Distribution Annual Planning Report

2018-19 to 2022-23

energex

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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.

Contact Information

Further information on Energex's network management is available on our website:

https://www.energex.com.au/about-us/company-information/our-network

GPO Box 1461 Brisbane QLD 4001
26 Reddacliff Street Newstead QLD 4006
Telephone 13 12 53
www.energex.com.au

Energex Limited ABN 40 078 849 055

Contents

Table of Figures

Table of Tables

Executive Summary

Energex'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 renewable energy resources. These factors are driving the transformation of our ageing network that connects and distributes electricity to approximately 1.5 million residential, commercial and industrial customers across a population base of around 3.4 million in South East Queensland and continues to see a steady growth of peak demand.

To promote greater understanding of our present environment, this years' 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. Many solutions seek customer and industry participation in resolving. The online interactive map increases the transparency of our network planning, asset management and investment decision making processes, providing guidance to stakeholders for solutions.

Community and Customer Engagement Input to the DAPR

Energex's vision as part of the Energy Queensland Limited Group is "Energising 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 and customers, 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; and
- Regulatory Proposal and Tariff Structure Statement Customer Research.

These programs will continue 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.

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 taking a no compromise approach to community and staff safety, 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; we have planned to replace more than 60 km of Low Voltage (LV) copper conductor in 2018/19 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 compared to reliability. Our approach to network security is dictated by our Safety Net obligations specified in our Distribution Authority. Overall the Energex network is performing well against these obligations as result of efficient historical investments into the network and our operational response capability. There were no network events in the 2017/18 period where the customer Safety Net targets were breached. With regard to managing peak demand, in February South East Queensland experienced very hot summer weather conditions which resulted in the new Summer System Peak of 4,920 MW on Wednesday 14 February 2018 at 4:30pm. This peak demand exceeded the previous highest recorded demand by 106 MW (4,814 MW in 2016/17).

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. Energex experienced a total of 8 significant weather events impacting its networks and requiring an escalation of its faults response processes. 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.

In 2017-18, Energex reliability of supply has outperformed 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 the duration and frequency of overall outages reducing by 32% and 52% respectively. This is a reflection of the targeted investment made during the last two regulatory control periods towards achieving the regulated MSS standards.

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

Energex has one of the highest capacities of residential rooftop solar PV per capita of any electricity network in the world. One in every three detached homes in South East Queensland now has a solar PV system installed, with over 45% of systems having an installed capacity of 3.5 kW or more. The growth rate in solar PV connection volumes has trended upwards in the last 12 months with an average of 1,900 new systems with a combined capacity of around 12 MW connected per month. At the end of June 2018, there were 356,137 solar PV embedded generating systems connected to the Energex network with a total installed capacity of approximately 1,388 MW.

The rapid uptake of solar PV has changed distribution of electricity impacting the Low voltage network and creating a number of system design and operation challenges. Strategic planning initiatives, such as implementation of the 230 V LV Standard, will help us manage network voltages for residential customers and enable further uptake of solar PV.

We continue to transform our networks into an intelligent grid so that our customers can leverage the many benefits of digital transformation, distributed energy resources and emerging technologies, like solar PV, 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.

2020-25 Regulatory Submission

Energex will submit our Regulatory Proposals to the AER in January 2019. Our Regulatory Proposals will explain our plans and the funding we need to deliver them. We want to ensure our capital investment, operating and pricing plans for 2020 to 2025 are comprehensively 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 South East Queensland.

Changes to 2017 DAPR

The following changes have occurred as compared to the 2017 DAPR:

- 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 providing information on proposed Major Asset Replacement Projects and Programs is available in Chapter 7, Section 7.2. Appendix D provides a link to Major Asset Replacement Projects. 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;
- Energex is currently in the advanced stages of implementing the Queensland Government's electricity industry reform with the creation of Energy Queensland;
- Review and update of maximum demand forecasts over the next five years based on the ACIL Tasman model using three weather stations weighted data and the 2017/18 summer results;
- Under system normal conditions, there is one substation with load at risk in 2018/19;
- Under contingency conditions, there are three zone substations with load at risk in 2018/19;
- Under contingency conditions, there are one 110 kV feeder with load at risk in 2018/19;
- Under contingency conditions, there are six 33 kV feeders with load at risk in 2018/19;
- No potential RIT-D projects were identified to address emerging network limitations as there were no projects approved with credible options having an estimated cost of the augmentation component greater than $5 million. RIT-D information is listed in section 7.5;
- Energex's metering investment due to implementation of Power of Choice on 1 December 2017 and the AER reclassification of metering services from Standard Control Services to Alternative Control Services;
- Energex's information and communication technology investment as detailed in Section 13.2;
- Asset Management Overview chapter 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;
- Update of Community and Customer Engagement chapter to align with customer interactions and 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; and
- Review and update on Energex's demand side management policy, strategy and initiatives.

Chapter 1

Introduction

- Foreword
- Our Obligations
- Alignment of Report Content
- Network Overview
- Changes from Previous Year's DAPR
- DAPR Enquiries

1 Introduction

1.1 Foreword

This Distribution Annual Planning Report (DAPR) explains how Energex is continuing to safely and efficiently manage the electricity distribution network in South East Queensland (SEQ).

In the release of this fifth edition, the DAPR aims to provide information to assist interested parties to:

- Identify locations that would benefit from significant electricity supply capability or demand side and non-network initiatives;
- Identify locations where major industrial loads could be located;
- Understand how the electricity supply system supports customer and participant needs; and
- Provide input to the future development of the network.

For readers seeking to learn of planning outcomes since the 2017 DAPR, they are referred to section 6.10 for joint planning outcomes, to section 7.5 for upcoming RIT-Ds, and to Appendix D for committed projects and proposed opportunities.

Energex understands that as cost of living pressures increase for many South East Queenslanders, prudent investment plans are required in order to maintain required performance targets whilst minimising operating and capital costs. In addition, Energex must continue to ensure the safety of the public and its employees by managing the risks associated with the electricity network. These factors take high priority in Energex's pursuit of the National Electricity Objective (NEO) to promote efficient investment in, and operation and use of, electricity services for the long term interests of customers.

This report captures the results of planning activities mandated by National Electricity Law (NEL), including forecasts of emerging network limitations for the purposes of market consultations. Importantly, customer supply risks are assessed through ongoing planning activities, and in conjunction with market participants, appropriate future investments are scheduled to ensure risks are addressed in accordance with obligated service standards.

Energex's operating environment is dynamic, reflecting customers' responses to economic pressures, electricity prices, technology, and the availability of new service offerings. Customers now have more choice in energy sources, which is enabling them to reduce reliance on the network, manage their own energy needs and engage with new providers in the energy value chain.

The traditional electricity network was characterised by centralised generation and one directional flow. This is now evolving to a connected network of decentralised generation, multi directional flow, many market participants and new products (including renewables and storage).

This plan has been developed consistent with the outcomes of Energex's AER determination with a focus on meeting customer's energy needs with cost effective solution. Key investment decisions will be based on meeting safety obligations and community expectations and supporting the continued expansion of renewable energy growth. This includes supporting the continued growth of domestic solar PV, which is already regarded as among the highest penetration rates in the world.

1.2 Our Obligations

This DAPR has been prepared to comply with National Electricity Rules (NER) clause 5.13.2 and clause 5.13.3. 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.

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 Energex network, including potential opportunities for non-network solutions – particularly for large investments where the AER Regulatory Investment Test for Distribution (RIT-D) applies.

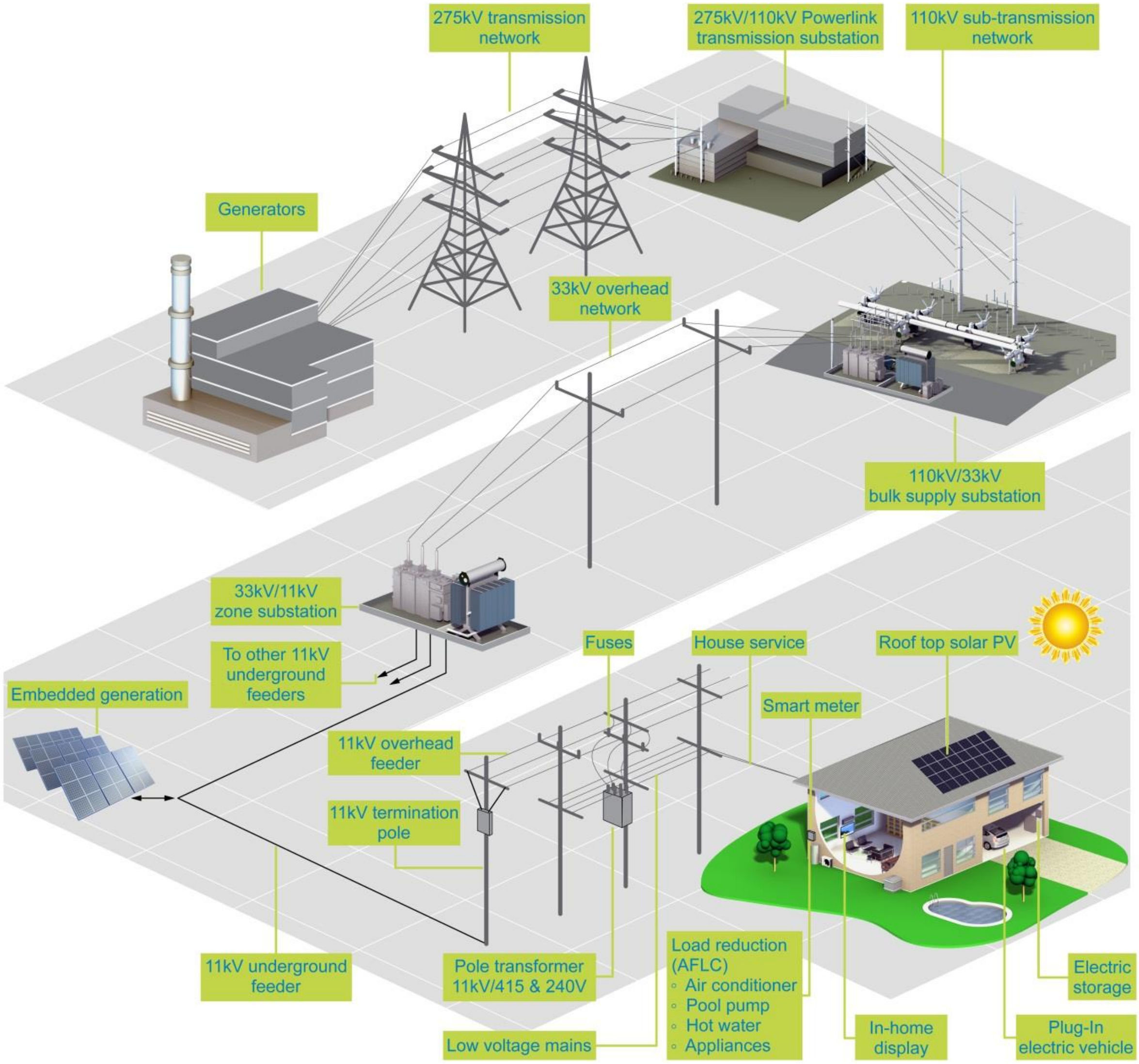
1.3 Alignment of Report Content

In 2017 Energex and Ergon Energy, as subsidiaries of Energy Queensland Limited, commenced the process of aligning our Distribution Annual Planning Reports (DAPR) by adopting similar structures. In 2018, the alignment between our DAPRs has been further progressed with the adoption of similar contents wherever possible. This initiative is part of the wider endeavour to align the businesses' activities in order to achieve greater efficiencies and consistency across Queensland.

1.4 Network Overview

Electricity is a commodity that is generated when it is required because the bulk of electricity consumed is not readily stored. Large generators located outside SEQ are connected to Powerlink's transmission network. In turn, Powerlink delivers this electricity to the Energex distribution network in order to distribute electricity to customers. Figure 1 summarises this electricity supply chain to illustrate how electricity is generated, transmitted and distributed to customers. Connection points exist between generators, transmission networks, distribution networks, embedded generators and large customers. 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 operating at 11 kV. Distribution feeders distribute electricity to transformers that supply low voltage lines at 415/240 volts for customers. Importantly, customers use the network to obtain electricity, and to export electricity when excess solar power is generated.

Figure 1 – Typical Electricity Supply Chain



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. Because 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. Energex 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 Energex system maximum native demand for 2017/18 was recorded at 4,920 MW on Wednesday 14 February 2018 at 4:30pm. This peak native demand exceeded the previous highest recorded demand by 106 MW (4,814 MW in 2017/18).

1.5 Changes from Previous Year's DAPR

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

The following changes have occurred as compared to the 2017 DAPR:

- 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 providing information on proposed Major Asset Replacement Projects and Programs is available in Chapter 7, Section 7.2. Appendix D provides a link to Major Asset Replacement Projects. 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;
- Energex is currently in the advanced stages of implementing the Queensland Government's electricity industry reform with the creation of Energy Queensland;
- Review and update of maximum demand forecasts over the next five years based on the ACIL Tasman model using three weather stations weighted data and the 2017/18 summer results;
- Under system normal conditions, there is one substation with load at risk in 2018/19;
- Under contingency conditions, there are three zone substations with load at risk in 2018/19;
- Under contingency conditions, there are one 110 kV feeder with load at risk in 2018/18;
- Under contingency conditions, there are six 33 kV feeders with load at risk in 2018/19;
- No potential RIT-D projects were identified to address emerging network limitations as there were no projects approved with credible options having an estimated cost of the augmentation component greater than $5 million. RIT-D information is listed in section 7.5;

- Energex's metering investment due to implementation of Power of Choice on 1 December 2017 and the AER reclassification of metering services from Standard Control Services to Alternative Control Services;
- Energex's information and communication technology investment as detailed in Section 13.2;
- Asset Management Overview chapter 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;
- Update of Community and Customer Engagement chapter to align with customer interactions and 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; and
- Review and update on Energex's demand side management policy, strategy and initiatives.

1.6 DAPR Enquiries

In accordance with NER 5.13.2(e), Energex advises that all enquiries and feedback relating to this document are to be submitted by email to the following address:

DAPR_Enquiries@energex.com.au

Energex welcomes feedback and any improvement opportunities identified by market participants and other stakeholders.

Chapter 2

Corporate Profile

- Energex Corporate Overview
- Electricity Distribution Network
- Network Operating Environment

2 Corporate Profile

2.1 Energex Corporate Overview

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

2.1.1 Vision

The Energy Queensland vision is to energise Queensland communities.

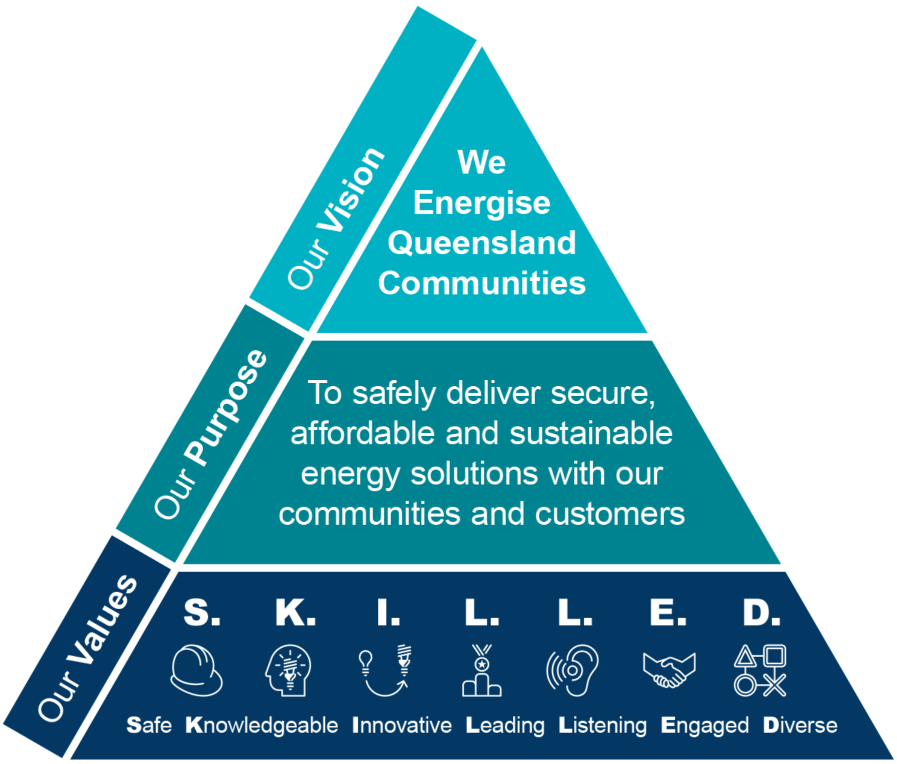
Energy Queensland provides an opportunity to deliver better outcomes for customers, employees and all Queenslanders. Energy Queensland will effectively manage Queensland's electricity network, and respond to the future needs of the energy market.

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

2.1.2 Purpose

To achieve the vision, Energy Queensland's purpose is to 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; and
- 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 $562m through efficiency measures by 2020;
- Merger synergies:
    - Functional (indirect) cost improvements; and
    - Operational (direct) cost improvements.
- Meet or outperform spending allowances set by the independent regulator; and
- 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; and
- 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; and
    - 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; and
- Innovative service delivery.

2.1.4 Business Function

Energy Queensland's core business functions are to:

- Build, operate and maintain its electricity network to deliver safe, efficient, and reliable quality of supply;
- Engage the community and manage electricity supply relationships with end use customers and electricity retailers;
- Balance short term network management and long term network aspirations by improving network performance and emergency response;
- Progress towards the delivery of an intelligent connective network and the provision of leading practice energy solutions to customers; and
- Meet regulatory and shareholder requirements including sustainable and sound commercial operations evidenced by affordable expenditure levels, a strong balance sheet and delivery of shareholder value.

2.2 Electricity Distribution Network

Energex distributes electricity to over 1.4 million residential, commercial and industrial customers across a population base of around 3.4 million in SEQ. At the core of the business is a high performing network that consists of property, plant and equipment and assets valued at approximately $12 billion.

The bulk of electricity distributed by Energex is carried by Powerlink to Energex connection points across large distances, because base-load generation is located remotely. However, Energex also enables connection of distributed generation, such as solar PV and embedded generators.

The Energex network is characterised by:

- Connection to Powerlink's high voltage transmission network at 28 connection points;
- High Density / Central Business District (CBD) areas such as the Brisbane CBD, and the Gold Coast and Sunshine Coast city areas which are typically supplied by 110/11 kV, 110/33 kV, 132/33 kV, or 132/11 kV substations;
- Urban and Rural areas where 110/33 kV or 132/33 kV bulk supply substations are typically used to supply 33/11 kV zone substations;
- Inner suburban areas close to the CBD which have extensive older, meshed 33 kV underground cable networks that supply zone substations;
- Outer suburbs and growth areas to the north, south and west of Brisbane, which are supplied via modern indoor substations of modular design that enable further modules to be readily added; and
- New subdivisions in urban and suburban areas which are supplied by underground networks with padmount substations.

Table 1 presents a summary of Energex's network and customer statistics over the past five years. Changes in asset numbers over this timeframe have occurred as a consequence of demands for electricity, residential, commercial and industrial developments.

Table 1 – Summary of Network and Customer Statistics

Assets	2013/14	2014/15	2015/16	2016/17	2017/18
Total Overhead and Underground (km)	52,176	52,635	53,270	53,774	54,289
Lines – Length of Overhead (km)					
Total	35,112	35,171[3]	35,177[3]	35,120	35,092
LV (Low Voltage)	14,242	14,226	14,222	14,202[5]	14,181
11 kV	17,541	17,553	17,571	17,572	17,569
33 kV	2,196	2,219	2,211	2,193[5]	2,188
132 kV and 110 kV	1,173	1,173[3]	1,173[3]	1,154	1,154
Cables – Length of Underground (km)					
Total	17,064	17,464	18,093	18,654	19,197
LV	10,599	10,848	11,300	11,727	12,102
11 kV	5,421	5,547	5,754	5,917	6,085
33 kV	892	913	883	845[5]	846
132 kV and 110 kV	152	156	156	164	164
Other Equipment (Quantity)					
Bulk Supply Substations	42	42	42	42	42
Zone Substations	242	244	246	246	246
Poles [1]	661,714	667,469	675,459	683,529	683,611
Distribution Transformers	47,875	48,436	49,093	49,781	50,374
Street Lights [2]	348,716	354,691	362,907	372,164	380,063
Customer Numbers					
Residential	1,250,326	1,271,644	1,297,106	1,323,876	1,346,968
Other	113,489	113,801	114,522	115,592	116,526
Total [6]	1,363,815	1,385,445	1,411,628	1,439,468	1,463,494

1 All poles including customer poles and streetlight poles held on record.

2 All streetlights including rate 3 streetlights.

3 Distance includes previously purchased 110 kV lines from Powerlink that are currently out of service.

4 All information as at June 30 each year.

5 Data siting in unknown feeder group has either been removed or allocated to correct feeder type.

6 Only ‘Active’ NMIs are counted. All other NMI status types are excluded.

The large number of Energex assets is managed across six hubs centred on geographical regions. These hubs provide regional asset and resource management, and can respond promptly to local network outages. The geographical boundaries for each hub are shown in Figure 3.

Figure 3 – Energex Distribution Hubs

2.3 Network Operating Environment

Key external drivers, associated industry impacts and safety and environmental commitments are presented in this section. Many of these have emerged from Energex's forward planning process which informs the identification of Energex's five year business objectives covering this forward planning period.

2.3.1 Physical Environment

South East Queensland (SEQ) experiences challenging environmental conditions in which to operate an electricity network. Although located in a temperate zone, SEQ has some of Australia's highest incidences of lightning activity, with Darwin the only other Australian capital city with a higher exposure. The spring and summer season is generally accompanied by severe storms where heavy rain and wind gusts in excess of 80 km/h are a common occurrence. These weather extremes expose the network to damage from overhanging vegetation, flying debris, wind damage and lightning. Climate change projections indicate increased storm and rainfall intensity, increased temperature, significant sea level rise as well as the potential for an increase in tropical cyclones tracking southward.

Other aspects of the region's climatic conditions impacting the distribution network are:

- High rainfall areas with rapid vegetation growth;
- Periods of sustained high temperatures and or high humidity;
- Salt spray in exposed coastal areas resulting in reduced life of assets due to corrosion; and
- Bushfires, flooding and storm surges.

Performance of the network under these conditions is discussed further in section 10.3.

2.3.2 Economic Activity

Average economic growth in SEQ is expected to be stronger over the next ten years than it has in the past two years. However, Energex has used NIEIR's "low case" economic forecast in the electricity modelling, to offset the impact of the large LNG exports on the economic growth figures – as they are expected to have a relatively smaller material impact on SEQ. One of the key drivers for electricity is population growth, which has been subdued for the past 3 years, but is projected to increase modestly over the next few years, boosting new connections which are also set to benefit from a continued decline in persons-per-household. For further details please refer to sections 5.1.6 and 5.1.7.

Rising electricity prices and government subsidies from 2011 have changed customers' behaviour towards electricity costs with reduced consumption and solar PV systems being installed in large numbers in SEQ. Cost of living pressures remain a concern for most people, so customers are looking at the alternative ways, such as solar PV and battery storage options, for improving their financial position.

Impacts

Changes in demand

The electricity sector continues to face significant challenges as residential customers and businesses respond to rising prices by reducing their energy purchases from the Energex network. With the increased uptake of solar PV in the residential sector and now the commercial sector, the likely uptake *of battery storage, and the potential demand of electric vehicles, the historical relationship between economic growth and grid supplied electricity is continuing to change.*

2.3.3 Social and Demographic Change

The sustained low fertility and increasing life expectancy lead to ageing in the Australia population. According to the March 2017 ABS report, the proportion of Australia people aged 65 years and over increased from 11.9% to 15.3% between 1995 and 2016. As the population ages and older workers retire, the new generation of primary income earners will hold different electricity usage patterns than previous generations. This was partly confirmed by the 2015/16 Queensland Household Energy Survey, with the results showing that the TV ownership was down from 97% in 2013/14 to 93% in 2015/16, while the ownership of multiple tablet devices continues to rise steadily. Accordingly, electricity consumption in Information Technology (IT) and home entertainment have decreased from a high of 1,055 GWh p.a. in 2011 to 747 GWh pa in 2017 according to the Energy Consult Pty Ltd report. The changes of social and demographic features will continue to impact typical network investment and asset lifespans and enable to transit the Queensland electricity market more quickly from non-renewable to renewable energy in the future.

Impacts

Increasing energy dependency

At work and at home, the range and volume of electrical and digital equipment continues to proliferate. E-commerce and the ability to work remotely or while on the move is now a lifestyle expectation, along with access to the internet and social media. The impact of power outages or poor power quality is therefore likely to be more acute than previous experience.

Emerging Technologies such as solar PV, Battery Storage and Electric Vehicles

Now that a significant volume of solar PV is connected to the network the community is considering battery storage and in some case the purchase of plug in Electric vehicles as further options to control their energy costs and reduce greenhouse emissions. The interplay of these technologies will affect the peak demand in different ways in different parts of the network. Energex is committed to ensuring that these technologies can be connected to the network.

Community Response

Securing permission to build infrastructure when and where it is required is an important element in maintaining a sustainable and cost effective supply of electricity to Queensland. Enhanced engagement with local councils and community groups is required with regard to infrastructure design, feeder route selection and the development of more efficient and consistent approval processes and timeframes.

2.3.4 Technological Change

New technology is influencing the way residential, commercial, and industrial customers use and source electricity. Trends affecting future consumption from the grid include increasing energy efficiency of equipment, the introduction of load control devices for home appliances, the change to energy efficient street lighting and the adoption of alternative energy supplies (solar PV). Future technology trends that are being monitored include battery storage and electric vehicles as well as the proliferation of internet enabled digital equipment, particularly as the National Broadband Network is rolled out. The further development of internet delivered and enabled service is expected to allow more sophisticated energy management systems.

Impacts

Changing supply and demand relationship

With the support of Government and regulatory policy, customers are seeking options to manage their electricity consumption and costs. In recent years this has been through improved energy efficiency, the adoption of solar PV, and the requirement for greater transparency and information on energy consumption. The net result is reduced consumption of electricity supplied from the grid and changes in the shape of network load profiles.

Technologies with the potential to significantly affect future consumption patterns include battery storage, electric vehicle, internet enabled technologies and services, particularly when combined with solar PV.

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 3,000 MW 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.

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; and
- 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 - 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

Energex aspires to be an industry leader in environment and cultural heritage as reflected in Energy Queensland's Health, Safety & Environment Policy. To support this, Energex environment and cultural heritage performance measures are being developed to support improvement. Energy Queensland 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.

Energex's electricity network traverses diverse environmental and culturally significant areas including coastal, rural and urban 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, Energex 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

Following the restructure of the Queensland Government's ownership of electricity distribution businesses on 1 July 2016, Energex Limited is now a wholly owned subsidiary of Energy Queensland Limited which is a Queensland Government Owned Corporation (GOC).

The two shareholding Ministers to whom Energy Queensland Limited's Board report under the Government Owned Corporations Act 1993, are the

- Premier and Minister for the Arts; and
- Minister for Main Roads, Road Safety and Ports and Minister for Energy, Biofuels and Water Supply.

Energex operates in accordance with all relevant laws and regulations, including:

- Government Owned Corporations Act 1993;
- Electricity Act 1994;
- Electricity Distribution Network Code;
- Electricity – National Scheme (Queensland) Act 1997;
- The National Electricity (Queensland) Law as set out in the schedule to the National Electricity (South Australia) Act 1996;
- The National Electricity (Queensland) Regulations under the National Electricity (South Australia) Act 1996;
- The National Electricity Rules and National Electricity Retail Rules;
- Electrical Safety Act 2002;
- Work Health and Safety Act 2011;
- The Electrical Safety Codes of Practice 2010 and 2013; and
- State and federal environment and planning laws, including the Environmental Protection and Biodiversity Act 1999 (Cth), Environmental Protection Act 1994 (Qld) and Sustainable Planning Act 2009 (Qld).

2.3.9 Economic Regulatory Environment

Energex is subject to economic regulation by the Australian Energy Regulator (AER) in accordance with the National Electricity Law and Rules. The AER sets the amount of revenue that Energex is allowed to recover from its customers (through network prices) over a regulatory control period (typically 5 years). Energex's current regulatory control period commenced on 1 July 2015 and ends on 30 June 2020.

Under the current regulatory framework, the AER sets the allowed revenues using a building block approach, consisting of the following elements:

- Efficient operating costs;
- Asset depreciation;
- Estimated cost of corporate income tax;
- Revenue adjustments resulting from the application of incentive schemes and from the application of a control mechanism in the previous regulatory control period;
- Revenue decrements arising from the use of assets that provide both standard control services and unregulated services; and
- An allowed return on capital, representing the return necessary to achieve a fair and reasonable rate of return on the assets invested in the business.

More information regarding Energex's allowed revenues and network prices can be found on the AER's website (www.aer.gov.au).

Chapter 3

Community and Customer Engagement

- Overview
- Our Engagement Program
- What We Already Know
- 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 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 is influences our investment plans in this report and aligns our future thinking with the long-term interests of our customers.

Figure 4 – Community and Customer Engagement Approach

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 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.

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 Customer Council Working Group dedicated solely to the Regulatory Proposal and the Tariff Structure Statement. This group is 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, Developer Forum, Public Lighting Forum and Agricultural Forum, and are continuing to focus on engaging with our industry partners. This work includes state-wide forums to listen and share knowledge with local electrical contractors and 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 is also to be used to engage with the remaining major centres across our 17 areas. This includes 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 areas future town infrastructure and technology plans.

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.

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

Energex and Ergon Energy, in conjunction with Powerlink Queensland, conduct 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 EVs estimated to increase by a factor of five in the next three years; and
- 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 with our future network investments plans and tariff reform journey.

The findings of this research will ensure our Regulatory Proposals, and future works programs, are informed appropriately by community and customer concerns. A summary of the research is provided in Table 2.

Table 2 – Community and Customer Research

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

3.3 What we already know

The key themes shown in Figure 5 were identified from the review of the Group's 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 comprehensive report on our engagement findings will be published on Talking Energy in January 2019.

Figure 5 – Key Themes for Customer Engagement

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 bill 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, Energex is committing 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 technology. The digitisation 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 Energex 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, so we will investigate this for our Regulatory Proposals.
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 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, providing 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; and
- ensure the electricity grid best meets the needs of future generations of Queenslanders and a transforming energy mix with sustainable investment.

We are aligning to the International Standard for Asset Management (ISO55000) 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 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 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 500 kVA threshold to distinguish between small and major customer connections coupled at high voltage;

- broadening the scope (in the Energex distribution area) of what will constitute a real estate development connection to align with the definition in the National Electricity Rules (NER); and
- 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 already almost 500,000 solar photovoltaic 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 230 V standard for our networks, which will increase the capacity for solar hosting and reduces voltage-related performance issues.

Chapter 4

Asset Management Overview

- Best Practice Asset Management
- Asset Management Policy
- Strategic Asset Management Plan
- Investment Process
- Further Information

4 Asset Management Overview

Management of Energex’s current and future assets is core business for Energex. Underpinning Energex’s approach to asset management are a number of key principles, including making the network 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 Energex's:

- Best Practice Asset Management;
- Asset Management Policy;
- Strategic Asset Management Plan (SAMP); and
- Network Investment Process.

4.1 Best Practice Asset Management

Energex 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, Energex’s asset management practice must be effective in gaining optimal value from assets.

Energex 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 focused 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

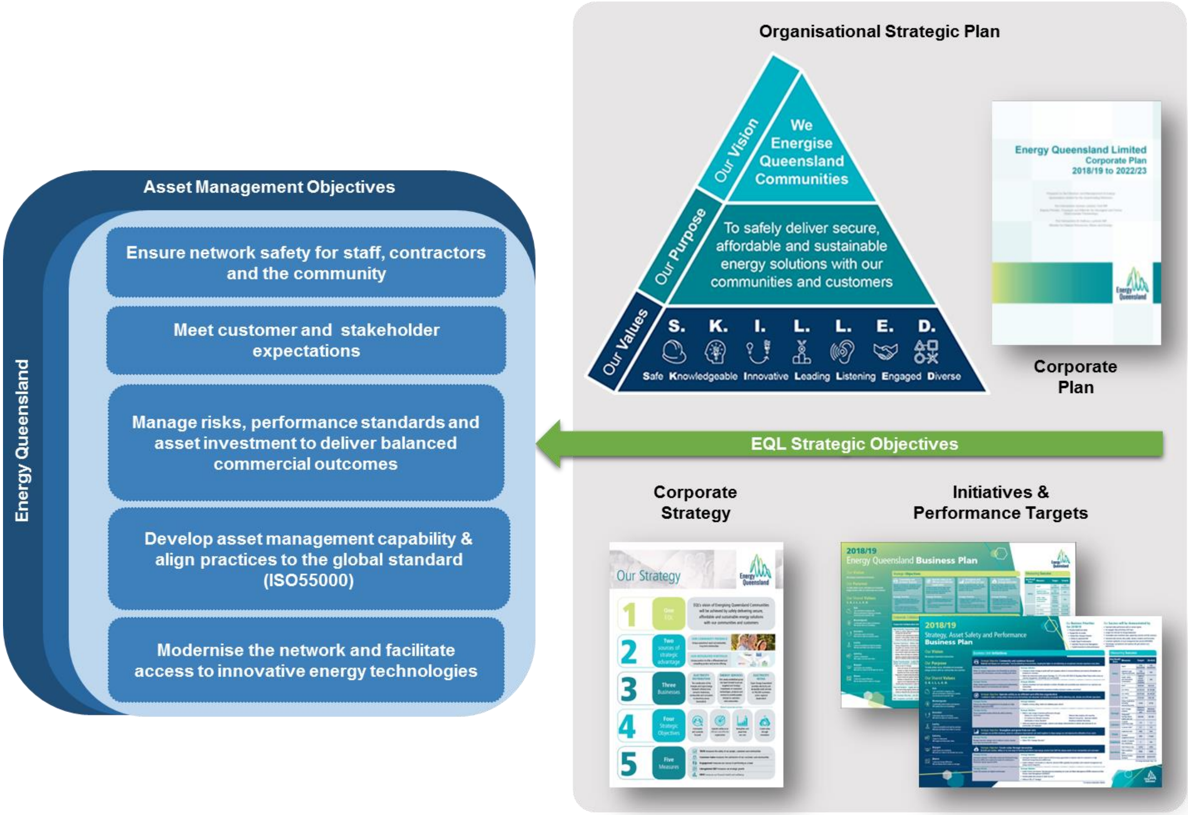
The asset management policy provides the direction and broad framework for the content and implementation of Energex’s asset management strategies, objectives and plans. The policy directs Energex to undertake requirements associated with safety & people, meeting customer needs, and the commitment to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

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

Energex’s strategic asset management plan (SAMP) is the interface that articulates how organisational objectives are converted into asset management objectives as shown in Figure 6. 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.

Figure 6 – SAMP translates Corporate Objectives to Asset Management Objectives



4.4 Investment Process

4.4.1 Corporate Governance

Energex has a four governance process to oversee future planning and expenditure on the distribution network as shown in Figure 7.

Central to Energex'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 Corporate Plan and Statement of Corporate Intent.

Figure 7 – Program of Work Governance

The four tiers include:

1. **Asset Management Strategy & Policy:** Alignment of future network development and operational management with Energex 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 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:** Energex 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; and.
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 Energex website:

https://www.energex.com.au/about-us

Chapter 5

Network Forecasting

- Forecasting Assumptions
- Electricity Delivered Forecasts
- Substation and Feeder Maximum Demand Forecasts
- 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.

Energex (EGX) 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 its forecasting models and continues to improve its 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 Program of Work.

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. Recent household survey results indicate customers are undertaking fewer energy efficiency measures and are less concerned about electricity prices than in previous years (annual Queensland Household Energy Survey).

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 generator station.

Small-scale systems are referred to as Micro Embedded Generation Units (MEGUs) and have capacities no greater than 30 kVA. 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.

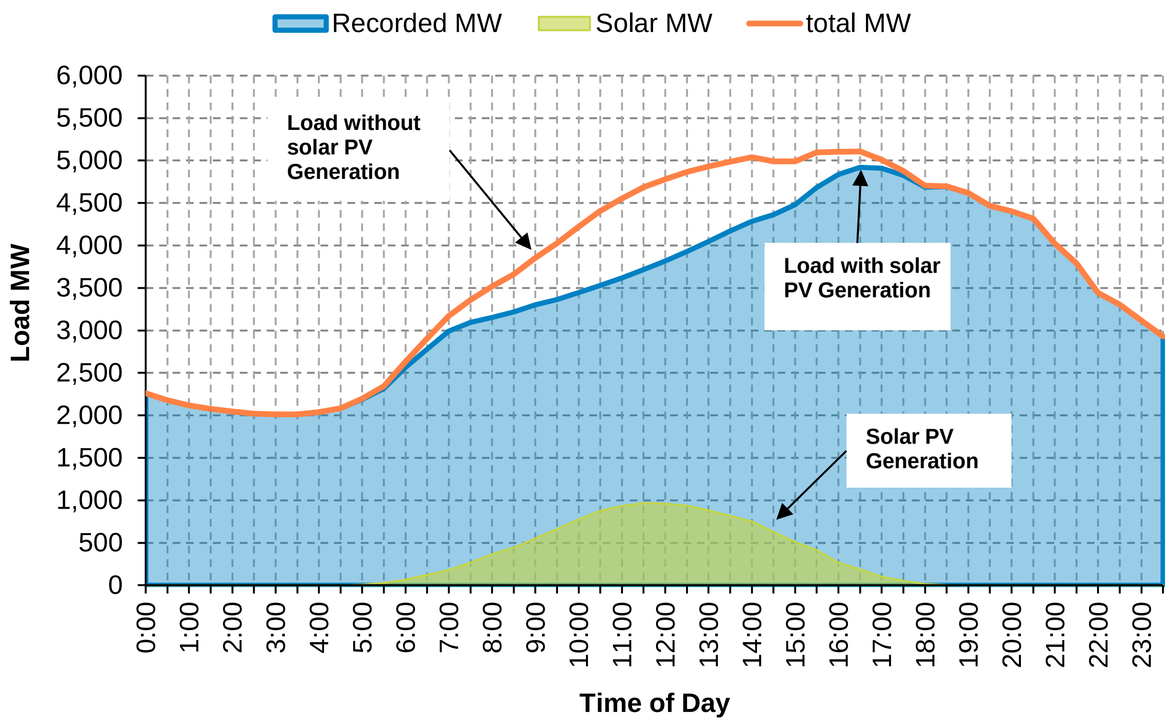
Status

Connected solar PV capacity of all types up to utility-scale, continues to grow at a steady pace. During the 2017/18 financial year, distributed solar PV systems were connecting at an average rate of over 2,200 connections per month. At the end of June 2018, there were about 359,000 solar PV systems connected to the distribution network, with a total generation capacity of 1,429 MVA. Amongst residential customers, the take-up rate is more than 26%.

The cumulative 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 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 PV generation.

As seen in Figure 8, the 2017-18 summer system peak of 4,920 MW occurred at 4.30 pm on 14 February 2018 and it was estimated that solar PV reduced the peak by almost 188 MW at that time. As battery storage becomes more affordable and therefore more widely used, daily peaks may revert to mid-to-late afternoon, although at lower levels and with a flatter profile than traditionally.

Figure 8 –System Demand – Solar PV Impact, 14 February 2018



Forecasting

Photovoltaics' 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. These estimates indicate that photovoltaic generation currently represents around 188 MW of system peak demand.

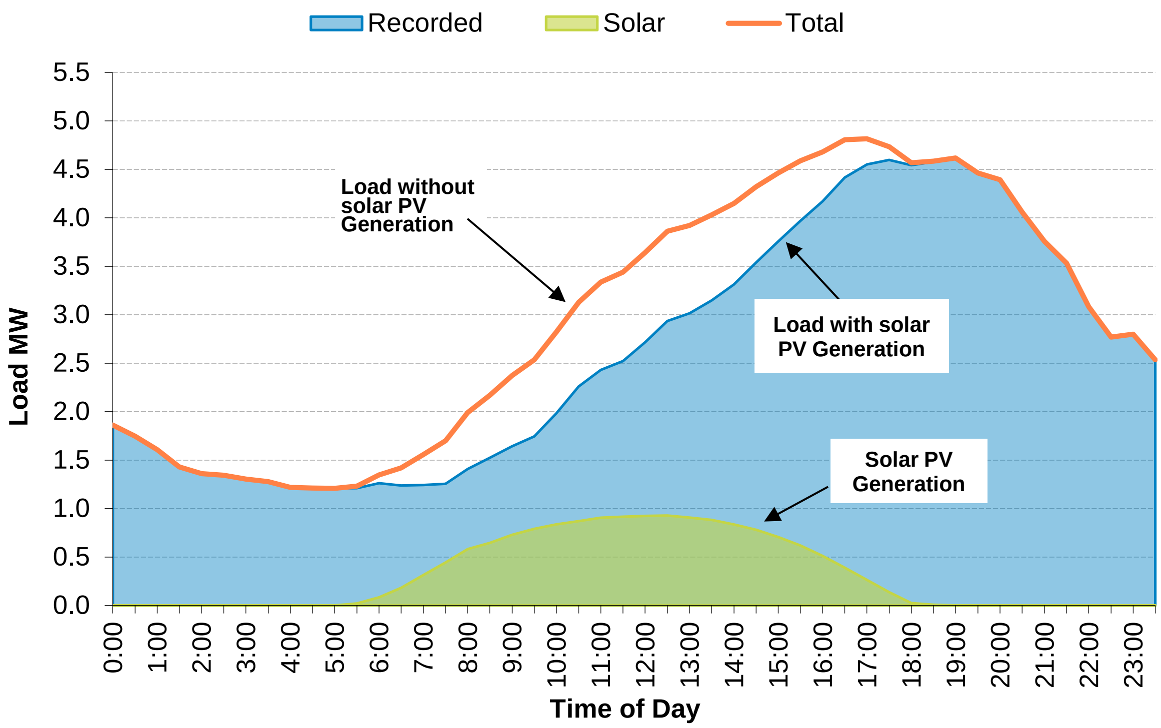
Embedded rooftop PV affects peak demand at a system level; however, at zone substation level there is currently no consistent material effect from PV on reducing load for augmentation expenditure purposes. This is partly due to the variable nature of PV demand reduction on a year-to-year basis. Additionally, for 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 3,000 megawatts of solar generation installed by 2020.

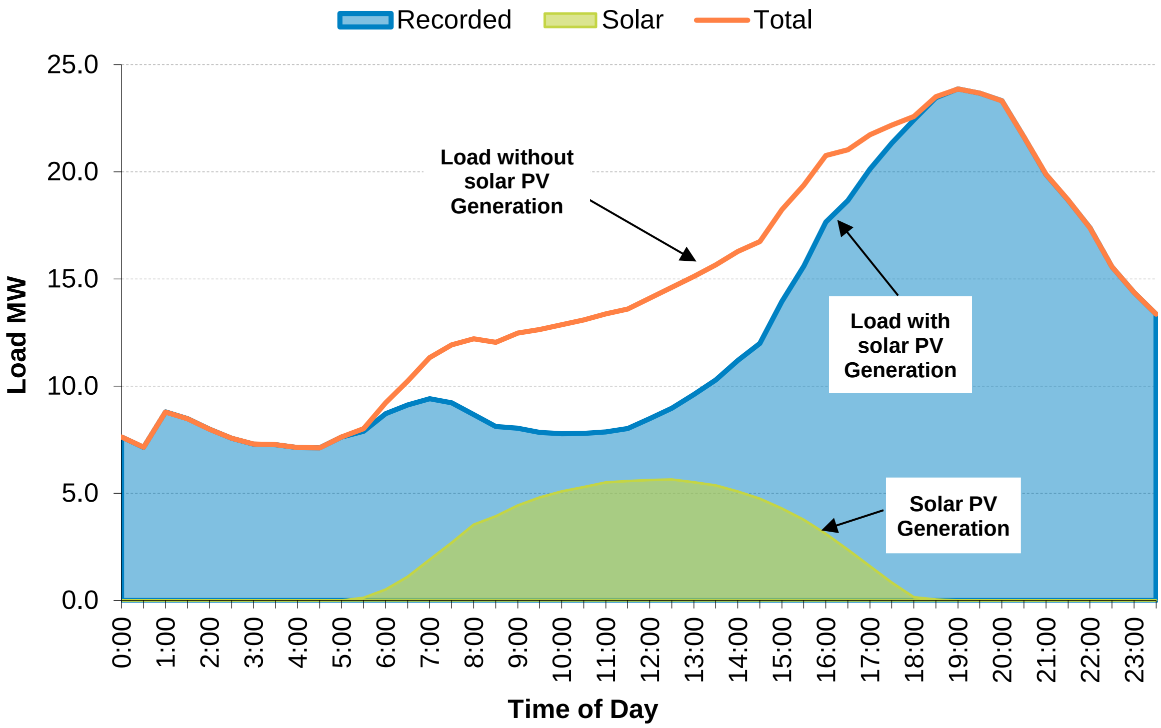
Figure 9 shows the effects of solar PV on Brisbane North 11 kV feeder AHL12A on a peak day. Solar PV generation is estimated to have around 1 MW impact on the peak demand for this feeder.

Figure 9 – Solar PV Impact on Arana Hills AHL 12A on the Peak Day



In contrast, Lota is a predominantly residential substation located east of Brisbane with a significant quantity of residential solar PV systems. Traditionally, substations with a high proportion of residential load experience peak demand in the early evening and the time of peak is largely unaffected by solar PV, despite it reducing afternoon load. This is demonstrated in Figure 10, where the impact on the half-hourly demand for a peak day is shown. On this day, the peak without PV might have been a little earlier but was little different from the net peak in early evening (around 7:00pm).

Figure 10 – Solar PV Impact on Lota Substation on a Peak Day



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. The estimated impact of plug-in electric vehicles 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 at more than 1,120 with total storage capacity of more than 14 MWh. 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. Energex 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, however, 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. 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 (10 PoE) 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 from three weather stations

- Amberley;
- Archerfield; and
- Brisbane Airport.

Other weather stations either did not have the necessary 50-year history or had substantial numbers 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.

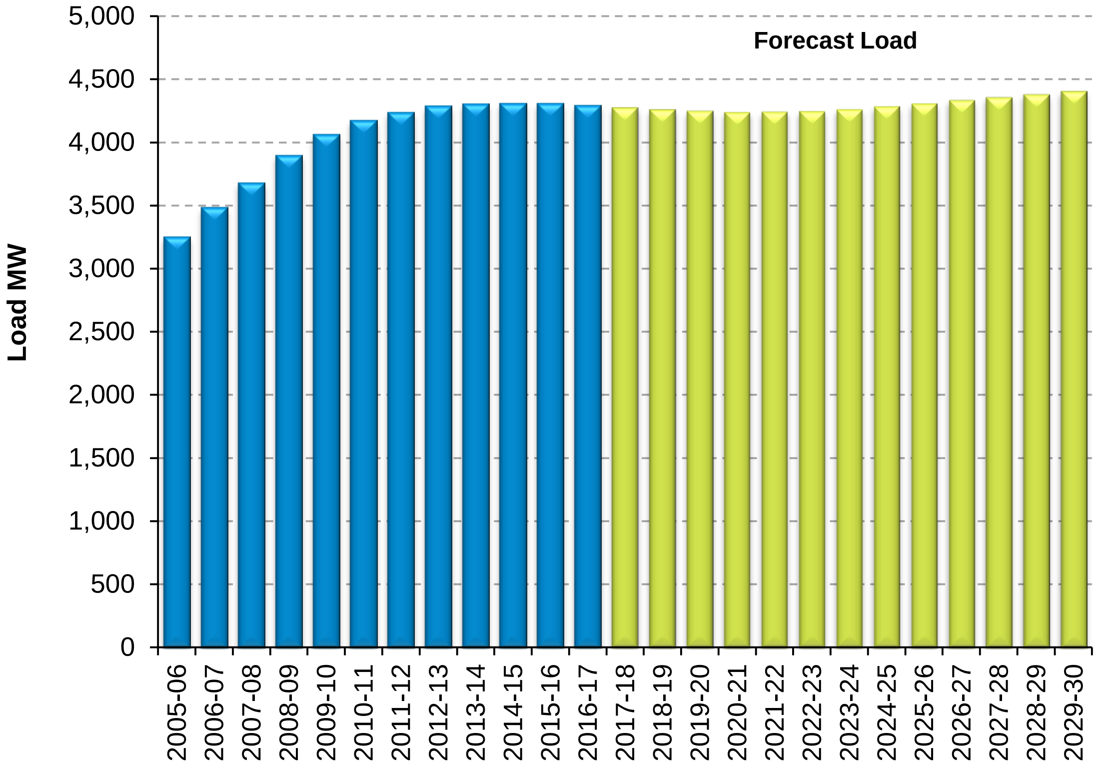
Air-Conditioning

Air-conditioner ownership has risen markedly (76% to 81%), likely to be the result of a series of heatwaves that affected SEQ. The Queensland Household Energy Survey (QHES) found that households stated an intention to increase their air-conditioning in the next two years, either by adding or replacing units or both (total of 13%).

