in flashover, with sometimes explosive failure. The potheads are typically in urban and business centre locations frequented by the community so the outcome could be catastrophic. This replacement program is progressing to replace this type of asset with polymeric alternatives which have benign failure modes.
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Expulsion Drop Out Fuse Replacement in High Fire Risk Areas

Operation of Expulsion Drop Out (EDOs) fuses can produce sparks and molten metal that fall to the ground. In dry tinder locations, this has been demonstrated to initiate bushfires. This presents public safety, asset, and significant legal and corporate risks. Past settlements relating to the Victorian bushfires, with the DNSP and the Victorian Government, associated with this phenomenon have been substantial. Even though Ergon Energy’s service area has lower risk bushfire areas compared to the conditions in Victoria, we intend to mitigate these risks by replacing EDOs with spark-less fuses. Replacement of these assets represents a key risk mitigation strategy.

Alkaline Copper Quaternary Treated Laminated Veneer Crossarms

There is a material safety risk due to a loss of strength of laminated veneer cross-arms resulting from Alkaline Copper Quaternary preservative leeching and subsequent fungus development. To mitigate public safety risks this program removes laminated cross-arms in special and high-risk locations (high rainfall/humidity and high pedestrian traffic locations) from service. Monitoring programs have been established to determine degradation patterns.

Modifications to Distribution Earth Defect Thresholds

The purpose of distribution earths is to limit voltage rises to a safe level under normal load and fault conditions and to provide a low impedance path for earth faults, ensuring a sufficient fault current to operate protective devices. Design principles and regulatory requirements for distribution earthing design are set out in the Electricity Safety Code of Practice 2010 – Works and good asset management practice. Ergon Energy has an ongoing maintenance and inspection program aimed at ensuring all earths perform as intended. This program is now incorporated in the Lines defect remediation program.

Replacement of Non-ceramic Fuses

Ergon Energy owns a population of obsolete non-ceramic service fuses which are installed on customer’s premises. A failure mode has been identified, which could result in the fuse overheating and potentially creating a fire risk. This program involves relocation and/or replacement of this type of fuse installation.

Distribution Feeder Reconductoring Program

Aged and annealed small diameter copper conductors are at risk of breaking and falling to the ground. This very old conductor is at or beyond economic end-of-life and failure has led to DEEs. There was a fatality in 2009 due to a member of the public making contact with energised LV copper conductor on the ground, and several similar close-call events since then. There was also a subsequent ‘Request for Improvement’ from the Queensland Electrical Safety Office. These assets are considered a significant safety risk, and renewal works are ongoing. This program will replace the entire remnant population, in excess of 1,200 circuit kilometres of 7/.064 and smaller LV copper conductors, initially focusing upon LV mains and streetlight wire. The program will eventually replace the small amount of HV copper conductor and other miscellaneous items in similarly degraded condition.
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Conductor Clearance to Ground Defect Remediation

Ergon Energy has an obligation to meet the minimum clearance standards specified under the *Electrical Safety Act (2002)* (Qld) and associated regulations. The Fugro Roames™ LiDAR technology has allowed the recent individual identification of conductor span clearance issues for all conductor types except service lines. This has revealed 15,000 separate locations where legislative minimum clearances are not being met. A risk prioritised program over three years is underway to ensure compliance.

Conductor Clearance to Structure Defect Remediation

Ergon Energy has an obligation to meet the minimum clearance standards specified under the *Electrical Safety Act (2002)* (Qld) and associated regulations. The Fugro Roames™ LiDAR technology has allowed the recent individual identification of conductor span clearance to structure issues for all conductor types except service lines. This has revealed 3,400 separate locations where legislative minimum clearances to structures need to be resolved. A risk prioritised program over two years is underway to ensure compliance.

Operational Two-way Radio Infrastructure Replacement

Ergon Energy’s private wireless communications network has for many decades been provided using an analogue VHF mobile radio network. It was recognised that this network was aged and required replacement as it became a maintenance liability as the elements went out of production. Network and individual asset failure consequences involve safety risks for staff working in rural and remote locations, reliability risks due to extended communications issues, and service risks due to inability to manage network operations. In March 2011, a program to replace VHF with a digital P25 network was approved by Ergon Energy to proactively replace the VHF asset to mitigate these risks. The majority of this program has now been completed; the final projects have commenced and will be completed this AER period.

(i) Mackay to Maryborough – P25 is being implemented using the same technology as previous P25 projects to meet the communications needs in medium to high voice traffic areas, for example coastal areas.

(ii) Western Queensland – A hybrid P25 and long range radio technology is being implemented in remote Queensland areas including Western Queensland. This technology provides low bandwidth voice communications over extremely long distances. It is well suited to areas requiring low volumes of voice traffic.

Digital Communication System Infrastructure Replacement

This initiative is primarily concerned with replacing telecommunication equipment within Ergon Energy’s CoreNet that have reached the end of operational life. This directly impacts the ability to operate as a business (office), substation protection and SCADA signalling. The failure risks include significant loss of corporate business and operational communication facilities, with ongoing business capability and staff safety issues. Ergon Energy is replacing these assets to mitigate these risks. It comprises of two components:

(i) Site infrastructure replacement – condition-based replacement of infrastructure and environmental support equipment typically at critical CoreNet sites. These sites are
central switching/routing locations with high throughput and form an integral part of the network between regional centres. They include DC power systems, uninterruptable power supplies, generators, air conditioning, structures and shelters, and communication buildings. Typically the corrective works program provides for general replacement of passive equipment at the more numerous non-critical CoreNet (lower functional layer sites).

(ii) Active equipment replacement – planned and programed replacement of key function end-of-life telecommunication equipment, due to the end of vendor support, and undertaking a targeted replacement of specific telecommunication equipment exhibiting high failure rates. The refurbishment of active communication equipment throughout the network includes replacement of end-of-life links or terminal devices, multiplexers, ageing switches and routers.

### 10.5 Asset Renewal Project Summaries

NER Schedule 5.8(g)(1) specifically requires a summary of all committed investments to be carried out within the forward planning period (5 years) with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address a refurbishment or replacement need. A committed investment must be approved for completion by an appropriate financial delegate (such as the Chief Executive Officer or Energy Queensland Limited Board) with all necessary funding made available.

There are three major investments which are expected to occur in the forward planning period with an estimated capital cost of $2 million or more that have received approval. Details of these projects are provided below in Table 26.

<table>
<thead>
<tr>
<th>Region</th>
<th>Project Reference</th>
<th>Description</th>
<th>Estimated Capital Cost ($M)</th>
<th>Scheduled Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>South West</td>
<td>1202738: Yarranlea Substation Rebuild</td>
<td>The substation is the primary source of supply for the Pittsworth, Millmerran, Cecil Plains, Pampas, Norwin and Yarranlea district southwest of Toowoomba. The site is a 110/33kV bulk supply point. Oil sampling and individual asset condition assessments have revealed a number of assets (including both power transformers) are at or beyond economic end of life and will require increased and ongoing maintenance. Risk of failure of individual assets is high. Both fixed tap transformers are considered at end of life, and their associated regulators are failing. Transformer protection is minimal, and substation loading is above acceptable Load at Risk conditions at peak times. Backup capability for other parts of the network are no longer viable. The substation no longer meets the Safety Net requirements of Ergon Energy’s Distribution Authority.</td>
<td>$11.6M</td>
<td>2020</td>
</tr>
</tbody>
</table>
Chapter 10. Asset Life-Cycle Management

<table>
<thead>
<tr>
<th>Region</th>
<th>Project Reference</th>
<th>Description</th>
<th>Estimated Capital Cost ($M)</th>
<th>Scheduled Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central</td>
<td>1212974: Tennyson Street Zone Substation Replacement</td>
<td>Tennyson Street 33/11 kV Zone Substation is located in the central region it is a 50 year old substation with the majority of the existing asset infrastructure past its operational life expectancy. A substation review has been performed by Ergon Energy's Network Planning and Refurbishment group identifying limitations and risks associated with aged assets, deteriorating equipment condition and performance, operational and safety concerns and capacity constraints. Rebuilding the substation will ensure that security of supply is met well into the future, mitigate identified risks and provide a safe reliable quality of supply for the commercial and residential customers in the Mackay region.</td>
<td>$28M</td>
<td>2020</td>
</tr>
<tr>
<td>Central</td>
<td>552296: Dysart Substation</td>
<td>Dysart substation is an existing 132/66/22kV substation located in central Queensland, and is a jointly owned substation by Powerlink and Ergon Energy. It is considered a critical site for supplying a number of coal mines connected at 66kV, as well as supplying both the Dysart township and rural loads at 22kV. Powerlink have identified the need to replace their two (2) x 132/66/22kV power transformers at this site. In order to eliminate disproportionate operational costs in maintaining poor condition and end-of-life plant, Ergon Energy have identified the need to concurrently install 2 x new 66/22kV 20MVA transformers and transformer bays, as well as replace the aged and deteriorated CBs and VTs.</td>
<td>$10.3M</td>
<td>2019</td>
</tr>
</tbody>
</table>

Note: In accordance with the transitional arrangements relating to excluded projects under clause 11.99.5 of the National Electricity Rules, the replacement projects listed above are excluded from the requirement to undertake the regulatory investment test for distribution as they are considered committed projects prior to 30 January 2018.

There are a significant number of smaller scale renewal and refurbishment projects which are managed under the programs of work described in Section 10.4.

10.6 Asset Condition and System Limitations

Asset condition issues that can have an effect on system limitations, identified through the process of asset management include:

- **Transformer condition;** limits the NCC rating (refer to Section 7.7.4) which is allowed for in the forecast NCC rating based on condition monitoring and assessment.
- **SVC and capacitor bank failures;** limit power factor correction capabilities and voltage support under high load.
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- **Feeder asset failures**; can invoke contingency network configurations with subsequent system limitations.
- **Feeder ground clearances below statutory limits**; limit feeder ratings due to sag under load.
- **Safety issues**; driven by asset conditions require network access restrictions which can create operational constraints affecting contingency and Safety Net operability and timeframes.
- **SCADA and Communication system failures**; can create operational constraints that affect contingency and Safety Net operability and timeframes.
- **Load control equipment failures**; limit the ability to shed load during peak demand and contingency periods, and also introduce the possibility of increasing the system peak demand and therefore risk of capacity limitations.
Chapter 11 – Network Reliability

11.1 Reliability Measures and Standards
11.2 Service Target Performance Incentive Scheme
11.3 High Impact Weather Events
11.4 Guaranteed Service Levels
11.5 Worst Performing Feeders
11.6 Safety Net Target Performance
11. Network Reliability

11.1 Reliability Measures and Standards

This section describes Ergon Energy’s reliability measures and standards. The planning criteria, already discussed, when combined with reliability targets, underpins prudent capital investment and operating costs to deliver the appropriate level of service to customers.

11.1.1 Reliability Measures and Standards

Ergon Energy uses the industry recognised reliability indices to report and assess the reliability performance of its supply network. The key measures used are:

- System Average Interruption Duration Index (SAIDI). This reliability performance index indicates the total minutes, on average, that the system is unavailable to provide electricity during the reporting period.
- System Average Interruption Frequency Index (SAIFI). This reliability performance index indicates the average number of occasions the system is interrupted during the reporting period.

11.1.2 Minimum Service Standards

The MSS define the reliability performance levels required of our network, including both planned and unplanned outages, and drive us to maintain the reliability performance levels where the MSS limits have been met. The MSS limits for both SAIDI and SAIFI are applied separately for each defined distribution feeder category – Urban, Short Rural and Long Rural.

The reliability limits are prescribed in Ergon Energy’s Distribution Authority, No. D01/99, 30 June 2014. Ergon Energy is required to use all reasonable endeavours to ensure that it does not exceed the SAIDI and SAIFI limits set out in the Distribution Authority for the relevant financial year. Circumstances beyond the distribution entity’s control are generally excluded from the calculation of SAIDI and SAIFI metrics. In particular, the MSS calculation excludes any interruption:

- with a duration of one minute or less (momentary)
- resulting from load shedding due to a shortfall in generation
- resulting from a direction by AEMO, a system operator or any other body exercising a similar function under the Electricity Act 1994 (Qld), NER or NEL
- resulting from automatic shedding of load under the control of under-frequency relays following the occurrence of a power system under-frequency condition described in the power system security and reliability standards
- resulting from failure of the shared transmission grid (Powerlink)
- resulting from a direction by a police officer or another authorised person exercising powers in relation to public safety
- that commences on a major event day
- caused by a customer’s electrical installation or failure of that electrical installation.
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Under Ergon Energy’s Distribution Authority, exceedance of the same MSS limit in three consecutive financial years is considered a ‘systemic failure’ and constitutes a breach. The MSS limits for the regulatory control period in Schedule 3 of the Distribution Authority remain flat to 2020. They are presented in Section 11.1.3, along with our performance against these limits.

11.1.3 Reliability Performance in 2016-17

The normalised results in Table 27 highlight a favourable performance against MSS for all of our network categories in 2016-17.

<table>
<thead>
<tr>
<th>Normalised Reliability Performance</th>
<th>2015-16 Actual</th>
<th>2016-17 Actual</th>
<th>2015-20(^{23}) MSS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SAIDI (mins)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>127.70</td>
<td>106.99</td>
<td>≤149</td>
</tr>
<tr>
<td>Short Rural</td>
<td>349.59</td>
<td>279.38</td>
<td>≤424</td>
</tr>
<tr>
<td>Long Rural</td>
<td>954.71</td>
<td>780.76</td>
<td>≤964</td>
</tr>
<tr>
<td><strong>SAIFI</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>1.272</td>
<td>1.135</td>
<td>≤1.98</td>
</tr>
<tr>
<td>Short Rural</td>
<td>3.023</td>
<td>2.637</td>
<td>≤3.95</td>
</tr>
<tr>
<td>Long Rural</td>
<td>6.766</td>
<td>5.804</td>
<td>≤7.40</td>
</tr>
</tbody>
</table>

In 2016-17, Ergon Energy reliability of supply outperformed the Distribution Authority’s MSS limits for all six measures. Our overall reliability performance has improved since the inception of MSS in 2005 with the duration of overall outages reducing by 47% and frequency reducing by 44%. Network reliability average duration and frequency of supply interruption events has continued to demonstrate improvement. The most recent performance figures indicate that the unplanned outage duration and frequency have improved by 17% and 11% respectively in the last five years. This is a reflection of the targeted investment made during the last regulatory control period towards achieving the regulated MSS standards. With the exception of outage frequency on the Long Rural Network, the network reliability results against the MSS in 2016-17 were the best since the standards were established in 2005-06.

Figure 26 shows the five-year rolling average reliability performance for both SAIDI and SAIFI which demonstrates continual improvement. The trends also show that the improvement in our network reliability could be flattening out, possibly indicating the optimal performance capability of the network without further reliability specific investment on its infrastructure.

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\(^{23}\)Ergon Energy’s MSS is ‘flat-lined’ for the current regulatory period 2015-2020.
11.1.4 Reliability Compliance Processes

To ensure that it delivers the annual reliability performance favourable to the MSS limits, Ergon Energy sets its internal overall SAIDI/SAIFI targets lower than the MSS limits for each of the feeder category for a regulatory year. There is, however, no capex allocated specifically to achieve these internal targets. These targets are intended to define the performance incentive for the operational teams across the business to outperform the MSS limit. The internal targets are used as the reference for tracking performance during a year and to put necessary operational measures where required and feasible.

The internal targets are further broken down between planned and unplanned targets, and by region, to ensure that adequate ‘room’ is allowed for maintenance, refurbishment and customer and the corporate initiated works, along with other forms of planned outages. The internal targets are set based on few factors such as the average historical performance, the expected volume of planned works on a particular type of network etc. These targets are also seasonallyised across the years to make greater allowance for unplanned outages during the storm season, between November and March.

11.1.5 Reliability Corrective Actions

As shown in Table 27 above, Ergon Energy met the MSS limits for its SAIDI/SAIFI performance in 2016-17 for all three of the distribution feeder categories. We have continued to put significant focus on our operational practices to improve the response time to unplanned outages and the management of planned outages that have direct impact on overall SAIDI, especially for our long rural network for which meeting the MSS SAIDI limit remains a challenge.

A number of opportunities, to improve the tools and other resources available to the Operations Control Centres to more effectively dispatch and coordinate response crews, continue to be outworked through a program of works.
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Ergon Energy continues to enhance and improve its Field Force Automation (FFA) with new and advanced user friendly functionalities which will add further efficiency in fault finding and outage management. FFA was first rolled out in 2014-15 and mainly included the field crews having ‘Toughpads’ in the field to manage outages and other field works. This has improved work efficiency including the response to faults through reduced paperwork, improved access to safety and job/outage information, less driving time and more time on technical work. During fault restoration, the network is sectionalised (where possible) to restore customers progressively. Ergon Energy continues to put a greater emphasis on returning of the key out-of-service plant to service and reducing network risk whilst weather forecasting services are being used to predict storm activity and prepare additional resources to respond to faults.

Ergon Energy is also maintaining a continuous improvement focus around information and technology and continues to explore new and emerging technologies that have the potential to improve reliability performance. We continue the implementation of the new ‘smart’ technologies such as communications capable Line Fault Indicators and Fuse Savers where efficient. These are considered as low cost, quick win opportunities to improve network reliability. In addition, we continue to explore and apply solutions for performance improvement through optimisation of our existing network assets and resources. An example of this approach includes application of appropriate changes in the protection settings of its sub-transmission and distribution feeders to reduce the adverse impact of transient faults on our overall network performance. Preventing the transient faults resulting in sustained supply interruptions also allows for an improved operational response to those events with permanent network faults. The field crews would have fewer events to deal with and so are directed to only those events that require repair, rather than travelling to patrol and switch for transient fault events. This improvement has the potential to yield savings in operational costs for the business along with the network reliability improvement.

Ergon Energy completed two of its key reliability improvement strategies in 2016-17. The Automatic Circuit Recloser (ACR) and/or Remote Controlled Gas Switch Strategies delivered increased fault sectionalising and switching capability on selected distribution feeders across the State. In early 2016-17, we completed our strategy to establish the communications to support the ACR investment. This will deliver remote control and supervision capability on existing reclosers across the distribution network. The integration of these ‘smart’ devices with those devices already installed and with the existing SCADA system will aid our achievement of network resilience and customer service expectations.

Ergon Energy is also in the process of implementing targeted low cost solutions to improve average outage duration on its Long Rural network. This mainly involves setting changes in secondary (protection) systems to improve transient performance and targeted low capital investment on long rural feeders consistently contributing high customer minutes over the years.

