Distribution Annual Planning Report

2020

energex

Version Control

Version	Date	Description
1.0	22/12/2020	Final
1.1	4/09/2023	Update new website links

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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. Forecasted data is subject to ongoing variation due to COVID 19 impacts. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

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Executive Summary

Energex's Distribution Annual Planning Report (DAPR) 2020 provides the company's intentions for the next five years in an environment characterised by rapid technological change and continuously high penetrations of renewable energy resources.

The DAPR provides the community and stakeholders with an insight into the key factors shaping our plans, the current and forecasted electricity demand, the state of our networks and service performance trends, as well as our investment intentions for the coming years. Many solutions seek customer and industry participation to resolve. In addition, the online interactive network maps for market proponents indicate locations for potential investments.

To ensure we are meeting the unique and diverse needs of our communities and customers, in a period where the energy sector is undergoing rapid transformation, we coordinate engagement and performance management programs which have shaped our Regulatory Determination for 2020-25, our network tariff reform program and our investment plans.

As Energex's network ages and the risk of equipment failure towards end of life increases, a focus on maintaining safety outcomes for our staff, customers and communities is paramount. We continue to focus on improving safety in our maintenance and replacement practices across all asset categories and continue to invest in trialling new technology that has the potential to deliver safer outcomes, more efficiently for our customers.

While COVID-19 has had an impact on the economy, we continued to provide reliable and secure supply to our customers. As a result, Energex's network reliability performance results in 2019-20 were favourable against all measures in the Distribution Authority.

The 2019-20 summer peak of 5,069MW, recorded at 5pm on Monday, 3 February 2020, was the second highest in the history of Energex. Rooftop Solar PV reduced the peak by 369MW.

The uptake of solar PV in the residential, commercial and industrial sectors has created the need to forecast minimum demand on the Energex network. Historically, Energex's minimum demand occurs in the late evening /early morning. The most recent minimum demand occurred on 8 September 2019 at noon with a daytime minimum of 1,136MW.

Cyber security is 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. ICT programs have been initiated to improve technology to deal with evolving business needs, a distributed workforce, changing ways of working and an increasingly complex cyber security environment.

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. As solar PV continues to grow at a steady level, the uptake rate of electric vehicles (EV) is expected to rise due to the number of new car models being released and the increased availability of public charging stations. In parallel, customer interest for battery storage systems is increasing, and with PVs and EVs and other distributed energy resources they will shape our energy and power demand profiles in the future.

Chapter 1

Introduction

- Foreword
- Network Overview
- Peak Demand
- Minimum Demand Forecasting
- Changes from Previous Year's DAPR
- DAPR Enquiries

1 Introduction

1.1 Foreword

This Distribution Annual Planning Report (DAPR) 2020 explains how Energex is continuing to safely and efficiently manage the electricity distribution network in South East Queensland (SEQ).

In the release of this eighth 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
- Provide input to the future development of the network.

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.