The reported 5% rise to 81% in one year is the same increase as in the previous five years. While all surveys can only ever estimate population trends, it does indicate a significant load that is likely to need network management in future extreme weather conditions. It also has to be viewed in the context of diversity of use, and more energy efficient air-conditioner replacements improving the overall population efficiency.

A base case air-conditioning forecast produced by consultants has been used in the early testing of the latest system demand model. Figure 11 represents the historical and forecast cumulative rated input power for air-conditioners before diversity. The air-conditioning load base case variable was used in the development of the peak demand forecast model.

Figure 11 – Air-Conditioning Connected Load Forecast



Note: The forecast air-conditioner load was considered as an input to the system demand forecast model. Not all air-conditioners operate or draw full power at the same time. Due to this diversity, the data do not represent the net contribution of air-conditioner load to the system peak demand.

Importantly, with air-conditioning load still rising, the sensitivity of the significant latent air-conditioning load already on the network presents a challenge to manage during extreme weather. Whilst peak demand sensitivity to temperature is forecast to continue to increase at a slower rate, given normal hot summers, temperature sensitive load will still strongly influence peak demand on the network.

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 12 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.

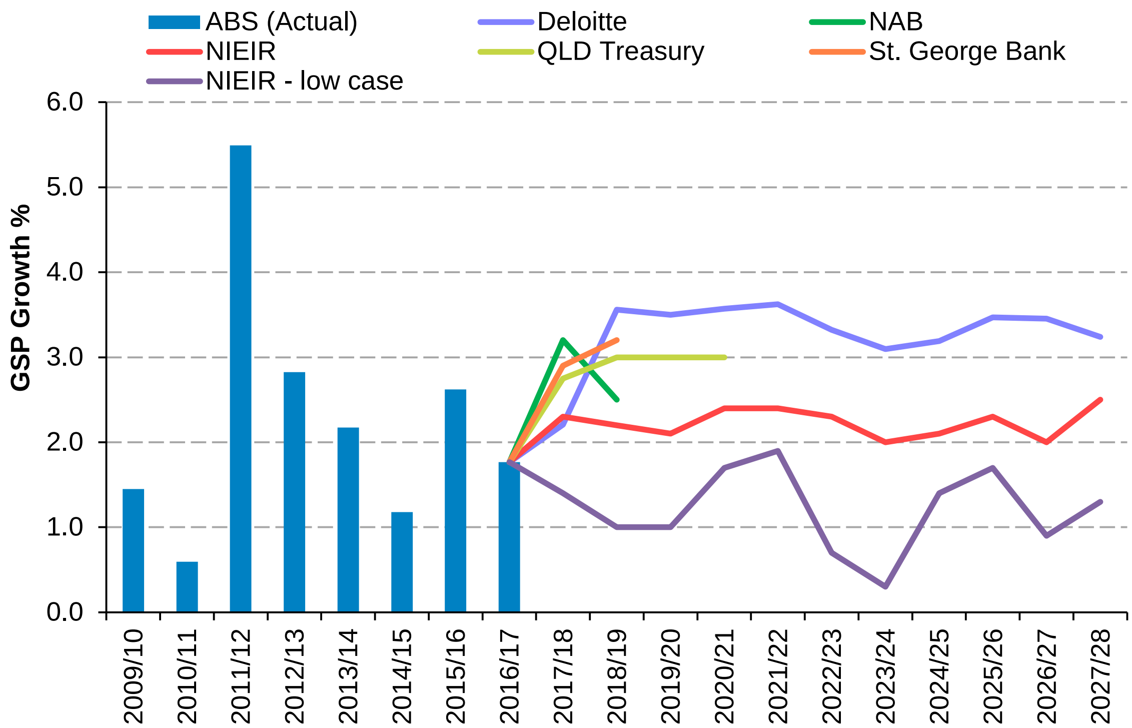
External sources have forecast that the Queensland economy might rise to a growth range as high as 3.0% to 3.5% from the 2018-19 year, boosted by improved activities in the volume of commodity exports, tourism, education services, housing, agriculture, and small manufacturing industries, as a result 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 economy.

Figure 12 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 Energex) have forecasts that sit apart by roughly 1%, DAE being the more optimistic. However, Energex 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. The new LNG plants in Central Queensland are pushing up the State economy as a whole but have limited impact on economic growth in SEQ. 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 12 – Queensland GSP Growth Forecasts



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

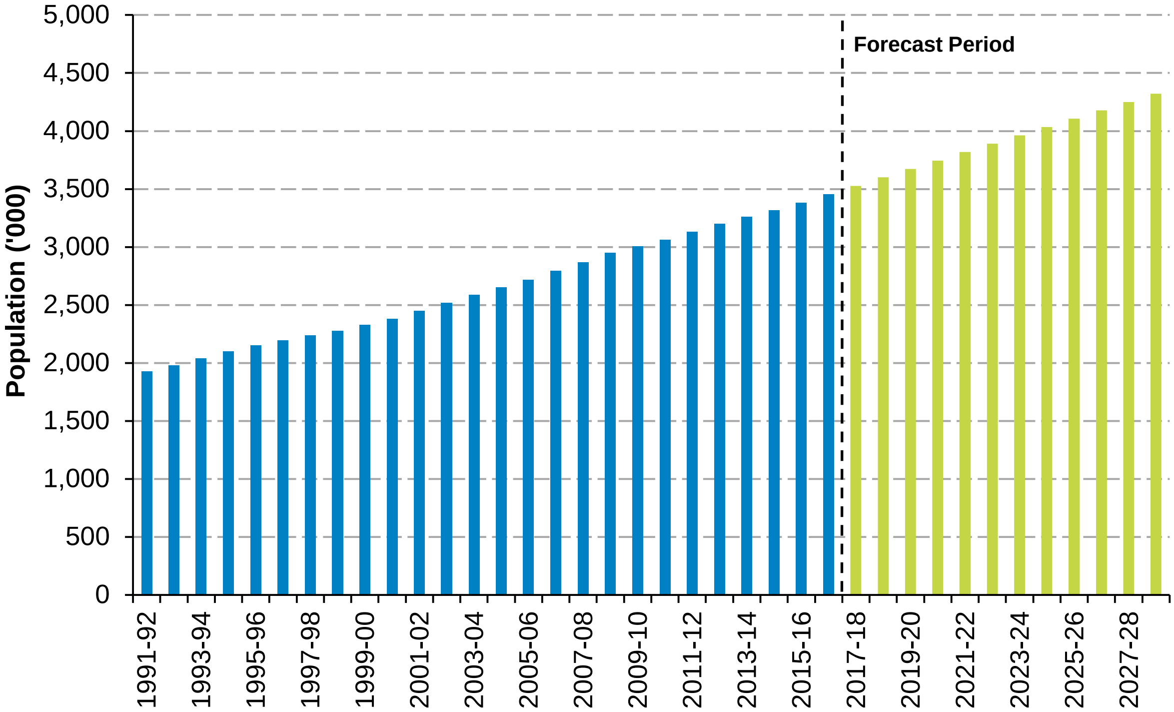
5.1.7 Population Growth

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, 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.

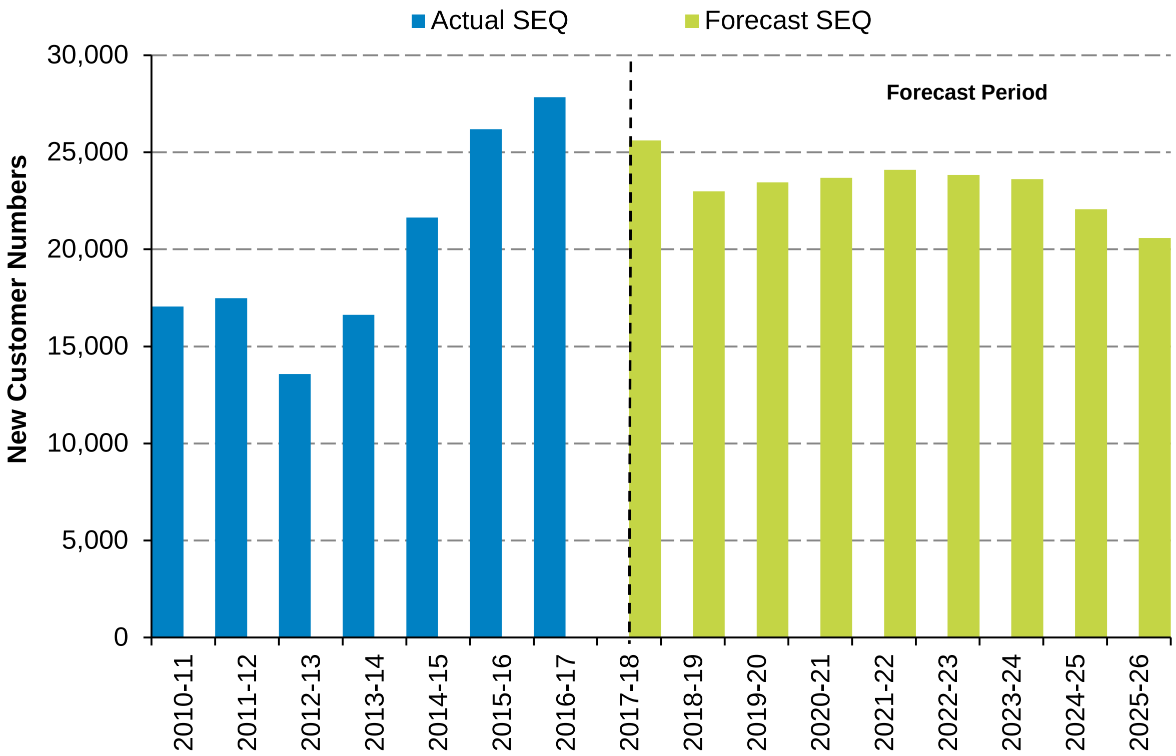
The majority of the Queensland population growth will occur in SEQ (with 68.8% of state population as at the end of June 2016). The fastest growing areas include Pimpama at 31%, Ripley at 15%, Jimboomba and North Lakes having some of the highest growth numbers. Population growth continues to support the growth in commercial/industrial customers in terms of employment and support facilities (e.g. shopping centres, sporting facilities and schools). A summary of projected population by location is shown in Figure 13 below.

Figure 13 – South-East 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. **Error! Reference source not found.** illustrates the forecasted total new customer numbers to June 2026. Total Energex customer numbers at the end of the 2017-18 year was 1,463,494.

Figure 14 – New Metered Customer Number Growth – South-East Qld



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 Energex, 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 is 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 PV connections, as shown in Figure 15, 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 3,000 megawatts of solar PV installed by 2020, and Solar 150 – which has a focus on encouraging new large-scale renewable energy projects in Queensland.

Figure 15 – Number of Solar PV Installations – South-East Qld

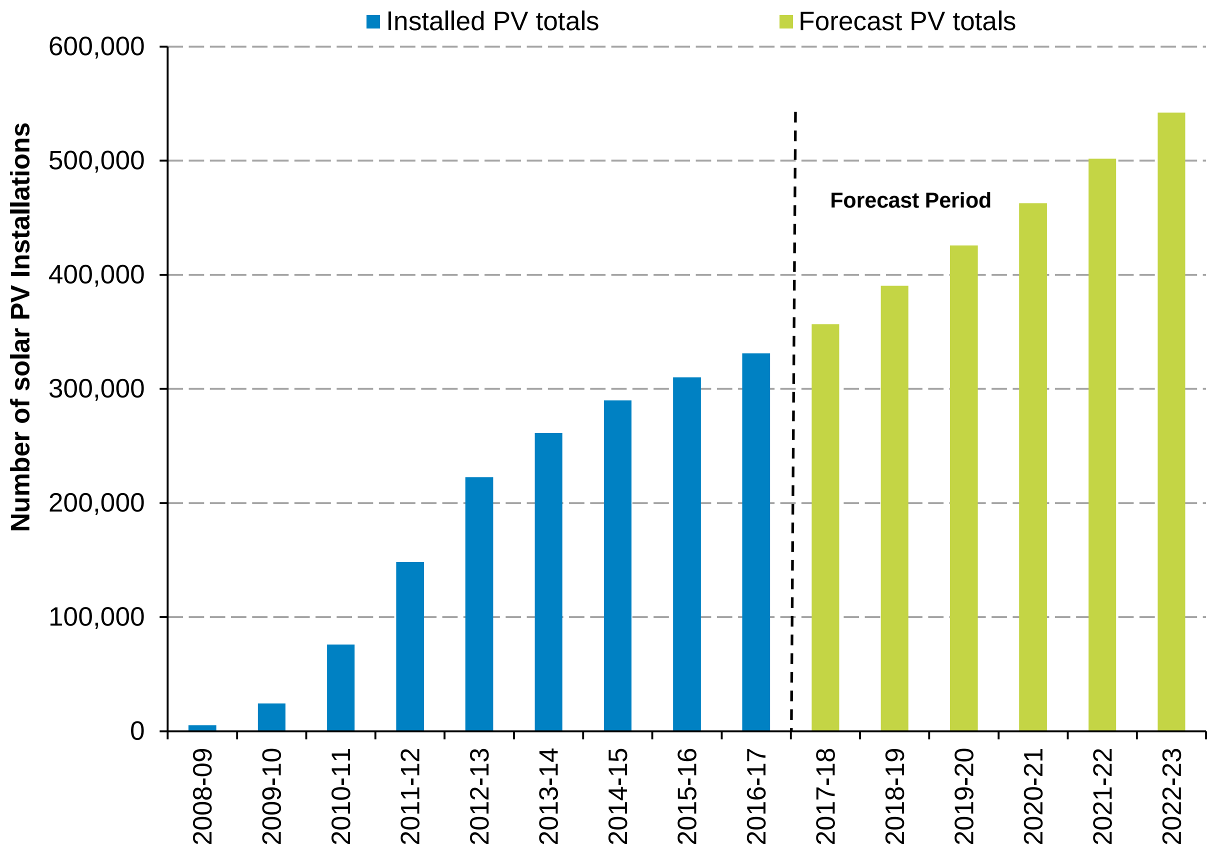
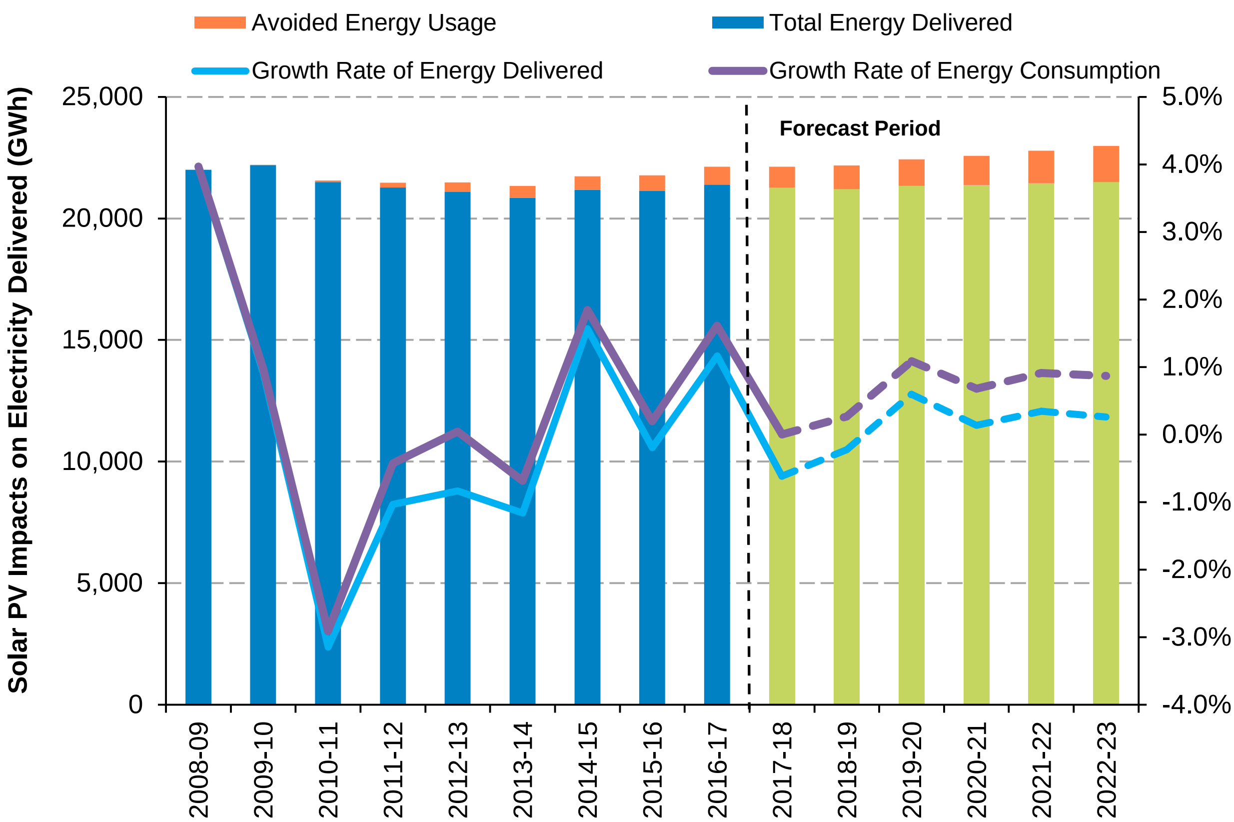


Figure 16 shows the increasing avoided electricity delivered as a direct result of solar PV generation supplied to both residential and non-residential customers. It becomes clear that while electricity delivered will be flat over the next nine years, electricity consumption (i.e. electricity delivered 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 21,385 GWh, which was 1.2% below the 2015-16 value.

Figure 16 –Solar PV Impacts on Electricity Delivered – South-East Qld



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 residential and non-residential customers, in alignment with their respective network tariffs.

For each of the network tariffs, 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 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, Energex 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.

Energex 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.

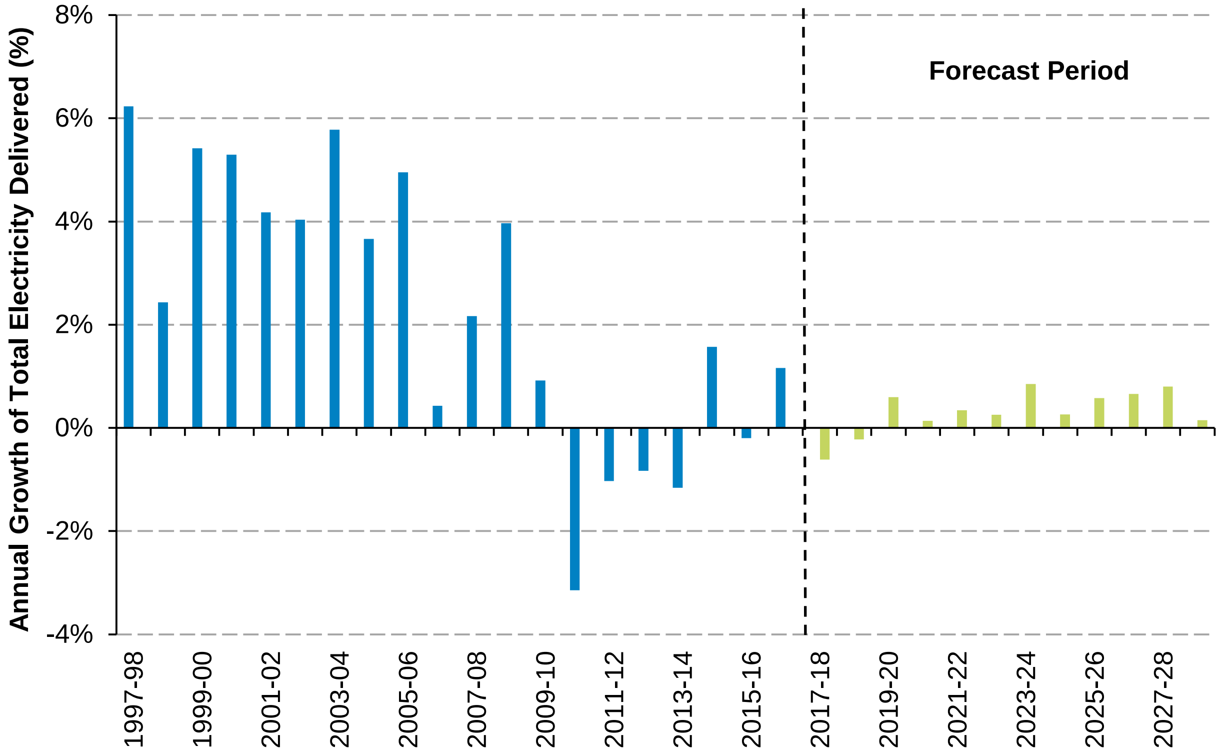
In addition, Energex has also developed an econometric electricity purchases model that is used at a total system level. This forecast is used to review and compare the bottom-up electricity delivered forecast after accounting for network losses.

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 almost 3% in electricity delivered occurred in 2010-11 which was reflected in most areas of the State. During the six years from 2011-12 to 2016-17, electricity delivered was completely flat (average annual growth of 0.0%) as shown in Figure 17.

Looking ahead, electricity delivered is expected to be flat over the next nine years to 2025-26, with annual average growth of only 0.4%. This is likely the result of solar PV installations and the continued reduction (or a potential closing down) of some industrial businesses. The most likely change might come from a rebound in population growth (driven by the gain of net overseas immigration) and more international tertiary students attracted by cheaper tuition fees (due to the lower Australian dollar). In the medium-to-long-term however, downward pressures will weigh on electricity delivered as new technologies, especially battery storage (which normally links to 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 saturation in the penetration of air-conditioners and reductions in consumption for low income households due to higher electricity prices, but should be partly countered by the potential increase in electric vehicle (EV) sales.

Figure 17 – Growth of Total Electricity Delivered – South-East Qld



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 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 1.8% in 2016-17, it is expected to rise to 2.3% and 2.2% in the 2017-18 and 2018-19 years respectively based on NIEIR's latest forecasts (base case). The forecast GSP figures are a key input into the forecasting process.

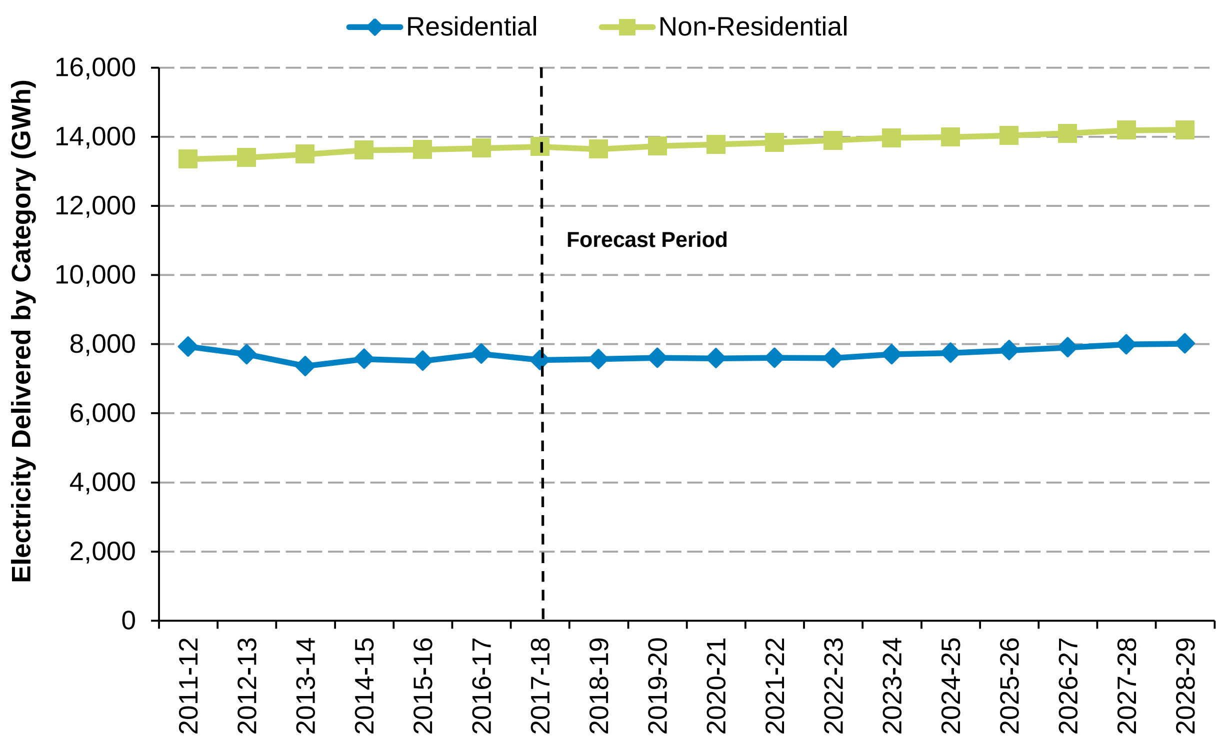
All of these factors have been modelled in determining a view on electricity delivered into the future. Based on these changing inputs, it is anticipated that electricity delivered will increase very slowly – with an average annual growth rate of around 0.24% over the next ten-year period. Continuing increases in electricity prices and improving appliance efficiencies have changed the long-term outlook for domestic electricity delivered. The annual average price elasticity for domestic electricity delivered is -0.26 calculated over the four-year period 2011-12 to 2015-16. Furthermore, electricity delivered for water heating has weakened for several reasons, including mild weather conditions, policies to reduce electric storage systems, and increases in energy efficiency measures in the construction of multi-unit dwellings. Despite the withdrawal of a Government directive for solar, gas and heat pumps to replace electric hot water heating, the long-term decline in controlled electric hot water installations is expected to continue with new developments incorporating gas, heat pumps or solar hot water heating.

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. Electricity delivered to non-residential customers is predicted to grow at an average of 0.3% p.a. over the next ten years.

Figure 18 provides a graphical representation of this electricity growth. It shows that annual electricity delivered to residential customers will be flat over the ten-year forecasting period. Non-residential electricity delivered growth will be relatively stable in the short term. In the long term however, the non-residential component will continue to increase in line with the long-term trend of the Queensland economy and the build-up in infrastructure investment.

Figure 18 – Electricity Delivered by Category (GWh pa)



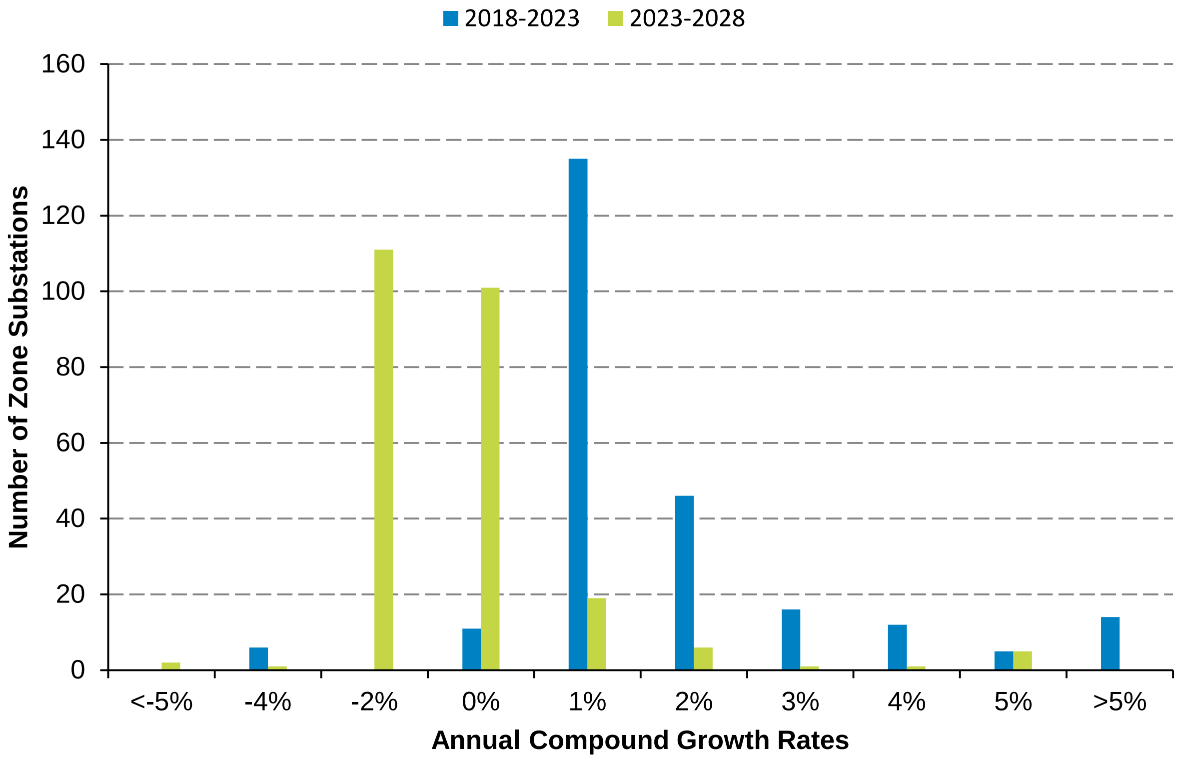
5.3 Substation and Feeder Maximum Demand Forecasts

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. Energex 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. Some substations supplying the outer regions of the major development areas such as south of Ipswich are growing strongly as areas like Ripley Valley are developed. Other growth areas include the northern Gold Coast, the southern Sunshine Coast, the Logan area including Yarrabilba and Flagstone, and the northern Brisbane gateway. 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 is shown in Figure 19.

Figure 19 – Zone Substation Growth Distribution 2018-2028 – South-East Qld



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 only 4.5% per cent of substations have a zero average compound growth rate while more than 80% of zone substations have 1.0% to 3.0% average annual compound growth rate. Almost 6% of zone substations have an annual compound growth rate exceeding 5% for the period 2018-23. Due to this growth, augmentation will be required to meet the additional demand on the network in these areas.

Demand management initiatives have impacted on peak loads at a number of zone substations, which has affected the substations. 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 Appendixes C, D, E, F and G of the DAPR.

The ten-year substation peak demand forecasts are prepared at the end of summer and winter each year, and are produced within the Substation Investment Forecast Tool 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 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

Energex 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 (Amberley, Archerfield airport, Coolangatta airport, Brisbane airport and Maroochydore airport). 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 electric vehicles have been included at the substation level for the first time.
- Year-on-year peak demand growth rates are determined from the customer load profiles;
- 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; and
- 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 the Substation Investment Forecasting Tool (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 33 kV 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.

Simulation models are created using existing network data. Future projects are then modelled with timings and proposed network configurations based on future project proposals being included. Future projects are automatically activated depending on the network analysis dates selected. The forecast peak loads at each substation for all years within the planning period are uploaded into the model from SIFT. Eight models are produced, each containing forecast load for the different seasons. These include summer day, summer night, winter day and winter night, and with 10 PoE or 50 PoE peak load. This enables the identification of worst-case risk period for each season.

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 occurring at different times/dates and the presence of phase imbalance. Also, the relationship between demand and average temperature is more sensitive at the distribution feeder level.

Forecasting of 11 kV feeder loads is performed on a feeder-by-feeder basis. The forecast begins by establishing a feeder load starting point by undertaking bi-annual 50 PoE temperature-corrected load assessments (post-summer and post-winter). This involves the analysis of daily peak loads for day and night to identify the load expected at a 50 PoE temperature after first identifying and removing any temporary (abnormal) loads and transfers.

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, a combination of trending of normalised historic load data and inputs including known future loads, economic growth, weather, local government development plans, etc. is used to arrive at load forecasts.

Using a statistical distribution, the 10 PoE load value is extrapolated by using 80% of the temperature sensitivity from the 50 PoE load assessment. The summer assessment covers the period of December-January-February, and the winter assessment from June-July-August. Growth rates are applied and specific known block loads are added and events associated with approved projects are also incorporated (such as load transfers and increased ratings) to develop the feeder forecast. In addition, the 10 PoE load forecast is used for determining voltage limitations.

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

- The historic maximum demand values, in order 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 are 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;
- 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; and
- Further forecast information obtained from discussions with current and future customers, local councils and government.

5.4 System Maximum Demand Forecast

Energex 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 Gross State Product (source: ABS website);
- temperature (source: BOM);
- air-conditioning sales (source: independent consultancy);
- solar PV generation (source: customer installation data); and
- 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); and
- 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.

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 more steady rate. Customer behaviour drivers are now incorporated into models used for system demand forecasting. The forecasts are developed using Australian Bureau of Statistics (ABS) data, Queensland Government data, the Australian Energy Market Operator (AEMO) data, the National Institute of Economic and Industry Research (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 maximum demand forecast as recommended by consultants ACIL Tasman is as follows:

- Develop a multiple regression equation for the relationship between demand and GSP, weighted maximum temperature, weighted minimum temperature, total electricity price, structural break, three continuous hot days, weekends, Fridays and Christmas period and December to February temperature data that excludes days with average temperature at selected weather stations that are below a set level (for example, Amberley temperatures < 23.5C). Three weather stations were incorporated into the model through a weighting system to try to capture the influence of the sea breeze on peak demand. Statistical testing is applied to the model before its application to ensure that there is minimal bias in the model;
- A Monte Carlo process is then used to simulate a distribution of summer maximum demands using the latest 30 years of summer temperatures plus an independent ten-year GSP forecast and an independent air-conditioning load forecast;
- Use the 30 annual summer peak maximum demands to produce a probability distribution of maximum demands to identify the 50 PoE and 10 PoE maximum demands;
- An error factor is applied to the simulated demands based on a random distribution of the multiple regression standard error. This process attempts to define the peak demand rather than the regression average demand; and
- Modify the calculated system peak demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for solar PV, battery storage and the expected impact of electric vehicles.

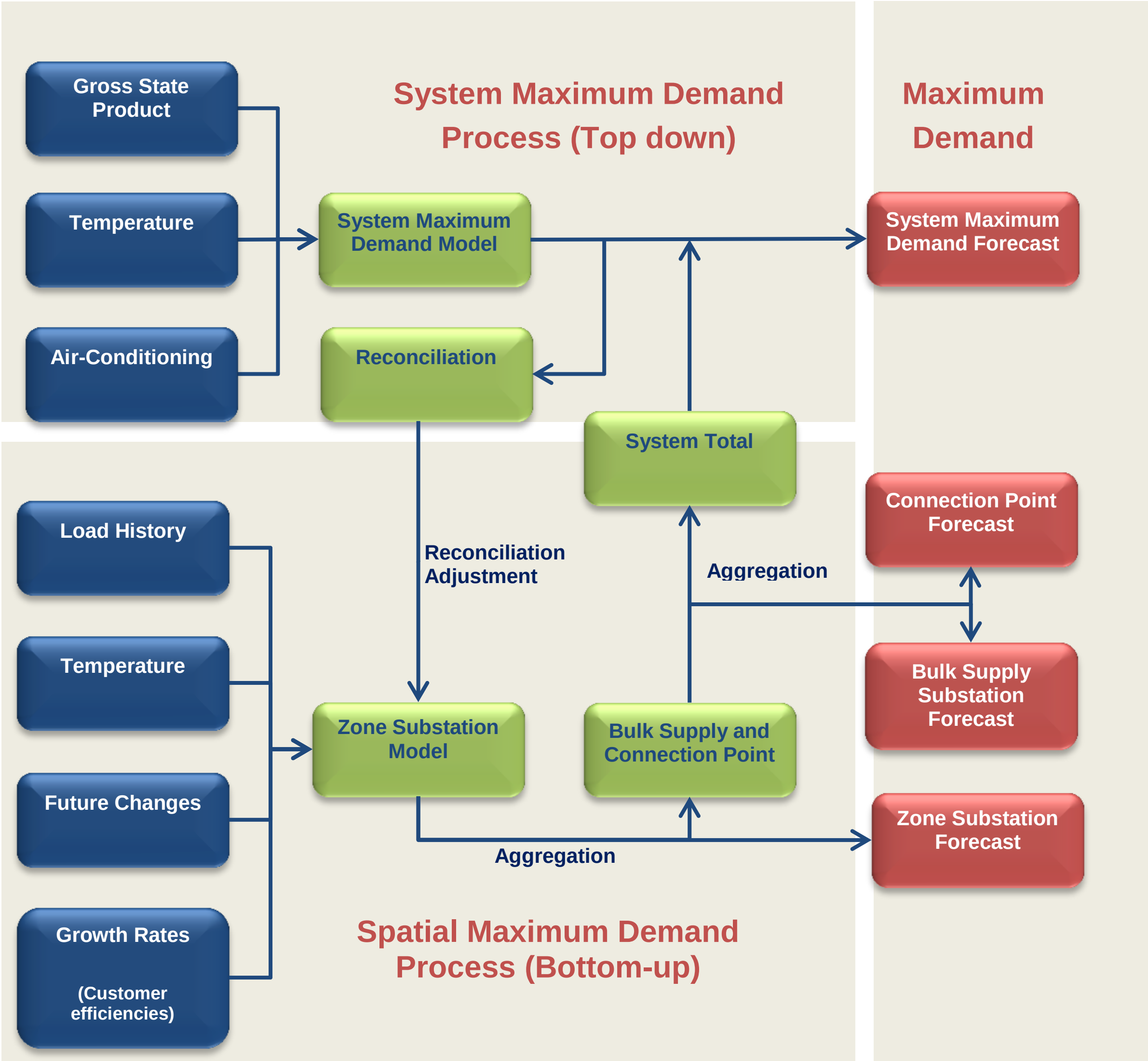
Important measures used in this methodology consist of the following:

- 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, extracted from the System Demand data set of system daily maximum demand loads. Temperature correction for 90%, 50% and 10% PoE system maximum demand is made using the past 30 years of daily temperature from selected weather stations throughout SEQ;
- Weather normalised data, derived using the past 50 years of temperatures; and
- System forecasts, 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 in Figure 20.

Figure 20 – 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.

Comparison of the final forecast with NIEIR and AEMO / Powerlink demand forecasts is undertaken to confirm that the forecast is reasonable.

Several alternative peak demand models were developed including a yearly peak demand model and a probabilistic model based on temperature at Amberley. These models are used for comparison with the independent demand forecast prepared by NIEIR each year. The latest system demand model incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

Demand MW = function of (Weekend, Christmas, Friday, weighted maximum, weighted minimum, total price, Qld GSP, structural break, three continuous hot days and a constant),

In particular, the total price component incorporated into the latest model aims to capture the response of customers to the increasing price of electricity. The impact of price is based on the medium scenarios for the Queensland residential price index forecast prepared by NIEIR system maximum demand forecasts.

In applying the above methodology, a system-level ten-year 50 PoE and 10 PoE maximum demand forecast is derived. Energex also contracted NIEIR to produce independent ten-year maximum demand forecasts using NIEIR models. The results of the forecasts are compared in Figure 21. Demand management load reductions are included in the forecast.

Figure 21 – Energex Peak Demand Forecast

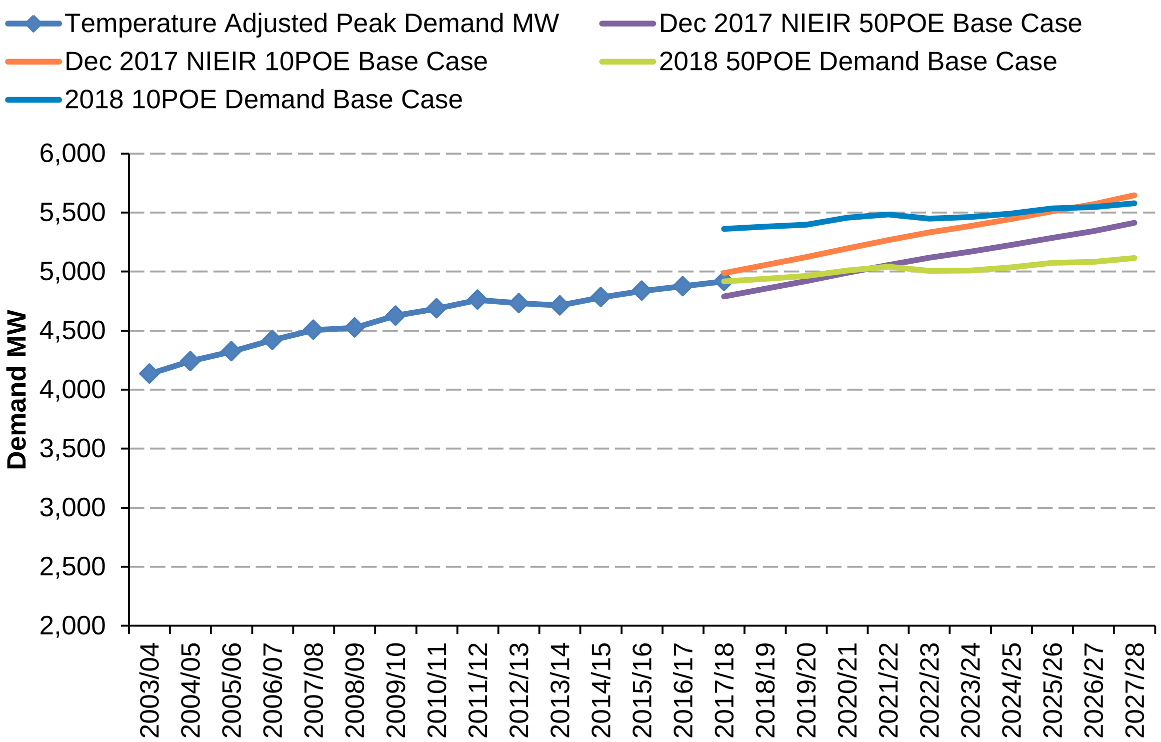
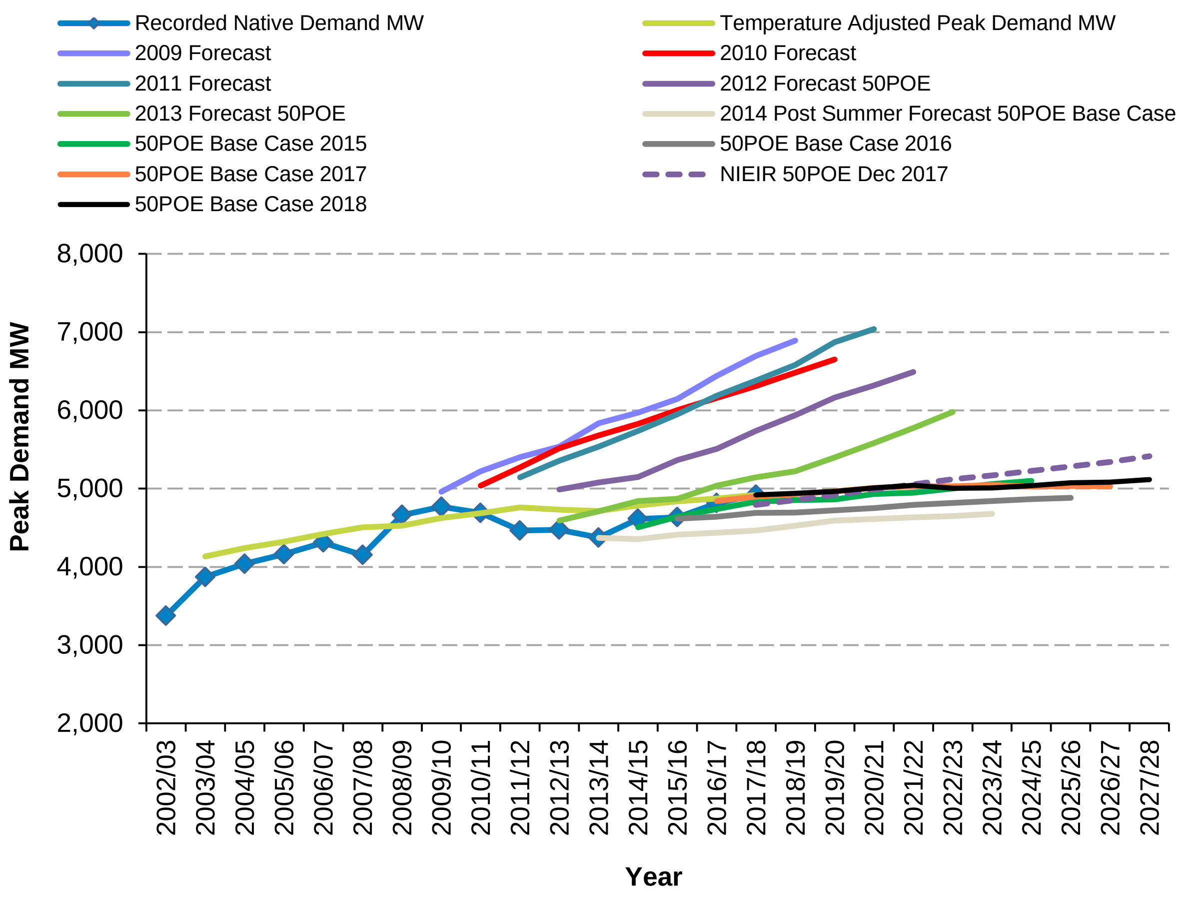


Figure 22 shows the variation that has occurred over the past five years in the summer system peak demand forecast. In each of the past five years, the forecast growth has been progressively reduced. Summer peak demand has continued to increase over the last four years as a result of improving economic conditions, continued growth in population, and significantly hotter summer conditions. Solar PV has also had a small but increasing influence on summer day peak system demand. Importantly, in comparison with prior years, decline in growth of peak demand has resulted in network limitations being deferred and this is reflected in the analysis contained in Appendixes C, D, E, F and G. It has also resulted in reduced capital expenditure.

Figure 22 – Previous Demand Forecast Comparison



The weekday 2017-18 system peak demand was 4,920 MW, whereas the previous summer peak demand was 4,814 MW. The temperature-corrected peak demand using the ACIL Allen methodology for 2017-18 was 4,900 MW, an increase compared with the 2016-17 temperature-corrected summer demand using three weather station temperatures. It is important to note that the potential for the system demand to meet or exceed the forecast demands is dependent on a range of key drivers including the summer temperatures and specifically, the behaviour of customers. For this reason, several hot summer days are always useful in allowing forecasting models to be recalibrated, and the magnitude of latent temperature-sensitive loads to be calculated. The summer of 2017-18 had extended hot periods in January and February.

However, analysis also indicates that the growth in underlying load is relatively slow. This situation is hard to reconcile intuitively given that commercial building developments and customer numbers have continued to grow, albeit at a slower rate than long-term historic trends. Industrial load is continuing to slowly decline with gradual loss in the industrial sector.

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 – South-East Qld

Demand	2013-14	2014-15	2015-16	2016-17	2017-18
Summer Actual (MW) [1]	4,375	4,614	4,633	4,814	4,920
Growth (%)	-1.7%	5.5%	0.4%	3.9%	2.2%
Summer 50% PoE (MW)	4,714	4,783	4,836	4,875	4,918
Growth (%)	-0.4%	1.5%	1.1%	0.8%	0.9%
	2013	**2014**	**2015**	**2016**	**2017**
Winter Actual (MW)	3,631	3,535	3,891	3,657	3,457
Growth (%)	-4.73%	-2.66%	10.06%	-6.01%	-5.43%
Winter 50% PoE (MW)	3,633	3,630	3,667	3,605	3,568
Growth (%)	-1.22%	-0.08%	1.02%	-1.70%	-1.03%

[1] The Summer Actual Demand has been adjusted to take account of embedded generation operating at the time of System Peak Demand.

Furthermore, Table 4 lists the maximum demand forecasts over the next five years based on the ACIL Allen model using three weather stations weighted data and the 2017-18 summer results. This table is based on weekday maximum demands.