As one of its regulatory obligations under the Distribution Authority, Ergon Energy also continues to deliver its Worst Performing Feeder improvement program. While, this program is not targeted towards improving the average system level reliability, it continues to address the reliability issues faced by a smaller cluster of customers supplied by the poorly performing feeders or a section of these feeders.

In addition to the reliability improvement specific works, Ergon Energy continued to focus on the reliability outcomes from its asset maintenance, asset replacement and works planning. The asset maintenance and replacement strategies will either continue to have positive influence on reliability
Chapter 11. Network Reliability

performance for this regulatory control period or provide additional benefits on reliability performance in the next regulatory period.

11.2 Service Target Performance Incentive Scheme

Since 2010-11, Ergon Energy has submitted data and information on an annual basis, relative to its performance under the AER’s Electricity Distribution Network Service Providers, Service Target Performance Incentive Scheme (STPIS). The information collected enables the AER to perform a review of service performance information (as required under clause 7.2 of STPIS).

The AER’s STPIS provides a financial incentive for our organisation to maintain and improve our service performance for our customers. The scheme rewards or penalises a DNSP, in the form of an increment or reduction on Annual Revenue Requirement, for its network performance relative to a series of predetermined service targets.

The scheme encompasses reliability of supply performance and customer service parameters. The reliability of supply parameters only include unplanned SAIDI and SAIFI, applied separately for each feeder category (Urban, Short Rural and Long Rural).

The incentive rates for the reliability of supply performance parameters of the STPIS are primarily based on the value that customers place on supply reliability (the VCR), energy consumption forecast by feeder type and the regulatory funding model. The VCR value used in the STPIS for the regulatory control period 2010-15 was $47,850/MWh (2008). For the regulatory control period 2015-20, the AER applied a VCR value of $40,206/MWh for each feeder. This was based on the VCR values published by AEMO in September 2014, escalated to the March 2015 quarter CPI.

The customer service performance target applies to our service area as a whole and is measured through a target percentage of calls being answered within agreed time frames. Service performance targets for all the parameters were determined at the beginning of the regulatory control period.

The AER requests the reporting of annual performance against the STPIS parameters applicable to Ergon Energy under its Distribution Determination, via a Regulatory Information Notice (RIN).

Ergon Energy’s 2016-17 Performance RIN’s response included completed templates (and relevant processes, assumptions and methodologies) relating to reliability performance reporting under the STPIS.


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24 November 2009
11.2.1 STPIS Results and Forecast

Ergon Energy’s reliability of supply performance statistics for 2016-17 are summarised in the following table. As this table presents average outage duration and the frequency of interruption, lower numbers indicate stronger results and less interruption to our customers’ electricity supply.

Table 28: Performance Compared to STPIS

<table>
<thead>
<tr>
<th>Normalised Reliability Performance</th>
<th>2015-16 Actual</th>
<th>2016-17 Actual</th>
<th>2015-20&lt;sup&gt;25&lt;/sup&gt; STPIS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unplanned SAIDI (mins)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>94.61</td>
<td>79.43</td>
<td>126.73</td>
</tr>
<tr>
<td>Short Rural</td>
<td>276.78</td>
<td>213.14</td>
<td>317.06</td>
</tr>
<tr>
<td>Long Rural</td>
<td>821.75</td>
<td>624.48</td>
<td>742.47</td>
</tr>
<tr>
<td>Unplanned SAIFI</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>1.070</td>
<td>0.922</td>
<td>1.503</td>
</tr>
<tr>
<td>Short Rural</td>
<td>2.587</td>
<td>2.261</td>
<td>3.019</td>
</tr>
<tr>
<td>Long Rural</td>
<td>6.035</td>
<td>4.892</td>
<td>5.348</td>
</tr>
</tbody>
</table>

In 2016-17, Ergon Energy’s reliability of supply outperformed the Australian Energy Regulator’s Service Target Performance Incentive Scheme (STPIS) for all six measures.

Figure 27 shows the STPIS targets and results for the 2010-17 period. The STPIS SAIDI and SAIFI forecast for the three feeder categories are based on their historical five year average performance. Both the actuals and the future forecast are the normalised values (i.e. exclusions are applied as per clause 3.3 of the STPIS).

<sup>25</sup> Ergon Energy’s STPIS is ‘flat-lined’ for the current regulatory period 2015-2020.
Figure 27: STPIS Targets and Results for 2010-17 Period
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11.3 High Impact Weather Events

11.3.1 Emergency Response

Ergon Energy is conscious that its responses to disruption events, particularly those driven by weather, are delivered in an environment of continually increasing need and expectation, both from customers and community stakeholders. More than ever, our response must consider the increasing customer dependency on electricity as technology and appliances become more sophisticated and economic activity becomes more reliant on e-commerce.

Ergon Energy’s response priorities in order of importance are:

- ensuring personal safety – both public and Ergon Energy employees
- protecting equipment and infrastructure from damage
- efficient supply restoration – including meeting communication requirements of customers and emergency service agencies.

As further commitment to these priorities and the communities we serve, Ergon Energy has established a dedicated team to lead Emergency Planning and Response on behalf of the distribution network. This team will focus on key priorities to further optimise our response capability being; emergency planning, preparation, resilience and response.

Disaster Scenario Exercises

To better enable our network to cope with disruption events, a number of simulation exercises will be conducted in preparation for the upcoming storm season. Participation in these exercises involves Ergon Energy working closely with the State Disaster Coordination Centre as well as local disaster management groups to further enhance our response capability, test process and ensure readiness.

Damage Assessment

The damage assessment process has been significantly enhanced through greater utilisation of technology including Field Force Automation. This process and supporting technology was utilised during Tropical Cyclone Debbie and enabled an increased turnaround of data for planning, recovery and restoration. This enabled improved data capture, more timely response and therefore provided significant savings to both Ergon Energy and the local economy.

Forecasting/Modelling/Tracking

We are improving our predictive modelling of weather events and their associated impacts through the utilisation of spatial systems. These applications are overlaid on our assets and draw from multiple data sources to enable Ergon Energy to make strategic and operational decisions for improved planning and response to events.
Tropical Cyclone Debbie Post Incident Review and Actions

Our response capability is constantly tested by a range of severe weather events across the state, and each event is unique in terms of scale and impact. In March 2017 Tropical Cyclone Debbie impacted a widespread area of Queensland disrupting power to 67,000 customer premises. A comprehensive post implementation review has since been conducted. This review identified further opportunities to enhance our processes, plans, technology, people development and overall response capability. These types of reviews are critical as part of continually meeting stakeholder expectations and reducing the negative impact of large scale disasters on the Queensland community.

11.3.2 Summer Preparedness

Summer Preparations for the 2017-18 storm season

The specific activities being undertaken to prepare the network for the 2017-18 summer season, and generally improve reliability, include:

- Network maintenance and other reliability improvement programs including: vegetation management, asset inspection and defect remediation, feeder patrols, bushfire mitigation program, ‘Fugro Roames™’ aerial inspections, network monitoring and control capability and flood risk mitigation.
- Network capacity and security improvement programs including; planning for security of supply, plant emergency rating information, strategic spare components, temporary load support and demand management.
- Securing generation assets including:
  - strategic mobilisation of ‘Pegasus’ HV mobile injection units that work in conjunction with generation equipment.
  - generation sharing agreements with Energex
  - generation hire arrangements with private suppliers
  - working closely with local disaster management groups and councils to identify critical infrastructure and generation requirements.

Ergon Energy continues to utilise its contract with Fugro Roames™ to acquire 3D representations of network assets which are displayed in a geo-spatial visualisation application to assist with vegetation management and asset maintenance. With this capability Ergon Energy has already carried out LiDAR inspection of the entire network each year. This information identifies defects and is contributing to reduced maintenance and planning costs, and increased safety and reliability of supply for our customers and communities.

The data captured is processed to enable measurement of the network and surrounding objects such as buildings, terrain and vegetation. In terms of disaster management assistance, this service provides post-disaster data capture flights to provide visibility of the environment and damage assessment to assist with restoration plans.

In addition to these specific activities, much of Ergon Energy’s annual program of work to develop, maintain and operate the network is aimed at providing a resilient network in preparation for the summer storm season.
Chapter 11. Network Reliability

Resources

Ergon Energy has a diverse range of skilled resources engaged both internally and externally. In the lead up to summer, substantial resources are available including:

- a field workforce of approximately 2,800 employees and contractors (including design, construction, maintenance, inspection and vegetation workers). This capability is deployed as necessary for any event that occurs through summer.
- leave rosters that are managed to ensure adequate availability of field resources for the summer period.

Customer engagement

Ergon Energy keeps its customers informed and engaged through:

- the Customer Solutions Contact Centre
- marketing programs to raise summer awareness
- media and community relations activity
- website, social media and other online communications.

11.4 Guaranteed Service Levels

Section 2.3 of the EDNC specifies a range of Guaranteed Service Levels (GSLs) that DNSPs must provide to their small customers. The GSLs are notified by the Queensland Competition Authority (QCA) through the code. Where we do not meet these GSLs we pay a financial rebate to the customer.

GSLs are applied by the type of feeder supplying a customer with limits appropriate to the type of GSL as outlined below in Table 29. Some specific exemptions to these requirements can apply. For example, we do not need to pay a GSL for an interruption to a small customer’s premises within a region affected by a natural disaster (as defined in the EDNC).

Table 29: GSL Limits Applied by Feeder Type

<table>
<thead>
<tr>
<th>EDNC Clause</th>
<th>GSL Description</th>
<th>Urban feeder</th>
<th>Short rural feeder</th>
<th>Long rural / isolated feeder</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.3.3</td>
<td><strong>Wrongful disconnections</strong> (Wrongfully disconnect a small customer)</td>
<td>Applies to all feeders equally</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.3.4</td>
<td><strong>Connections</strong> (Connection not provided)</td>
<td>On business day agreed with customer. Applies to all feeders equally</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.3.5</td>
<td><strong>Reconnections</strong> (Reconnection not provided within the required time)</td>
<td>If requested before 12:00pm -same business day. Otherwise next business day</td>
<td>Next business day</td>
<td>Within 10 business days</td>
</tr>
<tr>
<td>2.3.6</td>
<td><strong>Hot Water Supply</strong> (Failure to attend the customer’s premises within the time required concerning loss of hot water supply)</td>
<td>Within one business day</td>
<td>Within one business day</td>
<td>By business day agreed with customer</td>
</tr>
</tbody>
</table>
Chapter 11. Network Reliability

<table>
<thead>
<tr>
<th>EDNC</th>
<th>GSL</th>
<th>Urban feeder</th>
<th>Short rural feeder</th>
<th>Long rural / isolated feeder</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clause 2.3.7</td>
<td>Appointments (Failure to attend specific appointments on time)</td>
<td>On business day agreed with customer. Applies to all feeders equally</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clause 2.3.8</td>
<td>Planned Interruptions (Notice of a planned interruption to supply not given)</td>
<td>4 business days as defined in Division 6 of the NERR under Rule 90 (1). Applies to all feeders equally</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clause 2.3.9(a)(i)</td>
<td>Reliability – Interruption Duration (If an outage lasts longer than...)</td>
<td>18 hours 18 hours 24 hours</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clause 2.3.9(a)(ii)</td>
<td>Reliability – Interruption Frequency (A customer experiences equal or more interruptions in a financial year)</td>
<td>13 21 21</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

11.4.1 GSL Payment

The EDNC requires that a DNSP use its best endeavours to automatically remit a GSL payment to an eligible customer. Customers receive the payment for most GSLs within one month, however, in the case of Interruption Frequency GSL the payments will be paid to the currently known customer once the requisite number of interruptions has occurred. Table 30 shows the number of claims processed to date and paid in 2016-17.

Table 30: Number of Claims Processed to Date and Paid in 2016-17

<table>
<thead>
<tr>
<th>GSL</th>
<th>Number Paid</th>
<th>Amount Paid</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wrongful Disconnection</td>
<td>103</td>
<td>$14,626</td>
</tr>
<tr>
<td>Connection of Supply</td>
<td>28</td>
<td>$7,052</td>
</tr>
<tr>
<td>Customer Reconnection</td>
<td>4</td>
<td>$456</td>
</tr>
<tr>
<td>Hot Water Supply</td>
<td>1</td>
<td>$57</td>
</tr>
<tr>
<td>Appointments</td>
<td>157</td>
<td>$8,949</td>
</tr>
<tr>
<td>Planned Interruptions</td>
<td>1,323</td>
<td>$52,353</td>
</tr>
<tr>
<td>Duration of Interruption</td>
<td>3,445</td>
<td>$392,730</td>
</tr>
<tr>
<td>Frequency of Interruption</td>
<td>143</td>
<td>$16,302</td>
</tr>
<tr>
<td>TOTAL</td>
<td>5,204</td>
<td>$492,525</td>
</tr>
</tbody>
</table>

11.5 Worst Performing Feeders

In accordance with Section 11 of the Distribution Authority, Ergon Energy continues to monitor the worst performing feeders on its distribution network and report on their performance. Under the authority, Ergon Energy is also required to implement a program to improve the performance outcomes for the customers served by the worst performing feeders.

Ergon Energy’s worst performing feeders are classified based on three years of performance data.
and average performance indices. The distribution feeders are ranked (status assigned) according to their actual average SAIDI performance over that time. Feeder rankings are defined below:

- green feeders have a three years’ average SAIDI ≤ MSS
- yellow feeders have a three years’ average SAIDI > MSS < 150% MSS
- amber feeders have a three years’ average SAIDI > 150% MSS < 200% MSS
- red feeders have a three years’ average SAIDI > 200% MSS.

The Distribution Authority requires that we determine the top 50 worst performing feeders across all feeder categories, excluding feeders with less than 20 customers. Ergon Energy assesses the red feeders by looking for the highest (top 50) SAIDI ratios. The worst performing feeders in each of the Urban, Short Rural and Long Rural feeder categories are then analysed to identify performance improvement opportunities (the exclusion of feeders with less than 20 customers from the worst performing list allows sharing of the benefits of improvement investment across more customers). These opportunities are then evaluated and where appropriate, projects raised and carried through to the works program to deliver reliability improvement.

The list of our worst performing feeders, based on three years’ average annual SAIDI performance up to 2016-17, has been provided in Appendix C. Ergon Energy’s worst performing feeder assessment for 2016-17 is summarised below:

- 15% of our distribution feeders supplying more than 20 customers have been identified as red feeders at the end of 2016-17 (160 in total – 17 Urban, 119 Short Rural and 24 Long Rural). In addition, there are 44 red feeders, individually supplying less than 20 customers. However, these 44 feeders only supply a total of 0.03% of Ergon Energy customers.
- There has been a decrease of 7% in the total number of red feeders supplying more than 20 customers compared to the last financial year. The number of customers supplied by these feeders has also decreased by 1%. Our red feeders supply 5.38% of Ergon Energy’s total distribution customers.
- The top 50 worst performing feeders, which equate to 4.21% of the total distribution feeders, are targeted for reliability improvement investments.
- 36 of the worst performing feeders have carried over from the list identified in 2015-16.

**Review of Worst Performing Feeders Reported for 2015-16**

- 82% of the 50 worst performing feeders identified in 2015-16 show improvement in their annual SAIDI as of 2016-17 year end. Eight of those feeders now have improved annual SAIDI favourable to the June 2017 MSS limits.
- During 2016-17, Ergon Energy completed detailed engineering reviews of 28 of the 50 worst performing feeders that were identified based on their three years’ average SAIDI performance up to 2015-16. This included 2 Urban, 20 Short Rural and 6 Long Rural feeders scattered mainly in Northern Queensland, Capricornia and South West supply regions. Five of these feeders did not present any opportunities for capital investment to improve reliability with all of them showing significant performance improvement as of June 2017.
- The South West and Northern Queensland regions of Ergon Energy’s network dominate the worst performing feeder list for the Short Rural feeder category. This is because these regions have the highest number of Short Rural feeders compared to other supply regions of Ergon
Energy and the category dominates their total distribution feeder base at 51% and 57% respectively.

- The worst performing feeders reviews included detailed analysis of different type of outages (planned and unplanned) and outage triggers and contributing causes. The contributions from different segments of the electricity supply chain (sub-transmission, distribution, SWER etc.) were also analysed to understand the drivers of the poor performance and to identify the reliability improvement opportunities for the reviewed feeders.

- The contribution from the sub-transmission network outages to the worst performing feeders, especially for the Urban and Short Rural feeders, is proportionally high (more than 50% in most of the cases). Adverse weather conditions have also been the key contributor to the worst performing feeder performance.

- A small number of the worst performing feeders were found to have high average SAIDI due to one-off, low-probability events, often triggered by storm conditions. Most of the time, these feeders did not show need/prospect for capital investment and as such are being monitored for any potential deterioration in their future performance.

The outliers in the Southern region are mostly due to the radial nature of the network resulting in higher exposure to the adverse environmental elements. This supply region also has a higher exposure to thunderstorm activity compared to other regions. The length of exposure of Long Rural and Short Rural feeders, coupled with the geographically dispersed locations of attending depot/staff and their sub-transmission systems contribute significantly to the adverse performance of these feeders. The larger customer densities are on urban feeders, which mean a single outage event in this category contributes significantly to the SAIDI value for the feeder. Limited accessibility during the wet season has also been found to be one of the key contributing factors to the longer outage duration of the worst performing feeders. Network asset solutions that could be applied at sub-transmission network level are usually very high cost options. Such investment cannot be considered prudent to improve reliability for a small cluster of customers on a feeder or feeder section with very low customer density.

Ergon Energy only sought limited capex for the Worst Performing Feeder Improvement program from the AER for the 2015-20 regulatory control period. We are ensuring that the investment in the Worst Performing Feeders Improvement program is prudently spread across different feeders and regions.

The reliability improvement solutions identified from the worst performing feeder reviews conducted in the last two years have mainly included low to moderate capital investment options. The low cost, quick win solutions mainly included protection setting changes, installation of Line Fault Indicators with communication and Fuse Savers. The moderate investment options included installation of new Automatic Circuit Reclosers, Sectionalisers, Remote Controlled Gas Switches and also relocation and/or replacement of switching devices. The identified solutions are currently being implemented. Ergon Energy will continue reviews of its worst performing feeders during 2017-18.

