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Further Information

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


Disclaimer

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All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
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Executive Summary

Ergon Energy’s Distribution Annual Planning Report 2018-19 to 2022-23 (DAPR) details the corporation’s future direction and intentions for the next five years in an energy environment characterised by rapid technological change and already high penetrations of both small and utility scale renewable energy resources. These factors are driving the transformation of our ageing network, which connects and spans 97% of the state of Queensland, and will see a return to steady growth over the forecast horizon.

To promote greater understanding of our present environment, this year’s DAPR is a product of extensive revision, alignments and harmonisation of content, aimed at making it easier for readers to access information to support the development of innovative, targeted solutions.

The DAPR provides the community and stakeholders with an insight into the key challenges we face and our responses to them. To address these challenges we often seek customer and industry participation to reach the best outcome. The addition of data on emerging technologies, such as the inclusion of residential solar photovoltaic penetration rates in this year’s DAPR online map, increases the transparency of our network management approach.

Community and Customer Engagement Input to the DAPR

Ergon Energy’s vision as part of the Energy Queensland Group is to ‘energise Queensland communities’, with our purpose of providing ‘safe, secure, affordable and sustainable energy solutions for our customers and communities’. To ensure that we are meeting the unique and diverse needs of our communities, we have been continuously engaging with our customers and other stakeholders to understand their expectations, concerns and suggestions. This engagement has influenced our investment plans for our current regulatory submission and aligns our future thinking with the long-term interests of our customers.

Our current organisational engagement programs include the following:

- Online Engagement
- Customer Council Framework
- Community Leader Forums
- Voice of Customer Program
- Queensland Household Energy Survey

These programs will continue to help further refine our overall strategic direction, and more specifically the network businesses’ investment plans in our Regulatory Proposal for 2020 to 2025.

Safety

Safety is seen by the community as a no compromise area. As our networks age and the risk of equipment failure towards end-of-life increases, our focus on maintaining safety outcomes for our staff, customers and communities is paramount. We are leveraging innovative solutions that enable continuous improvement. We continue to focus on improvements in our maintenance and replacement practices across all asset categories and continue to invest in trialling new technology
that has the potential to deliver improved or more efficient outcomes for our customers. As examples of this commitment; in the last year we have replaced 369km of Low Voltage (LV) copper conductor and our inspection and condition monitoring work has provided the driver behind more than 20 specific component renewal programs.

Affordability

Our customers have told us that affordability is their primary concern – for both cost of living and business competitiveness. Affordability is more than part of our purpose statement, it is a fundamental consideration in how we manage our network. We have implemented a number of savings as part of the merger of Ergon Energy and Energex as part of Energy Queensland. To date these savings across both businesses is expected to be over $460 million which results in lower network prices to Queensland customers. Our forward investment program, reaching into the next regulatory period has been focused on minimising costs to customers, whilst still ensuring that we meet the outcomes that our customers expect. Our Asset Management strategies balance between customers’ need for an affordable, secure, safe, reliable, and high quality electricity supply, and their desire for this service to be provided at minimal cost. A key part of that process is to optimise the economic benefits of network improvement, considering actions beyond the boundaries of the network, such as demand management, embedded generation solutions and other non-traditional approaches.

Security

Energy security has become an increasing area of importance. Our approach to network security is dictated by our Safety Net obligations specified in our Distribution Authority. Overall the Ergon Energy network is performing well against these obligations as result of efficient historical investments in the network and our operational response capability. There were no network events in the 2017-18 period where the Safety Net targets were breached. With regard to managing peak demand, relatively milder ambient temperatures compared to last year across most of regional Queensland over the summer months, resulted in the summer system peak of 2,601MW at 6:00 pm (15/02/2018) and less than the previously recorded highest system peak (2,637MW in February 2017 at 7:30pm).

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. Ergon Energy experienced a total of 13 significant weather events impacting its networks and requiring an escalation of its faults response processes. In February 2018, Moranbah was affected by a major storm and associated flooding on the central coast of the state resulting in 71,228 customers affected. Ergon Energy also activated its major emergency arrangements in response to three tropical cyclones of which one, Tropical Cyclone Nora impacted the coastline in the Far North.

In 2017-18, Ergon Energy’s reliability of supply is forecasting to outperform the Distribution Authority’s Minimum Service Standard (MSS) limits for all six measures. Our overall reliability performance has improved since the inception of MSS in 2005 with both the duration and frequency of overall outages reducing by 45%. This is a reflection of the targeted investment made during the last two regulatory control periods towards achieving the regulated MSS standards.
Executive Summary

Feedback through the development of our regulatory submission has reinforced that customers generally don't want us to improve network performance but expect it to be maintained. Paramount to ensuring long term network security and reliability is ensuring that we maintain a sustainable program of work to deal with network replacement and that we continue to evolve our approach as markets and technology evolves. Cyber security is also an area of increasing focus of all utilities and we continue to evolve our approach as a fundamental part of maintaining network and business security.

Sustainability

Queensland has one of the highest penetrations of solar PV systems on detached houses (30%) in the world. The rapid uptake of solar PV has changed distribution of electricity impacting the LV network and creating a number of system design and operation challenges.

As at the end of June 2018, almost 145,000 solar PV embedded generating systems, from <1kW to 50MW, were connected to the Ergon Energy network with a total installed capacity of approx. 770MW. The volume of solar PV connections over the past 12 months is almost 50% higher than in the previous 12 months, with the total solar PV capacity added being 300% higher, also due to the connection of several large solar farms. Strategic planning initiatives, such as implementation of the 230V LV Standard, will help us manage voltages across the network and enable further uptake of solar PV.

Ergon Energy is supporting the connection of a large number of major renewable energy projects and has established formal connection agreements with major generators that will provide up to 1.1GW of renewable capacity. We are also working with a number of other generation proponents in the application phase that could further extend renewably generation by another 1GW in the coming years.

We continue to transform our networks into an intelligent grid so that our customers can leverage the many benefits of digital transformation and distributed energy resources and other emerging technologies (like solar, battery storage and electric vehicles), as well as the next generation of home and commercial energy management systems. We see this as fundamental to our role in the future and this has been supported by feedback from our customers as part of recent engagements. More importantly we see ourselves increasing our collaboration with our customers and market proponents, to help leverage the benefits of this new technology in our network and help deliver overall improved outcomes for customers.

Fringe of Grid Customers

The Ergon Energy network is typified by long distances and low customer densities. Ergon Energy’s 64,000km Single Wire Earth Return (SWER) network is approximately 40% of Ergon Energy’s distribution network and one of the largest in the world. We are actively engaged with the Queensland Government in looking at the cost of supply into our Western networks, including SWER to look at how technology advances may be able to deliver better customer and economic outcomes in these networks.
2020-25 Regulatory Submission

Ergon Energy will submit Regulatory Proposals to the AER in January 2019. It will explain our plans and the funding for the 2020 to 2025 period. Our capital investment, operating and pricing plans for 2020 to 2025 have been informed by our customers’ preferences and place us in the best position to deliver for Queensland, our industry, our communities and our customers into the future.

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.

Changes from 2017 DAPR

- Chapter 3, Community and Customer Engagement has been updated to include detailed information on our current community and customer engagement activities. Our engagement activities ensure we are meeting the unique and diverse needs of our communities and customers by continuously investing in talking and listening to our customers and other stakeholders about their expectations, concerns and suggestions.

- In 2017 new reporting obligations were introduced [National Electricity Rules (NER) Ch5 Schedule 5.8 (b1) & (b2)] requiring Distribution Network Service Providers (DNSPs) to report on network asset retirements and network asset de-rating that would result in system limitations. To meet these obligations a new sub-section and link to an Excel workbook providing information on proposed Major Asset Replacement Projects and Programs is available in Chapter 7 Section 7.6. There continues to be significant ongoing volumes of work related to many small scale renewal and refurbishment needs, these are described in Chapter 9, Section 9.4.

- Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy) and customer numbers. The methods applied and forecasting results are described in Chapter 5 Network Forecasting. Ergon Energy continues to improve demand and energy forecasting modelling outcomes which are validated by regular audits performed by external forecasting specialists.

- External sources have released forecast similar to last year on the Queensland economy which will see economic growth range between 3.0% to 3.5% from the 2018-19 year, and similarly boosted by improved activities in the volume of commodity and return on exports, tourism, education services, housing, agriculture, and small manufacturing industries, as a result of the relatively competitive lower value of the Australian dollar remaining with low interest rates. In the longer term, there continues to be considerable divergence in forecasts around the strength of the state’s economy.

- 75 distribution feeders will exceed the capacity planning levels (but not necessarily asset capability thresholds to trigger capital investments) within the next two years; this compares to 119 last year. This reduction is largely due to:
  - network improvements, load transfers and demand management
  - improved data accuracy, additional line surveys, analysis and network modelling capabilities
Executive Summary

- different load profiles and feeder growth rates.

- Under contingency conditions, there are six substations with load at risk in the forward planning period (2018-19 to 2022-23).

- Under contingency conditions, there are two sub-transmission feeders with load at risk in the forward planning period (2018-19 to 2022-23).

- There are currently three network limitations currently being addressed through a regulatory investment test for distribution (RIT-D) consultation and six potential RIT-D projects, addressing emerging network limitations having credible options with augmentation or asset replacement components greater than $6 million\(^1\). All RIT-D consultation activities are reported in section 7.7.

- Chapter 4, Asset Management Overview has been updated to align with Energy Queensland strategy. This includes the implementation of a Strategic Asset Management Plan (SAMP) that articulates how organisational objectives are converted into asset management objectives.

- And finally the geospatial interface (ESRI mapping tool) now includes distributed solar PV generation data at the distribution feeder level.

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\(^1\) On 20 November 2018 the AER published a final determination of the 2018 cost threshold review. The AER’s final determination for the distribution thresholds is that: The $5 million capital cost threshold referred to in NER clause 5.15.3(d)(1) be increased to $6 million. This is the cost threshold over which a RIT–D applies; The revised cost thresholds will take effect on 1 January 2019.
Chapter 1

Introduction

1.1 Foreward
1.2 Reporting Requirements
1.3 Network Overview
1.4 Peak Demand
1.5 Changes from 2017 DAPR
1.6 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, non-network initiatives, network investments, customer load and renewable connection support, reliability and supply quality in safe, prudent and efficient operation and management of our power network.

The DAPR supports our commitment to open and transparent customer, community and shareholder engagement. It presents the outcomes from our distribution network service provisions carried out in 2017-18 for the forward planning period 2018-19 to 2022-23 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
- approach to Asset Management and investment governance
- the trend in network demand and our forecasting methodology (energy and load)
- planning framework, including planning criteria and other methodologies
- customer load and renewable connections
- the network’s current and emerging limitations and risk mitigation strategies
- an overview of demand and energy management activities
- approach to Asset Life-Cycle Management and asset renewal
- the network’s reliability performance, including details on Worst Performing Feeders
- the quality of supply being experienced and the network’s power quality performance
- 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 Australian Energy Regulator’s (AER) Distribution Determination, and now extend to the strategies which will underpin our next regulatory proposal for the 2020-21 to 2024-25 control period.

Ergon Energy and Energex are now operating under our parent company Energy Queensland. 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 constraints now highlighted and tables presented in their geospatial context. The ESRI GIS Portal is accessible via the following weblink: [https://www.ergon.com.au/daprmmap2018](https://www.ergon.com.au/daprmmap2018)
Chapter 1. Introduction

1.2 Reporting Requirements

This DAPR has been prepared to comply with NER Rule 5.13 and Schedule 5.8. Clause 5.13.3 is a rule change that came into effect 1 July 2017 requiring DNSPs to submit a Distribution System Limitation template (DAPR template).

The publication of this DAPR is also in compliance with Queensland’s Electricity Distribution Network Code clause 2.2 and Distribution Authority (DA).

The forward planning horizon covers from 2018-19 to 2022-23. The aim of this document is to inform network participants and stakeholder groups about development of the Ergon Energy network, including potential opportunities for non-network solutions – particularly for large investments where the AER’s Regulatory Investment Test for Distribution (RIT-D) applies.

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

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.

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.

**Figure 1: Typical Electricity Supply Chain**

![Diagram of electricity supply chain](image)

---

This figure is simplified. Ergon Energy owns and operates assets at a wide variety of voltages, including:

- Sub-transmission lines at 220kV, 132kV, 110kV, 66kV and some 33kV not classified as distribution feeders
- Bulk Supply and/or Zone Substations at 220/11kV, 132/66kV, 132/33kV, 132/22kV, 132/11kV, 110/33kV, 110/11kV, 66/33kV, 66/22kV, 66/11kV, 33/22kV, 33/11kV, 33/6.6kV, 22/11kV
- MV distribution network, including SWER lines, at 33kV, 22kV, 19.1kV, 12.7kV, 11kV and 6.6kV.

Asset boundaries between Ergon Energy and other parties also vary.
1.4 Peak Demand

The capacity of a network is the amount of electricity it can carry to every customer at any point in time. As electricity cannot be readily stored, the network must have sufficient capacity to deliver power to meet the needs of every customer at any point in time. The demand for electricity at the point in time when prevailing electricity use is at its highest is known as peak demand. Growth in peak demand is a critical part of what drives design and operation of the electricity system. Peak demand occurs at different times in different locations, and this has different implications at different voltage levels of the network. Transmission levels must contain sufficient capacity to carry enough electricity to meet the global peak demand for the region serviced. Whereas, distribution levels of the network must contain sufficient capacity to carry enough electricity to meet peak demand in every street. The points in time that peak demand occurs on assets in each street, is often different to the point in time the peak occurs for the whole region. Therefore, there are varying degrees of diversity in demand between the points in time that peaks occur across each street, and the points in time that peak demands occur on the backbone network.

In a positive demand growth environment, increasing peak demand is a major driver of network costs. Ergon Energy must maintain sufficient capacity to supply every home and business on the day of the year when electricity demand is at its maximum, no matter where those customers are connected in the network. In addition, growth in peak demand may occur where new property developments are being established; whilst over the same period peak demand may be declining in areas where usage patterns are changing due to customer behaviour or from the impacts of alternative sources like solar PV and battery energy storage systems. This means that growth patterns of electricity demand may be flat on a global scale, but there may be pockets of insufficient network capacity emerging in local areas experiencing increasing peak demand or new development.

The Ergon Energy system maximum native demand for 2017-18 was recorded at 2,601MW on Wednesday 15 February 2018 at 6.00pm. This peak demand is lower than the previous highest recorded demand by 36MW (2,637MW in 2016-17).
Chapter 1. Introduction

1.5 Changes from 2017 DAPR

For consultation purposes, Ergon Energy is ensuring the DAPR remains relevant and evolves with ever changing market expectations. To this end, Ergon Energy has made a number of improvements in the 2018 DAPR. These changes aim to make relevant information accessible and understood by all stakeholders, non-network providers and interested parties.

- Chapter 3, Community and Customer Engagement has been updated to include detailed information on our current community and customer engagement activities. Our engagement activities ensure we are meeting the unique and diverse needs of our communities and customers by continuously investing in talking and listening to our customers and other stakeholders about their expectations, concerns and suggestions.

- In 2017 new reporting obligations were introduced [NER Ch5 Schedule 5.8 (b1) & (b2)] requiring DNSPs to report on network asset retirements and network asset de-rating that would result in system limitations. To meet these obligations a new sub-section and link to an Excel workbook providing information on proposed Major Asset Replacement Projects and Programs is available in Chapter 7 Section 7.6. There continues to be significant ongoing volumes of work related to many small scale renewal and refurbishment needs, these are described in Chapter 9, Section 9.4.

- Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy), and customer numbers. The methods applied and forecasting results are described in Chapter 5 Network Forecasting. Ergon Energy continues to improve demand and energy forecasting modelling outcomes which are validated by regular audits performed by external forecasting specialists.

- External sources have released forecast similar to last year on the Queensland economy which will see growth range between 3.0% to 3.5% from the 2018-19 year, and similarly boosted by improved activities in the volume of commodity and return on exports, tourism, education services, housing, agriculture, and small manufacturing industries, as a result of the relatively competitive lower value of the Australian dollar remaining with low interest rates. In the longer term, there continues to be considerable divergence in forecasts around the strength of the state’s economy.

- 75 distribution feeders will exceed the capacity planning levels (but not necessarily asset capability thresholds to trigger capital investments) within the next two years; this compares to 119 last year. This reduction is largely due to:
  - network improvements, load transfers and demand management
  - improved data accuracy, additional line surveys, analysis and network modelling capabilities
  - different load profiles and feeder growth rates.

- Under contingency conditions, there are six substations with load at risk in the forward planning period (2018-19 to 2022-23).

- Under contingency conditions, there are two sub-transmission feeders with load at risk in the forward planning period (2018-19 to 2022-23).

- There are currently three network limitations currently being addressed through a regulatory
Chapter 1. Introduction

investment test consultation and six potential RIT-D projects, addressing emerging network limitations having credible options with augmentation or asset replacement components greater than $6 million\(^3\). All RIT-D consultation activities are reported in section 7.7.

- Chapter 4, Asset Management Overview has been updated to align with Energy Queensland’s strategy. This includes the implementation of a Strategic Asset Management Plan (SAMP) that articulates how organisational objectives are converted into asset management objectives.
- And finally the geospatial interface (ESRI mapping tool) now includes distributed solar PV generation data at the distribution feeder level.

1.6 DAPR Enquiries

We welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au

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\(^3\) On 20 November 2018 the AER published a final determination of the 2018 cost threshold review. The AER’s final determination for the distribution thresholds is that: The $5 million capital cost threshold referred to in NER clause 5.15.3(d)(1) be increased to $6 million. This is the cost threshold over which a RIT–D applies; The revised cost thresholds will take effect on 1 January 2019.
Chapter 2

Ergon Energy Overview

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

2.1 Corporate Overview

Ergon Energy is a subsidiary of Energy Queensland Limited (Energy Queensland), a Queensland Government Owned Corporation (GOC). Energy Queensland was created through the merger of Ergon Energy (both network, Ergon Energy Corporation Limited and retail arms, Ergon Energy Queensland Pty Ltd (EEQ)), Energex Ltd and SPARQ Solutions on 30 June 2016.

2.1.1 Vision

Ergon Energy adopts Energy Queensland’s vision, which is to ‘energise Queensland communities’. This vision provides an opportunity to deliver better outcomes for customers, employees and all Queenslanders enabling Ergon Energy to effectively manage Queensland’s electricity networks and respond to the future needs of the energy market.

In the current environment, our 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 safely deliver secure, affordable and sustainable energy solutions with our communities and customers as shown in Figure 2.

Figure 2: Energy Queensland Vision, Purpose and Values
2.1.3 Energy Queensland Transformation Objectives

To achieve the vision, Energy Queensland’s objectives are as follows:

**Position Energy Queensland to support its local communities**
- Be the preferred provider of energy services through maintaining strong community trust
- Encourage energy efficiency and energy productivity
- Remain an active employer in local communities
- Retain local resources and continue to be a leader in emergency response.

**Achieve sustainable price outcomes for consumers**
- Drive network net savings of more than $562 million through efficiency measures by 2020\(^4\)
- Merger synergies:
  - Functional (indirect) cost improvements
  - Operational (direct) cost improvements.
- Meet or outperform spending allowances set by the independent regulator
- Undertake operational improvements to drive efficiency savings and better customer outcomes.

**Provide long term, sustainable returns to Government**
- Energy Queensland will be self-funding
- Reduce costs for Community Service Obligation payments
- Returns should be comparable to similar Australian and global businesses.

**Position Energy Queensland for growth and adaption to changes in electricity supply sector**
- Establish new Energy Services business to:
  - Offer new products and services to households, businesses and communities in regional Queensland
  - Offer network benefits including peak demand reductions, better network optimisation, and modern and contemporary customer services.

**Drive cultural change to re-position Energy Queensland as a customer-oriented, efficient business**
- Efficient and stable prices for customers
- Customer choice (particularly in regional Queensland)
- High levels of safety, reliability and product excellence
- Innovative asset management strategies to reduce business costs and government subsidies
- Innovative service delivery.

\(^4\) To date EQLSCI/CP have achieved net saving compared to AER of $467 million
2.1.4 Business Function

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.

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 National Electricity Market (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 64,000 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: 11kV, 12.7kV and 19.1kV in configurations as conventional, duplex, triplex and non-isolated SWERs. These systems are supplied by isolated transformers in the size range between 50kVA and 200kVA. 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.

### Table 1: Customer Density Comparison

<table>
<thead>
<tr>
<th>Proportion (%)</th>
<th>How Ergon Energy Compares to Other Distributors</th>
</tr>
</thead>
<tbody>
<tr>
<td>20%</td>
<td>Ergon Energy</td>
</tr>
<tr>
<td>15%</td>
<td>Ergon Energy</td>
</tr>
<tr>
<td>10%</td>
<td>Ergon Energy</td>
</tr>
<tr>
<td>5%</td>
<td>Ergon Energy</td>
</tr>
<tr>
<td>0%</td>
<td>Ergon Energy</td>
</tr>
</tbody>
</table>

**Source:** Huegin Ergon Energy Expenditure Benchmarking.
Chapter 2. Ergon Energy Overview

Ergon Energy also has 33 stand-alone diesel-fired power stations with total installed capacity of 46MW and small amount of solar and wind energy sources. Our isolated systems operate on 33kV, 22kV, 11kV, 6.6kVA, SWER and LV with peaks ranging between 68kW and 4.2MW. 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.

Ergon Energy’s network supplies the full range of end users. The bulk of the customers connected to the network use less than 100MWh of electricity a year – about 84% of these are residential customers and the remaining 16% are small to medium businesses. The network also supplies the majority of the state’s largest energy users.

A summary of our network assets and customer numbers is provided below.

Table 1: Network and Customer 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>Switching Stations</td>
<td>12</td>
</tr>
<tr>
<td>Bulk Supply Substations</td>
<td>30</td>
</tr>
<tr>
<td>Zone Substations (ZS)</td>
<td>288</td>
</tr>
<tr>
<td>Major Power Transformers (33kV to 132kV)</td>
<td>416</td>
</tr>
<tr>
<td>Distribution Transformers</td>
<td>101,000</td>
</tr>
<tr>
<td>Power Poles</td>
<td>973,700</td>
</tr>
<tr>
<td>Overhead Powerlines</td>
<td></td>
</tr>
<tr>
<td>- Sub-transmission</td>
<td>10,700km</td>
</tr>
<tr>
<td>- High Voltage Distribution</td>
<td>115,800km</td>
</tr>
<tr>
<td>- Low Voltage Distribution</td>
<td>16,500km</td>
</tr>
<tr>
<td>Underground Power Cable</td>
<td>8,810km</td>
</tr>
<tr>
<td>Number of Feeders</td>
<td></td>
</tr>
<tr>
<td>- Sub-transmission feeders</td>
<td>333</td>
</tr>
<tr>
<td>- Distribution feeders</td>
<td>1,135</td>
</tr>
<tr>
<td>- Other Feeders</td>
<td>97</td>
</tr>
</tbody>
</table>

| Network Customers                         |       |
|Customers on Urban Network                 | 246,057 |
|Customers on Short Rural Network           | 423,186 |
|Customers on Long Rural Network            | 83,600 |
|**Total Customers**                        | **752,909** |
|Isolated Network Customers                 | 8,321 |

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

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5 Includes island feeders

6 Regulated network customers, as at 30 June 2018, EB RIN T3.4
2.3 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.

2.3.1 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/repair times relative to more dense, urban networks. It also influences infrastructure design criteria and standards, as well as our strategies to respond to incidents on the distribution system; we cannot adopt a one-size-fits-all approach.
Chapter 2. Ergon Energy Overview

The environmental aspects impacting the network include:

- high probability of, and high exposure to cyclones in the coastal northern and far north regions
- high storm and lightning activity
- bushfires, flooding and storm surges
- significant summer-winter and day-night temperature variations
- high rainfall areas (e.g. increases vegetation growth and pole-top rot)
- salt spray in coastal areas resulting in reduced life of assets due to corrosion
- 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
- unstable soil types (e.g. Darling Downs).

2.3.2 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 Product⁷.

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 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.

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⁷ Queensland Budget 2017-18, Budget Strategy and Outlook, Budget Paper No. 2, P4
2.3.3 Social and Demographic Change

As the Australian population ages our customer base across regional Queensland continues to change. We are not only seeing an increasing proportion of people aged 65 years and over retiring, we are also seeing a further generation of primary income earners that have different electricity usage patterns than previous generations. Components of Queensland’s population annual increase to December 2017 comprise; 39.0% from the state itself, 39.1% from overseas and 21.9% from interstate migration. The total annual population state grew by 1.7%, an increase of 0.4% from the previous year. Cairns and Toowoomba had the highest regional growth areas over 1%, in the year to 30 June 2017.8

We track social and demographic change around the way the community is using electricity in the annual Queensland Household Energy Survey (Section 3.2.5). 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 residential energy use and expectations. The increase in 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 at home.

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.

2.3.4 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. 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 in their final decision on Ergon Energy’s Distribution Determination 2015-2020 supported

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8 Australian Government Statistician Office-personal communications.
the targeted deployment of light emitting diode (LED) public lights in a number of areas and meter capability continues to develop and provide additional network and customer functionality.

### 2.3.5 Shareholder and Government Expectations

In 2018-19, Energy Queensland will continue to build on the significant progress made during 2017-18 where the focus was to establish a strong safety culture, build innovation capability to drive business growth, deliver a valued and affordable customer experience and set up our people for success. Energy Queensland will continue to progress the ongoing transformation of its portfolio structure and operating model whilst also recognising the expectations of its shareholders.

In order to effectively respond to the emerging market challenges, Energy Queensland has established four core strategic objectives that have been developed to support the transformation of the network and services to meet the future energy needs of our customers.

These objectives are:

- **Community and customer focused** — maintain and deepen our communities’ trust by delivering on our promises, keeping the lights on and delivering a valued customer experience every time;

- **Operate safely as an efficient and effective organisation** — continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations;

- **Strengthen and grow from our core** — leverage our portfolio business, strive for continuous improvement and work together to shape energy use and improve the utilisation of our assets; and

- **Create value through innovation** — be bold and creative, willing to try new ways of working and to deliver new energy services that fulfil the unique needs of our communities and customer.

Energy Queensland continues to support the Queensland Government’s policy commitment to increasing the contribution of renewable energy to Queensland’s energy mix. This includes setting a target for one million rooftops or 3,000MW of solar PV in Queensland by 2020, and the continual support to connecting large-scale renewable generation to the State’s electricity network.

Similarly, with the support of the Queensland Government, the Energy Queensland continues to facilitate the adoption of emerging technology with on-going Battery Energy Storage System (BESS) trials aimed at investigating how this technology can best benefit the State’s power distribution network and provide greater choice and control for customers.

The Energy Queensland Group is also working to implement further industry reforms driven by the Federal Government, namely the Power of Choice (PoC) program that is being implemented in Queensland with the aim of providing power users with additional options in the way they use electricity, better access to power consumption data and to expand competition in metering and related services.
Chapter 2. Ergon Energy Overview

2.3.6 Community Safety

Community Powerline Safety Strategy 2018-2020

Safety is the number one value for Energy Queensland – safety for our employees, our customers and the community. The Community Powerline Safety Strategy (CPSS) outlines how Energy Queensland, through its network distribution businesses Energex and Ergon Energy Network, will invest and focus activities to build powerline safety awareness, educate and encourage behaviour change in the community and high risk industry sectors throughout 2018-2020.

Our CPSS is a publicly available document, which aims to:

- foster positive and proactive association of powerline safety within the community
- build community awareness of the dangers
- encourage education and behaviour change
- Demonstrate our commitment to community powerline safety.

We continue to target industries at risk, who frequently work in close proximity to powerlines, to raise awareness of the powerline safety dangers.

Information brochures were developed to build on our core ‘Look Up and Live’ and ‘Dial Before You Dig’ messaging. They are being used as part of our education programs targeting the agriculture, building and construction, road transport and aviation sectors, delivered through industry events. Here we again worked closely with these industry’s peak bodies and ‘Dial Before You Dig’. We also collaborated during the year with the Electrical Safety Office and Work Health and Safety Queensland to develop key safety messaging and progress important safety-related legislative reforms.

Statistics are used to focus our efforts in at risk areas. The majority of these remain out of control motor vehicles and road transport accidents; however, there were also a significant number of agricultural industry incidents, largely in regional Queensland, as well as vegetation management, construction and earth moving related incidents.

When it comes to powerline safety, planning and knowledge of the risks are paramount and our team are committed to close personal interaction with our customers and communities. Conducting face-to-face presentations and participating in industry events allows us to interact closely with and gain deeper insights into the mindsets of the community and industry groups. This personal, grassroots approach also provides the opportunity for one-on-one feedback on campaigns, approaches and materials.

Most importantly, our personal approach builds trust and credibility. This is vital to helping targeted community representatives to be receptive to our messages. The measurable outcomes per industry sector will continue to provide a valuable report card on its effectiveness.

2.3.7 Environmental Commitments

Ergon Energy aspires to be an industry leader in environment and cultural heritage as reflected in Energy Queensland’s Health, Safety and Environment Policy. To support this, environment and cultural heritage performance measures are being developed to support improvement. Ergon
Energy is committed to working together with customers, the community and other stakeholders including traditional owners to deliver sustainable energy solutions where all interests are managed.

Ergon Energy’s electricity network traverses diverse environmental and culturally significant areas across the state including coastal, rural, urban and remote landscapes. Under the guidance of our environmental management systems we strive to protect these unique environments whilst providing safe and efficient energy services.

As part of a merged entity, Ergon Energy seeks to integrate, innovate and simplify our ISO14001 certified management system processes to rationalise our operations, improve environmental and cultural heritage performance whilst recognising environmental benefit opportunities in the process.

### 2.3.8 Legislative Compliance

Prior to the establishment of Energy Queensland Limited, Ergon Energy was a Queensland GOC, with shareholding Ministers to whom the Board report. Ergon Energy is now a subsidiary of the GOC Energy Queensland 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 (DNRME), 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.
2.3.9 Economic Regulatory Environment

In accordance with the requirements of the National Electricity Law (NEL) and National Electricity Rules (NER), Ergon Energy is subject to economic regulation by the AER. The AER regulates the revenues of Ergon Energy by setting the annual revenue required we may recover from our customers during each year of the regulatory control period⁹.

The AER applied the following forms of control in this regulatory control period:

- Revenue cap— for services classified as Standard Control Services¹⁰ (SCS).
- Caps on the prices of individual services— for services classified as Alternative Control Services¹¹ (ACS).

For this regulatory control period, the AER reclassified a number of SCSs as ACS, most notably, default metering services, related to types 5 and 6 meters. It should be noted that, as a result of Power of Choice taking effect on 1 December 2017, the installation and delivery of most metering services have become the responsibility of third party service providers¹². However, Ergon Energy still recovers the costs of providing Default Metering Services through daily capital and non-capital charges based on the number and type of meters we provide the customer. These charges are billed to retailers.

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 Service Target Performance Incentive Scheme (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).

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⁹ 2015-2020. Note that customers supplied by Ergon Energy’s isolated generation assets are excluded from the jurisdiction of the AER. The isolated generation zone is regulated by DNRME.

¹⁰ Core distribution services associated with the access and supply of electricity to customers.

¹¹ Are customer specific and/or customer requested services.

¹² The Power of Choice changes only apply to supply networks that are connected to the national grid, and subject to Chapter 7 of the NER. Ergon Energy will remain responsible for metering in our Mount Isa-Cloncurry and Isolated supply networks.
Chapter 3
Community and Customer Engagement

3.1 Overview
3.2 Our Engagement Program
3.3 What We Already Know
3.4 Addressing Customer Concerns
3. Community and Customer Engagement

3.1 Overview

To ensure we’re meeting the unique and diverse needs of our communities and customers we’ve been continuously investing in talking and listening to our customers and other stakeholders about their expectations, concerns and suggestions.

With our industry undergoing a period of rapid transformation, we see an open dialogue as critical to enabling diversity of thought, innovation and, ultimately, more now than ever, better, more sustainable, customer-driven solutions.

We have a long history of operating in partnership with the communities we serve. These ‘conversations’ are fundamental to creating real long-term value for our customers and our business, and for Queensland.

Now, with a strong community mandate in our vision, we’re driving this ‘voice of the customer’ even more deeply into our businesses. To do this we have been rolling out a coordinated, multi-channel community and customer engagement and performance measurement program to extend our business-as-usual (BAU) program of customer, industry partner and community stakeholder engagement activities.

This engagement has been integral to developing our investment plans in this report, aligning our future thinking with the long-term interests of our customers.

Figure 5: Customer and Community Engagement Approach
Chapter 3. Community and Customer Engagement

Our current program of engagement activity will continue to May 2019 to help further refine our overall strategic direction, and more specifically the network businesses’ investment plans in our Regulatory Proposals for 2020 to 2025, and our network tariff reform program.

This chapter provides an overview of these engagement activities and describes how they enable us to put customers at the heart of everything we do. A more comprehensive report will be available in January 2019.

The insight from this engagement is building our understanding of potential future demand and energy usage scenarios. Feedback from our customers, communities and stakeholders are also allowing us to further develop our Asset Management and Distribution strategies in a customer-centric way. It also helps us to collaborate more effectively with our customers, industry partners and community stakeholders in different areas of our capital and operational programs.

An understating of future service expectations is critical to optimising our investment and delivery strategies. Insights are also key to informing our network tariff reform and market reform agenda.

3.2 Our Engagement Program

3.2.1 Online Engagement

To widen our engagement reach we recently launched Talking Energy, a new a digital engagement platform. The site has since provided an efficient and timely mechanism allowing us to engage interested stakeholders and individuals in the energy future conversation, specifically around our investment plans. The site has the stand-alone URL www.talkingenergy.com.au

The site has proven to be an effective tool to interact with targeted stakeholders, as well as a channel to reach a wider audience. Both of which are key to engaging on the issues in front of us and with our vast service area. The digital engagement platform facilitates online information provisions (e.g. newsletters; notification of document releases and events, etc.), as well as direct interactive engagement with interested parties (through idea sharing, surveys, polling, discussions, etc.).

The key piece of activity here has been our Future Energy Survey, which was open to the public and canvased over 2,000 participants. This discussion was about refreshing our service commitments, and planning for the future.
Chapter 3. Community and Customer Engagement

3.2.2 Customer Council Framework

Our engagement with customer advocacy groups was re-energised with the major Customer XChange Forum held in December 2017. Since then we have been engaging proactively through Energy Queensland’s Customer Council, as our flagship listening forum, providing us with a customer centric perspective to look at emerging issues or energy-related solutions for our customers across Queensland.