Table 4 – Maximum Demand Forecast (MW) – South-East Qld

Forecast [1, 2]	2018-19	2019-20	2020-21	2021-22	2022-23
Summer (50% PoE)	4,939	4,963	5,010	5,041	5,006
Growth (%)	0.43%	0.49%	0.95%	0.62%	-0.70%
Summer (10% PoE)	5,381	5,397	5,458	5,484	5,448
Growth (%)	0.37%	0.29%	1.13%	0.48%	-0.67%
	2018	**2019**	**2020**	**2021**	**2022**
Winter (50% PoE)	3,639	3,651	3,670	3,694	3,686
Growth (%)	2.0%	0.3%	0.5%	0.7%	-0.2%
Winter (10% PoE)	3,778	3,792	3,818	3,847	3,847
Growth (%)	2.1%	0.4%	0.7%	0.8%	0.0%

[1] The five year demand forecast was developed using three 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 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 2015-16 and 2016-17 summer seasons, which had peak demands occurring at 7:30 pm (the 2017-18 peak occurred at 6:00 pm).

Table 5 – Solar PV Contribution to Summer System Peak Demand

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Solar PV Capacity impact on System Peak Demand (MW)	-208	-123	-134	-145	-157	-169	-182	-196	-210	-225

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 electric vehicle 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
Electric Vehicle Load impact on System Peak Demand (MW)	1	3	6	11	19	32	48	67	88	110

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

The take-up of electric vehicles has been slow in an environment of limited model selection and limited incentives. However, we expect that it will increase markedly over the next few years as more models become available and price points decrease.

Energex 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)	-2	-10	-19	-33	-48	-63	-79	-95	-111	-125

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

- Background
- Planning Methodology
- Key Drivers for Augmentation
- Network Planning Criteria
- Voltage Limits
- Fault Level
- Planning of Customer Connections
- Large Customer Connections, including Embedded Generators
- Joint Planning
- Joint Planning Results
- Distribution Network Planning – Assessing System Limitations

6 Network Planning Framework

6.1 Background

The Energex distribution network services approximately 1.5 million customers. These customers connect to the network at voltage levels ranging from 230 V to 132 kV. Energex has a structured, coordinated network development planning framework to ensure solutions to address network limitations are optimal to meet both current and future requirements. To ensure that the objectives of network development planning are achieved, it is essential that it is undertaken in a structured, transparent and rigorous manner and makes best use of all relevant information available. The annual planning review systematically assesses the capability of the network to meet current and forecast customer demand requirements.

There are several definitions essential to the understanding of Energex's planning philosophy. Reliability of supply is the probability of a system adequately performing under operating conditions. A reliable network that meets obligations is an important objective, and is dependent on two measures; adequacy and security.

Adequacy is the capacity of the network and its components to supply the electricity demand within acceptable quality of supply limits. It includes requirements that network elements operate within their ratings whilst maintaining voltage within statutory limits.

Security is the ability of the network to cope with faults on major plant and equipment without the uncontrolled loss of load. A secure network often factors in redundancy of major plant and equipment to tolerate the loss of single elements of the system. Since 2014, Energex has adopted a more modern planning standard which takes into account the value of customer reliability and an obligated customer safety net to alleviate the adverse outcomes of low probability, high consequence events. Energex plans network investment to meet the Customer Outcome Standard (COS) detailed in Appendix C. The security standard takes into account the following key factors:

- Feeders and substations are assigned a category according to criteria or the area (CBD, Urban, Rural); and the appropriate safety net is assigned to associated network elements;
- Plant and power line ratings depend upon their ability to discharge heat and are therefore appreciably affected by the weather, including ambient temperature and in the case of overhead lines, wind speed;
- 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;
- Value of customer reliability to optimise investment timing; and
- Specific security requirements of large customer connections that are stipulated under the relevant connection agreements.

The application of the Customer Outcome Standard ensures that under system normal conditions the normal cyclic capacity of any network component must be greater than the forecast load (10 PoE). The capacity of the network is also assessed based on the failure of a single network component (transformers or power lines) and 50 PoE forecast load. This enables the load at risk under system normal (LARn) and the load at risk for contingency conditions (LARc) to be assessed as key inputs to investment planning against customer safety net targets.

Where these assessments indicate that the network is not able to meet the required safety net, the resulting network limitation must be addressed to ensure customer service obligations are achieved.

The Energex distribution network is also required to maintain voltage levels within legislative requirements and ensure safe operation under fault conditions. These requirements are addressed during the annual planning review.

6.2 Planning Methodology

6.2.1 Strategic Planning

Energex'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 PVs, electric vehicles 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; and
- 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

In order to address the forecast network limitations and ensure ongoing safe and reliable operation of the network, network augmentation and replacement projects are identified in the network development plan. With a typical outlook of 10 years, this information informs regulatory processes through Joint Planning, the DAPR, the revenue submission and regulatory information notices. This information also informs financial forecasting, easement and future substation acquisition activities.

Based on the network requirement dates, and/or the target completion dates, each capital project is brought into the PoW and then investigated in detail for the preparation of comprehensive business cases, regulatory documents and project approval reports in accordance with the NER and Energex standard practices, procedures and policies. This process ensures the current and future adequacy of the Energex transmission, sub-transmission and distribution networks. The information informs regulatory processes through the Regulatory Investment Test for Distribution (RIT-D), joint planning and demand side engagement activities.

The planning process involves the following major steps in a typical routine planning cycle:

- Identify network risks/limitations in the system;
- Validate load forecasts;
- Evaluate the capability of the existing system;
- Formulate network options to address these risks/limitations and identify any feasible non-network solutions from prospective proponents;
- Compare options on the basis of technical and economic considerations;
- Select preferred development option;
- Undertake the regulatory public consultations for the projects as required, and carry out detailed evaluation upon receipt of any alternative solutions from the registered participants/ proponents; and
- Initiate action to implement the preferred scheme through formal project approvals.

Project planning and approvals are currently carried out in accordance with the RIT-D that came into effect from 1 January 2014. RIT-D was previously applicable for the projects having credible options with more than $5 million augmentation component. However, the AEMC recent rule change that came in to effect from 18 September 2017 extended the application of RIT-D for all the projects including the replacements projects having credible options greater than $5 million,.

6.3 Key Drivers for Augmentation

Demand Forecast

Accurate demand forecasting is essential to the planning and development of the electricity supply network. Energex has adopted a detailed and mathematically rigorous approach to forecasting of electricity delivered, demand, and customer numbers. These methods are described in detail in chapter 5. Energex also undertakes regular audits and reviews by external forecasting specialists on the forecasting models. Demand forecasts are not only undertaken at the system level, but are also calculated for all substations and feeders for the forward planning period. These forecasts are used to identify emerging network limitations, and identify network risks, that need to be addressed by either supply side or non-network based solutions. The forecasts are then used as an input to determine the timing and scope of capital expenditure, or the timing required for demand reduction strategies to be established, or risk management plans to be put in place.

Plant Thermal Ratings

Plant thermal ratings are guided within Energex by the Plant Rating Manual. The methodology within the manual is written with reference to the appropriate Australian Standards. The plant thermal rating methodology provided encompass all primary current carrying components of all primary plant including overhead conductors, underground cables, power transformers and substation HV equipment. The information in the manual was reviewed and updated in 2016. This update included temperature data sourced from the Bureau of Meteorology.

Power transformers, switchgear and conductors are all designed to operate within their thermal ratings. Ratings are based on an upper limit which cannot be breached under any circumstances and also by the concept of reasonable use of life.

Plant thermal ratings are affected by the load cycle and ambient conditions such as ambient temperature, wind velocity and solar radiation. In general, Energex's plant thermal ratings are determined based on the following:

- Power transformers are rated in accordance with IEC 60076. The vast majority of the Energex power transformer fleet has remote temperature monitoring of their critical internal components. This real time temperature monitoring by Operations staff performs a vital role in the risk management of the transformers when the more arduous ratings are in force. Energex applies up to three different thermal ratings for power transformers dependant on network conditions.
    - The Normal Cyclic rating is the maximum permissible peak loading for the applied load cycle that a transformer can supply, given weighted ambient temperatures, without reducing the design life of the transformer;
    - The Emergency Cyclic rating is the maximum permissible peak loading for the applied load cycle that a transformer can supply without transgressing any of the physical temperature limitations of the materials of which the transformer is constructed. This rating is only applicable in substations where more than one power transformer shares the load, which is usually the case in Energex substations. This rating allows time for the repair/replacement of faulty plant; and
    - The Short time Emergency Cyclic rating is the maximum permissible loading for the given load cycle that a transformer can supply for up to two hours, immediately following the loss of one of the transformers in a multiple transformer zone substation. By the end of the two hour period, the load has to be reduced to at least the emergency cyclic rating. This rating allows for load transfers.
- HV switchgear is rated in accordance with AS 62271. HV switchgear also has a number of ratings which are based on the applied load cycle, ambient temperatures and the thermal mass of the individual switchgear;
- Overhead conductors are rated in accordance with ESAA publication D(b)5-1987. Reference is also made to AS 7000-2010. Energex's environmental assumptions are listed in Table 8 and Table 9. Energex's current overhead line design is based on a conductor operating temperature of 75 degrees Celsius. The ratings used are intended to maintain statutory clearance and maintain the working life of the conductors whilst obtaining the maximum capacity; and
- Underground cables are rated in accordance with IEC 60853 and IEC 60287. Energex's environmental assumptions for underground cable rating are shown in Table 10.

Table 8 – Standard Ambient Air Temperatures for Plant Ratings

Time Period	Standard Ambient Air Temperatures
Summer Noon	35°C
Summer Evening	25°C
Winter Noon	20°C
Winter Evening	15°C

Table 9 – Standard Atmospheric Conditions for Conductor Ratings

Parameter	Value
Wind velocity – Normal	1.0 m/sec
Wind velocity – 2HR Emergency (≥ 33 kV only)	2.0 m/sec
Wind yaw angle	90° to line
Wind turbulence	0.1%
Conductor emissivity	0.85
Conductor absorptivity	0.85
Albedo (reflectance from ground etc.)	0.2
Direct solar radiation intensity (day)	1,000 W/m^2
Diffuse solar radiation intensity (day)	100 W/m^2
Solar altitude (day)	86 Degrees
Atmospheric clearness number (day)	1.0

Table 10 – Standard Environmental Conditions for Cable Ratings

	Summer	Winter
Ground Temperature: at cable depth	29°C	20°C
Air Temperature:	40°C	25°C
Soil Thermal Resistivity:	1.2°C.m/W	

Note: The parameters above are not applied universally. Specific site conditions may also apply.

Load Transfer Capability

Energex's Customer Outcome Standard integrates the full use of load transfers between sub-transmission systems and zone substations. These use the sub-transmission or distribution feeder networks to reduce the impact of an outage in the event of a major plant failure. Load transfer capabilities for each substation are calculated annually using load flow studies, taking into account the thermal ratings and voltage stability of the network. The load transfer capability at a substation level is calculated based on 75% of the sum of all available transfers on each of the supplied distribution feeder. The 75% factor is applied to account for diversity and to provide a margin of error for unforeseen circumstances such as protection coverage. The transfer amount applies throughout the forward planning period. In addition, more detailed load transfer studies are incorporated during individual project planning phases.

Asset Age and Condition

Energex has an extensive Asset Lifecycle Management program which is discussed in detail in section 9. An important output of this program is the identification of equipment which is nearing end of life due to condition and/or age.

In the case of major plant items, such as power transformers, high voltage circuit breakers etc. the end of life information is considered within the planning process as a "network limitation," just like any other (capacity) network limitation. Hence, the options to either refurbish, replace, or retire the plant item is considered in the context of network safety, security, and reliability standards.

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.); and
- probabilistic (risk-based) approaches.

Energex is required under Distribution Authority No. D07/98 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, and;
- **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, 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; and
- 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.

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. Energex is required to meet the restoration targets defined in Schedule 3 of Energex's Distribution Authority (shown in Table 11) *"…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 11 – Service Safety Net Targets

Feeder Type	Targets
CBD	Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute.
Urban – Following an N-1 event	No greater than 40 MV.A is without supply for more than 30 minutes; No greater than 12 MV.A is without supply for more than 3 hours; No greater than 4 MV.A is without supply for more than 8 hours.
Short Rural – Following N-1 event	No greater than 40 MV.A is without supply for more than 30 minutes; No greater than 15 MV.A is without supply for more than 4 hours; No greater than 10 MV.A is without supply for more than 12 hours.

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 Planning 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. Energex 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.

Energex 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.

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 11 kV and 22 kV network.

CBD and Critical Loads

In the Energex CBD scenario, and 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 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

Under the RIT-D that came into effect from 1 January 2014, it is a requirement to take into account market benefits (including network losses) in an investment decision. Energex, as a RIT-D proponent, includes all classes of market benefits (including network losses) in its analysis that it considers to be material when applying a RIT-D. However, as per NER, the quantification of market benefits is optional for reliability driven projects.

For projects that are not subject to RIT-D process (where credible options with more than $5 million are not available), there is no regulatory requirement for the network losses (and other market benefits) to be considered in the appraisal of investment options. However, Energex estimates the saving in network losses in detailed planning and project approval phases of the projects. The estimated loss saving is not used quantitatively in the investment comparison when comparing options, but considered qualitatively in the comparison of advantages and disadvantages of alternative options.

Energex also takes into account network losses when specifying plant to meet the Minimum Energy Performance Standards (MEPS).

6.5 Voltage Limits

6.5.1 Voltage Levels

The Energex's HV distribution network consists of 4 different voltage levels. Table 12 contains the system nominal and the system maximum voltage that equipment is typically manufactured to operationally withstand, and as such the maximum voltage levels that can be imposed without damaging plant.

Table 12 – System Operating Voltages

System Nominal Voltage	System Maximum Voltage
132 kV	145 kV
110 kV	123 kV
33 kV	36 kV
11 kV	12 kV

6.5.1.1 Maximum Customer Voltage

The National Electricity Rules gives utilities the authority to specify the customer supply voltage range within the connection agreement for HV customers above 22 kV. The National Electricity Rules requires RMS phase voltages to remain between ±5% of the agreed target voltage (determined in consultation with AEMO), except for at times following a contingency event, where the supply voltage shall remain between ±10% of the system nominal RMS phase to phase voltage. In Queensland, for customers less than 22 kV, the Queensland Electricity Regulations (QER) specifies supply voltage ranges for LV and HV customers. In October 2017 the QER was amended to change the LV from 240 volts +/-6% to 230 volts +10%/-6% to harmonise with Australian Standards AS60038 and

AS61000.3.100. Table 13 details the standard voltages and the maximum allowable variances for each voltage range from the relevant QER and National Electricity Rules.

Table 13 – Maximum Allowable Voltage

Nominal Voltage	Maximum Allowable Variance
<1000 V (230 V Phase to Neutral 400 V Phase to Phase)	Nominal voltage +10%/- 6%
1000 V – 22,000 V	Nominal voltage +/- 5% or as agreed
>22,000 V	Nominal voltage +/- 10% or as agreed

The values in Table 13 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.

6.5.1.2 Transmission and Sub-transmission Voltage Limits

Target voltages on bulk supply substation busbars will be set in conjunction with Powerlink Queensland. In general, the sub-transmission busbars at Powerlink Connection Points are operated without Line Drop Compensation (LDC) and with a fixed voltage reference or automatic Volt Var Regulation (VVR) set point.

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.

Augmentation of the transmission and sub-transmission network generally occur when voltage limitations occur on the sub-transmission network under system normal conditions with 10 PoE forecast loads, or under N-1 conditions with 50 PoE forecast loads consistent with the Customer Outcome Standard.

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

6.5.1.3 Distribution Voltage Limits

Target voltages on zone substation busbars are set by Energex as relevant. These zone substation busbars are operated with either Line Drop Compensation (LDC), or with a fixed voltage reference or automatic Volt Var Regulation (VVR) set points. Downstream voltage regulators may also be set with LDC or with a standard set point.

For 11 kV distribution systems, the network is operated to supply voltage at a customer's point of connection, as described in Table 13, and considerations are also made to the variable impacts of the different Low Voltage 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 with 10 PoE forecast loads, or under N-1 conditions with 50 PoE forecast loads.

Table 14 provides an indicative level of the maximum HV voltage drops in the distribution network, to ensure acceptable supply voltage to LV customers. The drop defined is from the zone substation bus to the feeder extremity, for steady state conditions or 10 minute aggregate values.

Table 14 – Steady State Maximum Voltage Drop

Energex targets	Maximum voltage drop – no LDC	Maximum voltage drop – LDC
Urban	4%	7%
Short & Long Rural	-	10%

6.5.1.4 Low Voltage Limits

Typically LV network voltage is managed by a combination of real time voltage control at the zone substation 11 kV busbar to control the voltage regulation along the 11 kV feeders in conjunction with distribution transformer 'off-load' tap ratio settings. This approach makes it difficult to optimally manage voltage within LV limits at all times and all customer premises and is exacerbated by the intermittency of solar PV.

Augmentation of the low voltage network is generally required where rebalancing of customer loads and solar connections or resetting the distribution transformer taps is not sufficient to ensure voltages are within limits. In this case the augmentation solution is required to reduce the voltage drop through the transformer and LV circuits and will typically involve uprating or installing a new transformer and reconfiguring the LV network. Low Voltage Regulators (LVR) and Statcoms are also being trialled on LV circuits and may provide an additional reinforcement option.

6.5.2 Sub-transmission Network Voltage

Sub-transmission network configuration can impact the voltages on the downstream network. Energex maintains the voltages at the customers' connection points according to connection agreements where the customers are supplied directly at the 132 kV, 110 kV or 33 kV levels. For all other situations, the sub-transmission network aims to maintain voltage levels at the substation low voltage (11kV) buses within a target range. Energex utilises automatic schemes to control the voltages, accounting for the difference in voltage that can occur on the low voltage side of substations between periods of maximum demand and light load, and during single contingency outage conditions or high solar PV penetration. A voltage limitation occurs if a target bus voltage cannot be maintained. The target range depends on various factors such as the type and magnitude of load, customer category, and connection agreement. This is typically 11.3 kV in urban areas and 11.4 kV in rural areas during peak load times.

Augmentation generally occurs when voltage limitations occur on the sub-transmission network under system normal conditions with 10 PoE forecast loads, or under N-1 conditions with 50 PoE forecast loads.

These limitations are identified as part of the simulations carried out and described in section 7.1.3 and are also reported in the limitations tables contained in Appendix D.

6.5.3 11 kV Distribution Network

Assessment of the 11 kV feeder voltage level is performed using a load flow package with anticipated 10 PoE loads under system normal configuration.

In the main, the model assumes the following voltage levels at the substation at peak times:

- CBD Substations 99%;
- Urban Substations short 101.3%;
- Urban Substations Long 101.8%; and
- Rural Substations 102.7%.

The assessment identifies voltage drops anywhere on the 11 kV feeders, and prudent practices are applied to address areas that are outside the allowable limits.

At present, there are 11 kV feeders with voltage constraints identified in the Energex distribution network model during system normal conditions. Operational measures have been identified to address these feeders where a project has not been justified.

6.5.4 Low Voltage Network

There are over 45,000 Low voltage (LV) circuits in the Energex network. Design guidelines are available to determine transformer tap settings and the After Diversity Maximum Demands (ADMD) for customers.

Energex is required to manage the voltage on these LV circuits within a tolerance range of 230 volts + 10% -6% (216 volts to 253 volts). There are many factors which impact the voltage present at the customer connection point, including voltage regulation settings at the zone substation, 11 kV and LV network planning and design practices as well as customer owned installations such as embedded generators. In particular, the influx of solar PV systems connected to the LV network has added a new level of complexity to voltage management.

Energex has traditionally relied upon maximum demand indicators to identify limitations on distribution transformers. This approach is no longer adequate and Energex is now rolling out distribution transformer monitoring. These monitors, along with customer feedback, are now being used to identify areas of voltage non-compliance. Remedial works are being targeted initially to minimise the risk of damage to customer equipment from voltage excursions with high volts having the highest priority.

Energex has explored a number of remediation works which include:

- Changes to the Line Drop Compensation (LDC) or Volt Var Regulation (VVR) settings at the zone substation;
- Resetting distribution transformer taps;
- Balancing of the low voltage network with an emphasis on the solar PV load;
- Upgrading of the transformer or installation of a new transformer (to reduce the lengths of LV circuits);
- Increasing the LV conductor size; and
- Installation of targeted transformer monitoring devices in response to network LV changes and PV installations.

6.6 Fault Level

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

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

Fault level increases due to external factors are monitored by annual fault level reporting, which estimate the prospective short circuit fault levels at each substation. The results are then compared to the maximum allowable short circuit fault level rating of the switchgear, plant and lines to identify if plant is operated within fault level ratings. Energex obtains upstream fault level information from TNSPs annually and changes throughout the year are communicated through joint planning activities as described in section 6.9.5.

New connections of distributed generation and embedded generations which increases fault levels are assessed for each new connection to ensure limits are not infringed. Known embedded generators are added to Energex's simulation models so that the impacts of these generators on the system fault levels are determined.

Table 15 lists design fault level limits that apply at Energex installations.

Table 15 – Energex Fault Level Limits

Voltage level (kV)	Short circuit level (MVA)	Short circuit level (kA)
132 kV	5,715 / 7,200 MVA	25 / 31.5 kA
110 kV	4,763 / 6,000 MVA	25 / 31.5 kA
33 kV	749 / 1,428 MVA	13.1 / 25 kA
11 kV	250 MVA	13.1 kA

While Table 15 presents design fault ratings, new equipment typically has ratings higher than these figures, however, some old equipment may have lower ratings. Hence, site specific fault levels are considered in planning activities for network augmentations or non-network solutions to ensure the fault level does not exceed the ratings of the installed equipment. It should be noted that these fault levels are quoted with a 1 second duration, and a faster protection clearing time will be considered where appropriate. This can be further investigated when fault levels approach limits.

6.7 Planning of Customer Connections

Customer Initiated Capital Works (CICW) are defined as works to service new or upgraded customer connections that are requested by Energex 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.

Energex 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 on 1 July 2015.

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

CICW undertaken are generally of the following types:

- planning, designing and constructing shared network assets that are directly relevant to customer connections;
- planning, 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 embedded generator;
- relocation of shared network assets; and
- designing and constructing public lighting.

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

- Energex;
- someone acting on behalf of Energex (i.e. an accredited contractor); and
- real estate developers and Large Customer Connection (LCC) customers; via accredited service providers, where the assets are subsequently gifted to Energex.

Depending on the nature of the work being undertaken, CICW can be funded by:

- Energex, where it, or someone acting on its behalf, undertakes the works;
- a customer paying a capital contribution, an ACS fee, or both to Energex, where Energex or someone acting on its behalf, undertakes the works; and
- a real estate developer or LCC customer; via an accredited service provider, where after the assets are built, they are 'gifted' to Energex.

For contestable works, the LCC customer may construct and continue to own and operate the works at their cost. There may still be some costs for the works Energex 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.

6.8 Large Customer Connections, including Embedded Generators

Energex is committed to ensuring that, where technically viable, LCC customers are able to connect to the network. We have a clear LCC process available on our website that aligns with the connection processes in Chapters 5 and 5A of the NER. We have a dedicated Major Customer Team to support you. Information on the processes can be found at the following link.

https://www.energex.com.au/home/our-services/connections/major-business.

The process generally applies to proposed connections where the intended Authorised Demand (AD) or load, on our network exceeds 1,000 kVA (1 MVA) or where power usage is typically above 4 GWh per annum at a single site.

Energex also has clear processes for the connection of Embedded Generating (EG) systems units, which applies to EGs 30 kVA and above. The processes may vary depending on the size of the generating unit and whether the system is exporting into our network. These processes are also listed on our website at the link below.

https://www.energex.com.au/home/our-services/connections/major-business/large-generation-and-batteries

The connection of any LCC 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 Energex 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 LCC process is available on the Energex website at: https://www.energex.com.au/home/our-services/connections/major-business.

6.9 Joint Planning

6.9.1 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 Transmission Network Service Provider (TNSP) and Distribution Network Service Provider (DNSP) augmentations.

Energex conducts joint planning with distribution network service providers and transmission network service providers as required. Joint planning involves Essential Energy, Powerlink, TransGrid and Terranora Link in the vicinity of the NSW & Queensland border. Similarly, joint planning involves Powerlink in SEQ and Ergon near Toowoomba and north of Gympie.

The early identification, consultation and monitoring of emerging network limitations and prospective network developments is specifically aimed at providing proponents of alternative solutions adequate time to prepare proposals.

Once an emerging network limitation is identified, plausible options are assessed to address the emerging limit. However, some options are subsequently eliminated during the process following more detailed economic, environmental and technical analysis. The reasons why options have been eliminated are captured to satisfy market participants that the process has been undertaken without bias.

In assessing options, any subsequent or future limitations are identified. This determines the impact of implementing various options, as well as the interaction between options and the sequencing of subsequent future stages. This means that future limits, and the cost to address them, are also taken into account in the planning analysis.

Where the estimated cost of the options is similar, more information may be sought on scope and cost to inform the analysis. In addition, other relevant considerations are taken into account including the strategic and long-term development of the power system and the impact and timing on other developments and projects.

It is also prudent to take into account any plant and equipment that may be identified for retirement, replacement or refurbishment due to condition or age. This allows augmentation, retirement, replacement and refurbishment needs to be optimised for efficient expenditure outcomes.

6.9.2 Role of Energex 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 National Electricity Rules.

Through this process Energex 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; and
- Ensuring that its network complies with technical and reliability standards contained in the NER and jurisdictional instruments.

6.9.3 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;
- Plant fault ratings during network faults;
- Network voltage to remain within acceptable operating thresholds;
- Replacement of ageing or unreliable assets; and
- Network stability to ensure consistency with relevant standards.

Where forecasted power flows could exceed network capacity, Energex 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 National Electricity Rules, to identify the most cost effective solution regardless of asset boundaries, including potential non-network solutions.

6.9.4 Network Connection Proposals

The availability of easements and future substation sites are considered in the context of network developments under consideration. This is initially undertaken from a strategic planning perspective, consistent with good industry practice. This permits Energex to coordinate works in identified areas where forecasted plans by other relevant stakeholders are available. Stakeholders include the Queensland Government, Local Government and community consultations / engagement.

New connections can result from joint planning with the relevant DNSP or TNSP, or be initiated by customers. Planning of new or augmented connections involves consultation between Energex and the connecting party, determination of technical requirements and completion of connection agreements that include operating protocols.

6.9.5 Joint Planning Activities and Interactions

Effective joint planning is reliant on regular communication between network planning engineers employed by the relevant DNSPs, TNSPs, proponents, network service providers and interested parties, as summarised in Table 16.

Table 16 – Joint Planning Activities and Interactions

Joint Planning Activity	Frequency				
	Day-to-Day	Weekly	Monthly	Yearly	Regulated Planning Cycle
Sharing and validating information covering specific issues	✓		✓		
Sharing updates to network data and models	✓	✓	✓		
Identifying emerging limitations		✓			
Developing potential credible solutions		✓			
Estimating respective network cost estimates		✓			
Developing business cases		✓			
Preparing relevant regulatory documents		✓			
Sharing information for joint planning analysis			✓		
Sharing information for respective budgets				✓	
Sharing updates to demand forecasts				✓	
Joint planning workshops				✓	
Sharing information for regulatory information notices				✓	✓
Sharing planning and fault level reports				✓	
Sharing annual planning reports				✓	
Sharing information for AER revenue models					✓
Sharing information for the purposes of respective revenue submissions					✓

6.9.6 Joint Planning and Joint Implementation Register

A register has been set up to capture all information relating to limitation identification, planning, consultation and subsequent project implementation between Energex and external parties. This ensures joint activities are tracked throughout the lifetime of a project, from the time a limitation is identified to final commissioning of the chosen solution. The register is shared with the respective TNSP or DNSP and is updated regularly.

6.10 Joint Planning Results

Towards approval and implementation, there is often the potential for circumstances to change. Some of these changes may relate to:

- The emergence of new loads or limits which may impact upon the feasibility of existing options;
- A change in the load forecast as a result of economic, financial and other conditions;
- The identification of new or additional access or site constraints; and
- A more detailed consideration of the strategic direction of the joint planning entities and relevant State Government and/or Local Government requirements.

A material change in circumstances will necessarily require that options be reassessed to ensure they remain feasible and appropriate. For example, one option may be ruled out on the basis that the easement acquisition is no longer considered plausible.

As the planning analysis nears completion, the most appropriate option from a technical and high-level economic perspective emerges. A detailed estimate of this option is prepared, as well as more detailed estimates of the other potential credible options, to verify that it remains the most prudent option in light of economic and technical considerations.

Having undertaken the iterative process described above of developing and considering options in light of sequencing, network impacts, coordination of works, costs and new information, a shortlist of options emerges. Further analysis is also undertaken to finalise the sequencing of options and subsequent future stages.

The NERs require that consultation with customers and interested stakeholders be undertaken to demonstrate that, for reliability augmentations, the recommended option minimises the present value of costs in a majority of credible scenarios in line with the AER's Regulatory Investment Test. The outcomes of the joint planning process form the basis for public consultation under the AER's RIT-D and RIT-T. Submissions to the consultation process are assessed and incorporated into the planning process outcomes. Where material issues arise during the consultation process, further joint planning discussions and analysis may be undertaken to ensure that the final report has appropriately actioned the outcomes of the consultation process. All regulatory investment test documents are public, agreed and branded by all parties to the joint planning process.

6.10.1 Joint Planning with TNSP

In the past 12 months Energex has actively engaged with Powerlink on the following joint planning studies. These projects have network drivers that have a notional target date in the forward planning period (2018/19 to 2022/23), as summarised in Table 17.

Additional joint planning activities have occurred in the past 12 months for network drivers on the Energex, Ergon Energy and Powerlink networks that notionally occur beyond the forward planning period.

Table 17 – Joint Planning Activities Covering 2018/19 to 2022/23

Energex Works Estimated Cost ($ M)	Project Description	Indicative Timing	2017 DAPR Reported Timing	Comparison 2017 DAPR	Comments
1 – 2	Tennyson Upgrade secondary systems (Powerlink Project)	Mar 2018	Dec 2017[1]	Deferred	
0.3 – 1	Ashgrove West 110 kV Replace primary plant and secondary systems (Powerlink Project)	Oct 2020	Oct 2019[1]	—	Approved project
0.4 – 1	Sumner Upgrade 110/11/11 kV transformer protection (Energex Project)	Jun 2021	—	New Project	Subject to RIT-T
1 – 2	Molendinar Upgrade 110/11/11 kV transformer protection (Energex Project)	Jun 2019	—	New Project	Part of a program to upgrade backup protection reach.
1 – 2	Bundamba Upgrade 110/11/11 kV transformer protection (Energex Project)	April 2019	—	New Project	Part of a program to upgrade backup protection reach
1 – 2	Abermain Replace secondary systems (Powerlink Project)	Jun 2021	—	New Project	Subject to RIT-T
1 – 2	Redbank Plains 110 kV Replace primary plant (Powerlink Project)	Dec 2021	—	New Project	Subject to RIT-T
1 – 2	Retirement of Mudgeeraba 275/110 kV transformer (Powerlink Project)	Dec 2019	—	New Project	Subject to RIT-T
1 – 2	Line Refit Works on 110 kV Transmission Lines between: I. South Pine to Upper Kedron II. Sumner to West	Dec 2021	—	New Project	Subject to RIT-T

Energex Works Estimated Cost ($ M)	Project Description	Indicative Timing	2017 DAPR Reported Timing	Comparison 2017 DAPR	Comments
	Darra III. Rocklea to Sumner (Powerlink Project)				
1 – 2	Line Refit Works on 275 kV Transmission Lines between South Pine to Karana Tee (Powerlink Project)	Dec 2022	—	New Project	Subject to RIT-T
[1] Deferred by Powerlink					

6.10.2 Joint Planning with other DNSP

There were no specific joint planning network investigations necessary between Energex and other DNSPs during 2017/18. Energex continues to work closely with Ergon through joint business practices. Energex continues to monitor emerging network limitations beyond the forward planning period on the southern Gold Coast and broader region, associated with Essential Energy, TransGrid, Powerlink and Terranora Link.

6.10.3 Further Information on Joint Planning

Further information on Energex's joint planning and joint network investment can be obtained by submitting email to the following address:

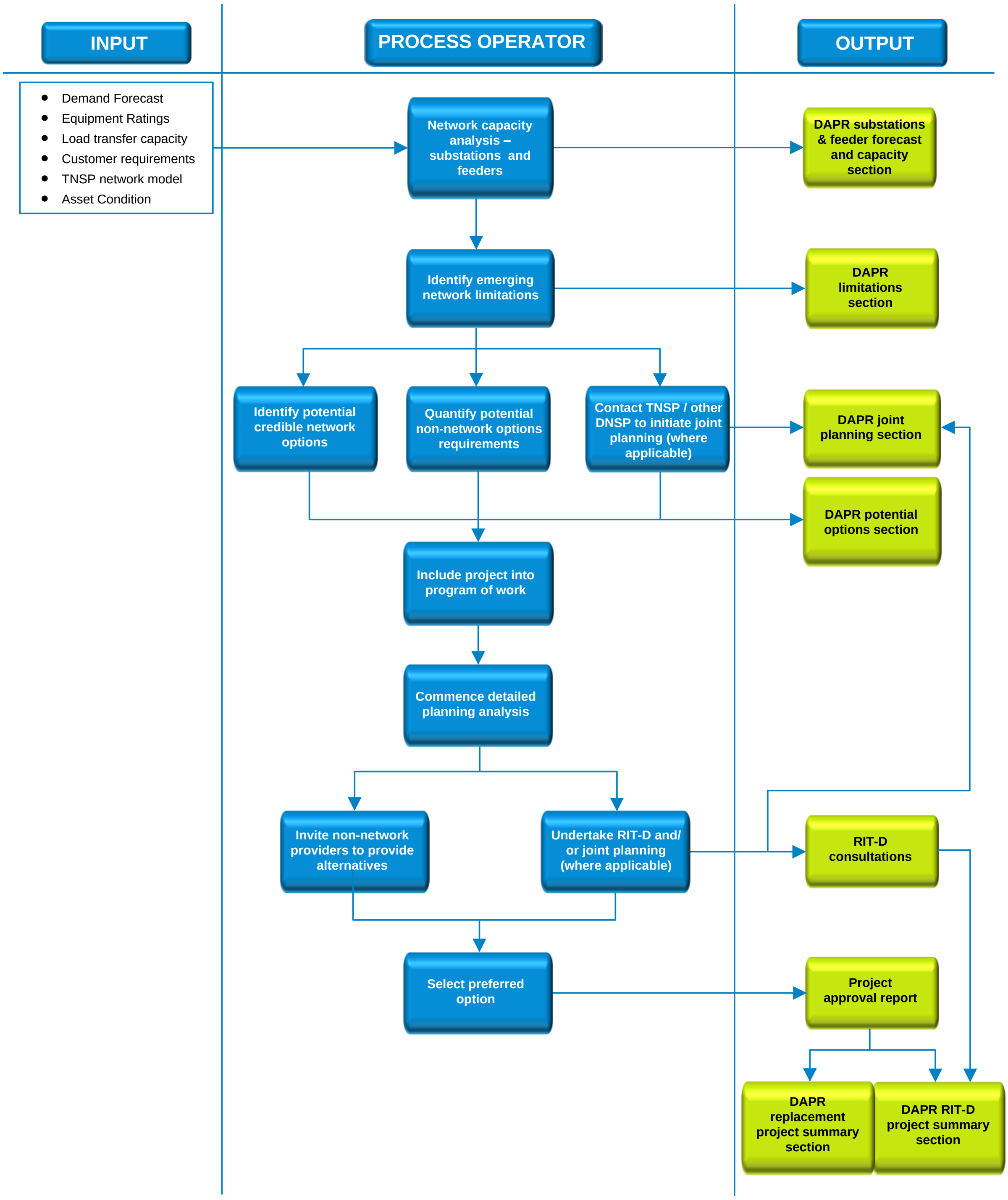
DAPR_Enquiries@energex.com.au

6.11 Distribution Network Planning – Assessing System Limitations

6.11.1 Overview of Methodology to Assess Limitations

The methodology shown in Figure 23 is used in the preparation of the Distribution Annual Planning Report to identify and address network limitations, joint planning projects and RIT-D projects.

Figure 23 – Distribution Annual Planning Report Process



Following the assessment of emerging network limitations, network and non-network options are considered for addressing the prevailing network limitations. These recommendations then become candidate projects for inclusion in the Energex Program of Work (PoW), and are allocated with a risk score based on the Energex network risk based assessment framework for prioritisation purposes.

The PoW also undergoes ongoing assessment to determine if targeted area demand management activities can defer or remove the need for particular projects or groups of projects. Remaining projects form the organisation’s PoW for the next five years. Detailed planning is also done for each PoW project to complete a RIT-D consultation if required, and obtain project approvals for acquisitions, construction and implementation.

6.11.2 Bulk and Zone Substation Analysis Methodology Assumptions

Energex uses a software tool to assess emerging capacity limitations for all bulk supply and zone substations, taking into account information such as non-network, manual, remote and automated load transfers, circuit breaker/secondary system ratings, generator support and reference to the current security standards. All reviews are performed annually with comprehensive results included in Appendix E of the DAPR. All assessments are evaluated based on the current network security standards which are detailed in Appendix C. All calculations are based on the latest load forecasts which align with the forecast information provided in section 5.3.1.

6.11.3 Transmission Feeder Analysis Methodology Assumptions

Based on the forecasting methodology described in section 5.3.2 using the simulation tool, load flow studies are performed to identify system limitations on the transmission network under system normal or contingency conditions.

Contingency analysis is performed to identify all overloaded feeders for all credible contingency events. Contingency transfers are not included in this automated model, but are considered in subsequent analysis. The load flow results are then exported to Energex’s analysis tools and reporting systems.

The Energex 110 kV Feeder Analysis Tool is used to review and analyse load flow results. The tool uses additional data which is not contained in the models itself. This includes information such as non-network alternatives, load transfer capacities (Manual, Remote and Automatic), circuit breaker/secondary system ratings, generator support and reference to the current security standards. The tool is also used in conjunction with other supporting tools to assist with the upload process and provides another level of error checking capability.

The outcome of the analysis would trigger further investigations and identification of potential solutions to address the limitations.

6.11.4 Sub-transmission Feeder Analysis Methodology Assumptions

Based on the forecasting methodology described in section 5.3.3, using the simulation tool, load flow studies are performed to identify limitations on the sub-transmission feeder network under system normal or contingency conditions.

Contingency analysis is performed to identify all overloaded feeders for all credible contingency events. Contingency transfers are not included in this automated model, but are considered in subsequent analysis. The load flow results are then exported to Energex's analysis tools and reporting systems.

The Energex 33 kV Feeder Analysis Tool is used to review and analyse the load flow results. The tool uses additional data which is not contained in the models. This includes information such as non-network alternatives, load transfer capacities (Manual, Remote and Automatic), circuit breaker/secondary system ratings, generator support and reference to the current security standards.

The outcome of the analysis would trigger further investigations and identification of potential solutions to address the limitations.

6.11.5 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. Energex temperature corrects these load maximum demands to 50 POE and 10 POE load assessments;
- The future forecast demands for each feeder are then calculated based on the historical and current customer growth rate, block loads (major developments) 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; and
- The year and season (i.e. summer or winter) is recorded where the maximum utilisation exceeds the Target Maximum Utilisation (TMU) for that feeder. The TMU of each feeder takes into account the ability of generally transferring loads from four feeders into three feeders with some use of mobile generation to restore all loads in the event of a fault on the 11 kV network. This is to allow for operational flexibility and load transfers to restore load during a contingency event. The TMU is generally 80% of the feeder rating for radial feeders, and is individually determined for meshed feeders, dedicated single customer feeders and feeders with limited tie capacity.

Note: the above mentioned methodology is only a planning level criteria, which triggers further detailed analysis based on a number of factors. Not all breaches of these criteria will trigger augmentation.

6.11.6 Fault Level Analysis Methodology Assumptions

Energex performs fault level analysis for switchgear at all 132 kV, 110 kV, 33 kV and 11 kV buses as well as 33 kV and 11 kV feeders. Both 3-phase and 1-phase to ground faults are simulated in the studies and the worst case is identified in accordance with IEC 60909 Short-circuit currents in three-phase a.c. systems.

The source impedances used in the model are provided by Powerlink. The Energex network model used is based on a system normal configuration. This means all normally open feeders and transformers remain on standby.

Fault level contributions from generators that are connected directly to the Energex network are modelled. Known generators that run during peak times or run continuously are included in the model. Standby / backup generators are generally excluded from the calculations.

All short circuit simulation results are stored in a database which is then validated and analysed. For meshed networks, additional analysis is carried out to identify the fault current contribution of individual circuits hence identifying the current which a breaker is subjected to under a fault condition. Equipment having a rated short circuit withstand below the observed fault level are then identified.

For 33 kV and 11 kV feeders, the analysis first identifies those feeders with fault current exceeding any conductor's one second current carrying capacity. Additional analysis is then carried out on these feeders using protection setting data to determine the actual fault clearing time. Conductors having a fault current carrying capacity below the observed fault level are then identified.

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; and
- All loads and capacitors are switched out of service.

For the 11 kV feeder fault analysis, the additional assumptions are as follows:

- The load flow analysis assumes only one source at the substation. Standby generation and solar PV fault level contributions are ignored (due to the characteristics of solar PV inverters);
- Individual fault levels are calculated for feeders with significant co-generation; and
- Fault levels are only calculated at nodes within the model with results showing individual line segments contribution to the fault.

With the proliferation of embedded generation and solar PV installations on the 11 kV and LV networks, investigations are continuing to identify software packages that will be able to model the fault level contributions to the network from these devices.

Chapter 7

Overview of Network Limitations and Recommended Solutions

- Network Limitations – Adequacy and Security
- Asset Retirement (Project Based)
- Summary of Emerging Network Limitations
- Emerging Network Limitations Maps
- Regulatory Investment Test for Distribution (RIT-D)
- Emerging Network Limitations Maps

7 Overview of Network Limitations and Recommended Solutions

7.1 Network Limitations – Adequacy and Security

7.1.1 Connection Point and Substation Limitations

There are no limitations identified on the transmission-distribution connection points with the TNSPs covering the forward planning period. Energex conducts joint planning with TNSPs as described in section 6.9.1. Limitations affecting either network will be investigated jointly and follow the RIT-T or RIT-D process to ensure prudent solutions are adopted.

For each substation, a separate summary forecast of capacity and limitations has been produced for summer and winter based on Customer Outcome Standard. Bulk supply and zone substation reports are contained in Appendix E, respectively.

Table 18 shows the projection of bulk supply and zone substation statistics out to 2022/23. It also provides the forecast number of bulk and zone substations with load at risk (LAR) under system normal conditions (LARn) and contingency conditions (LARc).

Under system normal conditions, there is no bulk and one zone substation forecasts which have LAR based on the expected completion of committed projects. This is not expected to change over the forward planning period. Under contingency conditions, there is no bulk supply substation forecast with LARc to 2022/23 based on completion of committed projects.

Under contingency conditions the forecast for zone substations with LARc in 2018/19 is three, decreases to two in 2019/20 and then increases to five in 2021/22.

Table 18 – Summary of Substation Limitations

Substation Type	Substation Condition	2018 / 19 Forecast	2019 / 20 Forecast	2020 / 21 Forecast	2021 / 22 Forecast	2022 / 23 Forecast
Bulk Supply	LARn > 0 MVA [1]	0	0	0	0	0
	LARc > 0 MVA [2]	0	0	0	0	0
	Total Substations [3]	42	42	42	42	42
Zone	LARn > 0 MVA [1]	1	1	1	0	0
	LARc > 0 MVA [2]	3	2	2	5	5
	Total Substations [4]	246	246	246	247	247

1 Assessment based on 10 PoE forecast and Customer Outcome Standard.

2 Assessment based on 50 PoE forecast and Customer Outcome Standard.

3 The bulk supply substation total count includes Powerlink owned 33 kV connection points.

4 The zone substation total count includes dedicated customer substations. Customer substation details are not included in this publication.

All information as at 30 November of each year.

Note: This table includes approved projects only. Proposed strategies to manage the limitations are contained in Appendix D.
Future refurbishment limitations that would result in a Customer Outcome Standard breach are not included in this table. A list of these refurbishment limitations is provided in Table 22 and Appendix D.

Substation limitations are also reported in the limitations tables contained in Appendix D. These tables also contain the approved or proposed strategy to manage the identified limitations, along with other related information.

Maps of Energex's network showing the location of all Energex's bulk supply and zone substations are presented via the following link: https://www.energex.com.au/daprmap2018.

These maps highlight which substations have limitations that have been identified through the process outlined in section 6.11.2.

7.1.2 Transmission Feeder Limitations

For each 132 kV and 110 kV feeder, a separate summary of forecast, capacity and limitations has been produced for summer and winter based on Customer Outcome Standard. These reports are contained in Appendix F.

Feeder limitations are identified using the simulation models and processes as described in section 5.3.3 and section 6.11.3. 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.

The outlook for the 132 kV and 110 kV feeders over the next five years is summarised in Table 19. With no feeders currently exposed to Load at Risk under normal conditions (LARn), it is not anticipated that this figure will change based on current demand forecasts. Under contingency conditions there are two feeders forecast to have LARc.

Table 19 – Summary of 132 kV and 110 kV Transmission Limitations

System Configuration	132 kV and 110 kV Feeder Condition	2018 / 19 Forecast	2019 / 20 Forecast	2020 / 21 Forecast	2021 / 22 Forecast	2022 / 23 Forecast
Normal 10 PoE	LARn > 0 MVA[1]	0	0	0	0	0
Contingency 50 PoE	LARc > 0 MVA[2]	1	2	2	2	1
Total Feeders		123	123	123	125	125

[1] Assessment based on 10 PoE forecast and Customer Outcome Standard.

[2] Assessment based on 50 PoE forecast and Customer Outcome Standard.

All information as at 30 November of each year.

Note: This table includes approved projects only. Proposed strategies to manage the limitations are contained in Appendix D.
Future refurbishment limitations that would result in a Customer Outcome Standard breach are not included in this table. A list of these refurbishment limitations is provided in Table 22 and Appendix D.

Limitations identified for 132 kV and 110 kV 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.

Maps of Energex's network showing the location of all Energex's bulk supply, zone substations and existing transmission feeders are presented via the following link:

https://www.energex.com.au/daprmap2018.

These maps highlight which transmission feeders have limitations that have been identified through the process outlined in section 5.3.2 and section 6.11.3

7.1.3 Sub-transmission Feeder Limitations

For each 33 kV feeder, a separate summary of forecast, capacity, and limitations has been produced for summer and winter based on Customer Outcome Standard. These reports are contained in Appendix F.

Feeder limitations are identified using the simulation models and processes as described in section 5.3.3 and section 6.11.4. The analysis provides load at risk information under normal and contingency conditions and evaluates whether the sub-transmission feeder meets its allocated security of supply standard. The outcome of this analysis would then trigger further investigations into potential solutions that may address limitations identified. For 33 kV feeders as listed in Table 20, there is no forecast LAR under normal conditions. Under contingency conditions the forecast number of feeders with LAR in 2018/19 is 6, increasing to 8 in 2022/23.

Table 20 – Summary of 33 kV Sub-transmission Limitations

System Configuration	33 kV Feeder Condition	2018 / 19 Forecast	2019 / 20 Forecast	2020 / 21 Forecast	2021 / 22 Forecast	2022 / 23 Forecast
Normal 10 PoE	LARn > 0 MVA[1]	0	0	0	0	0
Contingency 50 PoE	LARc > 0 MVA[2]	6	4	8	8	8
Total Feeders		395	393	392	388	388

[1] Assessment based on 10 PoE forecast and Customer Outcome Standard.

[2] Assessment based on 50 PoE forecast and Customer Outcome Standard.

All information as at 30 November of each year.

Note: This table includes approved projects only. Proposed strategies to manage the limitations are contained in Appendix D.
Future refurbishment limitations that would result in a Customer Outcome Standard breach are not included in this table. A list of these refurbishment limitations is provided in Table 22 and Appendix D.