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26 Approximately 60% of the customers in the South West supply region are supplied by radial networks.
The overall approach for the worst performing feeder performance improvement includes the following in order of preference and affordability:

1. Improved network operation by:
   - investigating to determine predominant outage cause
   - implementing reliability or operational improvements identified through the investigation of any unforeseen major incidents
   - improving fault-finding procedures with improved staff-resource availability, training and line access
   - improving availability of information to field staff to assist fault-finding, which could include communications, data management and availability of accurate maps and equipment
   - planning for known contingency risks until permanent solutions are available
   - improving and optimising management of planned works.

2. Prioritisation of preventive-corrective maintenance by:
   - scheduling asset inspection and defect management to poorly performing assets early in the cycle
   - scheduling red feeders first on the vegetation management cycle
   - undertaking wildlife mitigation (e.g. birds, snakes, possums, frogs) in the vicinity of red feeders

3. Augmentation and refurbishment through capex by:
   - refurbishing or replacing ageing assets (for both powerlines and substations).

### 11.6 Safety Net Target Performance

Ergon Energy’s Distribution Authority describes the performance reporting obligations against service Safety Net targets.

Supply interruption events over 2016-17 have been reviewed in detail to identify any instances where the actual restoration performance may not have achieved the service Safety Net targets set out in Schedule 4 of the Distribution Authority (as described in Section 7.4.2).

In 2016-17, there were no events exceeding the service Safety Net targets.
Chapter 12 – Power Quality

12.1 Quality of Supply Experienced by Customers
12.2 Quality of Supply Compliance Processes
12.3 Power Quality Supply Standards, Code Standards and Guidelines
12.4 Power Quality Performance in 2016-17
12.5 Power Quality Corrective Actions
12.6 Power Quality Ongoing Challenges
12. Power Quality

The quality of network power affects both customer experience and the efficiency and stability of the network. This section covers two related but distinct areas which are Quality of Supply (QoS) and Power Quality (PQ). QoS is a measure of the customer-initiated requests for Ergon Energy to investigate perceived issues with the quality of the supply. PQ is the compliance of measured system wide network conditions with defined parameter limits.

12.1 Quality of Supply Experienced by Customers

The QoS experienced by customers is measured by the number of QoS enquires lodged by customers. QoS enquires occur when a customer contacts Ergon Energy with a concern that their supply may not be meeting the standards. QoS issues are selected from categories on initial contact as follows: LV, voltage dips, voltage swell, voltage spike, solar PV, TV or radio interference, motor start problems, and noise from appliances. The breakdown of enquires for 2016-17 in relation to the previous 5 year periods is shown in Figure 28.

Figure 28: Quality of Supply Enquiries by Category

The number of QoS enquires received in 2016-17 decreased 8.91% when compared to the previous year from 1808 to 1660 when compared to the previous year. The step-change increase in 2012-13 was mainly attributed to solar PV enquires that coincided with the aggressive uptake of customer installation prior to the close of subsidies and access to the 44 cent/kWh Feed-in-Tariff. In 2013, Ergon Energy added an additional category of solar PV to cover the high number of enquires being received associated with solar PV issues. Solar PV enquires account for approximately 45.8% of all QoS enquires. The connection of solar PV systems has led to numerous network voltage issues, which have required responses ranging from reviewing tap plans to augmenting LV and HV networks in order to accommodate the solar PV systems.

The close out of QoS enquires is shown in Figure 29. The data shows that 37.4 % of enquires
Chapter 12. Power Quality

were due to a network issue, 24% there was no fault found and 5.1%, the fault was on the customers side of the connection. There are still 556 (33.5%) enquires still open under investigation.

Figure 29: Quality of Supply Enquires by Type at Close Out

Figure 30: Quality of Supply Enquiries by Feeder Type

12.2 Quality of Supply Compliance Processes

Ergon Energy has a defined process for when a customer makes a QoS enquiry. When a call is received, initial investigation is carried out. This may require the installation of temporary monitoring equipment at up to three locations associated with the customer’s connection. After initial examination of the monitoring data, engineering staff may review and provide a recommendation to remediate. The customer is advised on the outcome of the investigation via standardised documentation.


12.3 Power Quality Supply Standards, Code Standards and Guidelines

Ergon Energy is required by the Queensland Electricity Regulation and the NER to ensure PQ is maintained at the set performance levels. The relevant requirements are:

- **Magnitude of Power Frequency Voltage**: During credible contingency events, supply voltages should not rise above its normal voltage by more than the time dependent limits defined in Figure S5.1a.1 of the NER.

- **Voltage Fluctuations**: A NSP must maintain voltage fluctuation (flicker) levels in accordance with the limits defined in Figure 1 of *Australian Standard AS 2279.4:1991*. Although a superseded standard, it is specifically referenced under a derogation of the NER (S9.37.12) applicable to Queensland.

- **Voltage Harmonic Distortion**: A Network Service Provider (NSP) must use reasonable endeavours to design and operate its network to ensure that the effective harmonic distortion at any point in the network is less than the compatibility levels defined in Table 1 of *Australian Standard AS/NZS 61000.3.6:2001*.

- **Voltage Unbalance**: A NSP has a responsibility to ensure that the average voltage unbalance measured at a connection point does not vary more often than once per hour by more than the amount set out in Table S5.1a.1 of the NER.

Where there is need to clarify requirements; the relevant Australian and International Electrotechnical Commission (IEC) Standards are used to confirm compliance of our network for PQ. Ergon Energy and Energex also have the joint working document, Standard for Network Performance, which provides key reference values for the PQ parameters.

12.4 Power Quality Performance in 2016-17

**12.4.1 Power Quality Performance Monitoring**

Ergon Energy currently has in excess of 2,200 PQ monitors throughout the network, covering more than 850 feeders or roughly 60% of the feeders in the network. Ergon Energy also has access to more than 800 revenue meters that record PQ parameters.

The PQ data from these meters has been added to the PQ data warehouse. Each of these units contributes to give an indication of the state of the network for PQ parameters. The profile data obtained is accessed daily, recorded and presented based on 10 minute averages. The breakdown of the types of monitors and meters being read is shown in Figure 31. These figures show there is some variation in the total figures which is dependent on when the data is available.
12.4.2 Steady State Voltage Regulation – Overvoltage

The number of monitored sites that reported overvoltage outside of regulatory limits of 254.4 V was 14.3%. This means 14.3% of sites recorded an exceedance of the upper limit for more than 1% of the time. This is the fifth consecutive year that improvement has occurred to reduce the number of sites with overvoltage issues.

Figure 32 shows the number of monitored sites that have recorded over-voltage conditions.

Figure 33 shows the percentage of monitored over-voltage sites for the different feeder types. The significant increase in the number of the monitored sites during 2016-17 was, as stated previously, because of the number of customers’ meters with PQ ability that were added to the PQ data warehouse resulting in PQ data that could be used for reporting.

Most monitored sites are at the terminals of the distribution transformers and therefore the voltage may be within limits at the further end of the LV network under load conditions. Improvements will continue to be achieved by implementation of the PQ strategy.
12.4.3 Steady State Voltage Regulation – Under-voltage

The number of sites recording under-voltage issues has seen a small increase on 2015-16 figures with 3.9% of sites having under-voltage outside of the regulatory limit of 225.6 V. Figure 34 shows the number of monitored sites that have recorded under-voltage conditions. Figure 35 shows the percentage of monitored under-voltage sites for the different feeder types.

As discussed in Section 4.4.3, Ergon Energy has approval to undertake a trial of the 230 V standard. Should the state-wide transition to the 230 V standard be approved for implementation by the Queensland Government there will be an additional 4% of voltage range available. The initial trial data indicates that if the 230 V standard is implemented, the number of network under-voltage sites will be very small.
12.4.4 Voltage Unbalance

Data from the 3-phase sites shows that 5.6% of these sites were outside of required the unbalance standard during 2016-17. Typically unbalance is seen on the rural feeders where there are SWER networks in the associated downstream feeder, which impacts on the overall balance of the 3-phase feeder. During 2016-17 the increase in unbalance sites has been on the urban feeders.

Figure 36 shows the number of sites that have recorded unbalanced conditions, and the percentage of sites by feeder type is shown in Figure 37.
12.4.5 Harmonics

Harmonics are recorded as Total Harmonic Distortion (THD) representing all harmonics levels from the second to the fiftieth harmonic. There were 0.6% of sites recording harmonics that exceeded the regulatory limits during 2016-17. The data indicates that customer equipment is largely conforming to the Australian Standards for harmonics emissions but continual vigilance is required to ensure harmonic levels remain within the required limits.

Figure 38 shows THD for the previous five years. The percentage of sites by feeder type is shown in Figure 39.
12.5 Power Quality Corrective Actions

The PQ monitors and meters throughout the network are now accessed and downloaded every hour and the sites that are exceeding the PQ parameters are tabled for action by a daily email to PQ staff. There have been numerous examples where the PQ monitors have identified network faults before being noticed by customers or systems. In addition, a monthly phenomenon report summarises and grades the PQ issues for action. The report shows all sites that are exceeding any of the PQ standards. The report is used to determine where review of regulation tapping plans, equipment maintenance, replacement or augmentation is needed.

In the 2015-20 regulatory control period Ergon Energy will install approximately 1,100 additional PQ monitors to provide maximum coverage of feeders throughout the network to ensure a comprehensive report on PQ parameters is available. Where Ergon Energy has access to existing customer meters that record PQ parameters, the PQ data is loaded into the PQ warehouse. The utilisation of the PQ data provides an additional source of data to complement our network monitors. These meters are currently providing 800 additional sites of data.
12.6 Power Quality Ongoing Challenges

Ergon Energy has a high number of large industrial customers and large generators (solar farms) that have equipment that produce harmonics, many of which are on dedicated feeders. It is not possible to monitor all these customers' feeders; however, Ergon Energy has installed PQ analysers on a number of these feeders at zone substations and will be installing additional analysers in the coming years to build a profile of harmonics for the type of industry.

The high penetration of solar PV systems on the LV networks has highlighted some of the limitations in the network. The main issues have been in balancing the solar PV system during the day and peak loads during non-daylight periods. This will require continual vigilance to ensure the PQ parameters are maintained within limits.
Chapter 13 – Metering

13.1 Metering Environment
13.2 Ageing Meter Population
13.3 Metering Investments in 2016-17
13.4 Planned Metering Investments for 2017-18 to 2021-22
13. Metering

13.1 Metering Environment

The AEMC’s Power of Choice program is introducing changes effective from the first of December 2017 that provide consumers with more opportunities to make informed choices about the way they use electricity products and related services. Ergon Energy is actively supporting the introduction of this initiative and also the range of wider national market reforms that will make metering services contestable and retailer driven. This will mean that DNSPs will no longer install meters on NEM connected sites.

Ergon Energy will continue to provide cost-effective Type 7 metering services and efficient maintenance of existing Type 6 meters that remain in service.

We currently operate around 1.195 million meters. The total meter count has been slowly declining due to the policy of installing (for both new and replacement activities):

- a three phase meter in place of multiple single phase meters on two or three phase installations, and
- a dual element meter in place of two single phase meters for installations with a controlled load tariff.

Around 9,150 of our meter population are unregulated meters in isolated generation communities. 5,022 of these units are card operated prepayment meters, used in remote Aboriginal and Torres Strait Island communities.

Our current fleet of meters includes 843,540 electro-mechanical (disc) meters and 352,262 electronic meters. Approximately 247,000 of the electronic meters are capable of recording interval data. In accordance with the National Metrology Procedure Part A, Ergon Energy no longer installs mechanical meters and now installs only electronic load profile meters. The weighted average age of our electronic meters is 5.5 years; indicating considerable remaining functional life.

As the default Metering Coordinator for Type 6 meters installed prior to 1 Dec 2017, Ergon Energy will manage these in accordance with the Metering Asset Management Plan (MAMP). This will ensure that the value of these meters is maximised over their full useful life while they remain in service and are deemed fit for purpose.

Currently over 420,000 customers are connected to a controlled load tariff. This involves installation of a load control relay (remote controlled switch) in their meter box, which is switched via audio frequency signals superimposed over the supply network. Where audio frequency signals are not available to control load switching, control is provided using the built-in time clocks in electronic meters.

Load control management equipment reduces peak demand and helps defer capital intensive network augmentation; it is a valuable tool for network management and contingency planning. The benefits are shared amongst all customers in the form of more efficient network operation and investment. Ergon Energy is currently reviewing developments in new network control devices with expanded capability and functionality. External load control relays are referred to as Network Devices under the new competitive metering environment.

Responsibility for the provision of metering services to electricity customers will change on
1 December 2017 with the commencement of the expanding competition in metering and related services rule change. The new regulatory arrangements provide a framework for the competitive provision of advanced meters for residential and small business customers and greater opportunities for those customers to access a range of cost-effective service offerings. With the implementation of the new framework from 1 December 2017, DNSPs will no longer be responsible for installing meters but will continue to provide metering services at customers’ premises until existing meters are replaced by an advanced meter. To support this change, from 1 July 2015, Ergon Energy moved its metering assets out of its Standard Control Services (SCS) Regulatory Asset Base (RAB) to a separate Metering Asset Base (MAB). This ensures that the costs of providing Type 5 and 6 metering services are separated from the core costs associated with the access and supply of electricity to customers, appearing as a separate charge on customer bills.

Ergon Energy has been preparing for the transition to the new framework by ensuring our meters remain operationally relevant. Until 1 December 2017, new meters will be installed as standard Type 6 accumulation and manually read installations, as per current operations. These will be capable of providing customer and network services until they are replaced by retailers with Type 4 advanced meters that meet the minimum services specification. Until they are replaced, the ongoing capability of existing metering assets will be maintained to ensure the cost-effective delivery of metering services to customers and to enable network benefits, such as real time monitoring of PQ and customer loads to better manage voltage regulation on the LV network, to be captured where appropriate.

Ergon Energy plans to maintain load control as it relates to network operation and will work closely with Metering Coordinators to capture any efficiency in the delivery of load control via their Type 4 advanced meters. However, where this is not possible, Ergon Energy will negotiate with third-party metering providers to retain the Ergon Energy load control assets installed in customer switchboards to maintain our considerable load control facilities. Load control equipment and network devices external to the meter are provided as SCS and recovered as part of our network tariffs.

Ergon Energy has procured cost-effective electronic meters for the 2015-20 regulatory control period and will carefully monitor stock levels in preparation for commencement of the new metering framework. Ergon Energy will seek to maximise the remaining value in existing meter stocks by leveraging metering capabilities wherever possible. For example, the current suite of interval capable digital meters can be reprogrammed to support market offerings such as time-based pricing structures, including the new regulated retail tariffs set by the Queensland Competition Authority under delegation from the Queensland Government.

Under the Metering Asset Management Plan, Ergon Energy performs meter family testing, meter replacement programs and time-based meter testing for large customers. Analysis of in-service meter tests completed in 2015 identified another family of 3 phase meters (Email Type SDM) as non-compliant, while most other families passed with a 7 year compliance period. In-service meter testing is currently being undertaken on 1300 meters.

Ergon Energy’s transition plan will address consistent work practices and supporting standards, such as the Queensland Electrical Connection and Metering Manual, to separate the DNSP requirements from meter provider obligations and ensure these align with the rollout of communications enabled meters in a contestable marketplace. This transition will also require an
Chapter 13. Metering

appropriate jurisdictional framework. As such, Ergon Energy is working with the Queensland Government and Energex to ensure that a consistent approach and appropriate framework is introduced across Queensland.

As a contestable metering market is introduced, Ergon Energy will work to ensure that critical standards such as safety are updated to cover the growing range of metering service providers and market participants.

Figure 40 shows meter purchases from 2011-12 to 2016-17.

Figure 40: Meter Purchases 2011 to 2017

The above average purchase requirements for 2011-12 and 2012-13 for new meters was due principally to the installation of solar PV systems requiring bi-directional metering during the peak period for PV installations. An increase in 2014-15 related the replacement of BAZ non-compliant meters in the South West Queensland region, which is continued into 2015-16. The increase in purchases in 2016-17 is largely attributed to the BAZ and WF2 non-compliant meter replacement program across all regions of Ergon Energy. It is expected that approx. 24,000 meters will be removed and approx. 21,000 meters installed by 30 June 2017 above normal business as usual requirements.

Table 31: Contribution to Meter Usage Increases 2016-17

<table>
<thead>
<tr>
<th>Project</th>
<th>Quantity (approximate)</th>
<th>Description of Meters Used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additions and Alternations (Mostly Solar PV)</td>
<td>11,500</td>
<td>100% new</td>
</tr>
<tr>
<td>Metering Asset Management Plan (MAMP)</td>
<td>24,000</td>
<td>100% new</td>
</tr>
</tbody>
</table>

Other metering equipment installed this year includes load control relays and current transformers.
13.2 Ageing Meter Population

Figure 41 shows the age profile of both electro-mechanical and electronic Type 6 meters currently in service, and Figure 42 shows the age profile of single and poly-phase electronic meters.

The economic life of electro-mechanical meters is 25 years, and for electronic meters this expectancy is 15 years. These figures illustrate that a large number of electro-mechanical meters have exceeded their economic life with some reaching twice that age. The electronic meter populations are only now reaching the end of their economic life. The AER has approved the replacement of 108,500 meters over the current regulatory control period 2015–20. This includes 105,150 electro-mechanical meters that are more than 50 years old and 3,300 electronic meters that have failing components.

Ergon Energy will continue to utilise the aged assets and only replace these assets when they are determined to be non-compliant based on condition monitoring of population samples and failure.

Ergon Energy Distribution Annual Planning Report 2017-18 to 2021-22
Chapter 13. Metering

rates as outlined in the MAMP. After Power of Choice commences (1 December 2017), all meter failures and non-compliant meter replacements will be reported to the Retailer’s nominated Meter Coordinator to arrange a Type 4 remote read meter replacement.

Ergon Energy’s meter asset register was transitioned to ‘MARS’ (Meter Asset Register and Services) in March 2016. This move was to align Ergon Energy customer information and billing system ‘PEACE’ and meter asset register ‘MARS’ with the same systems used by Energex. MARS has improved functionality for in-service meter testing and reporting for regulatory requirements. Enhancements and changes to these systems are planned to meet the competitive metering environment and reduction in assets as Type 4 Meters are deployed for new and replacement applications.

13.3 Metering Investments in 2016-17

Table 32 provides a summary of metering opex expenditure for reactive (failed in service) and planned routine maintenance for 2016-17.