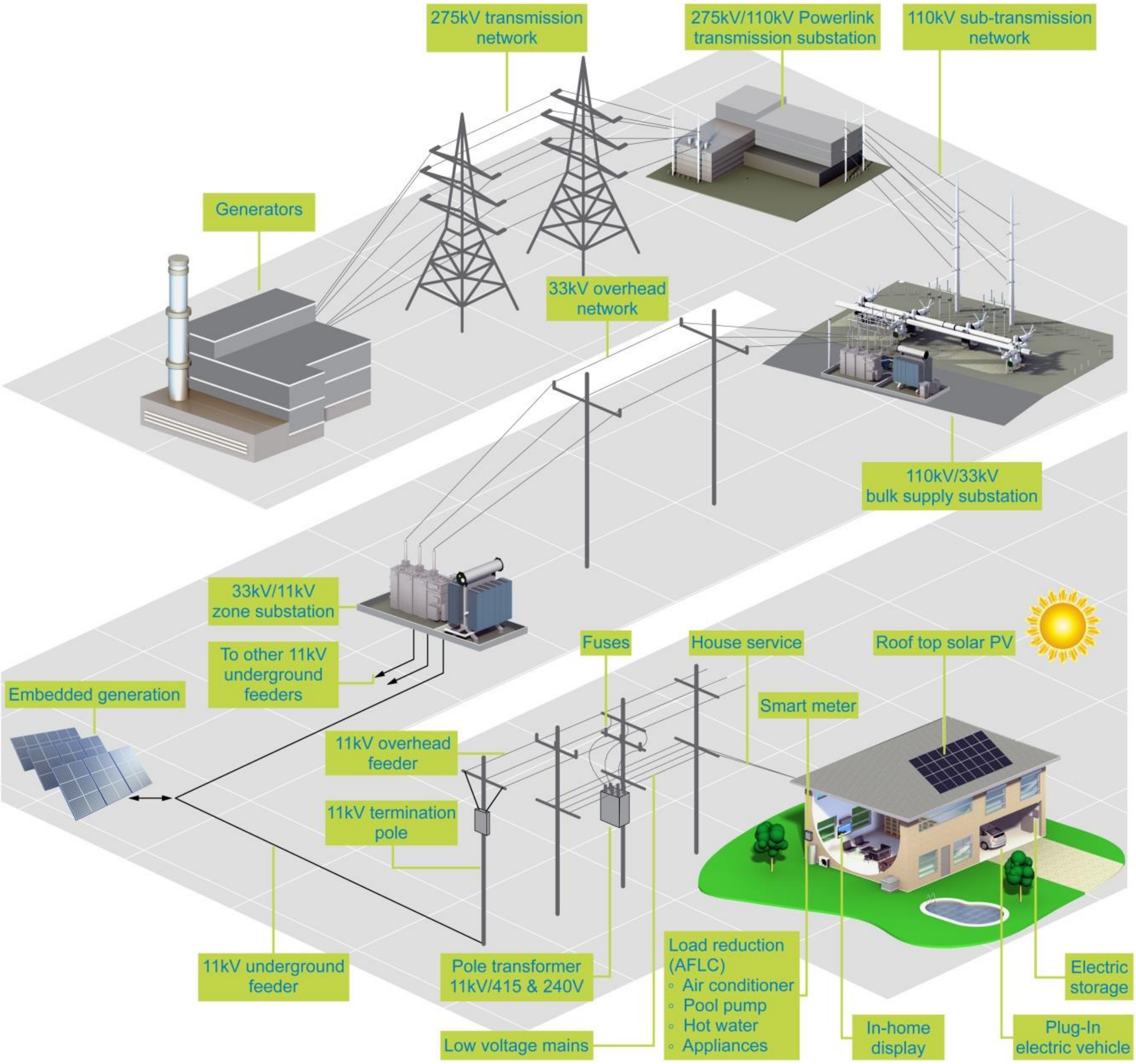
For readers seeking to learn of planning outcomes since the 2019 DAPR, they are referred to section 5.9 for joint planning outcomes, to section 6.4 for upcoming RIT-Ds, and to Appendix D for committed projects and proposed opportunities.

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.

1.2 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 11kV. 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



1.3 Peak Demand

In a positive demand growth environment, increasing peak demand may create the need for additional investment, dependant on detailed planning. Energex must maintain sufficient capacity and voltage stability 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. At the same time, 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 2019-20 was recorded at 5,069MW on Monday, 3 February 2020 at 5:00pm.

1.4 Minimum Demand Forecasting

Historically, Strategic Forecasting has focused on maximum demand, energy delivered, energy purchased and customer numbers. However, the uptake of solar PV in the residential, commercial and industrial sectors has created the need to forecast minimum demand on the Energy Queensland network.