We also have a Working Group dedicated solely to the Regulatory Proposal and the Tariff Structure Statement. This group has been meeting monthly to both build participants capacity to understand our industry and its regulatory framework, and to explore collaboratively the detail of the matters under consideration.

We are also continuing our BAU Major Customer Forum, Energy Retailer Forum, Public Lighting Forum and Agricultural Forum. We also are continuing to focus on engaging with our other industry partners. This work includes state-wide forums to listen and share knowledge with local electrical contractors and real estate developers, something especially important as we move through this next period of change.

3.2.3 Community Leader Forums

To help us connect with our communities and ensure we are effective at the local level, as part of the move to Energy Queensland, we have established 17 operational areas across the state. Each area has a locally based manager who is familiar with local community stakeholders and the areas unique concerns. This has allowed us to develop local Community Plans to enhance our local participation and build our relationships with our community leaders.

To build on this we have also conducted five Community Leader Forums, with a holistic view for 2020 and beyond. These conversations have involved significant interaction between our managers, who are making the decisions day-to-day about our operations and future plans, and our local stakeholders.

A condensed version of the content of the Community Leader Forum has also been used to engage with the remaining major centres across our 17 areas. This is including engagement with our Local Councils, led by the Area Managers and Asset Planners, to explore the local reality of economic forecasts and deepen our understanding of an area's future town infrastructure and technology plans. We have also initiated numerous follow-up opportunities.

3.2.4 Voice of the Customer Program

The establishment of the Energy Queensland Group has provided an opportunity to refresh our approach to ensure our customers’ voices penetrate more deeply into our business as we work to address our customers’ key concerns.

Our Voice of the Customer program is currently being embedded across the whole of Energy Queensland with best practice near ‘real time’ service performance monitoring at its core. The new program has led from earlier work exploring the strengths and pain points of our service delivery for each customer segment. It has seen a new index established as a corporate performance indicator.
Chapter 3. Community and Customer Engagement

The Customer Index measures customer satisfaction against the key drivers that are specific to each customer group, from our major customers to our residential customers. It is based on specific customer experience surveys that are triggered across all major touch points through our Voice of the Customer tool. Surveys responses are collected and displayed in dashboards to our teams in real time, allowing an immediate response to negative feedback and for us to ‘close the loop’ directly with the customer where appropriate.

This feedback mechanism is supported by our brand tracking research that show us what the wider community, who may or may not have had a recent interaction with us, is thinking in regards to value for money and reliability performance. The results are allowing us to target improvement initiatives, and the necessary cultural change needed to be a truly customer-centric business.

This program is also being used with other targeted research to build a deeper understanding of what our customers will be expecting from us in the future.

3.2.5 Queensland Household Energy Survey

Ergon Energy, in conjunction with Powerlink Queensland, conducts the Queensland Household Energy Survey annually. This online survey captures feedback from 4,500 Queensland households to understand a variety of topics, mainly focusing on energy use through air conditioning and other electrical appliances, energy efficiency behaviours, and emerging customer technologies. It also looks at overall attitudes to electricity prices. This information allows us to plan and deliver our network more efficiently and benchmark network forecasting against consumer trends.

Key findings from the most recent results of the research include:

- The penetration of air conditioning continues to increase across Queensland households. However, there is a slow trend of households moving other heavy energy consuming appliances, such as cook tops and hot water systems, away from electricity to the alternatives.
- An increasing proportion of households want to install solar PV, particularly in South East Queensland (19% of those without solar PV). Awareness of battery storage is growing at an accelerated rate. The number of systems could increase by a factor of 12 to over 22,000 by December 2020.
- At the same time, electric vehicles are growing in popularity with the number of Electric Vehicles (EVs) estimated to increase by a factor of five in the next three years.
- Households increasingly own multiples of the same electronic devices, such as multiple tablets, laptops or gaming consoles. This growing reliance on electronic devices may be an indication of openness to the idea of a Smart Home.

3.2.6 Regulatory Proposal and Tariff Structure Statement Customer Research

We have also conducted additional qualitative research (deliberative forums and focus groups) and quantitative research to explore other elements associated specifically with our future network investments plans and tariff reform journey.

The findings of this research have helped ensure our Regulatory Proposal, and future works programs, are informed appropriately by community and customer concerns. A summary of the research purpose is provided in the table below.
Chapter 3. Community and Customer Engagement

The findings of this research is available from [www.talkingenergy.com.au](http://www.talkingenergy.com.au)

Table 2: Customer and Community Research Topics and Purpose

<table>
<thead>
<tr>
<th>Topic</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Role of Electricity Distribution Networks</td>
<td>• Understand customer perceptions, understanding, and future expectations of Ergon Energy as an electricity distributor.</td>
</tr>
<tr>
<td>(Qualitative)</td>
<td>• Validate customer service commitments and key themes (based on existing research) to research further.</td>
</tr>
<tr>
<td>Cost versus reliability trade off</td>
<td>• Understand customers’ expectations, preferences and trade-offs regarding a number of supply and service elements.</td>
</tr>
<tr>
<td>(Quantitative)</td>
<td>• Understand expectations and tolerance for key measures including, but not limited to, duration and frequency of outages, quality of supply and various service interactions.</td>
</tr>
<tr>
<td></td>
<td>• Understand perceived willingness to forego reliability for electricity cost savings or conversely, willingness to pay more for greater reliability.</td>
</tr>
<tr>
<td></td>
<td>• Understand perceived willingness to have lesser service standards for electricity cost savings or conversely, willingness to pay more for improved service standards.</td>
</tr>
<tr>
<td>Customer investment priorities</td>
<td>• Understand perceptions towards proposed network charges and ranking of investment priorities.</td>
</tr>
<tr>
<td>(Quantitative)</td>
<td></td>
</tr>
</tbody>
</table>
Chapter 3. Community and Customer Engagement

3.3 What We Already Know

The key themes below were identified from the review of our earlier stakeholder engagement and customer research. These summarise the detail we have documented around what our customers and other stakeholders have expressed value or concerns.

A report on our most recent engagement findings will be published on Talking Energy in January 2019.

Figure 6: Key Themes for Customer Engagement

- I am concerned about electricity prices (from either an affordability value or what the future holds perspective).
- We depend on you being there ‘after the storm’ - getting the power back is key to community recovery.
- Understand my needs - be friendly, easy to deal with, and accessible, how and when I want to ‘talk’.
- I have specific needs as a business, industry partner or advocate - work with me to find the solutions.
- Overall I’m relatively happy with the safety, security, reliability of my electricity - outages are managed well.
- I want more choice around my energy solutions OR just make it easy as I really can’t be bothered.
- Focus on innovations, renewable energy and other technologies that address affordability and sustainability.
- You should do the right thing by the community - without it impacting significantly on my bill.
3.4 Addressing Customer Concerns

3.4.1 Affordability

Our customers have told us that affordability is their primary concern – for both cost of living and business competitiveness reasons. This means delivering electricity bill relief without impacting network service standards is a critical outcome.

Feedback from our stakeholders is that they support us ‘front-ending’ our revenue cuts in the next regulatory control period.

As distribution network charges make up around one-third of retail electricity bills in Queensland, our concerted efforts here are aimed at providing our Queensland customers with continued further real price relief as soon as we are able. We also intend to deliver network tariff reforms that are equitable and offer additional savings, value and choice that will reward customers for their role in our state’s energy transformation.

We will make changes whilst being mindful of effectively managing any potential impacts to our customers, especially those customers who are the most vulnerable in our society.

3.4.2 We have forecast a program of proactive savings

In order to deliver the reduction in distribution network charges, Ergon Energy is committed to top down Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) saving targets for the next regulatory control period. These savings will be achieved by a digital transformation of business and network operations through the introduction of new technology. The digitalisation of our business processes will deliver improved work scheduling and corporate processes, improve the operation of our networks and reduce distribution network charges for our customers.

We have applied the cost allocation method that we have submitted to the AER for approval. This means that our expenditure forecasts only include costs that properly relate to the electricity distribution services that Ergon Energy provide.

3.4.3 Our customers have directly influenced our plans

In addition to looking for efficiencies across our operations and continuing to transform our business, we are acting now to place continued downward pressure on our revenues and ultimately distribution network charges over time by managing our assets in line with customer needs and expectations.

1. Corrective Maintenance — Customers expect us to incorporate corrective maintenance expenditure reductions over the forecast period as a result of capital refurbishment programs.

2. Future network focus — We strengthened our future network focus based on customer feedback that emphasised that smart grid was important and hence we have ensured prioritisation of these programs within the capital expenditure forecast.

3. Self-insurance — Our customers said that we should self-insure our network assets and, rather than purchasing insurance, to continue to absorb the cost of damage to our network
in the unplanned maintenance expenditure budget. We will continue to self-insure distribution network assets, including poles, wires and substations.

3.4.4 Safe and secure networks

Safety is seen by the community as a no compromise area. Our top prioritisation of the safety of our communities, customers and staff and our customers is in line with this with a large component of our investments focused on ensuring that safety outcomes are maintained or, where relevant, improved. We continue to leverage new technologies and process improvements to deliver these safety outcomes as cost efficiently as possible.

Our customers expect our networks to be safe, secure and reliable, so that they have electricity when they need it. Most of our customers have told us that they are satisfied with the service levels that they currently receive.

We know that it is also important that we continue to ‘be there for the community after the storm’. Over recent years, following the major cyclone, storm and flood events our state has routinely experienced, we know how important this service is to an impacted community’s rapid recovery.

Our ongoing commitment is to continue our current high levels of service performance by maintaining the resilience of our network and response capability, while targeting expenditure savings. We will continue to improve outcomes where network outages are outside the standard. We need to do this whilst also addressing increasing risks around cyber security and data privacy and meeting discrete areas of strong growth, including from solar and other emerging technologies, across our network. We will do all this by making better use of data and analytics, and through the provision of digital services for our customers; such as by providing more transparent information on load growth and network reliability impacts to ensure our networks continue to meet customer expectations.

By improving network visibility through the implementation of new network monitoring technologies, we will also ensure safety by design with improved capability to sense and predict safety issues. Greater levels of visibility of our network will also improve power quality, outage management and identification and network operation in a high distributed energy resources future.

3.4.5 Sustainable energy solutions

Our plans need to position us well to support sustainable outcomes that are in our customers’ long-term interests. We will continue to investigate the best possible ways to build, maintain and operate our services, connect new customers and technologies, and provide the right information to customers.

We must continue to:

- enable renewable energy connections to support the transition to a low emissions society
- support our customers’ choices about how they want to source and use their energy in the future
- ensure the electricity grid best meets the needs of future generations of Queenslanders and a transforming energy mix with sustainable investment.
Chapter 3. Community and Customer Engagement

We are aligning to the International Standard for Asset Management (ISO 55000) to inform our asset management approach and investment decisions are further underpinned by our corporate Risk Management and Investment Governance Frameworks to ensure sustainable business outcomes.

Queensland is at the forefront in integrating distributed energy resources, renewable energy and other technologies into the grid. Our communities and customers are now benefitting from solar PV systems which enable the export and sharing of surplus energy.

In the future, our customers will have a growing range of choices about sourcing and using energy in different ways as new technologies appear and become more affordable. Our Regulatory Proposals will recognise, inform and facilitate this, and draw on targeted demand management programs to help us lower distribution network charges for all our customers.

3.4.6 Facilitating energy transformation and customer choice

The ways our customers source and use energy, and monitor their energy needs, are all rapidly changing. Our customers are telling us that they want greater choice and control over their energy solutions. Increasing customer choice is transforming the industry as new technologies are embraced to manage energy use and costs, and support action on climate change.

At the same time, we have new technologies available to us in providing network services. Demand management and embedded generation options continue to be a primary consideration when addressing limitations and optimising investment.

We will support sustainability outcomes and our role in enabling renewable energy connections and in transitioning to a low emissions society.

An increasingly connected future, with growing community-based energy solutions and rewards for individuals who provide services that optimise the use of the network, is key to keeping distribution network charges affordable and delivering efficiencies that benefit all.

Our 2020 to 2025 plan is to continue to transform our network into an intelligent grid to leverage digital transformation and effectively integrate the growing range of distributed energy resources. This means we no longer simply manage energy grid costs, but instead look to enable customers to maximise the value of their investments in new technologies while ensuring the grid integrates these effectively and in a manner that is resilient. In doing so we aim to help customers save money on their distribution network charges by reducing the cost to operate and maintain the network.

We are looking to the future and evolving our network to best support customer choice in electricity supply solutions. We will continually innovate to better integrate solar, batteries and other technologies into the network in a way that is cost effective and sustainable.

By transforming our network we will also ensure safety by design with improved capability to sense and predict safety issues, such as broken neutrals. Greater levels of visibility of our networks will improve power quality, outage management and identification and network operation in a high distributed energy resources future.

Our task ahead is to work with our customers to realise the value in this energy network transformation and to ensure the community benefits from today’s and tomorrow’s emerging
Chapter 3. Community and Customer Engagement

technologies.

We have based our demand management plan on what our customers and stakeholders have been telling us they value and we will continue to develop non-network alternatives with our communities, industry partners and customers where they are efficient.

We will continue to review our network planning processes to identify opportunities to increase non-network alternative projects being delivered where they can lower grid costs.

We will work proactively with communities, industry partners and customers to reduce demand in locations with emerging network limitations, to defer the need to build network projects.

3.4.7 Providing timely, affordable and easy network connections

We made more than 40,000 new connections in 2017-18 to our networks across Queensland. We expect these levels to remain stable in the coming years.

We have a connections policy and a connections process that distinguishes between different types of customers based on their specific needs. We have been taking into consideration customer segment impacts and are looking at what, alignment or changes we should put additionally in place.

These include:

- reviewing our connection processes to align where practical across Queensland and ensure they are fit for purpose
- seeking feedback on our proposal to use a 500kVA threshold to distinguish between small and major customer connections coupled at high voltage (HV)
- broadening the scope (in the Energex distribution area) of what will constitute a real estate development connection to align with the definition in the NER
- reviewing the thresholds for embedded generator connections to facilitate an efficient connection process.

3.4.8 Facilitating renewables

We recognise our role in supporting the establishment, growth and integration of renewable energy into our existing electricity distribution networks.

There are around 500,000 solar PV systems connected to our networks across the state, with new uptake still strong. In 2017-18 the level of new solar capacity connected to our networks doubled, compared to the previous year, largely due to the number of commercial and new utility-scale solar farms connecting.

We are continuing to evolve our standards for the connection of solar, batteries and other embedded generation to our distribution networks to best enable the increasing number of systems connected to the network. We will also continue to work with customers to facilitate connections and find options that make costly network upgrades a last resort.

Our proposed future network and network tariffs will further support communities to optimise value, where customers play a role in generating and trading energy between one another. We are
working towards an intelligent grid that enables improved real time information and value exchange through efficient and effective management of an increasingly complex and interconnected energy system. All of our replacement work and new infrastructure will help to gradually build this capability. By transforming our network we will also ensure safety by design with improved capability to sense and predict safety issues. Greater levels of visibility of our network will improve power quality, outage management and identification and network operation in a high distributed energy resources future.

We are using our established experience in managing high levels of solar penetration, and micro-grids and network stability, to inform our approach in this transformation. New smart power electronics devices and energy storage technologies are also being deployed as cost effective alternatives to traditional network augmentation.

New modelling techniques are also being developed to better identify network constraints and opportunities to work with customers in integrating new energy solutions.

By 2020 we will be underway with our transition to a 230V standard for our networks, which will increase the capacity for solar hosting and reduces voltage-related performance issues.
Chapter 4
Asset Management

4.1 Best Practice Asset Management
4.2 Asset Management Policy
4.3 Strategic Asset Management Plan
4.4 Investment Process
4.5 Further Information
4. 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) and
- Investment Process.

4.1 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).

4.2 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.

4.3 Strategic Asset Management Plan

Ergon Energy’s SAMP is the interface that articulates how organisational objectives are converted into asset management objectives as shown in Figure 7. 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.


4.4 Investment Process

4.4.1 Corporate Governance

Ergon Energy has a four-tier governance process to oversee future planning and expenditure on the distribution network as shown in Figure 8.

Central to Ergon Energy’s governance process is legislative compliance. The Government Owned Corporations (GOC) Act requires the submission of a Corporate Plan (CP) and Statement of Corporate Intent (SCI) while the NER requires preparation of the DAPR. The network investment portfolio expenditure forecast is included in the five year CP and SCI.
Chapter 4. Asset Management Overview

Figure 8: Program of Work Governance

The four tiers include:

1. **Asset Management Policy & Strategy**: Alignment of future network development and operational management with Ergon Energy’s strategic direction and policy frameworks to deliver best practice asset management;

2. **Network Investment Portfolio**: Development of seven year rolling expenditure programs and a 12-month detailed program of work (PoW) established through the annual planning review process. The Governing entities oversee:
   - fulfilment of compliance commitments;
   - ensure the network risk profile is managed and aligned to the corporate risk appetite;
   - approval of the annual network Programs of Work and forward expenditure forecasts;

3. **PoW Performance Reporting**: Ergon Energy has specific corporate Key Result Areas (KRA) to ensure the PoW is being effectively delivered and ensures performance standards and customer commitments are being met. Program assurance checks including review of operational and financial program performance is overseen by senior management through the monthly Network Operations Committee to ensure optimal outcomes with appropriate balance between governance, variation impact risks, emerging risks and efficiency of delivery.

   A comprehensive program of work scorecard is prepared monthly and key metrics are included in the Program of Work Delivery Index which is a corporate key performance indicator (KPI) that, with monthly performance reporting for key projects, informs the Executive and Board. Quarterly Program of Work updates are provided to the Board.

4. **Project and Program 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.
4.5 Further Information

Further information on our network management is available on the Ergon Energy website on the following link:

Chapter 5

Network Forecasting

5.1 Forecasting Assumptions
5.2 Electricity Delivered Forecasts
5.3 Substation and Feeder Maximum Demand Forecasts
5.4 System Maximum Demand Forecast
5. Network Forecasting

Forecasting is a critical element of our network planning and has become a difficult and complex task. However it is essential to the planning and development of the electricity supply network because it is the growth in peak demand, at the local and regional level, that is the key driver of investment decisions leading to augmentation of the network.

Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy), and customer numbers. The methods used are described in the following sections. Audits are regularly undertaken by external forecasting specialists on Ergon Energy’s forecasting models. These models continue to improve in their demand and energy forecasting methodologies.

Ten-year energy forecasts are prepared at the total system level, at customer category levels and for certain individual network tariffs. These forecasts are used to determine annual network losses and to establish network tariff prices. The energy forecasts are developed using the latest economic, electricity consumption and technology trend data. Key assumptions used in the development of these forecasts are documented and updated regularly.

In relation to demand, forecasts are not only undertaken at the system level, but are also calculated for all substations and feeders covering a period of 10 years. Growth in peak demand is not uniform across the state therefore these forecasts are used to identify emerging local network limitations and network risks that need to be addressed by either supply side or customer-based solutions. The forecasts then guide the timing and scope of capital expenditure (to expand or enhance the network), or the timing required for demand reduction strategies to be established, or for risk management plans to be put in place. Separate forecast are prepared for customer numbers as a key contributor to its PoW.

5.1 Forecast Assumptions

There are a number of factors which influence forecasts of peak demand, energy, and customer numbers. Assumptions used in the development of the demand and energy models are discussed in the following sections.

5.1.1 Customer Behaviour

Customer behaviour is a primary driver of peak demand and energy forecasts. There are several indicators of customer behaviour, including customer take-up of solar PV and/or battery storage, take-up of energy efficient appliances, the impact of higher electricity prices on customer response and the choices customers make about their use of electricity.

Customer behaviour is challenging to model as it can vary substantially between customer groups and from year to year. The acceptance and impact of solar PV has become more clear in recent years but there is currently too little take-up of other enabling or disruptive technologies such as battery storage and electric vehicles to allow more definitive modelling of impacts on peak demand and energy. Both these examples are expected to be significant but the timelines are little more than speculative.
5.1.2 Solar PV Systems

System types

There are two broad types of solar PV system – the small rooftop type installed by home-owners and small-to-medium commercial business owners, and the large utility-scale solar farm that acts in the same way as a traditional electricity power station.

Small-scale systems are referred to as Micro Embedded Generation Units (MEGUs) and have capacities no greater than 30kVA. These are designed to generate and consume energy primarily within the home with excess energy exported to the rest of the local electricity grid for use by other customers. Commercial-scale installations are larger versions of this, and in some cases consume all generated energy in-house with no export to the grid at all. Utility-scale solar farms are designed to act as generating stations and must be located as near as possible to high-voltage transmission lines and/or zone substations for best connections. There is another form of solar generation called solar thermal which is starting to be approved and constructed. It will perform a major role in the future due to its suitability for integrated energy storage, allowing the entire installation to operate as a baseload generator.

Status

Connected solar PV capacity of all types up to utility-scale, continues to grow at a steady pace. Solar MEGUs are now increasing at an average of 1,100 per month. At 30 April 2018, there were 138,404 solar PV systems connected with total inverter capacity of 729MVA. In terms of all residential customers, the take-up rate is 20.4%.

The cumulative solar PV generating capacity has resulted in daily load profiles that exhibit a ‘hollowed out’ pattern as evident in Figure 9 below. This has reduced afternoon peak demand in a number of areas, some significantly. It can be seen that without solar PV generation, the time of peak would have been earlier and the level higher than the peak that remained in early evening at a lower level. The graph shows that, as solar generation wanes to zero from late afternoon into evening, the demand remaining becomes the de facto peak demand for the day, due to the usual afternoon peak demand having been reduced. This effect is often poorly explained as ‘solar PV having no effect on evening peaks’ when in fact, the evening peaks are what remain after higher afternoon peaks have been reduced by solar PV generation.

The 2017-18 summer system peak occurred at 5.30pm on 15 February 2018. The difference between the peak estimated without any reduction by solar PV generation, and the actual metered peak remaining after reduction by solar PV was 174MW. As can be seen in Figure 9, solar PV generation resulted in a distinctly lower peak demand than would have occurred without its effect. On the third day of the period displayed, the difference was even greater at 245MW.
**Forecasting**

Solar PV’s impact on system peak demand is modelled separately by estimating and removing its historical impact, forecasting its future impact, and re-incorporating it into the overall system forecast.

Embedded rooftop solar PV affects peak demand at a system level; however, at zone substation level there is currently no consistent material effect from solar PV on reducing load for augmentation expenditure purposes. This is partly due to the variable nature of solar PV demand reduction on a year-to-year basis. Additionally, for solar PV generation to defer augmentation expenditure on a substation, the zone substation must consistently have peaks during daylight hours, and have a load growing at a rate for peak demand to reach the substation rated capacity. Although no zone substations have met these requirements to date, they are continually reviewed to address this possible effect.

**Benefits of energy storage**

Greater use of energy storage will have a significant impact on residential substation peak demands regardless of sun shining or time of day. The growing number of solar PV installations located on commercial and industrial buildings will also provide a growing benefit by reducing summer daytime peak demand which coincides with peak solar generation. This is likely to keep rising due to the Queensland Government’s aspirational target of having the equivalent of one
million rooftops or 3,000MW of solar generation installed by 2020.

5.1.3 Electric Vehicles

The widespread take-up of electric vehicles (EVs) and Plug-in Hybrid electric vehicles (PHEVs) has the potential to increase energy and demand forecasts in the future. Currently, the take-up rate of EVs and PHEVs has not been high due to the high initial cost and low availability of models and therefore the impact factored into the System Demand forecast has been relatively small. It is expected that the major part of the take-up will be in South East Queensland (SEQ). The estimated impact of plug-in EVs has been included in the latest forecast for residential zone substations.

5.1.4 Energy (battery) Storage

Customer interest in energy storage systems (batteries of various kinds) is increasing with the number of known energy storage systems in the Ergon Energy network is approximately 1,200 as of May 2018, with a combined storage capacity of over 10MWh. Over the next five to ten years this is likely to change due to several factors: price falls, new technology (safer, higher energy densities, larger capacities), and package-deals of solar PV and battery storage systems promoted by major retailers and solar PV installers. Ergon Energy has adopted a slow but steady reduction in peak demand due to the use of energy storage in the base case scenario forecasts for residential zone substations. The assessment used in the forecasting model is based on the peak day profile and the most likely customer usage pattern. These assumptions will be refined over time as more customers adopt storage systems and their usage data becomes available.

Two impediments exist, and efforts are currently being made to overcome them. The effect of energy storage on customer energy consumption is ‘behind the meter’ which means that it cannot be directly measured to be used for forecasting. Also, registering the capacity of installed energy storage systems is not currently regulated and the information available is therefore far from comprehensive which hampers the ability to develop reasonable forecasting models.

5.1.5 Temperature Sensitive Load and Air conditioning Growth

Temperature sensitive loads such as air conditioning and refrigeration are among the major drivers of peak demand load on the network. On particularly hot days, these loads can add significantly to levels of energy consumption, and more importantly, peak demand.

For some time, growth in air conditioning in the community has been revealed by data supplied by an independent consultancy, as well as the annual Queensland Household Energy Survey (QHES). The modelling process needed in forecasting requires the use of a suitable weather series to relate daily movements in system maximum demand to weather variation. Daily minimum and maximum temperature records are employed in the methodology as part of the regression model that relates weather drivers to system maximum demand. Long-run weather series are also used to derive the 10% Probability of Exceedance (10PoE) and 50 PoE demand figures.

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\textsuperscript{13} from five weather stations:

- Cairns Aero
- Townsville Aero
- Mackay Aero
- Gladstone Radar
- Amberley.

Amberley weather station is used due to its suitability to represent the South-Western region of Ergon Energy’s distribution area. Other weather stations either did not have the necessary 50-year history or had a substantial number of missing values.

In order to calibrate the models using 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.

**Other purposes for weather data**

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

The Himawari-8 weather 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 generation affected by cloud cover, more precise temperature information and instantaneous weather data which could be used for operational purposes during floods or storms.

**Air conditioning**

Air conditioner ownership has risen marginally in the last 12 months\textsuperscript{14}; from 73\% to 75\%. In the same period, ownership in central and northern Queensland eased back marginally, albeit at distinctly higher levels than the southern parts of the state (91\% from 92\%). From the QHES, customers indicated that upgrade by replacement of older systems with split air conditioners is the preferred option to increase numbers per household.

A base case air conditioning forecast produced by consultants has been used in the early testing of the latest system demand model. The air conditioning load base case variable was used in the development of the peak demand forecast model.

\textsuperscript{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.

\textsuperscript{14} Queensland Household Energy Survey 2017, page 76

5.1.6 Economic Growth

A second major driver of forecasts is the level of economic growth across the state. It can be seen from Figure 11 that the Queensland’s economy declined after the high of 5.5% in the 2011-12 financial year, with growth rates dropping to a low of 1.2% in 2014-15 before a slight resurgence to 2.6% the following year. This is well below the long-term average of 4.1% and was largely driven by sharp declines in both private (e.g. mining) and Government investment, significant falls in global commodity prices, and sluggish household spending.

External sources have forecast that the Queensland economy might rise to a growth range as high as 3.0% to 3.5% from the 2018-19 year, boosted by improved activities in the volume of commodity exports, tourism, education services, housing, agriculture, and small manufacturing industries, as a result of the relatively competitive lower value of the Australian dollar and low interest rates. In the longer term, there is considerable divergence in forecasts around the strength of the state’s
economy.

**Figure 11** shows the range of forecasts of Queensland Gross State Product (GSP) developed by a range of forecasting organisations including National Institute of Economic and Industry Research (NIEIR), Deloitte Access Economics (DAE), Queensland Treasury, National Australia Bank, and St. George Bank. The above organisations are considered independent and authoritative sources.

NIEIR and DAE (the only ten-year Queensland forecasts available to Ergon Energy) have forecasts that sit apart by roughly 1%, DAE being the more optimistic. However, Ergon Energy has used NIEIR’s figures currently (in the range of 2.0% to 2.5% per annum), and in the future, forecasts from Deloitte will be used at a more local level for economic growth in the peak demand forecast model.

The current forecasts are based on underlying assumptions: Firstly, GSP measures the aggregate economic activities throughout the whole rather than parts of Queensland, yet the state-wide maximum MW demand is largely influenced by demand in SEQ with its far greater population and commercial / industrial concentration. The new liquefied natural gas (LNG) plants in central Queensland are pushing up the state economy as a whole but have limited impact on economic growth in SEQ or many other regional areas. Secondly, while GSP directly affects business firms, its influence on ordinary households is limited because electricity is a necessary service for them. The majority of households, regardless of their income levels, will use more electricity in the peak period of a hot day (for air conditioning), but won’t use an unnecessary extra amount if temperatures are mild.

**Figure 11: Queensland GSP Growth Forecasts**

![Figure 11: Queensland GSP Growth Forecasts](image.png)

Note: Economic data was sourced from ABS, Deloitte, NIEIR, Queensland Treasury and St George Bank.
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5.1.7 Population Growth

Another driver of forecasts, closely tied to economic growth, is population growth. Queensland population growth has been subdued for the past three years as a direct result of the economic slowdown and reduced employment opportunities. For example, Queensland’s population only increased by 1.2% (in 2014-15), 1.4% (in 2015-16) and 1.6% (in 2016-17). In 2017, Net Overseas Migration (NOM) improved by 31,148 from that of the previous year and Net Interstate Migration (NIM) improved by a similar amount of 31,006.

In terms of future population movements, the main economic institutions such as NIEIR, the Queensland Government Statistician’s Office (QGSO), and DAE, project that population growth is expected to increase over the next few years in SEQ, boosted by a rebound in the state economy (which in turn will attract more inter-state migration and overseas migration) as well as a relatively competitive Australian currency (which in turn, will attract more overseas students and tourist arrivals). Accordingly, Queensland population growth is expected to increase to 1.5% in the 2019-20, and more or less stabilise at that rate over the following eight financial years.

The majority of the Queensland population growth will occur in SEQ (with 68.8% of state population as at the end of June 2016). In Rockhampton and Townsville a negative migration was recorded for both cities. A summary of projected population by location is shown in Figure 12 below.

Figure 12: Queensland Population Projections
In summary, population growth in Queensland will start to regain momentum over the next few years. Customer numbers will continue to increase at a steady rate over the next ten years. Figure 13 illustrates the forecasted total new customer numbers to June 2026.

Figure 13: New Metered Customer Number Growth

![Chart showing new customer numbers over time]

### 5.2 Electricity Delivered Forecasts

New ten-year electricity delivered forecasts are prepared once each year using the latest electricity delivered figures, economic, demographic and weather data. The forecasts are based on customer categories and disaggregated into two major groups – residential and non-residential. Non-residential includes commercial, industrial and rural sectors. The forecasts are used to review and develop network prices for Ergon Energy and Powerlink.

#### 5.2.1 Electricity Delivered versus Electricity Consumed

Electricity delivered (energy) represents the amount of electricity transported through the network, which is measured by customer meters. Electricity consumed is the amount of electricity actually used by customers within their premises, which therefore includes electricity supplied by other resources such as rooftop solar PV generation. Electricity delivered forecasts are a key input into the pricing process.
Solar PV has, and will continue to have, a significant impact on electricity delivered because consumers can use this alternative energy resource to partly (or wholly) offset the amount of electricity delivered by the network. However, it often has little impact on households’ total electricity consumption, since consumption is largely determined by different drivers such as household income, electricity prices and seasonal temperatures – rather than by different supply sources.

The number of solar PV connections had increased strongly over the 2009-10 to 2012-13 period, driven by escalation of electricity prices, solar feed-in-tariffs, environment issues and price reductions in solar panels. However, the growth rate has tapered in the last few years, as a result of the removal of the subsidies offered by the federal government and the policy change of the feed-in-tariff at the state level. Looking ahead, new solar PV connections, as shown in Figure 14, are expected to continue to increase. It is also worth noting that the capacity (in kW) per new installation keeps rising mainly due to cheaper solar panel unit prices. In addition, new non-domestic installation numbers, along with their capacity sizes, will continue to increase as firms also try to partly offset their electricity usage cost. The Queensland Government has a keen focus on renewables and they have a number of initiatives underway, including an aspirational target to have one million rooftops or the equivalent of 3,000MW of solar PV installed by 2020, and Solar 150 – which has a focus on encouraging new large-scale renewable energy projects in Queensland.

Figure 14: Number of Solar PV Installations

![Figure 14: Number of Solar PV Installations](image)

Figure 15 shows the increasing avoided electricity delivered as a direct result of solar PV generation supplied to both residential and non-residential customers. It becomes clear that while electricity delivered will be flat over the next nine years, electricity consumption (i.e. electricity delivered plus electricity generated and used internally) has started to stabilise and will begin to
increase, propelled by the expanding population base, increased household income, and the ‘plateau effect’ in energy efficiency improvements in key electrical appliances. Electricity delivered for the 2016-17 year was 13,332GWh, which was 0.3% below the 2015-16 value.

**Figure 15: Number of Customers and Energy Delivered**

![Diagram showing number of customers and energy delivered from 2010 to 2022, with projected values up to 2022.]

### 5.2.2 Electricity Delivered Forecast Methodology

The adopted approach for forecasting electricity delivered is a combination of statistically based time series analysis, multi-factor regression analysis, and the application of extensive customer knowledge and industry experience. Regression models and consultant reviews are used to substantiate the forecasts, which are separately formulated for each of the following categories:

<table>
<thead>
<tr>
<th>Regional Queensland service area categories</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Residential</td>
</tr>
<tr>
<td>• Commercial</td>
</tr>
<tr>
<td>• Industrial</td>
</tr>
<tr>
<td>• Rural</td>
</tr>
<tr>
<td>• Network tariffs</td>
</tr>
</tbody>
</table>

For each of the categories listed above, forecasts are produced for the total customer numbers and the amount of electricity usage per connection or customer. The forecasts of customer numbers and average usage per customer are then multiplied together to obtain total electricity consumption...
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for each segment. Total system electricity delivered 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 electricity use.

Each category is affected by different underlying drivers for growth. For example, population and income growth are generally of greater significance in driving electricity use in the residential category, whereas GSP growth is more important in the commercial category. Given these sensitivities, Ergon Energy treats 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.

Ergon Energy uses electricity delivered forecasts based on network tariff classes to assist with electricity pricing decisions. This approach follows a similar methodology where average consumption is modelled and multiplied by the number of customers with that tariff. It uses multiple regression techniques. The advantage of this approach is that weather; pricing and solar PV information drivers can be modelled separately giving greater insight into electricity delivered values.

In addition, Ergon Energy has also developed an econometric electricity purchases model that is used at a total system level. This forecast is used to review and compare the bottom-up electricity delivered forecast after accounting for network losses.