Table 32: Metering Operational Expenditure 2016-17

<table>
<thead>
<tr>
<th>Category</th>
<th>2016-17 $M Budget</th>
<th>2016-17 $M Actual$27</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive maintenance SCS</td>
<td>1.581</td>
<td>0.971</td>
</tr>
<tr>
<td>Planned maintenance SCS</td>
<td>2.505</td>
<td>1.919</td>
</tr>
<tr>
<td><strong>Total ($ M)</strong></td>
<td><strong>4.086</strong></td>
<td><strong>2.890</strong></td>
</tr>
</tbody>
</table>

13.4 Planned Metering Investments for 2017-18 to 2021-22

Current investment in metering by Ergon Energy will be significantly influenced by the development of the contestable market in regional Queensland. We are preparing plans to manage these changes.

Other factors influencing future metering investment include:

- continuing solar PV installations that require bi-directional measurement of electricity (import and export).
- demand management and pricing strategy changes that will require meter changes to support new tariffs, such as Seasonal Time-of-Use tariffs and Demand Controlled (e.g. air-conditioner control) tariffs.
- the roll-out of smart metering around the world which has resulted in the push to introduce smart meters for emerging market participation. These smart meters will have additional functionality at a cost that is higher than the basic electronic meter. NER changes include a new and replacement meter policy and market led deployment that will influence the overall cost and rate of deployment of these meters.
- the shorter life (from component failure and technology redundancy) and higher maintenance

$27 Actual Expenditure to May 2017.
costs of new electronic and smart meters compared to the old electro-mechanical type meters.

- exemptions which have been granted to install electronic meters with remote communications.
- replacement of the current card operated meter fleet by 1 July 2018 to meet new Queensland regulatory requirements.
- meter configuration systems to enable reprogramming of existing meters and improve service delivery efficiency.

Given the uncertainty around the timing of the reforms and unpredictable customer/market behaviour and churn rates, replacement volumes and investment costs of Type 6 meters have been forecast to align with Ergon Energy’s historical volumes of both planned and reactive meter replacements. The reactive meter replacements are estimated at 10,000 meters per annum based on historical records. Planned capital replacements are based on 108,450 non-compliant meters as approved by the AER. This allows for a total of 158,450 meter replacements.\(^{28}\)

The current approved AER expenditure for 2015 to 2020 was $40.709 million (2014-15 real dollars).

Table 33 shows Ergon Energy’s forecast capex metering replacement from 2017-18 to 2021-22. This has been revised down from the AER approved dollar values for 2017-18 to 2019-20 due to the impact of the Power of Choice. The revised capex for reactive and planned meter replacements is estimated at $28.603 million for the period 2017 to 2022. The small allocations of capex funds beyond 2018-19 allow for planned and reactive meter replacements for Non-NEM locations.

Table 33: Metering Capex Replacement Cost Estimates 2017-18 to 2021-22

<table>
<thead>
<tr>
<th>Category</th>
<th>2017-18</th>
<th>2018-19</th>
<th>2019-20</th>
<th>2020-21</th>
<th>2021-22</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive replacements approved</td>
<td>1.372</td>
<td>1.361</td>
<td>1.348</td>
<td>0.050</td>
<td>0.050</td>
<td>4.181</td>
</tr>
<tr>
<td>Reactive replacements estimated</td>
<td>0.605</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.805</td>
</tr>
<tr>
<td>Planned replacements approved</td>
<td>6.855</td>
<td>6.810</td>
<td>6.746</td>
<td>0.050</td>
<td>0.050</td>
<td>20.511</td>
</tr>
<tr>
<td>Planned replacements estimated</td>
<td>2.906</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>3.106</td>
</tr>
<tr>
<td><strong>Total ($M) approved</strong></td>
<td><strong>8.227</strong></td>
<td><strong>8.171</strong></td>
<td><strong>8.094</strong></td>
<td><strong>0.100</strong></td>
<td><strong>0.100</strong></td>
<td><strong>24.692</strong></td>
</tr>
<tr>
<td><strong>Total ($M) estimated</strong></td>
<td><strong>3.511</strong></td>
<td><strong>0.100</strong></td>
<td><strong>0.100</strong></td>
<td><strong>0.100</strong></td>
<td><strong>0.100</strong></td>
<td><strong>3.911</strong></td>
</tr>
</tbody>
</table>

Note: Any discrepancy in total cost can be attributed to rounding error.

\(^{28}\) This excludes capex to replace the existing card operated meters in isolated and remote communities.
\(^{29}\) The approved figures are as per the AER Distribution Determination for 2016-17 to 2019-20. The estimated figures are the expected impact of the Power of Choice from 1 Dec 2017. Small allowances have been retained to service Non-NEM connected areas.
\(^{30}\) Ibid.
\(^{31}\) Projected estimate based on 2015-20 figures. No Approved Budget for 2020-21 to 2021-22
\(^{32}\) Ibid Note 4
Chapter 14 – Information and Communication Technology

14.1 ICT Investment 2016-17
14.2 Forward ICT Investment Program
14. Information and Communication Technology

This section summarises the material investments Ergon Energy has made in the 2016-17 financial year, or plans to undertake over the forward planning period, relating to Information & Communications Technology (ICT) systems. As noted below, several projects have been deferred following the Queensland industry merger between Ergon Energy and Energex into Energy Queensland.

14.1 ICT Investment 2016-17

Table 34 provides a summary of ICT investments undertaken in 2016-17. These include projects which commenced prior to this year and investments which will not be completed until after 2016-17.

Table 34: ICT Investments 2016-17

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost $ M actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geographic Information System (GIS) Upgrade</td>
<td>9.14</td>
</tr>
<tr>
<td>Infrastructure &amp; Communications (inc. End User Devices)</td>
<td>7.66</td>
</tr>
<tr>
<td>Field Force Automation Phase 2</td>
<td>5.71</td>
</tr>
<tr>
<td>Enterprise Business Intelligence Program</td>
<td>6.63</td>
</tr>
<tr>
<td>Continuous Improvement &amp; Minor Applications</td>
<td>6.89</td>
</tr>
<tr>
<td>Network Operational Data Warehouse</td>
<td>3.24</td>
</tr>
<tr>
<td>Power of Choice Program</td>
<td>2.94</td>
</tr>
<tr>
<td>Enterprise Resource Planning (ERP) &amp; Enterprise Asset Management (EAM) Transformation Program (Procurement Phase)</td>
<td>2.23</td>
</tr>
<tr>
<td>Distribution Market Capability</td>
<td>0.80</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>45.23</strong></td>
</tr>
</tbody>
</table>

Note: Actuals includes ICT Managed Capex and Opex investment for Ergon Energy Corporation Limited only (i.e. does not include ICT investment funded through other portfolios already identified in other sections of this report).

GIS System Upgrade

The Ergon Energy Geographical Information System (GIS) spatially represents the physical electrical and communication assets within the Ergon Energy distribution network. It masters the as-designed as-constructed network model, and holds the “normal” electrical network connectivity model, being the only system that contains such a blend of information.

The primary investment objective of the GIS upgrade is the replacement of an end of life asset to ensure ongoing performance. Secondary objectives include; improved asset quality/performance, enhanced network asset safety and utilisation through better network models.
Chapter 14. Information and Communication Technology

Infrastructure & Communications

The renewal of Ergon Energy’s ICT infrastructure assets is delivered in accordance with Ergon Energy’s ICT Infrastructure Asset Renewal Guidelines. ICT infrastructure and technology software asset performance degrades due to age and technical obsolescence. To sustain capability an ongoing program is required to replace these assets. Assets covered by the program include; PC fleet (desktops, laptops), Windows server equipment, Unix server equipment, corporate data network equipment, Ergon Energy property works infrastructure, server storage infrastructure renewal and growth, asset renewal of ICT peripheral equipment including printers and mobile phones. The program also includes infrastructure software renewal of ICT technologies such as Exchange Email, integration technologies and database environments.

Field Force Automation Program

Ergon Energy had previously provided the foundation for works management to the field and rolled out Panasonic Toughpads to over 500 Customer Service field crews through Phase 1 of the Field Force Automation program. Phase 2 of the program continued in 2016-17 to extend the use of FFA service suite beyond Customer Service activities, to encompass planned work. This project aims to extend the use of FFA to more field crews, move from paper to electronic forms, provide the GE FieldSmart Client to all ToughPad users, rollout Focal Point to extend the reporting capabilities of FFA and enhance the Business Objects reports.

Enterprise Business Intelligence Program

This project will refresh the Ergon Energy business intelligence platform to ensure the ongoing provision of business unit and functional performance reporting and analytics capability.

Continuous Improvement & Minor Applications

This includes minor improvements and updates across the ICT systems footprint including; work force automation, asset management, market systems, network operations systems, knowledge management systems, ERP system and customer service systems which support Ergon Energy’s business operations. This also consists of minor ICT initiatives, including initiative expenditure carried over from 2015-16.

Network Operational Data Warehouse

This project provisioned network related operational data to a centralised repository of time-series data for use by corporate users and other ICT applications. The Network Operational Data Warehouse (NODW) will provision specific types of operational performance data, for analytical and other purposes. The project will also investigate the potential for replacement / decommission of existing other legacy data stores within the organisation.

Power of Choice Program

This program will deliver the ICT changes required to support reforms to the NEM recommended by the AEMC’s Power of Choice review. This includes the sub-program for the Market Systems Modernisation to update many of Ergon Energy’s market systems.
Chapter 14. Information and Communication Technology

The existing suite of market systems are being primarily enhanced or upgraded to meet the Power of Choice requirements. This program incorporates the current customer information system (CIS), service order management system, meter data management and business-to-business (B2B) systems.

**ERP/EAM Transformation Program**

Commencement of the planning and procurement phase for the replacement of Ergon Energy’s Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) systems began in 2016-17. Ergon Energy’s core ERP/EAM system reached both technical and financial obsolescence in mid-2015. Renewal of the ERP and EAM systems with contemporary systems will provide an opportunity for Ergon Energy to consolidate satellite applications. The project will encompass enterprise content management, procurement, employee performance, enterprise services, works & asset management footprints. The program will now be delivered as part of the Energy Queensland Enterprise Digital Initiatives program and will take a number of years to complete.

**Distribution Market Capability**

Ergon Energy’s customer and premises management capability was being provided by a 30+ year old proprietary FACOM mainframe system that operated on aging infrastructure and supported by an aging and limited support work force. This multi-year project replaced the existing customer and premise management systems used by Ergon Energy Distribution with the same set of systems as used by Energex. The project also enabled the separation of the distribution and retail functions from a systems and business process perspective. 2016-17 investment for this project was largely limited to close out costs that had carried over from the 2015-16 year.

**14.2 Forward ICT Program**

With the recent merger of Ergon Energy and Energex, the ICT strategic vision has been reviewed and updated. The revised strategic vision is to create an information enabled enterprise that will efficiently support the transformation to a Digital Utility.

The ICT strategy will be delivered by the following strategic themes:

- **Business aligned ICT change** – This includes planning and development of change programs to support business transformation while optimising ICT system efficiency and effectiveness. This is in response to rapid growth in technology and the need to manage complexity in order to minimise cost and risk in the future;
- **IT as a Service** – This will drive greater use of commodity ICT services, alternate sourcing approaches and modernisation of the applications portfolio. This strategy is in response to the growth in commodity ICT and cloud computing; and
- **Managed Information** – This will drive operational efficiency through technology and information enablement, unlocking future value through broad access to secure information. This strategy is in response to emerging technologies including big data, mobility and social media.
Chapter 14. Information and Communication Technology

Represented in Figure 43; the forward investment of the ICT portfolio will be focused around a key set of digital building blocks focused on transiting Ergon Energy into a digital utility.

Figure 43: Digital Building Blocks

This sequencing of the above noted proposed investments will be refined as Energy Queensland progress through the business case process. The timing of these initiatives is dependent on funding approval, industry restructure in Queensland and the overall regulatory program.

14.3 Forward Financial Forecasting

The scope and sequencing of initiatives are currently under consideration. They are subject to Energy Queensland’s Investment Governance Framework which reviews initiative prudence and efficiency, in conjunction with other criteria including change capacity.

Commercial negotiations are currently underway for a number of the above noted investment areas, therefore forecast investment against each individual proposal is excluded from this report. A high level summary of total potential ICT investment for the distribution business across the remainder of the regulatory control period is noted in Table 35 below. However the forecast is indicative only at this stage and subject to material change as planning and negotiation activities.
are completed:

**Table 35: ICT Investment Forecast 2017-18 to 2021-22**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$</td>
<td>80.20M</td>
<td>85.81M</td>
<td>67.12M</td>
<td>57.52M</td>
<td>54.77M</td>
</tr>
</tbody>
</table>

Note: Forecasts includes ICT Managed Capex and Opex investment for Ergon Energy Corporation Limited only (i.e. does not include ICT investment funded through other portfolios already identified in other sections of this report).
Chapter 15 – Telecommunications and Operational Technology

15.1 Telecommunications
15.2 Operational Systems
15.3 Operational Device Management
15.4 Investments in 2016-17
15.5 Planned Investments in 2017-18 to 2021-22
15. Telecommunications and Operational Technology

Traditional distribution networks are facing a number of challenges brought about by customer energy choices and the introduction of new technologies such as grid energy storage, private battery storage, solar PV, voltage regulation solutions and a multitude of specialised monitoring tools and devices. Ergon Energy recognises that these technologies play a key role in improving the utilisation, reliability, security and performance of our regulated electricity assets.

As these device numbers continue to grow, the associated data streams require systems to more efficiently collect, process and manage the information to maximise benefit to the power network. In light of this, Ergon Energy is working towards more structured systems architecture to enable effective insights into how the network is performing. This system structure is broken into four main categories:

- Level 1: Device, Network and Instrumentation (including telecommunications technology)
- Level 2: Operation and Supervision (includes data collection and automated processing)
- Level 3: Information Management (structured data storage)
- Level 4: Business Planning (advanced analytics on stored data)

This approach defines the boundaries for systems into distinct levels based on the timeliness of the data being operated on. This provides a guideline for deciding system boundaries, the interfaces between them and ownership at each level. ‘Level 3’ and ‘Level 4’ are classified as corporate systems and will not be covered further in this section.

15.1 Telecommunications

Ergon Energy’s telecommunication strategy comprises of four major goals:

i. To ensure that the existing telecommunication infrastructure continues to operate at a performance level required to support the operation of an electricity distribution network.

ii. To introduce new functionality and technology that supports operational improvement within the organisation, enabling the business to implement new initiatives in the area of network demand management to minimise the impact on the environment.

iii. To increase the telecommunications network’s capacity to accommodate the demand for connectivity ensuring operation and management of the electricity distribution network.

iv. To invest prudently in new infrastructure and the use of commercial services to provide the most cost effective outcome for Ergon Energy. Further, to minimise duplicate investment through establishing and using telecommunication infrastructure common to other government organisations.
The delivery of the following three major projects will support the achievement of Ergon Energy’s telecommunications strategy:

- the P25 Two-Way Radio Program currently underway to replace the aged analogue two-way mobile radio network with a secure digital two-way network – two parent projects will complete this program, “End of life radio refurbishment Mackay to Maryborough” and “End of life Radio refurbishment Western Queensland”.
- CoreNet Site Infrastructure Replacement Program will replace site support infrastructure such as power supplies and air conditioning to ensure that services remain in operation. This is based on a condition assessment of equipment’s capacity to provide satisfactory service and performance to meet the requirements for the distribution network.
- CoreNet Active Network Replacement will invest in the renewal of aged and unsupported telecommunications equipment, based on a condition assessment of equipment’s capacity to provide satisfactory service and performance to meet the requirements for the distribution network.

### 15.2 Operational Systems

Ergon Energy classifies Operational Technology (OT) as the systems, applications, and intelligent devices and their data that can directly or indirectly monitor, control or protect the power network. These systems are predominately located in the level 2 classification detailed above.

Our OT strategies therefore include:

- managing the technology environment independent of the underlying telecommunications environment, so that they can develop independently without impacting upon each other
- 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
- centrally managing support and maintenance of intelligent electronic devices
- developing greater security and resilience as part of the overall design, given the increased exposure to cyber and physical security threats.

Our forward program 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. Our ongoing mandate is to ensure a standards-based approach to all future and current operational systems and devices the network, including the interactions between them.

The current systems within the OT scope are detailed below.

#### 15.2.1 Supervisory Control and Data Acquisition (SCADA)

Currently there is a dedicated substation control system across a large portion of the network, with 97% of customers connected to substations with SCADA capability. This includes approximately 75% of the zone substations and over 1,800 reclosers. These are managed centrally through the Operational Control Centres (OCC) in Rockhampton and Townsville. The SCADA system is the largest OT system deployed in Ergon Energy. Its primary focus is the operation and control of the HV network.

Ergon Energy has completed upgrading this system to the current software version, as well as
decommissioning legacy field acquisition systems. A number of additional initiatives are underway to improve the efficiency of how the SCADA system is used by the OCC to manage the HV network.

15.2.2 Totem

The SCADA system is critical to the operation of the network, designed for high availability and careful consideration is given as to what is connected to the system. Historically only data points that are immediately useful to OCC operations are connected, reducing system size, cost and complexity. In recognition of this, Ergon Energy is investing in Totem - an alternative platform for the standardised collection and processing of data and devices beyond the scope of the SCADA system and will allow Ergon to explore new solutions for managing the customer facing ends of the power network.

15.2.3 Isolated Systems

Ergon Energy has a number of stand-alone power stations supplying communities isolated from the main grid, in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands, and Palm Island.

We are investing in the secure integration and interconnection of these sites for centralised operation and control within our primary OT environment.

15.2.4 Advanced Power Quality Infrastructure

Ergon Energy’s advanced power quality data collection and analysis tools are hosted and supported within the OT environment, enabling our PQ engineers to focus on the analysis rather than the underlying technology.

15.2.5 Demand Response

Ergon Energy has invested in technology to automate and scale customer-initiated demand response. This builds on the success of Queensland’s load management strategies around hot water and pool pump operation. In addition, further improvements continue to be made to the configuration of the AFLC system to improve efficiency and effectiveness of the system.

15.2.6 Operational Security

Ergon Energy recognises the importance of cyber-security for the power network and its users. We are investing in several projects to improve the security standing of the operational networks and have created a dedicated team to manage cyber security for operational systems.

15.3 Operational Device Management

Ergon Energy is setting down the foundations to enable the smarter network of the future. As a key part of these preparations, the Communications Network Operations Centre (CNOC) has begun accepting operational alarms from select devices in the field, with a view to expand to similar intelligent assets in the future. This increased capability is the first step in an extension of the centres normal activities that traditionally focuses on our communications infrastructure only.

In line with this capability, Ergon Energy is investing in its device configuration management...
system to centralise and standardise configuration management before device quantities are increased as forecasted.