The limitations identified in the 33 kV sub-transmission feeders are also reported in the limitations tables contained in Appendix D. These tables also contain the approved or proposed strategy to manage the emerging limitations, along with other related information.

Maps of Energex's network showing the location of all Energex's bulk supply, zone substations and existing sub-transmission feeders are presented via the following link:

https://www.energex.com.au/daprmap2018.

These maps highlight which of these sub-transmission feeders have limitations that have been identified through the process outlined in section 6.11.4.

7.1.4 11 kV Distribution Feeder Limitations

Results from analysis of 11 kV feeder loads, capacity and utilisation forecasts for five years are contained in Appendix F.

Table 21 provides a summary of the results of all the 11 kV feeder limitations analysis for 2017/18 - 2018/19.

Table 21 – Summary 11 kV Feeders > TMU

11 kV Feeder Condition	2018 / 19	2019 / 20	Detailed Results
Feeders with forecast TMU limitation	53	57	Appendix F
Total Number of Feeders	2,035	2,037	

Note: Total number of feeders excludes dedicated customer connection assets.

Maps of Energex's network showing the location of all Energex's bulk supply, zone substations and constrained 11 kV are presented via the following link: https://www.energex.com.au/daprmap2018.

7.1.5 Fault Level Limitation Projects

Energex performs fault level analysis for switchgear at all 132 kV, 110 kV, 33 kV and 11 kV buses as well as 33 kV and 11 kV feeders. Both 3-phase and 1-phase to ground faults are simulated in the studies and the worst case is identified in accordance with IEC 60909 Short-circuit currents in three-phase a.c. systems.

Where fault levels are forecast to exceed the allowable fault level limits, then fault level mitigation projects are initiated. This year detailed analysis did not identify any additional switchgear fault rating limitations in comparison to the 2017 DAPR.

7.1.6 11 kV Primary Overcurrent and Backup Protection Reach Limits

Energex engaged with a consultant to undertake a review of the existing protection settings of 11 kV distribution feeders in determining whether a systematic protection issue exists within the network.

As part of the report's recommendation, Energex conducted a review of its 11 kV feeder primary protection reach to further improve network safety and increase network transfer tie capabilities.

Six percent of the total Energex 11 kV feeders have been identified for potential improvements and is currently being addressed through protection setting changes, installation of 11 kV pole mounted reclosers (PMR) and fuses, and 11 kV feeder reconductoring works. These works have now been completed. Energex has also developed a program for rectifying backup protection reach limitations at around 100 zone substations across its network.

7.2 Asset Retirements (Project Based)

Energex has a range of project based planned asset retirements which will result in a system limitation. These retirements are based on the Asset Management Plans outlined in Section 4. Table 22 summarises these planned asset retirements for the forward planning period. 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.

Table 22 – Energex Asset Retirements (Project Based)

Asset	Location	Retirement Date	Change to Requirement Date
33 kV motorised isolator	Crestmead zone substation (SSCRM)	Jun-21	-
33 kV motorised isolator	Gaven zone substation (SSGVN)	Jun-21	-
33 kV motorised isolator	Gympie South zone substation (SSGYS)	Jun-21	-
33 kV VT's	Hays Inlet bulk supply substation (SSHIL)	Jun-23	-
33 kV motorised isolator	Hope Island zone substation (SSHIS)	Jun-22	-
1x 33/11 kV transformer	Hemmant zone substation (SSHMT)	May-21	-
33 kV motorised isolator	Heathwood zone substation (SSHWD)	Jun-21	-
33 kV VT	Inala zone substation (SSINA)	Jun-22	-
33 kV motorised isolator	Karrabin zone substation (SSKBN)	Jun-22	-
33/11 kV transformer	Lockrose zone substation (SSLRE)	Jul-22	-
33 kV motorised isolator	Morayfield zone substation (SSMFD)	Jun-22	-
33 kV motorised isolator	Morayfield North zone substation (SSMFN)	Jun-22	-
33 kV motorised isolator	Mango Hill zone substation (SSMHL)	Jun-23	-
33 kV motorised isolator	Mount Tamborine zone substation (SSMTB)	Jun-23	-

Asset	Location	Retirement Date	Change to Requirement Date
11 kV switchboard	Nudgee zone substation (SSNGE)	Mar-21	-
33 kV motorised isolator	North McLean zone substation (SSNMC)	Jun-23	-
3x 33/11 kV transformers	Palm Beach zone substation (SSPBH)	Jul-21	-
3x 33/11 kV transformers	Redland Bay zone substation (SSRLB)	Jun-21	-
33 kV motorised isolator	Samford zone substation (SSSMF)	Jun-23	-
1x 33/11 kV transformer, 1x 33 kV circuit breaker and 11 kV isolators	Stradbroke Island zone substation (SSSIS)	Oct-21	-
33 kV circuit breakers	Runcorn bulk supply substation (SST24, SSRBS)	Jun-23	-
33 kV motorised isolator	Crestmead zone substation (SSCRM)	Jun-21	-
33 kV motorised isolator	Gaven zone substation (SSGVN)	Jun-21	-
33 kV motorised isolator	Gympie South zone substation (SSGYS)	Jun-21	-
33 kV VT's	Hays Inlet bulk supply substation (SSHIL)	Jun-23	-
33 kV motorised isolator	Hope Island zone substation (SSHIS)	Jun-22	-
1x 33/11 kV transformer	Hemmant zone substation (SSHMT)	May-21	-
33 kV motorised isolator	Heathwood zone substation (SSHWD)	Jun-21	-
33 kV VT	Inala zone substation (SSINA)	Jun-22	-
33 kV motorised isolator	Karrabin zone substation (SSKBN)	Jun-22	-
33/11 kV transformer	Lockrose zone substation (SSLRE)	Jul-22	-
33 kV motorised isolator	Morayfield zone substation (SSMFD)	Jun-22	-
33 kV motorised isolator	Morayfield North zone substation (SSMFN)	Jun-22	-

Asset	Location	Retirement Date	Change to Requirement Date
33 kV motorised isolator	Mango Hill zone substation (SSMHL)	Jun-23	-
33 kV motorised isolator	Mount Tamborine zone substation (SSMTB)	Jun-23	-
11 kV switchboard	Nudgee zone substation (SSNGE)	Mar-21	-
33 kV motorised isolator	North McLean zone substation (SSNMC)	Jun-23	-
3x 33/11 kV transformers	Palm Beach zone substation (SSPBH)	Jul-21	-
3x 33/11 kV transformers	Redland Bay zone substation (SSRLB)	Jun-21	-
33 kV motorised isolator	Samford zone substation (SSSMF)	Jun-23	-
1x 33/11 kV transformer, 1x 33 kV circuit breaker and 11 kV isolators	Stradbroke Island zone substation (SSSIS)	Oct-21	-
33 kV circuit breakers	Runcorn bulk supply substation (SST24, SSRBS)	Jun-23	-
33 kV overhead conductor	F381 Lockrose bulk supply substation – Coominya and Paddy's Gully zone substations (SST78 – SSCMY – SSPGY)	Jun-20	-
33 kV overhead conductor	F309 Brendale bulk supply substation – Arana Hills zone substation (SSBRD – SSAHL)	Aug-20	-
33 kV overhead conductor	F569 Hemmant – Lota zone substations (SSHMT – SSLTA)	Jun-20	-
33 kV overhead conductor	F3359 Griffin – Hays Inlet bulk supply substations – Mango Hill zone substation (SSGFN – SSHIL – SSMHL)	Jun-20	-
33 kV overhead conductor	F3828 Esk – Paddy's Gully zone substations (SSESK – SSPGY)	Jun-21	-

Asset	Location	Retirement Date	Change to Requirement Date
33 kV overhead conductor	F531 Gatton bulk supply substation - Tenthill zone substation (SSGTN – SSTHL)	Jun-21	-
33 kV overhead conductor	F329 Redcliffe – Duffield Road zone substations (SSRCF – SSDRD)	Jun-21	-
33 kV overhead conductor	F344 Nambour bulk supply substation – Maleny zone substation (SST16 – SSMLY)	Jun-22	-
33 kV overhead conductor	F331 Hays Inlet bulk supply – Duffield Road zone substation (SSHIL – SSDRD)	Jun-22	-
33 kV overhead conductor	F447 Kilcoy – Somerset Dam zone substations (SSKCY – SSSDM)	Jun-22	-
33 kV underground cable	F631 Belmont bulk supply substation – Mt Gravatt zone substation (SSBBS – SSMTG)	Jun-22	-
33 kV underground cable	F632 Belmont bulk supply substation – Mt Gravatt zone substation (SSBBS – SSMTG)	Jun-22	-
33 kV underground cable	F607 and F525 Zillmere zone - Chermside zone substation (SSZMR - SSCSE)	Jun-20	-
33 kV overhead conductor	F312 Kallangur – Narangba zone substations (SSKLG – SSNRA)	Jun-23	-
33 kV overhead conductor	F487 Gatton bulk supply substation – Grantham zone substation (SSGBS – SSGHM)	Jun-23	-
33 kV overhead conductor	F339 Amamoor – Imbil – Mary River Pumping Station zone substations (SSAMR – SSIBL – SSMRR)	Jun-23	-

Asset	Location	Retirement Date	Change to Requirement Date
33 kV overhead conductor	F376 Postmans Ridge bulk supply substation – Helidon zone substation (SST29 – SSHDN)	Jun-23	-
33 kV overhead conductor	F477 Beerwah – Maleny – Woodford zone substations (SSBWH – SSMLY – SSWFD)	Jun-23	-

The assets assigned to the project based planned asset retirements are listed in Appendix D.

7.3 Summary of Emerging Network Limitations

Appendix D provides a summary of proposed committed works in the forward planning period and highlights the upcoming limitations for each bulk supply, zone substation, transmission feeder, sub-transmission and distribution feeders. Potential credible solutions are provided for limitations with no committed works.

7.4 Emerging Network Limitations 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 now available on the Energex website via the following link: https://www.energex.com.au/daprmap2018

The maps provide an overview of the Energex distribution network, including:

- Existing 132 kV, 110 kV and 33 kV feeders;
- Existing bulk supply and zone substations;
- Future bulk supply and zone substations approved in the five year forward planning period;
- Existing 132 kV, 110 kV and 33 kV feeders with identified security standard (COS) limitations within the five year forward planning period;
- Existing bulk supply and zone substations with identified security standard (COS) limitations within the five year forward planning period; and
- 11 kV feeders or feeder meshes with forecast limitations within the next two years of the forward planning period.

7.5 Regulatory Investment Test (RIT-D) Projects

7.5.1 Regulatory Investment Test Projects – In Progress and Complete

Formerly, a regulatory investment test for distribution (RIT-D) in accordance with clause 5.17.4 of the National Electricity Rules and the AER's RIT-D version 1 (23 August, 2013) was not required if the recommended development was related to refurbishment or replacement of existing assets and had no alternative option with an estimated augmentation component of more than $5 million.

As there were no projects approved with credible options having an estimated cost of the augmentation component greater than $5 million, the regulatory investment test for distribution in accordance with clause 5.17.4 of the National Electricity Rules was not required to be applied.

7.5.2 Projects Excluded from RIT-D Process

Recently Australian Energy Market Commission (AEMC) has implemented a new requirement to undertake a RIT-D for replacement expenditure, for projects having an alternative credible option of more than $5 million. This has commenced on 18 September, 2017.

To assist in the transition into this new arrangement, AEMC has provided an exemption for replacement projects which were already committed or which became committed by 30 January, 2018. Projects which met these prescribed criteria were excluded from the requirement to perform a RIT-D.

As there were no projects approved after 30 January, 2018 with credible options having an estimated cost greater than $5 million, regulatory investment test for distribution in accordance with clause 5.17.4 of the National Electricity Rules was not required to be applied.

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

https://www.energex.com.au/home/our-services/projects-And-maintenance/current-consultations/rit-d-excluded-projects

7.5.3 Foreseeable RIT-D Projects

The AER have recently increased the threshold for exemption from RIT-D from $5 million to $6 million which will take effect from 1 January 2019. The forward Energex Program of Work includes projects (having credible network options costing more than $6 million) that have the potential to become RIT-D projects. A summary list of such projects that have been identified to address emerging network limitations in the forward planning period is shown in Table 23.

Table 23 – Potential RIT-D Projects

Project Name	RIT-D Commencement
110kV Feeder Limitation from Jimboomba to Beaudesert	Qtr 1 2019
Doboy to Queensport – Establish new 33kV feeder	Qtr 2 2019
Kilcoy to Somerset Dam Replace 33kV Feeder F447	Qtr 1 2019
Bells Creek Central – Establish new zone substation	Qtr 2 2019

7.5.4 Urgent or Unforeseen Projects

During the year, there have been no urgent or unforeseen investments by Energex that would trigger the RIT-D exclusion conditions for the application of regulatory investment testing.

Chapter 8

Demand Management Activities

- Non-network options considered in 2017/18
- Key Issues Arising from Embedded Generation Applications
- Actions Promoting Non Network Proposals
- Demand Management Results for 2017/18
- Demand Management Programs for 2018/18 to 2022/23
- Other Demand Side Participation Activities

8 Demand Management Activities

Energex's Demand Management (DM) program forms part of an integrated approach that also includes forecasting, planning, intelligent grid and tariff strategies, to help lower electricity charges for its end use customers. DM involves working with end use customers and 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; and
- pricing or tariffs.

Annually, Energex publishes a DM Plan which includes strategy for the next five years and planned DM programs for next financial year. For the first time, the 2018-19 DM Plan has been developed to cover both the Energex and Ergon Energy networks. It brings together a unified approach to DM for the whole of Queensland, while at the same time acknowledging the differences in regions and networks. This plan is available on Energex's website: 2018-2019 DM Plan

Our plan has responded to the issues facing our network and what our customers and stakeholders are saying as listed in Table 24.

Table 24 – Our DM Strategies Respond to Customer Insights

DM Strategies	Customer Insights						
	Affordability	Reliability	Choice and control	Innovation	Approachable	Tailored	Community focused
Ensure efficient & well planned investment & infrastructure	●					●	●
Maintain reliable supply of electricity for all end use customers		●				●	●
Maximise power system security and reliability particularly during summer		●					●
Inform and engage our end use customers and stakeholders			●		●	●	

DM Strategies	Customer Insights						
	Affordability	Reliability	Choice and control	Innovation	Approachable	Tailored	Community focused
Activate the demand response market			●	●			
Support our program by investment in innovation				●		●	

During 2017 and 2018, demand on Energex'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 DM 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 DM 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

Energex reviews all significant augmentation, refurbishment and replacement projects to determine if there are any viable non-network alternatives to the preferred network options.

Non-network assessments examine the economics of viable non-network solutions compared to the preferred network investment option. Non-network solutions considered include a range of residential, commercial and industrial options covering:

- Permanent load reductions (such as energy efficiency improvements);
- Embedded generation; and
- Demand response, incorporating:
  - Residential: controllable loads including air-conditioning, electric storage hot water systems or pool pumps; and
  - Business: shifting of production times or shut down of processes.

No new non-network options were identified as credible alternatives to capital projects in the 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. Those Target Areas in market during the 2017-18 year are listed in Table 25.

Table 25 – Market Target Areas

Target Area Incentives	Active in 2017-18
Jimboomba West Substation area Up to $185 per kVA; Up to $41 per kVAR	Active
West End substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Wellington Road substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Makerston Street substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Sunrise Hill substation area Up to $185 per kVA; Up to $41 per kVAR	Active
West Maroochydore substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Caboolture substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Springfield substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Coomera substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Hollywell substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Hope Island substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Molendinar substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Goodna substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Beenleigh substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Brendale substation area Up to $185 per kVA; Up to $41 per kVAR	Active
Larapinta substation area Up to $185 per kVA; Up to $41 per kVAR	Active

In addition, the contracted embedded generation for network support enabling the deferral of the Beaudesert Bulk Supply substation was maintained.

8.2 Key Issues Arising from Embedded Generation Applications

Energex continues to experience a number of challenges with respect to connection enquiries and applications for embedded generators. The volume of solar PV applications continues to increase. The volume of medium scale systems in the range of 30 kW to 5,000 kW has doubled from 2016/17 to 2017/18. Energex continues to work on improving efficiency and deliver more satisfying customer experiences. The continued focus on the development of standards and revision of processes together with additional training for technical staff facing customers continues the path to developing a more customer-centric approach. A new Queensland connection standard for embedded generation systems in the range 30 kW to 1,500 kW connected to the LV distribution network, was introduced by Energex and Ergon Energy.

With regard to other large embedded generation some key issues are:

- Increasing numbers of larger solar PV installations in the range up to 1,000 kW or more at commercial and industrial premises;
- Management of voltage on distribution feeders in situations where there is significant solar PV generation connected;
- Management of fault level impacts, and increases in fault levels exceeding the rating of shared distribution assets located in the vicinity of embedded generator connections involving rotating machine generators ; and
- The on-going management of operational issues with an increasing number of embedded generators.

The above issues present on-going challenges to Energex in terms of managing operational costs while also maintaining compliance, safety and quality of supply to the standards required by regulations.

8.3 Actions Promoting Non-Network Proposals

Energex has been implementing DM initiatives as detailed in its 2015-2020 Regulatory Proposal. Initiatives undertaken involved a range of commercial, industrial and residential customer programs, along with ongoing development of longer-term DM strategies.

Continued review of Energex strategic network planning processes is underway to identify network forecast scenarios and subsequently provide earlier identification of emerging network constraints. This will be used to inform and support a lowest cost approach to constraint mitigation, including working with industry partners to deliver non network alternative projects.

For medium to long-term network limitations, where Energex believes a project deferral can be achieved through peak demand management, a targeted demand management campaign is initiated. For these campaigns, non-network providers may act on behalf of a customer with incentives paid directly to the customer by Energex. Non-network providers play an important role in promoting targeted demand management campaigns as they promote Energex incentives as a means of reducing the cost of energy conservation and demand management projects at customer sites.

Targeted campaign proposals are evaluated against the following mandatory criteria:

- Location of customer site residing within a targeted area;
- Technical viability of each option identified;
- Customer payback period for each opportunity identified (where applicable);
- Energex maximum $/kVA and/or $/kVAr for the relevant targeted area;
- Ability of each option to be measured and verified; and
- Ability of the customer to achieve stated load reductions within required timeframes.

If a proposal is accepted, Energex will enter into a contract with the customer. Energex will then work with either the customer or the customer's nominated non-network provider to ensure initiatives are undertaken and the load reductions measured and verified so that payments can be made to the customer, in accordance with the contract.

As per NER requirements, Energex has a Demand Side Engagement Facility ("the Facility") to allow parties to register their interest in being notified of developments relating to distribution network planning and expansion projects. In addition, Energex's Demand Side Engagement Strategy (DSES) outlines key information to assist non-network providers in providing submissions for credible non-network solutions as alternatives to network investment. The DSES has been developed in accordance with Clauses 5.13.1 I, (g) and (h) of the NER. Both "the Facility" and DSES are available on the Energex website at

https://www.energex.com.au/home/control-your-energy/managing-electricity-demand/demand-side-engagement

8.4 Demand Management Results for 2017/18

Energex has successfully exceeded its peak load reduction target of 27 MVA for the Demand Management program in 2017/18. The actual peak load reduction achieved for 2017/18 is 39.3 MVA. The financial year 2017-18 ended with the results shown in Table 26 for demand management activities and non-network embedded generation contracts.

Table 26– Demand Management Results for 2017/18

Initiative	MVA
Broad based program	25.8
Target area program	2.5
NNA generation[1]	11
DM Development[2]	-
Total for DM Program	**39.3**

[1] Embedded generation contracted for Bromelton

[2] MVA from load optimisation was not progress as there was a greater focus on the Residential and Business programs

8.4.1 Connection Enquiries Received

Energex has established processes which apply to connection enquiries and applications for embedded generators. These processes comply with the requirements of the National Electricity Rules. In 2017/18 the number of connection enquiries received is shown in Table 27. For micro EG 30 kW or less (mainly solar PV), there is no connection enquiry phase i.e. all connection requests are processed as applications.

Table 27 – Embedded Generator Enquiries

Connection Enquiries	Number 2017/18
Embedded Generator (EG) Connection Enquiries – Micro EG 30 kW or less	Not applicable
Embedded Generator Connection Enquiries – Other (>30 kW)	622

8.4.2 Applications to Connect Received

In 2017/18 the number of applications to connect is shown in Table 28.

Table 28 – Embedded Generator Applications

Connection Applications	Number 2017/18
Embedded Generator Connection Applications – Micro EG 30 kW or less	37,393
Embedded Generator Connection Applications – Other (>30 kW)	212

8.4.3 Average Time to Complete Connection

In 2017/18 the number of applications received and connected took an average time to complete as shown in Table 29.

Table 29 – Embedded Generator Applications – Average Time to Complete

Connection Applications	Average time to complete 2017/18
Embedded Generator Connection Applications – Micro EG 30 kW or less	23 business days
Embedded Generator Connection Applications – Other (>30 kW)	27 business days

8.5 Demand Management Programs for 2018/19 to 2022/23

Energex's demand management programs for 2018-2023 are detailed in our annual DM 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 30.

Table 30 Demand Management Programs

Program	Network	Description	2017-18	2018-19	2020-25
TARGET AREA PROGRAM					
Target area incentives	Energex	Provide incentives to business and industry for demand reductions. These areas are where there is an emerging constraint (5-10 years away).	Active	Active	Active
NON NETWORK ALTERNATIVES					
Contracted demand management	Energex	Contracts with 3rd parties for non-network alternative projects (such as embedded generators) to defer capital network investment.	Active	Active	Actives
BROADBASED PROGRAMS					
PeakSmart air conditioning	Energex	Provision of incentives to end use customers who participate in the PeakSmart air conditioning program t air conditioning program	Active	Active	
Load control tariffs	Energex	Provision of incentives to end use customers for connecting appliances to load control tariffs	Active	Active	Active
Procure reliability services from the market	Energex	Investigate feasibility and effectiveness of procuring reliability services from the market		New	Active
Alternative models for delivering demand response	Energex	Investigate feasibility and effectiveness of voluntary demand response program		New	Pending
Summer preparedness plan	Energex	Work with Queensland government to develop annual plan	Active	Active	Active
DEMAND MANAGEMENT DEVELOPMENT PROGRAMS					
Smart ADMD Tool	Energex	Continue to pilot and develop tool for use in greenfield residential developments	Prototype developed	Active	Active
Integrate DM into urban development rating tools	Energex	Work with developers and industry		New	Active
Provide simple DM advice	Energex	Provide simple DM advice to end use customers on how to reduce demand	Active	Active	Active
Raise awareness of demand tariffs	Energex	Raise awareness of demand tariffs	Active	Active	Active
Incentive maps	Energex	Publish incentive maps of Target Incentive areas		New	Active

Program	Network	Description	2017-18	2018-19	2020-25
PeakSmart air conditioner reward app	Energex	Develop app for installers to use to provide details of PeakSmart air conditioner installations and to apply for incentives		New	Pending
Electric vehicle connection advice	Energex	Provide simple and consistent electric vehicle connection advice	Active	Active	Active
Support development of demand response Standards	Energex	Support development of AS/NZS 4755.2	Active	Active	Active
INNOVATION PROGRAMS					
Innovative trials and projects	Energex	Undertake innovative projects and initiatives to test and validate DM products and processes. Some are funded through the Demand Management Innovation Allowance (DMIA)	Active	Active	Active

8.6 Other Demand Side Participation Activities

Energex 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 DM capabilities.

During 2017/18 Energex continued to influence demand management related standards and policies. One of the standards critical to the ongoing sustainability of Energex Demand Management is the suite of AS/NZS 4755 standards which outline demand response capabilities for residential appliances.

Work commenced with Standards Australia on a new standard AS/NZS 4755.2 which will cover “demand response systems” that do not require the individual physical elements defined in AS/NZS 4755.1. This will provide for alternative means to communicate demand response modes (or operational instructions (OIs)) to appliances, without the need for a physical Demand Response Enabled Device (DRED). It is expected that this Standard will increase adoption of standardised demand response by appliance manufacturers, aggregators and networks. This will enable further innovation and software solutions for demand response of appliances.

Energex has also been working with industry partners to develop AS 4755 compliant products, e.g. battery energy storage systems and home energy management systems. Trials of these offers have been underway. Preliminary results of the battery trial scan can be found on the Energex website:

Energex Battery Trials Preliminary Findings Report

Chapter 9

Asset Life-Cycle Management

- Approach
- Preventative Works
- Asset Condition Management
- Asset Replacement
- De-Rating

9 Asset Life-Cycle Management

9.1 Approach

Energex 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.

Energex'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. Energex'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; and
- 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 Energex 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 refurbishment/replacement 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

Energex 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

Energex generally employs condition and risk-based asset inspection, maintenance, refurbishment and replacement strategies in line with its asset management policies and strategies discussed in Section 4. 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; and
- electrical testing of circuit breakers.

In particular, Energex 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. Energex has a three year rolling average in-service pole failure rate of 10 failures per annum of the 579,971 poles, achieving 99.9982% 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, Energex 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 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, Energex 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.

Energex 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:

- Cyclic programs, to cut vegetation on all overhead line routes. The cycle times are managed by Energex's vegetation contractors to ensure the clearance zone is kept clear at all times; and
- 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, Energex 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

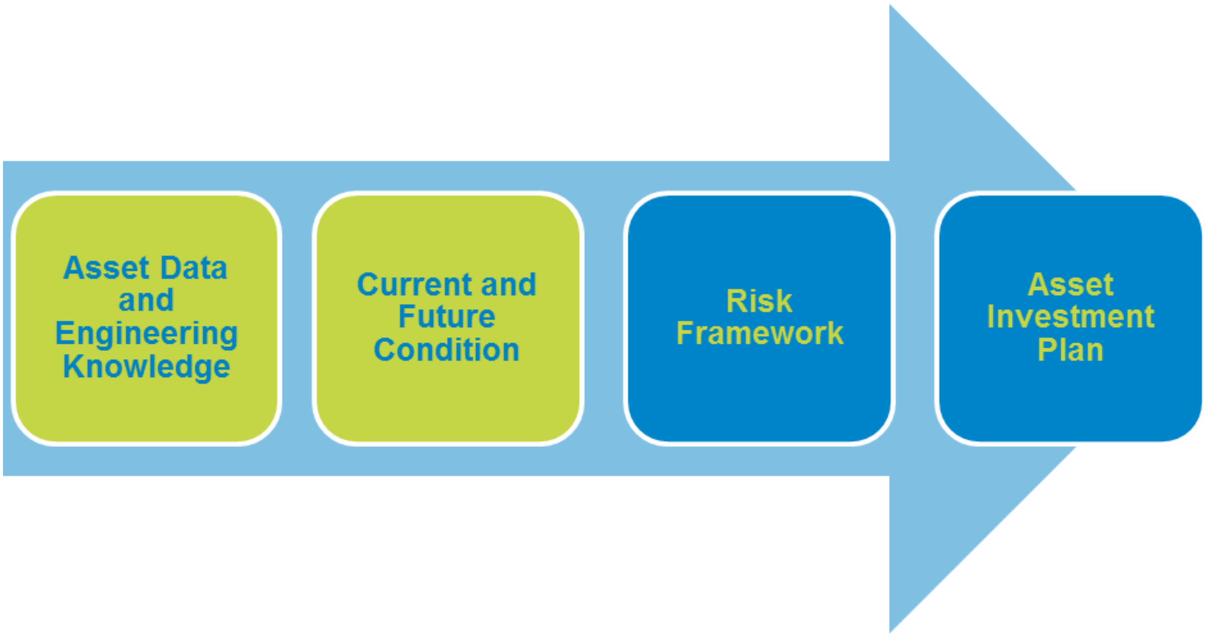
The processes for inspection and routine maintenance of Energex's assets are well established and constantly reviewed. Energex uses its asset management system to record and analyse asset condition data collected as a part of these programs. Formal risk assessments are conducted for all asset classes, 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.

Energex 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 Energex 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 24 below provides a summary of the process for delivering network asset investment planning condition based risk management.

Figure 24 – Process to Create Asset Investment Plan



9.4 Asset Replacement

Energex 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 Regulatory Investment Test for Distribution 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 limitations is recurring across multiple locations and does not require consideration under the Regulatory Investment Test for Distribution.

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

9.4.1 Substation Primary Plant

9.4.1.1 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, Energex has adopted a CBRM approach to define the highest priority and end-of-life replacement time of these assets, optimised for overall least cost and risk.

9.4.1.2 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, Energex 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.

A targeted replacement program has been implemented for 11 kV oil circuit breakers that are incapable of remote control. These are considered high risk assets, due to safety impacts upon failure for operating staff. The replacement program is expected to be complete by 2020.

9.4.1.3 Instrument Transformer Replacement and Refurbishment

Current Transformers (CTs) and Voltage Transformers (VTs) are condition monitored and require little maintenance. Energex maintains a CBRM model for 110 kV and 132 kV instrument transformers, and is yet to establish a working CBRM model for lower voltage instrument transformers. 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, Energex employs CBRM for 110 kV and 132 kV instrument transformers to identify the highest priority end-of-life replacement, optimised for overall least cost and risk. Energex has also implemented a program of voltage monitoring through the SCADA system for 110 kV and 132 kV voltage transformers as a means of early detection of failure. Lower voltage instrument transformers are managed via routine inspection and data quality initiatives are underway to enable future modelling in CBRM.

Energex has experienced multiple catastrophic failures of a specific type of 110 kV oil filled porcelain bushing voltage transformers. Catastrophic failure of these assets results in porcelain bushing projectiles as a result of explosive failure. This poses a high safety risk to field personnel and the public. Industry recommendations are to replace this type of unit at 20 years of age, and because of the safety risks involved, Energex has adopted this approach.

9.4.1.4 Substation Outdoor Isolator and Earth Switch Replacement and Refurbishment

Outdoor isolators are condition monitored and require no maintenance. Failure consequences are generally related to delays in performing other maintenance on other substation assets. Because this is relatively simple equipment, Energex has adopted a near run-to-failure approach for outdoor isolators and earth switches.

9.4.1.5 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, Energex 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.

9.4.2 Substation Secondary Systems

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

9.4.2.1 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, Energex has adopted a proactive replacement program targeting problematic and near end of life relays.

Wherever possible, replacement of obsolete protection schemes is undertaken with other capital work such as primary plant replacement or augmentation for efficiency reasons. In circumstances where this is not possible, stand alone projects for replacement of the obsolete protection schemes are undertaken.

9.4.2.2 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, Energex has adopted a proactive replacement program targeting ageing and obsolete RTUs and a planned replacement program for this asset class is underway.

9.4.2.3 Audio Frequency Load Control Replacement Program

AFLC equipment is condition monitored and requires little 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, in some rare cases 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. The fleet of units are all solid state units with good reliability performance and the risk posed from in-service failure is in the low range and as such no proactive replacement program is currently underway or planned for the coming AER period.

9.4.2.4 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, Energex has adopted a proactive replacement program targeting battery systems. Replacement of battery chargers under this program prioritises the problematic ripple chargers which reduce the life of the valve regulated lead acid batteries used as standard in the Energex network.

9.4.3 Sub-transmission and Distribution Line Equipment

9.4.3.1 Underground Cables

Underground cables operated at voltages of 33 kV, 66 kV and 110 kV are condition monitored and require minimal maintenance. Failure consequences involve reliability impacts related to technical ability to meet demand. Replacement times are typically very long due to the need to dig deep and long trenches in busy urban areas. Due to the potential failure consequences, Energex has adopted a CBRM approach to define the highest priority economic end-of-life replacement time of these cables, optimised for overall least cost and risk.

Underground cable operated at voltages of 11 kV and below are not condition monitored with only above ground portions visually inspected. Failure consequences involve lower level reliability impacts related to technical ability to meet demand. Due to the potential failure consequences, Energex has adopted a run to near failure approach for renewal.

9.4.3.2 Poles

Pole replacement occurs through a combination of poles failing inspection, capital works (including augmentation projects), and proactive pole replacement where age, type, location, and network risk are considered. Proactive pole replacement programs are used to remove the highest risk poles from the network in order to manage safety and network risk and maintain a sustainable pole replacement rate. These poles are typically the oldest poles in the network. Wherever possible, proactive pole replacement is undertaken in conjunction with reconductoring and other work for efficiency reasons.

9.4.3.3 Overhead Conductor

Conductor replacement programs are used to remove the highest risk conductor from the network to manage safety and network risk and maintain a sustainable conductor replacement rate. The programs are targeted to specific areas based on the age, type, and condition (presence of numerous joints and splices from previous failure) and the network risk associated with the conductor. These conductors are typically the oldest and of the lowest cross sectional area on the network or those exposed to more corrosive environments such as coastal regions.

Wherever possible, reconductoring includes the proactive replacement of poles and crossarms which meet refurbishment criteria for efficiency reasons. In the case of LV reconductoring, open wire conductor is replaced with LV ABC to achieve the additional safety and reliability benefits associated with insulated conductor. This also removes wooden crossarms which have less than half of the service life of other overhead assets from the LV network providing long term operational cost savings.

9.4.3.4 Crossarms and Pole Top Structures

Crossarm and pole top structure (e.g. wooden risers or transformer brackets) 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 vast majority of crossarm replacements on the Energex network are driven by the inspection process and treated as an operational cost. Relatively small volumes of crossarms are replaced proactively as a part of the reconductoring programs where they either meet refurbishment criteria based on type, age and condition or are removed with the construction of LV ABC in lieu of open wire.

9.4.3.5 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. As these asset types are addressed, proactive service replacement will move towards a more condition based approach with consideration of condition and population age. This includes PVC covered services (parallel web and twisted) and a portion of older XLPE insulated services.

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, Energex 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.

9.4.3.6 Distribution Plant

The Energex distribution network includes various pieces of operational plant including Automatic Circuit Reclosers (ACRs or Reclosers), Sectionalisers, Step Voltage Regulators (SVR’s), Distribution Transformers (pole and ground mounted), Distribution Substations (SD sites), Ring Main Units (RMU’s) and Manual and Remote Controlled Switches. Plant of this nature is primarily replaced when identified to be in poor condition either via routine inspection processes or during the course of other network activities.

9.4.3.7 Air Break Switch Replacement

Energex has experienced a series of failures of a specific type of 33 kV Air Break Switch manufactured between 1989 and 1996. Failures of this type of Air Break Switch have resulted in localised outages, potential safety incidents and network operating restrictions.

A program to replace the 33 kV Air Break Switches commenced in the 2015/16 financial year and is expected to be completed by 2020.

9.4.3.8 Ring Main Unit (RMU) Replacement

Energex has experienced approximately 20 in-service failures of a specific Ring Main Unit from 2009; with failures increasing in 2015 and 2016. The affected Ring Main Units which were manufactured between 1975 and 2007 are installed at various 11 kV Cubicle mount substation sites across the Energex network.

Due to inherent risks associated with the failure of these switches during operation and safety risks to the general public; a program to inspect and test the affected ring main units was initiated in 2016/17. An ongoing process of partial discharge testing on an 18 month cycle has been implemented to monitor the condition of the remaining population with replacements to occur based on condition.

9.4.3.9 LV Service Fuse Holder Replacement

There has been an increase in failures of a brand and type of LV service fuse holders in recent times. The common mode of failure appears to be overload of the fuse holder, causing insulation to become hot and melt, causing phase flashover.

Identification and removal of the fuse holders is being undertaken as a part of the 5 year pole inspection program and is expected to be completed by 2022/23.

9.4.3.10 Replace Ageing Cable Terminations

Energex has a population of approximately 4,100 ageing cable terminations with cast iron pot heads. The deterioration of the dielectric material inside the chamber of ageing terminations eventually leads to failure of the cast iron pot head which is potentially catastrophic (explosive). To address the public safety risk associated with failure, problematic pot heads of all voltages will be replaced as a targeted replacement program. Cast iron pot heads located near high risk areas such as schools and high pedestrian areas will be replaced as a priority in the initial years of the program. It is proposed to replace all problematic cable terminations by the end of 2025 (10 year program).

9.4.3.11 Overhead Network Clearance

Energex 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 was deployed in 2016/17 and has allowed individual identification of conductor span clearance to ground and structure issues for all conductor types except service lines. This has revealed 1,852 separate locations where legislative minimum clearances to structures need to be resolved and 14,648 separate spans where legislative minimum clearances to ground need to be resolved. A risk prioritised works program is underway to achieve compliance. The works program is expected to complete during 2020.

The Lidar technology has identified point in time clearance issues, but has not been integrated with span loading and design information. Energex intends to combine such information to further identify other conductor clearance issues that are impacted by network loading. This work is scheduled to occur once the Lidar identified works has been completed.

9.4.3.12 Basement Fire Systems

Energex has identified the hazard of a fire in a zone or bulk supply substation cable basement as a potential high consequence, low likelihood event. In response, Energex is undertaking cable basement fire risk mitigation works at strategic locations on its network to reduce the customer and safety related risks resulting from cable basement fires. These locations include 14 substations which supply CBD areas, hospitals or significant commercial and industrial customers. Site specific risk assessments have been undertaken to manage cable basement fire risk to ALARP. Works are in progress and it is anticipated all works will be completed in 2019.

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.

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

Chapter 10

Network Reliability

- Reliability Measures and Standards
- Service Target Performance Incentive Scheme (STPIS)
- High Impact Weather Events
- Guaranteed Service Levels (GSL)
- Worst Performing Feeders
- Safety Net Target Performance

10 Network Reliability

10.1 Reliability Measures and Standards

Energex's Distribution Authority DO7/98 (DA) details Minimum Service Standards (MSS) to be achieved for network reliability. The MSS are prescribed in the DA to provide a standard against which a distribution entity's feeder performance can be assessed across the network and from year to year. Two reliability measures are defined as follows:

- System Average Interruption Duration Index (SAIDI) limits; and
- System Average Interruption Frequency Index (SAIFI) limits.

SAIDI indicates the total minutes, on average, that customers are without electricity during the relevant period. By contrast, SAIFI indicates the average number of occasions each customer's supply is interrupted during the relevant period. Both indices are inclusive of both planned and unplanned events.

The DA prescribes that Energex must use all reasonable endeavours to ensure that it does not exceed the SAIDI and SAIFI limits set out in the DA 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 DA excludes the following events from the MSS calculations:

- An interruption of a duration of one minute or less (momentary);
- An interruption resulting from load shedding due to a shortfall in generation;
- An interruption resulting from a direction by AEMO, a system operator or any other body exercising a similar function under the Electricity Act, National Electricity Rules or National Electricity Law;
- An interruption 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;
- An interruption resulting from failure of the shared transmission grid (Powerlink);
- An interruption resulting from a direction by a police officer or another authorised person exercising powers in relation to public safety;
- An interruption to the supply of electricity which commences on a major event day; and
- An interruption caused by a customer's electrical installation or failure of that electrical installation.

Under Energex's DA, exceedance of the same MSS limit in three consecutive financial years is considered a "systemic failure" and constitutes a breach of the DA.

The MSS limits for 2017/18 and the 2015-20 regulatory period have been flat-lined and are presented in section 10.1.1, along with Energex's performance against these limits. The MSS limits are in accordance with Schedule 2 of the DA.

Also under Energex's DA, Energex is required to monitor and report on the performance of 11 kV Worst Performing Feeders (WPF) and improve their reliability. A summary of the performance of Energex's 2017/18 WPF feeders is presented in section 10.5, and a full report is contained in Appendix G of the DAPR.

Although Energex's DA does not include requirements to report on momentary interruptions (MAIFI), the AER does include this measure in its annual RINs and in the measures that may be applied in the STPIS. However, there is currently no requirement for Energex to report momentary interruptions. Energex's preference is for reporting momentary interruptions by the momentary average interruption frequency index by event (MAIFIe) rather than MAIFI, as MAIFIe does not include reclose attempts of a protection device which immediately precede a lockout or a successful reclose. Reporting by MAIFIe is also consistent with reporting in other jurisdictions.

10.1.1 Reliability Performance in 2017/18

The normalised results in Table 31 highlight a favourable performance against MSS for all of Energex's network categories.

Table 31 – Performance Compared to MSS

Normalised Reliability Performance		2017/18 Actual	2017/18 MSS	2015-20 [1] MSS
SAIDI (mins)	CBD	4.799	15	15
	Urban	73.092	106	106
	Short Rural	187.384	218	218
SAIFI	CBD	0.0352	0.15	0.15
	Urban	0.6712	1.26	1.26
	Short Rural	1.4561	2.46	2.46

[1] Energex's MSS is 'flat-lined' for the current regulatory period 2015-2020.

Figure 25 and Figure 26 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.

Figure 25 – Network SAIDI Performance Five-year Average Trend

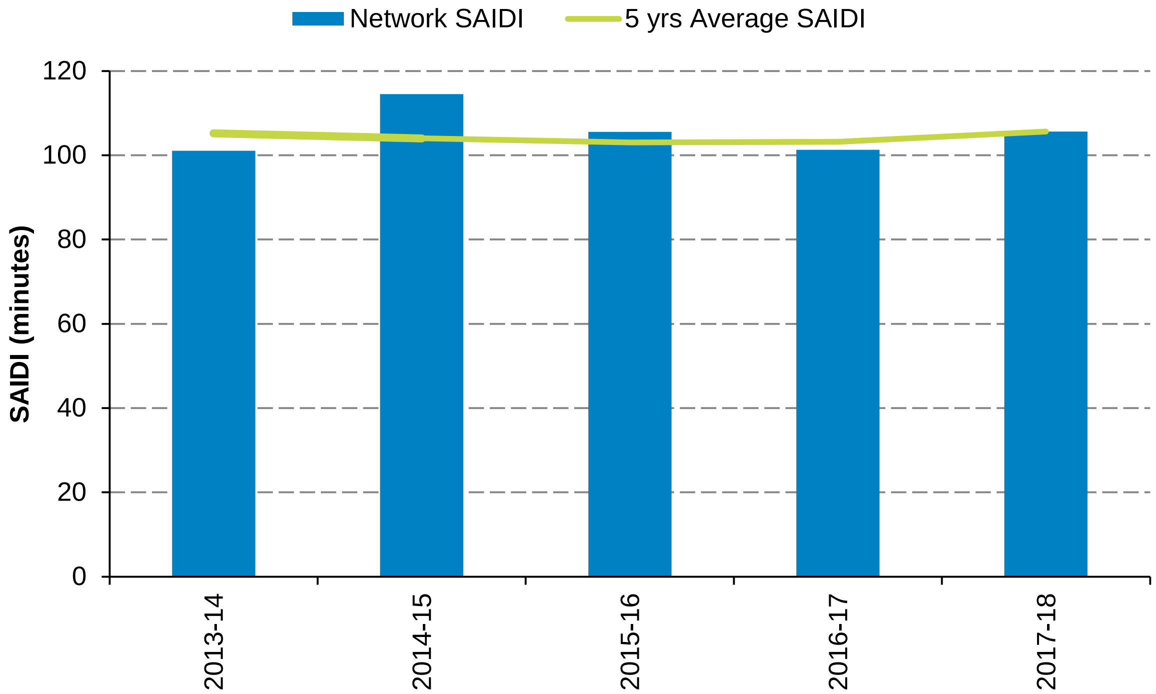
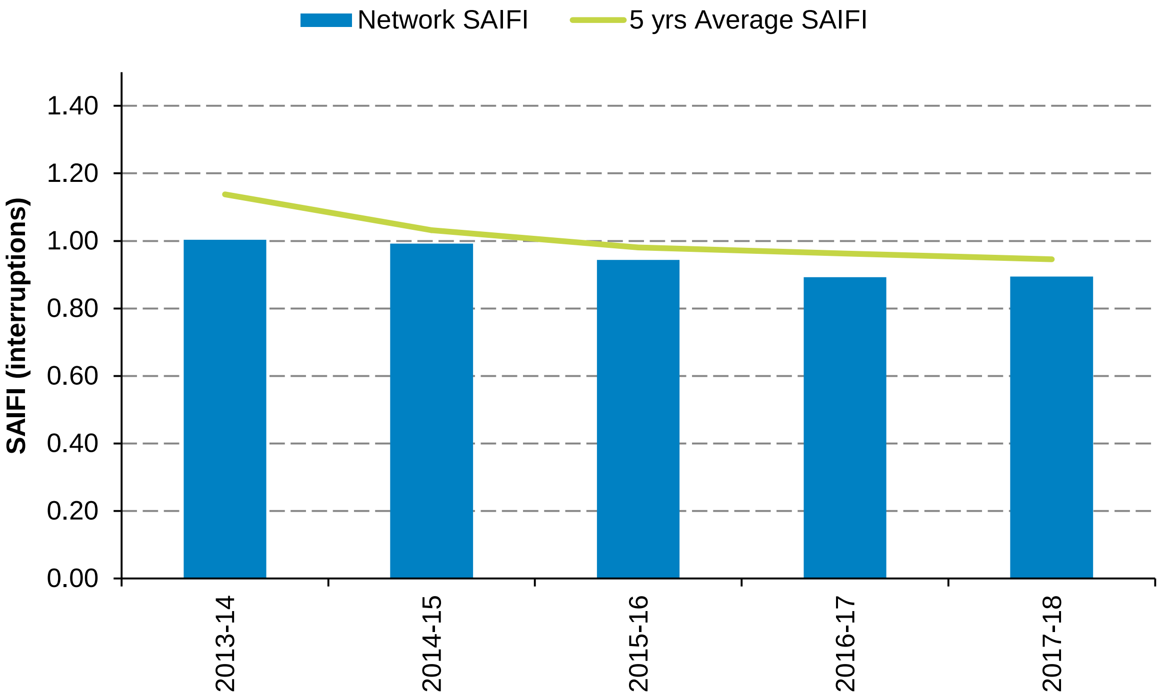


Figure 26 – Network SAIFI Performance Five-year Average Trend



10.1.2 Reliability Compliance Processes

Due to inherent statistical variability in reliability performance from year to year, mainly due to adverse weather, simply aiming for the MSS would lead to regular non-compliances and breaches of Energex's DA. To minimise the risk of non-compliance with MSS, Energex has set its internal targets 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.

A forecast of network performance for each category is carried out based on analysis of the three key components of historical performance planned outages, non-storm unplanned outages and storm unplanned outages. These forecasts are then adjusted to allow for both decreases in reliability (due to factors such as asset ageing), and expected improvements under Energex's existing reliability specific capital and operating expenditure program. These adjusted forecasts are then compared to the MSS limits to determine if a gap exists where the forecast performance is unfavourable to any of the limits.

If gaps in performance prevail, further network analysis is undertaken and programs are implemented to target those areas where the maximum reliability benefit can be achieved for minimum capital expenditure. Historically, the majority of these reliability programs have been made up of reliability improvements to specific 11 kV feeders, as Energex's 11 kV network is the highest contributor to its SAIDI and SAIFI results. By creating projects around individual 11 kV feeders, the performance of each feeder can be analysed, and the improvement works can then be targeted to the specific issues on each feeder.

This process is carried out once every five years as part of Energex's regulatory proposal which is submitted to the Australian Energy Regulator (AER). If it is determined that reliability works are required to be funded to achieve the Minimum Service Standards, then the estimated Capex required is submitted to the AER for approval. However, for the five year regulatory control period commencing 1 July 2015, Energex's forecasts show that the risk of exceeding MSS is tolerable. Therefore, no capital expenditure was proposed for MSS compliance before 2020.

10.1.3 Reliability Non-Compliance Corrective Actions

As shown in Table 31, Energex met its MSS reliability targets during 2017/18. This is mainly due to the realisation of previously completed reliability projects targeting poorly performing assets and/or poor reliability areas. A majority of severe weather events during the year have also been excluded under the Major Event Day criteria. Energex is planning to remain fully compliant with the MSS in future years by maintaining a focus on network reliability.

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

In addition to the reliability improvement specific works, Energex continues 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 (STPIS)

The SAIDI and SAIFI unplanned performance results (after removal of excluded events) compared to the STPIS targets are shown in Table 32.

Table 32 – 2017/18 STPIS Results

	2017/18 Actual	2017/18 Target
SAIDI Unplanned (minutes)		
CBD	0.357	3.897
Urban	48.146	60.118
Short Rural	116.058	144.475
SAIFI Unplanned (number pa)		
CBD	0.0018	0.0352
Urban	0.5742	0.9081
Short Rural	1.1871	1.8747

Energex exceeded the capped revenue for 2017/18. A breakdown of the revenue by feeder category and SAIDI and SAIFI is shown in Table 33.