5.2.3 Electricity Delivered History and Forecast

In general, growth in electricity consumption lags demographic changes and economic activity by about 9-12 months. A large decrease of 7% in electricity delivered occurred in 2010-11. During the six years from 2011-12 to 2016-17, grew by only 0.2% as shown in Figure 16.

Looking ahead, electricity delivered is expected to be similarly flat over the next nine years to 2025-26, with annual average growth of only 0.2%. This is likely the result of solar PV installations and the continued reduction of some industrial businesses. The most likely change might come from a rebound in regional population growth (driven by a return to possible commercial investment and tourism). In the medium-to-long-term however, downward pressures will weigh on electricity delivered as new technologies, especially battery storage (which normally links to solar PV installation) will provide an alternative source for customers to partly bypass electricity distributors. Over the longer term, electricity delivered growth will also be tempered by reductions in consumption for low income households due to higher electricity prices, but should be partly countered by the potential increase in EV sales, albeit at a slower rate than the South East of the state.
The increase in embedded generation of electricity by solar PV has had a two-fold effect on electricity consumption. Although solar PV does not decrease consumption directly, it may have an impact on electricity usage as customers become more conscious of their consumption patterns, especially for those solar PV customers who lost the benefit of the 44 cents feed-in tariff. Conversely, it does directly affect electricity delivered from the network. Customers can reduce their purchases of electricity by using output generated directly in-house. As detailed in section 5.1.2, solar PV output obviously occurs during daylight hours, automatically reducing electricity consumption during the middle period of the day, but waning in late afternoon. This reduces the load factor, and results in a new, generally lower peak demand for domestic customers that occurs in the early evening, which is the remnant level of demand after reduction of the afternoon peak.

In addition, economic growth is a major driver of electricity consumption. As noted earlier, there are a range of views regarding forecasts of Queensland GSP growth. In summary, while Queensland GSP only increased by 1.98% in 2015-16, it is expected to rise to 2.4% and 2.9% in the 2016-17 and 2017-18 years respectively based on NIEIR’s latest forecasts (low case – as explained above). The forecast GSP figures are a key input into the forecasting process.

All of these factors have been modelled in determining a view on electricity delivered into the future. Based on these changing inputs, it is anticipated that electricity delivered will increase very slowly – with an average annual growth rate of around 0.2% over the next ten-year period.

The contribution of solar PV is included in both residential and non-residential electricity delivered...
forecasts. Electricity generated by solar PV but used internally, is estimated, and when combined with electricity delivered from the network – is the total electricity consumption. Excess solar PV generation exported to the network is included in total electricity purchases. The solar PV forecast shows an ongoing solid rate of growth.

Forecasts for non-residential consumption growth are related to expected changes in GSP and the trend in changing average consumption.

5.3 Substation and Feeder Maximum Demand Forecasts

To ensure security and reliability of supply, capital investment in the distribution network is driven by growth in demand for electricity creating emerging limitations at substations and on feeders. Ergon Energy reviews and updates its temperature-corrected system summer peak demand forecasts after each summer season and each new forecast is 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. Importantly, no distribution network investment is directly driven by the total system peak demand.

Hence individual substation and feeder maximum demand forecasts are prepared to analyse and address limitations for prudent investment decisions. 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 being incorporated into models used for system and substation demand forecasting.

Balanced against this general customer trend, the forecasts produced post-summer 2017-18 have provided a range of demand growth rates. The forecasts are used to identify network limitations and then investigate the most cost-effective solution which may include increased capacity, load transfers or demand management alternatives. The distribution of growth rates for zone substations are shown in Figure 17.
While growth in demand continues to increase very slowly at a system level, there can be significant growth at a localised substation level.

In the 2018-23 period, 74% of substations have a zero average compound growth rate and 20% have just 0.5% to 1.0% growth. However, five substations have growth rates ranging from 5.5% to almost 12% which will necessitate close attention very soon.

Ergon Energy has incorporated demand management initiatives into the summer and winter substation forecasts. The initiatives include broad application of air conditioning control, pool pump control and hot water control capability. Demand management is also being targeted at substations with capacity limitations in an effort to defer capital expenditure. The approach used is to target commercial and industrial customers with incentives to reduce peak demand through efficiency and power factor improvements. The resulting reductions are captured in the Substation Investment Forecasting Tool (SIFT) and in the ten-year peak demand forecasts.

These forecasts underpin the detailed analysis provided in Appendix D of the DAPR.

The ten-year substation peak demand forecasts are prepared at the end of summer and are produced within SIFT. To enable appropriate technical evaluation of network limitations, these forecasts are completed for both existing and proposed substations. The forecasts are 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.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demand. Although there are limited numbers installed at this time, increasing penetration of solar PV at C&I
premises will provide benefits through reduced substation and feeder peak demands. There is also an impact by solar PV on feeders that have a mixed load of C&I and residential connections. Feeders that are predominantly residential exhibit load profiles that are ‘hollowed out’ in the afternoons, which generally results in the reduction of the peak demand that would have occurred without solar PV generation to offset it. The remaining shoulder of the modified afternoon peak demand then becomes the de facto peak demand for the day, which occurs in the early evening when solar generation has fallen. It is misleading to refer to this as ‘shifting the peak to the evening when solar PV has no effect’ – the peak that occurs in the evening is directly due to solar generation having ‘clipped’ the afternoon peak. The result is generally a lower peak demand.

5.3.1 Substation Forecasting Methodology

Ergon Energy employs a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts using validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. It also uses a feedback process with regional planning engineers (Delphi process) to review, discuss and agree upon growth rates and temperature-corrected starting points for the new forecast. This ensures the best forecast outcome using the local knowledge of planners in the absence of well-defined economic and demographic drivers which are not available at the level of individual zone substations.

Peak demand forecasts are produced for each zone substation for summer and winter seasons. The forecasts are calculated at the 10 PoE and 50 PoE levels and are projected forward for ten 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 ten years in advance.

Larger block loads are included separately after validation for size and timing by Asset Managers. The zone substation peak demand forecasts are then aggregated up to the ten-year bulk supply point and transmission connection point demand forecasts, which take into account diversity of individual zone substation peak demands (coincidence factors) 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 ten-year substation demand forecast is briefly described as follows:

- Validated uncompensated substation peak demands are determined for the most recent summer period
- Minimum and maximum temperature 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 (Cairns Aero, Townsville Aero, Mackay Aero, Gladstone Radar, and Amberley). The best-fit relationship is used to determine the temperature adjustment.

- Substations classified as industrial tend not to be sensitive to temperature and the 50 PoE and 10 PoE adjustments are therefore 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 (MVA), real power (MW) and reactive power (MVAr) are calculated for four periods – summer day, summer night, winter day and winter night.
- Demographic and population analysis is undertaken, customer load profiles are prepared, and checks made against customer connections and changes in population across the different regions.
- Expected impact and growth in solar PV, battery storage, and plug-in EVs have been included at the substation level.
- Year-on-year peak demand growth rates are determined from the customer load profiles, 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 with Asset Managers before inclusion in the forecast.
- Size and timing of load transfers are also reviewed with Asset Managers before inclusion in the forecast.
- Timing and scope of proposed transmission connection projects are reviewed with development planners before inclusion in the forecast.
- The growth rates, block loads, transfers and transmission projects are applied to the starting values to determine the forecast demand for each of the ten years starting from a coincident demand basis.
- Zone substation forecast peak demands are aggregated up to transmission connection point demands through 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 ten-year forecast period.
- Substation peak demand forecasts are reviewed each season and compared with previous forecasts. The relative error between recorded demand and the forecast is investigated for the most recent season. The substation forecast modelling tool can differentiate between approved and proposed projects in the process. However, to comply with the NER, the forecasts provided in the DAPR include approved projects only.
5.3.2 Transmission Feeder Forecasting Methodology

A simulation tool is used to model the 110 kV and 132 kV transmission network. The software was selected to align with tools used by Powerlink and the Australian Energy Market Operator (AEMO). Powerlink provides a base model on an annual basis. This base model is then refined to incorporate future network project components, and is uploaded with peak forecast loads at each bulk supply and connection point zone substation from SIFT.

Twenty models are created using this simulation tool, with each model representing the forecast for a particular season in a particular year. The models have five years of summer day 50 PoE and 10 PoE data and five years of winter night 50 PoE and 10 PoE data.

5.3.3 Sub-transmission Feeder Forecasting Methodology

Forecasts for sub-transmission feeders 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.

Modelling and simulation is used 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. A software tool models the 33kV sub-transmission network. The simulation tool has built-in support for network development which provides a variable simulation timeline that allows the modelling of future load and projects into a single model.

Ergon Energy combines 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.

5.3.4 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
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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 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 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 to determine approximate 10 and 50 PoE load levels, is extracted from the BOM website.

- further forecast information is obtained from discussions with current and future customers, local councils and government.

5.4 System Maximum Demand Forecast

Ergon Energy reviews and updates its ten-year 50 PoE and 10 PoE system summer peak demand forecasts after each summer season and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency and robustness, the system level peak demand forecast (‘top-down’) is reconciled with the substation peak demand forecast (‘bottom-up’) after allowances for network losses and diversity of peak loads.

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 GSP (source: ABS website)
- temperature (source: BOM)
- air conditioning sales (source: independent consultancy)
- solar PV generation (source: customer installation data)
- load history (source: corporate SCADA/metering database).

The system maximum demand forecast provides a benchmark against which aggregated zone substation forecasts (‘bottom-up’) are reconciled.

The ‘bottom-up’ forecast consists of a ten-year maximum demand forecast for all zone substations (also described as ‘spatial forecasts’) which are aggregated to a system total and reconciled to the econometrically-derived system maximum demand. These zone substation forecasts are also aggregated to produce forecasts for bulk supply substations and transmission connection points.
Zone substation forecasts are based upon a number of inputs, including:

- network topology (source: corporate equipment register)
- load history (source: corporate SCADA/metering database)
- known future developments (new major customers, network augmentation, etc.) (source: 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.

In recent years, there has been considerable volatility in Queensland economic conditions; weather patterns and customer behaviour which have all affected total system peak demand. The influence of Queensland’s moderate economic growth has had a moderating impact on peak demand growth through most of the state. At the same time, weather patterns have moved from extreme drought in 2009, to flooding and heavy rain in recent years, to extended hot conditions over the past several summer periods. Summer conditions in the last two years have produced new record high maximum demand figures.

To complete the scenario, customer reaction to recent electricity price increases has started to wane resulting in customer load above long-term average trends at the 50 PoE temperature conditions. The amount of solar PV generation that has been connected to the network over recent years has continued to grow although at a steadier rate. Customer behaviour drivers are now incorporated into models used for system demand forecasting. The forecasts are developed using ABS data, Queensland Government data, AEMO data, NIEIR, an independently produced Queensland air conditioning forecast, solar PV connection data and historical peak demand data.

### 5.4.1 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.
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 below in Figure 18.

Figure 18: Forecast Methodology

Naturally, 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 Probability of Exceedance (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.
5.4.2 System Maximum Demand Forecast Results

In 2017-18 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 2017-18 peak was 2,601MW at 6.00pm on 15 February 2018 an amount of 36MW less than last year’s peak, and as a result of the hot summer significantly larger than the temperature corrected 50 POE peak for this year but less than the 10 PoE peak. Weather extremes across Queensland were restricted to local areas including Rockhampton and Emerald. This was aligned with a 10 PoE peak demand (one in 10 year event).

With the global and domestic economy still 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 continuing to move 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.

GSP figures are continuing to return values larger than estimated as a result of higher than expected commodity prices.

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. Forecast values remain stable as economic conditions measured by actual and estimated GSP have slightly improved to that of last year’s economic projections.

Figure 19: Trend in System-wide Peak Demand

<table>
<thead>
<tr>
<th>Year</th>
<th>50POE [MW]-Medium</th>
<th>50POE-Low</th>
<th>50 POE-High</th>
<th>Actual</th>
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<td>2011-12</td>
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<td>2012-13</td>
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<td>2013-14</td>
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<td>2014-15</td>
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<tr>
<td>2015-16</td>
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<td>2016-17</td>
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<td>2017-18</td>
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<td>2018-19</td>
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<tr>
<td>2019-20</td>
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<tr>
<td>2020-21</td>
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<tr>
<td>2021-22</td>
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<td></td>
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<tr>
<td>2022-23</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Table 3 summarises the actual and temperature-corrected (50% PoE) demands based on a range of weather station temperatures and associated maximum demand growths over the past five
years. Each year the actual maximum demand recorded is corrected to a normalised or 50% PoE value by adjusting the demand up or down depending on the actual temperature recorded versus standard temperature and economic conditions. The corrected demand for each of the last four summers was derived through progressively improved ACIL Allen models. Therefore, comparisons between the 50% PoE loads for these and previous years should be made with care.

Table 3: Actual Maximum Demand Growth

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer Actual (MW)</td>
<td>2,481</td>
<td>2,355</td>
<td>2,481</td>
<td>2,637</td>
<td>2,601</td>
</tr>
<tr>
<td>Growth (%)</td>
<td>2.2%</td>
<td>-5.1%</td>
<td>5.3%</td>
<td>6.3%</td>
<td>-1.4%</td>
</tr>
</tbody>
</table>

1 Native Demand.

Furthermore, Table 4 lists the maximum demand forecasts over the next five years for the 50PoE and 10PoE cases of peak demand.

Table 4: Maximum Demand Forecast (MW)

<table>
<thead>
<tr>
<th>Forecast 1,2</th>
<th>2018-19</th>
<th>2019-20</th>
<th>2020-21</th>
<th>2021-22</th>
<th>2022-23</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer (50% PoE)</td>
<td>2,550</td>
<td>2,526</td>
<td>2,560</td>
<td>2,596</td>
<td>2,601</td>
</tr>
<tr>
<td>Growth (%)</td>
<td>-0.3%</td>
<td>-0.9%</td>
<td>1.3%</td>
<td>1.4%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Summer (10% PoE)</td>
<td>2,709</td>
<td>2,666</td>
<td>2,679</td>
<td>2,740</td>
<td>2,766</td>
</tr>
<tr>
<td>Growth (%)</td>
<td>-1.6%</td>
<td>-1.6%</td>
<td>0.5%</td>
<td>2.3%</td>
<td>0.9%</td>
</tr>
</tbody>
</table>

1 The five year demand forecast was developed using five weather station weighted data as recommended by ACIL Allen and includes the impact of summer 2017-18.
2 The demand forecasts include the impact of the forecast economic growth as assessed in April 2018.

The forecast of solar PV generation at the time of summer peak demand for regional Queensland is shown below in Table 5. Solar PV will continue to grow steadily with retailers providing options for customers to either bundle solar PV with battery storage or to purchase individual options. Analysis indicates that the continued growth of solar PV will reduce loads during daylight hours, causing system peak demands to occur at or around 7.30pm. This is consistent with the 2016-17 and 2017-18 summer seasons, which had peak demands occurring at 7.30pm (the 2017-18 peak occurred at 6:00pm).

Table 5: Solar PV Contribution to Summer System Peak Demand

<table>
<thead>
<tr>
<th>Year</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
<th>2027</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar PV Capacity impact on System Peak Demand (MW)</td>
<td>-66</td>
<td>-43</td>
<td>-12</td>
<td>-7</td>
<td>-7</td>
<td>-8</td>
<td>-8</td>
<td>-9</td>
<td>-9</td>
<td>-9</td>
</tr>
</tbody>
</table>

Although EV load has not been included in the System Forecast baseline for this current year, it will be included in forecast scenarios. While it is anticipated that the take-up of this technology will
be slow, it has the potential to increase significantly if costs decline or Government incentives are introduced as occurred with solar PV. EV charging is expected to generally occur from the early evening onwards and will extend into the middle of the night (off-peak). It is expected that the impact of EV charging on the system peak (afternoon period) will be negligible and is therefore excluded for the system peak demand. The EV impact on system demand forecast is shown in Table 6.

| Table 6: Electric Vehicle Contribution to Summer System Peak Demand |
|----------------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                      | 2019  | 2020  | 2021  | 2022  | 2023  | 2024  | 2025  | 2026  | 2027  | 2028  |
| EV Load impact on System Peak Demand (MW) | <1    | 1     | 2     | 4     | 6     | 11    | 16    | 22    | 30    | 37    |

Note – This assessment assumes that home vehicle charging is on controlled tariffs.

EV charging period is assumed to occur from 6pm to the early hours of the morning and will therefore not contribute to the afternoon peak demand but could well cause a rise in evening loads if not carried out on controlled tariffs.

Ergon Energy has also developed a model for the adoption of battery storage with the impact on peak demand being driven by large solar PV customers with little or no feed-in-tariffs (FiT). There are an increasing number of solar PV customers with systems that provide more electricity than they can use internally during the day but are not receiving the 44 cents per kWh FiT. These customers are likely to be very interested in battery storage and are seen to be the early adopters. Table 7 lists the projected impact of battery storage systems on system peak demand.

| Table 7: Battery Storage Systems Impact on Summer System Peak Demand |
|----------------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                      | 2019  | 2020  | 2021  | 2022  | 2023  | 2024  | 2025  | 2026  | 2027  | 2028  |
| Battery Storage Systems Load Impact on System Peak Demand (MW) | -8    | -18   | -31   | -40   | -67   | -84   | -99   | -112  | -124  | -131  |

Model is based on the assumption that battery storage will primarily be charged by solar PV and discharged over the late afternoon and early evening period between 4pm and 8pm with an initially small but growing impact on the system peak demand.
Chapter 6
Network Planning Framework

6.1 Background
6.2 Planning Methodology
6.3 Key Drivers of Augmentation
6.4 Network Planning Criteria
6.5 Voltage Limits
6.6 Fault Level Analysis
6.7 Ratings Methodology
6.8 Planning of Customer Connections
6.9 Major Customer Connections and Embedded Generators
6.10 Joint Planning
6.11 Joint Planning Results
6.12 DAPR Reporting Methodology
6. Network Planning Framework

6.1 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 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
6.2 Planning Methodology

6.2.1 Strategic Planning

Ergon Energy’s planning process involves production of 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. Scenario planning is used to obtain alternative development plans for a range of economic forecasts, population growths, and new technologies (such as solar PVs, EVs and battery energy storage systems). 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, tariff reform 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 constraints 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.

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 strategic site and easement acquisition and approvals to proceed. Specific outcomes of strategic network development plans may be used to identify areas where non-network solutions have potential to defer or avoid network augmentation. These are ongoing and reviewed as required.

6.2.2 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:
Chapter 6. Network Planning Framework

- non-network alternatives (NNA)
- fault levels
- voltage levels
- security of supply requirements
- quality of supply considerations
- asset renewal
- customer connections activity
- local, state and federal government decisions and directions.

Options are considered for technical and economic feasibility to address the various issues with a final proposal progressed for approval.

6.3 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 constraints 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. For example the increase in air conditioner installations in the 1990’s to the installation of Solar Systems in recent years

(ii) increases in the number of residential or small commercial customers in a particular part of the network to service 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 augmentation investment or non-network investment, customers’ increased demand can result in load exceeding planning limits (including component capacity/ratings, voltage regulation limitations 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). Work on Powerlink’s network may require compulsory activity within our network in order to ensure the transmission network integrity, and capacity can be delivered to the distribution network. Such activity could be the result of increased fault levels or plant rating limitations with these types of augmentation activities analysed and reviewed as part of the Joint Planning process conducted between Ergon Energy and Powerlink (or other DNSPs) as required by the NERs.
6.4 Network Planning Criteria

Network planning criteria is 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.

Ergon Energy is required under Distribution Authority No. D01/99 to adhere to the probabilistic planning approach where full consideration is given to the network risk at each location, including operational capability, plant condition and network meshing with load transfers.

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 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 probabilistic planning criteria is far more complex in application, the criteria increases the focus on customer service levels:

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

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). While mandatory investments may not be NPV positive, however, different options and benefits are considered for each project with the most cost positive option being selected for progression. All investments are risk ranked and prioritised for consideration against Ergon Energy’s budget and resource levels, with some network risks managed operationally.

6.4.1 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.

6.4.2 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-consequence-low-probability events could still cause significant disruption to supply with potential customer hardship and/or significant community or economic disruption.

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 8 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 very low probability, investment to further mitigate the risk would generally not be recommended, as per industry best practice.

Table 8: 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 20MVA after 1 hour</td>
</tr>
<tr>
<td></td>
<td>• Less than 15MVA after 6 hours</td>
</tr>
<tr>
<td></td>
<td>• Less than 5MVA after 12 hours</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 20MVA after 1 hour</td>
</tr>
<tr>
<td></td>
<td>• Less than 15MVA after 8 hours</td>
</tr>
<tr>
<td></td>
<td>• Less than 5MVA after 18 hours</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.

Safety Net review of the network’s sub-transmission feeders with zone and bulk supply substations are performed annually where the Planning team examine the network transfer capability, forecasts, substation asset ratings, bus section capability, network topology and protection schemes. Further work is undertaken to ensure items within the operational response plans are outworked; this may include asset spares, location of specialist machinery, access conditions and skills of crews. Ergon Energy annually reviews the inventory of mobile substations, skid substations and mobile generation and site suitability to apply injection if required to meet Safety Net compliance.

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.

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.


6.4.3 Distribution Networks Planning Criteria

Distribution feeder ratings are determined by the standard conductor/cable used, and installation conditions/stringing temperature. Consideration is also given to Electro-Magnetic Fields (EMF) impacts, as well as to the reliability impacts of increasing load and customer counts on a distribution feeder.

Target Maximum Utilisation (TMU) is used as a trigger for potential application of non-network solutions or capacity improvements for the 11kV and 22kV network.

CBD and Critical Loads

In the regional areas for loads that require an N-2 supply, meshed networks are utilised. Feeder mesh networks consist of multiple feeders from different bus sections of the same substation interconnected through common distribution substations. A mesh network can often lose a single component without losing supply – with the loss of any single feeder; the remaining feeders must be capable of supplying the total load of the mesh.

In a balanced feeder mesh network, each feeder supplies an approximately equal amount of load and has the same rating, as the name describes. Any feeder in a balanced three feeder mesh should be loaded to no more than 67% utilisation under system normal conditions at 50 PoE. Any feeder in a balanced two feeder mesh should be loaded to no more than 50% utilisation under system normal conditions at 50 PoE.

Mesh networks are more common in the Brisbane dense central business district (CBD) areas where high reliability is critical and thus the loss of a single feeder should not affect supply.

Urban Feeders

What is referred to as an Urban feeder in the security criteria is essentially a radial feeder, with ties to adjacent radial feeders. A radial feeder with effective ties to three or more feeders should be loaded to no more than 75% utilisation under system normal conditions at 50 PoE.

On the loss of a feeder, closing the ties to other feeders allows supply to be restored to the affected feeder without overloading the tie feeders.

Values of TMU may need to be adjusted to ensure that there is adequate tie capacity to adjacent zone substations in accordance with the Security Standard. Each case needs to be considered separately.

It is recognised that tie capacity may not be available under all loading conditions because of voltage limitations.

Rural Feeders

For a point load that has no ties, or a rural radial feeder, the TMU will be capped at 0.90 at 50 PoE, unless the supply agreement specifically requires a different value.

6.4.4 Consideration of Distribution Losses

Distribution losses refer to the transportation of energy across the distribution network. In 2015-16, network losses equated to 750.5GWh, which contributed 615.45 kilotonnes (tCO2-e) to Ergon
Energy’s carbon footprint.\textsuperscript{17} These losses represent 75% of Ergon Energy’s total greenhouse gas emissions for Scope 1, 2 emissions defined under the \textit{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.

\section{6.5 Voltage Limits}

\textbf{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. \textbf{Table 9} 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.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|}
\hline
\textbf{System Nominal Voltage} & \textbf{System Maximum Voltage} \\
\hline
132kV & 145kV \\
\hline
110kV & 123kV \\
\hline
66kV & 72kV \\
\hline
33kV & 36kV \\
\hline
22kV & 24kV \\
\hline
11kV & 12kV \\
\hline
\end{tabular}
\caption{System Operating Voltages}
\end{table}

\textbf{Maximum Customer Voltage}

The NER gives utilities the authority to specify the customer supply voltage range within the connection agreement for HV customers above 22kV. The NER requires Root Mean Square (RMS) phase voltages to remain between $\pm5\%$ of the agreed target voltage (determined in consultation with AEMO); provided that at all times the supply voltage remains between $\pm10\%$ of the system nominal RMS phase to phase voltage except as a consequence of a contingency event.

\textsuperscript{17} This information is based on available 2015-16 emissions data as the most up to date at the time of publishing.
In Queensland, for customers less than or equal to 22kV, the Queensland Electricity Regulation specifies supply voltage ranges for LV and HV customers. In 2017 the Queensland Electricity Regulation for LV change from 415/240 volts +/- 6% to 400/230 volts +10%, -6%.

**Table 10** below details the standard voltages and the maximum allowable variances for each voltage range from the relevant Queensland Electricity Regulation and the NER.

**Table 10: Maximum Allowable Voltage**

<table>
<thead>
<tr>
<th>Nominal Voltage</th>
<th>Maximum Allowable Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;1,000V</td>
<td>Nominal voltage +10% +/- 6%</td>
</tr>
<tr>
<td>230V Phase to Neutral</td>
<td></td>
</tr>
<tr>
<td>400V Phase to Phase</td>
<td></td>
</tr>
<tr>
<td>1,000V – 22,000V</td>
<td>Nominal voltage +/- 5% or as agreed</td>
</tr>
<tr>
<td>&gt;22,000V</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 and line regulators 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 11** 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 11: 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.

**6.6 Fault Level Analysis**

**6.6.1 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.

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:
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- 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 AS 3851. 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.

6.6.2 Standard Fault Level Limits

Table 12 lists design fault level limits that apply to our network.

Table 12: Design Fault Level Limits

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

While Table 12 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.

6.6.3 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
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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 TNSP’s 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.

6.7 Ratings Methodology

The evolution of large-scale renewable generation is challenging the philosophy of how network constraints are derived. This distributed generation results in two-way power flows, changing network profiles and in many cases increases the frequency in which constraints on primary assets are approached. Solar farms, for example, can push network assets to their thermal capacity daily, not seasonally. Utilisation levels have increased significantly on particular elements of the distribution and sub-transmission network where large-scale renewable generation connects to the shared network. Step changes in utilisation are expected to become more prevalent in pockets of the network as more large-scale renewables are commissioned.

Ergon Energy is responding with updating ratings philosophies to meet these future challenges. Changes include restricting conductor temperature rise limits under normal and contingency operation, standardising on power cable load factors for particular types of generation and limiting power transformer capacity to base ratings.

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.

6.7.1 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 6.7.2. 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.
- Align the rating with the feeder load profile. While summer day is predominantly the rating restriction, low wind speeds in the morning and evening can cause network limitations.
- 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.

### 6.7.2 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 Tables 13 to 19 below.

In design of run back schemes for renewable and other types of generation, a maximum threshold 100°C is applied to overhead lines to ensure that generators ramp back at a sufficient rate to maintain conductor temperatures below 100°C given the standard set of climate assumptions below.

**Weather study**

In 2010, we 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 13. The shoulder seasonal months of April, May, September, October and November are generally rated with summer parameters.

**Table 13: 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>
Climate zones

The climate study produced the overhead line rating weather parameters for the state shown in Table 14. These nine climate zones are shown in Figure 21.

Table 14: Climate Zone Parameters

<table>
<thead>
<tr>
<th>Region</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></td>
<td>Wind (m/s)</td>
<td>Ambient (°C)</td>
<td>Wind (m/s)</td>
<td>Ambient (°C)</td>
<td>Wind (m/s)</td>
<td>Ambient (°C)</td>
</tr>
<tr>
<td>Far North</td>
<td>0.8</td>
<td>38</td>
<td>0.4</td>
<td>34</td>
<td>0.2</td>
<td>30</td>
</tr>
<tr>
<td>Eastern &amp; Coastal</td>
<td>1.3</td>
<td>35</td>
<td>0.8</td>
<td>31</td>
<td>0.3</td>
<td>27</td>
</tr>
<tr>
<td>Mackay</td>
<td>1.9</td>
<td>33</td>
<td>1.5</td>
<td>27</td>
<td>1.2</td>
<td>27</td>
</tr>
<tr>
<td>Eastern &amp; Central Special</td>
<td>1.7</td>
<td>33</td>
<td>1.3</td>
<td>27</td>
<td>0.4</td>
<td>27</td>
</tr>
<tr>
<td>Toowoomba</td>
<td>1.8</td>
<td>33</td>
<td>1.8</td>
<td>27</td>
<td>1.8</td>
<td>21</td>
</tr>
<tr>
<td>Central Tablelands - North</td>
<td>1.3</td>
<td>37</td>
<td>0.7</td>
<td>34</td>
<td>0.2</td>
<td>29</td>
</tr>
<tr>
<td>Central Tablelands - South</td>
<td>1.3</td>
<td>37</td>
<td>0.7</td>
<td>34</td>
<td>0.2</td>
<td>29</td>
</tr>
<tr>
<td>Western</td>
<td>1.7</td>
<td>42</td>
<td>1.4</td>
<td>40</td>
<td>1.4</td>
<td>36</td>
</tr>
<tr>
<td>Western Special</td>
<td>1.5</td>
<td>41</td>
<td>0.8</td>
<td>37</td>
<td>0.3</td>
<td>32</td>
</tr>
</tbody>
</table>
Wind angle

This is the angle of airflow across the conductor and is the next most important factor in determining the line ratings. Table 15 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 15: Wind Angle and Turbulence Parameters

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

**Ground reflectivity factor**

The reflectivity of the ground beneath an overhead line, shown in Table 16, is based on the most appropriate ground cover.

Table 16: 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 17.

Table 17: 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</td>
<td>1</td>
</tr>
</tbody>
</table>

**The ground air differential**

Ground air temperature differential is based on season and time of day as shown in Table 18.

Table 18: 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>
Solar radiation

The solar radiation is based on season and time of day as shown in Table 19.

Table 19: 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>

6.7.3 Real Time Capacity Monitoring Ratings

Real time capacity monitoring has been trialled in the network to monitor feeder constraints 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 Distributive 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.

6.7.4 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.

Where generators are connecting to Ergon Energy’s network resulting in power transformer reverse power flows up to nameplate, transformer ratings are limited to the base cooling mode of
Oli Natural Air Natural (ONAN) for the purpose of the connection. Studies are being undertaken to assess the impact of accelerated aging under reverse power flows using the higher cooling modes.

### 6.8 Planning of Customer Connections

Customer Initiated Capital Works (CICW) is 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 EG, fully funded works also include works to remove a network constraint 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 constraint for an EG
- 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:

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18 *Electricity Act 1994* (Qld) s 42(c).

19 Ibid, s 43.
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- 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.

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.

6.9 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 1,500kVA (1.5MVA) or where power usage is typically above 4GWh per annum at a single site.

Ergon Energy also has clear processes for the connection of EG units, which applies to EG systems 30kVA 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 limitations 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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6.10 Joint Planning

6.10.1 Joint Planning Methodology

The joint planning process ensures that different network owners operating contiguous networks work cooperatively to facilitate the identification, review and efficient resolution of options to address emerging network limitations from a whole of distribution and transmission network perspective. In the context of joint planning, geographical boundaries between transmission and distribution networks are not relevant.

The National Electricity Objective (NEO) is to promote efficient investment in, and operation and use of, electricity services for the long term interests of customers. Joint planning ensures that the most efficient market outcomes for customers are implemented. This typically involves a combination of TNSP and DNSP augmentations.

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 275kV and 330kV network, as the TNSP, as well as some of the 110kV and 132kV network. Energex operates the distribution network in south-east Queensland. Ergon operates the distribution network in the rest of the state. Powerlink and Ergon Energy undertake formal annual joint planning meetings. These meetings are used to review known or emerging network constraints 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 6.11.1.

In addition, Ergon Energy also meets with Energex to discuss the interface between the two business’ distribution (11kV) and sub-transmission (33kV and 110kV) 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 Wagamba 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.
6.10.2 Role of Ergon Energy in Joint Planning

Joint planning often begins many years in advance of any investment decision to address a specific emerging network limitation. Timing is reviewed annually, with detailed planning and approval completed based on the forecasted need and the lead time to complete the project. In this process, there is a steady increase in the intensity of joint planning activities, which typically would lead to a regulatory investment test consultation (either RIT-T or RIT-D). Among other things, the scope and estimated cost of options (including anticipated and modelled projects) is provided in published regulatory investment test documents consistent with the NERs.

Through this process Ergon is tasked with:

- Ensuring that its network is operated with sufficient capability, and augmented if necessary, to provide network services to customers
- Conducting annual planning reviews with TNSPs and DNSPs whose networks are connected to Energex’s network
- 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 National Electricity Rules. Net present value analysis is conducted to ensure cost-effective, prudent solutions are developed. Solutions may include network upgrades or non-network options, such as local generation and demand side management initiatives
- Undertaking the role of the proponent for jointly planned distribution augmentations in SEQ
- Advising Registered Participants and interested parties of emerging network limitations within the time required for action
- Ensuring that its network complies with technical and reliability standards contained in the NER and jurisdictional instruments.

6.10.3 Emerging Joint Planning Limitations

For joint planning purposes, the primary focus is to ensure that network capacities are not exceeded. These limits relate to:

- Thermal plant and line ratings under normal and contingency conditions
- Overhead line ratings under normal climatic conditions (dynamic rating where appropriate)
- Plant fault ratings during network faults
- Network voltage to remain within acceptable operating thresholds
- Replacement of ageing or unreliable assets
- Network stability to ensure consistency with relevant standards.

Where forecasted power flows could exceed network capacity, Ergon is required to notify market participants of these forecast emerging network limitations through the DAPR. If augmentation is necessary, joint planning investigations are carried out with DNSPs or TNSPs in accordance with Clause 5.14 of the NER, to identify the most cost effective solution regardless of asset boundaries, including potential non-network solutions.
### 6.11 Joint Planning Results

#### 6.11.1 Joint Planning with TNSP

*Table 20* presents the outcomes of Ergon Energy’s joint planning investments undertaken with Powerlink as described in *Section 6.11.2* and *6.11.3* in 2017-18.