### 15.3.1 Configuration Management System

This project introduces a Configuration Management System (CMS) that is capable of covering all device classes, with the exception of smart meters and core telecommunication devices. The CMS will be configured initially to manage protection devices, as a replacement for the end-of-life, in-house developed Protection Database System.

### 15.4 Investments in 2016-17

Table 36 summarises Ergon Energy’s OT and associated Telecommunication investments for 2016-17.

<table>
<thead>
<tr>
<th>Description</th>
<th>Direct Cost ($M, 2016-17)</th>
</tr>
</thead>
<tbody>
<tr>
<td>End of life radio refurbishment Mackay to Maryborough – P25</td>
<td>$1.9</td>
</tr>
<tr>
<td>End of life radio refurbishment western Queensland – P25</td>
<td>$0.8</td>
</tr>
<tr>
<td>CoreNet Site Infrastructure Replacement Program</td>
<td>$1.3</td>
</tr>
<tr>
<td>CoreNet Active Equipment Replacement</td>
<td>$4.0</td>
</tr>
<tr>
<td>SCADA Upgrade Project</td>
<td>$2.0</td>
</tr>
<tr>
<td>OT Security Projects</td>
<td>$2.1</td>
</tr>
<tr>
<td>Totem Platform</td>
<td>$1.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$7.5</strong></td>
</tr>
</tbody>
</table>

### 15.5 Planned Investments in 2017-18 to 2021-22

Table 37 summarises Ergon Energy’s OT and associated Telecommunication planned investments for 2017-18 to 2021-22.

<table>
<thead>
<tr>
<th>Description</th>
<th>Direct Cost ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>End of life radio refurbishment Mackay to Maryborough – P25</td>
<td>$13.1</td>
</tr>
<tr>
<td>End of life radio refurbishment western Queensland – P25</td>
<td>$2.9</td>
</tr>
<tr>
<td>CoreNet Site Infrastructure Replacement Program</td>
<td>$16.8</td>
</tr>
<tr>
<td>CoreNet Active Equipment Replacement</td>
<td>$34.7</td>
</tr>
<tr>
<td>OT Security Projects</td>
<td>$0.1</td>
</tr>
<tr>
<td>Configuration Management System</td>
<td>$3.1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$15.5</strong></td>
</tr>
</tbody>
</table>
Appendix A – Network Description and Maps

A:1 Planning Regions Overview
A:2 Network GIS Online Maps
A:3 Far North Region
A:4 North Queensland Region
A:5 Mackay Region
A:6 Capricornia Region
A:7 Wide Bay Region
A:8 South West Region
Appendix A. Network Description and Maps

A:1. Planning Regions Overview

Ergon Energy has grouped the network broadly into three planning areas: Northern, Central and Southern as shown in Figure 44 below.

Due to the amalgamation of separate legacy electricity boards, there are six distinct planning regions within these areas, as shown in Table 38 below. The following sections provide a description of the six planning regions.
Appendix A. Network Description and Maps

Table 38: Ergon Energy Network Planning Regions

<table>
<thead>
<tr>
<th>Planning regions</th>
<th>Northern</th>
<th>Central</th>
<th>Southern</th>
</tr>
</thead>
<tbody>
<tr>
<td>Far North</td>
<td>Mackay</td>
<td>Wide Bay</td>
<td></td>
</tr>
<tr>
<td>North Queensland</td>
<td>Capricornia</td>
<td>South West</td>
<td></td>
</tr>
</tbody>
</table>

A:2. Network GIS Online Maps

Network maps covering the entire Ergon Energy area are provided in GIS format in an ESRI GIS Portal accessible via the following weblink:


The map also shows the forecast emerging network limitations. The limitations include: sub-transmission lines, zone substations and primary distribution feeders that are forecast to have limitations.

A:3. Far North Region

The Far North (FN) Queensland region is a tropical environment with high annual rainfall and exposure to summer electrical storms and cyclones. A substantial part of the wet tropics of the FN region is also World Heritage listed, requiring special consideration with regard to the operation and maintenance of any electrical infrastructure. The FN region consists of three main geographic areas with regard to Ergon Energy’s electrical infrastructure.

FN Coastal Area

The FN Coastal area covers the city of Cairns and environs, as well as the townships and surrounding rural areas along the coastal strip of Cardwell, Tully, Mission Beach, Innisfail, Gordonvale and Babinda. The area is served by seven 132/22 kV connection points which are supplied from the Powerlink 132 kV network. In addition the Cairns City and Cairns North 132/22 kV zone substations are supplied via Ergon Energy owned 132 kV dual circuit lines connected to Powerlink’s Woree 275/132 kV connection point.

FN Tablelands Area

The FN Tablelands area is centred on the major rural towns of Atherton and Mareeba and includes the smaller rural communities of Malanda, Millaa Millaa, Ravenshoe, Mt Molloy, Dimbulah and Chillagoe. In addition, the coastal communities of Mossman, Port Douglas and Cooktown are supplied from the Tablelands network. The area is served from the one 132/66 kV connection point, T55 Turkinje substation (located near Mareeba). The Tableland system consists of a 66 kV sub-transmission network, a dual circuit 132 kV transmission line from Turkinje to the Craignie 132/22 kV zone substation near Port Douglas, and a single circuit 132 kV line to the Lakeland 132/66/22 kV substation that supplies the Cooktown area.
Appendix A. Network Description and Maps

FN Western Area

The FN Western system takes in the Georgetown, Normanton, Croydon, and Karumba communities in the Gulf of Carpentaria. The area is served from the Ross connection point in Townsville where a 132 kV single circuit line owned by Ergon Energy to supply this area originates.

A:4. North Queensland Region

The North Queensland (NQ) region is a tropical environment extending from Bowen in the south to Ingham in the north and west to the Northern Territory border. It consists of four main geographic areas with regard to Ergon Energy’s electrical infrastructure.

Townsville Area

The Townsville area covers the city of Townsville and environs, as well as the townships and surrounding rural areas north to and including Ingham. The area is served by five 132/66 kV connection points (one in Ingham and four in Townsville), and one 132/11 kV connection point, which are supplied from the Powerlink 132 kV network. Ergon Energy takes supply at the 66 kV side of Powerlink’s 132/66 kV transformers for five of these connection points, and at the 132 kV terminals of the 132/11 kV transformers at the Alan Sherriff 132/11 kV connection point.

Burdekin/Bowen Area

This area basically covers the coastal strip of the NQ region south of Townsville and is centred around the major rural towns of Ayr and Home Hill in the Burdekin, and the coastal community of Bowen. It also includes the town of Collinsville and its surrounding rural loads. The Burdekin area is served from the one connection point, T193 Clare South, located near the Clare township.

The Bowen system is supplied by the T181 Bowen North connection point, located near the Merinda township and two 66 kV feeders emanating from the T039 Proserpine 132/66 kV connection point which is located in the Ergon Energy Mackay region. Collinsville is supplied at 33 kV from an Ergon Energy 33 kV switching station connected to the T220 Collinsville North connection point.

NQ Midwestern Area

The NQ Midwestern system extends from Charters Towers west to Julia Creek and takes in the towns of Hughenden, Winton and Richmond. All these towns are connected at 66 kV.

Ergon Energy’s Millchester 132/66 kV substation is located on the outskirts of Charters Towers and is supplied by an Ergon Energy owned single circuit 132 kV transmission line from Powerlink’s Ross substation in Townsville. Limited capacity is also available via 66 kV lines from Stuart substation (Townsville) and Clare South substation to Charters Towers substation.

The area west of Charters Towers is supplied by two 66 kV feeders, one from Charters Towers substation and one from Millchester substation, to Hughenden substation. Each of these 250km long feeders goes through a 66 kV voltage regulator at Cape River substation, which is about 100km from Charters Towers.
Appendix A. Network Description and Maps

NQ Western Area

The NQ Western area comprises the Mount Isa and Cloncurry regions, and also the non-regulated network supplying the Carpentaria Minerals Province mining loads.

This network is isolated from the coastal network, which interconnects eastern Australia, and operates outside of the NEM. Our network here is supplied at 132 kV from the Mica Creek Power Station and Diamantina Power Station in Mount Isa. The Duchess Road substation, which services the Mount Isa load, is supplied by two 132 kV feeders from Mica Creek B Yard.

Ergon Energy's Mica Creek 132/220 kV C Yard supplies the Carpentaria Minerals Province mining loads and the Chumvale 220/66 kV substation by two 220 kV feeders. Chumvale substation provides 66 kV supply to Cloncurry's two 66/11 kV substations.

A:5. Mackay Region

The Mackay region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas with regard to electrical infrastructure.

Mackay (Alligator Creek, Proserpine, Pioneer Valley, Mackay) Area

The Mackay area centred on the provincial city of Mackay and extends from the small rural community of Carmila in the south, to the rural township of Proserpine and surrounding area in the north including the tourist destinations of Airlie Beach and Laguna Quays. The coastal strip supply area also provides supply to the Hayman, Hamilton, Daydream, South Molle and Long Islands of the Whitsunday group. The area is served by the two 132/33 kV connection points of Alligator Creek and Mackay and two 132/66 kV connection points of Pioneer Valley and Proserpine, all of which are supplied from Powerlink's 132 kV network. Ergon Energy takes supply at the connection points at the 33 kV or 66 kV sides of Powerlink's transformers.

Bowen Basin (Moranbah) Area

The Bowen Basin area is centred about the mining towns of Moranbah, Glenden and Nebo and includes around 16 major coal mines.

The mines are either supplied from substations connected to the 66 kV supply system from the Moranbah 132/66 kV connection point, the 66 kV supply system from the Kemmis 132/66 kV connection point, or from substations connected to the Powerlink 132 kV network.

A:6. Capricornia Region

The Capricorn region extends from Miriam Vale in the south to Clairview in the north and west to Longreach, including the major provincial centres of Rockhampton and Gladstone. Rockhampton is located just north of the Tropic of Capricorn and is considered the beef capital of Australia. Numerous coal mines are established in the western areas of the region. Major coal fired power stations providing a significant proportion of Queensland's power requirements are located at Stanwell, Callide and Gladstone.

The Capricornia region consists of three operational areas with regard to electrical infrastructure. These are discussed below followed by the maps indicating the limitations in these areas.
Northern Area

The Northern area incorporates the provincial city of Rockhampton and the surrounding coastal area. The Northern area extends from the Capricornia/Mackay regional boundary south to Raglan and west to the Great Dividing Range. The area is served by 11 zone substations, which are supplied from three Powerlink 132/66 kV connection points at T23 Rockhampton, T127 Egans Hill and T061 Pandoin. Ergon Energy takes supply at the connection points at the 66 kV sides of the Powerlink 132/66 kV transformers.

Southern (Biloela, Gladstone) Area

The Southern area takes in the port city of Gladstone and the western communities of Biloela and Moura, extending south to the Capricornia/Wide Bay regional boundary. The Gladstone area is serviced by 10 zone substations supplied from T019 Gladstone South, H067 Calliope River, T199 Yarwun bulk connection points, and Ergon Energy Boat Creek and Gladstone North 132/66 kV substations. Biloela, Moura and surrounding areas are serviced by six zone substations supplied from the T026 Biloela and T027 Moura 132/66 kV bulk connection points. South of the Gladstone area, Ergon Energy has the T166 Granite Creek 132/66 kV substation which then supplies Ergon Energy’s 66/22 kV Agnes Water zone substation. Ergon Energy takes supply from Powerlink at 132 kV for Boat Creek and Gladstone North substations, 66 kV and 11 kV at Gladstone South, 66 kV and 11 kV at Biloela, 66 kV and 22 kV at Moura and 132 kV at Gin Gin to supply Granite Creek.

Western (Lilyvale) Area

The Western area takes in the major rural and mining communities of Emerald, Blackwater, Barcaldine, Clermont and Dysart, along with their surrounding areas. The area extends north to the Capricornia/Mackay/North Queensland regional boundaries, south to the Capricornia/Wide Bay/South West regional boundary and west to the Queensland/Northern Territory/South Australia state border. This area is serviced by 13 zone substations, supplied from the Powerlink connection points of T032 Blackwater, H15 Lilyvale and T035 Dysart, and also Ergon Energy’s T076 Barcaldine. Ergon Energy also takes supply at 11 kV at Moura and Blackwater and at 22 kV at Dysart in addition to the 66 kV supply at these locations.

A:7. Wide Bay Region

The Wide Bay region extends from Yarraman in the south-west to Bundaberg in the north, including the major provincial centre of Maryborough, as well as the Hervey Bay coastal area. The region also includes the Burnett area involving the rural centres of Kingaroy, Gayndah and Mundubbera. The Tarong coal fired power station is also located in the Wide Bay supply area. The HV network in the Wide Bay region consists of both 132 kV and 66 kV sub-transmission networks covering five geographic areas as follows:

132 kV Network

Ergon Energy owns and operates the 132 kV network between the Woolooga, Kilkivan, Teebar Creek, Aramara, Maryborough, Isis, Bundaberg and Gin Gin substations and also owns and operates the 132/66 kV Kilkivan, Maryborough, Isis and Bundaberg substations and the Aramara
Appendix A. Network Description and Maps

132 kV switching station. In the past this 132 kV network was operated in parallel with the Powerlink 275 kV transmission network between the Woolooga and Gin Gin 275/132 kV substations, but with H63 Teebar Creek 275/132 kV bulk supply substation and Aramara 132 kV switching station in service the 132 kV network has been opened normally between T12 Kilkivan and Aramara, and between T131 Isis and T20 Bundaberg. Ergon Energy also owns and operates the 132 kV radial lines supplying the Queensland Rail (QR) substations at Mungar and Clayton.

Bundaberg Area

The Bundaberg area is centred about the provincial city of Bundaberg and also takes in the smaller rural communities of Givelda, Bullyard, South Kolan, Wallaville, Gooburrum, Meadowvale as well as the coastal communities of Bargara and Burnett Heads. The area is served by thirteen zone substations supplied from the Bundaberg 132/66 kV substation. Two 66 kV rings exist; the first, connects the Bundaberg and South Kolan substations, and the other connects the Bundaberg, South Bundaberg, East Bundaberg, Bundaberg Central and West Bundaberg substations.

Tarong Area

South west of Kilkivan is the Kingaroy network area centred about the rural town of Kingaroy and taking in the rural communities of Nanango, Yarraman and Kumbia. The area is served by nine zone substations with the 66 kV supply originating from H18 Tarong 275/132/66 kV Transmission Connection Point (TCP) located in the area. Six of the zone substations were installed to provide supply for Sunwater pumping operations. A 66 kV line connects the Kingaroy substation with the Murgon zone substation that is supplied from the Kilkivan 132/66 kV substation. This line is operated normally open at the Kingaroy substation.

Isis - Maryborough - Kilkivan Area

The Isis area covers the rural communities of Howard, Childers, Farnsfield, Gayndah, Mundubbera and Eidsvold west of Maryborough and is served by nine zone substations. The privately owned Mount Rawdon substation is supplied from a 66 kV spur line off the 66 kV Isis-Gayndah line. The 66 kV network is operated with normally open points at Isis 132/66 kV substation looking towards Bundaberg 132/66 kV substation, Farnsfield zone substation looking towards Givelda zone substation, and at Maryborough 132/66 kV substation looking towards Howard zone substation. A 66 kV ring connects Isis, Childers, Gayndah and Degilbo substations.

The Maryborough area covers the provincial city of Maryborough and rural communities of Owanyilla and Gootchie to the south west, and the Hervey Bay coastal area centred on Point Vernon, Pialba and Torquay. The area is presently served by nine zone substations which are supplied from the Maryborough 132/66 kV substation. The 66 kV network extends north to the Isis 132/66 kV substation area and south west to the Kilkivan 132/66 kV substation area and is operated with normally open points at Maryborough 132/66 kV substation looking towards Howard zone substation, and at Woolooga zone substation looking towards Gootchie zone substation. A 66 kV ring connects Maryborough, Torquay, Pialba and Point Vernon zone substations. Another 66 kV ring supplies Rocky St, Maryborough City, Walkers and Tuan zone substations.

South west of Maryborough is the Kilkivan area. This area takes in the rural communities of Kilkivan, Goomeri, Murgon, Wondai and Proston and is served by four zone substations supplied from the Kilkivan 132/66 kV substation. A 66 kV ring exists connecting the Kilkivan Town and
Appendix A. Network Description and Maps

Murgon substations. A 66 kV line also connects with the Kingaroy substation but is operated normally open at Kingaroy.

A:8. South West Region

The region commences near Toowoomba in the east (just west of the Energex network boundary) and extends west to the South Australian border. The southern boundary of the region is predominantly the New South Wales border (Essential Energy control a region around Goondiwindi). The region consists of three main geographic areas with regard to electrical infrastructure.

Eastern (Toowoomba and Warwick) Area

The Toowoomba/Warwick area covers the provincial city of Toowoomba and environs, and extends south to include Warwick and Stanthorpe. The area is served by the Middle Ridge 330/275/110 kV connection point.

Ergon Energy takes supply at 110 kV from eight Powerlink owned 110 kV feeder bays at the Middle Ridge connection point. These Ergon Energy owned 110 kV feeders supply Ergon Energy’s South Toowoomba, Torrington, Yarranlea, Warwick, and Stanthorpe 110 kV bulk supply substations, and the Kearneys Spring and Toowoomba Central 110/11 kV zone substations.

The T189 Oakey 110/33 kV bulk supply substation, the 110 kV lines and 110 kV bus are owned by Powerlink with Ergon Energy owning the 110/33 kV transformers. A number of 33/11 kV zone substations are then supplied from the 110 kV bulk supply substations mentioned above.

In addition, Ergon Energy takes supply at 33 kV from the Energex owned Postmans Ridge substation. From Postmans Ridge substation two Ergon Energy owned 33 kV lines supply a number of Toowoomba Regional Council water pumping stations as well as Ergon Energy’s Crows Nest zone substation. Another 33 kV feeder bay at Postmans Ridge substation provides a 33 kV contingency supply to the North Street zone substation in Toowoomba.

Central (Dalby/Chinchilla) Area

This area is situated to the north west of Toowoomba and basically covers the towns and surrounds of Dalby and Chinchilla including south to Meandarra, north to Wandoan, and west to about half way between Miles and Roma.

Dalby East substation is supplied via two Ergon Energy owned single circuit 110 kV transmission lines from Powerlink's Tangkam 110 kV switching station. Chinchilla substation is supplied by Powerlink owned double circuit 132 kV line from either Powerlink’s Tarong switchyard or Powerlink’s 275/132 kV Columboola substation. The Columboola 132/33 kV substation connects the Condamine power station into the Chinchilla-Roma 132 kV lines and provides 33 kV supply to the surrounding region including Miles 33/11 kV zone substation.