The $38.17 M result is above the capped reward of 1.9% of revenue of $26.52 M which Energex is eligible to claim.

Table 33 – 2017/18 STPIS Uncapped Revenue

STPIS Revenue (Uncapped) $ M	SAIDI	SAIFI	Total
CBD	$0.14	$0.13	$0.27
Urban	$8.33	$15.79	$24.12
Short Rural	$4.53	$9.25	$13.78
Total	$13.00	$25.17	$38.17

10.2.1 STPIS Methodology

The STPIS that Energex is operating under in this regulatory period includes six reliability targets, or SAIDI and SAIFI for each of the feeder categories of Urban, Rural and CBD.

Due to the inherent variability in the network performance, the outcomes under STPIS are probabilistic in nature rather than deterministic. Each of the six STPIS reliability parameters has an underlying probability distribution. The intrinsic assumption in the forecast methodology is that the past variability will be a reasonably good predictor of the future variability.

The forecast for Energex's CBD, Urban and Rural networks is based on their historical five year average normalised performance summarised in Table 34. The total performance is then compared with the STPIS targets, shown in Table 35 to determine the forecast gap in performance as shown in Table 36. A positive gap means the performance is favourable to target and negative unfavourable to target.

A forecast of Energex's performance against the STPIS targets cannot be provided beyond 2019/20 as STPIS targets for the next regulatory period are yet to be determined. The targets for 2020/21 to 2024/25 will be determined as part of Energex's regulatory proposal for that period.

10.2.2 STPIS Results and Forecast

STPIS forecasts and targets for the remaining two years in the current regulatory period are shown below in Table 34 and Table 35.

Table 34 – STPIS SAIDI / SAIFI Forecast

Year	SAIDI (mins)			SAIFI (Int)		
	Urban	Rural	CBD	Urban	Rural	CBD
2018/19	53.37	119.6	1.67	0.64	1.32	0.034
2019/20	53.37	119.6	1.67	0.64	1.32	0.034

Table 35 – STPIS SAIDI / SAIFI Targets

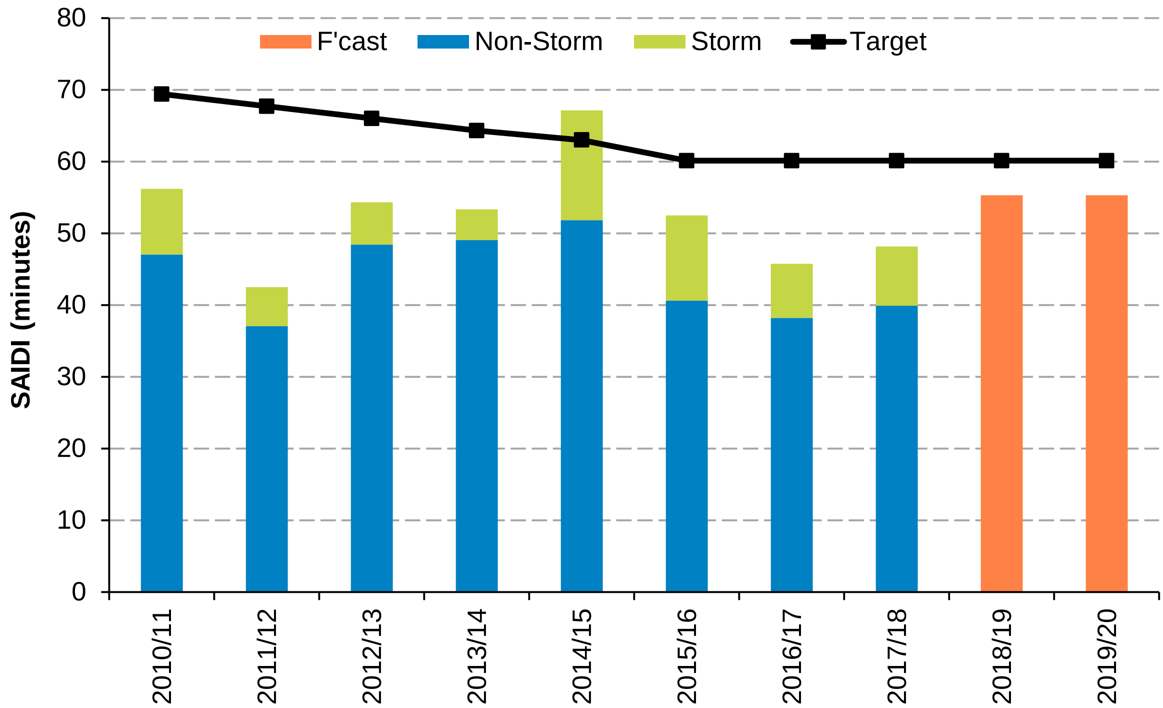
Year	SAIDI (mins)			SAIFI (Int)		
	Urban	Rural	CBD	Urban	Rural	CBD
2018/19	60.118	144.475	3.897	0.9081	1.8747	0.0352
2019/20	60.118	144.475	3.897	0.9081	1.8747	0.0352

Table 36 – STPIS SAIDI / SAIFI Forecast Performance Comparison

Year	SAIDI (mins)			SAIFI (Int)		
	Urban	Rural	CBD	Urban	Rural	CBD
2018/19	6.75	24.85	2.229	0.264	0.5448	0.006
2019/20	6.75	24.85	2.229	0.264	0.5448	0.006

As indicated in Table 36, Energex's forecast results are all favourable to targets for 2018/19 to 2019/20. Figure 27, Figure 28 and Figure 29 summarise the Urban, Rural and CBD historical performance and forecast compared to targets.

Figure 27 – STPIS Urban SAIDI / SAIFI Forecast Historical, Actuals and Forecast



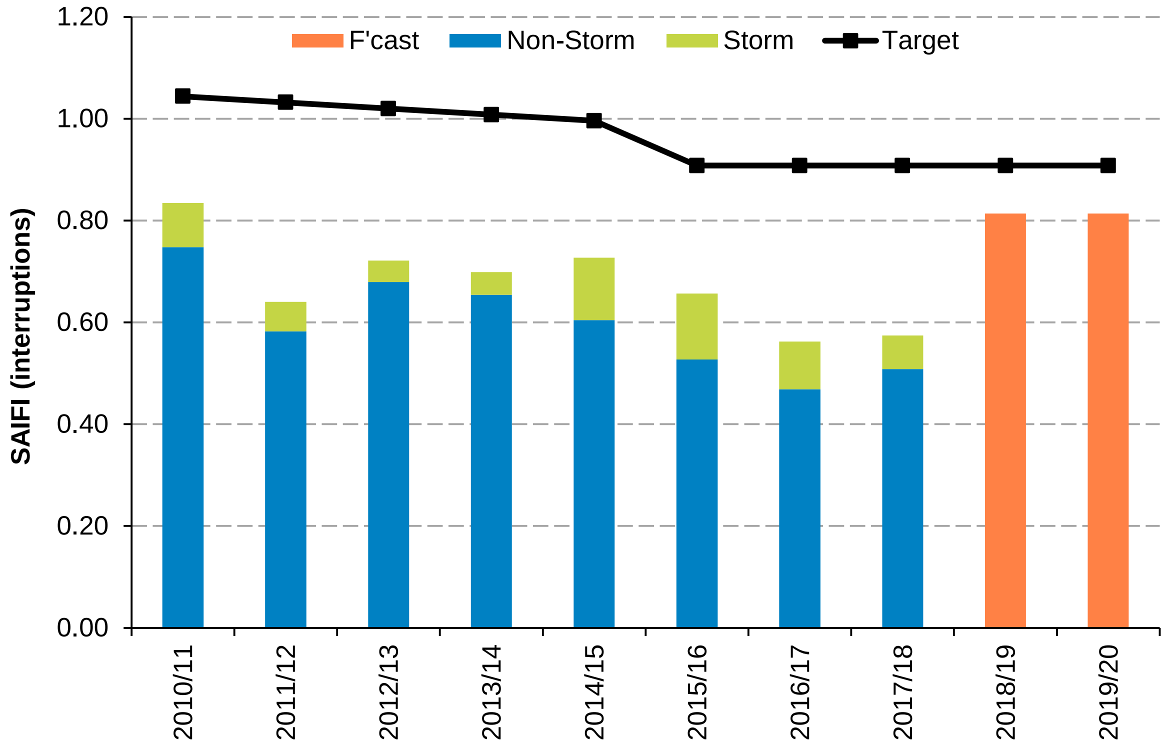
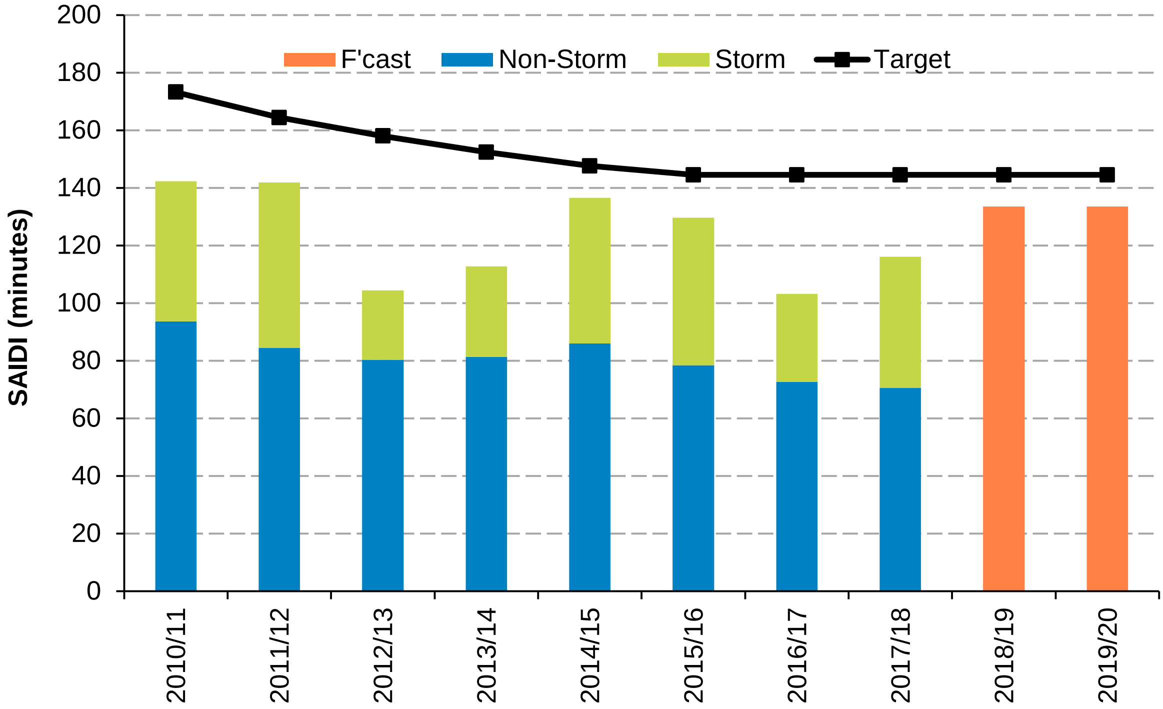


Figure 28 – STPIS Rural SAIDI / SAIFI Forecast



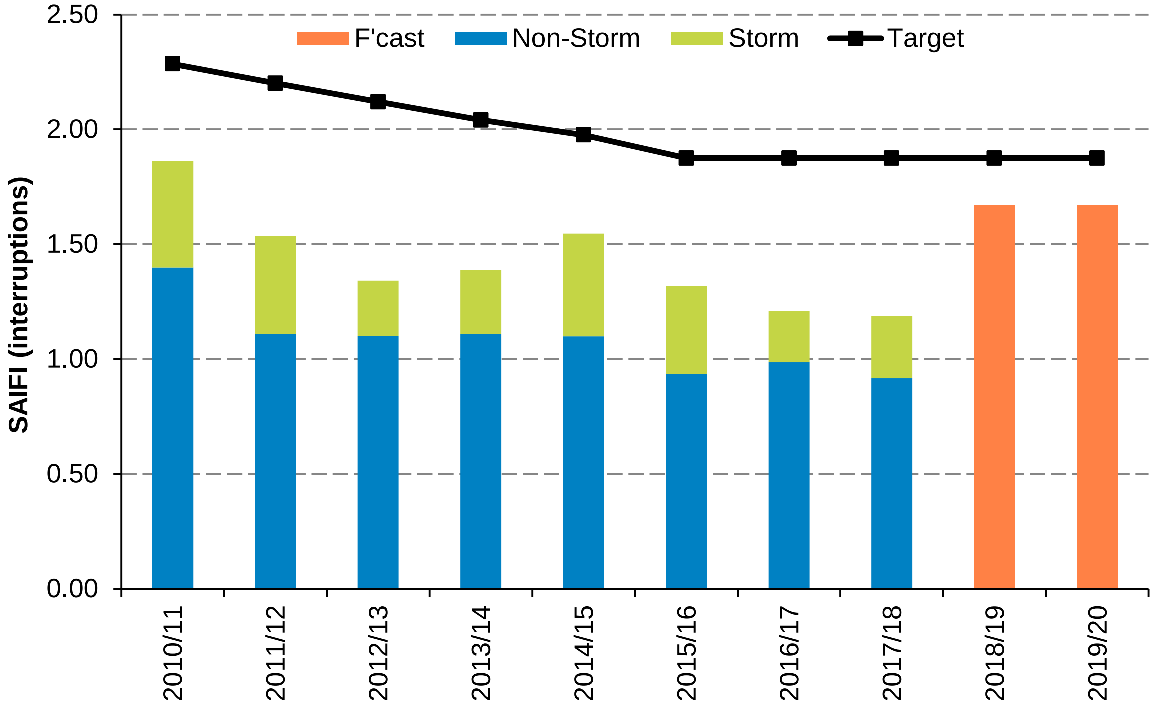
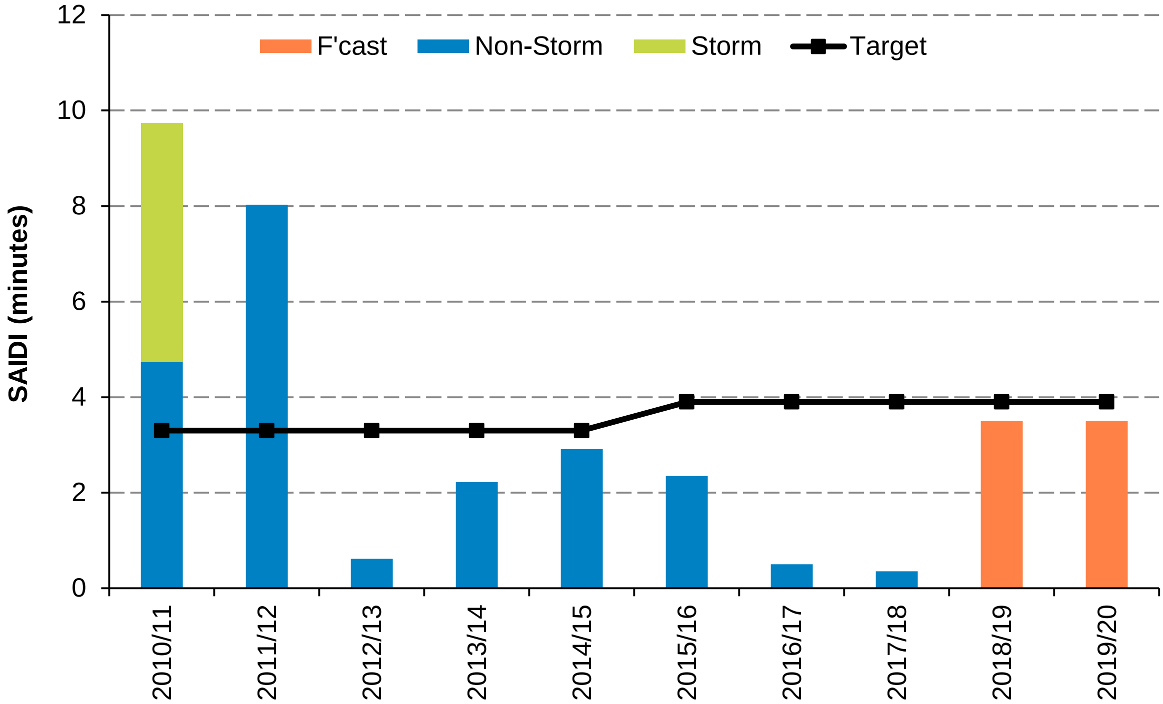
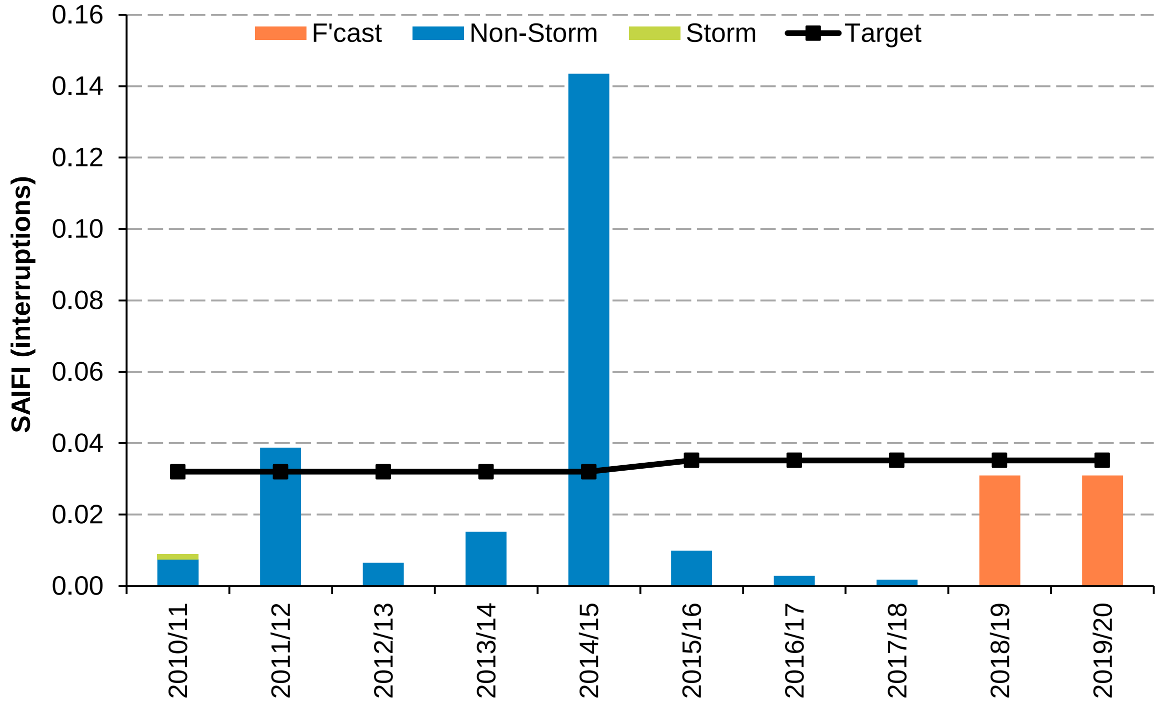


Figure 29 – STPIS CBD SAIDI / SAIFI Forecast





10.3 High Impact Weather Events

Section 2.3.1 outlines the physical environment within which Energex operates its network and provides an overview of the weather conditions faced. As a consequence, Energex plans for the occurrence of extreme weather events and has developed the following Plans:

- Summer Preparedness Plan;
- Flood Risk Management Plan; and
- Bushfire Risk Management Plan.

The current version of the Summer Preparedness Plan, Flood Risk Management Plan and Bushfire Risk Management Plan are available at 'The company policies and reports' page and 'Network Plans' section on Energex's website (www.energex.com.au/about-us/company-information/company-policies-And-reports).

In February 2018, Brisbane was impacted by a significant storm and heatwave which affected 196,039 customers over a 4 day period. The effects of the storm were significant and reached across multiple operational areas. Approximately 860 staff from Energex and Ergon Energy responded to safely restore customers affected.

Several other smaller but severe storms impacted the Energex distribution network and subsequently required an increased level of response from field and support groups.

Energex regularly conducts detailed reviews of all escalated response events to ensure it confirms the effectiveness of processes and identifies opportunities to improve the safe and timely restoration for the community.

10.3.1 Summer Preparedness

Energex conduct annual preparations prior to each summer storm season to provide Queensland with a reliable network to minimise interruptions during extreme weather conditions. Where disruptions occur, we plan to keep the community fully informed and respond as quickly as possible to restore supply safely. Preparations include the review of response programs and processes, resourcing and ongoing network related capital and operating works prior to summer to achieve a secure and reliable network.

10.3.2 Bushfire Management

Energex 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. Energex 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. Energex 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.

10.3.3 Flood Resilience

Following the 2010/11 floods which impacted the regions of Brisbane, Ipswich, Gympie and the Lockyer Valley Energex updated its planning guidelines for installing infrastructure in flood prone and areas and reviewed flood resilience measures. Flood resilient electrical infrastructure is important, not least because other essential services needed during and after a flood depend on electricity to operate. A number of flood resilience projects at CBD substations and several zone and bulk substations have been completed and operational plans incorporating the dispatch of generators and flood isolation switching have been reviewed and updated for the Brisbane, Bremer and Nerang River systems. From 2016, Energex has been developing revised operational plans based on new flood models obtained from Brisbane City Council for creeks in the council area.

10.4 Guaranteed Service Levels (GSL)

The Queensland Electricity Distribution Network Code (Code) clause 2.3 specifies a range of Guaranteed Service Levels (GSLs) that distribution entities must provide to their customers. Failure to meet these GSLs requires the payment of financial rebates to any customer whose service does not meet these GSLs. Whilst most of the GSLs are not network related, there are a number of reliability service levels as shown in Table 37. Depending on the type of feeder supplying a customer, limits are defined for acceptable outage durations and frequency of unplanned interruptions. Some specific exemptions to these requirements include planned interruptions and those unplanned interruptions which occur within a region currently affected by a natural disaster as defined in the Code.

Table 37 – Reliability GSLs

Feeder Type	Interruption Duration GSL (for each incident)	Interruption Frequency GSL (Number per financial year)
CBD	> 8 hours	10
Urban	> 18 hours	10
Short Rural	> 18 hours	16

10.4.1 Automated GSL Payment

Since 1 July 2010, the Code requires that a distributor use its best endeavours to automatically remit a GSL payment to an eligible small customer. Customers will receive the payment for Interruption Duration GSLs within one month, whereas Interruption Frequency GSL payments will be paid to the currently known customer once the requisite number of interruptions has occurred.

Table 38 shows the number of claims paid in 2017/18.

Table 38 – Reliability GSLs Claims Paid 2017/18

GSL Description	Paid Claims
Reliability – Duration	41,910
Reliability – Frequency	0
Total Reliability GSLs	41,910

10.5 Worst Performing Feeders

The Minimum Service Standards represent a measure of the average performance of the network. However, this means that there are groups of customers receiving performance which is worse than the average. Some of these customers may be eligible for GSL payments if the network performance they are experiencing is greater than the duration and frequency thresholds outlined in the previous section.

In accordance with Energex's Distribution Authority, Energex is required to monitor, improve and annually report on the Worst Performing Feeders (WPF) performance.

Energex's previous 2017/18 Distribution Annual Planning Report defined 142 11 kV feeders as its WPF, of which 54 were Urban and 88 were Rural.

Table 39 and **Error! Reference source not found.** compares the performance of this pool of feeders as reported last year with their current SAIDI and SAIFI performance. The performance of the feeders is measured by the normalised three year average feeder SAIDI and SAIFI and includes both planned and unplanned interruptions.

Table 39 – Worst Performing Feeder SAIDI Performance Comparison

	2016/17 3 Year Average Feeder SAIDI (mins)			2017/18 3 Year Average Feeder SAIDI (mins)		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Urban	64	329	1,002	41	294	1,046
Rural	84	438	1,047	146	475	1,281

Table 40 – Worst Performing Feeder SAIFI Performance Comparison

	2016/17 3 Year Average Feeder SAIFI (interruptions)			2017/18 3 Year Average Feeder SAIFI (interruptions)		
	Minimum	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Urban	1.0	2.4	4.0	0.39	1.94	5.80
Rural	2.2	4.3	6.8	1.32	3.50	7.35

Table 39 shows that the three year average performance of the Urban WPF SAIDI has improved by 10.6% and the average performance of the Rural WPF SAIDI has degraded by 8.4%. **Error! Reference source not found.** shows that the three year average performance of the Urban WPF SAIFI has improved by 19.2% and the average performance of the Rural WPF SAIFI has improved by 18.6%.

Figure 30 and Figure 31 compares the number of outages by cause on the urban and rural worst performing feeders for the current year and the previous year. The comparisons are based on the normalised performance excluding major event days. Overall, the number of outages on urban worst performing feeders has improved for the majority of causes except for Overhead Equipment and where no causes were found. On the Rural network there was a slight increase in outages for Overhead Equipment, No Cause, Planned and Wildlife with the other causes relatively constant.

Figure 30 – Normalised Count and Causes of Urban Outages

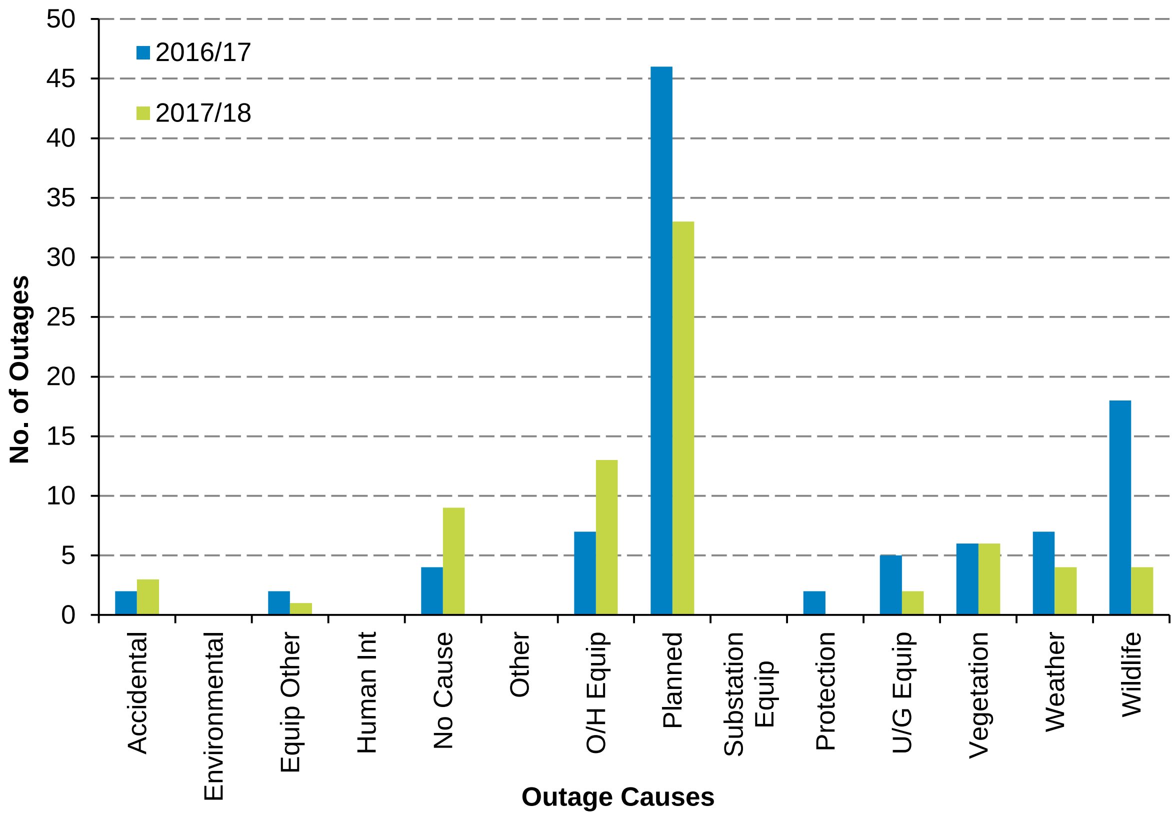
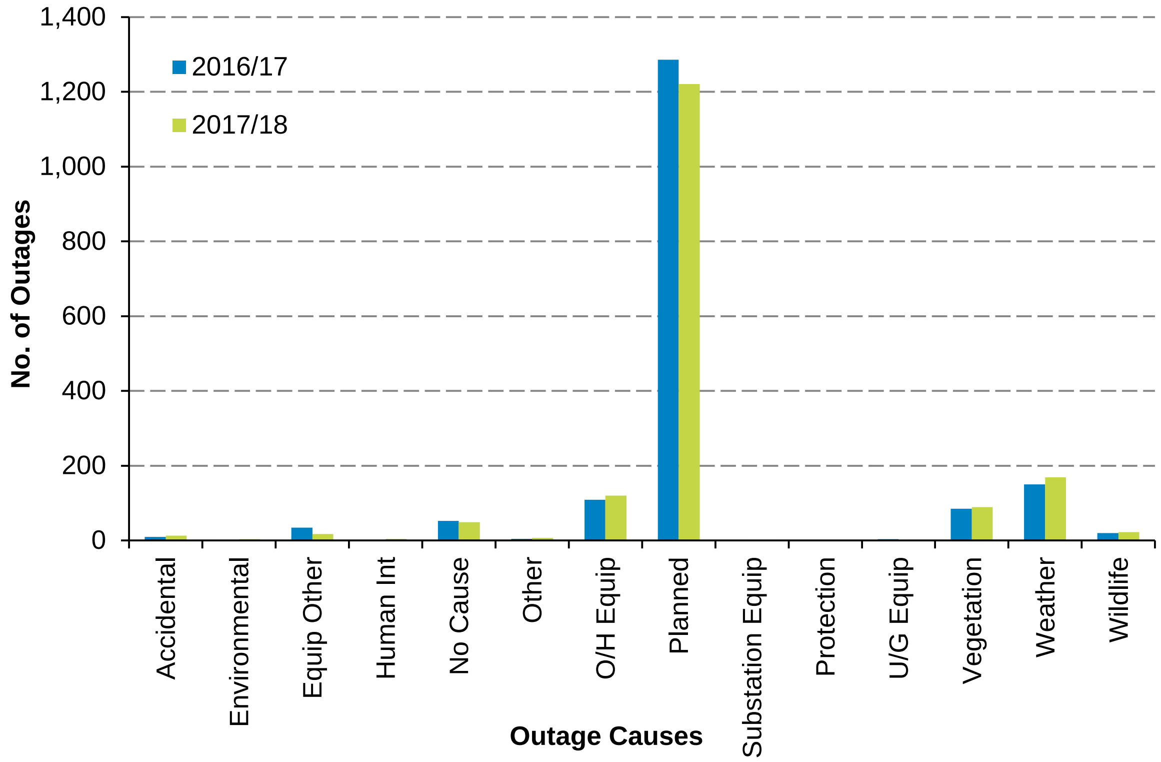


Figure 31– Normalised Count and Causes of Rural Outages



Details of the 2017/18 Worst Performing Feeder is available is available in Appendix G.

Under Energex's Distribution Authority, the method of classifying WPF is shown in Table 41 and includes a cap on the total number of feeders in the program and through the inclusion of SAIFI in addition to SAIDI measures, will give increased weighting to feeders with a high number of customer interruptions than if SAIFI were not included.

This section provides information on the worst performing feeders for the urban and rural categories for 2018/19 which have been identified based on 3 years average SAIDI/SAIFI up to financial year 2017-18.

Table 41 – Worst Performing Feeder Performance Criteria

WPF Criteria
The worst performing 11 kV feeder program will apply to any 11 kV feeder which meets the following criteria: I. The 11 kV feeder performance based on: a. 3 year average feeder SAIDI in worst 10%; AND b. 3 year average feeder SAIDI ≥ 150% of the MSS SAIDI Limit for the applicable feeder category; OR II. The 11 kV feeder performance based on: a. 3 year average feeder SAIFI in worst 10%; AND b. 3 year average feeder SAIFI ≥ 150% of the MSS SAIFI Limit for the applicable feeder category;

Based on the criteria, Energex has determined the feeders which will be classified as worst performing for the coming financial year and their current 2017/18 performance shown in Table 42. This includes 140 feeders of which 59 are Urban and 81 are Rural.

As outlined in Table 41 above, these feeders can be defined as worst performing due to either SAIDI or SAIFI performance. Therefore, the details presented in Appendix G have been split to show "SAIDI" worst performing feeders and "SAIFI" worst performing feeders. However, there are 32 feeders which appear in both lists.

Table 42 – 2017/18 Worst Performing Feeder List – Current Performance (2017/18)

	3 Year Average Feeder SAIDI (mins)			3 Year Average Feeder SAIFI (int.)		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Urban	137	399	1,046	1.96	2.56	4.05
Rural	328	524	1,281	3.71	5.05	7.35

Note that the minimum and average SAIDI values are only for those worst performing feeders which have a SAIDI which is higher than the 150% SAIDI threshold. Similarly, the minimum and average SAIFI values are only for those feeders which have a SAIFI higher than the 150% SAIFI threshold.

Urban feeders

The urban worst performing feeder list consists of 31 feeders in the "SAIDI" list, and 33 feeders in the "SAIFI" list. However, 5 of these feeders appear in both lists, resulting in 59 unique worst performing urban feeders.

Interruptions on the low voltage network contributed an average of 8.6% to the performance of the worst performing urban SAIDI feeders. The contribution from interruptions on the sub-transmission network to the worst performing feeders is lower for the worst performing SAIDI feeders, with an overall average SAIDI contribution of 4.5%. However, this increases to 17.5% for the worst performing SAIFI feeders. The two highest contributors to the number of outages over the last three years were planned interruptions and Asset failures which in total made up 35% of all high voltage interruptions on the worst performing SAIDI feeders.

Six urban feeders identified on the SAIDI list have significantly improved their performance over the last two years, and have achieved a greater than 40% reduction when compared to the three year reported history. These feeders are unlikely to remain as worst performing feeders next year.

Rural feeders

The rural worst performing feeder list consists of 77 feeders in the “SAIDI” list, and 31 feeders in the “SAIFI” list. However, 27 of these feeders appear in both lists, resulting in 81 unique worst performing rural feeders.

Interruptions on the low voltage network contributed an average of 5.1% to the performance of the worst performing rural SAIDI feeders. The contribution from interruptions on the sub-transmission network to the worst performing feeders is higher against the worst performing SAIDI feeders, with an overall average SAIDI contribution of 6.2%. This however decreases to 3.5% for the worst performing SAIFI feeders. The highest contributor to the number of outages over the last three years was planned interruptions, which made up 70.5% of all high voltage interruptions.

A full report on Energex’s 2018/19 Worst Performing 11 kV Feeders is available in Appendix G.

Energex 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 that meet the definition in the DA.

The reliability improvement solutions identified from the worst performing feeder reviews conducted in in this regulatory period have mainly included moderate capital investment options. These mainly included installation of new Automatic Circuit Reclosers, Sectionalisers, Remote Controlled Gas Switches and also relocation and/or replacement of switching devices. Some of the higher capital investment options have included re-conductoring, covered conductors and overhead tie points. Energex 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:
    - investigating to determine predominant outage cause;
    - implementing reliability or operational improvements identified through the investigation of any unforeseen major incidents;
    - improving fault-finding procedures with improved staff-resource availability, training and line access;
    - improving availability of information to field staff to assist fault-finding, which could include communications, data management and availability of accurate maps and equipment;
    - planning for known contingency risks until permanent solutions are available; and
    - improving and optimising management of planned works.

2. Prioritisation of preventive-corrective maintenance by:

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

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

10.6 Safety Net Target Performance

Energex's Distribution Authority DO7/98 (DA) details customer safety net performance reporting obligations for the purposes of reviewing network investment criteria.

A detailed review of network events over the 2017/18 period was undertaken. The review investigated breaches of the customer safety net targets outlined in the Distribution Authority and described in Appendix C.

Four events were shortlisted for detailed investigations. Investigations into each of these events revealed that all involved non-credible events for the purposes of planning and investment. Therefore there are no network events in the 2017/18 period where the customer safety net targets were breached.

Chapter 11

Power Quality

- Customer Experience
- Power Quality Supply Standards, Codes Standards and Guidelines
- Power Quality Performance in 2017/18
- Quality of Supply Processes
- Strategic Objectives 2015-20
- Solar PV Systems
- Queensland Electricity Regulation Change
- Power Quality Ongoing Challenges and Corrective Actions
- Planned Actions for the 2020-25 Regulatory Period
- 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 Energex to investigate perceived issues with the quality of the supply. PQ is the compliance of measured system wide network conditions with defined parameter limits.

11.1 Customer Experience

Energex traditionally tracks the customer experience by the number of power quality enquiries it receives. QoS enquiries occur when a customer contacts Energex with a concern that their supply may not be meeting the standards. Figure 32 shows that the overall number of enquiries on a normalised basis per 10,000 customers per month varies significantly from month to month and displays some seasonality, being higher over the summer periods. However the overall long-term trend measured over the last 3 years is relatively stable.

Figure 33 shows a breakdown of the enquiries received by the reported symptoms over the last 12 months, with the largest identifiable category, at 43%, related to solar PV issues. These are usually 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.

Figure 34 shows the number of Quality of Supply received from 2013 – 2018. The supply queries can mainly be categorised into low voltage, voltage swell, voltage spike, solar PV related and other queries. Based on the last five years, Solar PV related queries have continuously dominated (approximately above 50%) the QoS queries and this clearly indicates growing number of PV system connected on the distribution network.

Figure 32 – Power Quality Voltage Enquiries

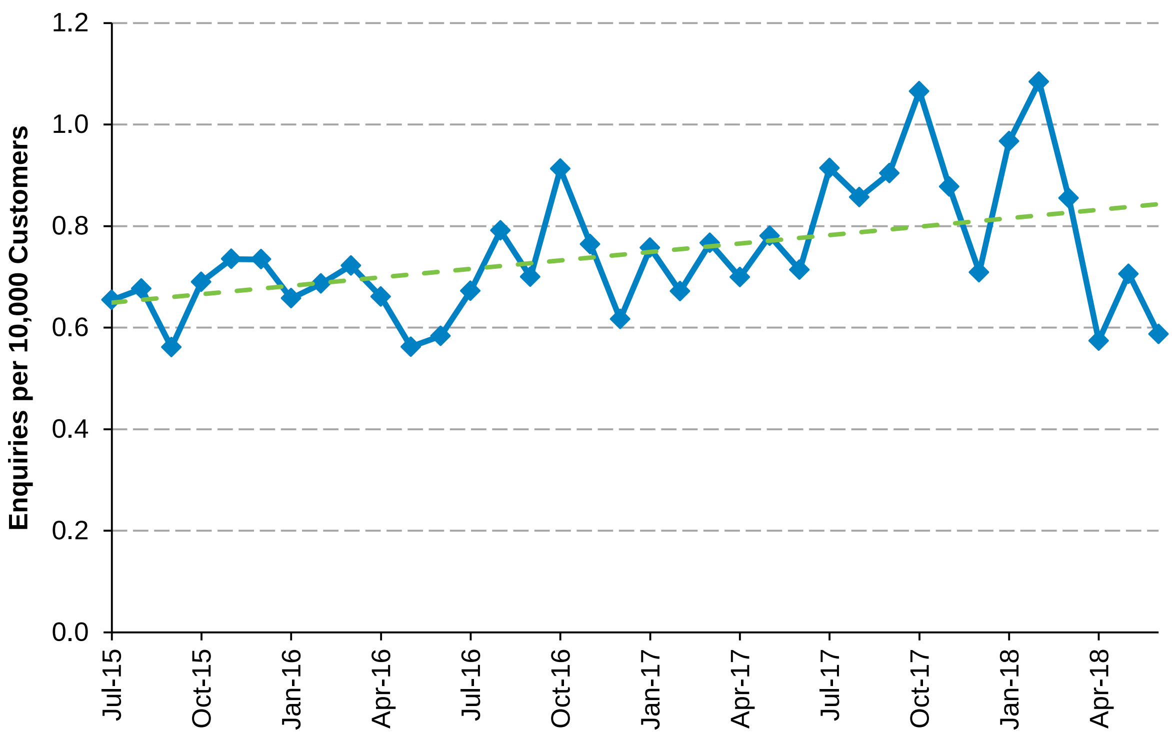


Figure 33 – Power Quality Voltage Categories

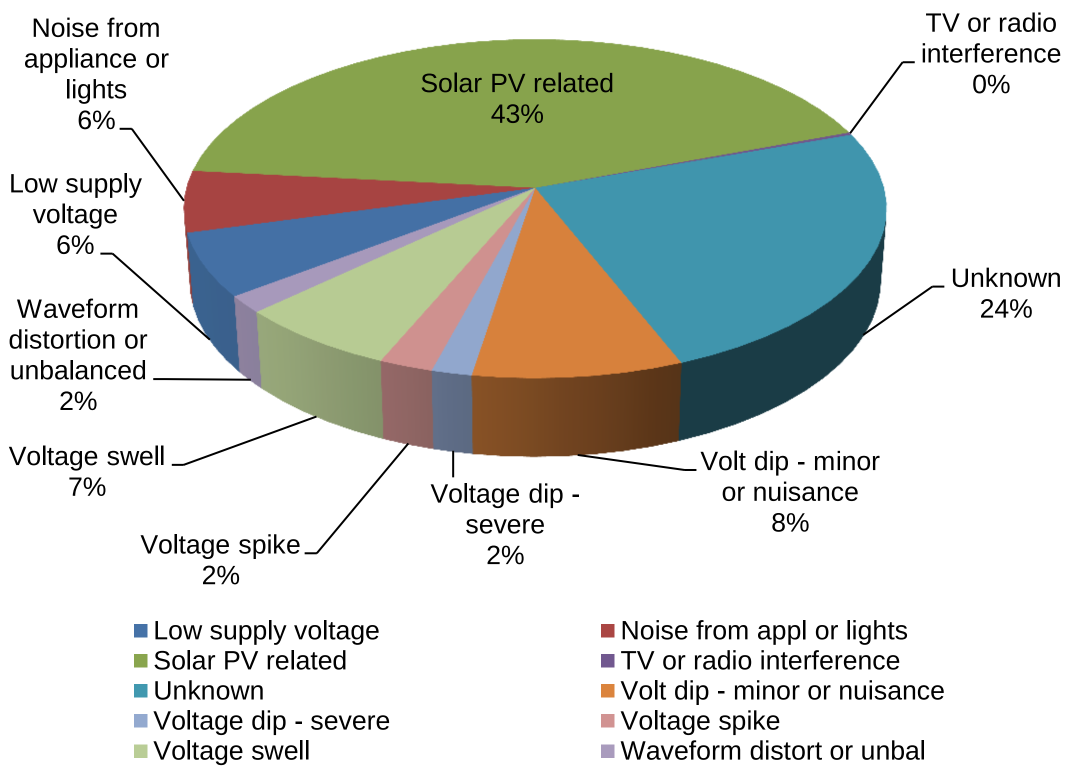


Figure 34 – Quality of Supply Enquiries per Year

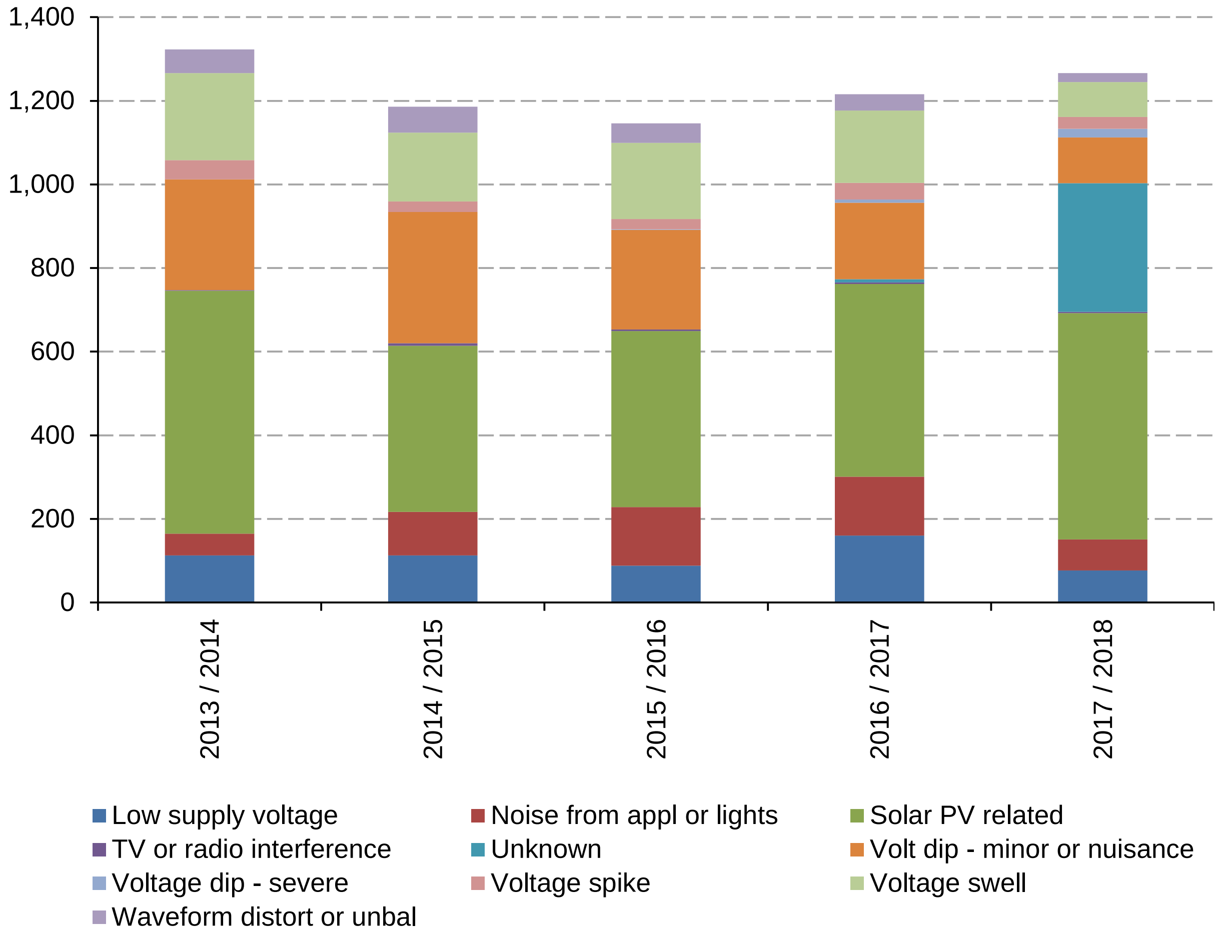
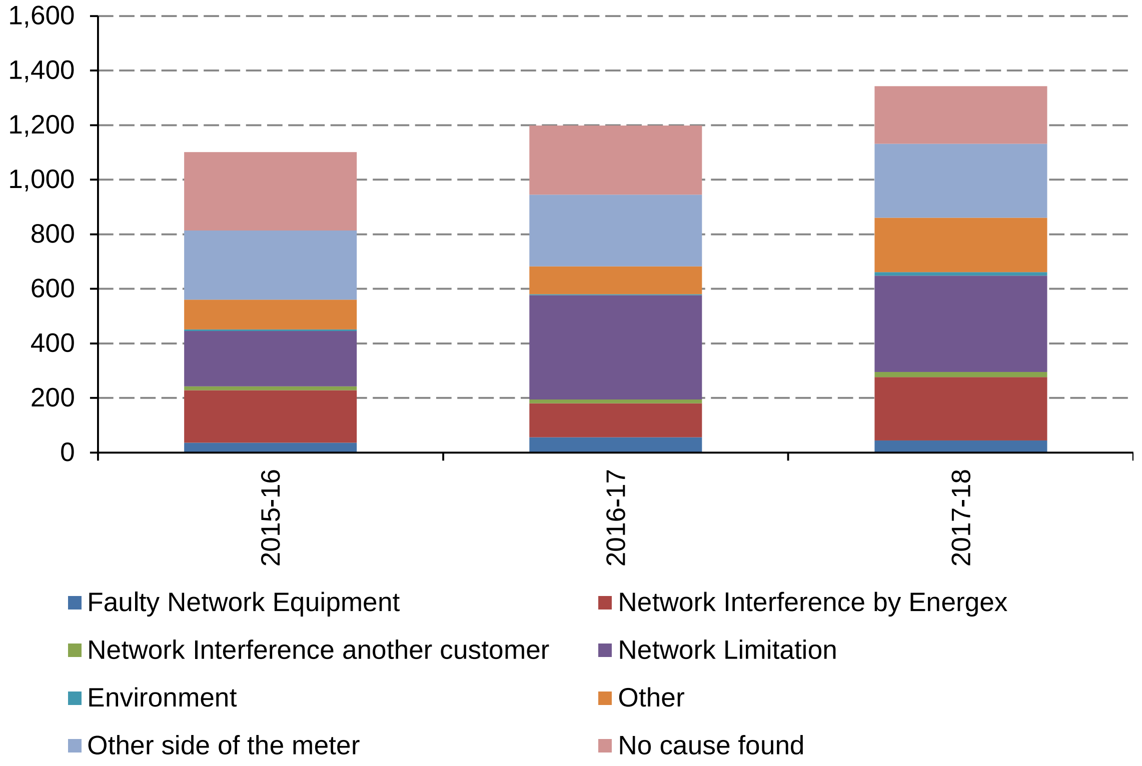


Figure 35 shows means of resolving the Quality of Supply queries from 2015- 2018. The plot shows that network limitations plays important role in close out of supply queries. Due to network limitations, QoS queries may not always have complete resolution. Network and customer safety however is always ensured.