The impact of a daily minimum demand caused by the increase of rooftop solar uptake affects the distribution network at three levels all of which will affect CAPEX expenditure:

- System level – Oversupply during the middle of the day may force large solar generators to be switched off as ramp up times are quicker than coal fired power stations. To date Energy Queensland has been able to leverage voltage regulation at the transmission connection point to limit the need for downstream remediation, but increasingly this will not be possible as the transmission network runs out of transformer tap or ‘buck’ range
- Substation level – Cyclic issues due to reverse flow may reduce the life of zone substation transformers
- At a Feeder level – May impact the stability of individual feeders causing voltage fluctuations which, in turn, impact protection settings at a feeder level. (Given the high number of open and closed delta regulators on Energex distribution feeder network, cogeneration settings on regulators would need to be revisited to ensure voltage levels on feeders remain at a stable level during the day).

Rooftop PV is driving an increasingly rapid change in the load on the network from the day to night. This may give rise to an expanded role for fast-ramping but more expensive generators to manage the transition and supply overnight - again limiting the economic viability of existing baseload and new renewable generators and increasing the cost of wholesale energy. Managing the transition may necessitate greater dynamic reactive plant and give rise to challenges in system operation.

Residential rooftop solar installations within the Energex region continues to grow strongly with inverter capacity growing around 20% p.a. and approximately 300MW of capacity being installed per year. A considerable proportion of larger systems are being installed on commercial and industrial sectors which is indicative of possible future trends in small scale industrial and commercial solar installation.

The high number of residential rooftop solar on the network along with forecast installations has shifted the daily minimum demand on the network from a night time minimum to a daytime minimum. Typically, Energex’s minimum demand occurs in the late evening /early morning with the lowest overnight minimum demand recorded in 2002 with a low of 1,147MW. This record has now been surpassed in 2019 with a daytime minimum of 1,136MW.

The minimum demand for 2019 occurred on the 8th September at approximately 12pm and although the minimum demand on the network was not negative, analysis of the historical minimum demand trend shows that, at a system level, daytime minimum demands have fallen by 6.1% p.a. since 2012. This trend indicates that future system minimum demands will be expected to occur the day and not at night.

The minimum demand in 2019 occurred in the month of September which is classed as the traditional “shoulder season”. As the relative solar exposure that typically occurs in September is approximately 80% of that which occurs in December, a shift of negative minimum demand from the shoulder period to the peak summer period is possible in coming years. Therefore, the Energex network may observe minimum system demands occurring on holidays such as Christmas day rather than during earlier shoulder periods such as September.

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 2020 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 2019 DAPR:

- Review and merge Corporate Profile and Asset Management overview chapters into Chapter 2
- Review and streamlined Chapter 4 – Strategic Forecasting
- Added: “Summary of Substation and Feeder Limitations” - Table 11
- There were four projects approved with credible options having an estimated cost of the augmentation component greater than $6 million. RIT-D information is listed in section 6.4
- Review and update on Energex’s demand side management policy, strategy and initiatives
- Merged Information, Communication and Technology, Metering and Operational and Future Technology chapters into Chapter 12 – Information Technology and Communication Systems.

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 and Asset Management

- Corporate Overview
- Electricity Distribution Network
- Network Operating Environment
- Asset Management Overview