**Table 20: 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>Northern</td>
<td><strong>T53 Kamerunga</strong> — Ergon Energy work associated with Powerlink replacement of 132kV plant.</td>
<td>$0.5M</td>
<td>Aug-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</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 100MVA transformers.</td>
<td>$1.25M</td>
<td>Aug-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T48 Tully</strong> — Ergon Energy work related to Powerlink’s Secondary Systems Upgrade</td>
<td>$0.66M</td>
<td>Jul-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T55 Turkinje</strong> — Ergon Energy work related to Powerlink’s Secondary Systems Upgrade.</td>
<td>$0.69M</td>
<td>Nov-18</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>H11 Nebo</strong> — 11kV works required to replace end of life Transformer RMU.</td>
<td>$0.8M</td>
<td>Feb-20</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T38 Mackay</strong> — CT replacements for revenue and check metering compliance.</td>
<td>$2.2M</td>
<td>Jul-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T157 Ingham South</strong> — Ergon Energy work related to Powerlink’s Transformer 1 and Transformer 2 replacement.</td>
<td>$0.95M</td>
<td>Oct-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T67 Kemmis</strong> — Ergon Energy work related to Powerlink’s Transformer 2 replacement.</td>
<td>$1.5M</td>
<td>Jul-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T51 Cairns</strong> — Ergon Energy work to address constrained cable capacity.</td>
<td>$1.7M</td>
<td>Jun-22</td>
<td>Ergon Energy</td>
</tr>
<tr>
<td>Northern</td>
<td><strong>T92 Dan Gleeson</strong> — Ergon Energy work related to Powerlink’s Secondary Systems Upgrade.</td>
<td>$1.0M</td>
<td>Oct-19</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Southern</td>
<td><strong>T035 Dysart substation</strong> — Install two 66/22kV 20MVA transformers to supply the Dysart area distribution network once Powerlink remove the existing 2 x 70MVA 132/66/22kV.</td>
<td>$11M</td>
<td>Jun-20</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Southern</td>
<td><strong>T032 Blackwater</strong> — Ergon Energy install two 66/22kV 20MVA transformers to supply the Blackwater area distribution network once Powerlink replace Transformers 1 &amp; 2, 132/66/11kV with single 160MVA.</td>
<td>$15.5M</td>
<td>Oct-22</td>
<td>Powerlink</td>
</tr>
<tr>
<td>Southern</td>
<td><strong>Egans Hill</strong> — Secondary Systems Replacement</td>
<td>$1.2M</td>
<td>Oct-18</td>
<td>Powerlink</td>
</tr>
</tbody>
</table>

* Ergon Energy component (including overheads)
6.11.2 Joint Planning with other DNSP

There were no investments resulting from joint planning in 2017-18 with Essential Energy, Energex, mining sector service providers or generators in the North Queensland Western Region.

6.11.3 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
6.12 DAPR Reporting Methodology

The methodology shown in Figure 22 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
6.12.1 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 PV 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.

6.12.2 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 6.2.2 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 6.4.2, 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 SIFT. The SIFT tool utilises the data from the forecast coupled with this rating data to provide an overview of a substation's limitation.

6.12.3 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 6.7. The outcome of this methodology, as per the planning process discussed is Section 6.2, 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.
6.12.4 Distribution Feeder Analysis Methodology Assumptions

Methodology and assumptions used for calculating the distribution feeder constraints 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.
- 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 0):
  - 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' constraints using load flow analysis; however, these studies are done on a case by case basis and are therefore not included in this methodology. Similarly, constraints on SWER and LV systems are also excluded.
Chapter 7
Network Limitations and Recommended Solutions

7.1 Emerging Network Limitation Maps
7.2 Forecast Load and Capacity Tables
7.3 Substation Limitations
7.4 Sub-transmission Feeder Limitations
7.5 Distribution Feeder Limitations
7.6 Network Asset Retirements and De-Ratings
7.7 Regulatory Investment Test Projects
7. Network Limitations and Recommended Solutions

7.1 Emerging Network Limitation Maps

This section covers the requirements outlined in the NER under Schedule 5.8 (n), which includes providing maps of the distribution network, and maps of forecasted emerging network limitations. The extent of information shown on maps, using graphical formats, has been prepared to balance adequate viewing resolution against the number or incidences of maps that must be reported. In addition to system-wide maps, limiting network maps are broken up into groupings by voltage. For confidentiality purposes, where third party connections are directly involved, the connecting network is not shown.

This information is provided to assist parties to identify elements of the network using geographical representation. Importantly, this does not show how the network is operated electrically. More importantly, this information should not be used beyond its intended purpose.

Following feedback from customers, interactive maps are available on the Ergon Energy website via the following link:


The maps provide an overview of the Ergon Energy network, including:

- Existing 132kV, 110kV, 66kV and 33kV feeders
- Existing bulk supply and zone substations
- Existing transmission connection points
- Existing 132kV, 110kV, 66kV and 33kV feeders with identified Safety Net / security standard limitations within the five year forward planning period
- Existing bulk supply and zone substations with identified Safety Net / security standard limitations within the five year forward planning period
- Existing distribution feeders or feeder meshes
- Existing distribution feeders or feeder meshes with forecast limitations within the next two years of the forward planning period
- MEGU penetration percentage
- Planning regions.

7.2 Forecast Load and Capacity Tables

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

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
7.3 Substation Limitations

7.3.1 Summary of Limitations

Substation limitations are identified using the models and processes as described in Section 5.3.1 and Section 6.4.

Table 21 shows the projection of substation statistics out to 2022-23. It also provides the forecast number of substations with load at risk (LAR) under contingency conditions (LARc).

Table 21: Summary of Substation Limitations

<table>
<thead>
<tr>
<th>Region</th>
<th>Substation Type</th>
<th>LARc &gt; 0MVA (Forecast Limitations)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern</td>
<td>KIRK — Kirknie 66/11kV</td>
<td>0.3</td>
</tr>
<tr>
<td>Northern</td>
<td>GEOR — Georgetown BSP 132/66kV</td>
<td>0</td>
</tr>
<tr>
<td>Southern</td>
<td>BROX — Broxburn 33/11kV</td>
<td>0</td>
</tr>
<tr>
<td>Southern</td>
<td>MOSI — Mt Sibley 33/11kV</td>
<td>0.3</td>
</tr>
<tr>
<td>Southern</td>
<td>SOBL — South Blackwater 66/22kV</td>
<td>0.4</td>
</tr>
<tr>
<td>Southern</td>
<td>T072 — Barcaldine BSP 132/66kV</td>
<td>0.1</td>
</tr>
</tbody>
</table>

Assessment based on 10 PoE forecast and Network Planning Criteria.
The zone substation total count excludes dedicated customer substations.
All information as at 30 June of each year.
Note: Proposed strategies to manage the limitations are contained in Substation DAPR System Limitation Templates.

7.3.2 Proposed Solutions

Details on proposed solutions addressing known Substation system limitations are documented in the Substation DAPR System Limitation Template (DAPR Template) which can be accessed from the following link:

Substations-Limitations-and-Proposed-Solutions-2018.xlsx

7.3.3 Committed Solutions

Details on committed solutions addressing known Substation system limitations are documented in the Substation Limitations and Committed Solutions template which can be accessed from the following link:

Substation-Limitations-and-Committed-Solutions-2018.xlsx
7.4 Sub-transmission Feeder Limitations

7.4.1 Summary of Limitations

Sub-transmission Feeder limitations are identified using the simulation models and processes as described in Section 5.3.2 and Section 6.4. The analysis provides load at risk information under normal and contingency conditions and evaluates whether the transmission feeder meets its allocated security of supply standard. The outcome of this analysis would then potentially trigger the creation of new strategic projects which indirectly may or may not trigger an update of the forecast and re-run of the models.

Table 22: Summary of Sub-transmission Feeder Limitations

<table>
<thead>
<tr>
<th>Region</th>
<th>No of Feeders Utilisation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern</td>
<td>0</td>
</tr>
<tr>
<td>Southern</td>
<td>2</td>
</tr>
</tbody>
</table>

Limitations identified for 132kV and 110kV sub-transmission feeders are also reported in the limitations tables contained in Appendix D. These tables outline the approved or proposed strategy to manage the emerging limitations, along with other related information.

7.4.2 Proposed Solutions

Details on proposed solutions are documented in the Sub-transmission Feeders DAPR System Limitation Template (DAPR Template) which can be accessed from the following links:

Transmission-and-Sub-transmission-Feeders-Limitations-and-Proposed-Solutions-2018.xlsx

Further information and reports on Projects subject to the RIT-D process can be accessed from the Ergon Energy RIT-D Consultations Web Page.

Chapter 7. Network Limitations and Recommended Solutions

7.5 Distribution Feeder Limitations

Of the 1,135 distribution feeders in our network, there are 75 forecast to be constrained in the next two years based on utilisation against the distribution planning/security criteria. These capacity constraints have been assessed against the security criteria loading of 75% for Urban feeders and 90% for other feeder categories. For further details on the methodology used, refer to Section 5.3.4. Note that identification of an asset as ‘constrained’ does not necessarily imply that the integrity or capability threshold of the asset has been compromised.

Table 23: Distribution Feeder Summary Report

<table>
<thead>
<tr>
<th>Region</th>
<th>Total feeder numbers**</th>
<th>Total forecast capacity constraints* (after 2 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern</td>
<td>572</td>
<td>24</td>
</tr>
<tr>
<td>Southern</td>
<td>563</td>
<td>51</td>
</tr>
<tr>
<td>All Regions</td>
<td>1,135</td>
<td>75</td>
</tr>
</tbody>
</table>

*Capacity constraint against the Security Criteria loading (75% for Urban Feeders and 90% for all feeder categories.
**Note dedicated customer connection assets are excluded from the analysis.

Results from analysis of Ergon Energy’s Distribution Feeder loads, capacity and utilisation forecasts in the next two years are available from the following:

Distribution-Feeder-Limitations-and-Committed-Solutions-2018.xlsx

7.5.1 Proposed 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 constraints 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 7. Network Limitations and Recommended Solutions

- 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.

7.6 Network Asset Retirements and De-Ratings

Ergon Energy has a range of Project and Program based planned asset retirements which, if not addressed, will result in a system limitation. These retirements are based on the Asset Management Plans outlined in Chapter 4. Some of these needs may be addressed by options that are yet to be determined and which could trigger the requirement to undertake a RIT-D assessment. A listing of planned projects is available from the link below and Table 24 summarises planned Programs involving Distribution Line assets for the forward planning period.

Asset-Replacement-Projects-2018.xlsx

Table 24: Ergon Asset Retirements (Program Based)

<table>
<thead>
<tr>
<th>Asset</th>
<th>Location</th>
<th>Rationale for Retirement</th>
<th>Retirement Date</th>
<th>Change to Retirement Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead HV reconductoring</td>
<td>Northern &amp; Southern Regions</td>
<td>Asset condition and Risk</td>
<td>2019-2023</td>
<td>NA</td>
</tr>
<tr>
<td>Overhead LV reconductoring</td>
<td>Northern &amp; Southern Regions</td>
<td>Asset condition and Risk</td>
<td>2019-2023</td>
<td>NA</td>
</tr>
<tr>
<td>Overhead Service Line replacement</td>
<td>Northern &amp; Southern Regions</td>
<td>Asset condition and Risk</td>
<td>2019-2023</td>
<td>NA</td>
</tr>
<tr>
<td>Pole Replacements</td>
<td>Northern &amp; Southern Regions</td>
<td>Asset condition and Risk</td>
<td>2019-2023</td>
<td>NA</td>
</tr>
<tr>
<td>Pole mounted plant replacement</td>
<td>Northern &amp; Southern Regions</td>
<td>Asset condition and Risk</td>
<td>2019-2023</td>
<td>NA</td>
</tr>
</tbody>
</table>
Chapter 7. Network Limitations and Recommended Solutions

7.7 Regulatory Investment Test Projects

7.7.1 Regulatory Investment Test Projects — In Progress

This section describes the RIT-Ds that were commenced in 2017-18 and includes several replacement driven projects that now require RIT-D assessment, as specified in the National Electricity Amendment published by the AER on 18 July 2017. Estimated costs are provided in real 2018-19 dollars and are inclusive of overheads.

Table 25: Regulatory Test Investments — In Progress

<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>WR445103 Charleville Static VAR Compensator (SVC) Replacement</td>
<td>$7.4M</td>
<td>Nil impact beyond regulated revenue.</td>
</tr>
</tbody>
</table>

Project need:
- The Charleville SVC is approaching the end of its design life and has been exhibiting unreliable operation for some time. This SVC is recommended for replacement on the basis of its age and poor reliability.
- There are a number of operational challenges at Charleville substation associated with voltage control in the event that the SVC is out of service. This presents safety, voltage compliance and reliability risks.

Credible Options:
1. Replace the existing SVC at Charleville substation with split STATCOM configuration, two power modules on 22kV and one power module on 11kV bus each with a power transformer, with a controller on each bus (NPV = $6.52M)
2. Replace the existing SVC at Charleville substation with 1±8MVAr capacity STATCOM on the 22kV bus using 8MVA transformer and 1±4MVAr capacity upgradable STATCOM on the 11kV bus via 8MVA transformer, with a controller on each bus (NPV = $6.48M)
3. Replace the existing SVC at Charleville substation with 3 x ±4MVAr STATCOM power modules via 3 x LV/MV transformers, RMUs, MV switchboard and a 15MVA, MV/66kV transformer on a single 66kV feeder bay (NPV = $6.5M)
4. Non network option to Defer Option 1 indefinitely – Various currently under evaluation.

Conclusion: Final Recommendation is currently being developed.

Status: Evaluation of Non-Network Options underway.

Ergon Energy has received, and is currently evaluating various non-network proposals.
## Chapter 7. Network Limitations and Recommended Solutions

### Project Need, Credible Options and Conclusion

<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>WR168413 South West Toowoomba Reinforcement</td>
<td>$4.8M</td>
<td>Nil impact beyond regulated revenue.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Project need:**
- The South western edge of Toowoomba is experiencing strong population and load growth in the communities of Westbrook, Wyreema, Cambooya and Vale View. The three (3) existing 11kV feeders supply a total of 4,438 customers (an increase of 348 customers since October 2013) and are suffering from issues comprised of:
  - Capacity constraints (Eiser ST expected to exceed firm capacity in 2017-18, West ST expected to exceed firm capacity in 2017-18 and Westbrook feeder approaching firm limit in a rapidly expanding area).
  - Voltage constraints (feeders exceeding statutory limits during periods of high loads).
- **Credible Options:**
  1. Creation of an additional feeder from KESP Substation and the transfer of USQ load (NPV = -$M)
  2. Carry out 11kV overhead and underground distribution works that allow the creation of a new ‘Cambooya’ feeder and reconfiguration of the ‘Darling Heights’ feeder. (NPV = -$M)

**Conclusion:** Final recommendation is currently being developed.

**Status:** Notice of non-network options report has been published.

Ergon Energy has published a non-network options report to external parties to identify the requirements that Option 1 addresses. This initial phase of the consultation closed on 4 August 2018.
Chapter 7. Network Limitations and Recommended Solutions

<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>
</table>

**Project need:**

A structural engineering report in 2016 identified a number of at risk aged structures. Consequently a substation condition assessment report (SCAR) was completed in early 2018 which identified the assets which are nearing (or at) end of life. The predominant assets which were identified for replacement was the 66kV outdoor switchgear including; circuit breakers, voltage and current transformers, insulators stacks, isolators, the strung bus, the solid bus and all their supporting structures.

**Credible Options:**

1) 66kV switchgear replacement with 66kV GIS located in an industrial shed and modular control room at the existing Garbutt Substation. (NPV = -$6.7M)

**Conclusion:** The final recommendation is currently being developed.

**Status:** Notice of no credible non-network options report published.

Ergon Energy has published a notice of no credible non-network options to external parties to notify the market of Ergon Energy’s intentions. This consultation closed on 31 July 2018.

Further information on current augmentation and replacement RIT-D consultations are available on the Ergon Energy website at:

Chapter 7. Network Limitations and Recommended Solutions

7.7.2 Regulatory Investment Test Projects — Completed

This section describes the RIT-Ds that were completed in 2017-18. Estimated costs are provided in real 2018-19 dollars and are inclusive of overheads.

Table 26: Regulatory Test Investments — Completed

<table>
<thead>
<tr>
<th>Project Need, Credible Options and Conclusion</th>
<th>Preferred option</th>
<th>Impact Network Users (Preferred Option)</th>
</tr>
</thead>
</table>

**Project need:**

Capacity and voltage constraints have been identified, modelled and experienced in the connection of new customers to the Charlton, Wellcamp and Kingsthorpe regions. Some customers have been denied connection to the 11kV network or relatively small loads moved to 33kV due to the following constraints:

1) Two of TORR substation’s 11kV feeders would have exceeded planning criteria (75% NCC or 3 into 4) in or before 2015-16.
2) Voltage constraints exist in the current and future network. Voltage at some points were predicted (even with the completion of DCP17765) to be down to 85%. Although pole-mounted voltage regulators can mitigate this voltage initially, long terms loads are likely to exceed the rating of these regulators.
3) Two further feeders would have exceeded the planning criteria by 2019-20, these two feeders supply industrial and domestic load in the Torrington and Cotswold Hills region.

**Credible Options:**

1) Install a new 33/11kV skid substation at Charlton (NPV = -$11.34)
2) Install a new 11kV express feeder from Torrington Substation (NPV = -$12.23M)
3) Install a single TF 32 MVA 33/11kV substation at Charlton (NPV = -$13.78M).

**Conclusion:** The final recommendation was Option (1), $11.34M, approved in February 2018.

**Status:** Final Project Assessment Report (FPAR) published
1) Ergon Energy published the FPAR on 8 of May 2018.
### Project Need, Credible Options and Conclusion

<table>
<thead>
<tr>
<th>Preferred option</th>
<th>Impact Network (Preferred Option)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td>Est. Delivery</td>
</tr>
</tbody>
</table>

| WR1072816 Gracemere Substation Establishment | $23.7M | Construction Commencing Est. March 2019 Commissioning Est. April 2021 | Nil impact beyond regulated revenue. |

### Project need:

*Within the coming years, Malchi risks being in breach of the Safety Net Requirements, risks constraint in the distribution network, and is expected to exceed its N rating (22.6MVA)*.

### Credible Options:

1. Install 20MVA transformer-ended substation (NPV = -$15.6M)
2. Establish Gavial Road substation as skid 1 x 20MVA (NPV = -$18.99M)
4. Malchi substation 132kV upgrade (NPV = -$42.02M).

### Conclusion:
The final recommendation is currently being developed.

### Status: Final Project Assessment Report (FPAR) published

1. Ergon Energy has published the FPAR on 8 of May 2018.
Chapter 7. Network Limitations and Recommended Solutions

<table>
<thead>
<tr>
<th>Project Need, Credible Options and Conclusion</th>
<th>Preferred option</th>
<th>Impact on Network Users</th>
</tr>
</thead>
</table>

Project need:

Although Bundaberg T020 has no Load at Risk (LAR), in its current configuration there is high likelihood it will not meet the Safety Net outage restoration times should a 132kV or 66kV bus outage occur. The absence of bus tie breakers in 132kV and 66kV bus requires manual bus section separation which will significantly increase outage duration. In the event of a bus outage a load between 30MVA and 127MVA will be off-line.

Credible Options:

1) Installation of 66kV and 132kV bus section breakers.

Conclusion: The final recommendation is Option (1), $7.3M, July 2022

Status: The Final Project Assessment Report (FPAR) has been published

1) Ergon Energy has published a notice of no credible non-network options to external parties to notify the market of Ergon Energy's intentions. This phase of the consultation closed on 25 May 2018
2) Ergon Energy has published a FPAR on 8 May 2018.

Further information on completed augmentation and replacement RIT-D consultations is available on the Ergon Energy website at:

Chapter 7. Network Limitations and Recommended Solutions

7.7.3 Regulatory Investment Test Projects — Excluded

This section describes the replacement driven projects for which Ergon Energy was exempted from undertaking a RIT-D assessment. This is in accordance with the transitional arrangements of the National Electricity Amendment proposed by the AER and published on 18 July 2017.

Table 27: Replacement Projects Excluded from RIT-D

<table>
<thead>
<tr>
<th>Region</th>
<th>Driver</th>
<th>Proposed Solution</th>
<th>Expected completion (Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern - Capricornia Region</td>
<td>Asset Condition</td>
<td>Dysart 132/66/22kV Substation — installation of 2 x new 66/22kV 20 MVA transformers and transformer bays, replacing aged and deteriorated Circuit Breakers (CBs) and Voltage Transformers (VTs).</td>
<td>2019</td>
</tr>
<tr>
<td>Southern - Maryborough Region</td>
<td>Asset Condition</td>
<td>Howard 66/11kV Substation Refurbishment — As most assets in the 66kV yard are at the end of their useful life and now requires replacement there is an opportunity now to rationalise and re-design the 66kV switchyard and remove redundant assets as well as address transformer condition. Aged oil filled 11kV CBs will also be addressed.</td>
<td>2019</td>
</tr>
<tr>
<td>Northern &amp; Southern Asset Condition</td>
<td>LV 7/064 Copper Conductor Replacement Program — A steadily increasing volume of failures have been occurring, each creating potentially dangerous situations for the public and staff working on the asset. A program has been developed to remove and replace the conductor.</td>
<td>2020</td>
<td></td>
</tr>
<tr>
<td>Northern &amp; Southern Asset Condition</td>
<td>Low Voltage Spreader Installation — Spreaders and LV transformer fuses are being installed to reduce the risk of LV conductor failure, allow sufficient time to complete the LV copper replacement program and improve resilience of the network under cyclonic wind conditions.</td>
<td>2020</td>
<td></td>
</tr>
<tr>
<td>Northern - Mackay Region Asset Condition</td>
<td>Tennyson Street 33/11kV Zone Substation (Mackay) — 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>2020</td>
<td></td>
</tr>
<tr>
<td>Southern - Toowoomba Region Asset Condition</td>
<td>Yarranlea (110kV Bulk Supply Point) substation rebuild — replacement of both power transformers and regulators as the substation no longer meets the Safety Net requirements of Ergon Energy’s Distribution Authority.</td>
<td>2020</td>
<td></td>
</tr>
</tbody>
</table>

Further information on excluded replacement RIT-D projects is available on the Ergon Energy website at:

Chapter 7. Network Limitations and Recommended Solutions

7.7.4 Foreseeable RIT-D Projects

This section describes the augmentation and replacement driven projects for which a RIT-D assessment is expected to be initiated in the forward planning period.

On 20 November 2018 the AER published a final determination of the 2018 cost threshold review. The AER’s final determination for the distribution thresholds is that:

- The $5 million capital cost threshold referred to in NER clause 5.15.3(d)(1) be increased to $6 million. This is the cost threshold over which a RIT-D applies.

The revised cost thresholds will take effect on 1 January 2019.

The following table identifies those projects, addressing long term constraints, for which Ergon Energy has determined will require a RIT-D assessment.

Table 28: Foreseeable RIT-D Projects to address long term constraints (>6M)

<table>
<thead>
<tr>
<th>Region</th>
<th>Driver</th>
<th>Location and Proposed Solution</th>
<th>Expected completion (Mth-Yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern</td>
<td>Load Growth</td>
<td>DURO/CLON (Duchess Road to Cloncurry) 66kV line</td>
<td>Jun 2025</td>
</tr>
<tr>
<td>Northern</td>
<td>Asset Condition</td>
<td>TURK (Turkinje) Replace CBs, CTs, VTs, ESs &amp; IS</td>
<td>Jun 2021</td>
</tr>
<tr>
<td>Northern</td>
<td>Asset Condition</td>
<td>MOSS (Mossman) Replace TRs, CBs, CTs, VTs, Ess, Iss, PRs</td>
<td>Dec 2021</td>
</tr>
<tr>
<td>Northern</td>
<td>Asset Condition</td>
<td>SARI (Sarina) Replace 2*TR 33SWBD 11SWBD</td>
<td>Jun 2025</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>KILK (T012) Replace 3<em>66CBs, 6</em>66CTs, 6*66VTs, PRs</td>
<td>Jun 2023</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>MERN (Meringandan) Replace 2<em>CBs, 21</em>CTs, 3*VTs &amp; Iss</td>
<td>Sep 2023</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>PIAL (Pialba) Replace 7<em>CBs, 3</em>CTs &amp; 3*ISS</td>
<td>Jun 2023</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>EABU (East Bundaberg) Replace 1<em>TR, 8</em>CTs, 5<em>VTs, ESs &amp; 9</em>Iss</td>
<td>Dec 2021</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>CHIN/T013 (Chinchilla BSP) Replace 8*CBs &amp; TR</td>
<td>Apr 2025</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>ROSE (Rockhampton South) Replace 1*Z6_32MVA</td>
<td>Jun 2025</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>WETO (West Toowoomba) Stage 1 — Replace 9<em>33CB 4</em>VTs &amp; 33*Iss</td>
<td>Jun 2022</td>
</tr>
<tr>
<td>Southern</td>
<td>Asset Condition</td>
<td>WETO (West Toowoomba) Stage 2 — Replace 7*CBs</td>
<td>Jun 2023</td>
</tr>
<tr>
<td>Southern</td>
<td>Load Growth</td>
<td>NIKE/POVE (Nikenbah to Point Vernon) new 66kV line</td>
<td>Jun 2022</td>
</tr>
</tbody>
</table>

7.7.5 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 8
Demand Management Activities

8.1 Non Network Options Considered in 2017-18
8.2 Key Issues Arising from Embedded Generation Applications
8.3 Actions Promoting Non Network Solutions
8.4 Demand Management Results for 2017-18
8.5 Demand Management Programs for 2018-23
8.6 Other Demand Side Participation Activities
8. Demand Management Activities

Our demand management program forms part of an integrated approach that also includes our forecasting, planning, intelligent grid and tariff strategies, to help lower electricity charges for our end use customers. Demand management involves working with end use customers and our industry partners to reduce demand to maintain system reliability in the short term and over the longer term, defer the need to build more ‘poles and wires’.

Demand management solutions can be in front or behind the meter and include:

- direct load control
- distributed generation, including standby generation and cogeneration
- demand response
- energy efficiency
- fuel substitution (e.g. solar PV)
- interruptible loads
- load shifting
- power factor correction
- pricing/tariffs.

Annually, Ergon Energy publishes a Demand Management Plan which includes our strategy for the next five years and planned demand management programs for next financial year. For the first time, the 2018-19 Demand Management Plan has been developed to cover both the Energex and Ergon Energy networks. It brings together a unified approach to demand management for the whole of Queensland, while at the same time acknowledging the differences in regions and networks. This plan is available on our website.

**2018-2019 Demand Management Plan**

Our plan has responded to the issues facing our network and what our customers and stakeholders are saying.

**Table 29: Our Demand Management Strategies responding to customer insights**

<table>
<thead>
<tr>
<th>Demand Management Strategies</th>
<th>Customer Insights</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Affordability</td>
</tr>
<tr>
<td>Ensure efficient &amp; well planned investment &amp; infrastructure</td>
<td></td>
</tr>
<tr>
<td>Maintain reliable supply of electricity for all end use customers</td>
<td></td>
</tr>
<tr>
<td>Maximise power system security and reliability particularly during summer</td>
<td></td>
</tr>
<tr>
<td>Inform and engage our end use customers</td>
<td></td>
</tr>
</tbody>
</table>
Chapter 8. Demand Management Activities

<table>
<thead>
<tr>
<th>Demand Management Strategies</th>
<th>Customer Insights</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Affordability</td>
</tr>
<tr>
<td>and stakeholders</td>
<td></td>
</tr>
<tr>
<td>Activate the demand response market</td>
<td></td>
</tr>
<tr>
<td>Support our program by investment in innovation</td>
<td></td>
</tr>
</tbody>
</table>

During 2017 and 2018 demand on Ergon Energy’s network reached record peaks, reinforcing the need for demand management. There is also localised and seasonal demand growth that requires careful management. Ergon Energy is well placed to build on its demand management program to provide solutions for customers to manage peak demand. Given the lead times in securing demand under management, Ergon Energy will continue to pursue cost-efficient demand management initiatives over the next five year period to ensure that it has a full range of integrated network and non-network solutions readily available to address demand growth as it arises.

8.1 Non-Network Options Considered in 2017-18

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.

Target Area Incentives have been activated in areas identified with future constraints. Ergon Energy has published incentive maps showing the location, incentive value ($/kVA) and demand response required (e.g. summer, 4-9pm). Those Target Areas in market during the 2017-18 year are listed in Table 30 and the maps can be found on the Ergon Energy website:

**Ergon Incentives**

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 8. Demand Management Activities

## Table 30: In Market Targeted Area Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
<th>Sub-programs</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Target Areas Incentives</strong></td>
<td>Geographical based feeder demand management program utilising a program delivery approach which 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: 4pm - 9.30pm, Mon to Fri, November to March&lt;br&gt;Up to $290 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Cairns South</strong>&lt;br&gt;Peak demand period: 4pm – 9.30pm, Mon to Fri, November to March&lt;br&gt;Up to $272 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Cannonvale</strong>&lt;br&gt;Peak demand period: 12pm - 8pm, Mon to Fri, November to April&lt;br&gt;Up to $350 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Chinchilla</strong>&lt;br&gt;Peak demand period: 9am - 8pm, Mon to Sat, November to April&lt;br&gt;Up to $200 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Emerald</strong>&lt;br&gt;Peak demand period: 1pm - 9pm, Mon to Sun, November to March&lt;br&gt;Up to $225 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Hervey Bay</strong>&lt;br&gt;</td>
<td>Pending</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Mackay Northern Beaches</strong>&lt;br&gt;Peak demand period: 4pm - 8pm, Mon to Sun, November to April&lt;br&gt;Up to $200 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Mackay South</strong>&lt;br&gt;Peak demand period: 10am - 2pm, Mon to Fri, October to April&lt;br&gt;Up to $300 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Roma</strong>&lt;br&gt;</td>
<td>Pending</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Townsville North-West 1</strong>&lt;br&gt;Peak demand period: 8am - 5pm, Mon to Fri, November to April&lt;br&gt;Up to $350 per kVA</td>
<td>Active</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Townsville North-West 1</strong>&lt;br&gt;Peak demand period: 4pm - 9pm, Mon to Fri, November to April&lt;br&gt;Up to $350 per kVA</td>
<td>Active</td>
</tr>
</tbody>
</table>

In addition, a number of contracts for the supply of non-network projects were maintained during the 2017-18 year.
Table 31: 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></td>
</tr>
<tr>
<td>Mt Isa</td>
<td>Network support for the Mt Isa network derived from customer and network embedded generators.</td>
<td></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></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></td>
</tr>
<tr>
<td>Barcaldine</td>
<td>Network embedded generator enabled to support the Barcaldine area during network outages.</td>
<td></td>
</tr>
<tr>
<td>Dajarra</td>
<td>Network embedded generator in the Dajarra area for supporting voltage and outages.</td>
<td></td>
</tr>
<tr>
<td>Kajabbi</td>
<td>Network embedded generator in the Kajabbi area for supporting voltage and outages.</td>
<td></td>
</tr>
</tbody>
</table>

8.2 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 a similar time. The complex network impacts are made more challenging by the speculative nature of these enquiries. 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.
Chapter 8. Demand Management Activities

8.3 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.

Inform and engage our customers AND activate the demand response 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 (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 promotional materials.

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.

8.4 Demand Management Results for 2017-18

The financial year 2017-18 ended with the results shown in Table 32 and Table 33 for demand management activities and EG connections, which are largely forecast to remain in place to 2021.

Table 32: Demand Under Control 2017-18

<table>
<thead>
<tr>
<th>Initiative</th>
<th>MVA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Broad based program</td>
<td>0</td>
</tr>
<tr>
<td>Target areas program</td>
<td>--</td>
</tr>
<tr>
<td>NNA generation</td>
<td>27</td>
</tr>
<tr>
<td>Demand Management Development</td>
<td>n/a</td>
</tr>
<tr>
<td>TOTAL for Demand Management Program</td>
<td>27</td>
</tr>
</tbody>
</table>

Table 33: Embedded Generation Connections

<table>
<thead>
<tr>
<th>NER Requirement</th>
<th>No. received since 1 July 2017</th>
<th>Average Time to complete (Business days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EG connection enquiries received under clause 5.3A.5</td>
<td>40</td>
<td>–</td>
</tr>
<tr>
<td>EG applications to connect received under clause 5.3A.9</td>
<td>9</td>
<td>–</td>
</tr>
<tr>
<td>Average time to complete EG applications to connect</td>
<td>5</td>
<td>1 years 6 months from Application</td>
</tr>
</tbody>
</table>
Chapter 8. Demand Management Activities

8.5 Demand Management Programs for 2018-23

Ergon Energy’s demand management programs for 2018-2023 are detailed in our annual Demand Management Plan which can be found on our website and at the below link:

Demand Management Plan 2018-19

A summary of the programs is detailed in Table 34.

Table 34: Demand Management Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Network</th>
<th>Description</th>
<th>2017-18</th>
<th>2018-19</th>
<th>2020-25</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TARGET AREA PROGRAM</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Target area incentives</td>
<td>Ergon Energy</td>
<td>Provide incentives to business and industry for demand reductions. These areas are where there is an emerging constraint (5-10 years away).</td>
<td>Active</td>
<td>Active</td>
<td>Active</td>
</tr>
<tr>
<td><strong>NON NETWORK ALTERNATIVES</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Contracted demand management</td>
<td>Ergon Energy</td>
<td>Contracts with 3rd parties for non-network alternative projects (such as embedded generators) to defer capital network investment</td>
<td>Active</td>
<td>Active</td>
<td>Actives</td>
</tr>
<tr>
<td><strong>BROAD BASED PROGRAMS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PeakSmart air conditioning</td>
<td>Ergon Energy</td>
<td>Provision of incentives to end use customers who participate in the PeakSmart air conditioning program</td>
<td>Active</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td>Load control tariffs</td>
<td>Ergon Energy</td>
<td>Provision of incentives to end use customers for connecting appliances to load control tariffs</td>
<td>Active</td>
<td>Active</td>
<td>Active</td>
</tr>
<tr>
<td>Procure reliability services from the market</td>
<td>Ergon Energy</td>
<td>Investigate feasibility and effectiveness of procuring reliability services from the market</td>
<td>New</td>
<td></td>
<td>Active</td>
</tr>
<tr>
<td>Alternative models for delivering demand response</td>
<td>Ergon Energy</td>
<td>Investigate feasibility and effectiveness of voluntary demand response program</td>
<td>New</td>
<td></td>
<td>Pending</td>
</tr>
<tr>
<td>Summer preparedness plan</td>
<td>Ergon Energy</td>
<td>Work with Queensland government to develop annual plan</td>
<td>Active</td>
<td>Active</td>
<td>Active</td>
</tr>
</tbody>
</table>
### DEMAND MANAGEMENT DEVELOPMENT PROGRAMS

<table>
<thead>
<tr>
<th>Program</th>
<th>Network</th>
<th>Description</th>
<th>2017-18</th>
<th>2018-19</th>
<th>2020-25</th>
</tr>
</thead>
<tbody>
<tr>
<td>Smart ADMD Tool</td>
<td>Ergon Energy</td>
<td>Continue to pilot and develop tool for use in greenfield residential developments</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Prototype developed</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integrate DM into urban development rating tools</td>
<td>Ergon Energy</td>
<td>Work with developers and industry</td>
<td></td>
<td>New</td>
<td>Active</td>
</tr>
<tr>
<td>Provide simple DM advice</td>
<td>Ergon Energy</td>
<td>Provide simple DM advice to end use customers on how to reduce demand</td>
<td></td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>New</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Raise awareness of demand tariffs</td>
<td>Ergon Energy</td>
<td>Raise awareness of demand tariffs</td>
<td></td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>New</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incentive maps</td>
<td>Ergon Energy</td>
<td>Publish incentive maps of Target Incentive areas</td>
<td></td>
<td>New</td>
<td>Active</td>
</tr>
<tr>
<td>Electric vehicle connection advice</td>
<td>Ergon Energy</td>
<td>Provide simple and consistent electric vehicle connection advice</td>
<td></td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>New</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Support development of demand response Standards</td>
<td>Ergon Energy</td>
<td>Support development of AS/NZS 4755.2</td>
<td></td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>New</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### INNOVATION PROGRAMS

<table>
<thead>
<tr>
<th>Program</th>
<th>Network</th>
<th>Description</th>
<th>2017-18</th>
<th>2018-19</th>
<th>2020-25</th>
</tr>
</thead>
<tbody>
<tr>
<td>Innovative trials and projects</td>
<td>Ergon Energy</td>
<td>Undertake innovative projects and initiatives to test and validate DM products and processes. Some are funded through the Demand Management Innovation Allowance (DMIA)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 8.6 Other Demand Side Participation Activities

Ergon Energy has also maintained involvement and input to a range of market and industry consultations, forums and development of standards, and will continue to support the long-term development of demand management capabilities.