A number of 33 kV feeders emanate from Dalby, Chinchilla, Miles and Columboola substations to supply the 33/11 kV and 33/22 kV zone substations (and several customer owned 33/0.433 kV substations) in the area.
Appendix A. Network Description and Maps

Roma and Western Area

The Roma and Western system extends from Roma westward and takes in the towns of Charleville, Quilpie, Thargomindah and Cunnamulla. It also extends south of Roma to include the St George and Dirranbandi areas.

Roma substation is supplied via an Ergon Energy owned double circuit 132 kV line from Columboola 132 kV switchyard. A 132/66 kV transformer at Roma substation supplies 66 kV feeders to St George substation and Charleville substation (from which 66 kV feeders to Cunnamulla and Quilpie emanate). A 132/33 kV transformer at Roma substation supplies 33 kV feeders to a number of zone substations in the vicinity including Roma East, Roma West, and Mitchell along with three large distribution 33 kV feeders. The large (in length) 33 kV feeders supply numerous 33/0.433 kV distribution substations 19.1 kV and 12.7 kV SWER systems.

Four 33 kV feeders emanate from St George substation to supply zone and distribution substations along with 19.1 kV and 12.7 kV SWER systems in the area.

Charleville substation is supplied from a single 66 kV feeder from Roma substation. Charleville substation contains 1 x 66/11 kV transformer and 1 x 66/22 kV transformer, and also a 22/11 kV transformer to link the 22 kV and 11 kV busbars and hence provide backup for each of the 66 kV transformers. Local (urban) load is supplied via the 11 kV feeders, and two (rural) 22 kV feeders emanate to supply distribution substations and SWER isolators in the area.

Cunnamulla substation is supplied via a single 66 kV feeder from Charleville substation and contains 1 x 66/11 kV transformer and 1 x 66/22 kV transformer, and also a 22/11 kV transformer to link the 22 kV and 11 kV busbars and hence provide backup for each of the 66 kV transformers. Local (urban) load is supplied via the 11 kV feeders, and three (rural) 22 kV feeders emanate to supply zone and distribution substations and SWER isolators in the area.

Quilpie substation is also supplied via a 66 kV feeder from Charleville substation but only provides 11 kV as a distribution voltage to the region from which duplex SWERs emanate.
Appendix B – Network Capacity and Load Forecasts

B:1 Transmission Connection Point Load Forecast

B:2 Substation Capacity and Load Forecasts

B:3 Sub-transmission Feeder Capacity and Load Forecast

B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points

B:5 Distribution Feeder Limitations Forecast
Appendix B. Network Capacity and Load Forecasts

Detailed forecast results and identified limitations for bulk connection points, zone substations, sub-transmission lines, and distribution feeders are presented via an ESRI GIS Portal and in spreadsheet format via the hyperlinks in this appendix.

All files can also be downloaded directly from the Ergon Energy website at this location: https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal accessible via the following weblink:


B:1 Transmission Connection Point Load Forecast

The detailed load forecasts for TCPs are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link. (Note that TCPs where Ergon Energy owns the power transformers are categorised in this document as bulk supply substations and are included in Appendix B:2).

<table>
<thead>
<tr>
<th>Forecast</th>
<th>Link to Microsoft Excel compatible file and ESRI GIS Portal</th>
</tr>
</thead>
<tbody>
<tr>
<td>TCPs (where Ergon Energy does not own the power transformers)</td>
<td>Transmission-Connection-Point-Forecasts.xls (MS Excel Document, 0.1MB)</td>
</tr>
</tbody>
</table>

Contents

- The tables contained in this spreadsheet include the following information for 50 PoE and 10 PoE loads in Summer and Winter:
  - Ergon Energy region;
  - TNI : NEM - Transmission Node Identity
  - TCP Name : Name of the Transmission Connection Point
  - Forecast Peak Load (MW)
  - Forecast Peak Load (MVARu) (VARu = Volt Amps Reactive Uncompensated, i.e. with stated compensation not active)
  - Forecast Compensation (MVAR).
  - Note: The forecast loads are given exclusive of any connected embedded generation.

Exclusions

Forecast capacity is not provided in this spreadsheet. In the majority of cases, the capacity at the TCP is controlled by the TNSP, and hence reported by them. In the relatively few cases where the
Appendix B. Network Capacity and Load Forecasts

Ergon Energy asset boundary at the TCP is inclusive of power transformers, the substation capacity will appear in the zone or bulk supply substation forecast tables in Appendix B:2.

Embedded generation

Table 39 presents embedded generation connected to the load side of TCPs where Ergon Energy does not own the power transformers. All other embedded generation appears in the substation capacity and load forecasts in Appendix B:2.

Table 39: Embedded Generation Connected to Load Side of TCP

<table>
<thead>
<tr>
<th>Region</th>
<th>Connection Point</th>
<th>Nameplate Rating (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Far North</td>
<td>South Johnstone Mill 22/11 kV Substation, 22 kV</td>
<td>17.3</td>
</tr>
<tr>
<td>Far North</td>
<td>Gordonvale 22 kV Switching Station, 22 kV</td>
<td>13</td>
</tr>
<tr>
<td>Far North</td>
<td>T048 Tully 132/22 kV Substation, Tully Mill 22 kV Feeder</td>
<td>19.8</td>
</tr>
<tr>
<td>Far North</td>
<td>T055 Turkinje 132/66 kV Substation, Dimbulah 66 kV Feeder</td>
<td>7</td>
</tr>
<tr>
<td>North Qld</td>
<td>Pioneer Mill 66 kV Switching Station</td>
<td>67.8</td>
</tr>
<tr>
<td>North Qld</td>
<td>Townsville Power Station 66 kV Switchyard</td>
<td>82</td>
</tr>
<tr>
<td>North Qld</td>
<td>Ingham 66/11 kV Substation, Victoria Mill 66 kV Feeder</td>
<td>24</td>
</tr>
<tr>
<td>Mackay</td>
<td>T38 Mackay 33 kV</td>
<td>30</td>
</tr>
<tr>
<td>Mackay</td>
<td>T141 Pioneer Valley to GLEL Glenella 66 kV Feeder</td>
<td>38</td>
</tr>
<tr>
<td>Mackay</td>
<td>T34 Moranbah 11 kV</td>
<td>12</td>
</tr>
<tr>
<td>Mackay</td>
<td>T34 Moranbah 66 kV</td>
<td>57</td>
</tr>
<tr>
<td>Capricornia</td>
<td>H015 Lilyvale 66 kV</td>
<td>63</td>
</tr>
<tr>
<td>Capricornia</td>
<td>Barcaldine Substation 132 kV</td>
<td>37</td>
</tr>
<tr>
<td>South West</td>
<td>T83 Roma 132 kV</td>
<td>2x45</td>
</tr>
</tbody>
</table>
Appendix B. Network Capacity and Load Forecasts

B:2 Substation Capacity and Load Forecasts

The detailed capacity and load forecasts for bulk supply and zone substations where Ergon Energy owns the power transformers are presented on the ESRI GIS Portal and in Microsoft Excel format via the following link. Where limitations are identified in this table, further explanation is given in Section 8.2.

<table>
<thead>
<tr>
<th>Forecast</th>
<th>Link to Microsoft Excel compatible file and ESRI GIS Portal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk supply and zone substations:</td>
<td>Substation-Forecasts.xls  (MS Excel Document, 4.0MB)</td>
</tr>
<tr>
<td></td>
<td><a href="https://www.ergon.com.au/__data/assets/excel_doc/0004/370237/Substation-Forecasts.xls">https://www.ergon.com.au/__data/assets/excel_doc/0004/370237/Substation-Forecasts.xls</a></td>
</tr>
</tbody>
</table>

Contents

The tables include the following information:

- Region
- Substation name
- Capacity of commissioned Embedded Generation (with Connection Agreements)
- Forecast over the next five years for:
  - Normal Cyclic Capacity - the total capacity with network components and equipment intact
  - Emergency Cyclic Capacity – the long term firm delivery capacity under single contingency conditions
  - Maximum demand (MVA) (50% PoE and 10% PoE)
  - Hours above 95% of maximum demand
  - Expected power factor at peak load
  - Summer and Winter firm capacity
  - The load in MVA which can be transferred to other supply sources (automatically and manually)
  - The time taken to effect the load transfer, or to transfer to the alternative transformer
  - Whether required security is achieved.

Exclusions

- Where transfers or generation are not required to meet Safety Net, available transfer capacity has not been assessed and therefore is not included in the reports.
- Bulk supply substations owned by Powerlink or other NSPs connected to the Ergon Energy network.
- Bulk supply substations dedicated to major customers at which the security criteria are a function of the particular customer connection agreement.
- Bulk supply substations that are shared sites where Ergon Energy does not own the bulk supply power transformers.
- Zone substations owned by Powerlink which provide a connection point at 11 kV or 22 kV to
Appendix B. Network Capacity and Load Forecasts

the Ergon Energy network.

- Zone substations dedicated to major customers at which the security criteria are a function of the particular customer connection agreement.
- Minor zone substations (Maximum demand <0.5 MVA) which are regarded as ‘defacto’ distribution transformers.
- De-rating factors such as transformer cables and bus ratings are not considered in these forecasts. Substation capacity is based on transformer ratings only.
Appendix B. Network Capacity and Load Forecasts

B:3 Sub-transmission Feeder Capacity and Load Forecast

Sub-transmission line capacity and load forecasts for both summer and winter are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link:

<table>
<thead>
<tr>
<th>Forecast</th>
<th>Link to Microsoft Excel compatible file and ESRI GIS Portal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sub-transmission feeder</td>
<td>Subtransmission-Feeder-Forecast.xls (MS Excel Document, 0.5MB)</td>
</tr>
</tbody>
</table>

Information is presented for both current and future forecasts for the relevant network asset.

The sub-transmission line tables include the following information:

- Ergon Energy operational code
- Sub-transmission line name and description
- Rating (Amps)
- Loading (Amps)
- Summer and Winter capacity & load forecasts for five years
- SD = Summer Day (9am to 5pm)
- SE = Summer Evening (5pm to 10pm)
- SN/M = Summer Night/Morning (10pm to 9am)
- WD = Winter Day (9am to 5pm)
- WE = Winter Evening (5pm to 10pm)
- WN/M = Winter Night/Morning (10pm to 9am).

Note:

- Winter - June to August
- Summer - December to February
- All other months are classed as summer - March, April, May, September, October, and November.
Appendix B. Network Capacity and Load Forecasts

B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points

Table 40, Table 41 and Table 42 set out the forecast capacity for the forward planning period for approved future substations, sub-transmission lines and transmission connection points.

Table 40: Forecasts for Future Substations

<table>
<thead>
<tr>
<th>Region</th>
<th>Future Substation</th>
<th>Location</th>
<th>Proposed Commissioning Time</th>
<th>Future Loading Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>SW</td>
<td>Charlton (33/11 kV)</td>
<td>Toowoomba</td>
<td>Dec 2017</td>
<td>Refer Appendix B:2</td>
</tr>
</tbody>
</table>

Table 41: Forecasts for Future Sub-transmission Lines

<table>
<thead>
<tr>
<th>Region</th>
<th>Future Sub-transmission Line</th>
<th>Location</th>
<th>Proposed Commissioning Time</th>
<th>Future Loading Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>Nil approved</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 42: Forecasts for Future Transmission Connection Points

<table>
<thead>
<tr>
<th>Region</th>
<th>Future Transmission Connection Point</th>
<th>Location</th>
<th>Proposed Commissioning Time</th>
<th>Future Loading Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>Nil approved</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
Appendix B. Network Capacity and Load Forecasts

B:5 Distribution Feeder Limitations Forecast

Primary distribution feeders which are currently overloaded or forecast to experience an overload in the next two years are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link:

<table>
<thead>
<tr>
<th>Forecast</th>
<th>Link to Microsoft Excel compatible file and ESRI GIS Portal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution feeder limitations</td>
<td>Distribution-Feeder-Limitations.xls  (MS Excel Document, 0.2MB)</td>
</tr>
</tbody>
</table>

Contents of Table:

The distribution feeder limitation tables include the following information:

- Ergon Energy region
- Distribution feeder name, ID and location
- Load exceedance after two years (MVA)
- Forecast season that exceedance occurs (Summer / Winter)
- Forecast year that exceedance occurs
- Forecast month/s that exceedance occurs
- Load reduction needed to defer the exceedance by 12 months (MW).

Note: assumed power factor of 0.9.

Connection Points for Load Reduction:

In all cases, the connection point to apply load reduction would be downstream of the substation exit feeder cable and/or first section of line.

Possible Solutions:

Refer to Section 8.3 for a list of possible solutions.

Exclusions:

Dedicated customer connection assets are excluded from the analysis.
Appendix C – Worst Performing Feeder Improvement Program
## Appendix C. Worst Performing Feeder Improvement Program

Table 43: Worst Performing Feeders

<table>
<thead>
<tr>
<th>Feeder Asset ID</th>
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<th>Carried Over from 2015-16</th>
<th>WPF Plan Item Status</th>
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<th>Feeder Category</th>
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<th>Customer Number</th>
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<th>3 Yr Avg SAIDI Ratio</th>
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### Appendix C. Worst Performing Feeder Improvement Program

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## Appendix D. NER and DA Cross-Reference

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<tr>
<td>Schedule 5.8 Distribution Annual Planning Report</td>
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<td>12.3 Power Quality Supply Standards, Code Standards and Guidelines</td>
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<td>(b) forecasts for the forward planning period, including at least:</td>
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Appendix D. NER and DA Cross-Reference

National Electricity Rules Version 96
Chapter 5: Network Connection, Planning and Regulation
Schedule 5.8 Distribution Annual Planning Report
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:

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<td>(iii) for zone substations,</td>
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<td>(v) firm delivery capacity for summer periods and winter periods;</td>
<td>Appendix B Network Capacity and Load Forecasts</td>
</tr>
<tr>
<td>(vi) peak load (summer or winter and an estimate of the number of hours per year that 95% of peak load is expected to be reached);</td>
<td>Appendix B Network Capacity and Load Forecasts</td>
</tr>
<tr>
<td>(vii) power factor at time of peak load;</td>
<td>Appendix B Network Capacity and Load Forecasts</td>
</tr>
<tr>
<td>(viii) load transfer capacities; and</td>
<td>Appendix B Network Capacity and Load Forecasts</td>
</tr>
<tr>
<td>(ix) generation capacity of known embedded generating units;</td>
<td>Appendix B Network Capacity and Load Forecasts</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Report Section</th>
<th>B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>(3) forecasts of future transmission-distribution connection points (and any associated connection assets), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation:</td>
<td>B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points</td>
</tr>
<tr>
<td>(i) location;</td>
<td>B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points</td>
</tr>
<tr>
<td>(ii) future loading level; and</td>
<td>B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points</td>
</tr>
<tr>
<td>(iii) proposed commissioning time (estimate of month and year);</td>
<td>B:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Report Section</th>
<th>11.2.1 STPIS Results and Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>(4) forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service target performance incentive scheme; and</td>
<td>11.2.1 STPIS Results and Forecast</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Report Section</th>
<th>2.2 The Electricity Distribution Network</th>
</tr>
</thead>
<tbody>
<tr>
<td>(5) a description of any factors that may have a material impact on its network, including factors affecting:</td>
<td>2.2 The Electricity Distribution Network</td>
</tr>
<tr>
<td>(i) fault levels;</td>
<td>2.2 The Electricity Distribution Network</td>
</tr>
<tr>
<td>(ii) voltage levels;</td>
<td>2.2 The Electricity Distribution Network</td>
</tr>
<tr>
<td>(iii) other power system security requirements;</td>
<td>2.2 The Electricity Distribution Network</td>
</tr>
<tr>
<td>(iv) the quality of supply to other Network Users (where relevant); and</td>
<td>2.2 The Electricity Distribution Network</td>
</tr>
<tr>
<td>(v) ageing and potentially unreliable assets;</td>
<td>2.2 The Electricity Distribution Network</td>
</tr>
</tbody>
</table>
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:

<table>
<thead>
<tr>
<th>Report Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>(b1) for all <em>network</em> asset retirements, and for all <em>network</em> asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset:</td>
</tr>
<tr>
<td>1) a description of the <em>network</em> asset, including location;</td>
</tr>
<tr>
<td>2) the reasons, including methodologies and assumptions used by the <em>Distribution Network Service Provider</em>, for deciding that it is necessary or prudent for the <em>network</em> asset to be retired or de-rated, taking into account factors such as the condition of the <em>network</em> asset;</td>
</tr>
<tr>
<td>3) the date from which the <em>Distribution Network Service Provider</em> proposes that the <em>network</em> asset will be retired or de-rated; and</td>
</tr>
<tr>
<td>4) if the date to retire or de-rate the <em>network</em> asset has changed since the previous <em>Distribution Annual Planning Report</em>, an explanation of why this has occurred;</td>
</tr>
</tbody>
</table>

| To be addressed in the 2018 DAPR |

| (b2) for the purposes of subparagraph (b1), where two or more *network* assets are: |
| 1) of the same type; |
| 2) to be retired or de-rated across more than one location; |
| 3) to be retired or de-rated in the same calendar year; and |
| 4) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination), those assets can be reported together by setting out in the *Distribution Annual Planning Report*: |
| 5) a description of the network assets, including a summarised description of their locations; |
| 6) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets; |
| 7) the date from which the *Distribution Network Service Provider* proposes that the network assets will be retired or de-rated; and |
| 8) if the calendar year to retire or de-rate the network assets has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred; |

| To be addressed in the 2018 DAPR |
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:

(c) information on system limitations for sub-transmission lines and zone substations, including at least:

| (1) | estimates of the location and timing (month(s) and year) of the system limitation; | 8.1 Emerging Network Limitation Maps |
| (2) | analysis of any potential for load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment; | 8.2 Substation and Sub-transmission Limitations and Mitigation Strategies |
| (3) | impact of the system limitation if any, on the capacity at transmission-distribution connection points; | 8.5 Regulatory Investment Test Projects |
| (4) | a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and | 8.5.3 Urgent and Unforeseen Projects |
| (5) | where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include: | |
| (i) | an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1); | |
| (ii) | the relevant connection points at which the estimated reduction in forecast load may occur; and | |
| (iii) | the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation; | |