Figure 35 – Quality of Supply Enquiries by Type at Close Out



11.2 Power Quality Supply Standards, Codes Standards and Guidelines

The Queensland Electricity Regulations and Schedule 5.1 of the NER lists a range of network performance requirements to be achieved by Network Service Providers (NSPs). Accordingly, Energex's planning policy takes these performance requirements into consideration when considering network developments. The tighter of the limits is applied where there is any overlap between the Regulations and the NER. Although the existing voltage standard in Queensland is 240 V, both Energex and Ergon Energy support a proposal to have the Electricity Regulations changed to 230 V to harmonise with the Australian Standard AS 61000-3-100. The Queensland Government Department of Energy and Water Supply (DEWS) have released a Regulatory Impact Statement on the proposal for public consultation. Further discussion on the proposal is outlined in Chapter 12 of the DAPR.

Some of the requirements under the Regulations / Rules are listed below and further defined in Table 43, Table 44, Table 45 and Table 46.

- **Magnitude of Power Frequency Voltage**: During credible contingency events, supply voltages should not rise above the time dependent limits defined in Figure S5.1a.1 of the Rules. (For normal steady state conditions, a requirement of ±6% for low voltage and ±5% for high voltage of 22 kV or less is specified in the Electricity Regulations S13.);
- **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 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; and
- **Voltage Unbalance**: A NSP has a responsibility to ensure that the average voltage unbalance measured at a connection point should not vary by more than the amount set out in Table S5.1a.1 of the NER Rules.

Table 43 – Allowable Variations from the Relevant Standard Nominal Voltages

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1 kV)	±6%[1]	±10%
Medium voltage (1 kV to 22 kV)	±5%[1]	±10%
High voltage (22 kV to 132 kV)	As Agreed	±10%

[1] Limit is only applicable at customer's terminals.

Table 44 – Allowable Planning Voltage Fluctuation (Flicker) Limits

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

Table 45 – Allowable Planning Voltage Total Harmonic Distortion Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1 kV)	Not Specified	7.3%
Medium voltage (11 kV)	Not Specified	6.6%
Medium voltage (33 kV)	Not Specified	4.4%
High voltage (110 kV, 132 kV)	Not Specified	3%

Table 46 – Allowable Voltage Unbalance Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1 kV)	Not Specified	2.5%
Medium voltage (1 kV to 33 kV)	Not Specified	2%
High voltage (33 kV to 132 kV)	Not Specified	1%

Where there is need to clarify requirements; the relevant Australian and International Electro technical Commission (IEC) Standards are used to confirm compliance of our network for PQ. EQL also has the Standard for Network Performance, which provides key reference values for the PQ parameters.

The Power Quality Planning Guideline and the Stand for Transmission and Distribution and Planning is a joint working document with Ergon Energy 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

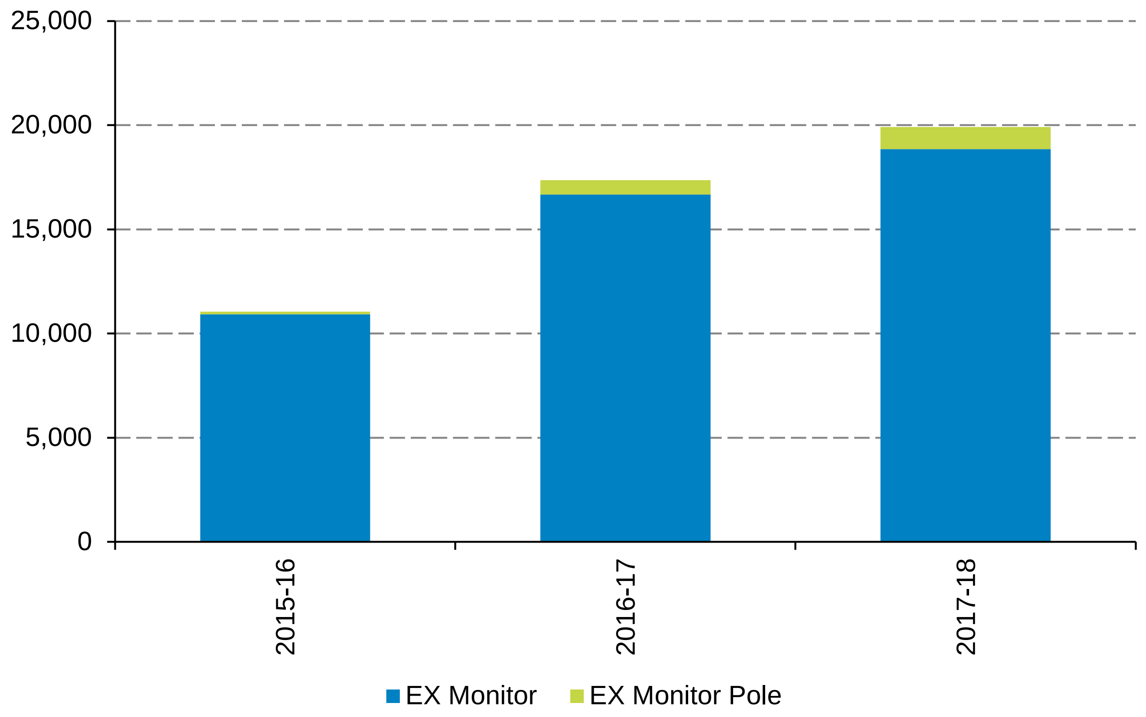
11.3.1 Power Quality Performance Monitoring

Processes for power quality monitoring have been developed from the requirements of the Queensland Electricity Regulation and the Rules. Processes for power quality monitoring have been developed from the requirements of the Queensland Electricity Regulations and the NER Rules.

The introduction of a distribution transformer monitoring program in 2011/12 has provided a substantial source of data for analysis. Energex currently has in excess of 22,000 PQ monitors on distribution transformers throughout the network that monitor and record the network PQ performance. This program involves the installation of remotely monitored electronic metering on distribution transformers installed throughout Energex's network and is providing an insight into power quality performance at the junction between the 11 kV and LV network.

Data collected at these monitored sites is analysed annually to generate the figures shown on the following pages. It is acknowledged that voltage is likely to be different at the end of the LV circuit compared to at the distribution transformer for both peak load and light load conditions (or times of peak solar PV generation in high penetration areas). To address this limitation, Energex introduced a new program in 2016/17, consistent with its power quality strategic plan, to install three phase voltage only monitors at the end of LV circuits in areas assessed to have a higher risk of high voltage (e.g. high solar PV penetration areas with long lengths of overhead circuit). Energex also completed a pilot project to install power quality monitoring in up to 2,500 domestic customer premises in a relatively localised area of the network. The expanded monitoring will enable Energex to further understand and quantify the power quality performance being delivered to customers and the impacts of solar PV. The breakdown of the types of monitors and the meters being read is shown in Figure 36. EX Monitor Pole represent the monitors at the end of long LV runs. Voltage data presented in this report is based on the 230 volts (+10/-6%) limits.

Figure 36 – Types of Power Quality Monitors and Meters



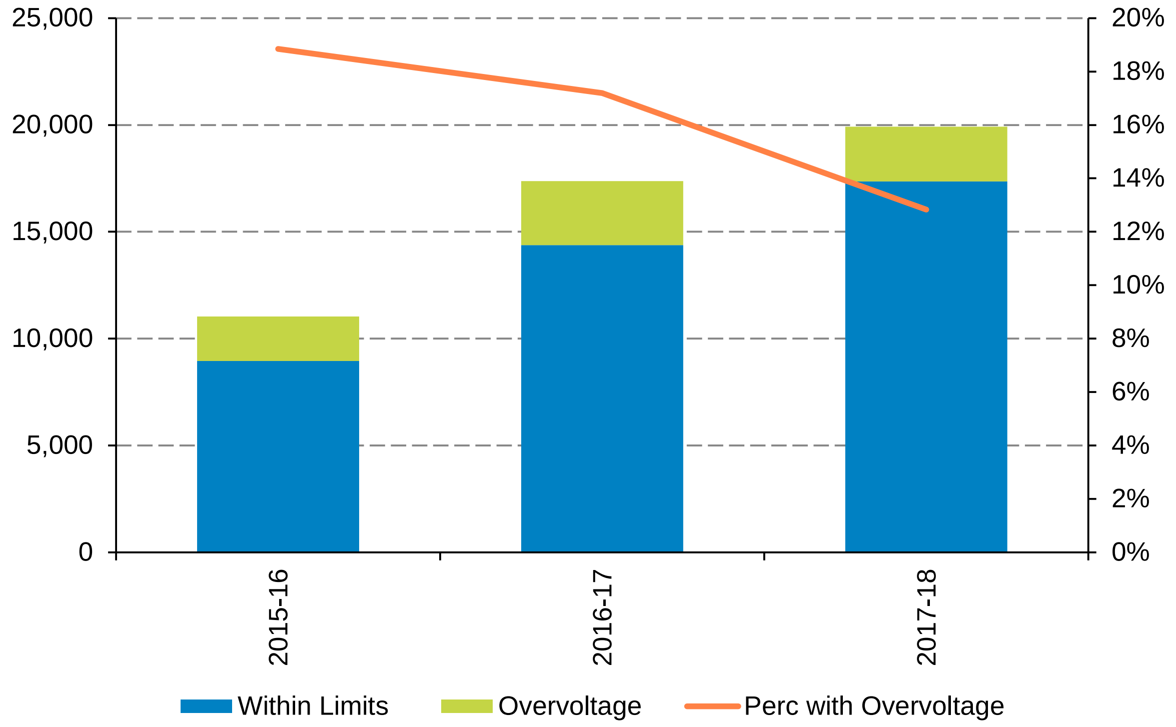
11.3.2 Steady State Voltage Regulation - Overvoltage

The number of monitored sites that reported overvoltage outside of regulatory limits of 254.4 V was 12.83% for 2017-18. This means 12.85% of monitored 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 17.19% sites of sites with overvoltage. Figure 37 shows the number of monitored sites that have recorded over-voltage conditions for the last 3 years and percentage of overvoltage sites for each year. This is the third consecutive year that improvement has occurred to reduce the number of sites with overvoltage issues.

Further analysis of monitored transformers is continuing as more sites are fitted with monitoring. The take-up of solar PV is substantially greater in South East Queensland than in Southern states and as a result the requirement to monitor power quality is commensurately greater.

Most PQ monitor sites are at the terminals of the distribution transformers however Energex also have a number of monitors at the end of long LV runs. These monitors are referred to as the EX Monitor Pole sites in Figure 36. 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.

Figure 37 – Overvoltage Sites

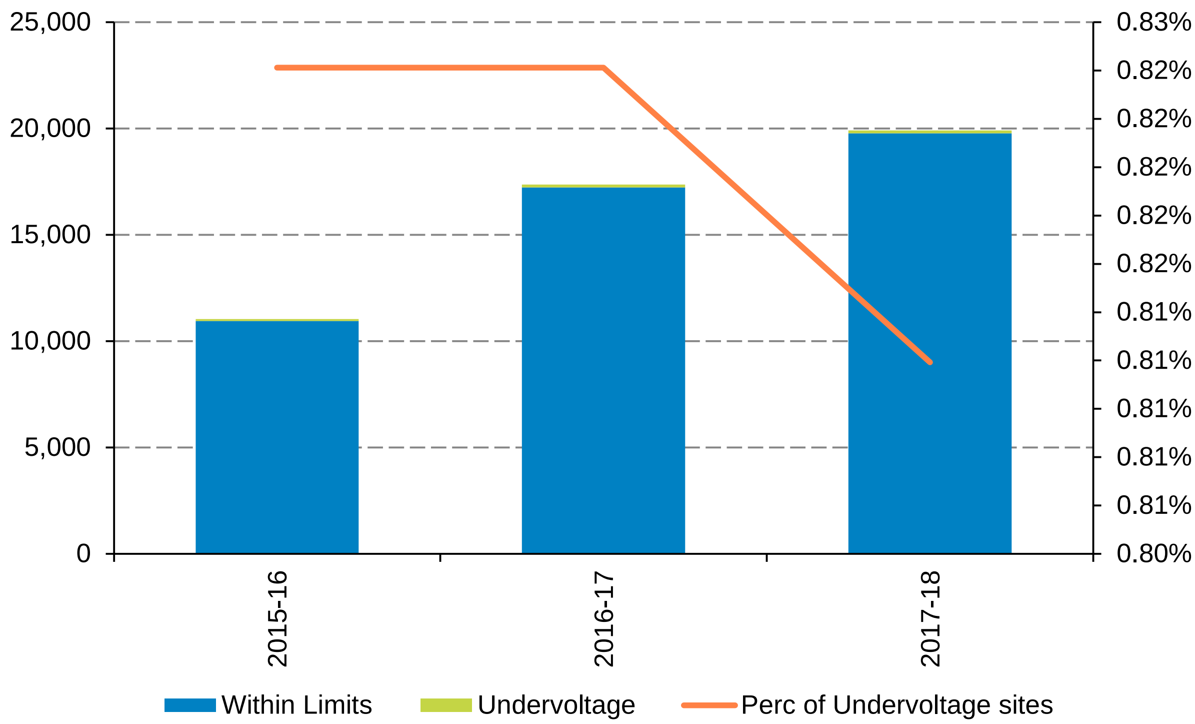


11.3.3 Steady State Voltage Regulation – Under Voltage

The number of monitored sites that recorded under voltage outside of regulatory limits of 216.2 V was 0.81% for 2017-18. This means 0.81% of monitored sites recorded an exceedance of the lower limit for more than 1% of the time based on 10 minute averages. Figure 38 shows the number of monitored sites that have recorded under-voltage conditions for the last 3 years. There has been a small improvement from the 16-17 year when there were 0.82% of sites with under-voltage.

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

Figure 38 – Under Voltage Sites



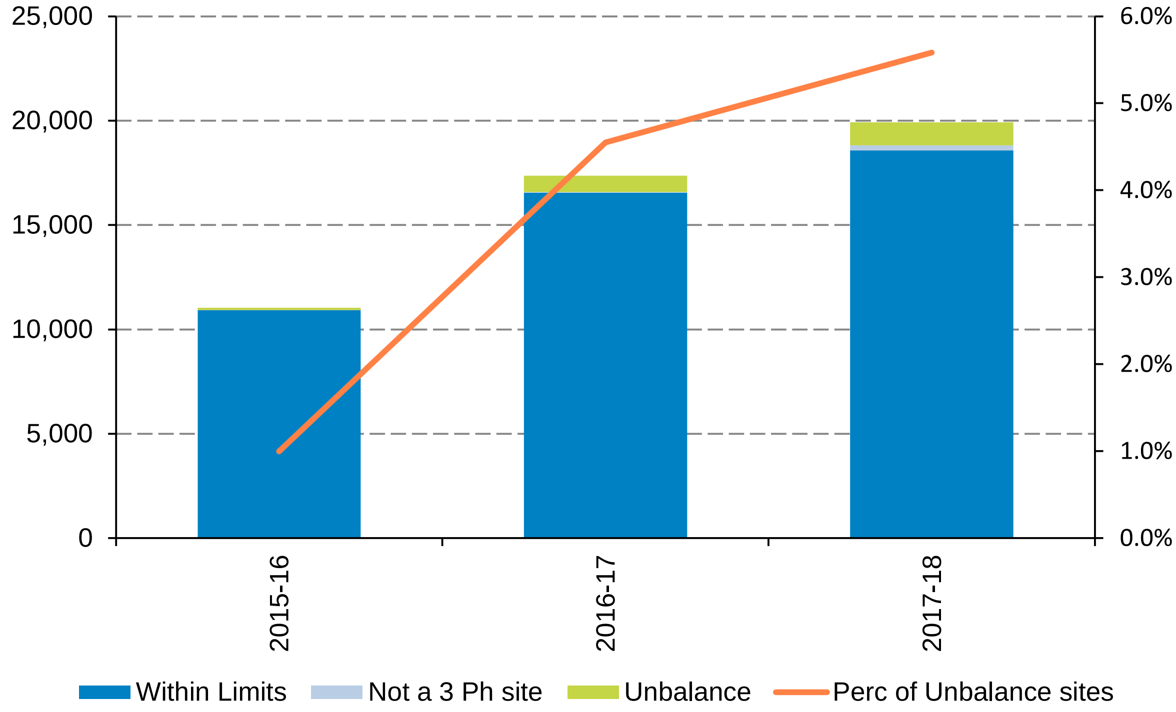
11.3.4 Voltage Unbalance

Data from the 3-phases sites shows that 5.58% of these sites were outside of the required unbalance standard of 2.5% during 2017-18.

Typically unbalance is seen on the rural feeders where there are single phase transformer customers in the associated downstream feeder, which impacts on the overall balance of the 3-phase feeder. Unbalance can also occur on monitored sites where there is a high percentage of solar systems as during the daylight periods there is unbalance as the solar systems are not balanced across the LV network.

Figure 39 shows the number of sites that have recorded unbalanced conditions.

Figure 39 – Voltage Unbalance Sites

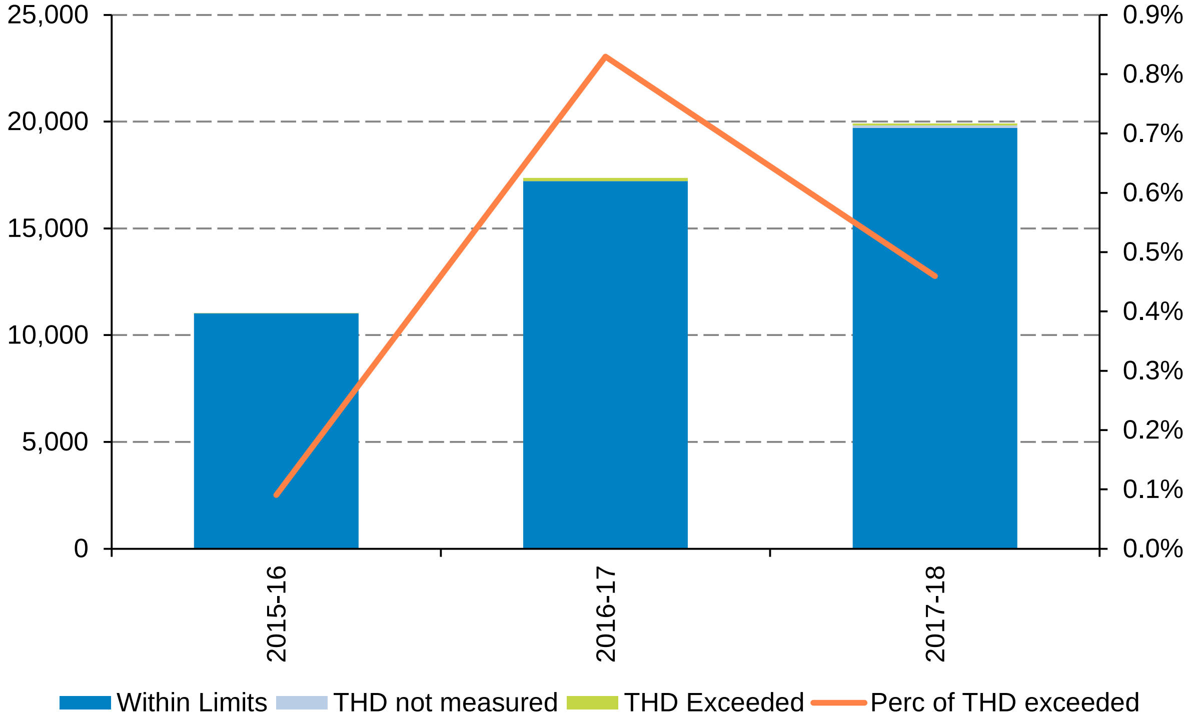


11.3.5 Harmonic Distortion

Total harmonic distortion (THD) is a measure of the impurity of the supply voltage and in an ideal scenario would be negligible. Data from monitored distribution transformers was analysed for THD and this is displayed in Figure 40 over the last 12 months ending 30 June 2018. The graph shows that 0.46% of monitored sites had THD that exceed the 8% threshold stipulated in Australian Standard AS 61000.3.6:2001. This is a decrease from the 2016-17 figure of 0.83%. Of the monitored sites, 0.6% could not record THD.

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.

Figure 40 – Total Harmonic Distortion Sites



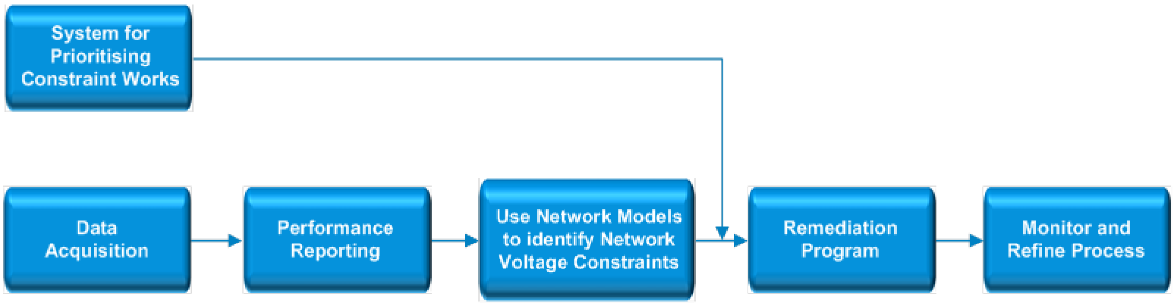
11.4 Quality of Supply Processes

Energex responds to customer voltage enquiries / complaints by carrying out a voltage investigation which may include the installation of temporary voltage monitoring equipment on the network and at customers' premises and this data is used in conjunction with existing network monitors to analyse and determine what remediation is necessary.

Due to the complexity of the network and the large number of sites involved, the management of voltage presents many challenges. To address these challenges, a proactive and systematic approach shown in Figure 41 is being 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; and
- Measuring results to refine the network model and remediation options.

Figure 41 – Systematic Approach to Voltage Management



Energex has developed a series of reports from the Distribution Monitoring Analytics (DMA) platform to identify and prioritise power quality issues. The DMA platform also enables the large volume of power quality time series data captured from the monitoring devices to be more easily analysed with possible drivers such as solar PV penetration and network topology (e.g. length of LV circuit from transformer to customer).

11.5 Strategic Objectives 2015-20

During 2017-18 Energex voltage management strategy focussed on the impacts on low voltage customers. In 2018, Energy Queensland finalised the Customer Quality of Supply Strategy which covers the LV areas of the Power Quality strategy for Energex and Ergon Energy. 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 electric vehicles.

During 2017-18 Energex continued the implementation of the current PQ strategy by installing 1500Q Onitros on distribution transformers. This will bring the total installed monitors to approximately 22,000 which represents approximately 44% of the distribution transformers in South East Queensland.

The PQ monitors throughout the network are now accessed and PQ data downloaded monthly in the DMA system. 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.

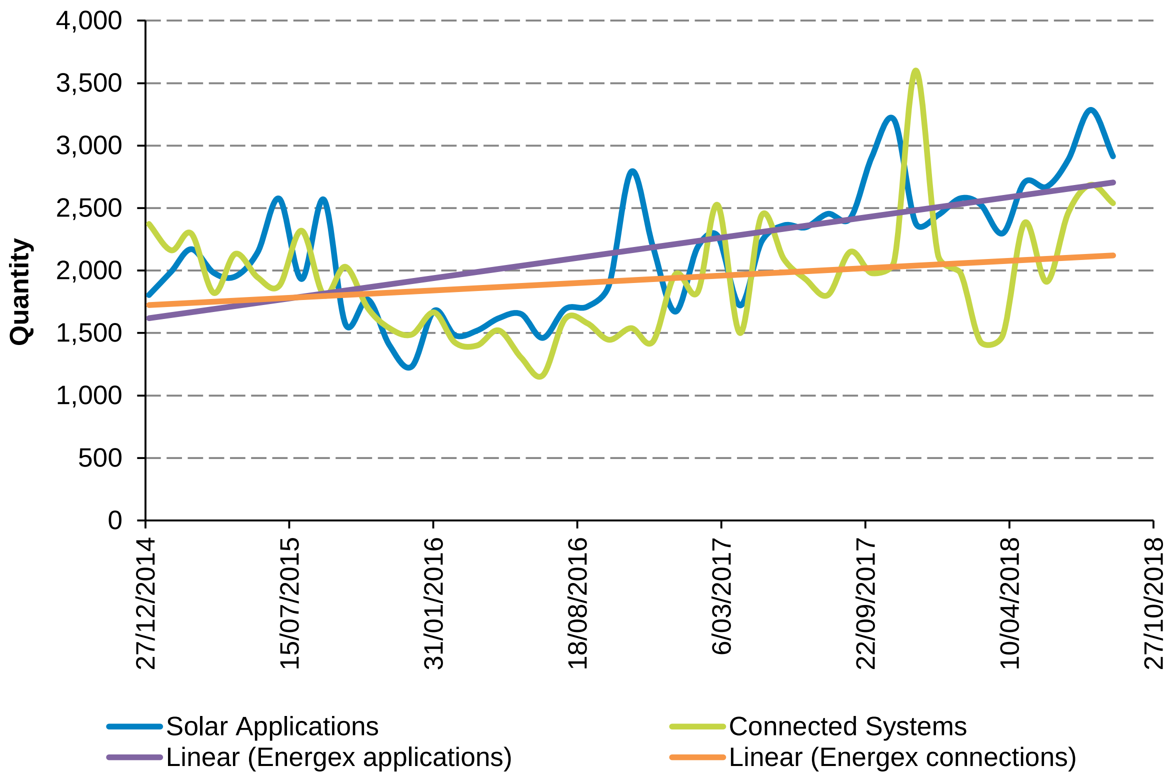
Energex is committed to install approximately 1500 additional PQ monitors in 2018-19 to provide further coverage of feeders throughout the network to ensure a comprehensive report on PQ parameters is available for all feeders.

11.6 Solar PV Systems

Energex'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 Quality of Supply enquires showed a steady decrease however in the 2016-18 the number of enquires increased again. Referring to Figure 42 it shows that the number of solar applications and connections has continued to increase each year for the past 5 years considering the Feed in Tariff (FiT) reduced in 2013 from 44 cents to currently around 8 cents. The continued increase of solar PV 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 the high percentage of LV customers with solar systems will require continual work in balancing customers connections on the LV network to minimise neutral current and negative load in the MV network.

All solar farms larger than 1.5 M W are now 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 on going compliance when operating.

Figure 42 – Solar PV Applications and Connections



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%. The change requires initial compliance with the new statutory voltage limits of 216-253 V as per AS60038 to be achieved by October 2018 with full compliance to AS61000.3.100 by October 2020. The change has seen a number of bus voltages at Zone Substations adjusted to meet the requirements. At the same time feeder model reviews are occurring to determine the required changes to regulator settings and transformer tap changers. The current modelling and measurements, indicate that the number of futures changes required will require some network augmentation and some transformer upgrades along with conductor upgrades and changes.

11.8 Power Quality Ongoing Challenges and Corrective Actions

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 PQ strategy for 2020-25 has identified the need for further monitoring of the LV network. The strategy identified the need for all transformers larger than 200 kVA supplying a large number of residence customers with the total solar ratio greater than 50% to have a monitor installed. It has also been found that where there are long LV feeders there is a need to monitor the end of the LV run.

Energex has a high percentage of distribution transformers installed with a PQ monitor and with the growth in solar PV penetration it has been identified that a further 1,500 monitors will be required to monitor transformers where solar PV penetration levels are exceeding 40% of the transformer rating and where LV circuit lengths exceed 400 meters (LV circuit lengths to the customer can add a further 400 m). Although the selection criteria used by Energex are based on simplified models, evidence suggests that the assumptions made are prudent and reasonable.

11.9 Planned Actions for the 2020-25 Regulatory Period

For the next regulatory AER 2020-25 control period, Energex 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 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).

Table 47 – Summary of Power Quality 2017/18 Initiatives

Initiative Title	2017/18 units	2018/19 Proposed units
Monitoring / Reporting & Data Analytics		
Distribution Transformer monitoring (<100 kVA) – Pole	500	500
Distribution Transformer monitoring (≥ 100 kVA) – Pole [1]	2,706	1,000
Distribution Transformer monitoring – Padmount	22	250
LV Circuit monitoring	500	250
Customer monitoring	1,000	Nil
Rectification Works		
Uprate & Reconfigure LV Network (OH)	150	100
Uprate & Reconfigure LV Network (UG)	Nil	Nil
[1] Power Quality meters are installed as part of an LV fuse installation program.		

With regard to remediation measures that address the impacts of high levels of solar PV penetration, Energex has considered the practical range of network options shown in Table 48. In general, as the solar PV penetration level rises, so does the cost of remedial work.

Table 48 – Network Solutions for Varying Levels of solar PV Penetration

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

As part of its Opex program, Energex will carry out targeted transformer tap adjustment programs and rebalancing programs to address voltage issues in areas with PV penetration exceeding 30%. 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.

11.10 Risk Assessment

Energex is managing the risks associated with high solar PV penetration and voltage rise on the LV network through the Power Quality (PQ) 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 ultimately be coupled into 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, Energex identifies and prioritise 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 230 V standards.

Chapter 12

Emerging Network Challenges and Opportunities

- Solar PV
- Strategic Response
- Electric Vehicles
- Battery Energy Storage Systems
- Land and Easement Acquisition
- Impact of Climate Change on the Network

12 Emerging Network Challenges and Opportunities

Energex faces a number of specific network challenges relating to balancing customer service and cost. These include the impact of solar PV, energy storage systems, electric vehicles and land and easement acquisition.

12.1 Solar PV

12.1.1 Solar PV Emerging Issue and Statistics

Energex has one of the highest capacities of residential rooftop solar PV per capita of any electricity network in the world. One in every three detached homes in South East Queensland now has a solar PV system installed, with over 45% of systems having an installed capacity of 3.5 kW or more.The growth rate in solar PV connection volumes has trended upwards in the last 12 months with an average of 1,900 new systems with a combined capacity of around 12 MW connected per month. Parts of the reason for the upward trend are likely to be the increasing use of solar leasing financial products (usually no or minimal upfront costs) and the increasing incidence of a solar PV system being a standard inclusion in new homes. Energex now has a total of 356,137 (at June 2018) systems connected with an installed capacity of 1,388 MW, the majority of which are installed on residential rooftops.

Figure 43 shows the increase in installed solar PV inverter capacity. This growth is leading to a large number of distribution transformers with high solar PV penetration, 11 kV feeders with very little load during the middle of the day and in some cases, 11 kV feeders experiencing reverse power flow.

Traditionally, distribution networks around the world were designed to accommodate voltage drops arising from the flow of power from the high voltage systems through to the low voltage system. With the connection of embedded generation on the distribution network, particularly the large number of connections of rooftop solar PV to LV networks, in some areas power flows in the reverse direction from the LV to HV have occurred at times of peak solar generation. This reverse power flow is challenging to predict and leads to both voltage rise and voltage drop at different times along the feeding network having to be managed to ensure voltage at customer terminals stays within statutory voltage limits.

Energex is managing the risks associated with high solar PV penetration and voltage rise on the LV network through the Power Quality (PQ) 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, improving knowledge and decision-making capability. 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, Energex identifies and prioritises areas for PQ improvement.

Energex's proposed LV monitoring and remediation program, discussed in section 11.4 will address the community safety risks and meet legislative compliance. Energex introduced changes in October 2015 to the solar PV connection guideline to require AS 4777-certified reactive-power-controlled inverters to minimise voltage rise and is supporting the proposed change to the Electricity Regulations to introduce the 230 volt standard that will provide greater regulating voltage range. This is discussed further in section 12.2 and 12.2.2.

The connection guidelines have been further updated to extend the reactive control mode from a fixed 0.9 power factor lagging setting for inverters greater than 3 kVA to an optional dynamic volt var response mode. The volt var response mode has a voltage range within which the generator is able to export its maximum real power at unity power factor. For voltages outside this range there is a proportional increase in the reactive power supplied or absorbed by the inverters up to a set limit to help maintain network voltages. Solar PV customers are also advised to consider the benefits of installing 3-phase inverters over single-phase inverters for the same output capacity. Although 3-phase inverters are typically more expensive than single-phase inverters, spreading the inverter capacity across three phases can result in more stable operation, with less voltage and frequency swings and less nuisance tripping off.

To help explain these benefits to customers, Energex is developing new web-based information explaining 3-phase inverter benefits in simple language so interested customers can educate themselves.

Figure 43 – Grid Connected solar PV System Capacity by Tariff

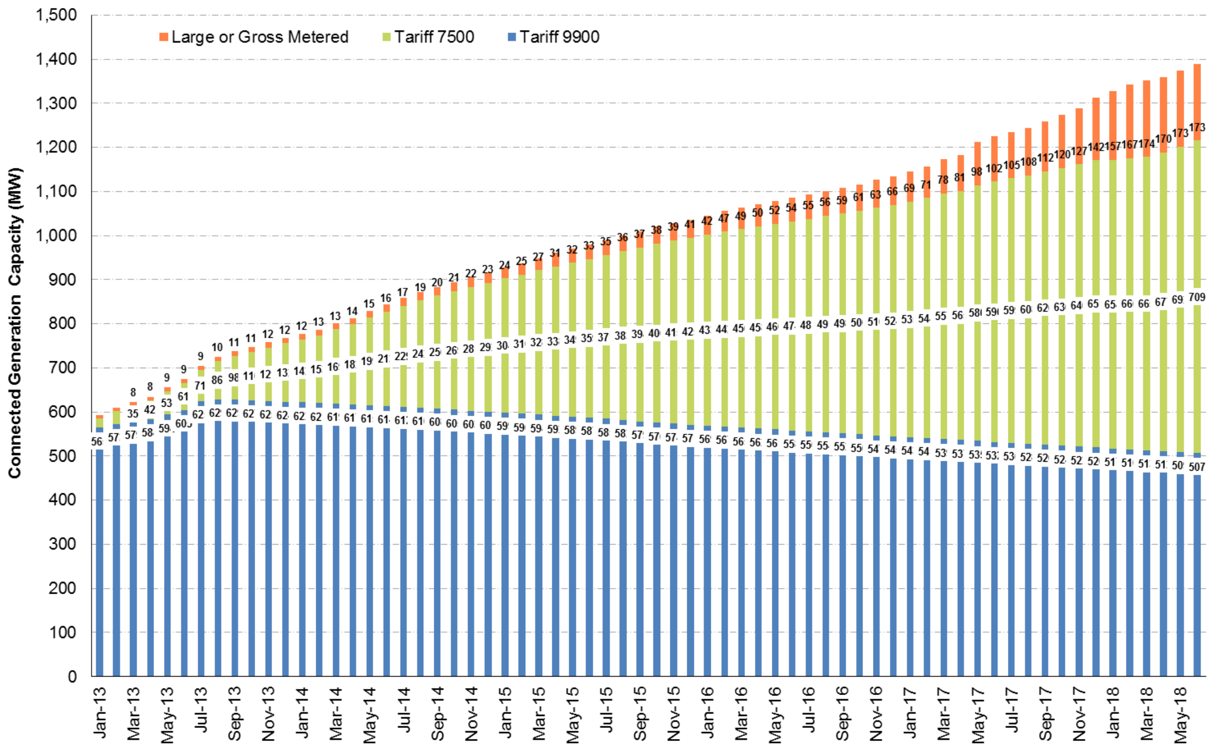


Figure 44 shows the daily load pattern on a residential feeder out of Currimundi zone substation on the Sunshine Coast for four consecutive years as the penetration of solar PV systems on this feeder has grown. Despite the day shown having reduced solar radiation, the trend of increasing reduction of load on the feeder during daylight hours is apparent. There also appears to be some evidence of load being shifted away from daylight hours with higher loads in the pre-dawn and evening hours in the latter years. This may be as a result of customer's changing behaviour to maximise the benefit of the renewable feed in tariffs which are based on net rather than gross solar PV generation. However, there does not appear to be any change to the evening peak in the example shown.

Figure 44 – Impacts of Solar PV on Currimundi CMD15A (2nd Tuesday in November)

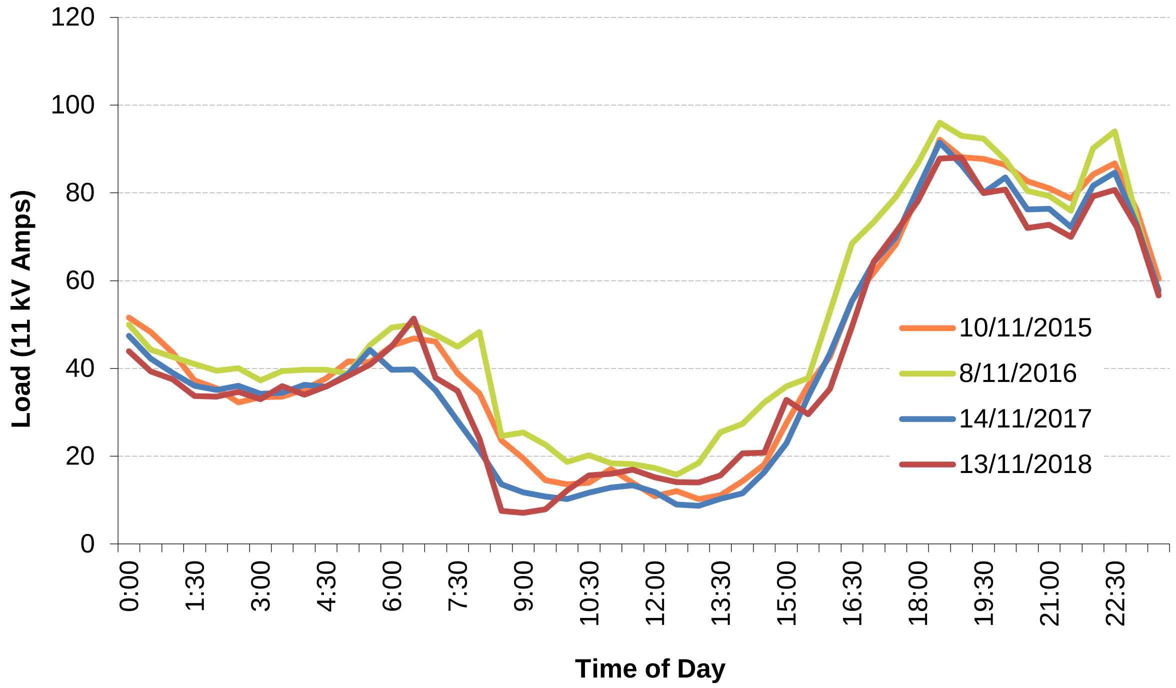


Figure 45 and Figure 46 shows the uptake of solar PV across the Energex network based on zone substation supply areas. Figure 45 indicates the total number of customers in each zone who have solar PV installed, and Figure 46 indicates the total installed capacity in the same areas. The five zone substation areas with the highest numbers have been highlighted on each map.

Figure 45 – Number of customers with Solar PV by Zone Substation

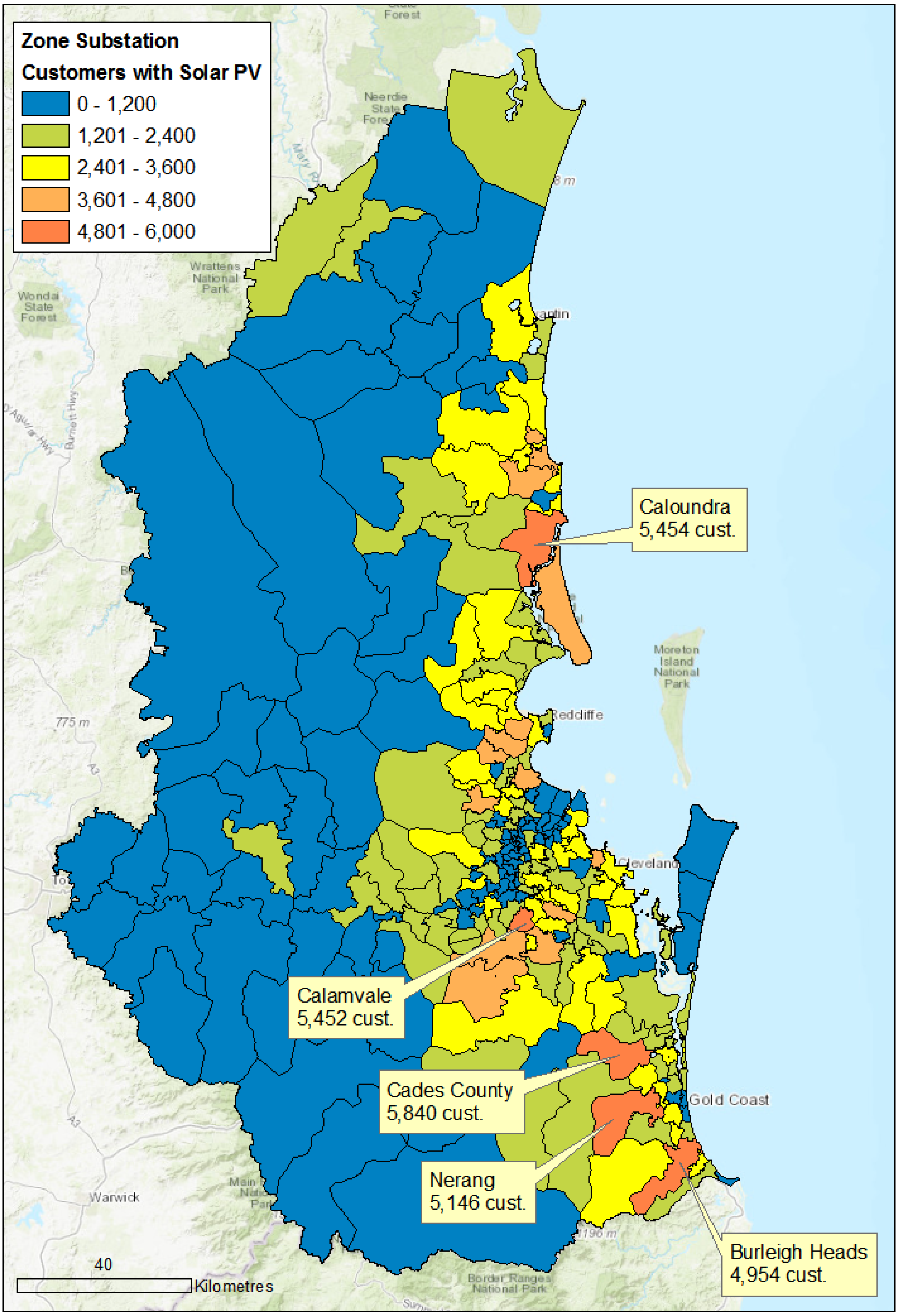
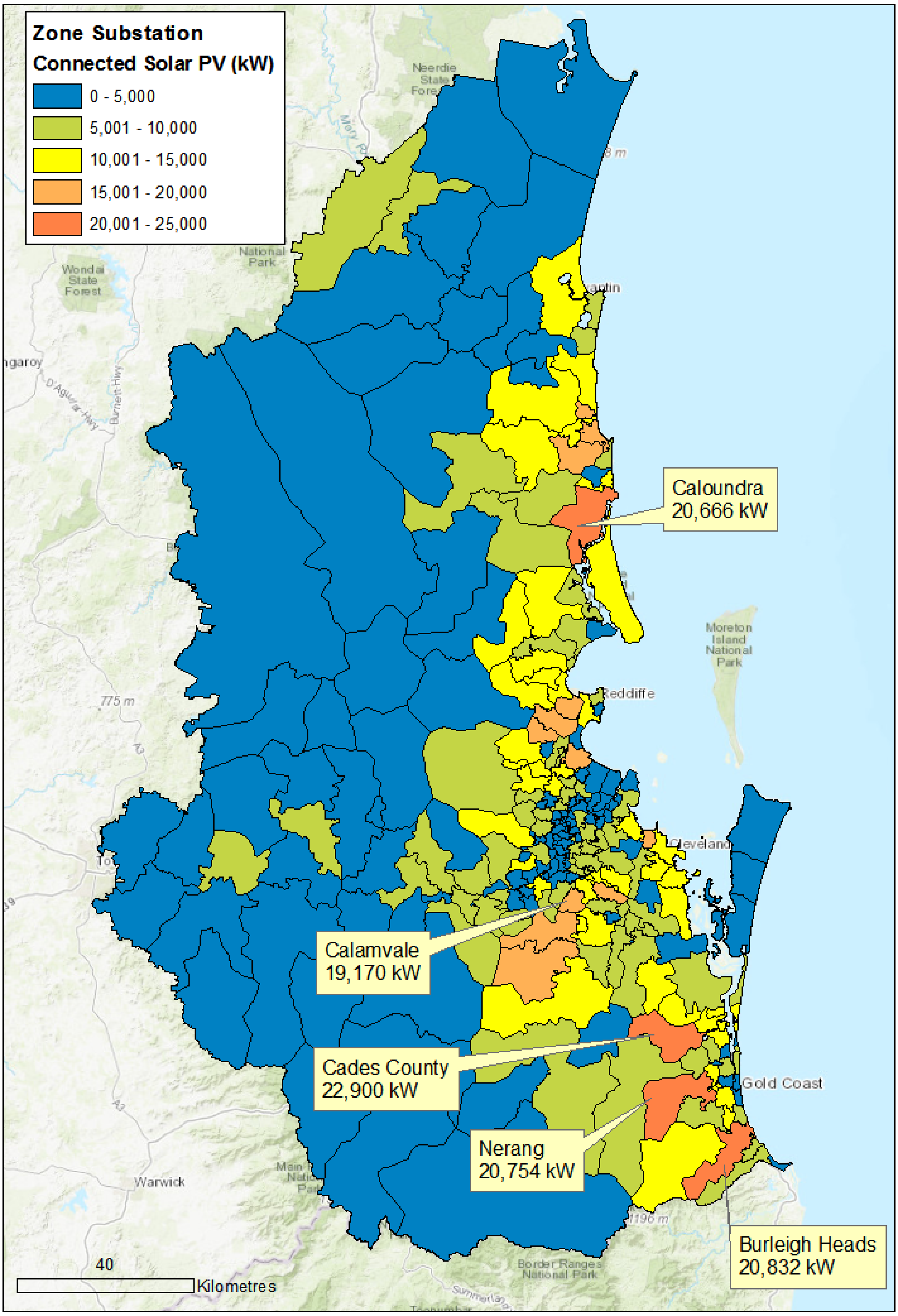


Figure 46 – Installed Capacity of Solar PV by Zone Substation



12.1.2 Future Impacts of Solar PV on Asset Ratings

The monitoring of NCC, ECC, and 2HR ratings of Energex switchgear and transformers continues as an on-going process due to the ever changing load profiles resulting from the connection of solar PV systems to the network.

The Domestic / Mixed / Industrial / Continuous methodology of plant ratings continues to show a drift from “Mixed” to “Domestic” ratings due to new solar PV connections. In years gone by, the rate of solar PV connections was as high as 3,500+ connections per month; however, the current rate of connections over the last 12 months has stabilised to about 1,900 connections per month.