We have continued 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.
Chapter 9

Asset Life-Cycle Management

9.1 Approach
9.2 Preventative Works
9.3 Asset Condition Management
9.4 Asset Replacement
9.5 Derating
9. Asset Life-Cycle Management

9.1 Approach

Ergon Energy has a legislated duty to ensure all staff, the Queensland community and its customers are electrically safe. This duty extends to eliminating safety risks so far as is reasonably practical, and if not practical to eliminate, to mitigate so far as is reasonable practical.

Ergon Energy’s approach to asset life-cycle management, including asset inspection, maintenance, refurbishment and renewal, integrates several key objectives including; achieving its legislated safety duty, delivering customer service and network performance to meet the required standards, and maintaining an efficient and sustainable cost structure.

Policies are used to provide corporate direction and guidance, and plans are prepared to provide a safe, reliable distribution network that delivers a quality of supply to customers consistent with legislative compliance requirements and optimum asset life. These policies and plans cover equipment installed in substations, the various components of overhead powerlines, underground cables and other distribution equipment. The policies and plans define inspection and maintenance requirements, and refurbishment and renewal strategies for each type of network asset. Asset life optimisation takes into consideration maintenance and replacement costs, equipment degradation and failure modes as well as safety, customer, 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:

- Inspection and preventative maintenance works, where each asset is periodically assessed for condition, and essential maintenance is performed to ensure each asset continues to perform its intended function and service throughout its expected life
- Proactive refurbishment and replacement, where the objective is to renew assets just before they fail in service by predicting assets’ end-of-life based on condition and risk
- Run-to-failure refurbishment and replacement, which includes replacing assets that have failed in service.

A proactive approach is undertaken typically for high-cost, discrete assets, such as substation plant, where Ergon Energy records plant information history and condition data. This information is used to adjust maintenance plans and schedules, initiate life extension works if possible, and predict the remaining economic life of each asset. Proactive replacement or refurbishment is then scheduled as near to the predicted end of economic life as practical. This approach is considered the most prudent and efficient approach to achieve all 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 overall works program.

Low-cost 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 through an inspection regime, which is also required under legislation. The objective of this regime is to
identify and replace assets that are very likely to fail before their next scheduled inspection. In addition, asset class collective failure performance is assessed and analysed regularly, with adverse trends and increasing risk issues becoming drivers for targeted maintenance, refurbishment or replacement programs.

Actual asset failures are addressed by a number of approaches depending on the nature of the equipment, identified failure modes and assessed risk. The approaches include on-condition component replacement, bulk replacement to mitigate similar circumstances, risk based refurbishmentreplacement and run to failure strategies.

All inspection, maintenance, refurbishment and renewal works programs are monitored, individually and collectively, to ensure the intended works are performed in a timely, safe and cost effective fashion. These outcomes feed back into asset strategies to support prudent and targeted continuous improvement in life cycle performance overall.

9.2 Preventative Works

Ergon Energy manages safety and service compliance requirements via various preventative inspection and minor maintenance programs. These are collectively described below.

9.2.1 Asset Inspections and Condition Based Maintenance

Ergon Energy generally employs condition and risk-based asset inspection, maintenance, refurbishment and replacement strategies in line with its asset management policies and strategies discussed in Chapter 4 Asset Management Overview. 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.

All equipment is inspected at scheduled intervals to detect physical indications of degradation exceeding thresholds that are predictive of a near-future failure. 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 customer 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
- electrical testing of circuit breakers.

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 Queensland code of practice guideline limit of 99.9900%.
Consistent with the principles of ISO 55000 Asset Management, Ergon Energy is building its capability with an ongoing investment into technologies that deliver improvement in risk outcomes and efficiency. These efforts include utilising lidar data from the aerial asset and vegetation monitoring management technology. 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 identification and 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 physical network and the surrounding environment, particularly vegetation. 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 analysis with other innovative identification systems being developed.

9.2.2 Vegetation Management

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

Ergon Energy annually updates its 3D geo-spatial representations of network assets to assist not only with ongoing vegetation management but other aspects of asset inspection. This technology includes predictive capability for vegetation growth rates.

Ergon Energy maintains a comprehensive vegetation management program to minimise 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. Cycle times are varied, based upon Lidar analysis and network analytics enabling optimisation of field crew dispersion, ensuring the powerline clearance zone is kept clear at all times.
- Reactive spot activities to address localised instances where vegetation is found to be within clearance requirements 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.

9.3 Asset Condition Management

The processes for inspection and routine maintenance of Ergon Energy’s assets are well established and constantly reviewed. Ergon Energy uses its asset management system to record and analyse asset condition data collected as a part of these programs. Formal risk assessments are conducted for all asset classes, identifying failure modes and consequences, as well as suitable mitigation measures. The results of these programs are regularly monitored, with
inspection, maintenance, refurbishment and renewal strategies evolving accordingly. These strategies in turn are used to inform forecast expenditure.

Ergon Energy has recently implemented Intelligent Process Solutions’ (IPS) condition monitoring and management software, to collect and analyse asset condition data. The IPS system employs test result analytics, supporting targeted and prioritised maintenance strategies. The primary application of IPS in Ergon Energy is currently in managing the power transformer fleet and plans are progressing to expand across other asset types.

Ergon Energy employs EA Technology’s Condition Based Risk Management (CBRM) modelling methodology for high value assets where the effort required to develop, maintain and collect the information required to support the models is justified. This methodology combines current asset condition information, engineering knowledge and practical experience to predict future asset condition, performance and residual life of assets. The CBRM system supports targeted and prioritised replacement strategies. The outputs from CBRM, Health Indices, are used in conjunction with an engineering assessment to form the basis of the application of the risk based methodology. The risk based methodology allows Ergon Energy to rank projects based on their consequence of failure in addition to their probability of failure. The development of the asset investment plan and specific projects are based on the risk score in conjunction with the engineering assessment and optimised to derive the asset investment program.

**Figure 23** below provides a summary of the process for delivering network asset investment planning condition based risk management.

**Figure 23: Process to Create Asset Investment Plan**
9.4 Asset Replacement

Ergon Energy manages the replacement of assets identified for retirement through a combination of specific projects and more general programs.

Projects are undertaken where limitations are identified that are specific to a site or feeder. Limitations of this nature are considered in conjunction with other network limitations including augmentation and connections to identify opportunities to optimise the scope of the project to address multiple issues and minimise cost. Project planning is undertaken in accordance with the RIT-D which considers the ongoing need for the asset to meet network requirements as well alternative solutions to replacement and the impact on system losses where material. Assets without an ongoing need are retired at economic end of life and are not considered for replacement.

Programs of replacement are undertaken when the scope of works to address the identified limitation is recurring across multiple locations and does not require consideration under the RIT-D.

The following sections provide a summary of the replacement methodologies for the various asset classes in the Ergon Energy network.

9.4.1 Substation Primary Plant

Power Transformer Replacement and Refurbishment

Transformers are condition monitored and require regular tap-changer maintenance. Failure consequences involve safety impacts for employees and nearby assets in the vicinity at the time of failure, reliability impacts related to technical ability to meet demand, environmental impacts from the quantities of oil involved, and high costs of replacement. Explosive bushing failures and transformer fire are recognised as significant safety risks. Due to the potential failure consequences, Ergon Energy has adopted a CBRM approach to define the highest priority end-of-life replacement time of these assets, optimised for overall least cost and risk.

Circuit Breaker and Switchboard Replacement and Refurbishment

Circuit breakers and switchboards are condition monitored and require regular maintenance. Failure consequences involve safety impacts for employees and nearby assets in the vicinity at the time of failure and reliability impacts related to technical ability to meet demand. Explosive failure of the circuit breaker, electrical arcing consequences causing collateral damage to nearby equipment, and inability to break load and fault currents are recognised as significant safety risks. Due to the potential failure consequences, Ergon Energy has adopted a CBRM approach to define the highest priority end-of-life replacement time of circuit breakers, optimised for overall least cost and risk.

Instrument Transformer Replacement and Refurbishment

Current Transformers (CTs) and Voltage Transformers (VTs) are condition monitored and require little maintenance. Failure consequences are related to safety impacts for employees and nearby assets in the vicinity at the time of failure and reliability impacts related to technical ability to meet demand. Explosive failure of the transformer, electrical arcing consequences causing collateral...
damage to nearby equipment, and inability to perform network protection functions are recognised as significant safety risks. Due to the failure consequences, Ergon Energy has adopted a CBRM approach to identify the highest priority end-of-life replacement of current and voltage transformers for replacement, optimised for overall least cost and risk.

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

Outdoor isolators are condition monitored and require periodic mechanical maintenance. 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 are condition monitored and require little maintenance. Failure consequences are generally related to ability to supply load under transformer contingency situations and in some locations, increased risk of power system instability. 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)**

SVCs are condition monitored. Modern units require little maintenance, however older units require extensive maintenance. Failure consequences are generally related to dynamic network voltage performance, ability to meet legislated voltage compliance obligations, ability to supply load under high system load conditions and in some locations, increased risk of power system instability and voltage collapse. These assets are uniquely designed to suit local power system conditions. Replacement is justified individually, based upon operational and financial performance outcomes.

9.4.2 **Substation Secondary Systems**

More detail can be found for secondary system replacement programs in Chapter 15.

**Protection Relay Replacement Program**

Protection relays are condition monitored and older models require regular maintenance. Protection relays react to power system faults and automatically initiate supply de-energisation. Failure consequences are predominantly safety impacts, including loss of ability to respond to power system faults and heightened safety risks due to continued energisation of failed assets. Duplication and redundancy are typically employed to reduce these safety risks, although some older sites retain designs where backup protection does not completely compensate for initial protection asset failure. Due to the failure consequences, Ergon Energy has adopted a proactive replacement program targeting problematic and near end of life relays.
Chapter 9. Asset Life-Cycle Management

Remote Terminal Unit (RTU) Replacement Program

RTUs are condition monitored and require little maintenance. RTUs allow remote monitoring and control of substations. Failure consequences include safety impacts including inability to de-energise the network upon reported emergency situations; reliability impacts including an inability to operate the power system, and inability to react to asset alerts and alarms in a timely manner and extended customer outages.

Aged RTU technology deployed in our network has become obsolete. Due to the extensive wiring in place when installed, replacement is time and resource intensive, and a high-cost exercise. Due to the failure consequences, Ergon Energy has adopted a proactive replacement program targeting ageing and obsolete RTUs and a planned replacement program for this asset class is underway.

Audio Frequency Load Control (AFLC) Replacement Program

AFLC equipment is condition monitored and the electromechanical types require some maintenance. AFLC systems achieve customer demand management by facilitating peak load lopping of hot water systems, pool pumps and other large fixed installation loads. Failure consequences generally have reliability impacts, including increased localised load peaks, overloading of distribution assets (shortening life) and overload tripping of assets, with the potential for customer outages. 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.

Substation dc supply systems

Substation dc supply systems are condition monitored and require little maintenance. Failure consequences include loss of protection capabilities; loss of circuit breaker functional capabilities; loss of substation monitoring and control capabilities; and loss of communications system capabilities. The impact of this loss of facility includes adverse safety, reliability and business function performance. Due to the failure consequences, Ergon Energy has adopted a proactive replacement program targeting battery systems.

9.4.3 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 be in line with asset age trends.
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. The works program is expected to completed before 2020.

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. The works program is expected to complete before 2020.

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 Dangerous Electrical Events (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 7/0.64 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. The works program is expected to extend beyond 2025, and it is anticipated that other aging conductor replacement issues will also become prominent during this time, extending these sorts of works programs indefinitely.

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 results 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.

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. The program is around 50% complete and scheduled to be complete by 2020.

### 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.

### 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. The targeted program has commenced.

### Customer Service Lines

Customer service line replacement occurs through a combination of failing inspection, capital works (including augmentation projects), and proactive replacement where age, type, condition, and network risk are considered. The proactive replacement of customer service lines is currently focused on open wire and concentric neutral services, as well as a population of problematic XLPE services experiencing insulation degradation, as they have been assessed as presenting the highest safety risk.

Failure of the neutral circuit components of customer service lines is the leading cause of asset related public shocks. While service line replacement mitigates this problem, it is typically a reactive solution, Ergon Energy intends to establish an LV Visibility and Control project that will use technology-based techniques to identify high impedance and open circuit neutral situations. Pre-emptive repair is intended to occur before anyone experiences any shocks. A trial is intended for a small number of residences to confirm viability of the approach. If effective, the trial will be expanded.

### 9.5 Derating

In some circumstances, asset condition can be managed through reducing the available capacity of the asset (derating) in order to reduce the potential for failure or extend the life; for example reducing the normal cyclic rating of a power transformer due to moisture content. The reduction of available capacity may have an impact on the ability of the network to supply the forecast load either in system normal or contingency configurations and therefore result in a network limitation.
Limitations of this nature are managed in alignment to augmentation processes.
Refer to Section 7.5 for information on the assets that Ergon Energy is planning to replace as major projects and proactive replacement programs in the next five years.

We welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au
Chapter 10
Network Reliability

10.1 Reliability Measures and Standards
10.2 Service Target Performance Incentive Scheme
10.3 High Impact Weather Events
10.4 Guaranteed Service Levels
10.5 Worst Performing Feeders
10.6 Safety Net Target Performance
10. Network Reliability

10.1 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.

10.1.1 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.

10.1.2 Minimum Service Standards (MSS)

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 10.1.3, along with our performance against these limits.

10.1.3 Reliability Performance in 2017-18

The normalised results in Table 35 highlight’s a favourable performance against MSS for all of our network categories in 2017-18.

Table 35: Performance Compared to MSS

<table>
<thead>
<tr>
<th>Normalised Reliability Performance</th>
<th>2016-17 Actual</th>
<th>2017-18 Actual</th>
<th>2015-20 MSS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SAIDI (mins)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>106.99</td>
<td>124.82</td>
<td>149</td>
</tr>
<tr>
<td>Short Rural</td>
<td>279.38</td>
<td>318.23</td>
<td>424</td>
</tr>
<tr>
<td>Long Rural</td>
<td>780.76</td>
<td>891.29</td>
<td>964</td>
</tr>
<tr>
<td><strong>SAIFI</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>1.135</td>
<td>1.490</td>
<td>1.98</td>
</tr>
<tr>
<td>Short Rural</td>
<td>2.637</td>
<td>2.708</td>
<td>3.95</td>
</tr>
<tr>
<td>Long Rural</td>
<td>5.804</td>
<td>5.551</td>
<td>7.40</td>
</tr>
</tbody>
</table>

In 2017-18, 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 both the duration and frequency of overall outages reducing by 40% and 41% respectively. This is a reflection of the targeted investment made during the last two regulatory control period towards achieving the regulated MSS standards.

Figure 24 and Figure 25 depict the five-year rolling average reliability performance for both SAIDI and SAIFI at whole of regulated network level, which demonstrate continual improvement. The trends also show that our network reliability outcomes could have reached the plateau, possibly indicating the optimal performance capability of the network without further reliability specific investment on its infrastructure.

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22 Ergon Energy’s MSS is ‘flat-lined’ for the current regulatory period 2015-2020.
Chapter 10. Network Reliability

Figure 24: Network SAIDI Performance Five-year Average Trend

Figure 25: Network SAIFI Performance Five-year Average Trend
10.1.4 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 seasonalised across the years to make greater allowance for unplanned outages during the storm season, between November and March.

10.1.5 Reliability Corrective Actions

As shown in Table 35 above, Ergon Energy is has met all the MSS limits for its SAIDI/SAIFI performance in 2017-18 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.

Ergon Energy continues to utilise advanced tools and other resources available to the Operations Control Centres to assist field operations with a more effective dispatch and coordination of response crews.

Early years of 2015-20 regulatory control period saw full implementation of Field Force Automation (FFA), with the field crews having ‘Toughpads’ with advanced user friendly functionalities to manage outages and other field works. This has added further efficiency in fault finding and outage management and continues to yield 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.

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.
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Ergon Energy is maintaining a continuous improvement focus around information and existing technologies and advanced modelling techniques. In the same time Ergon energy 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.

During the early years of 2015-20 regulatory control period, Ergon Energy completed two of its key reliability improvement strategies, Automatic Circuit Recloser (ACR) and/or Remote Controlled Gas Switch Strategies to increase fault sectionalising and switching capability on selected distribution feeders across the State. This was further supported by the completion of our strategy to establish the communications to ACR. This has delivered 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.

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

10.2 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).

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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 applicable revenue change is applied in the third year from the regulatory year when the performance outcomes are measured.

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 category. 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 2017-18 Performance RIN’s response included completed templates (and relevant processes, assumptions and methodologies) relating to reliability performance reporting under the STPIS.

10.2.1 STPIS Results and Forecast

The normalised results in Table 36 highlight a favourable year end performance against STPIS for all of network categories in 2017-18. As this table presents average duration and the frequency of unplanned supply interruptions, lower numbers indicate stronger results and less interruption to our customers’ electricity supply.

Table 36: Performance Compared to STPIS

<table>
<thead>
<tr>
<th>Normalised Reliability Performance</th>
<th>2016-17 Actual</th>
<th>2017-18 Actual</th>
<th>2015-2024 STPIS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unplanned SAIDI (mins)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>79.43</td>
<td>84.55</td>
<td>126.73</td>
</tr>
<tr>
<td>Short Rural</td>
<td>213.14</td>
<td>234.56</td>
<td>317.06</td>
</tr>
<tr>
<td>Long Rural</td>
<td>624.48</td>
<td>681.58</td>
<td>742.47</td>
</tr>
<tr>
<td>Unplanned SAIFI</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban</td>
<td>0.922</td>
<td>1.233</td>
<td>1.503</td>
</tr>
<tr>
<td>Short Rural</td>
<td>2.261</td>
<td>2.253</td>
<td>3.019</td>
</tr>
<tr>
<td>Long Rural</td>
<td>4.892</td>
<td>4.539</td>
<td>5.348</td>
</tr>
</tbody>
</table>

In 2017-18, Ergon Energy’s reliability of supply outperformed the unplanned performance targets under the Australian Energy STPIS for all six measures.

Figure 26 depicts the STPIS targets and results for the 2011-18 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).

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24 Ergon Energy’s STPIS is ‘flat-lined’ for the current regulatory period 2015-2020.
Chapter 10. Network Reliability

Figure 26: STPIS Targets and Results for 2011-18 Period
10.3 High Impact Weather Events

10.3.1 Emergency Response

Ergon Energy is conscious that its responses to emergency 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 and Emergency Exercises

To better enable our network to cope with emergency events, a number of simulation exercises will be conducted in preparation for the upcoming storm season. Participation in these exercises involves staff across Ergon Energy to confirm and enhance their knowledge of the approach to an emergency response. Ergon Energy also participates in external disaster exercises and 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 and mapping services. The combined process produces more accurate and timely field data for the planning, restoration and recovery, which supports improved response times and savings to Ergon Energy and the local economy.

Forecasting/Modelling/Tracking

We are improving our use of 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.
Post Event Reviews 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 while in February 2018, severe thunderstorms impacted over 196,000 customers in Brisbane. Comprehensive post implementation reviews are conducted to identify 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.

10.3.2 Summer Preparedness

Summer Preparations for the 2018-19 storm season

The specific activities being undertaken to prepare the network for the 2018-19 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, 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 priorities 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 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.
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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.
- additional resource support from Energy Queensland and interstate Distribution Network Service Providers.

Customer and community engagement

Ergon Energy keeps its customers informed and engaged through:

- the Customer Contact Centre
- community awareness and education campaigns
- direct media and community engagement forums
- website, social media and other online communications.

10.3.3 Bushfire Management

Ergon reviews and updates a Bushfire Risk Management Plan annually. The Plan is published in August each year and contains a list of programs and specific initiatives to reduce bushfire risks. Ergon has on-going programs to replace aged conductors, install spacers, install gas insulated switches in lieu of air break switches, replacement of sub optimal pole top constructions and utilises sparkless fuses in high bushfire risk areas. Ergon also undertakes pre-summer inspections in bushfire risk areas and rectifies the high priority defects identified on the patrols. It also reports and investigates suspected asset related bushfires.
10.4 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 37. 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 37: GSL Limits Applied by Feeder Type

<table>
<thead>
<tr>
<th>EDNC Clause</th>
<th>GSL</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>Wrongful disconnections (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>Connections (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>Reconnections (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>Hot Water Supply (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>
<tr>
<td>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>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>2.3.9(a)(i)</td>
<td>Reliability – Interruption Duration (If an outage lasts longer than...)</td>
<td>18 hours</td>
<td>18 hours</td>
<td>24 hours</td>
</tr>
<tr>
<td>2.3.9(a)(ii)</td>
<td>Reliability – Interruption Frequency (A customer experiences equal or more interruptions in a financial year)</td>
<td>13</td>
<td>21</td>
<td>21</td>
</tr>
</tbody>
</table>

10.4.1 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 38 shows the number of claims processed to date and paid in 2017-18.
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Table 38: Number of Claims Processed to Date and Paid in 2017-18

<table>
<thead>
<tr>
<th>GSL</th>
<th>Number Paid</th>
<th>Amount Paid</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wrongful Disconnection</td>
<td>64</td>
<td>$9,088</td>
</tr>
<tr>
<td>Connection of Supply</td>
<td>61</td>
<td>$12,363</td>
</tr>
<tr>
<td>Customer Reconnection</td>
<td>23</td>
<td>$2,107</td>
</tr>
<tr>
<td>Hot Water Supply</td>
<td>1</td>
<td>$57</td>
</tr>
<tr>
<td>Appointments</td>
<td>160</td>
<td>$9,120</td>
</tr>
<tr>
<td>Planned Interruptions</td>
<td>1,381</td>
<td>$48,085</td>
</tr>
<tr>
<td>Duration of Interruption</td>
<td>22,716</td>
<td>$2,589,624</td>
</tr>
<tr>
<td>Frequency of Interruption</td>
<td>59</td>
<td>$6,726</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>24,465</strong></td>
<td><strong>$2,677,170</strong></td>
</tr>
</tbody>
</table>

10.5 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 June 2018, has been provided in Appendix E. Ergon Energy’s worst performing feeder assessment for 2017-18 is summarised below:
• 13% of our distribution feeders supplying more than 20 customers have been identified as red feeders at June 2018 (147 in total – 16 Urban, 105 Short Rural and 26 Long Rural). In addition, there are 43 red feeders, individually supplying less than 20 customers. However, these 43 feeders only supply a total of 0.03% of Ergon Energy customers.
• There has been a decrease of 8% in the total number of red feeders supplying more than 20 customers compared to the last financial year. These red feeders supply less than 4.98% of Ergon Energy’s total distribution customers.
• The top 50 worst performing feeders, which equate to 4.17% of the total distribution feeders, are targeted for reliability improvement investments.
• 35 of the worst performing feeders have carried over from the list identified either in 2016-17 or previous years in 2015-20 regulatory period.

Review of Worst Performing Feeders Reported for 2016-17

• 44% of the 50 worst performing feeders identified in 2016-17 saw an improvement in their annual SAIDI as of June 2018. Eight of those feeders now have significantly improved annual SAIDI, and are now favourable to the June 2018 MSS limits.
• During 2017-18, 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 2016-17. This included 5 Urban, 17 Short Rural and 6 Long Rural feeders scattered mainly in Northern Queensland, Mackay and South West supply regions. Eight of these feeders did not present any opportunities for capital investment to improve reliability with some of them showing significant performance improvement as of June 2018.
• 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.
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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 and such investment cannot be considered prudent to improve reliability for a small cluster of customers or a feeder/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/regions.

The reliability improvement solutions identified from the worst performing feeder reviews conducted in this regulatory period 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 2018-19.

The overall approach for the worst performing feeder performance improvement includes the following in order of preference and affordability:

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

Approximately 60% of the customers in the South West supply region are supplied by radial networks.
2. Prioritisation of preventive-corrective maintenance by:
   o scheduling asset inspection and defect management to poorly performing assets early in the cycle
   o scheduling red feeders first on the vegetation management cycle
   o undertaking wildlife mitigation (e.g. birds, snakes, possums, frogs) in the vicinity of red feeders

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

10.6 Safety Net Target Performance

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

Supply interruption events over 2017-18 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 6.4.2).

In 2017-18, there were no events exceeding the service Safety Net targets.
Chapter 11
Power Quality

11.1 Customer Experience
11.2 Power Quality Supply Standards, Code Standards and Guidelines
11.3 Power Quality Performance in 2017-18
11.4 Quality of Supply Process
11.5 Strategic Objectives 2015-20
11.6 Solar PV Systems
11.7 Queensland Electricity Regulation Change
11.8 Power Quality Ongoing Challenges and Corrective Actions
11.9 Risk Assessment
11. 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 their quality of the supply. PQ is the compliance of measured system wide network conditions with defined parameter limits.

11.1 Customer Experience

The QoS experienced by customers is measured by the number of QoS enquiries lodged by customers. QoS enquiries occur when a customer contacts Ergon Energy with a concern that their supply may not be meeting the standards. Figure 27 shows that the number of enquiries on a normalised basis per 10,000 customers per month. There has been a slight decrease during the 2017-18 year mainly due to the increase in customers.

Figure 27: Quality of Supply Enquiries per 10,000 customers

QoS enquiries are selected from categories on initial contact as follows: Low Voltage, voltage dips, voltage swell, voltage spike, solar PV, TV or radio interference, motor start problems, and noise from appliances. Figure 28 shows a breakdown of the enquiries received by the reported symptoms over the last 12 months, with the largest identifiable category, at 56%, related to solar PV issues. Many of these are associated with customer installations where solar PV inverters could not export without raising voltages above statutory limits, (although inverters are designed to disconnect when voltage rises excessively, regular occurrences of this reduce the level of electricity exported and can often cause voltage fluctuations and customer complaints). The relationship to the previous five years is shown in Figure 29.
The number of QoS enquiries received in 2017-18 increased by 13.73% when compared to the previous year from 1660 to 1888 enquiries. Solar PV enquiries account for approximately 56% of all QoS enquiries. The connection of solar PV systems has led to numerous network voltage issues, which have required responses ranging from reviewing tap plans, reviewing regulator settings to...
augmenting LV and HV networks in order to accommodate the solar PV systems.

The close out of QoS enquires is shown in Figure 30. The data shows that 38% of enquires to date were due to a network issue, 25% there was no fault found and 5.2%, the fault was on the customers side of the connection. There are still 545 (28.8%) enquires still open under investigation.

Figure 30: Quality of Supply Enquires by Type at Close Out

11.2 Power Quality Supply Standards, Code Standards and Guidelines

The Queensland Electricity Regulation and Schedule 5.1 of the NER lists a range of network performance requirements to be achieved by Network Service Providers (NSPs). Ergon Energy’s planning policies takes these performance requirements into consideration when reviewing network developments. The tighter of the limits is applied where there is an overlap between regulations and the NER.

In October 2017 the Queensland Electricity Regulation has amended to change the low voltage (LV) from 415/240 volts +/-6% to 400/230V +10%/-6% to harmonise with Australian Standard 61000.3.100 and a majority of other Australian states.

Some of the relevant requirements under the Regulations/Rules are listed below and further defined in Table 39, Table 40, Table 41 and Table 42.

- **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 Rules.
- **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 Rules (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.

### Table 39: Allowable Variations from the Relevant Standard Nominal Voltages

<table>
<thead>
<tr>
<th>Voltage Levels</th>
<th>Electricity Regulations</th>
<th>NER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low voltage (less than 1kV)</td>
<td>+10 / -6%¹</td>
<td>±10%</td>
</tr>
<tr>
<td>Medium voltage (1kV to 22kV)</td>
<td>±5%¹</td>
<td>±10%</td>
</tr>
<tr>
<td>High voltage (22kV to 132kV)</td>
<td>As Agreed</td>
<td>±10%</td>
</tr>
</tbody>
</table>

¹ Limit is only applicable at customer’s terminals.

### Table 40: Allowable Planning Voltage Fluctuation (Flicker) Limits

<table>
<thead>
<tr>
<th>Voltage Levels</th>
<th>Electricity Regulations</th>
<th>NER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low voltage (less than 1kV)</td>
<td>Not Specified</td>
<td>Pst = 1.0, Plt =0.8, (ΔV/V – 5%)</td>
</tr>
<tr>
<td>Medium voltage (11kV and 33kV)</td>
<td>Not Specified</td>
<td>Pst= 0.9, Plt=0.8, (ΔV/V – 4%)</td>
</tr>
<tr>
<td>High voltage (33kV to 132kV)</td>
<td>Not Specified</td>
<td>Pst= 0.8, Plt=0.6, (ΔV/V – 3%)</td>
</tr>
</tbody>
</table>

### Table 41: Allowable Planning Voltage Total Harmonic Distortion Limits

<table>
<thead>
<tr>
<th>Voltage Levels</th>
<th>Electricity Regulations</th>
<th>NER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low voltage (less than 1kV)</td>
<td>Not Specified</td>
<td>7.3%</td>
</tr>
<tr>
<td>Medium voltage (11kV)</td>
<td>Not Specified</td>
<td>6.6%</td>
</tr>
<tr>
<td>Medium voltage (33kV)</td>
<td>Not Specified</td>
<td>4.4%</td>
</tr>
<tr>
<td>High voltage (110kV, 132kV)</td>
<td>Not Specified</td>
<td>3%</td>
</tr>
</tbody>
</table>
Where there is need to clarify requirements; the relevant Australian and International Electrical Technical Commission (IEC) Standards are used to confirm compliance of our network for PQ. Energy Queensland also has the Standard for Network Performance, which provides key reference values for the PQ parameters.

The Power Quality Planning Guideline and the Standard for Transmission and Distribution and Planning is a joint working document with Energex that describes the planning requirements including with respect to power quality. These guidelines apply to all supply and distribution planning activities associated with the network.

### 11.3 Power Quality Performance in 2017-18

#### 11.3.1 Power Quality Performance Monitoring

Processes for PQ monitoring have been developed from the requirements of the Queensland Electricity Regulations and the NER Rules. Ergon Energy started to install network monitors in 2009 and currently has in excess of 2,390 PQ monitors on distribution transformers and 1260 customer meters throughout the network that monitor and record the network PQ performance. These monitors are remotely monitored and provide an insight into power quality performance at the junction of the Medium Voltage (MV) and LV network. Monitors currently cover more than 900 feeders or roughly 75% of the feeders in the network.

Each of these monitors contributes to give an indication of the state of the network for PQ parameters. The monitor data is downloaded 4 times daily, recorded, accessed and presented based on 10 minute averages. The data is available the following day and presented to various departments within Ergon Energy monthly as part of the PQ Monthly report. All PQ monitors are installed on the terminals of the distribution transformer and therefore there maybe differences at the end of the LV feeder due to high load during the evening load and rise in voltage during the day depending on the amount of solar along the feeder. 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 meters have been available. A number of customer meters are no longer available with the change due to Power of Choice (PoC).

Voltage data presented in this report is based on the 230V +10/-6 limits.

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**Table 42: Allowable Voltage Unbalance Limits**

<table>
<thead>
<tr>
<th>Voltage Levels</th>
<th>Electricity Regulations</th>
<th>NER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low voltage (less than 1kV)</td>
<td>Not Specified</td>
<td>2.5%</td>
</tr>
<tr>
<td>Medium voltage (1kV to 33kV)</td>
<td>Not Specified</td>
<td>2%</td>
</tr>
<tr>
<td>High voltage (33kV to 132kV)</td>
<td>Not Specified</td>
<td>1%</td>
</tr>
</tbody>
</table>
11.3.2 Steady State Voltage Regulation – Overvoltage

The number of monitored sites that reported overvoltage outside of regulatory limits of 253V was 17.85% for 2017-18. This means 17.85% of sites recorded an exceedance of the upper limit for more than 1% of the time based on 10 minute averages. This is small improvement from the 16-17 year when there were 21.74% of sites with overvoltage. Figure 32 shows the number of monitored sites that have recorded over-voltage conditions for the last five years and percentage of overvoltage sites for each year. This is the fifth consecutive year that improvement has occurred to reduce the number of sites with overvoltage issues.

Ergon Energy has continued to improve the network voltage performance by constantly working to review network data and modelling and make the necessary changes to ensure the network is meeting all PQ parameters. The take-up of solar PV is continuing throughout regional Queensland and as a result the requirement to monitor power quality is a necessity.

Most PQ monitor sites are at the terminals of the distribution transformers and Ergon Energy recognises the need to have monitors at the end of long LV runs where a high percentage of customers have solar systems. Sites that only have a monitor at the transformer terminals may find the voltage not within limits at the further end of the LV network under load conditions. Improvements will continue to be achieved by implementation of the Customer Quality of Supply strategy. Further analysis of monitored transformers is continuing as more sites are fitted with monitors.
11.3.3 Steady State Voltage Regulation – Undervoltage

The number of monitored sites recording under-voltage issues outside of the regulatory limit of 216.2V was 0.85% for 2017-18. This means 0.85% of monitored sites recorded an exceedance of the lower limit for more than 1% of the time based on 10 minute averages. Figure 33 shows the number of monitored sites that have recorded under-voltage conditions for the last five years. There has been a small improvement from the 2016-17 year when there were 1.3% of sites with under-voltage.