(d) for any primary distribution feeders for which a Distribution Network Service Provider has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the Distribution Network Service Provider must set out:

| (1) | the location of the primary distribution feeder; | 8.1 Emerging Network Limitation Maps |
| (2) | the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods); | 8.3 Distribution Feeder Limitations |
| (3) | the types of potential solutions that may address the overload or forecast overload; and | 8.4 Distribution Feeder Potential Solutions |
| | | B:5 Distribution Feeder Limitations Forecast |
## Appendix D. NER and DA Cross-Reference

<table>
<thead>
<tr>
<th>National Electricity Rules Version 96</th>
<th>Report Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chapter 5: Network Connection, Planning and Regulation</td>
<td>8.5 Regulatory Investment Test Projects</td>
</tr>
<tr>
<td>Schedule 5.8 Distribution Annual Planning Report</td>
<td></td>
</tr>
<tr>
<td>For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</td>
<td></td>
</tr>
<tr>
<td>(4) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:</td>
<td>8.5.2 Foreseeable RIT-D Projects</td>
</tr>
<tr>
<td>(i) estimate of the month and year in which the overload is forecast to occur;</td>
<td></td>
</tr>
<tr>
<td>(ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload;</td>
<td></td>
</tr>
<tr>
<td>(iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation;</td>
<td></td>
</tr>
<tr>
<td>(e) a high-level summary of each RIT-D project for which the regulatory investment test for distribution has been completed in the preceding year or is in progress, including:</td>
<td>8.5.3 Urgent and Unforeseen Projects</td>
</tr>
<tr>
<td>(1) if the regulatory investment test for distribution is in progress, the current stage in the process;</td>
<td></td>
</tr>
<tr>
<td>(2) a brief description of the identified need;</td>
<td></td>
</tr>
<tr>
<td>(3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);</td>
<td></td>
</tr>
<tr>
<td>(4) if the regulatory investment test for distribution has been completed a brief description of the conclusion, including:</td>
<td></td>
</tr>
<tr>
<td>(i) the net economic benefit of each credible option;</td>
<td></td>
</tr>
<tr>
<td>(ii) the estimated capital cost of the preferred option; and</td>
<td></td>
</tr>
<tr>
<td>(iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and</td>
<td></td>
</tr>
<tr>
<td>(5) any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;</td>
<td></td>
</tr>
<tr>
<td>(f) for each identified system limitation which a Distribution Network Service Provider has determined will require a regulatory investment test for distribution, provide an estimate of the month and year when the test is expected to commence;</td>
<td></td>
</tr>
<tr>
<td>(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address:</td>
<td></td>
</tr>
<tr>
<td>(1) a refurbishment or replacement need; or</td>
<td>(g)(1) will not apply in 2018</td>
</tr>
<tr>
<td>(2) an urgent and unforeseen network issue as described in clause 5.17.3(a)(1).</td>
<td>10.5 Asset Renewal Project Summaries</td>
</tr>
</tbody>
</table>

### Ergon Energy Distribution Annual Planning Report 2017-18 to 2021-22
Appendix D. NER and DA Cross-Reference

<table>
<thead>
<tr>
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<td></td>
</tr>
<tr>
<td>Schedule 5.8 Distribution Annual Planning Report</td>
<td></td>
</tr>
<tr>
<td>For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</td>
<td></td>
</tr>
<tr>
<td>(1)</td>
<td>a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;</td>
</tr>
<tr>
<td>(2)</td>
<td>a brief description of the alternative options considered by the Distribution Network Service Provider in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, generation options, demand side options, and options involving other distribution or transmission networks;</td>
</tr>
<tr>
<td><strong>(h) the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:</strong></td>
<td></td>
</tr>
<tr>
<td>(1)</td>
<td>a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning; 7.10 Joint Planning</td>
</tr>
<tr>
<td>(2)</td>
<td>a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and</td>
</tr>
<tr>
<td>(3)</td>
<td>where additional information on the investments may be obtained;</td>
</tr>
<tr>
<td><strong>(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:</strong></td>
<td></td>
</tr>
<tr>
<td>(1)</td>
<td>a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning; 7.10 Joint Planning</td>
</tr>
<tr>
<td>(2)</td>
<td>a brief description of any investments that have been planned through this process, including the estimated capital cost of the investment and an estimate of the timing (month and year) of the investment; and</td>
</tr>
<tr>
<td>(3)</td>
<td>where additional information on the investments may be obtained;</td>
</tr>
<tr>
<td><strong>(j) information on the performance of the Distribution Network Service Provider’s network, including:</strong></td>
<td></td>
</tr>
<tr>
<td>(1)</td>
<td>a summary description of reliability measures and standards in applicable regulatory instruments; 11 Network Reliability</td>
</tr>
<tr>
<td>(2)</td>
<td>a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines; 12 Power Quality</td>
</tr>
<tr>
<td>(3)</td>
<td>a summary description of the performance of the distribution network against the measures and standards described under subparagraphs (1) and (2) for the preceding year;</td>
</tr>
</tbody>
</table>
### Appendix D. NER and DA Cross-Reference

<table>
<thead>
<tr>
<th>National Electricity Rules Version 96</th>
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<tr>
<td>Chapter 5: Network Connection, Planning and Regulation</td>
<td></td>
</tr>
<tr>
<td>Schedule 5.8 Distribution Annual Planning Report</td>
<td></td>
</tr>
<tr>
<td>For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</td>
<td></td>
</tr>
<tr>
<td>(4) where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned;</td>
<td></td>
</tr>
<tr>
<td>(5) a summary description of the Distribution Network Service Provider's processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and</td>
<td></td>
</tr>
<tr>
<td>(6) an outline of the information contained in the Distribution Network Service Provider's most recent submission to the AER under the service target performance incentive scheme;</td>
<td>11.2 Service Target Performance Incentive Scheme</td>
</tr>
<tr>
<td>(k) information on the Distribution Network Service Provider's asset management approach, including:</td>
<td></td>
</tr>
<tr>
<td>(1) a summary of any asset management strategy employed by the Distribution Network Service Provider;</td>
<td>5 Asset Management Overview 10 Asset Life-Cycle Management</td>
</tr>
<tr>
<td>(1A) an explanation of how the Distribution Network Service Provider takes into account the cost of distribution losses when developing and implementing its asset management and investment strategy;</td>
<td>7.4.3 Consideration of Distribution Losses</td>
</tr>
<tr>
<td>(2) a summary of any issues that may impact on the system limitations identified in the Distribution Annual Planning Report that has been identified through carrying out asset management; and</td>
<td>5 Asset Management Overview 10 Asset Life-Cycle Management 10.4 Specific Plant Replacement Programs 10.6 Asset Condition and System Limitations</td>
</tr>
<tr>
<td>(3) information about where further information on the asset management strategy and methodology adopted by the Distribution Network Service Provider may be obtained;</td>
<td>5.6 Further Information</td>
</tr>
<tr>
<td>(l) information on the Distribution Network Service Provider's demand management activities, including:</td>
<td></td>
</tr>
<tr>
<td>(1) a qualitative summary of:</td>
<td>9 Demand Management Activities</td>
</tr>
<tr>
<td>(i) non-network options that have been considered in the past year, including generation from embedded generating units;</td>
<td></td>
</tr>
<tr>
<td>(ii) key issues arising from applications to connect embedded generating units received in the past year;</td>
<td></td>
</tr>
<tr>
<td>(iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units;</td>
<td></td>
</tr>
<tr>
<td>(iv) the Distribution Network Service Provider’s plans for demand management and generation from embedded generating units over the forward planning period;</td>
<td></td>
</tr>
<tr>
<td>(2) a quantitative summary of the following:</td>
<td></td>
</tr>
</tbody>
</table>
## Appendix D. NER and DA Cross-Reference

### Table 45: DA Cross Reference

<table>
<thead>
<tr>
<th>Distribution Authority No. D01/99</th>
<th>Report Section</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>10.2 Safety Net Targets:</strong></td>
<td></td>
</tr>
<tr>
<td>(b) From 1 July 2014 onwards, the distribution entity will, as part of its Distribution Annual Planning Report, monitor and report on the measures taken to achieve its Safety Net targets.</td>
<td><strong>7.4.2 Safety Net</strong></td>
</tr>
<tr>
<td>(c) From 1 July 2015 onwards, the distribution entity will, as part of its Distribution Annual Planning Report, monitor and report on its performance against its Safety Net targets.</td>
<td><strong>11.6 Safety Net Target Performance</strong></td>
</tr>
<tr>
<td><strong>11.2 Improvement Programs requirements:</strong></td>
<td></td>
</tr>
<tr>
<td>(a) From 1 July 2014 onwards, the distribution entity will, as part of its Distribution Annual Planning Report, monitor and report on the reliability of the distribution entity’s worst performing distribution feeders;</td>
<td><strong>11.5 Worst Performing Feeders Appendix C Worst Performing Feeder Improvement Program</strong></td>
</tr>
<tr>
<td><strong>14.3 Periodic Reports and Plans:</strong></td>
<td></td>
</tr>
</tbody>
</table>

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### National Electricity Rules Version 96

**Chapter 5: Network Connection, Planning and Regulation**

**Schedule 5.8 Distribution Annual Planning Report**

For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:

1. connection enquiries received (under clause 5.3A.5);
2. applications to connect received (under clause 5.3A.9); and
3. the average time taken to complete applications to connect;

- **(m) information on the Distribution Network Service Provider’s investments in** metering or information technology and communication systems which occurred in the preceding year, and planned investments in metering or information technology and communication systems related to management of network assets in the forward planning period; and

- **(n) a regional development plan consisting of a map of the Distribution Network Service Provider’s network as a whole, or maps by regions, in accordance with the Distribution Network Service Provider’s planning methodology or as required under any regulatory obligation or requirement, identifying:**
  1. sub-transmission lines, zone substations and transmission-distribution connection points; and
  2. any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders

---

### 9.4 Demand Management Results for 2016-1

- **13 Metering (will not apply in 2018)**
- **14 Information and Communication Technology**
- **15 Telecommunications and Operational Technology**

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### Ergon Energy Distribution Annual Planning Report 2017-18 to 2021-22
## Appendix D. NER and DA Cross-Reference

<table>
<thead>
<tr>
<th>Distribution Authority No. D01/99</th>
<th>Report Section</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DAPR reporting obligations:</strong></td>
<td>From 1 July 2014 onwards, the distribution entity must report in its Distribution Annual Planning Report on the implementation of its Distribution Network Planning approach under clause 8 Distribution Network Planning.</td>
</tr>
<tr>
<td><strong>Clause 8: Distribution Network Planning</strong></td>
<td>7.4 Network Planning Criteria</td>
</tr>
<tr>
<td>8.1 Subject to clauses 9 Minimum Service Standards, 10 Safety Net and 11 Improvement Programs of this authority and any other regulatory requirements, the distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services.</td>
<td>11 Network Reliability</td>
</tr>
<tr>
<td></td>
<td><strong>Appendix C Worst Performing Feeder Improvement Program</strong></td>
</tr>
</tbody>
</table>
Appendix E – Abbreviations and Definitions
## Appendix E. Abbreviations and Definitions

<table>
<thead>
<tr>
<th>Term/Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 PoE Forecast</td>
<td>Peak load forecast with 10% probability of being exceeded in any year (i.e. a forecast likely to be exceeded only once every 10 years), based on normal expected growth rates and temperature corrected starting loads. 10 PoE forecast load is not to exceed NCC for system normal (network intact) in all cases excepting distribution substations network element category.</td>
</tr>
<tr>
<td>50 PoE Forecast</td>
<td>Peak load forecast with 50% probability of being exceeded in any year (i.e. an upper range forecast likely to be exceeded only once every two years), based on normal expected growth rates and temperature corrected starting loads.</td>
</tr>
<tr>
<td>A7</td>
<td>Artemis (A7) Work Plan: a project management tool that resides within the A7 portfolio suite and allows project management capability when interfaced with Microsoft Project (MSP).</td>
</tr>
<tr>
<td>ABS</td>
<td>Australian Bureau of Statistics</td>
</tr>
<tr>
<td>AC / ac</td>
<td>Alternating Current</td>
</tr>
<tr>
<td>ACR</td>
<td>Automatic Circuit Recloser: an Integrated fault break switch and control system (including protection trip and reclose) suitable for pole mounting.</td>
</tr>
<tr>
<td>ACS</td>
<td>Alternative Control Services: a distribution service provided by Ergon Energy that the AER has classified as an Alternative Control Service under the NER. Includes fee based services, quoted services, Public Lighting Services and Default Metering Services.</td>
</tr>
<tr>
<td>ADMD</td>
<td>After Diversity Maximum Demand</td>
</tr>
<tr>
<td>AEMC</td>
<td>Australian Energy Market Commission</td>
</tr>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>AER</td>
<td>Australian Energy Regulator</td>
</tr>
<tr>
<td>AFLC</td>
<td>Audio Frequency Load Control: a method of switching loads by modulating audio frequency signals transmitted over the powerline.</td>
</tr>
<tr>
<td>AIDM</td>
<td>Asset Inspection and Defect Management</td>
</tr>
<tr>
<td>Bulk Supply Substation</td>
<td>Bulk Supply Substation is a substation that converts energy from transmission voltages to sub-transmission voltages. Note: A Bulk Supply Substation is not a Transmission Connection Point if Ergon Energy owns the incoming ‘transmission voltage’ feeder. Refer to definition of ‘TCP’ and ‘Transmission Network’ below for further explanation.</td>
</tr>
<tr>
<td>BOM</td>
<td>Bureau of Meteorology</td>
</tr>
<tr>
<td>B2B</td>
<td>Business to business</td>
</tr>
<tr>
<td>CA</td>
<td>Capricornia Region</td>
</tr>
<tr>
<td>CAIDI</td>
<td>Customer Average Interruption Duration Index: a network reliability performance index, indicating the interruption duration that each customer experiences on average (minutes) per interruption.</td>
</tr>
<tr>
<td>Capacitor bank (Shunt Capacitor)</td>
<td>An assembly at one location of capacitors and all necessary accessories, such as switching equipment, protective equipment and controls, required for a complete operating installation.</td>
</tr>
<tr>
<td>capex</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>CBRM</td>
<td>Condition-Based Risk Management</td>
</tr>
<tr>
<td>CICW</td>
<td>Customer Initiated Capital Works</td>
</tr>
<tr>
<td>Circuit Breaker (CB)</td>
<td>A mechanical switch device capable of making, carrying and breaking currents under normal circuit conditions as well as making, carrying for a specified time and breaking currents under specified abnormal conditions, such as those of short circuit.</td>
</tr>
<tr>
<td>CIS</td>
<td>Customer Information System</td>
</tr>
</tbody>
</table>
### Appendix E. Abbreviations and Definitions

<table>
<thead>
<tr>
<th>Term/Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Committed Investment</td>
<td>For the purposes of this document a committed investment has received project approval and financial release of funds by the authorised investment governance authority. In accordance with the Ergon Energy Investment Approval Gated Methodology this correlates with project approval and full funding release for an appropriate Gate 3 business case.</td>
</tr>
<tr>
<td>Constraint</td>
<td>A condition whereby a limit, that has been pre-set to a declared criteria, is exceeded. For the purposes of this document a constraint is deemed to be a condition that exceeds the planning and security criteria for each asset class, as determined by Ergon Energy. It should be noted that identification of an asset as ‘constrained’ does not necessarily imply that the integrity or capability threshold of the asset has been compromised.</td>
</tr>
<tr>
<td>Contingency Event</td>
<td>As defined by the NER, ‘an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units or transmission elements’</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
</tr>
<tr>
<td>CT</td>
<td>Current Transformer: a device typically used in protection and metering systems to measure current in primary conductors.</td>
</tr>
<tr>
<td>Customer Minutes</td>
<td>Customer Minutes: a measure of the number of customers interrupted multiplied by the duration of a power outage or outages, incorporating any staged restoration.</td>
</tr>
<tr>
<td>Cyclic Load</td>
<td>Power load that occurs in such a way that periods of overloads are followed by periods of light load. A piece of equipment may be cyclically loaded and the life expectancy will not be reduced if the accelerated rate of deterioration of the insulation during the heavily loaded periods is counterbalanced by the decelerated rate of deterioration during the light loaded periods.</td>
</tr>
<tr>
<td>CymCap</td>
<td>Software by CYME International T&amp;D for calculation of ampacity and temperature rise calculations for power cable installations</td>
</tr>
<tr>
<td>DA</td>
<td>Ergon Energy’s Distribution Authority DO1/99 (DA)</td>
</tr>
<tr>
<td>DAPR</td>
<td>Ergon Energy’s Distribution Annual Planning Report</td>
</tr>
<tr>
<td>DC / dc</td>
<td>Direct Current</td>
</tr>
<tr>
<td>Demand Side Management (DSM)</td>
<td>Demand Side Management: the design and implementation of programs designed to influence customer use of electricity in ways that will produce a desired change in system load shape.</td>
</tr>
<tr>
<td>DNRME</td>
<td>Queensland Department of Natural Resources, Mines and Energy</td>
</tr>
<tr>
<td>DF</td>
<td>Distribution Feeder</td>
</tr>
<tr>
<td>DFD</td>
<td>Distribution Feeder Database</td>
</tr>
<tr>
<td>DINIS</td>
<td>“DINIS” is an integrated data capture and electrical network analysis software package used by Ergon Energy for network modelling, load flow analysis, fault studies, flicker analysis, etc.</td>
</tr>
<tr>
<td>DLC</td>
<td>Direct Load Control</td>
</tr>
<tr>
<td>DM</td>
<td>Demand Management. Alternate term is Non-Network Alternatives (NNA)</td>
</tr>
<tr>
<td>DMS</td>
<td>Distribution Management System</td>
</tr>
<tr>
<td>DNAP</td>
<td>Distribution Network Augmentation Plans</td>
</tr>
<tr>
<td>DNCR</td>
<td>Distribution Network Capability Report</td>
</tr>
<tr>
<td>DNSP</td>
<td>Distribution Network Service Provider</td>
</tr>
<tr>
<td>DR</td>
<td>Demand Reduction</td>
</tr>
<tr>
<td>DRIM</td>
<td>Demand Reduction Incentive Map, where customer demand reduction incentives, reflective of the value of capital deferral and network security risk, will be provided to the market</td>
</tr>
</tbody>
</table>
## Appendix E. Abbreviations and Definitions