2 Corporate Profile

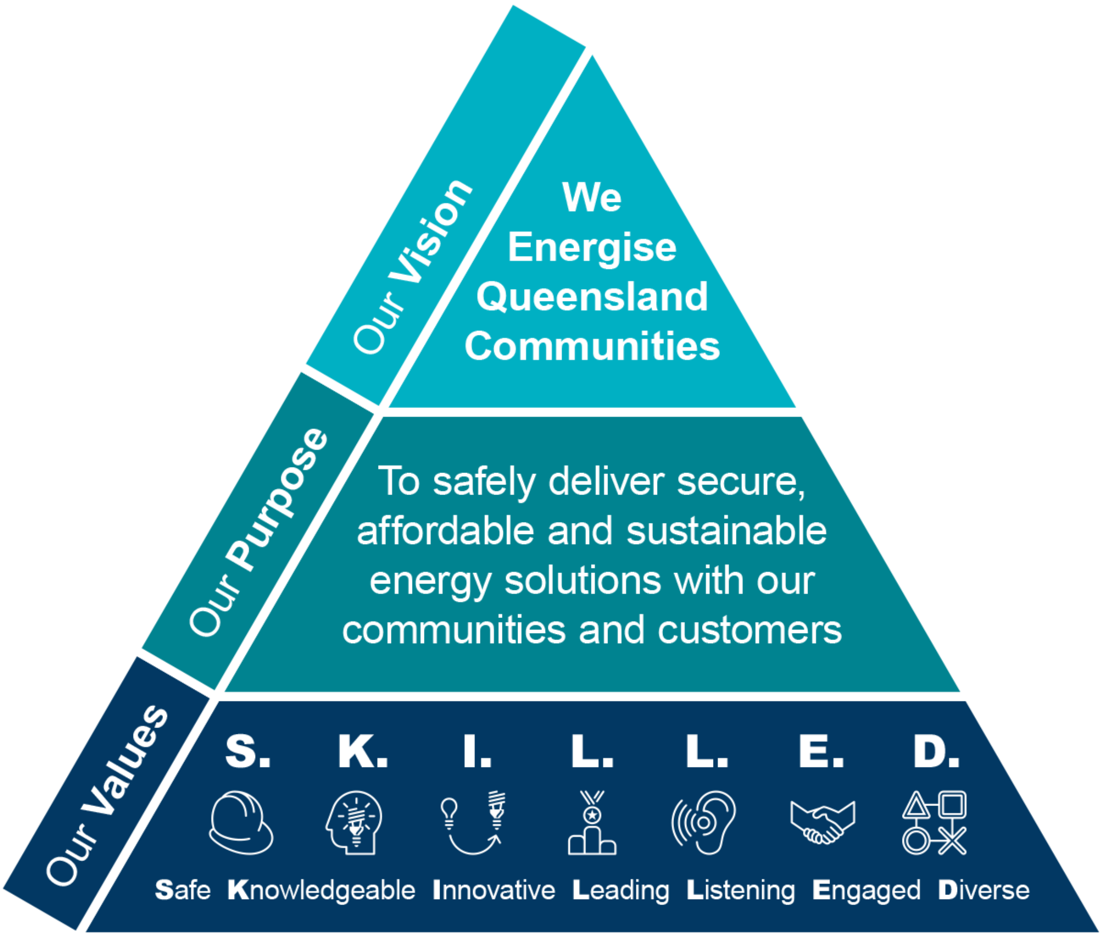
2.1 Corporate Overview

Energex (Energex Limited) is a subsidiary of Energy Queensland Limited, the Queensland government owned corporation formed through a merger in June 2016.

2.1.1 Vision, Purpose and Values

Energy Queensland's corporate vision is to energise Queensland communities. Our purpose is to deliver secure, affordable and sustainable energy solutions with our communities and customers, and our SKILLED Values are as shown in Figure 2.

Figure 2 – Energy Queensland Vision, Purpose and Values



2.2 Electricity Distribution Network

Energex distributes electricity to approximately 1.5 million residential, commercial and industrial customer connections, supporting a population base of around 3.5 million in South East Queensland.

At the core of the business is a high performing electricity distribution network that consists of property, plant and equipment and assets valued at approximately $12 billion.

The bulk of the electricity distributed enters Energex's distribution network through connection points into Powerlink Queensland's high voltage transmission network, which brings the electricity from the state's major generation plants. However, Energex also enables connection of distributed energy resources, such as solar energy systems and other embedded generators.

The Energex network is characterised by:

- Connection to Powerlink's transmission network at 27[1] connection points
- High density areas, such as the Brisbane Central Business District (CBD) , and the Gold Coast and Sunshine Coast city areas, typically supplied by 110/11kV, 110/33kV, 132/33kV, or 132/11kV substations
- Urban and Rural areas where 110/33kV or 132/33kV bulk supply substations are typically used to supply 33/11kV zone substations
- Inner Brisbane suburban areas with extensive older, meshed 33kV 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 can be readily added
- New subdivisions in urban and suburban areas supplied by underground networks with padmount substations.

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

[1] Note: Count is distinguished by voltage level.