The change to 230V sees the lower limit for low voltage move to 215V. This change is expected to result in the number of non-compliant sites reduce to virtually zero.

Figure 33: Undervoltage sites

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Figure 32: Overvoltage sites

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11.3.4 Voltage Unbalance

Data from the 3-phase sites shows that 4.8% of these sites were outside of required the unbalance standard of 2.5% during 2017-18.

Typically, unbalance is seen on the rural feeders where there are SWER networks and a large number of single phase customers in the associated downstream feeder, which impacts on the overall balance of the three phase feeder. Due to radical nature and high number single phase transformers, Ergon Energy has a high number of monitors on single phase transformers. Monitors sites that are not three phase, are shown as part of the result.

Figure 34 shows the number of sites that have recorded unbalanced conditions for the past five years.

Figure 34: Voltage Unbalance Sites

11.3.5 Harmonics Distortion

Harmonics are a measure of the impurity of the voltage and are recorded as Total Harmonic Distortion (THD) representing all harmonics levels from the second to the fiftieth harmonic. Not all monitored sites are capable of measuring harmonic with 1384 of the 3659 sites (37.5%) not capable of harmonic reporting. There were 1.1% of sites recording harmonics that exceeded the regulatory limits of 8% during 2017-18. This figure will be at the upper limit as when some faults occur with voltage and unbalance it impacts on harmonics recorded values. Figure 35 shows the percentage of sites that exceed THD limits.
Typical sources of harmonic distortion include electronic equipment incorporating switch mode power supplies, modern air conditioners with variable speed drive inverters and solar PV inverters. 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.

### 11.4 Quality of Supply Process

Ergon Energy responds to customer QoS enquiries / complaints by carrying out an investigation which may include the installation of temporary monitoring equipment on the network and at customers’ premises and this data is used in conjunction with existing network monitors to analysis and determine what remediating is necessary.

Due to the complexity of the network and the large number of sites involved, the management of quality of supply presents many challenges. To address these challenges, a proactive and systematic approach shown in Figure 36 is adopted. This involves:

- Establishing suitable data acquisition (monitoring) and reporting systems to identify problem areas
- Establishing objective measures and supporting systems for prioritising remedial works
- Developing network models down to the LV that allow problem areas to be predicted
- Implementing and tracking improvements from remediation programs
- Measuring results to refine the network model and remediation options.
Ergon Energy has developed a series of reports from the Data Warehouse to identify and prioritise power quality issues. These reports enable the large volume of power quality time series data captured from the monitoring devices to be more easily analysed with possible drivers such as equipment failure and network topology as possible causes. Ergon Energy takes a pro-active approach to identify possible sites where QoS issues why result. Sites that exceed limits are prioritised and emailed to PQ staff daily for action. PQ staff then work with Customer Service and Network staff to rectify issues before the issue is seen or impacts customers equipment.

11.5 Strategic Objectives 2015-20

During 2017-18 Ergon Energy continued to focus its voltage management strategy on all voltage levels of the network however a high percentage were associated with the LV customers. In the 2017, Energy Queensland developed the Customer Quality of Supply Strategy which covers the Power Quality strategy for Ergon Energy and Energex. It covers the changing network connections and configurations, increasing customer peak demands, the high penetration of solar PV and its continued growth, the battery energy storage systems and the impact of EVs.

During 2017-18 Ergon Energy continued the implementation of the current PQ strategy by installing 450 PQ monitors on distribution transformers and 10 PQ analysers within substations to disturbing load feeders. This will bring the total installed monitors to more than 2900 which represent approximately 3% of the distribution transformers in regional Queensland. The number of analysers installed to a total of 130.

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 this PQ data provides an additional source of data to complement our network monitors. These monitors are currently providing approximately 1200 additional sites of data and will reduce due to Power of Choice.

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 if there is equipment failure or where a review of regulator settings or tapping plans is required, 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 from most feeders. An additional 50 PQ analyser will also be installed within substations connected to disturbing load feeders.

Due to the diversity and type of the Ergon Energy networks, unbalance is another PQ parameter that shows exceedances in various locations and numerous times throughout the year. Unbalance will be managed as per the PQ Planning Guidelines and the Standard for Transmission and Distribution Planning.

The Harmonic levels being seen on the network have remained constant. Continual vigilance will need that harmonics levels do not impact on the effective operation of the network.

### 11.6 Solar PV Systems

Ergon Energy’s strategy continues to have a strong focus on the voltage management for low voltage customers due to the high number of residential customers with a high percentage of solar systems. During the period 2012-16 the number of QoS enquires showed a steady decrease however in the 2017-18 the number of enquires increased again. Referring to Figure 37 it shows that the number of solar applications and connections has continued to increase each year for the past 2 years in the range of 11%. This is considering the Feed-in-Tariff (FiT) reduced in 2013 from 44 cents to currently around 8 cents.

The continued increase of solar connections shows that continual vigilance and expenditure will be required throughout the network to ensure it remains compliant. The Customer Quality of Supply Strategy has identified that due to the high percentage of LV customers with solar systems it will require continual work in balancing customers connections on the LV network to minimise neutral current and negative load in the MV network.

**Figure 37: Solar PV Applications and Connections**

![Solar PV Applications and Connections](image)

Throughout regional Queensland there has been high number of applications for large scale solar
farms during 2017-18 and more than 70MW of solar farms have connected. Refer to Chapter 12 for further details of all solar farms connections. Solar Farms larger than 1.5MW are required to have a PQ analyser at the connection point. The PQ analyser is used as part of the commissioning process and used to ensure ongoing compliance when operating.

11.7 Queensland Electricity Regulation Change

In October 2017 the Queensland Government changed the Queensland Electricity Regulation for a change in the low voltage from 415/240 +/-6% to 400/230 +10/-6%. This is also known at 230V. The change requires initial compliance with the new statutory voltage limits of 216-253V as per AS60038 to be achieved by October 2018 with full compliance to AS 61000.3.100 by October 2020.

The change has seen a number of zone substations bus voltages adjusted to meet the requirements. At the same time, feeder model reviews are occurring to determine the required changes to regulator settings and what transformer tap changes are required. As of 30 June 2018 the changes that have been implemented, show that 86% of Ergon Energy’s network is compliant for 230V. The current modelling and measurements, indicate that the number of future changes will require some augmentation costs and some transformer upgrades along with conductor upgrades and changes.

11.8 Power Quality Ongoing Challenges and Corrective Actions

11.8.1 Medium/High Voltage Network

Ergon Energy has a high number of large industrial customers and large generators (solar farms) that have equipment that can exceed the power quality parameters such as harmonics. Many of these customers are on dedicated feeders and 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 the power quality parameters for the type of industry.

11.8.2 Low Voltage Network

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 systems during the day and peak loads during non-daylight periods on the LV network. This will require on going work to ensure the PQ parameters are maintained within limits and to ensure neutral currents to not become excessive. The Customer Quality of Supply Strategy for 2020-25 has identified the need for further monitoring of the LV network. The strategy has identified the need for all transformers larger than 200kVA supplying a large number of residence customers with the total solar ratio greater than 50% to have a PQ monitor installed. It has also been found that where there are long LV feeders exceeding 400 meters, there is a need to monitor the end of the LV run also. Table 43 lists the initiatives that have occurred during 2017-18 along with the expected work for 2018-19.
### Table 43: Summary of Power Quality 2018/19 Initiatives

<table>
<thead>
<tr>
<th>Initiative Title</th>
<th>2017/18 units</th>
<th>2018/19 Proposed units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Monitoring / Reporting &amp; Data Analytics</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Distribution Transformer monitoring Including SWER</td>
<td>530</td>
<td>610</td>
</tr>
<tr>
<td>Distribution Transformer monitoring – Padmount</td>
<td>22</td>
<td>50</td>
</tr>
<tr>
<td><strong>Rectification Works</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uprate &amp; Reconfigure LV Network — Overhead (OH)</td>
<td>50</td>
<td>100</td>
</tr>
<tr>
<td>Uprate &amp; Reconfigure LV Network — Underground (UG)</td>
<td>Nil</td>
<td>Nil</td>
</tr>
</tbody>
</table>

With regard to remediation measures that address the impacts of high levels of solar PV penetration, Ergon Energy has considered the practical range of network options shown in Table 44. In general, as the solar PV penetration level rises, so does the cost of remedial work.

### Table 44: Network Solutions for Varying Levels of solar PV Penetration

<table>
<thead>
<tr>
<th>Solar PV Penetration Level</th>
<th>Network Solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>From 30% to 70%</td>
<td>1. Balance of PV load</td>
</tr>
<tr>
<td></td>
<td>2. Change transformer tap</td>
</tr>
<tr>
<td>From 40% to 100%</td>
<td>3. 1 and 2 above</td>
</tr>
<tr>
<td></td>
<td>4. Upgrade transformer</td>
</tr>
<tr>
<td></td>
<td>5. Additional transformer (incl. reconfigure LV area)</td>
</tr>
<tr>
<td></td>
<td>6. Re-conductor mains</td>
</tr>
<tr>
<td>From 100% to 200%</td>
<td>7. 1 to 6 above</td>
</tr>
<tr>
<td></td>
<td>8. New technology (On load tap transformer, LV regulator, Statcom)</td>
</tr>
</tbody>
</table>

As part of its Opex program, Ergon Energy will carry out targeted transformer tap adjustment programs and rebalancing programs to address voltage issues in areas with solar PV penetration exceeding 50%. This is supported by data showing significant numbers of distribution transformer tap settings on non-optimal settings and unbalance of voltages at distribution transformer LV terminals.

### 11.8.3 Planned actions for 2020-25 Regulatory Period

For the next regulatory control period, Ergon Energy will continue to have a strong focus on voltage management for low and medium voltage network issues identified through PQ data analysis. This will be further supported by installation of additional PQ monitors and analysers on our network at the terminals of distribution transformer and end of long LV feeders and PQ analysers at the connection point of large disturbing loads and generation sources. Typical rectification of voltage and PQ issues will include installation of Statcoms, switched capacitor, Low Voltage Regulator (LVR) and On Load Tap Changers (OLTC).
11.9 Risk Assessment

Ergon Energy is managing the risks associated with high solar PV penetration and voltage rise on the LV network through the Power Quality Strategy and the strategic initiative to invest in fit for purpose smart technologies. The PQ strategy will provide enhanced LV visibility by rolling out PQ data monitors across the LV network and will review the suitability of real-time ‘State Estimation’ algorithms as part of the intelligent grid transformation. The most recent initiative extends monitoring from the LV distribution transformer terminals to the end of LV circuits and within customer switchboards. Based on the monitoring data and predictive models developed, Ergon Energy identifies and prioritises areas for PQ improvement.

Compliance risks are also being managed through the revised connection standards for solar PV inverters / batteries and the future adoption of the 230V standards.
Chapter 12
Emerging Network Challenges and Opportunities

12.1 Solar PV
12.2 Battery Energy Storage Systems
12.3 Electric Vehicles
12.4 Strategic Response
12.5 Large Scale Renewable Projects
12.6 Land and Easement Acquisition Timeframes
12.7 Impact of Climate Change on the Network
12. 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 challenges of solar PV, land and easement acquisition and climate change, and the exciting opportunities that battery energy storage systems and electric vehicles present.

12.1 Solar PV

12.1.1 Solar PV Emerging Issues and Statistics

Queensland has the highest penetration of solar PV systems on detached houses (30%) not only in Australia\(^{26}\), but compared with any country. In our network, 24% 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 bi-directional energy flow. The impact is greatest in the LV network and creates a number of system design and operation challenges. Due to the PV penetration level and the nature of its network, Ergon Energy is on the leading edge of the distribution industry in responding to these issues. It 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 38 shows the increase in installed capacity associated with solar PV. Over the past 12 months, the volume of connections increased by 50%, and the PV capacity increased by almost 300%, compared with the previous 12-month period.

Figure 38: Grid-Connected Solar PV System Installed Capacity by Tariff as at June 2018

Chapter 12. Emerging Network Challenges and Opportunities

The escalating issue of reverse power flow occurs where local generation exceeds demand on a network element such as a feeder. Ergon Energy estimates that there are over 516 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 light, solar PV reduces network demand further, and solar PV inverters export to the grid. 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 1,050 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 becomes 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 constraints, including; transitioning to a 230V network standard, tariff review, trialling new technologies such as LV statcom and energy storage trials. Implementing a 230V network standard will allow more voltage variation, allowing many existing solar PV systems to operate more effectively and allow more solar PV systems to connect and export to the grid.

From a customer perspective Ergon Energy continues to streamline the application process and reduce network risks by enabling minimal- and partial-export connections. Minimal-export EG units essentially don't permit export of generated electricity to the distribution network. Applications for export-limited inverters now account for around 11% of new micro EG unit applications. This proportion has reduced since the increase in the capacity limit under the Queensland Government’s Regional Feed-in-tariff from 5kW to 30kW. Ergon Energy and Energex have jointly released an updated LV connection standard and draft HV connection standard covering solar PV systems and are undertaking a trial of the 230V standard, as discussed in Sections 12.4.2 and 12.4.3 respectively.

12.1.2 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 2017-18 demand peak was recorded at 5.30pm in the evening, the actual peak in consumption would have occurred mid-afternoon. However, on that day in February 2018, solar generation was at one point meeting almost 17% of the total network demand. While this changed the shape of the network demand during the day, the late-afternoon peak remained relatively unaffected, reduced by only 1% by PV.

The change in load pattern as the penetration of solar PV systems on a feeder has increased is illustrated in Figure 39. This figure shows the daily load pattern on a residential feeder in Burrum Heads (near Hervey Bay) for the lowest spring midday demand day over eight consecutive years. The daytime generation of solar has increased to the point that the feeder back-feeds significantly through to the zone substation.

The summer peak demand for the feeder is still occurring at approximately the same time of night in 2018 as it did in 2010. While the night summer peak demand has been growing slowly over the years, the midday demand in spring has reduced by over 1.5MW. This increase in daily variance
Chapter 12. Emerging Network Challenges and Opportunities

makes it more challenging to keep the network voltage within statutory limits, and can also result in decreased asset life of some equipment as voltage regulation devices operate more frequently.

**Figure 39: Burrum Heads Feeder Profile: Annual changes observed for Spring 2010 – 2017**

The increase in EG on our feeders makes it more 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 fully apparent when an unexpected event causes the solar PV systems to stop generating.

**Figure 40** 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 reduction was delayed. 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 40**, could result in excessive voltage drops, overloading of components, protection operation issues and loss of supply if not appropriately managed.
12.2 Battery Energy Storage Systems

Ergon Energy continues to monitor developments in the residential and commercial Battery Energy Storage Systems (BESS) market. We have built on our previous trials and extended the testing of BESS 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 BESS to provide network benefits (peak demand and/or power quality issues); however, we also recognise the barriers to effectively utilising this developing resource.

After Ergon Energy and Energex updated the joint standard for micro EG units up to 30kVA in 2016-17, a new joint Standard for the Connection of EG Systems (>30kW to 1,500kW) to a Distributor’s LV Network was released in September 2017. Among other things, this enables greater opportunity for business customers to connect BESS to new or existing solar PV installations.

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 BESS to achieve the same result in the future.
Chapter 12. Emerging Network Challenges and Opportunities

12.3 Electric Vehicles

Ergon Energy aims to remove as many barriers to EV ownership as possible, and is developing strategies to do this. This will enable our customers’ choice in transport fuels and, if EV charging is managed appropriately, also enhance network utilisation and place downward pressure on electricity prices. EVs, which are still an emerging industry in Australia, are already popular overseas and their numbers are expected to grow in Queensland as their purchase costs decrease, availability increases and more charging infrastructure is deployed. In the 12 months to 30 June 2018, the volume of plug-in EVs registered in Queensland has increased by 45% to more than 1,500 vehicles. A number of promoted EV releases in Australia in 2018-19 are likely to accelerate the growth rate.

In 2017-18, Energy Queensland’s unregulated business, Yurika Energy, worked with industry partners, including Ergon Energy, and the Queensland Government to deploy an EV charging highway from Toowoomba in the south east of Queensland to Cairns in the north. Ergon Energy plays a vital role in enabling access to our network for other entities wishing to deploy EV charging infrastructure. Ideally, EV charging would minimally increase peak demand but notably increase demand at times when the network has ample capacity such as the middle of the day and especially during the night.

12.4 Strategic Response

12.4.1 Roadmap to an Intelligent Grid

While there are a number of scenarios that could eventuate beyond 2025, it is certain that the immediate period (to 2025) and ultimately at least the next two decades will see significantly higher levels of intermittent and controllable Distributed Energy Resources (DER), new and increasingly active energy service providers, and an increased emphasis on the role of distribution networks on the overall system and market operation. Drawing from work such as the Energy Network Association and CSIRO Electricity Network Transformation Roadmap (ENTR), and looking globally at other progressive markets – such as the UK, Germany, California, New York, and New Zealand – it is apparent that the network business model will need to further evolve to become the operator of an intelligent grid platform.

In response Ergon Energy has developed a Future Network Strategy — Roadmap to an Intelligent Grid to provide a guiding holistic pathway for transforming the network business to have the capability necessary to achieve the following:

- Support affordability whilst maintaining security and reliability of the energy system
- Ensure optimal customer outcomes and value across short, medium and long-term horizons – both for those with and without their own DER
- Support customer choice through the provision of technology neutrality and reducing barriers to access the distribution network
- Ensure the adaptability of the distribution system to new technologies
- Promoting information transparency and price signals that enable efficient investment and operational decisions.
Chapter 12. Emerging Network Challenges and Opportunities

As an immediate priority, the roadmap also outlines the no-regret investments necessary for the Ergon Energy Network AER2020 submission to ensure efficient management and operation of the distribution network during the immediate period, while allowing a smooth transition to the future network business role.

12.4.2 Improving Standards for Increased DER Connections

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 DER connection standards. Ergon Energy has the highest volume of confirmed large DER connections of any DNSP on the NEM. With the rapid connection of large DER onto the network Ergon Energy is uniquely positioned to identify opportunities for standards improvement to assist in streamlining and reducing the cost of connections whilst ensuring safe and secure operation of the network.

In September 2017 Ergon Energy delivered a draft joint LV connection standard for DER with Energex which delivered modern and streamlined requirements for LV connected DER between 30kW and 1.5MW. The new standard has been positively received as it delivered benefits for industry and the network by delivering:

- Cost reduction by eliminating the requirement for Neutral Voltage Displacement (NVD) protection and zero export relays
- Improved equipment performance by utilising use of volt-var reactive control in inverters
- Ease of compliance with clear requirements for protection and definitions for the various types of generating technology (inverters or rotating machines).

Ergon Energy has delivered a draft joint HV connection standard for DER with Energex which:

- Leverages modern industry standards for solar PV inverter technology, aligning with the joint LV standard and removing barriers for solar connections under 1.5MW
- Introduces Class A1, A2 and B based on system size and the strength of the network where the connection is occurring. Having the three categories enable Proponents to have improved visibility of DER connection requirements based on the location and size of their planned connection
- Replaces four standards for HV DER connections in Queensland with one. Minimising the number of standards will enable improved compliance and assist in delivering aligned and streamlined connection application processes and assessments in Queensland. Ultimately having greater standards alignment in Queensland will reduce the time it takes to review, approve and connect DER to the network.

Energy Networks Australia is producing DER Grid Connections Guidelines and released a Framework and Principles document in May 2018. Further technical requirement documentation will be released in October 2018 and March 2019. Ergon Energy is planning to align to the National guidelines to assist in delivering improved alignment and continuity of DER connection standards in Australia.
12.4.3 Transition to the 230 Volt Low Voltage Standard

The Queensland Government recently legislated a change in low voltage from 240V (+/-6%) to 230V (+10/-6%) across the state to bring us into line with the Australian Standards AS60038 and AS61000.3.

While the upper supply limit of the 230V Australian Standard is similar (253.0V versus existing limit of 254.4V), the lower end of the Australian Standard moves down to 216.2V (versus the existing 225.6 V). This change is necessary because Australian Standards guide the importing / manufacturing of new appliances and electronic equipment.

The introduction of the 230V standard also aligns Queensland to other Southern states. It will provide greater flexibility to manage voltage and help to mitigate the growth and cost for voltage related issues. This will enable more solar PV to be connected to the network.

Small voltage reductions will be applied to the medium voltage at many sites across Queensland to achieve compliance on the LV network by 27 October 2018.

The legislated changes allow an approximate 32 month period to transition to the 230V standard and from 1 July 2020 Ergon Energy will maintain network supply voltages within the preferred range of between 225V and 244V.

Before this change was made, a trial was carried out in 2015-2016 in seven areas across the state. The trial involved 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 transformer tap plans, regulator settings and/or bus voltage set points to monitor for the 230V criteria. Analysis of these feeders confirmed the technical assumptions made in the network-wide business case and the impact to customers.

More information on the 230V transition 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 230V. Ergon Energy and Energex have provided the backing and support on the proposed change, and provided detailed feedback on the options considered for transition. Further information about the review can be found on the Queensland Governments website here:


12.5 Large Scale Renewable Projects

Ergon Energy is currently actively managing more than 110 enquiries for major EG 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 2-3GW 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 41: Active Renewable Energy Projects 2013-2017**

**Supporting solar power to do utility-scale 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 Ergon Energy worked with the owners and their inverter manufacturer to test for any QoS 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 and assess any capacity limitations, and 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 20MW.

During the year the 5MW 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 15MW 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.

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

Purchasing green energy for our customers

EEQ entered into a new Power Purchasing Agreement with Fotowatio Renewable Ventures for the output of its proposed 100MW 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 170MW 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 Far North Queensland’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 39MW large-scale renewables and 444MW 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.dews.qld.gov.au/electricity/renewables/tools/solar-maps

12.6 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 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.
12.7 Impact of Climate Change on the Network

A changing climate is leading to changes in the frequency and intensity of extreme weather and climate events including extreme temperatures, greater variations in wet and dry weather patterns (e.g. flooding, drought), bush fires, an increase in the severity of tropical cyclones, storms and storm surges as well as changing oceans and sea levels*. This suggests that there may be the likelihood of inundation or other damage to exposed and low lying Energy Queensland assets creating reliability problems as well as associated maintenance and asset replacement expenditures.

Ergon Energy as part of Energy Queensland partners with various organisations such as the Queensland Climate Resilient Council, Queensland Climate Adaption Strategy Partners and Queensland Reconstruction Authority to develop strategies dealing with climate change and to build more disaster resilient energy infrastructure.

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

- Keeping abreast of changes in planning guidelines and construction standards
- Keeping abreast of new storm surges and flood layers produced by councils and other agencies
- Undertaking surveillance and flood planning studies on network assets which are likely to be impacted by significant weather events, storm surges and flooding
- Undertaking network adaptations that mitigate the risk of bushfire (e.g. LV spreaders, sparkless fuses, conductor replacement).

Ergon Energy has works programs to adapt network assets to mitigate the risks of severe environmental events (e.g. cyclones, floods, bushfires and storms). These programs include both capital and operating expenditures.

Chapter 13

Information and Communication Technology

13.1 ICT Investment 2017-18

13.2 Forward ICT Program
13. Information and Communication Technology

With the recent merger of Ergon Energy and Energex into a single entity, the Information and Communication Technology (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.

Forward investment of the ICT Portfolio will be focused around a key set of Digital Building Blocks focused on transitioning Energy Queensland into a Digital Utility:

**Figure 42: Digital Enterprise Building Blocks**

The Digital Enterprise Building Blocks (DEBBs) will provide a common set of systems and processes, reducing complexity, simplifying Energy Queensland's processes and bringing the broader Energy Queensland entity onto a common, digital enterprise platform.
Chapter 13. Information and Communication Technology

13.1 ICT Investment 2017-18

This section summarises the material investments Ergon Energy has made in the 2017-18 financial year, or plans to undertake over the forward planning period, relating to ICT systems.

Significant work commenced in the 2017-18 year to initiate a number of the key programs within the DEBB portfolio, with the following major investments approved to commence delivery:

- Intelligence platform foundation
- People and culture
- Procurement
- Finance and planning
- Enterprise services.

In addition to this there were a number of smaller operational investments commenced or completed to ensure the ongoing stability of Energy Queensland’s suite of digital capability and infrastructure.

Table 45 provides an initiative level summary of ICT investments undertaken in 2017-18\textsuperscript{27}. These include projects which commenced prior to this year and investments which will not be completed until after 2017-18. Further information on the scope of each initiative can be noted below.

<table>
<thead>
<tr>
<th>Description</th>
<th>2017/18 Cost $ M actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Systems Modernisation (Power of Choice)</td>
<td>$10.07</td>
</tr>
<tr>
<td>Network Planning &amp; Design</td>
<td>$9.45</td>
</tr>
<tr>
<td>Intelligence Platform Renewal</td>
<td>$7.16</td>
</tr>
<tr>
<td>Infrastructure, Security &amp; Devices</td>
<td>$7.05</td>
</tr>
<tr>
<td>ERP EAM Portfolio of Projects</td>
<td>$5.12</td>
</tr>
<tr>
<td>Minor Applications Change and Compliance</td>
<td>$3.02</td>
</tr>
<tr>
<td>Distributed Workforce Automation</td>
<td>$3.10</td>
</tr>
<tr>
<td>Customer Systems</td>
<td>$1.28</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$46.25</strong></td>
</tr>
</tbody>
</table>

Note: Actuals includes ICT Managed Capex and Opex Program of work specific 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).

Market Systems Modernisation (Power of Choice)

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.

\textsuperscript{27} All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
Chapter 13. 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.

Network Planning and Design

Investment in this area was largely focused on; upgrading the GIS for Ergon Energy, as well as sustainment activities for Ergon Energy's Forecasting and Planning tools.

The 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.

Work is progressing on establishing a common approach to forecasting and planning which will require the replacement of the joint forecasting tool. Some minor investment has been required to sustain existing capability out to the end of the current control period.

The Statistical Metering Data Base (SMDB) for Ergon Energy, which is a legacy application that is used for load forecasting, carried a significant business risk as it was due to be replaced at the end of the previous regulatory period. The SMDB risk mitigation project, currently in delivery, will replace SMDB and thereby mitigate this business risk.

Intelligence Platform Renewal

This investment seeks to establish a centralised Intelligence Platform as an efficient, scalable and reliable solution in addressing the current and future demands on Ergon Energy’s data landscape as it transitions to a Digital Utility to ensure that Ergon Energy can:

- Address the data growth demands and duplication of siloed solutions (E.g. Power of Choice, customer data and future smart technologies)
- Create an industry standard intelligence platform for now and the future
- Build reliance on quality, consolidated and unified self-service reporting for better and faster decision making. Whilst mitigating the need for manual intervention and data quality issues in reporting
- Optimise license pricing through a partnership view and bulk purchase arrangements
- Maximise response to market and regulation changes whilst seeking better opportunities to influence and empower consumers.

Infrastructure, Security and Devices

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.

**ERP EAM Portfolio of Projects**

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 sub programs within this initiative encompass the following:

**People, Culture and Safety:**

- Replace systems and processes that support the core Human Resource, Payroll and Health, Safety and Environment (HSE) functionality. There will be new tools to Support core HR and Payroll, Performance, Recruitment, Training, Workforce Planning and HSE functions.
  - Solutions will help to integrate data across core processes; standardise reporting and analysis and ensure key processes may be performed from the internal network and from mobile devices.

**Asset and Works Management:**

- Implement a single system and process that supports asset and works management functionality within Strategy, Asset Safety and Performance (SAS&P) and Distribution business units. There will be new tools to:
  - Support lifecycle and financial management for assets through all stages of the asset life cycle.

**Procurement:**

- Replace systems and processes that support procurement with a single unified Energy Queensland solution. Including managing, sourcing, contract and supplier management, and buying processes.
- Integrated processes and systems, both internally and externally, improving collaboration with stakeholders and suppliers.
- An advanced source-to-settle solution with the ability to acquire goods and services from the community with simplicity, governance and affordability.

**Enterprise Services:**

- The objective is to enable common processes and standardised analysis and reporting in order to provide oversight and insights into organisational performance.
- Including end-to-end purchasing; maintenance work execution (non network); time capture and reporting; financial accounting and reporting; solution accessibility through internal network and mobile devices.
- Deploy foundation capability for portfolio and project management processes.
Chapter 13. Information and Communication Technology

Finance and Planning:

- Deploy foundation capability for financial planning, budgeting and consolidation financial reporting processes.
- Implement a unified chart of accounts, legal entity, purchasing organisation, and maintenance organisation structures for Energy Queensland.

Minor Applications Change and Compliance

This includes minor improvements and updates across the ICT systems footprint including; workforce automation, asset management, market systems, network operations systems, knowledge management systems, and customer service systems which support Ergon Energy’s business operations. Key investments in this area across 2017-18 included the upgrade of the Digital Service Management Tool, a minor Contact Centre Technology upgrade, the Market Systems releases required to meet market compliance obligations, the commencement of the replacement of the Field Mobile Computing asset inspection solution, and the Energy Queensland’s Enterprise Agreement payroll system configurations.

Distributed Workforce Automation

The Field Force Automation (FFA) program continued in 2017-18 to extend the use of FFA service suite beyond Customer Service activities, to encompass planned work. This program extended the use of FFA to more field crews, moved from paper to electronic forms, rollout Focal Point to extend the reporting capabilities of FFA and enhance the Business Objects reports. A second project was also commenced in 2017-18 to provide an uplift of field work management capability for the FFA platform as well as maintaining supportability. This will be achieved by an upgrade of ABB Service Suite to version 9.5, enabling the future use of contemporary Windows 10 devices as an option for FFA.

Customer Systems

Ergon Energy’s Distribution Customer & Market Operations business continues to function in a period of much internal change (i.e. merger) and regulatory reforms. Substantial regulatory reforms such as National Energy Customer Framework (NECF) and more recently the introduction of the Power of Choice are driving consumer flexibility and choices in the way consumer’s use and purchase electricity. Industry impacts such as solar, battery storage, intelligent networks and electric vehicles are also driving customer choice.

Investment against this initiative in 2017-18 was focused on providing customers with contemporary communication channels, workflow automation and workflow alignment (across all area of the state) to meet customer requirements and exploit opportunities to streamline process.
13.2 Forward ICT Program

The forward ICT strategy will continue to be focused on 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.

- Utilisation of various sourcing models – 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.

- 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.

In addition to the building block investments that commenced delivery in the 2017-18 year, the following investments have also commenced the initiation and business case development stages:

- Enterprise Content Management
- Asset and Works Management
- Desktop Transformation
- Health, Safety and Environment.

The remainder of the forward ICT Program will see the continuation of the in delivery and currently being initiated key building block items, with the addition of the early analysis and scoping phases of the Customer, and Unified GIS business blocks. In addition to this, the next phase of the intelligence building block will be initiated which will be focused on Big Data and Predictive Analytics for Energy Queensland.

A high level summary of total potential ICT investment for the Distribution Business across the remainder of the regulatory control period is shown in Table 46. These values are indicative only at this stage and subject to material change as planning, prioritisation and commercial negotiation activities are completed. This includes both forecasts for the Strategic initiatives identified in the DEBBs, as well as a number of operational renewal/replacement/compliance investments for the broader set of technologies that Energy Queensland utilise. Forward investment forecasts have been grouped by Initiative names as proposed to the regulator in the 2020-25 submission plan:

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28 All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
Chapter 13. Information and Communication Technology

Table 46: ICT Investment Forecast 2018-19 to 2022-23

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Asset and Works Management</td>
<td>$5.74</td>
<td>$14.18</td>
<td>$12.82</td>
<td>$8.56</td>
<td>$14.21</td>
</tr>
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<td>Distribution Network Operations</td>
<td>$8.05</td>
<td>$8.79</td>
<td>$14.61</td>
<td>$11.60</td>
<td>$2.37</td>
</tr>
<tr>
<td>Customer and Market Systems</td>
<td>$12.32</td>
<td>$3.87</td>
<td>$5.45</td>
<td>$10.91</td>
<td>$10.08</td>
</tr>
<tr>
<td>Corporate Systems</td>
<td>$40.31</td>
<td>$11.42</td>
<td>$2.71</td>
<td>$0.46</td>
<td>$3.33</td>
</tr>
<tr>
<td>ICT Management Systems, Productivity and Cybersecurity</td>
<td>$11.76*</td>
<td>$7.70*</td>
<td>$1.17</td>
<td>$3.54</td>
<td>$2.95</td>
</tr>
<tr>
<td>Infrastructure Program</td>
<td>$7.58</td>
<td>$8.67</td>
<td>$6.25</td>
<td>$6.88</td>
<td>$6.91</td>
</tr>
<tr>
<td>Minor Applications Change</td>
<td>$3.41</td>
<td>$4.73</td>
<td>$3.32</td>
<td>$3.32</td>
<td>$3.30</td>
</tr>
<tr>
<td><strong>Grand Total</strong></td>
<td><strong>$89.17</strong></td>
<td><strong>$59.36</strong></td>
<td><strong>$46.33</strong></td>
<td><strong>$45.28</strong></td>
<td><strong>$43.14</strong></td>
</tr>
</tbody>
</table>

* Symbol identifies the inclusion of Value-Add investment proposed to be benefits justified (i.e. through the introduction of this technology, hard financial savings will be able to be realised elsewhere across the regulated business). These investments will be required to deliver a positive return on investment in order to receive approval to proceed. The remaining investments noted are considered necessary to sustain existing capability, in line with Asset renewal guidelines as submitted to the regulator, or to meet regulatory or market compliance obligations (e.g. Power of Choice).

Note: Forecasts includes ICT Managed Capex 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).

**Asset and Works Management**

Future planned investment under the Enterprise Asset Management segment is aimed at addressing the remaining EAM tools not already being addressed through the ERP EAM Portfolio of Projects, including; Field Mobile Computing, Condition Monitoring, Asset Management Inspection tool and overhead imagery capability.

In Ergon Energy the GIS is a key system in the asset management process. Between the EAM and the GIS, the core data for the individual asset and the physical and electrical network are mastered. The GIS play a key role in supporting the major asset life cycle processes of asset design, build, commissioning and maintenance planning.

Ergon Energy utilises the GE Smallworld Electric Office product as the GIS, and ESRI GIS products for spatial visualisation and analytics. In 2016 the merger of Ergon Energy and Energex into Energy Queensland was announced. An important part of the realisation of the benefits of this merger is the successful merging of business processes and works practices within the reorganised merged entity. This entails the move from disparate digital solutions to unified solutions, of which the GIS solutions are prominent examples.