<table>
<thead>
<tr>
<th>Term/Acronym</th>
<th>Definition</th>
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<tbody>
<tr>
<td>Dropout Fuse</td>
<td>A fuse in which the fuse carrier drops into a position to provide an isolating distance after the fuse has operated.</td>
</tr>
<tr>
<td>DT</td>
<td>Distribution Transformer</td>
</tr>
<tr>
<td>DTS</td>
<td>Distributive Temperature Sensor</td>
</tr>
<tr>
<td>DUOS</td>
<td>Distribution Use Of System</td>
</tr>
<tr>
<td>EAM</td>
<td>Enterprise Asset Management</td>
</tr>
<tr>
<td>EDNC</td>
<td>Electricity Distribution Network Code (replaced the EIC on 1 July 2015)</td>
</tr>
<tr>
<td>EDO Fuse</td>
<td>Expulsion Drop-Out (EDO) disconnector fuse units</td>
</tr>
<tr>
<td>EECL, Ergon Energy</td>
<td>Ergon Energy Corporation Limited</td>
</tr>
<tr>
<td>EEQ</td>
<td>Ergon Energy Queensland Pty Ltd</td>
</tr>
<tr>
<td>EG</td>
<td>Embedded generating units &gt;30 kVA in size.</td>
</tr>
<tr>
<td>EQL</td>
<td>Energy Queensland Limited</td>
</tr>
<tr>
<td>ERP</td>
<td>Enterprise resource planning: business management software, typically a suite of integrated applications, that a company can use to collect, store, manage and interpret data from many business activities.</td>
</tr>
<tr>
<td>ESRI</td>
<td>Environmental Systems Research Institute</td>
</tr>
<tr>
<td>Fault</td>
<td>1. A defect in any equipment in the system. 2. In an electric power system, a fault is any abnormal electric current. For example, a short circuit is a fault in which current bypasses the normal load. An open-circuit fault occurs if a circuit is interrupted by some failure. In three-phase systems, a fault may involve one or more phases and ground, or may occur only between phases. In a 'ground fault' or 'earth fault', current flows into the earth.</td>
</tr>
<tr>
<td>Feeder Utilisation</td>
<td>Percentage of feeder rating utilised under network maximum demand conditions with thermal rating of the feeder measured at the time and season of maximum demand.</td>
</tr>
<tr>
<td>FFA</td>
<td>Field Force Automation</td>
</tr>
<tr>
<td>FN</td>
<td>Far North region of Queensland</td>
</tr>
<tr>
<td>FPAR</td>
<td>Final Project Assessment Report</td>
</tr>
<tr>
<td>GIS</td>
<td>Geographic Information System: a system that lets users visualize, question, analyse, interpret, and understand data to reveal relationships, patterns, and trends.</td>
</tr>
<tr>
<td>GOC</td>
<td>Government Owned Corporation</td>
</tr>
<tr>
<td>GSL</td>
<td>Guaranteed Service Level</td>
</tr>
<tr>
<td>GSP</td>
<td>Gross State Product: sourced from the ABS website</td>
</tr>
<tr>
<td>GUSS</td>
<td>Grid Utility Support System: an energy storage system developed by Ergon Energy and optimised for Single Wire Earth Return (SWER) systems. The main functions of GUSS are: Peak Load and Voltage support of the SWER. It provides a solution to relieve both capacity and voltage constraints as an alternative to traditional poles, wires &amp; transformer upgrades.</td>
</tr>
<tr>
<td>High Voltage (HV)</td>
<td>1. For distribution networks in Australia, HV normally refers to 11,000 V or higher. 2. For the purpose of the Electrical Safety Act 2002 (Qld), HV is defined as voltage above 1000 V AC or 1500 V DC. 3. HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.</td>
</tr>
<tr>
<td>ICT</td>
<td>Information and Communications Technology</td>
</tr>
<tr>
<td>IT</td>
<td>Isolation Transformer (SWER)</td>
</tr>
<tr>
<td>Joint Workings</td>
<td>A collaboration between Ergon Energy and Energex to jointly work on key initiatives to reduce customer cost and provide a consistent customer experience throughout the State.</td>
</tr>
<tr>
<td>LDC</td>
<td>Line Drop Compensation</td>
</tr>
</tbody>
</table>
### Appendix E. Abbreviations and Definitions

<table>
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<th>Term/Acronym</th>
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<tbody>
<tr>
<td>LiDAR</td>
<td>Light Detection And Ranging. A remote sensing technology that measures distance by illuminating a target with a laser and analysing the reflected light.</td>
</tr>
<tr>
<td>Limitation</td>
<td>See Network Limitation.</td>
</tr>
<tr>
<td>Load Factor</td>
<td>The ratio of the average demand to the peak demand. This gives an indication of the ‘flatness’ of load profile.</td>
</tr>
<tr>
<td>Load Forecast</td>
<td>Forecast loads for a minimum of 10 years based on validated starting loads, forecast growth rates, identified load transfers and block loads.</td>
</tr>
<tr>
<td>Long Rural Feeder (LR)</td>
<td>A feeder which is not a CBD, urban or isolated feeder with a total route length greater than 200km.</td>
</tr>
<tr>
<td>Low Voltage (LV)</td>
<td>1. For distribution networks in Australia, LV is nominally 240/415 V AC, or 230/400 V AC at 50Hz. 2. For the purpose of the electrical safety act, LV is defined as voltage above 32 V AC or 120 V DC (ripple free) and not exceeding 1000 V AC, or 1500 V DC. respectively. 3. HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.</td>
</tr>
<tr>
<td>MARS</td>
<td>Meter Asset Register and Services.</td>
</tr>
<tr>
<td>MAMP</td>
<td>Metering Asset Management Plan</td>
</tr>
<tr>
<td>Maximum Demand (MD)</td>
<td>The maximum electrical load over a set period of time. The figure may be for use with tariff calculations or load surveys and the units may be in; kVA, kW or amps.</td>
</tr>
<tr>
<td>MD</td>
<td>Maximum or Peak Demand</td>
</tr>
<tr>
<td>MDI</td>
<td>Maximum Demand Indicator</td>
</tr>
<tr>
<td>MED</td>
<td>Major Event Day</td>
</tr>
<tr>
<td>Micro EG</td>
<td>Micro embedded generating units which are between 0 to 30 kVA in size as defined in AS4777, which includes inverter energy systems such as solar PV generators</td>
</tr>
<tr>
<td>MK</td>
<td>Mackay region</td>
</tr>
<tr>
<td>MSS</td>
<td>Minimum Service Standards</td>
</tr>
<tr>
<td>N/A</td>
<td>Not available as yet or Not applicable to the requirement</td>
</tr>
<tr>
<td>N-1</td>
<td>The conditions under which all (or a certain percentage) of the electricity load will continue to be supplied under conditions whereby a critical system element is out of service. ‘N’ is all elements in service, ‘N-1’ is with one element (normally one with the highest capacity) out of service. Also known as a credible contingency.</td>
</tr>
<tr>
<td>NAPM</td>
<td>Network Asset Preventative Maintenance</td>
</tr>
<tr>
<td>NCC</td>
<td>Normal Cyclic Capacity</td>
</tr>
<tr>
<td>NECF</td>
<td>National Energy Customer Framework is a set of national laws, rules and regulations governing the sale and supply of energy (electricity and reticulated natural gas) to consumers. Refer to <a href="https://www.dnrme.qld.gov.au/energy">https://www.dnrme.qld.gov.au/energy</a></td>
</tr>
<tr>
<td>NEM</td>
<td>National Electricity Market</td>
</tr>
<tr>
<td>NER</td>
<td>National Electricity Rules</td>
</tr>
<tr>
<td>Network Limitations</td>
<td>A network limitation can be defined as a situation when the HV network is unable to supply electricity to the customer in accordance with the relevant organisational supply standards.</td>
</tr>
<tr>
<td>NGER</td>
<td>National Greenhouse and Energy Reporting Act 2007 (Cth)</td>
</tr>
<tr>
<td>NNA</td>
<td>Non-Network Alternatives. An alternate term is Demand Management</td>
</tr>
<tr>
<td>NODW</td>
<td>Network Operations Data Warehouse</td>
</tr>
<tr>
<td>NOMAD</td>
<td>A 10 MVA mobile substation developed by Ergon Energy for planned work and emergency response.</td>
</tr>
</tbody>
</table>
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<tr>
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<tr>
<td>Net Present Value (NPV)</td>
<td>A calculation that compares the amount invested today to the present value of the future cash receipts from the investment. In other words, the amount invested is compared to the future cash amounts after they are discounted by a specified rate of return.</td>
</tr>
<tr>
<td>NQ</td>
<td>North Queensland region</td>
</tr>
<tr>
<td>OC/EF</td>
<td>Over Current and Earth Fault</td>
</tr>
<tr>
<td>OCC</td>
<td>Operational Control Centres</td>
</tr>
<tr>
<td>OH</td>
<td>Overhead</td>
</tr>
<tr>
<td>OHEW</td>
<td>Overhead Earth Wires</td>
</tr>
<tr>
<td>OLTC</td>
<td>On Load Tap-Changer: A device for changing a transformer’s tapping ratio suitable for operation whilst the transformer is energised or on load. Generally, it consists of a diverter switch with a transition impedance and a tap selector which can be with or without a change-over selector, the whole being operated by the driving mechanism. In some forms of tap-changers, the functions of the diverter switch and the tap selector are combined in a selector switch.</td>
</tr>
<tr>
<td>opex</td>
<td>Operating Expenditure</td>
</tr>
<tr>
<td>OT</td>
<td>Operational Technology (OT) is the information communications technology (ICT) systems, applications, and intelligent power network devices and their data that can directly, or indirectly, monitor, control or protect the power network.</td>
</tr>
<tr>
<td>Power factor (pf)</td>
<td>The ratio of ‘real’ power (W) to total power (VA)</td>
</tr>
<tr>
<td>Power of Choice</td>
<td>Power of Choice was a milestone report from the Australian Energy Market Commission, commissioned by Australia’s Federal, State and Territory energy ministers to help identify ways to help consumers better manage their electricity use and costs. This report has impacted the way in which DNSPs: work on embedded networks, provide metering, interact with the market and provide customer education.</td>
</tr>
<tr>
<td>PoE</td>
<td>Probability of Exceedance</td>
</tr>
<tr>
<td>Powerlink</td>
<td>Queensland Electricity Transmission Corporation Limited</td>
</tr>
<tr>
<td>PQ</td>
<td>Power Quality</td>
</tr>
<tr>
<td>Primary Distribution System</td>
<td>Refers to the 11 kV and 22 kV and in some instances 33 kV electricity supply network.</td>
</tr>
<tr>
<td>PV</td>
<td>PV stands for photovoltaic which is a technical term for solar power generation.</td>
</tr>
<tr>
<td>QCA</td>
<td>Queensland Competition Authority</td>
</tr>
<tr>
<td>QoS</td>
<td>Quality of Supply</td>
</tr>
<tr>
<td>Recloser</td>
<td>A fault-make and break device which monitors the line current and automatically trips for a fault condition. It is fitted with auto reclosing capability.</td>
</tr>
<tr>
<td>RFI</td>
<td>Request For Information</td>
</tr>
<tr>
<td>RIN</td>
<td>Regulatory Information Notice. The AER issues RINs under Division 4 of Part 3 of the National Electricity (Queensland) Law (NEL) to EECL for information collection purposes.</td>
</tr>
<tr>
<td>RIT-D</td>
<td>The RIT-D is a cost-benefit test that electricity distribution network businesses must apply when assessing the economic efficiency of different investment options</td>
</tr>
<tr>
<td>RTD</td>
<td>Resistive Temperature Device</td>
</tr>
<tr>
<td>RTU</td>
<td>Remote Termination Unit. This is a key part of the Supervisory Control and Data Acquisition (SCADA) system used in substations.</td>
</tr>
<tr>
<td>SAIDI</td>
<td>System Average Interruption Duration Index – Network reliability performance index, indicating the total minutes, on average, that customers are without electricity during the relevant period (minutes).</td>
</tr>
<tr>
<td>Term/Acronym</td>
<td>Definition</td>
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<tr>
<td>-------------</td>
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</tr>
<tr>
<td>SAIFI</td>
<td>System Average Interruption Frequency Index – Network reliability performance index, indicating the average number of occasions each customer is interrupted during the relevant period (interruptions).</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory Control and Data Acquisition</td>
</tr>
<tr>
<td>SCI</td>
<td>Statement of Corporate Intent</td>
</tr>
<tr>
<td>SIFT</td>
<td>Substation Investment Forecast Tool, used to produce the demand forecasts</td>
</tr>
<tr>
<td>SKID</td>
<td>Refers to Ergon Energy’s 33/11 kV and/or 66/11 kV skid mounted substations located across the network. The units were developed for longer term emergency/contingency response, and longer term maintenance works at substations without N-1 capacity or sufficient Safety Net contingency.</td>
</tr>
<tr>
<td>SMDB</td>
<td>Statistical Metering Database</td>
</tr>
<tr>
<td>SNAP</td>
<td>Sub-transmission Network Augmentation Plan</td>
</tr>
<tr>
<td>SSI</td>
<td>Sag Severity Index - a value given to a voltage sag based on contours of the CBEMA curve. As voltage sags increase in depth and duration so does the sag severity index reflecting the increasing disturbance of sags as this occurs. SSI is based on the University of Wollongong’s methodology.</td>
</tr>
</tbody>
</table>
| Statcom or Static Synchronous Compensator | A shunt device, which uses force-commutated power electronics, to control power flow and improve transient stability on electrical power networks. In addition, static synchronous compensators are installed in select points in the power system to perform the following: 
  - Voltage support and control 
  - Voltage fluctuation and flicker mitigation 
  - Unsymmetrical load balancing 
  - Power factor correction 
  - Active harmonics cancellation 
  - Improve transient stability of the power system |
| STPIS       | Service Target Performance Incentive Scheme, as documented under *Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme (AER, Nov 2009)* with targets set through the AER’s Distribution Determination process. |
| Substation (S/S or SS) | An assemblage of equipment at one location, including any necessary housing, for the conversion or transformation of electric energy and connection between two or more feeders. |
| Sub-transmission | An intermediate voltage used for connections between transmission connections points / bulk supply substations and zone substations. It is also used to connect between zone substations. Typically sub-transmission voltages are 33 kV and above. (Note however that 33 kV is also used for distribution in some parts of the Ergon Energy network.) |
| Surge Arrester / Surge Diverter | A device designed to protect electrical apparatus from high transient voltage. |
| SVC         | Static VarCompensator |
| SVR         | Step Voltage Regulator |
| SW          | South Western region of Queensland |
| SWER        | Single Wire Earth Return. Distribution to customers using a single wire conductor with the greater mass of Earth as the return path. Used extensively to supply remote rural areas |
| Switchgear  | The combination of electrical disconnects, fuses and/or circuit breakers used to isolate electrical equipment. The use of switchgear is both to de-energize equipment to allow work to be done and to clear faults downstream |
| TAN         | Trade Ally Network. A registry of local, state and national businesses that can assist customers in exploring energy efficiency and demand management opportunities and cashback incentive payment claims. |
## Appendix E. Abbreviations and Definitions

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<tr>
<th>Term/Acronym</th>
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<tbody>
<tr>
<td>Transmission Connection Point (TCP)</td>
<td>Transmission Connection Point: A point at which connection is made between a transmission network and the Ergon Energy network. Otherwise known as a transmission-distribution connection point.</td>
</tr>
<tr>
<td>TF, TX</td>
<td>Transformer</td>
</tr>
<tr>
<td>THD</td>
<td>Total Harmonic Distortion</td>
</tr>
<tr>
<td>THDI</td>
<td>Total Harmonic Distortion Index – THDI is the maximum of the three (one for each phase) 95th percentile THD levels at a site. THDI is expressed as a percentage of the reference voltage.</td>
</tr>
<tr>
<td>TMU</td>
<td>Target Maximum Utilisation</td>
</tr>
<tr>
<td>TNI</td>
<td>Transmission Node Identity</td>
</tr>
<tr>
<td>TNSP</td>
<td>Transmission Network Service Provider</td>
</tr>
<tr>
<td>Transmission Network</td>
<td>Generally, the electricity supply network operating at or above a nominal voltage of 110 kV. However, as Ergon Energy owns some HV assets that might otherwise be owned and operated by a TNSP, clause 9.32.1(b) of the NER provides a permanent derogation in relation to the definition of ‘transmission network’ in Queensland to allow Ergon Energy to own and operate these assets as a DNSP. Hence Ergon Energy does not own or operate a transmission network.</td>
</tr>
<tr>
<td>UG</td>
<td>Underground</td>
</tr>
<tr>
<td>UoSA</td>
<td>Use of System Agreement</td>
</tr>
<tr>
<td>UR</td>
<td>Urban</td>
</tr>
<tr>
<td>V</td>
<td>Volts</td>
</tr>
<tr>
<td>VA</td>
<td>Volt Amps - unit of the vector magnitude of electrical power</td>
</tr>
<tr>
<td>VAR</td>
<td>Volt Amps Reactive - unit of the reactive component of electrical power</td>
</tr>
<tr>
<td>VCR</td>
<td>Value of Customer Reliability – an economic measure of unsupplied energy to customers</td>
</tr>
<tr>
<td>Voltage Regulation</td>
<td>The level of variation in the voltage that occurs at a site</td>
</tr>
<tr>
<td>Voltage Regulator (VR)</td>
<td>A device that controls voltages in the power networks</td>
</tr>
<tr>
<td>Voltage Sag</td>
<td>A temporary reduction of the voltage at a point in the electrical system below 90% of the nominal. The description of voltage sags can be by retained voltage and duration. Voltage sags may last from half a cycle to one minute.</td>
</tr>
<tr>
<td>Voltage Unbalance</td>
<td>A condition in poly-phase systems in which the RMS values of line-to-line voltages (fundamental component) or the phase angles between them are not all equal.</td>
</tr>
<tr>
<td>VT</td>
<td>Voltage Transformer: a device typically used in protection and metering systems to measure voltage in primary conductors.</td>
</tr>
<tr>
<td>W</td>
<td>Watts - unit of the ‘real’ component of electrical power</td>
</tr>
<tr>
<td>WB</td>
<td>Wide Bay region of Queensland</td>
</tr>
<tr>
<td>WPF</td>
<td>Worst Performing Feeder – has meaning in the Ergon Energy Distribution Authority</td>
</tr>
<tr>
<td>Zone Substation (ZS) or (ZSS)</td>
<td>A substation that converts energy from transmission or sub-transmission voltages to distribution voltages.</td>
</tr>
</tbody>
</table>
**Faults Only**
13 22 96  
24 hours a day, 7 days a week

**Life-Threatening Emergencies Only**
Triple zero (000) or 13 16 70  
24 hours a day, 7 days a week