Even with this reduction in connection rates, the impact of the new connections over the last 12 months has:

1. Continued to contribute to further lowering the load factors on many distribution transformers, zone transformers, and 11 kV feeders to below 0.5 on a regular basis;
2. At least 9 zone transformers (with a NCC rating up to 30 MVA) are now exporting back into the 33 kV network on multiple occasions, especially in autumn and spring shoulder conditions;
3. Over 30 zone substations have daytime loads of less than 1 MW for durations of up to 6 hours;
4. An additional 5 substations have had their load profile changed from “Mixed” to “Domestic” over the last 12 months; and
5. The increase of total network substation capacity, as a result of profile changes over the last 12 months, has risen from 681.2 MVA to 702.9 MVA.

Of the 246 Energex substations under review, the following summary identifies the current categories of rating classifications of substations as:

- Continuous (8);
- Industrial (47);
- Mixed (43); and
- Domestic (148).

Monitoring of network load profiles in the future is expected to realise a continuing trend of reducing load factors and transfer of plant from “Mixed” to “Domestic” classifications. An additional 5 zone substations are currently under review, with the expectation that they will be transferred to a “Domestic” load profile from a previous “Mixed” profile by March 2019 resulting in an increased substation capacity (total) of approximately 26 MVA.

12.2 Strategic Response

12.2.1 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 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 Energex 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.

As an immediate priority, the roadmap also outlines the no-regret investments necessary for the Energex 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.

12.2.2 230 V Low Voltage Standard

The Queensland Government recently confirmed a change in voltage from 240 volts (+/-6%) to 230 volts (+10/-6%) across the state to bring us into line with the *Australian Standards AS60038* and *AS61000.3.100*.

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

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

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

From 1 July 2020 Energex will maintain network supply voltages with the preferred range of between 225 volts and 244 volts.

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 Queensland.

The feeders chosen were; one urban and one rural feeder from the Central, Northern and Southern Queensland, 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, changes were implemented to three feeders through tap plans, regulator settings and/or bus voltage set points to monitor for the 230 V 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 230 V transition is available at:

https://www.ergon.com.au/network/network-management/network-infrastructure/230-volt-trial

In March 2016 the Queensland Government went out for public comment on a Regulatory Impact Statement regarding a state-wide move to 230 Volts. Energex and Ergon Energy 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:

https://www.dnrme.qld.gov.au/energy/initiatives/statutory-voltage-limits

12.2.3 Improving Standards for Increased DER Connections

In order to ensure that Energex continues to develop collaborative and mutually beneficial stakeholder relationships we have continued to engage with the solar PV and battery industries to evolve distribute energy resource (DER) connection standards. Ergon Energy has the highest volume of confirmed large DER connections of any Network Service Provider (NSP) on the National Electricity Market (NEM).

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

- Cost reduction by eliminated 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; and
- Ease of compliance with clear requirements for protection and definitions for the various types of generating technology (inverters or rotating machines).

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

- Leverages modern industry standards for solar PV inverter technology, aligning with the joint LV standard and removing barriers for solar connections under 1.5 MW;
- 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; and
- 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 (ENA) 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. Energex are planning to align to the National guidelines to assist in delivering improved alignment and continuity of DER connection standards in Australia.

12.3 Electric Vehicles

Plug-in Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs) are a new class of electrical load that could have significant impact on the low voltage electricity network. Battery storage capacity of currently available PHEVs and BEVs is in the range of 16 kWh (Mitsubishi Outlander PHEV) to 100 kWh (Tesla Model S [BEV]). Tesla's fast-charging station is typically rated at 120 kW and capable of charging the Model S battery to 80% capacity in just 40 minutes.

Currently, electric vehicle (EV) uptake in Australia is among the lowest in the Organization for Economic Cooperation and Development (OECD) countries. In 2018, EVs account for only 0.05% of registered cars in Queensland. The uptake rate of EVs is expected to rise modestly in the next 12 months due to a number of new models being released, the increased availability of public EV charging stations and growing consumer appetite. However, factors such as a lack of national and state government supporting policies, high purchase costs relative to normal vehicles, and range anxiety will continue to dampen the market. However, rapid development, and resulting lower costs, of lithium-ion and other battery technologies could be a game changer.

Energex has been monitoring the development of EVs, and battery storage technology, to better understand the potential impact of these emerging technologies on the distribution network. Energex has adopted a scenario-based approach for long-term planning studies to deal with the uncertainty and forecast demand considering high penetration of emerging technologies such as EVs. The aggregated impact of EVs on the high voltage network is not as significant as local capacity constraints on the low voltage distribution network. Uncontrolled EV charging can occur when the charger is connected to a continuous supply tariff that the customer accesses at their convenience, which is often at the end of the day. Under this scenario, or with high penetration of EVs, significant network augmentation (such as transformer and feeder upgrades) will be required; this may consequently lead to higher electricity prices. However, intelligent EV charging in coordination with local network constraints and price signals – known as controlled EV charging – may avoid network augmentation and could generate electricity sales revenue for distribution utilities and increase asset utilisation.

As the proportion of renewable energy entering the grid, and the uptake of solar PV systems, increase, the greenhouse gas emissions intensity of electricity reduces, creating an increasing environmental advantage for EVs over petrol- or diesel-fuelled vehicles.

Figure 47 – Impact of Controlled and Uncontrolled EV Charging on a Residential Feeder

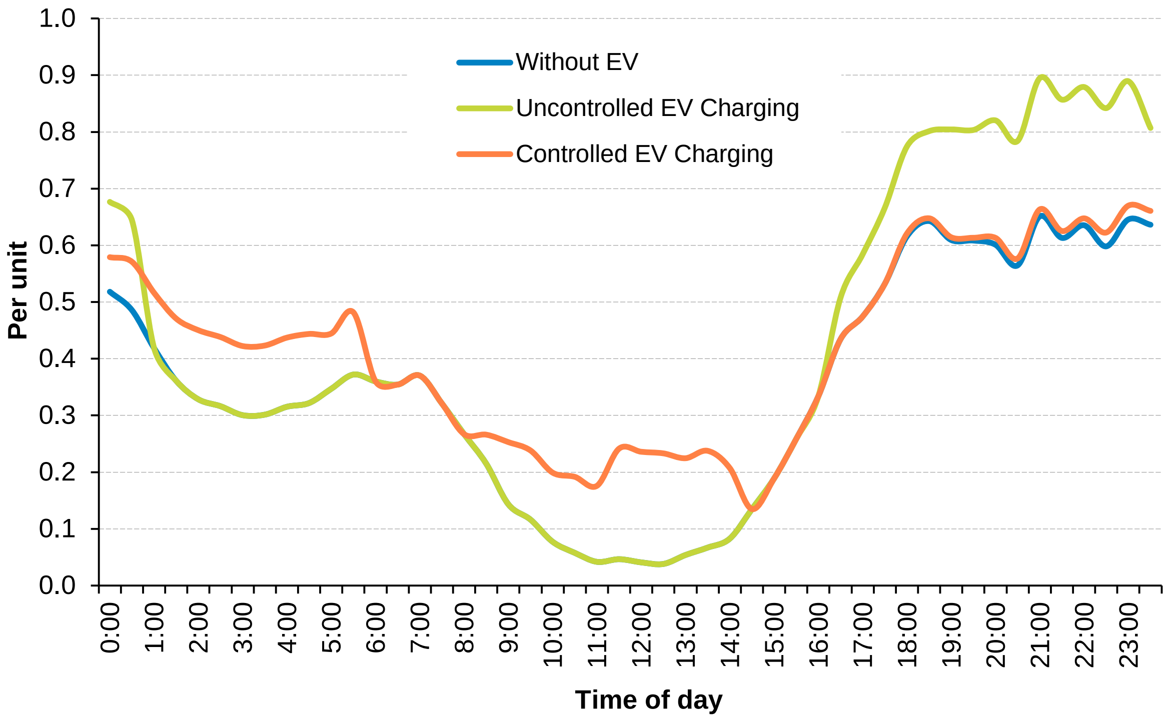


Figure 47 simulates the impact of controlled and uncontrolled EV charging on a typical residential feeder load curve with relatively high penetration of PV rooftops. This illustrates how charging EVs during off-peak and shoulder hours (where there is excess PV generation) could improve the utilisation factor without increasing the peak demand. Conversely, uncontrolled charging increases the peak demand significantly.

12.4 Battery Energy Storage Systems

Energex 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 (addressing 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 embedded generating units up to 30 kVA in 2016/17, a new joint Standard for the Connection of Embedded Generating Systems (>30 kW to 1,500 kW) 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 PV installations.

12.5 Land and Easement Acquisition

One of the key difficulties for large community infrastructure projects is the ability to locate infrastructure over large distances and across several communities. Without the land and property acquired in advance, there can be no design, construction or connection of new electricity infrastructure or non-network solutions to meet the increasing electricity demands within a region.

Community expectations have risen over the years by increased calls for input and participation into these projects, which Energex must now consider for future works, while ensuring that statutory requirements are met regarding social, technical and environmental disciplines, all with the intent of providing a value for money outcome for all.

Corridor easement acquisition projects often span over more than one regulatory period and there is increasing evidence that further upfront community engagement, planning and investigation will improve the ability of Energex to construct these corridors in a more timely fashion, once community and key stakeholders have predominantly endorsed the specific route determined for the new lines.

A key risk with this requirement involves the availability of obtaining key design resources and personnel so far in advance of the actual project. In order to ensure that corridor projects are approved, there is a need for dedicated budget to address planning, community collaboration and education as well as investigation of various routes in order to ensure the corridor selected meets the requirement of both statutory, key stakeholder and community expectations. These objectives must be met whilst also meeting Energex's obligation to our customers to get an outcome that is value for money, while still meeting the key technical, environment and social requirements.

12.6 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 Energex assets creating reliability problems as well as associated maintenance and asset replacement expenditures.

Energex being, a 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.

Energex 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; and
- Undertaking network adaptations that mitigate the risk of bushfire (e.g. LV spreaders, spark-less fuses, conductor replacement).

Energex 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.

https://www.csiro.au/en/Research/OandA/Areas/Assessing-our-climate/Climate-change-QA/Extreme-weather

Chapter 13

Information and Communication Technology (ICT)

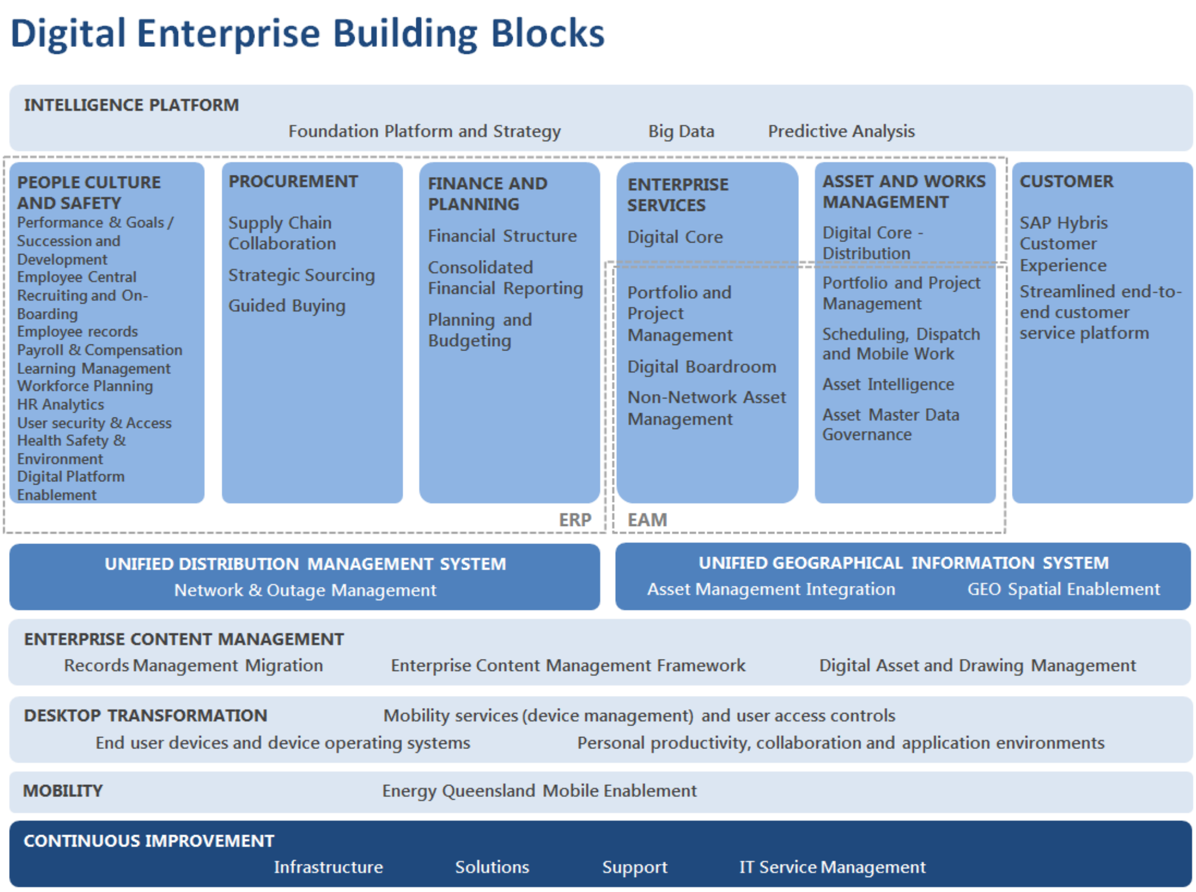
- ICT Investments 2017/18
- Forward ICT Program

13 Information and Communication Technology (ICT)

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

Forward investment of the ICT Portfolio will be focused around a key set of Digital Building Blocks as shown in Figure 48 which will facilitate the transition of Energy Queensland into a Digital Utility.

Figure 48 – Digital Enterprise Building Blocks



The Digital Enterprise Building Blocks will provide a common set of systems and processes, reducing complexity, simplifying Energy Queensland's processes and bringing the broader EQL entity onto a common, digital enterprise platform.

13.1 ICT Investments 2017/18

This section summarises the material investments Energex has made in the 2017/18 financial year, or plans to undertake over the forward planning period, relating to Information & Communications Technology (ICT) systems.

Significant work commenced in the 2017/18 year to initiate a number of the key programs within the Digital Enterprise building block portfolio, with the following major investments approved to commence delivery:

- Intelligence Platform Foundation;
- People and Culture;
- Procurement;
- Finance and Planning; and
- 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 49 contains a summary of ICT investments undertaken in 2017/18. 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 49 – ICT Investments 2017/18

Description	Cost $ M actual
Market Systems Modernisation (Inc. Power of Choice)	14.45
Network Planning & Design	-12.93
Intelligence Platform Renewal	8.89
Infrastructure, Security & End User Devices	9.57
ERP EAM Portfolio of Projects	5.57
Minor Applications Change and Compliance	3.73
Distributed Workforce Automation	0.87
Customer Systems	-0.01
Total	**$30.14**

Note: Actuals noted include ICT Managed Capex Program of Work specific investment for Energex only (i.e. does not include ICT investment funded through other portfolios already identified in other sections of this report).

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.

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 Energex's market systems.

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

Phase 1 of the program will finalise the replacement Energex's ageing master asset register and network model that has reached both technical and financial obsolescence. This phase of the replacement will incorporate a contemporary, flexible Geographic Information System (GIS) and will provide Energex with a single data source for its connectivity model catering for utility specific information needs (e.g. associating electrical characteristics to the model).

The joint forecasting tool replacement has been delayed, as a joint forecasting and planning approach could not be established and agreed across the new Energy Queensland Entity. As a result some minor investment was required to sustain existing capability out to the end of the current control period.

Intelligence Platform Renewal

This investment seeks to establish a centralised Energex Intelligence Platform as an efficient, scalable and reliable solution in addressing the current and future demands on Energex's data landscape as it transitions to a Digital Utility to ensure that Energex 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 Licence pricing through a partnership view and bulk purchase arrangements; and
- Maximise response to market and regulation changes whilst seeking better opportunities to influence and empower consumers.

Infrastructure, Security and End User Devices

The renewal of Energex's ICT infrastructure assets is delivered in accordance with Energex'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, Energex 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 Energex Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) systems began in 2016/17. Energex 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 Energex to consolidate satellite applications. The initiatives encompass procurement, people, culture, safety, finance and planning, corporate services and works & asset management footprints. The program will now be delivered as part of the Energy Queensland Enterprise Digital Initiatives program and will take a number of years to complete. 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 EQL internal network and from mobile devices.

Asset and Works Management:

- Implement a single system and process that supports asset and works management functionality within AS&P and Distribution. 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 signal unified EQL 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; and
- 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 EQL internal network and mobile devices; and
- Deploy foundation capability for portfolio and project management processes.

Finance and Planning:

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

Minor Applications Change and Compliance

This includes minor improvements and updates across the ICT systems footprint including; work force automation, asset management, market systems, network operations systems, knowledge management systems, and customer service systems which support Energex'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, and the Energy Queensland Limited Enterprise Agreement payroll system configurations.

Distributed Workforce Automation

A project 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 Program

Energex'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 (PoC) 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; and
- Managed Information – This will drive operational efficiency through technology and information enablement, unlocking future value through broad access to secure information. This strategy is in response to emerging technologies including big data, mobility and social media.

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; and
- Health, Safety and Environment.

The 2018/19 year 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, Unified DMS 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 EQL.

13.2.1 Forward Financial Forecasting

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 50. 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 Digital Enterprise Building Blocks, 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 reported to the regulator in the 2015-2020 submission plan.

Table 50 – ICT Investment 2018-19 to 2022-23

Initiative Name	2018/19 $M	2019/20 $M	2020/21 $M	2021/22 $M	2022/23 $M
Asset and Works Management	2.65	11.91	12.73	8.43	16.69
Distribution Network Operations	8.99	8.10	6.78	5.09	2.13
Customer and Market Systems	10.21[1]	3.87[1]	7.35	13.47	12.13
Corporate Systems	40.31	11.42	4.27	0.72	3.74
ICT Management Systems, Productivity and Cybersecurity	11.77[1]	7.77[1]	1.18	4.01	3.22
Infrastructure Program	8.12	9.32	5.34	5.99	5.91
Minor Applications Change	2.78	4.23	3.37	3.37	3.37
Grand Total	**84.81**	**56.56**	**41.02**	**41.08**	**47.19**

[1] identifies 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 Energex Limited (i.e. does not include ICT investment funded through other portfolios already identified in other sections of this report).

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.

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 Energex the Geographical Information System (GIS) is a key system in the asset management process. Between the Enterprise Asset Management solution (EAM) and the GIS, the core data for the individual asset and the physical and electrical network are mastered. The GIS plays a key role in supporting the major asset life cycle processes of asset design, build, commissioning and maintenance planning.

Energex utilises an in-house developed solution, which is supplemented with Esri products on older versions as the spatial viewer. In 2016 the merger of Ergon Energy and Energex into Energy Queensland (EQL) 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, EQL has embarked on the preparation of business cases to implement a new Enterprise Asset Management solution (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 EQL.

The allocation against this initiative will also cover the replacement of a number of other Network forecasting tools currently being utilised across Energex.

Distribution Network Operations

Energex deployed a Distribution Management System (DMS) in the previous regulatory period and is using it to manage the MV & HV networks in South-East Queensland (network and outage management).

With the formation of EQL, alignment activities are taking place and having a converged DMS system is required to allow a complete transition to merged operational practices. A converged DMS will also support EQL in the intent to realise benefits of merging the two DNSP's.

The program is expected to carry over well into the 2020-25 regulatory period. In this regulatory period it will address the need for ICT asset renewal of the Energex DMS assets and A4S. In the upcoming regulatory period it will incorporate the necessary ICT asset renewal for Ergon's FeederStat.

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, outage and Fault management capabilities, Linux server applications that provide the interface to the field radios for the ROSS client and database, and RTU design and configuration tools.

The replacement of Energex's Field Force Automation Tool is scheduled for the 2022-23 financial year. 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, 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 Energex'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.

High level benefit opportunities:

- Lower TCO of a simplified and configurable architecture;
- Integrated, consistent and simplified end to end processes;
- Real time insight for decision support (KPI 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; and
- Reduced Customer, electrical contractor and retailer cost to serve.

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.

Enterprise Content Management systems manage much of the companies' legal records, network drawings and critical documentation supporting, to varying degrees, business processes across all Ergon Energy major business functions including Legal, Network Design, Finance, Human Resources, Procurement, Asset Management and Works Management.

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.

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; and
- Supports our daily productivity through software and applications 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 Digital Enterprise Building Blocks (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.

The next for Business Intelligence, is to build and embed 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;
- Predictive Maintenance - derive insight from operational data, statistics to predict, plan maintenance based on asset wear and condition;
- 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; and
- Customer Fraud Prediction - Identify customers in all segments that may fail to pay the bills and proactively initiate communications.

This capability will allow Energex 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; and
- 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, Power Quality 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.

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 IT/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

- Ageing Metering Population
- Metering Investments in 2017/18
- Metering Investments in 2018/19 to 2022/23

14 Metering

The metering environment is continuing to change rapidly, driven by a range of national market reform initiatives to make metering services contestable. While Energex is supportive of the development and introduction of a national competitive metering market, to provide customers with a range of choices in metering and related services, Energex needs to ensure that cost-effective metering is available to all customers who do not choose to change to another metering provider.

During the development and introduction of a competitive market, Energex needs to ensure that it can continue to provide effective and efficient metering services and products to customers, as well as to ensure that new metering products continue to remain relevant in the changing marketplace. Energex currently operates over 2.091 million meters, and conducts around 6 million site-visits each year to service meters and provide metering products and billing data critical for all customers and market participants.

Energex's current fleet of meters includes 1.312 million mechanical (disk) meters and 779,782 electronic meters, with approximately 752,821 of these electronic meters capable of recording interval data. Energex no longer installs meters as of 1 December 2017 due to the introduction of Power of Choice. The average age of Energex electronic meters is 12.5 years. The older meters will be managed in accordance with the metering strategy and Metering Asset Management Plan (MAMP). This strategy will ensure that the value of these meters is maximised over the full useful life of these devices. Looking forward, addressing ageing metering assets in a cost-effective manner whilst in a changing competitive environment will be a key challenge for Energex.

Currently over 661,238 customers supplied by Energex are connected to a load control tariff, including a load control relay (remote controlled switch) installed in their meter box. Approximately 118,552 of these relays are integrated into the meter, with the majority installed as a stand-alone, separate relay. This load control equipment allows Energex to shift and manage hundreds of MW's of peak load, which reduces peak demand and helps defer capital intensive network augmentation. These facilities also provide Energex with a valuable tool for network management and contingency planning. The benefits of load control are shared amongst all customers in the form of more efficient network operation and investment. Energex will work to ensure that this capability is maintained and protected whilst changes occur in the competitive metering environment.

Energex is currently separating load control from metering, as it relates to network operation and network management. Energex is seeking to retain the right to install network load control network devices in customer meter boxes. Energex's plans will require that third-party metering providers retain the Energex load control assets installed in customer switchboards to maintain Energex's considerable load control facilities.

Energex will seek to maximise the remaining value in existing meter stocks, by leveraging existing metering capabilities wherever possible. For example, the current suite of interval capable electronic meters may be reprogramed to support market offerings such as Time-of-Use (ToU) tariffs or other similar time-based pricing structures.

Energex will also continue to operate a Meter Asset Management Plan (MAMP) in a prudent and efficient manner to enable enhanced benefits and cost savings to customers.

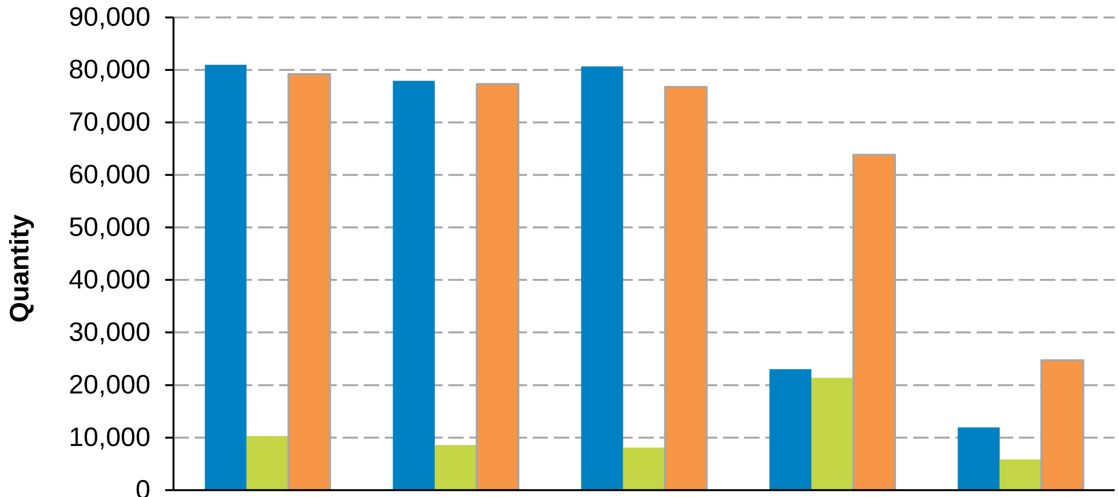
Energex will continue to develop and implement consistent work practices and supporting standards, such as the Queensland Electrical Connection and Metering Manual (QECMM), to ensure these align with the rollout of smart-ready meters in a contestable marketplace.

As a contestable metering market is introduced, Energex will work to ensure that critical standards such as safety are updated to cover the growing range of metering service providers and market participants. Energex is committed to supporting the market developments outlined, as well as continuing to provide cost-effective metering and network services to customers.

In 2017/18, Energex installed 24,721 meters, which is much lower than the average over the last 5 years of about 80,469 meters per annum. This was due to the legislation that came into force on 1 December 2017 which restricted the ability of Energex to install new and replacement meters past this date.

Figure 49 shows the total numbers of meters installed per year over the past six years.

Figure 49 – Historical Meter Usage July 2012 to June 2018



	2013/14	2014/15	2015/16	2016/17	2017/18
QTY PURCH	80,958	77,888	80,640	23,018	11,958
QTY REFURB	10,269	8,576	8,092	21,395	5,805
QTY INST	79,179	77,309	76,738	63,818	24,721

The changing requirements for new meters in recent years compared with the longer term average are due to the following factors:

- Reduced stockholding of meters in preparation for Power of Choice metering competition,
- Reduction in solar PV installations requiring two way metering; and
- Reduction in meter replacements due to floods and storms than in previous years.

Within the figures above, Table 51 shows the number of new meters installed due to emerging or exceptional drivers over the past five years.

Table 51 – Contribution to Meter Usage (5 years)

Project	Quantity (approximate)	Description Of Meters Used
Smart Grid Trials (SGT) (2013)	503	100% new
Solar PV (2011-2013)	222,338	80% new, 20% refurbished
Power Quality Project (2016)	3,000	100% new

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

14.1 Ageing Meter Population

Figure 50 shows the age profile of all Energex type 6 meters currently in service, and Figure 51 shows the age profile of electronic meters.

The economic life of electro-mechanical meters is 25 years, and electronic meters 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.

Figure 50 – Energex Meters Age Profile

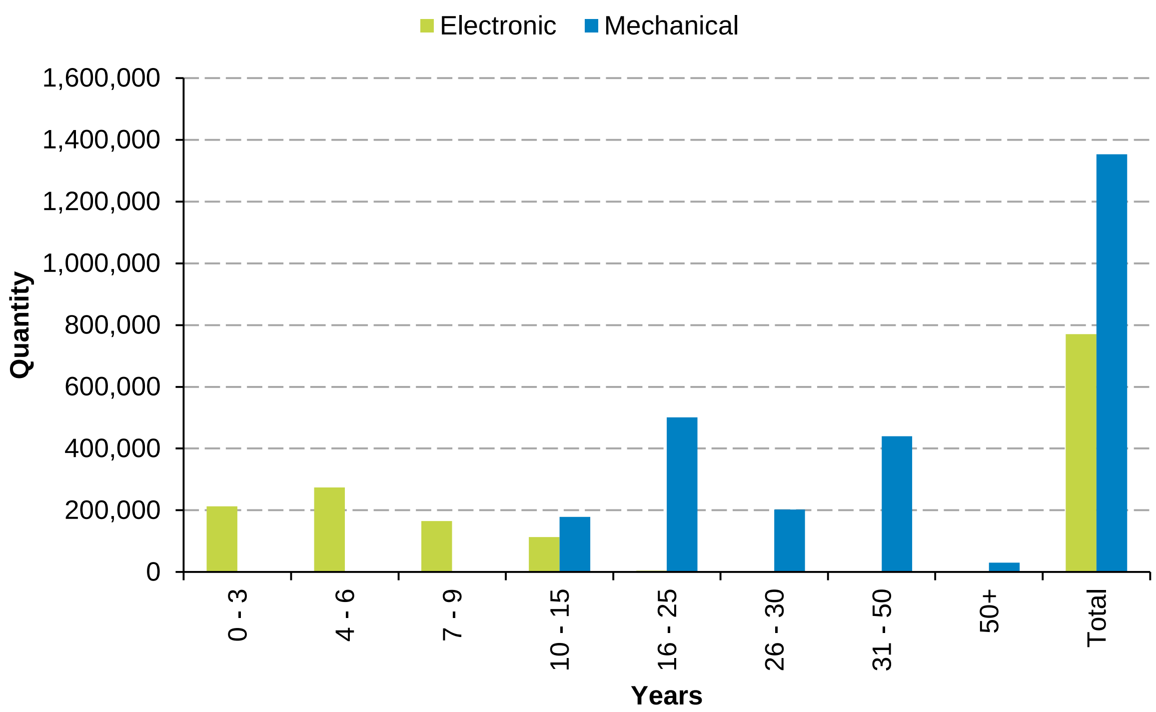
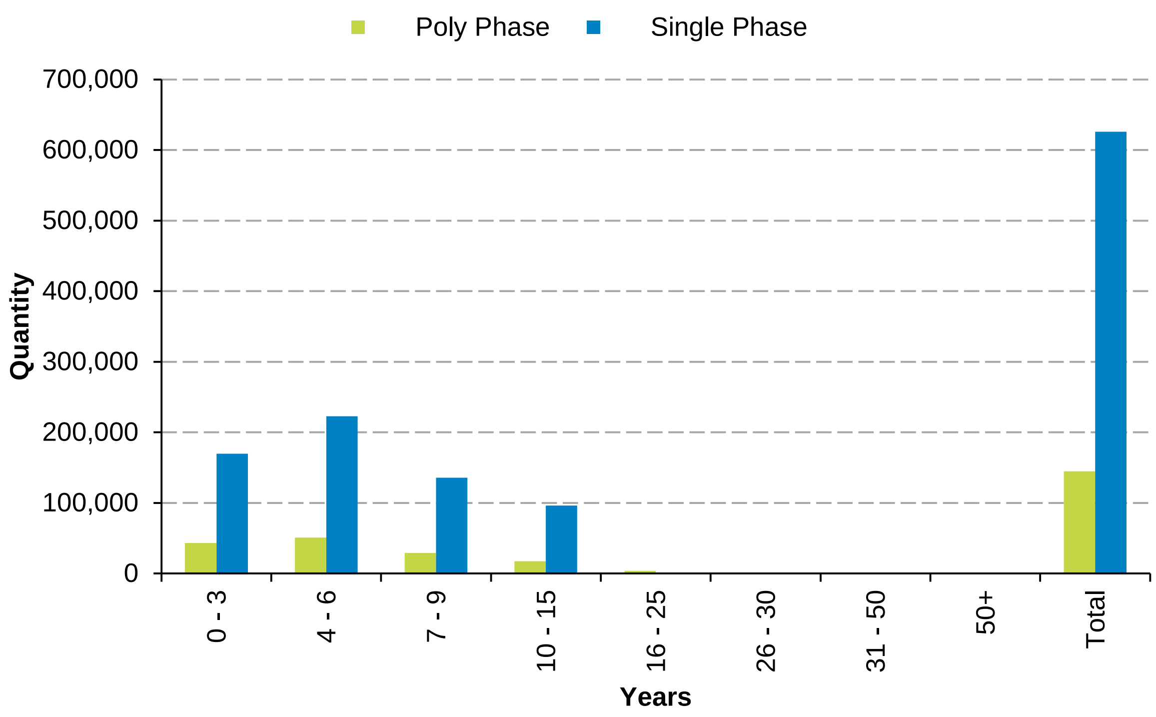


Figure 51 – Energex Electronic Meter Age Profile



Energex will continue to utilise the aged assets, and only replace the assets based on condition monitoring of population samples and failure rates as outlined in the Energex Metering Asset Management Plan.

14.2 Metering Investments in 2017/18

Table 52 provides a summary of metering investments for 2017/18.

Table 52 – Metering Investments 2017/18

Project	Estimated Cost $ M
Meter Replacements (planned and reactive)	3.2

14.3 Metering Investments from 2018/19 to 2022/23

The future investment in metering by Energex will be minimal and will mainly be focused on network devices.

Chapter 15

Operational and Future Technology

- Telecommunications
- Operational Systems
- Investments in 2017/18
- Planned Investments for 2018/19 to 2022/23

15 Operational and Future Technology

Energex 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. Energex 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 2010-2015, 2015-2020 and 2020-2030. 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

Energex's telecommunication strategy comprises a range of directions for the company:

- Continued rollout of the Core IP/MPLS network;
- Continued rollout of Optical Fibre cable bearers for;
    - Core IP/MPLS network deployment;
    - Core IP/MPLS network alternate paths; and
    - Replacement of obsolete Copper Pilot cables.
- Migration of services from external service providers to internal networks for reduction of ongoing monthly carrier charges and reduced downtime;
- Enhanced cyber security toolsets and facilities;
- Improved configuration management toolsets and procedures;
- Asset management toolsets for planning & managing the operational telecommunications networks. Integration with GIS and with DM&A;
- The increased deployment of 'intelligent' power network devices with Ethernet/IP interfaces, the increased deployment of modern IP/MPLS based telecommunications network products and associated advanced management toolsets will require continued skills training and development for our capable workforce. Modern networks and advanced toolsets will enable business efficiencies, and increased value extraction from assets; and
- Teleprotection over MPLS.

Key project / programs supporting the strategic directions are detailed below:-

- Project Matrix. This is the core Internet Protocol/Multi-Protocol Label Switching (IP/MPLS) communications network and OTE providing Ethernet/IP services to support current and future operational systems. This is a multi-stage project;
- Optical fibre cable infill program. Optical fibre is the preferred media for operational telecommunications links between substations. To achieve lowest cost deployment, the majority of optical fibre links are provisioned as part of new or refurbished feeder works in the distribution network PoW. However, this approach leaves gaps that must be filled in by other projects. The optical fibre infill program provides the missing links that are needed for other key projects such as Project Matrix;
- Replacement of obsolete equipment. Energex's existing operational telecommunications network is extensive and covers the majority of bulk and zone substations. The majority of the equipment utilises Plesiochronous Digital Hierarchy (PDH) technology, and is now 20+ years old with key items starting to show increasing in service failure rates and the equipment is no longer supported by the original vendors. The strategy is to eventually replace links over optical fibre with IP/MPLS technology being rolled out on Project Matrix, and PDH radio links with IP radio links. This will be a key focus for the next 5-10 years. In the meantime, the current systems must be supported whilst the new IP/MPLS network is being deployed; and
- Replacement of obsolete copper cable links. Much of the existing copper pilot cable network is 30 to 40 years old and is reaching end of design life. The strategy is to replace with optical fibre cable where practical. However, this often requires the associated replacement of substation equipment such as feeder protection relays.

15.2 Operational Systems

Energex 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. The current systems within the OT scope are detailed below.

15.2.1 Supervisory Control and Data Acquisition (SCADA)

The SCADA system provides control for bulk and zone substations, selected Customer and Industrial (C&I) substations, pole mounted reclosers and provides interfacing for control from Powerlink. The system provides Control Centre capability at the main and Disaster Recovery sites.

The Substation Automation Control System (SACS) at zone and bulk substations provides substation automation applications such as Volt Var Regulation (VVR), and Network Overload Mitigation Software (NOMS), and local operator Human Machine Interface (HMI). Numerous feeder auto-change over schemes are deployed throughout the power distribution network as applications running in SACS, or in Remote Data Concentrators (RDC).

Energex's strategic plan for control systems called for the remote terminal units (RTUs) at substations to be upgraded to a consistent software version over a 5 year period in this reporting period. The Distribution Management System (DMS) is receiving a refresh of hardware and an upgrade of selected software components.

Work to select a replacement RTU for the in house developed unit and to commence changing support systems to allow the new equipment to suitably integrate into the current environment continued.

The need for greater integration of substation secondary systems, including protection, SCADA, and telecommunications facilities has continued. Energex continues to evolve the solutions to enable the following advanced features to be deployed into the network:

- Protection relay interfacing with SCADA via Ethernet-IP based communications; and
- Migration of auto-reclose functions from SACS to protection relay to enable additional operational modes to provide improved safety of live line workers.

Energex is continuing the migration to Ethernet-IP based communications for a range of substation secondary systems devices including protection, SCADA, and telecommunications facilities.

15.2.2 Switching sheet automation

Energex completed a deployment of a switching sheet automation application. The implementation also required upgrading of a range of OT infrastructure to cater for extra performance and security requirements of the application.

15.2.3 Other changes

Energex continued the deployment of the Operational Technology Environment (OTE) at operational data Centres. The following, work was undertaken:

- Halted the implementation of a new phone system to replace existing operator consoles, in order to re-asses the best approach for the new merged EQL entity;
- Completed the implementation of the operational telephony network that services operational sites including substations;
- Completed the implementation of Storage Area Network Infrastructure; and
- Continued replacement of various end of life components within the Data Centres, including the firewalls and other components.

15.2.4 Operational Security

Energex implemented enhanced security processes and technology in preparation for the Commonwealth games in 2018. Additional threats were identified during the period and a range of mitigation activities has occurred.

15.3 Investments in 2017/18

Table 53 summarises the SCADA and Communications investments for 2017/18.

Table 53 – Information Technology and Communication Systems Investments 2017/18

Project	Cost $ M actual
Telecommunications Network	
Telecommunications equipment replacement	$3.75
MPLS system implementation	$0.39
Fibre Cable installation	$4.23
Operational Systems	
SCADA and Automation Refurbishment / Replacement	$1.01
OT Security projects	$0.13
Total	**$9.51**

Note: 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 54 summarises Energex's OT and associated Telecommunication planned investments for 2018-19 to 2022-23[1].

Table 54 – Operational Technology Planned Investments 2018-19 to 2022-23

Project	Cost $ M actual
Telecommunications Network	
Telecommunications equipment replacement	$10.50
MPLS system implementation	$7.27
Fibre Cable installation	$15.65
Operational Systems	
Security Enhancements	$1.20
SCADA and Automation Enhancement	$2.90
SCADA and Automation Refurbishment / Replacement	$10.20
OT Refurbishment / Replacement	$2.40
Control Room Enhancements	$3.10
Infrastructure Expansion	$3.70
LV Visibility and Control Improvements	$5.50
Distributed Energy Resources Management	$5.30
Intelligent Grid Applications	$3.70
Total	**$72.70**

[1] expenditure is provisional only and will be dependent on AER submission outcomes for 2020-21 to 2022-23 financial years.

Note: 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

Abbreviations	
10 PoE	10% Probability of Exceedance (Peak load forecast based on normal expected growth which has a 10% probability of being exceeded in any year)
50 PoE	50% Probability of Exceedance (Peak load forecast based on normal expected growth which has a 50% probability of being exceeded in any year)
2HEC	Two Hour Emergency Capacity (of all equipment excluding the largest parallel element)
ABS	Air Break Switch or Australian Bureau of Statistics
ACS	Alternative Control Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Marker Operator
AER	Australian Energy Regulator
AFLC	Audio Frequency Load Control
AS	Australian Standard
B2B	Business to Business
BESS	Battery Energy Storage Systems
BMS	Business Management System
BOM	Bureau of Meteorology
Bus/es Busbar	A common connection point in a network substation or switchyard
CATS	Consumer Administration and Transfer Solution
C&I	Commercial and Industrial
CAPEX	Capital Expenditure
CB	Circuit Breaker
CBEMA	Computer and Business Equipment Manufacturers' Association
CBRM	Condition Based Risk Management
CCT	Abbreviation for Circuit
CIS	Customer Information System

Abbreviations	
COAG	Council of Australian Governments
Code	Electricity Distribution Network Code
COS	Customer Outcome Standard or security standard
CRI	Community Regard Index
CVT	Capacitor Voltage Transformer
Customer	End use customer plus Retailer
DA	Distribution Authority
DAPR	Distribution Annual Planning Report
DCCT	Double circuit
DER	Distributed Energy Resources
DEWS	Department of Energy and Water Supply
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DMA	Distribution Monitoring Analytics
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DRED	Demand Response Enabling Device
DSS	Distribution System SCADA
EAM	Enterprise Asset Management
EBSS	Efficiency Benefits Sharing Scheme
ECC	Emergency Cyclic Capacity (for a substation this is the maximum cyclic rating of all equipment excluding the largest, resulting in an accelerated but acceptable rate of wear)
EDRMS	Electronic Document Records Management System
EDSD	Independent Panel's Report – Electricity Distribution and Service Delivery
ENCAP	Electricity Network Capital Program Review 2011
EPBC	Environment Protection and Biodiversity Conservation Act
ERP	Enterprise Resource Planning
EV	Electric Vehicle

Abbreviations	
Feeder	Power line that can be any nominal voltage, overhead or underground.
FFA	Field Force Automation
FIT	Feed in Tariff/s
GFC	Global Financial Crisis
GIS	Geographical Information System or Gas Insulated Switchgear
GOC	Government Owned Corporation
GSL	Guaranteed Service Level
GSP	Gross State Product
HEV	Hybrid Electric Vehicle
HMI	Human Machine Interface
HV	High Voltage – alternating current voltage above 1,000 volts
IAM	Identity Access Management
ICT	Information and Communication Technology
IDC	Inter-Departmental Committee
IP/MPLS	Internet Protocol / Multi Protocol Label Switching
IRP	Independent Review Panel
ISO	International Organisation for Standardisation
IT	Information Technology
KPI	Key Performance Indicator
kV	Kilo-Volt or 1,000 volts
kVA	Kilo-Volt Ampere unit of power
LAR	Load at Risk
LARc	Load at Risk under Contingent Condition
LARn	Load at Risk under System Normal Condition
LDC	Line Drop Compensation
LV	Low Voltage (alternating current voltage above 50 volts and not exceeding 1,000 volts)
MAB	Metering Asset Base
MAIFI	Momentary Average Interruptions Frequency Index

Abbreviations	
MAIFIe	Momentary Average Interruptions Frequency Index by Event
MAMP	Metering Asset Management Plan or Mains Asset Management Policy
MEPS	Minimum Energy Performance Standard
Meshed (network)	Interconnecting feeders
MSS	Minimum Service Standard or Minimum Services Specification
MW	Mega-Watt unit of real power
MVA	Mega-Volt Ampere unit of power
MVAr	Mega-Volt Ampere Reactive unit of reactive power
N-1	Security Standard where supply is maintained following a single credible contingency event
NCC	Normal Cyclic Capacity (for a substation this is the maximum cyclic rating of all parallel equipment resulting in a normal rate of wear)
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NIM	Net Interstate Migration
NOM	Net Overseas Migration
NMP	Network Management Plan
NOMS	Network Overload Mitigation Software
NPV	Net Present Value
NSP	Network Service Provider
NVD	Neutral Voltage Displacement
OECD	Organisation for Economic Cooperation and Development
OESR	The Office of Economic and Statistical Research (OESR)
OLTC	On Load Tap Changer

Abbreviations	
OPEX	Operating Expenditure
OTE	Operational Technology Environment
PAR	Project Approval Report
PDH	Plesiochronous Digital Hierarchy
PHEV	Plug-in Hybrid Electric Vehicle
PMR	Pole mounted recloser
PoC	Power of Choice
PoE	Probability of Exceedance
POPS	Plant Overload Protection System
PoW	Program of Work
pu	Per-unit measure
PV	Photo Voltaic
QCA	Queensland Competition Authority
QECMM	Queensland Electrical Connection and Metering Manual
QHES	Queensland Household Energy Survey
QPC	Queensland Productivity Commission
RAB	Regulated Asset Base
RBT	Rewards Based Tariff (project)
RDC	Remote Data Concentrators
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RMU	Ring Main Unit
RPEQ	Registered Professional Engineer of Queensland
RTU	Remote Terminal Unit
Rules	National Electricity Rules
SAC	Standard Asset Customers
SACS	Substation Automation Control System

Abbreviations	
SAIDI	System Average Interruption Duration Index. (Performance measure of network reliability, indicating the total minutes, on average, that customers are without electricity during the relevant period)
SAIFI	System Average Interruption Frequency Index. (Performance measure of network reliability, indicating the average number of occasions each customer is interrupted during the relevant period)
SAMP	Substation Asset Maintenance Policy
SCCT	Single circuit
SCS	Standard Control Services
SEQ	South East Queensland
SF6	Sulphur Hexafluoride
SCADA	Supervisory Control and Data Acquisition
SGT	Smart Grid Trials
SIFT	Substation Investment Forecast Tool
SPI	Service Performance Index
SRR	Switching Request Register
SSI	Sag Severity Indicator
STOC	SCADA & Telecommunications Operational Centre
STPIS	Service Target Performance Incentive Scheme
THD	Total Harmonic Distortion
ToU	Time-of-Use tariff
TMU	Target Maximum Utilisation
TNSP	Transmission Network Service Provider
TSA	Telecommunication Supply Agreement
TSS	Tariff Structure Statement
UCC	Unified Communication and Collaboration
V	Volt or volts
VVR	Volt Var Regulation
WPF	Worst Performing Feeder
XLPE	Cross-Linked Polyethylene

Appendix B

NER and DA Cross Reference

Appendix B
NER and DA Cross Reference

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
(a) information regarding the Distribution Network Service Provider and its network, including:	
(1) a description of its network;	**1.4** Network Overview **2.2** Electricity Distribution Network
(2) a description of its operating environment;	**2.3** Network Operating Environment **3** Community and Customer Engagement **10.1** Reliability Measures and Standards **10.2** Service Target Performance Incentive Scheme (STPIS) **10.3** High Impact Weather Events **11.2** Power Quality Supply Standards, Codes Standards and Guidelines **12** Emerging Network Challenges and Opportunities
(3) the number and types of its distribution assets;	**2.2** Electricity Distribution Network
(4) methodologies used in preparing the Distribution Annual Planning Report, including methodologies used to identify system limitations and any assumptions applied; and	**6.2** Planning Methodology **6.3** Key Drivers for Augmentation **6.4** Network Planning Criteria **6.5** Voltage Limits **6.6** Fault Level **6.10** Joint Planning Results **6.11** Distribution Network Planning – Assessing System Limitations **9.3** Asset Condition Management **10.2.1** STPIS Methodology
(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	**1.5** Changes from Previous Year's DAPR

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
preceding year;	
(b) forecasts for the forward planning period, including at least:	
(1) a description of the forecasting methodology used, sources of input information, and the assumptions applied;	**5** Network Forecasting **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables
(2) load forecast:	**5** Network Forecasting **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables
(i) at the transmission-distribution connection points. Including, where applicable;	**Appendix E** Substations Forecast and Capacity Tables 'Bulk Supply Substation'
(iv) total capacity;	'NCC Rating (MVA)'
(v) firm delivery capacity for summer periods and winter periods;	'ECC Rating (MVA)' '2HR Rating (MVA)'
(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);	'Hours PA Exceeding 95% Peak Load'
(vii) power factor at time of peak load;	'Power Factor at Peak Load'
(viii) load transfer capacities; and	'Auto Trans Avail (MVA)' 'Remote Trans Avail (MVA)' 'Manual Trans Avail (MVA)' 'Mobile Plant Avail (MVA)'
(ix) generation capacity of known embedded generating units;	'Capacity of commissioned Embedded Generation (with Connection Agreements)'