In parallel, Energy Queensland has embarked on the preparation of business cases to implement a new EAM. As EAM and GIS are inherently intertwined in the asset lifecycle processes, an EAM renewal will have major impacts on any existing GIS solution and interdependencies on any major work on GIS. This initiative aims to deliver a unified GIS solution, that provides unified network model, tools and related business processes, (e.g. data maintenance, design) and spatial
visualisation / analytics across all of Energy Queensland.

Future year allocations against this initiative will also cover the replacement of a number of other network forecasting, design tools currently being utilised across Ergon Energy.

**Distribution Network Operations**

With the formation of Energy Queensland, alignment activities are taking place and having a converged Distribution Management System (DMS) is required to allow a complete transition to merged operational practices. A converged DMS will also support the intent to realise benefits of merging the two DNSP’s.

Future control period forecast investment also covers the asset renewal of a suite of applications used by the regulated business for managing Distribution Operations including; LV Switching capability, network asset topology, metering head end system for distribution meters, outtage and Fault management capabilities, Linux server applications that provide the interface to the field radios for the ROSS client and database, and Remote Terminal Units (RTU) design and configuration tools.

The replacement of the Ergon Energy FFA tool is scheduled for the 2022-23 financial year. The current assumption is that the replacement would see a consolidation of the Energex and Ergon Energy Solutions into a single workforce management tool. Forward forecasts also include allocation for the replacement of the Micro-scheduler tool which allows users to schedule current work order tasks to crews, see their schedules, invoke systems services to update the master data with the new schedule dates and crews, and to report on Micro-scheduler data.

**Customer and Market Systems**

In January 2017 the Power of Choice program was split into multi-phase releases. In order to meet the mandatory compliance date of 1 December 2017 functionality was deferred to post Release 1. This functionality is required to meet both Distribution business’s market obligations and customer experience objectives. The next phase of this program will see the completion of all legislated requirements not implemented in release 1 due to time constraints (e.g. notified parties, meter exchange, site access, Network Tariff Code (NTC) outbound, comms meter detail updates etc). It will also address the automation of Ring fencing requirements currently being completed manually.

Future control period allocations include forecast investment in the renewal or replacement of end of life assets including Market Gateway, Meter Asset Management, Metering Reading Software, Network Billing system, and the Meter Data Management Application.

Further investment in this area seeks to replace existing customer service-related IT platforms with an end-to-end customer service platform that offers streamlined technology capable of catering to the needs of Ergon Energy’s customers. Enhanced tools and easier access to relevant customer data to make service interactions smooth and more personalised will impact channels such as telephony, customer recognition, social media, as well as email.
Chapter 13. Information and Communication Technology

High level benefit opportunities:

- Lower total cost of ownership of a simplified and configurable architecture
- Integrated, consistent and simplified end to end processes
- Real time insight for decision support (performance driven workforce)
- Enabled digital core to provide business agility for future changes
- Increased flexibility to respond to market regulatory changes.
- Increase Customer, electrical contractor and retailer satisfaction
- Reduced Customer, electrical contractor and retailer cost to serve

Forecast investment will also cover the replacement of existing end of life customer technology assets including web hosting and services, and customer mobile apps.

Corporate Systems

The next two years will see the continuation of the delivery of the ERP EAM Portfolio of Projects. Refer summary of scope in section 13.1

ICT Management Systems, Productivity and Cybersecurity

Enterprise Content Management is the capture, classification, standardisation, storage, integration, use, and retirement of records, document, drawings and digital media assets.


This future investment seeks to implement a new, efficient, intuitive, and mobile-ready technology solution, to consolidate enterprise content across the business, replace end life technology and provide the capability to integrate this content into enterprise business processes.

The next phase of this initiative aims to embed Business Intelligence, by building and embedding various analytical use cases in planning and day-to-day process execution across the enterprise. The Business Intelligence platform will use its ‘single-source of truth’ to build real time operations, customer insights and financial modelling, across areas including:

- Load Forecasting & Capacity Planning — gain deep insight to base and peak loads considering detailed patterns from end points
- Asset Health Analytics — compare, contrast, visualise asset health conditions
- Outage Management — monitor factors contributing to outages
- Predictive Call Centre — accelerate and anticipate response to customer calls (particularly during high demand events)
- Customer Behavioural Segmentation — efficient and precise targeting for sales & marketing campaigns
- Customer Fraud Prediction — identify customers in all segments that may fail to pay the bills and proactively initiate communications.
Chapter 13. Information and Communication Technology

This capability will allow Ergon Energy to:

- Minimise the impact of network costs on customers
- Generate insights supporting prudent network investment, timely maintenance and management of distributed energy resources
- Maintain a customer-focused business
- Promote customer choice and satisfaction with optimised products and improved information availability
- Operate with ethical, social and environmental responsibility.

Planned investment in this area covers the end of life replacement of a number of existing analytics tools including those used for reporting and analytics related to solar PV and other embedded generation across the distribution network, PQ performance as well as advance analytical capability for root cause analysis and investigations, the enterprise repository used for management and performance reporting and analytics, spatial visualisation reporting tools, and time series report data control systems.

To deal with evolving business needs, a distributed workforce, changing ways of working and an increasingly complex cyber security environment we must evolve the technology we use every day into what has been termed the Digital Workplace. Specifically ‘technology’ in this instance is referring to capability which:

- Enables us to connect to and consume digital services and information securely based on our identity and role.
- Provides the operating environment and devices that we use throughout the course of our work.

Supports our daily productivity through software and apps such as Microsoft Office, SharePoint and other productivity, communication and collaboration tools.

These three pillars of capability form the scope of the Digital Workplace building block that is part of the overall DEBB portfolio of projects. This will take a number of years to complete and will include Office 365 Migration and Windows 7 Replacement on all devices.

Future planned investment in cyber security will include the replacement of various security software and backend infrastructure with contemporary solutions that address evolving cyber security concerns. This investment is necessary to protect Energy Queensland’s critical infrastructure in direct response to increasing cyber threats resulting from more IP enabled devices being connected to the Information Technology and Operational Technology (OT) networks.

Infrastructure Program
Refer summary of scope in section 13.1

Minor Applications Change
Refer summary of scope in section 13.1.
Chapter 14

Metering

14.1 Metering Environment
14.2 Ageing Meter Population
14.3 Metering Investments in 2017-18
14.4 Planned Metering Investments for 2018-19 to 2022-23
14. Metering

14.1 Metering Environment

The metering environment is changing rapidly, driven by a range of national market reform initiatives to make metering services contestable and retailer driven. Ergon Energy is supporting the development and introduction of a national competitive metering framework to provide customers with a range of choices in metering and related services.

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

We currently operate around 1.177 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
- a dual element meter in place of two single phase meters for installations with a controlled load tariff.

This count will further decline due to the Power of Choice legislation that prevents Ergon Energy from installing new and replacement meters.

Around 9,270 of our meter population are unregulated meters in isolated generation communities. 5,178 of these units are card operated prepayment meters, used in remote Aboriginal and Torres Strait Island communities.

Our current fleet of meters includes 800,029 electro-mechanical (disc) meters and 376,795 electronic meters. Approximately 348,000 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 6.35 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 393,000 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 changed 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 on 1 December 2017, DNSPs are no longer 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 were installed as standard Type 6 accumulation and manually read installations, as per current operations. These are 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 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.

Under the Metering Asset Management Plan, Ergon Energy performs meter family testing, meter replacement programs and time-based meter testing for large customers.

Ergon Energy will continue to develop and implement 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.

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 43 shows meter purchases from 2012-13 to 2017-18.
The above average purchase requirements for 2012-13 for new meters was due principally to the installation of solar PV systems requiring bi-directional metering during the peak period for solar 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.

Other metering equipment installed this year includes load control relays and current transformers.

### 14.2 Ageing Meter Population

**Figure 44** shows the age profile of both electro-mechanical and electronic Type 6 meters currently in service, and **Figure 45** 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 3,350 electronic meters.
that have failing components. However due to legislation changes relating to Power of Choice, only 24,600 of these meters have been replaced by Ergon Energy.

**Figure 44: All Meters by Age Profile**

![Bar chart showing all meters by age profile](image)

**Figure 45: Electronic Meters by Age Profile**

![Bar chart showing electronic meters by age profile](image)

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...
rates as outlined in the MAMP. 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.

14.3 Metering Investments in 2017-18

Table 48 provides a summary of metering opex expenditure for reactive (failed in service) and planned routine maintenance for 2017-18.

Table 48: Metering Operational Expenditure 2017-18

<table>
<thead>
<tr>
<th>Category</th>
<th>2017-18 $M Budget</th>
<th>2017-18 $M Actual</th>
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<tbody>
<tr>
<td>Reactive maintenance SCS</td>
<td>0.615</td>
<td>0.323</td>
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<tr>
<td>Planned maintenance SCS</td>
<td>1.812</td>
<td>2.018</td>
</tr>
<tr>
<td>Total ($ M)</td>
<td>2.427</td>
<td>2.341</td>
</tr>
</tbody>
</table>

14.4 Planned Metering Investments for 2018-19 to 2022-23

Metering investment in Ergon Energy will be minimal due to legislation changes preventing Ergon Energy from installing new and replacement meters from the 1st December 2018. The current approved AER expenditure for 2015 to 2020 was $40.709 million (2014-15 real dollars). Table 49 shows Ergon Energy’s forecast capex metering replacement from 2018-19 to 2022-23. 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 $0.5 million for the period 2019 to 2023. The small allocations of capex funds beyond 2018-19 allow for planned and reactive meter replacements for Non-NEM locations.

Table 49: Metering Capex Replacement Cost Estimates 2018-19 to 2022-23

<table>
<thead>
<tr>
<th></th>
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<tr>
<td>Reactive replacements</td>
<td>1.361</td>
<td>1.348</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>2.859</td>
</tr>
</tbody>
</table>

29 All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
30 Actual Expenditure to May 2018.
31 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.
32 Note 3
33 Projected estimate based on 2015-20 figures. No Approved Budget for 2020-21 to 2022-23
34 Note 6
35 Note 6
<table>
<thead>
<tr>
<th>Category</th>
<th>2018-19</th>
<th>2019-20</th>
<th>2020-21</th>
<th>2021-22</th>
<th>2022-23</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive replacements estimated</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.250</td>
</tr>
<tr>
<td>Planned replacements Approved</td>
<td>6.810</td>
<td>6.746</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>13.706</td>
</tr>
<tr>
<td>Planned replacements estimated</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
<td>0.250</td>
</tr>
<tr>
<td><strong>Total ($M) Approved</strong></td>
<td>8.171</td>
<td>8.094</td>
<td>0.100</td>
<td>0.100</td>
<td>0.100</td>
<td>16.565</td>
</tr>
<tr>
<td><strong>Total ($M) Estimated</strong></td>
<td>0.100</td>
<td>0.100</td>
<td>0.100</td>
<td>0.100</td>
<td>0.100</td>
<td>0.500</td>
</tr>
</tbody>
</table>

Note: Any discrepancy in total cost can be attributed to rounding error.\(^{36}\)

\(^{36}\) All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
Chapter 15
Operational Technology and Communications

15.1 Telecommunications
15.2 Operational Systems
15.3 Investments in 2017-18
15.4 Planned Investments for 2018-19 to 2022-23
15. Operational Technology and Communications Systems

Ergon Energy is responsible for optimising the reliability, security and utilisation performance of the regulated electricity assets to ensure that both regulatory and corporate performance outcomes are achieved in a manner that is safe to the workplace and the public. 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.

Energex and Ergon Energy have developed a joint Network Technology Strategy and Roadmap to guide the use of technology. The roadmap identifies the key technologies to be researched and implemented in the periods 2010-15, 2015-20 and 2020-30. It is being used to guide technology in key areas of real time condition monitoring, communications networks, reliability, power quality, demand management, environmental sustainability, customer energy management and power system operational management.

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 major categories of work will support the achievement of Ergon Energy’s telecommunications strategy:

1. Field mobile radio networks – These networks provide field workforce primary mission critical voice communications to support a safe and efficient work environment.
   o Over the last seven years, from Toowoomba to the North of Cairns, the legacy VHF two way mobile network has been progressively replaced by a P25 based network. This area typically has the highest density of network and staff within Ergon distribution areas. P25 provides a secure digital two-way network and achieves the required quality, availability and reliability to support the field mobile radio networks strategy. The final
Chapter 15. Operational Technology and Communications Systems

P25 projects required to complete the planned replacement of the east coast VHF two-way mobile network have been approved and have commenced. These projects will be completed progressively completed over the next three years.

- Provision of a platform to achieve the field mobile radio network strategy in western Queensland areas needed a different approach to P25 due to the vast areas involved and a typical lower density of network and staff. The original planned technology to be used in these areas was called Long Range Digital Radio and used the HF radio frequency range. Problems with this platform have become apparent and it has not meet operational requirements in terms of quality and availability. Re-examination of available technology options identified a commercial product called SATPTT that had been recently adopted by other Queensland Government agencies operating in rural and remote areas. A trial confirmed the SATPTT product meets operational requirements for western areas. Implementation of SATPTT has been approved and will be completed across the 2018-19 and 2019-20 financial years.

2. CoreNet Site Infrastructure Replacement Program — This program replaces site support infrastructure such as power supplies and air conditioning to ensure that services remain in operation. This is an ongoing business as usual aged replacement program that is based on a condition assessment of equipment’s capacity to provide satisfactory service and performance to meet the requirements for the distribution network. Accelerated battery replacements are anticipated over the next three years due to the asset categories’ age profile and higher than forecast battery cell failure rates.

3. CoreNet Active Network Replacement programs — these invest in the renewal of aged and unsupported active 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. Projects progressed over 2017-18 include Network Management Systems and legacy voice related aged replacements. Significant projects that have been approved for implementation over the next five years include Time Division Multiplexing (TDM) related projects. These projects will:

- Extend the life of the existing TDM network
- Confirm a Tele-protection solution for carriage over an IP/MPLS network
- Replacement of a Legacy Telco service management system.

Aged replacement projects expected to be approved over the coming 12 to 36 months will cover the following technologies:

- Ethernet related asset classes
- Microwave Radios assets
- Operational Support Systems servers
- Additional Legacy Voice related asset classes.
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.

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 remains focused on 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 the majority of pole top devices. These are managed centrally through the Operational Control Centre (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.

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 actively makes use of ‘Totem’ — an IoT (Internet of Things) platform for the collection and processing of data beyond the scope of the SCADA system. Using Totem will help Ergon Energy minimise expenditure associated with broader network data collection.

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
Chapter 15. Operational Technology and Communications Systems

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 serving our customers rather than the underlying technology.

15.2.5 Demand Response

Ergon Energy has finalised its investment in technology to automate and scale customer-initiated demand response. It was anticipated that this area of technology would evolve rapidly and as such Ergon Energy leased rather than owned the technology. The change in market needs and technology has allowed Ergon Energy to finalise this contract and is actively looking at newer and more cost effect solutions for the next five years.

15.2.6 Operational Security

Ergon Energy recognises the importance of cyber security for the power network and its users and continues to invest in the security standing of all operational systems.

15.2.7 Configuration Management System

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 has invested in a device Configuration Management System (CMS) to centralise and standardise configuration management of intelligent devices deployed on the power network. The CMS is currently used to manage protection devices, with more device classes expected to be added in the future.
15.3 Investments in 2017-18

Table 50 summarises Ergon Energy’s Information Technology and Communication systems investments for 2017-18\textsuperscript{37}.

Table 50: Information Technology and Communication systems Investments 2017-18

<table>
<thead>
<tr>
<th>Description</th>
<th>Direct Cost ($M, 2017-18)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Telecomms network</strong></td>
<td></td>
</tr>
<tr>
<td>Field mobile voice comms</td>
<td></td>
</tr>
<tr>
<td>End of life radio refurbishment Mackay to Maryborough – P25</td>
<td>$2.0</td>
</tr>
<tr>
<td>End of life radio refurbishment western Queensland – P25</td>
<td>$1.1</td>
</tr>
<tr>
<td>CoreNet Site Infrastructure Replacement Program</td>
<td>$1.7</td>
</tr>
<tr>
<td>CoreNet Active Equipment Replacement</td>
<td>$2.6</td>
</tr>
<tr>
<td><strong>Operational Systems</strong></td>
<td></td>
</tr>
<tr>
<td>OT Security Projects</td>
<td>$1.1</td>
</tr>
<tr>
<td>Configuration Management System</td>
<td>$0.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$9.4</strong></td>
</tr>
</tbody>
</table>

\textsuperscript{37} All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
## 15.4 Planned Investments for 2018-19 to 2022-23

Table 51 summarises Ergon Energy’s OT and associated Telecommunication planned investments for 2018-19 to 2022-23\textsuperscript{38}.

**Table 51: Operational Technology Planned Investments 2018-19 to 2022-23**

<table>
<thead>
<tr>
<th>Description</th>
<th>Direct Cost ($M)\textsuperscript{1}</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Telecoms network</strong></td>
<td></td>
</tr>
<tr>
<td>End of life radio refurbishment – P25</td>
<td>$17.9</td>
</tr>
<tr>
<td>End of life radio refurbishment - Western</td>
<td>$2.0</td>
</tr>
<tr>
<td>CoreNet Site Infrastructure Replacement Program</td>
<td>$24.6</td>
</tr>
<tr>
<td>CoreNet Active Equipment Replacement</td>
<td>$31.4</td>
</tr>
<tr>
<td><strong>Operational Systems</strong></td>
<td></td>
</tr>
<tr>
<td>SCADA and Automation Refurbishment / Replacement</td>
<td>$1.1</td>
</tr>
<tr>
<td>OT Refurbishment / Replacement</td>
<td>$1.2</td>
</tr>
<tr>
<td>Control Room Enhancements</td>
<td>$2.9</td>
</tr>
<tr>
<td>Infrastructure Expansion</td>
<td>$2.3</td>
</tr>
<tr>
<td>LV Visibility and Control Improvements</td>
<td>$2.5</td>
</tr>
<tr>
<td>Distributed Energy Resources Management</td>
<td>$3.2</td>
</tr>
<tr>
<td>Intelligent Grid Applications</td>
<td>$2.4</td>
</tr>
<tr>
<td>Security Enhancements</td>
<td>$1.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 168.7</strong></td>
</tr>
</tbody>
</table>

\textsuperscript{1} expenditure is provisional only and will be dependent on AER submission outcomes for 2020-21 to 2022-23 financial years.

\textsuperscript{38} All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is still finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.
Appendix A

Terms and Definitions
## Appendix A. Terms 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>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>AVT</td>
<td>Automatic Voltage Regulator</td>
</tr>
<tr>
<td>BAU</td>
<td>Business As Usual</td>
</tr>
<tr>
<td>BESS</td>
<td>Battery Energy Storage Systems</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 / capex</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>CBRM</td>
<td>Condition-Based Risk Management</td>
</tr>
<tr>
<td>CESS</td>
<td>Capital Expenditure Sharing Scheme</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>Commercial and Industrial – Customer classification</td>
</tr>
<tr>
<td>CICW</td>
<td>Customer Initiated Capital Works</td>
</tr>
<tr>
<td>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</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>
<tr>
<td>CMS</td>
<td>Configuration Management System</td>
</tr>
<tr>
<td>CNOC</td>
<td>Communications Network Operations Centre</td>
</tr>
<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>CP</td>
<td>Corporate Plan</td>
</tr>
<tr>
<td>CPSS</td>
<td>Community Powerline Safety Strategy</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>DAE</td>
<td>Deloitte Access Economics</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>DEBB</td>
<td>Digital Enterprise Building Blocks</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>DEE</td>
<td>Dangerous Electrical Event</td>
</tr>
<tr>
<td>DER</td>
<td>Distributed Energy Resources</td>
</tr>
<tr>
<td>DF</td>
<td>Distribution Feeder</td>
</tr>
<tr>
<td>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------</td>
<td>------------</td>
</tr>
<tr>
<td>DFD</td>
<td>Distribution Feeder Database</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>DMIA</td>
<td>Demand Management Innovation Allowance</td>
</tr>
<tr>
<td>DMS</td>
<td>Distribution Management System</td>
</tr>
<tr>
<td>DMIS</td>
<td>Demand Management Incentive Scheme</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>DNRME</td>
<td>Queensland Department of Natural Resources, Mines and Energy</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>
<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>EBSS</td>
<td>Efficiency Benefit Sharing Scheme</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>EMF</td>
<td>Electro Magnetic Field</td>
</tr>
<tr>
<td>ENTR</td>
<td>Electricity Network Transformation Roadmap</td>
</tr>
<tr>
<td>EQL</td>
<td>Energy Queensland Limited</td>
</tr>
<tr>
<td>EG</td>
<td>Embedded generating units &gt;30kVA 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>EV</td>
<td>Electric Vehicle</td>
</tr>
<tr>
<td>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------</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’, charge 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>FIT</td>
<td>Feed-in-tariff</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 1000V AC or 1500V 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>HSE</td>
<td>Health, Safety and Environment</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>IoT</td>
<td>Internet of Things</td>
</tr>
<tr>
<td>Joint Workings</td>
<td>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>KPI</td>
<td>Key Performance Indicators</td>
</tr>
<tr>
<td>KRA</td>
<td>Key Result Areas</td>
</tr>
<tr>
<td>LAR</td>
<td>Load at Risk</td>
</tr>
<tr>
<td>LDC</td>
<td>Line Drop Compensation</td>
</tr>
<tr>
<td>LED</td>
<td>Light-emitting Diode. Is a semiconductor device that emits visible light when an electric current passes through it</td>
</tr>
<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>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>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</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 240/415V AC or 230/400V AC at 50Hz. 2. For the purpose of the electrical safety act, LV is defined as voltage above 32V AC or 120V DC (ripple free) and not exceeding 1,000V AC, or 1,500V 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>LVR</td>
<td>Low Voltage Regulator</td>
</tr>
<tr>
<td>MAB</td>
<td>Metering Asset Base</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>MCC</td>
<td>Major Customer Connection</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>MEGU</td>
<td>Micro embedded generating units which are between 0 to 30kVA 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>MVA</td>
<td>Mega Volt Amp</td>
</tr>
<tr>
<td>MVAR</td>
<td>Mega Volt Amps (reactive)</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt – nameplate capacity</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.dews.qld.gov.au">https://www.dews.qld.gov.au</a> for more information.</td>
</tr>
<tr>
<td>NEL</td>
<td>National Electricity Law</td>
</tr>
<tr>
<td>NEM</td>
<td>National Electricity Market</td>
</tr>
<tr>
<td>NEO</td>
<td>National Energy Objectives (AEMC)</td>
</tr>
<tr>
<td>NER</td>
<td>National Electricity Rules</td>
</tr>
<tr>
<td>NERL</td>
<td>National Energy Retail Law</td>
</tr>
<tr>
<td>NERR</td>
<td>National Energy Retail Rules</td>
</tr>
<tr>
<td>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>------------</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 following supply standards.</td>
</tr>
<tr>
<td>NGER</td>
<td>National Greenhouse and Energy Reporting Act 2007 (Cth)</td>
</tr>
<tr>
<td>NIEIR</td>
<td>National Institute of Economic and Industry Research</td>
</tr>
<tr>
<td>NIM</td>
<td>Net Interstate Migration (NIM)</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>NOM</td>
<td>Net Overseas Migration</td>
</tr>
<tr>
<td>NOMAD</td>
<td>A 10MVA mobile substation developed by Ergon Energy for planned work and emergency response.</td>
</tr>
<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>NVD</td>
<td>Neutral Voltage Displacement</td>
</tr>
<tr>
<td>NQ</td>
<td>North Queensland region</td>
</tr>
<tr>
<td>NTC</td>
<td>Network Tariff Code</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>ONAN</td>
<td>Oil Natural Air Natural</td>
</tr>
<tr>
<td>OPEX / 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>PHEV</td>
<td>Plug-in Hybrid Electric Vehicle</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 / PoC</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>PoW</td>
<td>Program of Work</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>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>------------</td>
</tr>
<tr>
<td>Primary Distribution System</td>
<td>Refers to the 11kV and 22kV and in some instances 33kV 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>QGSO</td>
<td>Queensland Government Statistician’s Office</td>
</tr>
<tr>
<td>QHES</td>
<td>Queensland Household Energy Survey</td>
</tr>
<tr>
<td>QoS</td>
<td>Quality of Supply</td>
</tr>
<tr>
<td>RAB</td>
<td>Regulated Asset Base</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>RMS</td>
<td>Root Mean Square</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>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>SAMP</td>
<td>Strategic Asset Management Plan</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory Control and Data Acquisition</td>
</tr>
<tr>
<td>SCAR</td>
<td>Substation condition assessment report</td>
</tr>
<tr>
<td>SCI</td>
<td>Statement of Corporate Intent</td>
</tr>
<tr>
<td>SCS</td>
<td>Standard Control Services: are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network) and some connection services (e.g. small customer connections). We recover our costs in providing Standard Control Services through network tariffs billed to retailers.</td>
</tr>
<tr>
<td>SEQ</td>
<td>South East Queensland</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 33/11kV and/or 66/11kV 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>Term/Acronym</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>------------</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>
<tr>
<td>Statcom or Static Synchronous Compensator</td>
<td>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</td>
</tr>
<tr>
<td>STPIS</td>
<td>Service Target Performance Incentive Scheme, as documented under <em>Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme (AER, Nov 2009)</em> with targets set through the AER’s Distribution Determination process.</td>
</tr>
<tr>
<td>Substation (S/S or SS)</td>
<td>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.</td>
</tr>
<tr>
<td>Sub-transmission</td>
<td>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 33kV and above. (Note however that 33kV is also used for distribution in some parts of the Ergon Energy network.)</td>
</tr>
<tr>
<td>Surge Arrester / Surge Diverter</td>
<td>A device designed to protect electrical apparatus from high transient voltage.</td>
</tr>
<tr>
<td>SVC</td>
<td>Static Var Compensator</td>
</tr>
<tr>
<td>SVR</td>
<td>Step Voltage Regulator</td>
</tr>
<tr>
<td>SW</td>
<td>South Western region of Queensland</td>
</tr>
<tr>
<td>SWER</td>
<td>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</td>
</tr>
<tr>
<td>Switchgear</td>
<td>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</td>
</tr>
<tr>
<td>TAN</td>
<td>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.</td>
</tr>
<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>TDM</td>
<td>Time Division Multiplexing</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>
</tbody>
</table>
### Term/Acronym | Definition
--- | ---
TMU | Target Maximum Utilisation
TNI | Transmission Node Identity
TNSP | Transmission Network Service Provider
Transmission Network | 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.
UG | Underground
UoSA | Use of System Agreement
UR | Urban
V | Volts
VA | Volt Amps - unit of the vector magnitude of electrical power
VAR | Volt Amps Reactive - unit of the reactive component of electrical power
VCR | Value of Customer Reliability – an economic measure of unsupplied energy to customers
Voltage Regulation | The level of variation in the voltage that occurs at a site
Voltage Regulator (VR) | A device that controls voltages in the power networks
Voltage Sag | 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.
Voltage Unbalance | 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.
VB | Wide Bay region of Queensland
VT | Voltage Transformer: a device typically used in protection and metering systems to measure voltage in primary conductors.
W | Watts - unit of the ‘real’ component of electrical power
WB | Wide Bay region of Queensland
WPF | Worst Performing Feeder – has meaning in the Ergon Energy Distribution Authority
Zone Substation (ZS) or (ZSS) | A substation that converts energy from transmission or sub-transmission voltages to distribution voltages.
Appendix B

NER and DA Cross-Reference
### Appendix B. NER and DA Cross-Reference

#### Table 52: NER Cross Reference

<table>
<thead>
<tr>
<th>National Electricity Rules Version 116</th>
<th>Report Section</th>
</tr>
</thead>
<tbody>
<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>
</tbody>
</table>

<table>
<thead>
<tr>
<th>(a) information regarding the DNSP and its network including:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) a description of its network;</td>
<td>1.3 Network Overview</td>
</tr>
<tr>
<td></td>
<td>2.2 Ergon Energy Electricity Distribution Network</td>
</tr>
<tr>
<td></td>
<td>12 Emerging Network Challenges and Opportunities</td>
</tr>
<tr>
<td></td>
<td>Appendix C Network Security Standards</td>
</tr>
<tr>
<td>(2) a description of its operating environment;</td>
<td>1.3 Network Overview</td>
</tr>
<tr>
<td></td>
<td>2.2 Ergon Energy Electricity Distribution Network</td>
</tr>
<tr>
<td></td>
<td>2.3 Network Operating Environment</td>
</tr>
<tr>
<td></td>
<td>3 Community and Customer Engagement</td>
</tr>
<tr>
<td></td>
<td>10.1 Reliability Measures and Standards</td>
</tr>
<tr>
<td></td>
<td>10.2 Service Target Performance Incentive Scheme</td>
</tr>
<tr>
<td></td>
<td>10.3 High Impact Weather Events</td>
</tr>
<tr>
<td></td>
<td>11.2 Power Quality Supply Standards, Code Standards and Guidelines</td>
</tr>
<tr>
<td></td>
<td>12 Emerging Network Challenges and Opportunities</td>
</tr>
<tr>
<td>(3) the number and types of its distribution assets;</td>
<td>2.2 Ergon Energy Electricity Distribution Network</td>
</tr>
<tr>
<td>(4) methodologies used in preparing the Distribution Annual Planning Report, including methodologies used to identify system limitations and any assumptions applied; and</td>
<td>6.2 Planning Methodology</td>
</tr>
<tr>
<td></td>
<td>6.4 Network Planning Criteria</td>
</tr>
<tr>
<td></td>
<td>6.5 Voltage Limits</td>
</tr>
<tr>
<td></td>
<td>6.6 Fault Level Analysis</td>
</tr>
<tr>
<td></td>
<td>6.7 Ratings Methodology</td>
</tr>
<tr>
<td></td>
<td>6.12 DAPR Reporting Methodology</td>
</tr>
<tr>
<td></td>
<td>Appendix D Network Capacity and Load Forecasts</td>
</tr>
<tr>
<td>(5) analysis and explanation of any aspects of forecasts and information provided in the Distribution Annual Planning Report that have changed significantly from previous forecasts and information provided in the preceding year;</td>
<td>1.5 Changes from 2017 DAPR</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>(b) forecasts for the forward planning period, including at least:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) a description of the forecasting methodology used, sources of input information, and the assumptions applied;</td>
<td>5 Network Forecasting</td>
</tr>
<tr>
<td>(2) load forecasts</td>
<td>7.1 Emerging Network Limitation Maps</td>
</tr>
<tr>
<td>(i) at the transmission-distribution connection points;</td>
<td>7.2 Forecast Load and Capacity Tables</td>
</tr>
<tr>
<td>(ii) for sub-transmission lines; and</td>
<td>Appendix D Network Capacity and Load Forecasts</td>
</tr>
<tr>
<td>(iii) for zone substations,</td>
<td></td>
</tr>
</tbody>
</table>
National Electricity Rules Version 116
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:

including, where applicable, for each item specified above:

<table>
<thead>
<tr>
<th>Report Section</th>
<th>Report Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>(iv) total capacity;</td>
<td>7.1 Emerging Network Limitation Maps</td>
</tr>
<tr>
<td>(v) firm delivery capacity for summer periods and winter periods;</td>
<td>7.2 Forecast Load and Capacity Tables</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 D:1 Transmission Connection Point Load Forecasts</td>
</tr>
<tr>
<td>(vii) power factor at time of peak load;</td>
<td>Appendix D:4 Forecasts for Future Substations, Subtransmission Lines and TCPs</td>
</tr>
<tr>
<td>(viii) load transfer capacities; and</td>
<td></td>
</tr>
<tr>
<td>(ix) generation capacity of known embedded generating units;</td>
<td></td>
</tr>
</tbody>
</table>

(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:

<table>
<thead>
<tr>
<th>Section</th>
<th>Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i) location;</td>
<td>7.1 Emerging Network Limitation Maps</td>
</tr>
<tr>
<td>(ii) future loading level; and</td>
<td>7.2 Forecast Load and Capacity Tables</td>
</tr>
<tr>
<td>(iii) proposed commissioning time (estimate of month and year);</td>
<td>Appendix D:1 Transmission Connection Point Load Forecasts</td>
</tr>
</tbody>
</table>

(4) forecasts of the Distribution Network Service Provider’s performance against any reliability targets in a service target performance incentive scheme; and

<table>
<thead>
<tr>
<th>Section</th>
<th>Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.2 Service Target Performance Incentive Scheme</td>
<td>2.2 Ergon Energy Electricity Distribution Network</td>
</tr>
</tbody>
</table>

(5) a description of any factors that may have a material impact on its network, including factors affecting:

<table>
<thead>
<tr>
<th>Section</th>
<th>Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i) fault levels;</td>
<td>6 Network Planning Framework</td>
</tr>
<tr>
<td>(ii) voltage levels;</td>
<td>7 Network Limitations and Recommended Solutions</td>
</tr>
<tr>
<td>(iii) other power system security requirements;</td>
<td>8.2 Key issues arising from embedded generation applications</td>
</tr>
<tr>
<td>(iv) the quality of supply to other Network Users (where relevant);</td>
<td>8.3 Actions promoting non-network solutions</td>
</tr>
<tr>
<td>(v) ageing and potentially unreliable assets;</td>
<td>9 Asset Life-Cycle Management</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Section</th>
<th>Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.1.5 Reliability Corrective Actions</td>
<td>10.3 High Impact Weather Events</td>
</tr>
<tr>
<td>10.5 Worst performing feeders</td>
<td>11 Power Quality</td>
</tr>
<tr>
<td>12 Emerging Network Challenges and Opportunities</td>
<td></td>
</tr>
</tbody>
</table>
### 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:

<table>
<thead>
<tr>
<th>Report Section</th>
<th>(b1) for all network asset retirements, and for all network 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:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1) a description of the network asset, including location;</td>
</tr>
<tr>
<td></td>
<td>2) the reasons, including methodologies and assumptions used by the Distribution Network Service Provider, for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset;</td>
</tr>
<tr>
<td></td>
<td>3) the date from which the Distribution Network Service Provider proposes that the network asset will be retired or de-rated; and</td>
</tr>
<tr>
<td></td>
<td>4) if the date to retire or de-rate the network asset has changed since the previous Distribution Annual Planning Report, an explanation of why this has occurred;</td>
</tr>
</tbody>
</table>

#### 7.6 Network Asset Retirements and De-Ratings
### National Electricity Rules Version 116

#### 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:

**(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;

### (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; |
| (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; |
| (3) | impact of the system limitation if any, on the capacity at transmission-distribution connection points; |
| (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 |