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
(ii) for sub-transmission lines *Including, where applicable:*	**Appendix F** Feeders Forecast and Capacity Tables
(iv) total capacity;	'NCC Rating (A)'
(v) firm delivery capacity for summer periods and winter periods;	'ECC Rating (A)' '2HR Rating (A)'
(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);	'Hours PA Exceeding 95% Peak Load', Only applicable to sub – transmission lines which do not meet security standard.
(vii) power factor at time of peak load;	'Power Factor (System Normal)'
(viii) load transfer capacities; and	'Auto Trans Avail (A)' 'Remote Trans Avail (A)' 'Manual Trans Avail (A)'
(ix) generation capacity of known embedded generating units.	
(iii) for zone substations *including, where applicable:*	**Appendix E** Substations Forecast and Capacity Tables 'Zone Substation'
(iv) total capacity;	'NCC Rating (MVA)'
(v) firm delivery capacity for summer periods and winter periods;	'ECC Rating (MVA)' '2HR Rating (MVA)'
(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);	'Hours PA Exceeding 95% Peak Load'
(vii) power factor at time of peak load;	'Power Factor at Peak Load'
(viii) load transfer capacities; and	'Auto Trans Avail (MVA)' 'Remote Trans Avail (MVA)' 'Manual Trans Avail (MVA)' 'Mobile Plant Avail (MVA)'

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
(ix) generation capacity of known embedded generating units.	'Capacity of commissioned Embedded Generation (with Connection Agreements)'
(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:	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(i) location;	**7.4** Emerging Network Limitations Maps **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(ii) future loading level; and	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables
(iii) proposed commissioning time (estimate of month and year);	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(4) forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service target performance incentive scheme; and	**10.2** Service Target Performance Incentive Scheme (STPIS)
(5) a description of any factors that may have a material impact on its network, including factors affecting;	

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
(i) fault levels;	**6.6** Fault Level
(ii) voltage levels;	**6.5** Voltage Limits
(iii) other power system security requirements;	**10.3** High Impact Weather Events **Appendix C** Network Security Standards
(iv) the quality of supply to other Network Users (where relevant); and	**11.3** Power Quality Performance in 2017/18 **12.1** Solar PV **12.2.2** 230 V Low Voltage Standard
(v) ageing and potentially unreliable assets;	**9.1** Approach **9.2** Preventative Works **9.3** Asset Condition Management **9.4** Asset Replacement **Appendix D** Network Limitations and Mitigation Strategies
(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:	**7.2** Asset Retirements (Project Based)
(1) a description of the network asset, including location;	
(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;	
(3) the date from which the Distribution Network Service Provider proposes that the network asset will be retired or de-rated; and	
(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	

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
occurred;	
(b2) for the purposes of subparagraph (b1), where two or more network assets are:	**7.2** Asset Retirements (Project Based)
(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:	**7** Overview of Network Limitations and Recommended Solutions

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
	7.1.1 Connection Point and Substation Limitations **6.5.2** Sub-transmission Network Voltage **7.1.2** Transmission Feeder Limitations **7.1.3** Sub-transmission Feeder Limitations **7.3** Summary of Emerging Network Limitations **7.4** Emerging Network Limitations Maps **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(1) estimates of the location and timing (month(s) and year) of the system limitation;	7 Overview of Network Limitations and Recommended Solutions **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(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;	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables
(3) impact of the system limitation, if any, on the capacity at transmission-distribution connection points;	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables
(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	**Appendix E** Substations Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
(5) where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include:	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1);	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(ii) the relevant connection points at which the estimated reduction in forecast load may occur; and	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation;	**Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(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:	**6.5.3** 11 kV Distribution Network **7** Overview of Network Limitations and Recommended Solutions **7.1.4** 11 kV Distribution Feeder Limitations **7.3** Summary of Emerging Network Limitations **7.4** Emerging Network Limitations Maps **Appendix F** Feeders Forecast and Capacity Tables

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
	Appendix D Network Limitations and Mitigation Strategies
(1) the location of the primary distribution feeder;	**7** Overview of Network Limitations and Recommended Solutions **7.4** Emerging Network Limitations Maps **Appendix F** Feeders Forecast and Capacity Tables
(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);	**Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(3) the types of potential solutions that may address the overload or forecast overload; and	**Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(4) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:	**Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(i) estimate of the month and year in which the overload is forecast to occur;	**Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload;	**7** Overview of Network Limitations and Recommended Solutions **7.4** Emerging Network Limitations Maps **Appendix D** Network Limitations and Mitigation Strategies **Appendix F** Feeders Forecast and Capacity Tables
(iii) the estimated reduction in forecast load in MW needed to defer the forecast	**Appendix D** Network Limitations and Mitigation

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
system limitation;	Strategies **Appendix F** Feeders Forecast and Capacity Tables
(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:	**7.5** Regulatory Investment Test (RIT-D) Projects **Appendix D** Network Limitations and Mitigation Strategies
(1) if the regulatory investment test for distribution is in progress, the current stage in the process;	**Appendix D** Network Limitations and Mitigation Strategies
(2) a brief description of the identified need;	**Appendix D** Network Limitations and Mitigation Strategies
(3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);	**Appendix D** Network Limitations and Mitigation Strategies
(4) if the regulatory investment test for distribution has been completed a brief description of the conclusion, including:	**Appendix D** Network Limitations and Mitigation Strategies
(i) the net economic benefit of each credible option;	**Appendix D** Network Limitations and Mitigation Strategies
(ii) the estimated capital cost of the preferred option; and	**Appendix D** Network Limitations and Mitigation Strategies
(iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and	**Appendix D** Network Limitations and Mitigation Strategies
(5) any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;	**Appendix D** Network Limitations and Mitigation Strategies
(f) for each identified system limitation which a Distribution Network Service Provider has determined will require a regulatory investment test for distribution, provide an estimate of the month and year when the test is expected to commence;	**7.5.3** Foreseeable RIT-D Projects

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address an urgent and unforeseen network issue as described in clause 5.17.3(a)(1), including:	**6.10** Joint Planning Results **7.5** Regulatory Investment Test (RIT-D) Projects **Appendix D** Network Limitations and Mitigation Strategies
(1) 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;	**Appendix D** Network Limitations and Mitigation Strategies
(2) 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;	**6.10** Joint Planning Results **Appendix D** Network Limitations and Mitigation Strategies
(h) the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:	
(1) a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning;	**6.9** Joint Planning **6.10** Joint Planning Results
(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	**6.9** Joint Planning **6.10** Joint Planning Results
(3) where additional information on the investments may be obtained;	**6.9** Joint Planning **6.10.3** Further Information on Joint Planning
(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year,	

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
including:	
(1) a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning;	**6.9** Joint Planning **6.10** 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	**6.10** Joint Planning Results **6.10.2** Joint Planning with other DNSP
(3) where additional information on the investments may be obtained;	**6.9** Joint Planning **6.10.3** Further Information on Joint Planning
(j) information on the performance of the Distribution Network Service Provider's network, including:	**10** Network Reliability **11** Power Quality
(1) a summary description of reliability measures and standards in applicable regulatory instruments;	**10.1** Reliability Measures and Standards **10.2** Service Target Performance Incentive Scheme (STPIS) **10.4** Guaranteed Service Levels (GSL) **10.5** Worst Performing Feeders
(2) a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;	**11.2** Power Quality Supply Standards, 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;	**10.1.1** Reliability Performance in 2017/18 **11.3** Power Quality Performance in 2017/18
(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;	**10.1.3** Reliability Non-Compliance Corrective Actions **11.8** Power Quality Ongoing Challenges and Corrective Actions
(5) a summary description of the Distribution Network Service Provider's processes to ensure compliance with the measures and standards described under	**10.1.2** Reliability Compliance Processes **11.4** Quality of Supply Processes

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
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 (STPIS)
(k) information on the Distribution Network Service Provider's asset management approach, including:	**4** Asset Management Overview
(1) a summary of any asset management strategy employed by the Distribution Network Service Provider;	**4** Asset Management Overview **4.2** Asset Management Policy **9** Asset Life-Cycle Management
(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;	**6.4.4** Consideration of Distribution Losses
(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	**9** Asset Life-Cycle Management **12** Emerging Network Challenges and Opportunities
(3) information about where further information on the asset management strategy and methodology adopted by the Distribution Network Service Provider may be obtained;	**4.5** Further Information **1.6** DAPR Enquiries
(l) information on the Distribution Network Service Provider's demand management activities, including a qualitative summary of:	
(i) non-network options that have been considered in the past year, including generation from embedded generating units;	**8.1** Non-Network Options Considered in 2017/18 **8.4** Demand Management Results for 2017/18
(ii) key issues arising from applications to connect embedded generating units received in the past year;	**8.2** Key Issues Arising from Embedded Generation Applications
(iii) actions taken to promote non-network proposals in the preceding year, including	**8.3** Actions Promoting Non-Network Proposals

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
generation from embedded generating units; and	**8.4** Demand Management Results for 2017/18
(iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period;	**8.5** Demand Management Programs for 2018/19 to 2022/23 **8.6** Other Demand Side Participation Activities
(2) a quantitative summary of:	
(i) connection enquiries received under clause 5.3A.5;	**8.4.1** Connection Enquiries Received
(ii) applications to connect received under clause 5.3A.9; and	**8.4.2** Applications to Connect Received
(iii) the average time taken to complete applications to connect;	**8.4.3** Average Time to Complete Connection
(m) information on the Distribution Network Service Provider's investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of network assets in the forward planning period; and	**13** Information and Communication Technology (ICT) **14** Metering **15** Operational and Future Technology
(n) a regional development plan consisting of a map of the Distribution Network Service Provider's network as a whole, or maps by regions, in accordance with the Distribution Network Service Provider's planning methodology or as required under any regulatory obligation or requirement, identifying:	**7** Overview of Network Limitations and Recommended Solutions **7.4** Emerging Network Limitations Maps
(1) sub-transmission lines, zone substations and transmission-distribution connection points; and	**7** Overview of Network Limitations and Recommended Solutions **7.4** Emerging Network Limitations Maps
(2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders.	**7** Overview of Network Limitations and Recommended Solutions **7.4** Emerging Network Limitations Maps

Other Rules including Distribution Authority (DA) obligations	DAPR Section Number/Energex Terminology
DA 10 Safety net	
DA 10.2 Safety net targets	
(a) the distribution entity will design, plan and operate its supply network to ensure, to the extent reasonably practicable, that it achieves its safety net targets as specified in Schedule 3.	**7** Overview of Network Limitations and Recommended Solutions **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(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.	**6.4.2** Safety Net **10** Network Reliability **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(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.	**10.6** Safety Net Target Performance
DA 11 Improvement programs	
DA 11.2 Requirements	
(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 11 kV feeders;	**10** Network Reliability **10.5** Worst Performing Feeders **Appendix G** Worst Performing 11 kV Feeders
DA 14.3 Requirements	
From 1 July 2014 onwards, Distribution entity must report in its Distribution Annual Planning Reports on the implementation of its Distribution Network Planning Approach under clause 8 Distribution Network Planning.	**6** Network Planning Framework
DA 8.1 Requirements	
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	**6.4** Network Planning Criteria **10** Network Reliability **10.5** Worst Performing Feeders **Appendix G** Worst Performing 11 kV Feeders

NER Schedule 5.8 version 116 Clause / Sub-Clause	DAPR Section Number/Energex Terminology
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	**Note - the blue text denotes the Energex terminology used in the relevant section in Appendices**
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.	

Appendix C

Network Security Standards

Appendix C
Network Security Standards

Under the Distribution Authority, Energex 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. Energex is also obligated to continue the Worst Performing Feeder policy, reporting annual results in this report.

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, planning practices have adopted the safety net targets and are defined in the Customer Outcome Standard for the different categories of CBD, Urban and Rural.

The Customer Outcome Standard takes into account the following key factors:

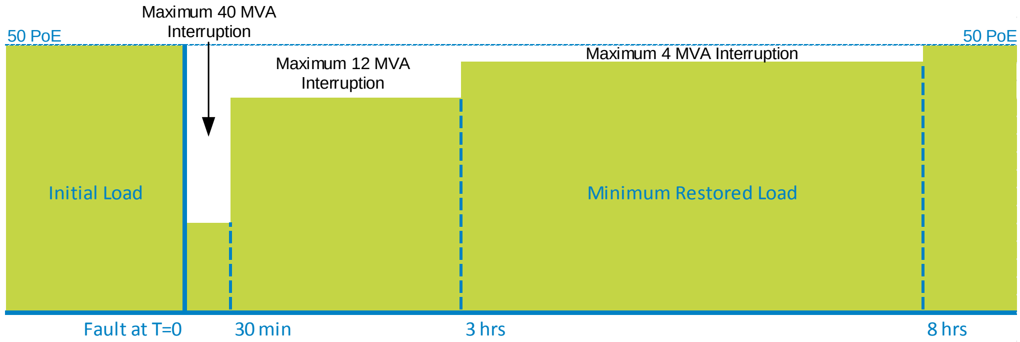
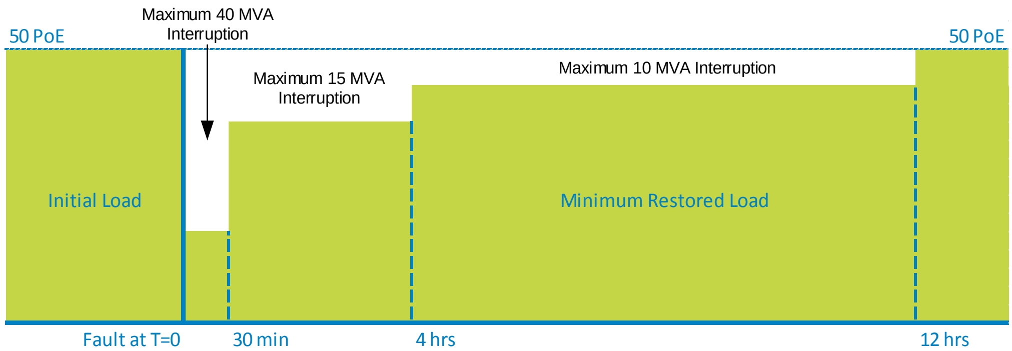
Feeders and substations are assigned a category according to criteria or the area (CBD, Urban, Rural); and the appropriate safety net is assigned to associated network elements;
Plant and power line ratings depend upon their ability to discharge heat and are therefore appreciably affected by the weather, including ambient temperature and in the case of overhead lines, wind speed;
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; and
Specific security requirements of large customer connections that are stipulated under the relevant connection agreements.

The standard allows Energex to make use of available transfers and non-network capabilities and is 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.

The safety net targets contained in the Energex Distribution Authority and applied in the Energex Customer Outcome Standard are shown in Table C1.

Table C1 – Customer Outcome Standard Safety Net Targets

<table>
<tr><th>Category</th><th>Customer Outcome Standard Safety Net Targets</th></tr>
<tr><td>High Security</td><td>Ensure that any single credible event does not result in a loss of customer supply.</td></tr>
<tr><td>CBD</td><td>Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute.

</td></tr>
<tr><td>Urban</td><td>no greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes;
no greater than 12 MVA (5,000 customers) is without supply for more than 3 hours; and
no greater than 4 MVA (1,600 customers) is without supply for more than 8 hours.

</td></tr>
<tr><td>Rural</td><td>no greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes;
no greater than 15 MVA (6,000 customers) is without supply for more than 4 hours; and
no greater than 10 MVA (4,000 customers) is without supply for more than 12 hours.

</td></tr>
</table>

In compliance with the Distribution Authority, CBD applies to predominantly commercial high-rise buildings using high voltage underground network with significant inter-connection when compared to urban areas. Whereas, urban applies to non-CBD areas predominantly supplying actual maximum demand per total feeder route length of greater than 0.3 MVA per km. Rural then applies to non-CBD and non-urban areas. All analysis is based on 50 PoE loads.

For the CBD sub-transmission network, interruption to supply due to a single credible event will be restored within 1 minute. The economic value that CBD customers place on reliability is used to determine if the timing of any investments that exceed safety net targets are economic.

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.

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.

Appendix D

Network Limitations and Mitigation Strategies

Appendix D
Network Limitations and Mitigation Strategies

This section provides details on asset limitations and presents the committed solutions or the types of potential options for each of the limitations.

In comparison to the 2017 DAPR, some projects to address network limitations will have completed the regulatory process, or have entered construction, or have been commissioned. However, some projects identified in the 2017 DAPR have been deferred beyond the forward planning period due to declining growth in demand forecasts and the introduction of the customer outcome standard. Furthermore, some projects have been re-assessed and subsequently cancelled. This section provides updated information for the forward planning period.

Details on asset limitations and the types of potential options to address each of the limitations are contained in the Distribution System Limitation Template (prepared in accordance with Australian Energy Regulator's (AER) Distribution Annual Planning Report Template) via the following hyperlinks:

Distribution Feeders Limitations and Proposed Solutions Part A
Distribution Feeders Limitations and Proposed Solutions Part B

Substations Limitations and Proposed Solutions Part A
Substations Limitations and Proposed Solutions Part B

Transmission and Sub-Transmission Feeders Limitations and Proposed Solutions Part A
Transmission and Sub-Transmission Feeders Limitations and Proposed Solutions Part B

Details on limitations where Energex has committed projects to address can be accessed via the following hyperlinks:

Summaries of Replacement / Unforeseen Projects approved in the past 12 months
Summaries of RIT-D Projects approved in the past 12 months
Substations Limitations and Committed Solutions
Transmission and Sub-Transmission Feeders Limitations and Committed Solutions
Distribution Feeders Committed Solutions

Details on limitations where Energex does not plan to address within the forward planning period can be obtained via the hyperlink below.

Limitations Not Addressed

Further details can be obtained from the Energex website accessible via the following hyperlink:

https://www.energex.com.au/dapr2018

Appendix E

Substations Forecast and Capacity Tables

Appendix E
Substations Forecast and Capacity Tables

The Substations Forecast and Capacity Tables is a summary of planning information for all existing and committed future bulk supply and zone substations. These are made available in spreadsheet format via the following hyperlinks:

Bulk Supply Substations Load Forecast
Zone Substations Load Forecast

In general, the summary includes only substations that supply multiple customers. Customer owned substations and substations dedicated to single large customers are not included.

Further details can be obtained from the Energex website accessible via the following link:

https://www.energex.com.au/dapr2018

E.1 Supporting Notes

Each summary sheet contains a brief description of the substation, including its location, land area, construction type, installed transformers and capacity of known embedded generation connected to the substation. Localities give a general view of the areas serviced by the substation. Load categories indicate the type of loads supplied. Growth rates for the zone substations provide a projection of the expected growth rates for the next five years for planning purposes.

With respect to growth rates:

None of the bulk supply substations directly supply customers, therefore there is no growth rates provided for these substations; and
Large individual or block loads (existing and new) are treated on an individual basis and not listed in these substation summaries, but these are factored into load forecasts.

The next section includes a summary of performance and capability.

The latest compensated peak demand is displayed along with the typical daily compensated load profile. In addition, the compensated descriptor refers to the slightly reduced transformer load experienced when available capacitors are in service. Entries in the major loads section indicate there are significant or large customers connected to the substation. Both summer and winter profiles are presented where available. Where a substation has less than 12 months of metering data available, such as small substations and newly established substations, the graphs and the information against these fields is either blank or not applicable (N/A).

The summary sheets also show two graphs of reliability performance for System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). The last five years of this data is shown for all events impacting customers supplied from the specific substation. While total measures as experienced by these customers are shown, any contributions of major event days are highlighted in the top blue segment of the bars. Reliability data cannot be determined for some small substations with no 11 kV outgoing circuits and new substations where no data has been recorded. The charts are blank in these cases.

A summary of any projects and additional comments relating to the substation are provided below the peak load forecast and capacity table. The committed projects and proposed timeframe section provide a list of relevant committed projects and their proposed commissioning time. The supplementary notes provide additional comments such as operational strategies and land or spatial constraints.

E.2 Peak Load Forecast and Capacity Tables

A definition of terms for these tables is shown in Table E1. These tables show information about the substation's customer category, transformer capacity, including emergency cyclic capacity and normal cyclic capacity, load at risk, and the compliance of each substation with its security standard. To assess whether a substation meets its security standard, four possible risk periods are considered: winter day, winter night, summer day and summer night. The highest risk period for each season is displayed for each year of the forward planning period.

A total of eight peak, reconciled and compensated load forecasts have been used in the analysis: 50 PoE summer (day & night); 50 PoE winter (day & night); 10 PoE summer (day & night); and 10 PoE winter (day & night). The summer forecasts are based on summer 2017/18 starting values, and the winter forecasts are based on winter 2017 starting values. Both sets of forecasts include load transfers expected from committed projects with the proposed timings scheduled in the program of work as of June 2018. Substation capacities include the single contingency emergency cyclic capacity and the total substation normal cyclic capacity corresponding to the plant present at the start of the risk period. These ratings have also been adjusted for known committed project proposals.

The forecast and capacity cut-off date for the winter season is 1 June of each year, and for the summer season is 1 December of each year. For example, 2018 winter forecast includes all committed projects with a proposed commissioning date up to 1 June 2018, and the 2018/19 summer forecast includes all committed projects with a proposed commissioning date up to 1 December 2018.

The security standard applicable to a substation is based on the customer category. The peak risk period is the one with the highest calculated load at risk for normal or contingency conditions. Load at risk is calculated using the forecast loads, the planned substation capacity, and the capacity of the network to allow the transfer of load away from the substation to other sources of supply based on the substation security standard criteria. A detailed explanation of the derivation of load at risk is provided in Section E.2.1. If there is no load at risk, the substation meets the security standard.

Although transformers are usually the limiting factor for a substation's capacity, there are other significant items of plant, such as cables and switchgear that can also restrict capacity. Load sharing between parallel transformers can also be limited due to operational constraints (e.g. split bus configurations to manage fault levels) or differing transformer characteristics (e.g. tapping range or impedance differences). Both of these factors have been taken into account in the production of these tables.

Table E1 – Definition of Terms Peak Load Forecast and Capacity Tables

Term	Definition
Peak Risk Period	The time period over which the load is highest (Day/Night).
NCC Rating (MVA)	Normal Cyclic Capacity – the total capacity with all network components and equipment in service. The maximum permissible peak daily loading for a given load cycle that plant can supply each day of its life. Taking impedance mismatch into consideration, it is considered the maximum rating for a transformer to be loaded under normal load conditions.
Contracted non-network (MVA)	The amount of embedded generation and contracted curtailed demand management capacity available within the supply area of a substation during peak times. The impacts of these have been incorporated into the load forecasts. Solar PV connections are not included in the reported figure.
10 PoE Load (MVA)	Peak load forecast with 10% probability of being exceeded (one in every 10 years will be exceeded). Based on normal expected growth rates & weather corrected starting loads.
LARn (MVA)	Security standard load at risk under system normal condition, expressed in MVA.
LARn (MW)	Security standard load at risk under system normal condition, expressed in MW.
Power Factor at Peak Load	Compensated power factor at 50 PoE Load. Capacitive compensation is switched according to the size of the capacitor banks installed at the substation, compensation is generally limited to prevent a substation from going into leading power factor.
ECC Rating (MVA)	Emergency Cyclic Capacity – the long term firm delivery capacity under a single contingent condition. The maximum permissible peak emergency loading for a given load cycle that an item of plant can supply for an extended period of time without unacceptable damage. For substations with multiple transformers, the ECC is the minimum emergency cyclic capacity of all transformer combinations taking impedance mismatches into consideration, with one transformer off line.
50 PoE Load (MVA)	Peak load forecast with 50% probability of being exceeded (one in every two years will be exceeded). Based on normal expected growth rates and weather corrected starting loads.
50 PoE Load > 95% (MVA)	The amount of load greater than 95% 50 PoE Load. (50 PoE Load – 0.95 x 50 PoE Load)
Hours PA > 95% Peak Load	The number of hours per annum (maximum over the last 3 years) where the load exceeded 95% of the peak 50 PoE demand.
Raw LAR (MVA)	The amount of load exceeding ECC rating. (50 PoE Load – ECC Rating)

Term	Definition
2-Hour Rating (MVA)	Two-Hour Emergency Capacity (2HEC) – the short term or firm delivery capacity under a single contingent condition. The maximum permissible peak emergency loading for a given load cycle that an item of plant can supply up to two hours without causing unacceptable damage. For substations with multiple transformers, the 2HEC is the minimum two hour emergency rating of all transformer combinations taking impedance mismatches into consideration, with one transformer off line.
Auto Trans Avail (MVA)	SCADA or automatically controlled load transfers that can be implemented within one minute.
Remote Trans Avail (MVA)	Load transfers that can be implemented through SCADA switching procedures by the network control officer. It is assumed that this can generally be achieved within 30 minutes excluding complex or time –consuming restoration procedures.
Manual Trans Avail (MVA)	Load transfers can also be deployed via manually controlled switchgear locally by field staff. It is assumed that the implementation of manual switching procedures to isolate the faulted portion of the network to restore supply to healthy parts of the network can be fully implemented within three hours (urban) or four hours (rural). Manual transfers are obtained from load flow studies performed on each 11 kV distribution feeder based on the forecast 2016/17 load, the sum of all available 11 kV transfers at a substation is multiplied by a 0.75 factor to account for diversity and to provide a margin of error to avoid voltage collapse. The same approach applies throughout the forward planning period.
Mobile Plant Avail (MVA)	The capacity of mobile substation or mobile generation that can be deployed within the timeframe prescribed by the security standard. The maximum allowable mobile generator capacity is limited to 4 MVA for urban and 10 MVA for rural. The maximum mobile substation capacity is 15 MVA.
POPS	Plant Overload Protection Scheme consists of several applications which continuously monitor specific items of plant for overload conditions. If overload conditions are detected and validated, POPS will initiate predefined actions in order to relieve the overload condition.
Bus Configuration	An indication of the electrical configuration of the substation 11 kV bus (e.g. split bus or solid bus)
LARc (MVA)	Security standard load at risk for single contingent conditions.
LARc (MW)	Estimated generation / load reduction required to defer the forecast system limitation. This is the security standard load at risk for a single contingency, expressed in MW.
Customer Category	For security standard application, the general type of customer a substation or feeder supplying the area.

E.2.1 Calculation of Load at Risk

The load at risk is evaluated for both normal (LARn) and contingent (LARc) conditions. Under normal conditions, the loadings on a substation are not to exceed the normal cyclic capacity (NCC) of a major network component such as a zone substation transformer. Under contingent conditions, the loadings of a substation are not to exceed the available emergency supply under contingency whilst taking into consideration the security of supply standards of the substation.

Load at risk is the shortfall between the forecast load (either 10 PoE or 50 PoE) and the available supply. The general equations for LAR are as follows:

- **LARn** = 10 PoE – NCC where NCC is the normal cyclic capacity
- **LARc** = 50 PoE – available capacity – available supply (within security standard timeframe)

Network security standards are not being met if LARn or LARc is greater than 0.

Generally, there are two available capacities and five available sources of supply that can be deployed upon loss of a major network component such as a transformer.

Types of available capacity:

- **Emergency Cyclic Capacity (ECC)** – The maximum permissible peak emergency loading for a given load cycle that a plant can supply for an extended period of time without doing unacceptable damage. For substations with multiple transformers, the ECC is the minimum emergency cyclic capacity of all transformer combinations taking impedance mismatches into consideration, with one transformer off line.
- **Two Hour Emergency Capacity (2HEC)** – The maximum permissible peak emergency loading for a given load cycle that a plant can supply up to two hours without doing unacceptable damage. For substations with multiple transformer, the 2HEC is the minimum 2 hour emergency rating of all transformer combinations taking impedance mismatches into consideration, with one transformer off line. By the end of the 2 hours, the transformer load must be reduced to or below ECC.

Types of available supply:

- **Automatic Transfers (AT)** – SCADA or automatically controlled load transfers that can be implemented within 1 minute. Examples include auto changeover switching capacity from adjacent bus sections, standby transformers or via dedicated tie feeders from other substations. Such capacity has been considered at a number of substations where it is available.
- **Remote Transfers (RT)** – Load transfer capacity can be deployed via remotely controlled switchgear. The implementation of a series of SCADA controlled switching procedures to isolate the faulted portion of the network whilst restoring supply to fault free portions can be fully implemented within 30 minutes and is available for extended periods. At present, only remote transfers to other substations or standby transformers, using SCADA control of substation circuit breakers, have been considered.
- **Manual Transfers (MT)** – Load transfer capacity can be deployed via manually controlled switchgear. The implementation of a series of manual switching procedures to isolate the faulted portion of the network whilst restoring supply to fault free portions can be fully implemented within 3 hours (urban) or 4 hours (rural) and is available for extended periods. Some manual transfers are likely to be implemented within 2 hours but this has not been quantified at this time. Analysis done to identify the available 11 kV transfer capability in the

systems for every substation. To accommodate future 11 kV network changes and system coincidence peak, a 75% factor is applied to ensure the transfers are practical and achievable throughout the analysis period. The manual switching of standby transformers, which do not have automatic switching, has also been included where available.

- **Mobile Generation (MG)** – Alternate supply from mobile generators can be sourced within 8 hours (urban) or 12 hours (rural). These are generally smaller 500 kVA units that do not require transport permits or police escorts and can be rapidly deployed. Up to 4 MVA (urban) or 10 MVA (rural) of mobile generation may be committed to a single contingency event.
- **Mobile Substation (MS)** – Alternate supply provided through deployment of a mobile substation within 8 hours (urban and non-urban) – only applies to 33/11 kV zone substation contingencies. These mobile substations generally do not require transport permits or police escorts and can be rapidly deployed. The standard size of the mobile substation transformer is 18 MVA however a capacity of 15 MVA is used in the assessment of zone substation security standard compliance. Use of the mobile substation may be committed to a single contingency event.

E.2.2 Network Security Standards

The network security standards are outlined in Appendix C. Referred to as the Customer Outcome Standard (COS), the safety net targets for customers are defined. This safety net approach complies with jurisdictional obligations. In compliance with the Distribution Authority, CBD applies to predominantly commercial high-rise buildings using high voltage underground network with significant inter-connection when compared to urban areas. Whereas, urban applies to non-CBD areas predominantly supplying actual maximum demand per total feeder route length of greater than 0.3 MVA per km. rural then applies to non-CBD and non-urban areas.

Appendix F

Feeders Forecast and Capacities Tables

Appendix F
Feeders Forecast and Capacity Tables

The Feeders Forecast and Capacity Tables contains the capacity and forecast loads on the 132 kV, 110 kV, 33 kV and 11 kV feeders in the Energex network.

These are made available in spreadsheet format via the following hyperlinks:

11 kV Feeders Summer and Winter Forecast
33 kV Feeders Summer Forecast
33 kV Feeders Winter Forecast
110 kV and 132 kV Feeders Summer Forecast
110 kV and 132 kV Feeders Winter Forecast

In general, the tables contain only feeders that supply multiple customers. Dedicated feeders that supply single large customers are not included.

Further details can be obtained from the Energex website accessible via the following link:

https://www.energex.com.au/dapr2018

F.1 Supporting Notes on Feeders

The following sections list the 132 kV and 110 kV, 33 kV and 11 kV feeders, their forecast loads and their capacity limitations. The feeder loads are calculated from load flow results using forecast substation demands. For the transmission and sub-transmission feeders, load flow studies are conducted for system normal and single contingency situations. For 11 kV feeders, studies are conducted under normal conditions. The limitation tables provide details on feeders having a capacity limitation, and present the most likely solution to address the limitation.

F.2 Peak Load Forecast and Capacity Tables

A definition of terms for these tables is shown in Table F1. These tables show information about the feeder capacity, load at risk, and the compliance of each feeder with its security standard. To assess whether a feeder meets its security standard, four possible risk periods are considered: winter day, winter night, summer day and summer night. The highest risk period for each season is displayed for each year of the forward planning period.

The forecast and capacity cut-off date for the winter season is 1 June of each year, and for the summer season is 1 December of each year. For example, 2018 winter forecast includes all committed projects with a proposed commissioning date up to 1 June 2018, and the 2018/19 summer forecast includes all committed projects with a proposed commissioning date up to 1 December 2018.

Assessment of 33 kV feeders is performed under four possible risk periods: winter day, winter night, summer day and summer night.

Due to the modelling complexity of the 132 kV and 110 kV, two dominant risk periods are considered in the analysis: summer day and winter night.

Peak, reconciled, compensated load forecasts have been used in the 132 kV and 110 kV and 33 kV feeder analyses, with 50 PoE forecast load used for single contingency studies, and 10 PoE forecast load used for system normal studies. The analysis includes load transfers expected from committed projects with the proposed timings scheduled in the program of work as of June 2018, and the 132 kV and 110 kV studies are based on the summer 2016/17 Queensland peak generation scenario[1].

Feeder capacities are shown for 2HEC, ECC and NCC. These ratings have also been adjusted for known committed project proposals. All load transfers associated with contingent condition include acceptable feeder voltage profiles.

Although the conductor rating is generally the limiting factor for feeder capacity, there are other significant items of plant, such as the feeder circuit breaker, that can also restrict capacity. Furthermore, other factors such as voltage constraints and load sharing between parallel underground feeders can sometimes de-rate the capacity of the feeders due to thermal characteristic constraints. Each of these factors has been taken into account in the production of the forecast tables.

The tables also show, for each of the next five years, the compliance of each feeder with its security standard. The peak risk period is the one with the highest calculated load at risk (normal or contingency). Load at risk is calculated using the forecast loads, the feeder capacity, and the capacity of the network to allow the transfer of load away from the feeder to an alternative source of supply. A detailed explanation of the derivation of load at risk is provided in Section F.2.4. If there is no load at risk, then a feeder meets the security standard.

Interconnected or feeders that supply multiple customers are examined in the following tables. Feeders exclusively supplying a customer owned substation or dedicated to a customer are not included in these tables. For transmission and sub-transmission feeders, if there is any load at risk during normal or contingent conditions, the feeder is flagged as not meeting the security standard. Although this may in some cases arise due to inadequate supply for only short periods of time, this approach has been adopted as the best means of fully assessing whether the security standard is being met. As such it will provide evidence of benefits arising from such activities as the installation of remotely controlled switchgear to bolster remote transfer capabilities where these exist.

F.2.1 Transmission Studies

The 132 kV and 110 kV forecast tables provide load at risk based on a contingent event. The contingency scenario considered in the analysis includes the Powerlink upstream network. Due to the meshed nature of the transmission network, a contingent event on a connection point substation or a Powerlink 275 kV transmission network element would have the potential to change load flow dynamics of the system and cause unprecedented overload conditions. As the limitation stems from

[1]The Queensland peak generation scenario is sourced from the 2018 Powerlink Queensland Annual Planning Report using committed generation only, which is based on sample generation dispatch patterns to meet forecast Queensland Region demand conditions.

the upstream network, these results are subsequently used as inputs to joint planning activities to address the limitation prudently or economically.

F.2.2 Sub-Transmission Studies

The 33 kV forecast tables provide load at risk based on a contingent event as described above. For contingencies where automatic transfers via auto change-over schemes are available, N-1 load at risk is shown only if the automatic transfers are not sufficient to fully restore supply to customers.

F.2.3 Distribution (11 kV) Feeder Studies

For the 11 kV feeder studies, the 50 PoE and 10 PoE load forecasts are assessed based on the 2018 winter and 2018/19 summer starting values, and include some load transfers expected from approved project proposals as at June 2018. The forecast winter loads are for the winter season following the summer quoted in that financial year. The 50 PoE load forecasts and the normal cyclic capacity of feeder rating are then used to determine limitations. Where projects have been approved to augment a feeder, the augmented rating has been used in the analysis. Permanent remediation strategies to correct network limitations beyond those resolved via approved projects have not been modelled in the study as these are developed year by year.

Instead of load at risk calculations, the analysis compares feeder utilisation under normal conditions against the acceptable levels of utilisation specific to each feeder. The target utilisation assigned to each feeder depends on its configuration, with radial feeders tending to have higher utilisations of about 80% and balanced three feeder meshes such as those typically found in the CBD having target utilisations of 67%. This approach accommodates the different purposes to which feeders may be employed (e.g. dedicated to single point customer loads, ties or dual feeders). This utilisation is calculated according to the following:

Utilisation (Normal Conditions) = 50 PoE Load / NCC Rating

The conditions used to determine security are as follows:

If Utilisation > Target Utilisation $\Rightarrow$ site does not meet security standard

Projects have been put in place to address all feeders with loads beyond their NCC rating.

Table is the definition of terms for the feeder capacity and forecast tables.

Table F1 – Definition of Terms Feeder Capacity and Forecast Tables

Term	Definition
NCC Rating (A)	Normal Cyclic Capacity - the total capacity with all network components and equipment intact. This is the maximum permissible peak daily loading for a given load cycle that a feeder can supply each day of its life. For overhead feeders, the NCC is the conductor rating with an assumed 1m/s wind, orthogonal to the line. For underground cables, the NCC assumes that there are sufficient temperature and current operating margins from the thermal inertia of the cable and its surroundings.

Term	Definition
10 PoE Load (A)	Peak load forecast with 10% probability of being exceeded (one in every 10 years will be exceeded). Based on normal expected growth rates and weather corrected starting loads.
Power Factor (System Normal)	Lowest power factor along the feeder at 10 PoE Peak Load.
LARn (A)	Security standard load at risk under system normal condition, expressed in Amps.
LARn (MW)	Security standard load at risk under system normal condition, expressed in MW, assuming the nominal system voltages and lowest power factor. $$\frac{\text{(LARn (A) x Nominal Voltage x Power Factor (System Normal) x sqrt(3))}}{1000000}$$
ECC Rating (A)	Emergency Cyclic Capacity – the long term firm delivery capacity under single contingency conditions. Some underground cables are installed in close proximity to other circuits and are normally de-rated to allow for the heat generated by the adjacent cables. ECC is the higher capacity available when any adjacent circuits have been unloaded. For overhead conductors which do not benefit from this phenomenon, the ECC is synonymous with the NCC.
50 PoE Load (A)	Peak load forecast with 50% probability of being exceeded (one in every two years will be exceeded). Based on normal expected growth rates & weather corrected starting loads.
Hours PA > 95% Peak Load	The forecast number of hours per annum where the load exceeded 95% of the peak 50 PoE demand.
Raw LAR (A)	The amount of load exceeding ECC rating. (Load – ECC Rating)

Term	Definition
2-Hour Rating (A)	Two Hour Emergency Capacity (2HEC) – the short term firm delivery capacity under single contingency conditions. For overhead feeders, the 2HEC is the conductor rating with an assumed 2m/s wind, orthogonal to the line (compared to the 1.0 m/s wind speed used for NCC ratings). For underground cables, the 2HEC assumes that there are sufficient temperature and current operating margins immediately prior to the contingency to extract additional capacity from the thermal inertia of the cable and its surrounds.
Auto Trans Avail (A)	SCADA or automatically controlled load transfers that can be implemented within one minute. Examples include auto changeover switching to alternate feeders. A blank entry indicates that this type of transfer is not considered as available in the evaluation of security standard compliance.
Remote Trans Avail (A)	Load transfers that can be implemented through SCADA switching procedures by the network control officer. It is assumed that this can generally be achieved within 30 minutes. A blank entry indicates that this type of transfer is not considered as available in the evaluation of security standard compliance.
Manual Trans Avail (A)	Load transfers can also be deployed via manually controlled switchgear locally by field staff. It is assumed the implementation of manual switching procedures to isolate the faulted portion of the network whilst restoring supply to fault free portions can be fully implemented within three hours (urban) or four hours (rural). Manual transfers are obtained from load flow studies performed on each 11 kV distribution feeder based on the forecast 2016/17 load, the sum of all available 11 kV transfers at a substation is multiplied by a 0.75 factor to account for diversity and to provide an error margin. The same amount of transfers is applied throughout the forward planning period. A blank entry indicates that this type of transfer is not considered as available in the evaluation of security standard compliance.

Term	Definition
POPS	Plant Overload Protection Scheme (POPS) consists of several applications which continuously monitor specific items of plant for overload conditions. If overload conditions are detected and validated, POPS will initiate predefined actions in order to relieve the overload condition.
Mobile Gen Reqd (A)	The amount of generation required under the contingency, capped at the maximum MVA allowable under the security standard requirements. Where required, alternate supply from mobile generators can be sourced within 8 hours (urban) or 12hours (rural). These are generally smaller 500 kVA units that do not require transport permits or police escorts and can be rapidly deployed. Up to 4 MVA (urban) or 10 MVA (rural) of mobile generation may be committed to a single contingency event.
LARc (A)	Security standards load at risk under single contingency condition, expressed in Amps.
LARc (MW)	Estimated generation / load reduction required to defer the forecast system limitation. This is the security standard load at risk under single contingency condition, expressed in MW, assuming the nominal system voltages and the lowest power factor on the feeder under system normal condition. $\frac{\text{(LARc (A) x Nominal Voltage x Power Factor (System Normal) x sqrt(3))}}{1000000}$
Customer Category	For security standard application, the general type of customer a sub-transmission, or transmission feeder is supplying.

F.2.4 Calculation of Load at Risk

The Load at Risk (LAR) is evaluated for both normal (LARn) and contingent (LARc) conditions. Under normal conditions, the loading on a substation is not to exceed the normal cyclic capacity (NCC) of the supplying feeders. Under contingent conditions, the loading of a substation is not to exceed the available supply, whilst taking into consideration the security of supply standards of the supplying feeder.

Load at risk is the shortfall between the feeder forecast load (either 10 PoE or 50 PoE) and the available supply. The equations for feeder LAR are as follows:

- **LARn** = 10 PoE – NCC where NCC is the normal cyclic capacity
- **LARc** = 50 PoE – available capacity – available supply (within security standard timeframe)

Network security standards are not being met if LARn or LARc is greater than 0.

Generally, there are two available capacities and four available sources of supply that can be deployed upon loss of a major network component such as a sub-transmission/transmission feeder.

Types of available capacity:

- **Emergency Cyclic Capacity (ECC)** – Some underground cables are installed in close proximity to other circuits and are normally de-rated to allow for the heat generated by the adjacent cables. ECC is the higher capacity available when any adjacent circuits have been unloaded. For overhead conductors which do not benefit from this phenomenon, the ECC is synonymous with the NCC.
- **Two Hour Emergency Capacity (2HEC)** – For overhead feeders, the 2HEC is the conductor rating with an assumed 2m/s wind, orthogonal to the line (compared to the 1.0 m/s wind speed used for NCC ratings). For underground cables, the 2HEC assumes that there are sufficient temperature and current operating margins immediately prior to the contingency to extract additional capacity from the thermal inertia of the cable and its surroundings. The philosophy of using 2HEC feeder ratings assumes that load is reduced to ECC (if appropriate) or NCC by the end of 2 hours at this capacity.

Types of available supply:

- **Automatic Transfers (AT)** – SCADA or automatically controlled load transfers that can be implemented within 1 minute. Examples include auto changeover switching to alternate feeders. Such capacity has been considered where it is available.
- **Remote Transfers (RT)** – Most of the transmission and sub-transmission network employs remotely controlled switchgear. Some load transfers can therefore be achieved through SCADA switching procedures.
- **Manual Transfers (MT)** – Load transfers can also be deployed via manually controlled switchgear. The implementation of manual switching procedures to isolate the faulted portion of the network whilst restoring supply to fault free portions can be fully implemented within 3 hours (urban) or 4 hours (rural) and is available for extended periods.
- **Mobile Generation (MG)** – Alternate supply from mobile generators can be sourced within 8 hours (urban) or 12 hours (rural). These are generally smaller 500 kVA units that do not require transport permits or police escorts and can be rapidly deployed. Up to 4 MVA (urban) or 10 MVA (rural) of mobile generation may be committed to a single contingency event.

F.2.5 Network Security Standards

The network security standards are outlined in Appendix C. Referred to as the Customer Outcome Standard (COS), the safety net targets for customers are defined. This safety net approach complies with jurisdictional obligations. In compliance with the Distribution Authority, CBD applies to predominantly commercial high-rise buildings using high voltage underground network with significant inter-connection when compared to urban areas. Whereas, urban applies to non-CBD areas predominantly supplying actual maximum demand per total feeder route length of greater than 0.3 MVA per km. Rural then applies to non-CBD and non-urban areas.

F.2.6 Qualification on the Information Provided

For a given 110 kV, 132 kV and 33 kV feeder:

If there is no Raw LAR forecast over the period reported:

- Forecast:
  - 10 PoE forecast is shown;
  - 50 PoE is not shown; and
  - shown as blank for feeders not normally supplying load.
- Rating:
  - NCC rating is shown; and
  - ECC and 2HEC ratings are not shown.
- Transfers:
  - no details shown.

If there is forecast Raw LAR in any year over the period reported:

- Forecast:
  - 10 PoE is shown in all years; and
  - 50 PoE is shown in years when Raw LAR is forecast and shown as blank in years where no Raw LAR is forecast.
- Rating:
  - NCC is shown in all years; and
  - ECC and 2HEC are shown in years when Raw LAR is forecast and shown as blank in years where no Raw LAR is forecast.
- Transfers – Auto, Remote and Manual:
  - where available, details are provided in years where Raw LAR is forecast and shown as blank in years where no Raw LAR is forecast.
- Load at Risk :
  - where available, details are provided in years where Raw LAR is forecast and shown as blank in years where no Raw LAR is forecast.

Appendix G

Worst Performing 11 kV Feeders

Appendix G
Worst Performing 11 kV Feeders

The Worst Performing 11 kV Feeders contains the 2017/18 and 2018/19 Worst Performing 11 kV Feeder. This is available in spreadsheet format via the following hyperlinks:

2017-18 Review of Worst Performing 11 kV Feeders
2018-19 Worst Performing 11 kV Feeders Details

In general, the tables contain only feeders that supply multiple customers. Dedicated feeders that supply single large customers are not included.

Review of Worst Performing 11 kV Feeders 2017/18

This section details the latest performance of each of the feeders with the highest SAIDI and SAIFI identified from their three year average performance up to 2016/17. These are divided into urban SAIDI feeders (25), urban SAIFI feeders (33), rural SAIDI feeders (81) and rural SAIFI feeders (29).

Each feeder contains location information, including the name of the feeder, suburbs serviced by the feeder and the distribution services hub area. Location is an important parameter as it can strongly influence feeder performance due to associated environmental conditions. The tables also contain the route length of the feeders and number of customers connected, which are other characteristics that strongly influence performance.

The three year average SAIDI and SAIFI performance is shown for each feeder with all events included. Normalised SAIDI and SAIFI data is also provided to remove the effect of major event days. Including all events gives transparency to the customer by reflecting the performance actually experienced by them. However a truer reflection of the underlying performance of the feeder is obtained by excluding extreme events, which are well beyond the capability of the feeder. The feeders included in the plan have been identified based on their normalised performance.

The three year average number of outages and the major causes are given for each feeder. This information provides a strong indication of the reasons for poor performance and provides a basis for identifying improvement opportunities.

The red and green arrows in the SAIDI and SAIFI average trend column indicate the SAIDI and SAIFI trend for each feeder for a rolling three year average.

Green ticks in the tick or star column indicate that the reliability of a feeder has significantly improved, and is unlikely to be a reliability concern in the future.

Orange stars in the tick or star column indicate that the reliability of a feeder has improved, and will be monitored for further improvements in the future.

Further details can be obtained from the Energex website accessible via the following link:

https://www.energex.com.au/dapr2018

2018/19 Worst Performing 11 kV Feeder Details

This section details the performance of each of the feeders with the highest SAIDI and SAIFI identified from their three year average performance up to 2017/18. These are divided into urban SAIDI feeders (31), urban SAIFI feeders (33), rural SAIDI feeders (82) and rural SAIFI feeders (79).

Each feeder contains location information, including the name of the feeder, suburbs serviced by the feeder and the distribution services hub area. Location is an important parameter as it can strongly influence feeder performance due to associated environmental conditions. The tables also contain the route length of the feeders and number of customers connected, which are other characteristics that strongly influence performance.

The three year average SAIDI and SAIFI performance is shown for each feeder with all events included. Normalised SAIDI and SAIFI data is also provided to remove the effect of major event days. Including all events gives transparency to the customer by reflecting the performance actually experienced by them. However a truer reflection of the underlying performance of the feeder is obtained by excluding extreme events, which are well beyond the capability of the feeder. The feeders included in the plan have been identified based on their normalised performance.

The three year average number of outages and the major causes are given for each feeder. This information provides a strong indication of the reasons for poor performance and provides a basis for identifying improvement opportunities.

The red and green arrows in the SAIDI and SAIFI average trend column indicate the SAIDI and SAIFI trend for each feeder for a rolling three year average.

Green ticks in the tick or star column indicate that the reliability of a feeder has significantly improved, and is unlikely to be a reliability concern in the future.

Orange stars in the tick or star column indicate that the reliability of a feeder has improved, and will be monitored for further improvements in the future.

Further details can be obtained from the Energex website accessible via the following link:

https://www.energex.com.au/dapr2018

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Energex Limited
ABN 40 078 849 055

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