#### 7.6 Network Asset Retirements and De-Ratings

### 7.1 Emerging Network Limitation Maps

### 7.4 Sub-transmission Feeder Limitations

**Appendix D:2** Substation Capacity and Load Forecasts

**Appendix D:3** Sub-transmission Feeder Capacity and Load Forecasts

**Appendix D:4** Forecasts for future substations, sub-transmission lines and TCPs
National Electricity Rules Version 116
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:

<table>
<thead>
<tr>
<th>Report Section</th>
<th>(5) where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1);</td>
</tr>
<tr>
<td></td>
<td>(ii) the relevant connection points at which the estimated reduction in forecast load may occur; and</td>
</tr>
<tr>
<td></td>
<td>(iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation;</td>
</tr>
<tr>
<td>(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:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(1) the location of the primary distribution feeder;</td>
</tr>
<tr>
<td></td>
<td>(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);</td>
</tr>
<tr>
<td></td>
<td>(3) the types of potential solutions that may address the overload or forecast overload; and</td>
</tr>
<tr>
<td></td>
<td>(4) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:</td>
</tr>
<tr>
<td></td>
<td>(i) estimate of the month and year in which the overload is forecast to occur;</td>
</tr>
<tr>
<td></td>
<td>(ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload;</td>
</tr>
<tr>
<td></td>
<td>(iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation;</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></td>
</tr>
<tr>
<td></td>
<td>(1) if the regulatory investment test for distribution is in progress, the current stage in the process;</td>
</tr>
<tr>
<td></td>
<td>(2) a brief description of the identified need;</td>
</tr>
<tr>
<td></td>
<td>(3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);</td>
</tr>
<tr>
<td>----------------</td>
<td>---------------------------------------</td>
</tr>
<tr>
<td><strong>4</strong></td>
<td>if the regulatory investment test for distribution has been completed a brief description of the conclusion, including:</td>
</tr>
<tr>
<td><strong>(i)</strong></td>
<td>the net economic benefit of each credible option;</td>
</tr>
<tr>
<td><strong>(ii)</strong></td>
<td>the estimated capital cost of the preferred option; and</td>
</tr>
<tr>
<td><strong>(iii)</strong></td>
<td>the estimated construction timetable and commissioning date (where relevant) of the preferred option; and</td>
</tr>
<tr>
<td><strong>5</strong></td>
<td>any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;</td>
</tr>
<tr>
<td><strong>(f)</strong></td>
<td>any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;</td>
</tr>
<tr>
<td><strong>(g)</strong></td>
<td>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 an urgent and unforeseen network issue as described in clause 5.17.3(a)(1), including:</td>
</tr>
<tr>
<td><strong>(1)</strong></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><strong>(2)</strong></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)</strong></td>
<td>the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:</td>
</tr>
<tr>
<td></td>
<td><strong>6.10 Joint Planning</strong></td>
</tr>
<tr>
<td>National Electricity Rules Version 116</td>
<td>Report Section</td>
</tr>
<tr>
<td>--------------------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>Chapter 5: Network Connection, Planning and Regulation</td>
<td>Schedule 5.8 Distribution Annual Planning Report</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>
</tbody>
</table>

(2) 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

(3) where additional information on the investments may be obtained;

(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:

(1) a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning;  
6.10 Joint Planning  
6.11 Joint Planning Results

(2) 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

(3) where additional information on the investments may be obtained;

(j) information on the performance of the Distribution Network Service Provider’s network, including:

(1) a summary description of reliability measures and standards in applicable regulatory instruments;  
10 Network Reliability  
11 Power Quality

(2) a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;

(3) 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;

(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;

(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

(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;  
10.2 Service Target Performance Incentive Scheme
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:

(k) information on the Distribution Network Service Provider’s asset management approach, including:

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>4 Asset Management Overview</td>
<td>(1) a summary of any asset management strategy employed by the Distribution Network Service Provider;</td>
</tr>
<tr>
<td>9 Asset Life-Cycle Management</td>
<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>
</tr>
<tr>
<td>6.4.4 Consideration of Distribution Losses</td>
<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>
</tr>
<tr>
<td>4 Asset Management Overview</td>
<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>
</tr>
<tr>
<td>7.6 Network Asset Retirements and De-Ratings</td>
<td>(l) information on the Distribution Network Service Provider’s demand management activities, including:</td>
</tr>
<tr>
<td>9 Asset Life-Cycle Management</td>
<td>8 Demand Management Activities</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.4.4 Consideration of Distribution Losses</td>
<td>(1) a qualitative summary of:</td>
</tr>
<tr>
<td>4 Asset Management Overview</td>
<td>(i) non-network options that have been considered in the past year, including generation from embedded generating units;</td>
</tr>
<tr>
<td>7.6 Network Asset Retirements and De-Ratings</td>
<td>(ii) key issues arising from applications to connect embedded generating units received in the past year;</td>
</tr>
<tr>
<td>9 Asset Life-Cycle Management</td>
<td>(iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units;</td>
</tr>
<tr>
<td>8.4 Demand Management Results for 2017-18</td>
<td>(iv) the Distribution Network Service Provider’s plans for demand management and generation from embedded generating units over the forward planning period;</td>
</tr>
<tr>
<td>4.5 Further Information</td>
<td>(2) a quantitative summary of the following:</td>
</tr>
<tr>
<td>8.4 Demand Management Results for 2017-18</td>
<td>(i) connection enquiries received (under clause 5.3A.5);</td>
</tr>
<tr>
<td>4.5 Further Information</td>
<td>(ii) applications to connect received (under clause 5.3 A.9); and</td>
</tr>
<tr>
<td>8.4 Demand Management Results for 2017-18</td>
<td>(iii) the average time taken to complete applications to connect;</td>
</tr>
</tbody>
</table>
### Table 53: 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></td>
</tr>
<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>6.4.2 Safety Net</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>10.6 Safety Net Target Performance</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>10.5 Worst Performing Feeders Appendix E Worst Performing Feeder Improvement Program</td>
</tr>
<tr>
<td><strong>14.3 Periodic Reports and Plans:</strong></td>
<td></td>
</tr>
<tr>
<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>
<td></td>
</tr>
<tr>
<td>Distribution Authority No. D01/99</td>
<td>Report Section</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td><strong>DAPR reporting obligations:</strong></td>
<td><strong>Clause 8: Distribution Network Planning</strong></td>
</tr>
<tr>
<td></td>
<td>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>
</tr>
<tr>
<td></td>
<td><strong>6.4 Network Planning Criteria</strong></td>
</tr>
<tr>
<td></td>
<td><strong>10 Network Reliability</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Appendix E Worst Performing Feeder Improvement Program</strong></td>
</tr>
</tbody>
</table>
Appendix C
Network Security Standards
Appendix C. Network Security Standards

Under the Distribution Authority, Ergon Energy is obligated to promulgate customer value, which provides customer safety net targets approved under the provisions in the Electricity Act 1994. These targets applied from 1 July 2014, and form the basis for the Distribution Annual Planning Report and the AER regulatory determination covering the period 2015 – 2020. Safety Net requirements address the network operation issues and the customer impacts arising from high-consequence-low-probability network events and are only applicable to credible contingency (N-1) events.

Customer value can be leveraged by combining Minimum Service Standard (MSS) provisions, Worst Performing Feeder programs, concurrent maintenance plans, network operating strategies, contingency plans, and safety net targets. This underpins prudent capital and operating costs and delivers value to the customer. To this end, Ergon Energy’s strategic planning practices have adopted the safety net targets.

The Safety Net criteria allow Ergon Energy to make use of available network transfers and zone substation and bulk supply capabilities and are inherent in the assessment of security standard compliance. Where these assessments indicate that the network is not able to meet the required security standards, the resulting system limitation are addressed to ensure customer service expectations are achieved. A range of actions to defer or avoid investments such as non-network solutions, automated, remote and manual load transfer schemes and the deployment of a mobile substation and/or mobile generation increase utilisation of network assets are also considered to comply with Safety Net criteria. Specific security requirements of large customer connections that are stipulated under the relevant connection agreement, are treated separate to the Safety Net criteria.

The safety net targets contained in the Ergon Energy’s Distribution Authority and applied in the Ergon Energy’s strategic network planning are shown in Table 54.
## Appendix C. Network Security Standards

### Table 54: Ergon Energy 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><strong>Regional Centre</strong>&lt;sup&gt;39&lt;/sup&gt;</td>
<td>Following an N-1 Event, load not supplied must be:</td>
</tr>
<tr>
<td></td>
<td>• Less than 20MVA after 1 hour;</td>
</tr>
<tr>
<td></td>
<td>• Less than 15MVA after 6 hours;</td>
</tr>
<tr>
<td></td>
<td>• Less than 5MVA after 12 hours; and</td>
</tr>
<tr>
<td></td>
<td>• Fully restored within 24 hours.</td>
</tr>
<tr>
<td><strong>Rural Areas</strong></td>
<td>Following an N-1 Event, load not supplied must be:</td>
</tr>
<tr>
<td></td>
<td>• Less than 20MVA after 1 hour;</td>
</tr>
<tr>
<td></td>
<td>• Less 15MVA after 8 hours;</td>
</tr>
<tr>
<td></td>
<td>• Less 5MVA after 18 hours; and</td>
</tr>
<tr>
<td></td>
<td>• Fully restored within 48 hours.</td>
</tr>
</tbody>
</table>

In compliance with the Distribution Authority, Regional Centre applies to non-CBD urban areas predominantly supplying actual maximum demand per total feeder route length of greater than 0.3MVA per km. Rural Areas then apply to non-CBD and non-urban areas. All analysis is based on 50% Probability of Exceedance (PoE) loads.

The economic merits of exceeding safety net targets will be derived by customer reliability value assessment. A key input to calculating the economic value customers place on reliability is Value of Customer Reliability (VCR). The economic customer value based approach will be utilised to optimise the timing of individual projects and to assist in prioritising significant projects addressing Safety Net issues.

In a limited number of cases, a higher level of network security will be considered in the interest of public safety or significant economic or community impact.

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<sup>39</sup> 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.
Appendix D
Network Capacity and Load Forecasts

D:1 Transmission Connection Point Load Forecast
D:2 Sub-transmission Capacity and Load Forecasts
D:3 Sub-transmission Feeder Capacity and Load Forecasts
D:4 Forecasts for Future Substations, Sub-transmission Lines and Transmission Connection Points
D:5 Distribution Feeder Limitations Forecast
Appendix D. 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:

D: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 1.D: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-2018.xlsx</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
Appendix D. Network Capacity and Load Forecasts

TCP is controlled by the TNSP, and hence reported by them. In the relatively few cases where the 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 0.

Embedded generation

Table 55 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 below in Appendix D2.

Table 55: 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>Northern</td>
<td>South Johnstone Mill 22/11kV Substation, 22kV</td>
<td>17.3</td>
</tr>
<tr>
<td>Northern</td>
<td>Gordonvale 22kV Switching Station, 22kV</td>
<td>13</td>
</tr>
<tr>
<td>Northern</td>
<td>T048 Tully 132/22kV Substation, Tully Mill 22kV Feeder</td>
<td>19.8</td>
</tr>
<tr>
<td>Northern</td>
<td>T055 Turkinje 132/66kV Substation, Dimbulah 66kV Feeder</td>
<td>7</td>
</tr>
<tr>
<td>Northern</td>
<td>Kidston 132/6.6kV Substation, 132kV</td>
<td>50</td>
</tr>
<tr>
<td>Northern</td>
<td>Pioneer Mill 66kV Switching Station</td>
<td>67.8</td>
</tr>
<tr>
<td>Northern</td>
<td>Townsville Power Station 66kV Switchyard</td>
<td>82</td>
</tr>
<tr>
<td>Northern</td>
<td>Ingham 66/11kV Substation, Victoria Mill 66kV Feeder</td>
<td>24</td>
</tr>
<tr>
<td>Northern</td>
<td>Collinsville 33kV Substation</td>
<td>42.5</td>
</tr>
<tr>
<td>Northern</td>
<td>T38 Mackay 33kV</td>
<td>30</td>
</tr>
<tr>
<td>Northern</td>
<td>T141 Pioneer Valley to GLEL Glenella 66kV Feeder</td>
<td>38</td>
</tr>
<tr>
<td>Northern</td>
<td>T34 Moranbah 11kV</td>
<td>12</td>
</tr>
<tr>
<td>Northern</td>
<td>T34 Moranbah 66kV</td>
<td>100</td>
</tr>
<tr>
<td>Southern</td>
<td>H015 Lilyvale 66kV</td>
<td>63</td>
</tr>
<tr>
<td>Southern</td>
<td>Barcaldine Substation 132kV</td>
<td>37</td>
</tr>
<tr>
<td>Southern</td>
<td>T83 Roma 132kV</td>
<td>2x45</td>
</tr>
</tbody>
</table>
## Appendix D. Network Capacity and Load Forecasts

### D: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 7.3.

<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-2018.xlsx</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
Appendix D. Network Capacity and Load Forecasts

supply power transformers.

- Zone substations owned by Powerlink which provide a connection point at 11kV or 22kV to 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 <0.5MVA) 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 D. Network Capacity and Load Forecasts

D: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>Sub-transmission-Feeder-Forecast-2018.xlsx</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 region
- Ergon Energy ECORP code
- Ergon Energy operational code
- Sub-transmission feeder name and description
- % of Rated Amps
- Loading (Amps)
- Power Factor
- Rating (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)

Note:
- Summer - December to March
- All other months are classed as summer - March, April, May, September, October, and November.
Appendix D. Network Capacity and Load Forecasts

D:4 Forecasts for Future Substations, Sub-transmission Lines and TCPs

Table 56, Table 57 and Table 58 set out the forecast capacity for the forward planning period for approved future substations, sub-transmission lines and transmission connection points.

Table 56: 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>Southern</td>
<td>Gracemere 66/11kV - New Substation</td>
<td>Rockhampton Region</td>
<td>Apr 2021</td>
<td>Refer Appendix D: D:2</td>
</tr>
</tbody>
</table>

Table 57: 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>Southern</td>
<td>Egans Hill – Gracemere - New 66kV OH Line Construction</td>
<td>Rockhampton Region</td>
<td>Apr 2021</td>
<td>Available in 2019</td>
</tr>
<tr>
<td>Southern</td>
<td>Reinforce Burnett Heads - New 66kV OH Line Construction</td>
<td>Bundaberg Region</td>
<td>Jun 2025</td>
<td>Available in 2020</td>
</tr>
<tr>
<td>Southern</td>
<td>Nikenbah to Point Vernon – New 66kV Line Construction</td>
<td>Maryborough Region</td>
<td>Jun 2022</td>
<td>Available in 2019</td>
</tr>
<tr>
<td>Northern</td>
<td>Planella - New 33kV OH Line Construction</td>
<td>Mackay Region</td>
<td>Oct 2023</td>
<td>Available in 2020</td>
</tr>
</tbody>
</table>

Table 58: 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 D. Network Capacity and Load Forecasts

D5 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</td>
<td>Distribution-Feeder-Limitations-and-Committed-Solutions-2018.xlsx</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 7.4 for a list of possible solutions.

Exclusions:

Dedicated customer connection assets are excluded from the analysis.
Appendix E

Worst Performing Feeder Improvement Program
## Appendix E. Worst Performing Feeder Improvement Program

Table 59: Worst Performing Feeders

<table>
<thead>
<tr>
<th>Feeder Asset ID</th>
<th>Review Complete</th>
<th>Carried Over from Previous Years</th>
<th>WPF Plan Item Status</th>
<th>Region</th>
<th>2017 Length (km)</th>
<th>Feeder Category</th>
<th>2017-18 MSS SAIDI LIMIT</th>
<th>Customer Number</th>
<th>3 Yr Avg SAIDI</th>
<th>3 Yr Avg SAIDI Ratio</th>
</tr>
</thead>
<tbody>
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<td>25273274</td>
<td>2016-17</td>
<td>YES</td>
<td>Completed</td>
<td>NQ</td>
<td>134</td>
<td>SR</td>
<td>424</td>
<td>21</td>
<td>3,528</td>
<td>8.32</td>
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<td>2015-16</td>
<td>YES</td>
<td>Completed</td>
<td>NQ</td>
<td>96</td>
<td>SR</td>
<td>424</td>
<td>104</td>
<td>3,448</td>
<td>8.13</td>
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<tr>
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<td>2016-17</td>
<td>YES</td>
<td>Implementation</td>
<td>CA</td>
<td>139</td>
<td>SR</td>
<td>424</td>
<td>31</td>
<td>3,020</td>
<td>7.12</td>
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<tr>
<td>25268404</td>
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<td>UR</td>
<td>149</td>
<td>159</td>
<td>1,004</td>
<td>6.74</td>
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<td>LR</td>
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<td>6.62</td>
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<tr>
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<td>2016-17</td>
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<td>Implementation</td>
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<td>LR</td>
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<td>Implementation</td>
<td>MK</td>
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<td>5.48</td>
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<tr>
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<td>2015-16</td>
<td>YES</td>
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<td>5.36</td>
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<tr>
<td>25272934</td>
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<td>Completed</td>
<td>NQ</td>
<td>90</td>
<td>SR</td>
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<td>21</td>
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<td>149</td>
<td>98</td>
<td>761</td>
<td>5.11</td>
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<td>25273297</td>
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<tr>
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<tr>
<td>20008745</td>
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<td>Implementation</td>
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<td>LR</td>
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<td>4,607</td>
<td>4.78</td>
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<tr>
<td>20003387</td>
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<td>No Capital Work</td>
<td>NQ</td>
<td>4</td>
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<td>706</td>
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<td>20007634</td>
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<td>NQ</td>
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<td>SW</td>
<td>86</td>
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<td>424</td>
<td>74</td>
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<td>77</td>
<td>SR</td>
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<td>96</td>
<td>1,824</td>
<td>4.30</td>
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<td>2014-15</td>
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<td>No Capital work</td>
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<td>55</td>
<td>SR</td>
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<td>UR</td>
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<td>964</td>
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<td>3,905</td>
<td>4.05</td>
</tr>
</tbody>
</table>
### Appendix E. Worst Performing Feeder Improvement Program

<table>
<thead>
<tr>
<th>Feeder Asset ID</th>
<th>Review Complete</th>
<th>Carried Over from Previous Years</th>
<th>WPF Plan Item Status</th>
<th>Region</th>
<th>2017 Length (km)</th>
<th>Feeder Category</th>
<th>2017-18 MSS SAIDI LIMIT</th>
<th>Customer Number</th>
<th>3 Yr Avg SAIDI</th>
<th>3 Yr Avg SAIDI Ratio</th>
</tr>
</thead>
<tbody>
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<td>20007497</td>
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<td>1,686</td>
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<td>No Capital work</td>
<td>NQ</td>
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<td>180</td>
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<td>2017-18</td>
<td>YES</td>
<td>Implementation</td>
<td>WB</td>
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<td>1,393</td>
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<td>SR</td>
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<td>162</td>
<td>SR</td>
<td>424</td>
<td>160</td>
<td>1,361</td>
<td>3.21</td>
</tr>
</tbody>
</table>
Appendix F

Network Description and Maps

F:1  Planning Regions Overview
F:2  Network GIS Online Maps
F:3  Northern Regions
F:4  Southern Regions
Appendix F. Network Description and Maps

F:1 Planning Regions Overview

As Energy Queensland moves into its current structure, new boundaries and terminology are being adopted for grouping field areas to support efficient service delivery. There are three geographic regions in the Distribution business unit - Northern, Southern and South East.

Ergon Energy has grouped the network broadly into two new planning areas: Northern and Southern as shown in Figure 46 below.

Figure 46: Ergon Energy Network Planning Areas

Within the Northern and Southern regions there are now eleven distinct planning regions within these areas, as shown in Table 60 below. The following sections provide a description of the planning regions and the hubs they envelop.
Appendix F. Network Description and Maps

Table 60: Ergon Energy Network Planning Regions

<table>
<thead>
<tr>
<th>Planning regions</th>
<th>Northern</th>
<th>Southern</th>
</tr>
</thead>
<tbody>
<tr>
<td>Far North</td>
<td>Central West</td>
<td></td>
</tr>
<tr>
<td>Tropical Coast</td>
<td>Capricornia</td>
<td></td>
</tr>
<tr>
<td>Herbert</td>
<td>Bundaberg Burnett</td>
<td></td>
</tr>
<tr>
<td>Flinders</td>
<td>South West</td>
<td></td>
</tr>
<tr>
<td>Pioneer</td>
<td>Fraser Burnett</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Daring Downs</td>
<td></td>
</tr>
</tbody>
</table>

F: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 constraints.

F:3 Northern Region

The Northern Region commences at St Lawrence on the east coast, extending west to the Northern Territory border and north to the northern most island in Torres Strait, Boigu Island. The region consists of five major areas – Far North, Tropical Coast, Herbert, Flinders and Pioneer.

The Far North and Tropical Coast areas, with Cairns as the major centre, are tropical environments with high annual rainfall and exposure to summer electrical storms and cyclones. A substantial part of the wet tropics is also World Heritage Listed, requiring special consideration with regard to the operation and maintenance of any electrical infrastructure.

The Herbert (with Townsville as the major centre) and parts of the Flinders areas are also tropical environments with exposure to summer electrical storms and cyclones. These two areas extend from Bowen in the south to Ingham in the north and west to the Northern Territory border.

The Pioneer region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas (Mackay and Bowen Basin) with regard to electrical infrastructure.
Appendix F. Network Description and Maps

The Northern Region includes many small regional towns with the following representing some of the larger communities in the area:

<table>
<thead>
<tr>
<th>Sub Regions</th>
<th>Regional Communities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Far North</td>
<td>Cooktown, Mossman, Port Douglas, Mareeba, Atherton, Malanda, Millaa Millaa, Mt Molloy, Dimbulah, Chillagoe, Ravenshoe, Georgetown, Normanton, Croydon and Karumba</td>
</tr>
<tr>
<td>Tropical Coast</td>
<td>Cairns, Gordonvale, Babinda, Innisfail, Tully, Mission Beach and Cardwell</td>
</tr>
<tr>
<td>Herbert</td>
<td>Townsville, Ingham, Magnetic Island</td>
</tr>
<tr>
<td>Flinders</td>
<td>Ayr, Clare, Home Hill, Giru, Gumlu, Bowen, Collinsville, Charters Towers, Julia Creek, Hughenden, Winton, Richmond, Mount Isa, Cloncurry</td>
</tr>
<tr>
<td>Pioneer</td>
<td>Mackay, Carmila, Proserpine, Airlie Beach, Laguna Quays, Hayman, Hamilton, Daydream, South Molle, Long Islands, Moranbah, Gienden Nebo, Sarina, Pleystowe, Eungella, Eton and Rosella</td>
</tr>
</tbody>
</table>

**Far North**

The Far North area is centred on the major rural towns of Mareeba and Atherton and includes the smaller rural communities of Malanda, Millaa Millaa, Mt Molloy, Dimbulah and Chillagoe. In addition, the coastal communities of Mossman, Port Douglas and Cooktown are supplied from the Far North network. The area is served from the one 132/66kV connection point, T55 Turkinje substation (located near Mareeba). The Far North system consists of a 66kV sub-transmission network, a dual circuit 132kV transmission line from Turkinje to the Craiglie 132/22kV zone substation near Port Douglas, and a single circuit 132kV line to the Lakeland 132/66/22kV substation that supplies the Cooktown area.

In addition, the Far North western system takes in the Georgetown, Normanton, Croydon, and Karumba communities in the Gulf of Carpentaria. The area is served from the H13 Ross connection point in Townsville where a 132kV single circuit line owned by Ergon Energy to supply this area originates.

**Tropical Coast**

The Tropical Coast area covers the city of Cairns and environs, as well as the townships of Tully, Innisfail, Cardwell and Mission Beach along the coastal strip. The area is served by 132/22kV connection points which are supplied from the Powerlink 132kV network. In addition the Cairns City and Cairns North 132/22kV zone substations are supplied via Ergon Energy owned 132kV dual circuit lines connected to Powerlink’s Woree 275/132kV connection point.

**Herbert**

The Herbert 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 132/66kV
connection points (one in Ingham and four in Townsville), and one 132/11kV connection point, which are supplied from the Powerlink 132kV network. Ergon Energy takes supply at the 66kV side of Powerlink’s 132/66kV transformers for five of these connection points, and at the 132kV terminals of the 132/11kV transformers at the Alan Sherriff 132/11kV connection point. Where Ergon Energy takes supply from Powerlink at the four connection points in Townsville a meshed 66kV network is formed that provides supply to fifteen 66/11kV zone substations.

**Flinders**

This area basically covers Burdekin/Bowen, Midwestern and Western areas of the North Queensland region.

South of Townsville is the coastal strip centred around the major rural towns of Ayr and Home Hill in the Burdekin, and the coastal community of Bowen. It also includes the mining township of Collinsville and its surrounding rural loads. The Burdekin area is served from the connection point at T193 Clare South, located near the Clare township, the Bowen area including the township of Merinda is served from the T181 Bowen North connection point, located near the Merinda township and two 66kV feeders emanating from the T039 Proserpine 132/66kV connection point which is located in the Ergon Energy Mackay region. Collinsville is supplied at 33kV from an Ergon Energy 33kV switching station connected to the T220 Collinsville North connection point.

The mid-western system of the Flinders area extends from Charters Towers west to Julia Creek and takes in the towns of Hughenden, Winton and Richmond. All these towns are connected at 66kV. Ergon Energy’s Millchester 132/66kV substation is located on the outskirts of Charters Towers and is supplied by an Ergon Energy owned single circuit 132kV transmission line from Powerlink's Ross substation in Townsville. Limited capacity is also available via 66kV lines from Stuart substation (Townsville) and T193 Clare South substation to Charters Towers substation. The area west of Charters Towers is supplied by two 66kV feeders, one from Charters Towers substation and one from Millchester substation, to Hughenden substation. Each of these 250km long feeders goes through a 66kV voltage regulator at Cape River substation, which is about 100km from Charters Towers.

The Flinders 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 132kV 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 132kV feeders from Mica Creek B Yard. Ergon Energy’s Mica Creek 132/220kV C Yard supplies the Carpentaria Minerals Province mining loads and the Chumvale 220/66kV substation by two 220kV feeders. Chumvale substation provides 66kV supply to two 66/11kV substations that serve the township of Cloncurry.

**Pioneer**

The Pioneer region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas (Mackay and Bowen Basin) with regard to electrical infrastructure.
Appendix F. Network Description and Maps

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 132/33kV connection points of Alligator Creek and Mackay and two 132/66kV connection points of Pioneer Valley and Proserpine, all of which are supplied from Powerlink's 132kV network. Ergon Energy takes supply at the connection points at the 33kV or 66kV sides of Powerlink’s transformers.

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 66kV supply system from the Moranbah 132/66kV connection point, the 66kV supply system from the Kemmis 132/66kV connection point, or from substations connected to the Powerlink 132kV network.
Appendix F. Network Description and Maps

F:4 Southern Region

The Southern Region commences near Stanthorpe in the South East Queensland and extends west to the South Australia and Northern Territory boarder. The Northern extremity of the region includes areas of Rockhampton, Middlemount, Clearmont and Longreach. The area includes the Sub Regions of Central West, Capricornia, Bundaberg Burnett, South west, Fraser Burnett and the Darling Downs.

The Southern Region includes many small regional towns with the following representing some of the larger communities in the area:

<table>
<thead>
<tr>
<th>Sub Regions</th>
<th>Regional Communities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central West</td>
<td>Longreach, Barcaldine, Blackall, Springsure, Emerald, Blackwater, Clermont, Middlemount, Dysart, Boulia, Bedourie, Birdsville, Windorah</td>
</tr>
<tr>
<td>Capricornia</td>
<td>Yeppoon, Rockhampton, Gladstone, Miriam Vale, Moura, Biloela, Monto, Theodore, Anges Waters, Seventeen Seventy, Taroom</td>
</tr>
<tr>
<td>Bundaberg Burnett</td>
<td>Bundaberg, Gin Gin, Childers, Mundubbera, Biggenden, Gayndah, Proston, Eidsvold, Mt Perry, Bargara, Moore Park, Woodgate</td>
</tr>
<tr>
<td>South West</td>
<td>Quilpie, Charleville, Cunnamulla, Roma, St George, Wandoan, Chinchilla, Tara, Dalby, Miles, Dirranbandi, Mitchell, Augathella, Thargomindah</td>
</tr>
<tr>
<td>Fraser Burnett</td>
<td>Murgon, Kingaroy, Yarraman, Kilkivan, Maryborough, Hervey Bay, Nanango, Yarraman, Blackbutt, Wondai, Howard, Burrum Heads</td>
</tr>
<tr>
<td>Darling Downs</td>
<td>Toowoomba, Millmerran, Warwick, Stanthorpe, Pittsworth, Oakey, Crows Nest, Cecil Plains</td>
</tr>
</tbody>
</table>

Central West

The Central West area takes in the major rural and mining communities of Emerald, Blackwater, Barcaldine, Clermont and Dysart, along with their surrounding areas. The area also extends west to supply the communities of Barcaldine, Longreach and Blackall and further west to the west to the Queensland/Northern Territory/South Australia state border. This area is 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 lower voltages at Blackwater (66kV and 11kV) and Dysart (22kV). The Central West systems include extensive SWER networks.

Capricornia

The Capricornia area incorporates the provincial city of Rockhampton and the surrounding coastal area including Yeppoon and Emu Park, as well as Biloela and Gladstone areas. The Rockhampton area takes supply from Powerlink 132/66kV connection points at T23 Rockhampton, T127 Egans Hill and T061 Pandoin. Ergon Energy takes supply at the connection points at the 66kV sides of the Powerlink 132/66kV transformers.

The Gladstone area is supplied from T019 Gladstone South, H067 Calliope River, T199 Yarwun bulk connection points, and Ergon Energy’s Boat Creek and Gladstone North 132/66kV
Appendix F. Network Description and Maps

substations. Biloela, Moura and surrounding areas are supplied from the T026 Biloela and T027 Moura 132/66kV bulk connection points. South of the Gladstone area, Ergon Energy has the T166 Granite Creek 132/66kV substation which then supplies Ergon Energy’s 66/22kV Agnes Water zone substation. Ergon Energy takes supply from Powerlink at 132kV for Boat Creek and Gladstone North substations, 66kV and 11kV at Gladstone South, 66kV and 11kV at Biloela, 66 kV and 22kV at Moura and 132kV at Gin Gin to supply Granite Creek. Supply from Biloela also extends into the North Burnett to supply Ergon Energy’s Monto substation.

Bundaberg Burnett

The local 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. Bundaberg is supplied from Powerlink Gin Gin and Teebar Creek 275/132kV substations. Voltage is transformed from 132kV to 66kV at Ergon Energy’s T20 Bundaberg supply point. Two main 66kV 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. Ergon’s Isis 132/66kV substation supplies Childers, as well as parts of the North Burnett including Degilbo, Munduberra, Gayndah and Eisvold.

South West

Ergon Energy’s Roma 132/6/33kV substation is supplied via an Ergon Energy owned double circuit 132kV line from Powerlink’s Columboola 132kV switchyard. A 132/66kV transformer at Roma substation supplies 66kV feeders to St George substation and Charleville substation (from which 66kV feeders to Cunnamulla and Quilpie emanate). The distribution supply network from these systems also extends through to Thargomindah, Dirranbandi and Augathella.

Ergon Energy’s Dalby East substation which services the Dalby region is supplied via two Ergon Energy owned single circuit 110kV transmission lines from Powerlink’s Tangkam 110kV switching station. Chinchilla substation is supplied by Powerlink owned double circuit 132kV line from either Powerlink’s Tarong switchyard or Powerlink’s 275/132kV Columboola substation. The Columboola 132/33kV substation connects the Condamine power station into the Chinchilla-Roma 132kV lines and provides 33kV supply to the surrounding region including Miles 33/11kV zone substation. A number of 33kV feeders emanate from Dalby, Chinchilla, Miles and Columboola substations to supply the 33/11kV and 33/22kV zone substations (and several customer owned 33/0.433kV substations) in the area.

Numerous 19.1kV and 12.7kV SWER systems existing in the South West Area

Fraser Burnett

Ergon Energy’s Kingaroy substation is supplied via Powerlink’s H18 Tarong 275/132/66kV substation. 66kV feeders emanate from Kingaroy Substation to supply rural communities of Nanango, Yarraman and Kumbia as well as Sunwater and Stanwell pumping sites. A 66kV line connects the Kingaroy substation with the Murgon zone substation that is supplied from the Kilkivan 132/66kV substation. This line is operated normally open at the Kingaroy substation.
Appendix F. Network Description and Maps

Ergon Energy’s Maryborough 132/66kV substation is supplied from Ergon Energy’s Aramara Switching station which connects via two 132kV feeders into Powerlink’s Tee Bar Creek 275/132kV substation. Maryborough 132/66kV substation supplies Maryborough, Hervey Bay, and rural communities of Owanyilla, Gootchie, Woolooga and Howard to the south west, and the Hervey Bay coastal area. The area is presently served by nine zone substations which are supplied from the Maryborough 132/66kV substation. Ergon Energy’s Kilkivan 132/66kV substation is supplied via dual circuit 132kV feeder from Powerlink’s 275/132kV Woolooga site. Kilkivan 132/66 kV substation supplies Kilkivan, Goomeri, Murgon, Wondai and Proston. A 66kV ring exists connecting the Kilkivan Town and Murgon substations. From Murgon a 66kV line also connects with the Kingaroy substation but is operated normally open at Kingaroy.

Darling Downs

To supply the Toowoomba, Warwick and Stanthorpe areas, Ergon Energy takes supply at 110kV from Powerlink owned 110kV feeder bays at the Middle Ridge 330/275/110kV connection point. 110kV feeders supply Ergon Energy’s South Toowoomba, Torrington, Yarranlea, Warwick, and Stanthorpe 110kV bulk supply substations, and the Kearneys Spring and Toowoomba Central 110/11kV zone substations.

The T189 Oakey 110/33kV bulk supply substation, the 110kV lines and 110kV bus are owned by Powerlink with Ergon Energy owning the 110/33kV transformers. A number of 33/11kV zone substations are then supplied from the 110kV bulk supply substations mentioned above.

In addition, Ergon Energy takes supply at 33kV from the Energex owned Postmans Ridge substation. From Postmans Ridge substation two Ergon Energy owned 33kV lines supply a number of Toowoomba Regional Council water pumping stations as well as Ergon Energy’s Crows Nest zone substation. Another 33kV feeder bay at Postmans Ridge substation provides a 33kV contingency supply to the North Street zone substation in Toowoomba.