Table 1 – Summary of Network and Customer Statistics for 2019-20

Assets	2019-20
Total Overhead and Underground (km)	55,223
Lines – Length of Overhead (km)	
Total	35,074
LV (Low Voltage)	14,169
11kV	17,557
33kV	2,194
132 kV and 110 kV	1,154
Cables – Length of Underground (km)	
Total	20,149
LV	12,755
11kV	6,395
33kV	834
132kV and 110kV	165
Other Equipment (Quantity)	
Bulk Supply Substations	42
Zone Substations	246
Poles [1]	695,587
Distribution Transformers	51,289
Street Lights [2]	392,785
Customer Numbers	
Residential	1,393,090
Other	132,258
Total [4]	1,525,348

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

2 All streetlights including rate 3 streetlights.

3 All information as at June 30 each year.

4 Active and de-energised 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

This section presents 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.

Features 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.
- SEQ has some of Australia's highest incidence of Lightning activity.

Performance of the network under these conditions is discussed further in section 9.3.

2.3.2 Shareholder and Government Expectations

We are also continuing to increase the choices available to our customers, working to progress tariff reforms and developing innovative energy-related services.

This supports the Queensland Government's commitment to supply 20% of its electricity consumption with renewable energy sources by the end of 2020, making significant progress to reaching its 50% renewable energy target by 2030.

Similarly, with the support of the Queensland Government, we are continuing to facilitate the adoption of emerging storage technology, both Battery Energy Storage Systems (BESS) and Electric Vehicles (EVs).

2.3.3 Community Safety

Community Powerline Safety Strategy 2018-2020

Our Community Powerline Safety Strategy (CPSS) is a publicly available document, which aims to:

- Foster positive and proactive association of powerline safety within the community
- Build community awareness of the dangers
- Encourage education and behaviour change
- Demonstrate our commitment to community powerline safety.

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

2.3.4 EQL Health, Safety and Environment Integrated Management System

The Energy Queensland Limited Health, Safety and Environment Integrated Management System (EQL HSE IMS) has been developed to provide a framework to effectively manage health, safety, environment, cultural heritage and security risks across the organisation. This framework was modelled upon the existing management system requirements for Energex and Ergon Energy to enable the transition to a centralised EQL HSE IMS. The EQL HSE IMS is currently accredited to:

- ISO 14001:2015 Environment Management System; and
- AS/NZS 4801:2001 Occupational Health and Safety Management System

The EQL HSE IMS consists of 12 Standards which are aligned to accreditation requirements. Standard 8 Control of Work consists of 14 Hazard Controls (HCs) to enable business units to implement fit for purpose risk controls. HCs include requirements which are accepted practice across Energy Queensland, which may exceed legal requirements and include:

1. Transport
2. Access and Entry
3. Community Safety
4. Plant, Tools and Equipment
5. Working with Electricity
6. Asset Safety
7. Manual Tasks
8. Hazardous Materials and Waste Management
9. Fit for Work
10. Land and Water Management and Disturbance
11. Air, Energy and Greenhouse Gas
12. Occupational Health, Noise and Amenity
13. Security
14. Working at Heights.

Please refer to R284. EQL HSE IMS Hazard Control Manual for further guidance on these. The EQL HSE IMS is subject to third party HSE IMS Surveillance audits and the Electrical Safety (ESO) Electrical Entity audit conducted once per year.

2.3.5 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.

2.3.6 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

- Treasurer and Minister for Investment
- Minister for Energy, Renewables and Hydrogen and Minister for Public Works and Procurement.

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
- State and federal environment and planning laws, including the Environment Protection and Biodiversity Conservation Act 1999 (Cth), Environmental Protection Act 1994 (Qld) and Planning Act 2016 (Qld).

2.3.7 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 applies an incentive-based regulatory framework that encourages Energex to provide services as efficiently as possible. The AER does so by setting the maximum regulated revenues that we are allowed to recover from our customers during each year of the regulatory control period. The revenues are based on an estimate of the costs that a prudent and efficient network business would incur to meet its regulatory obligations. Given that the revenues are locked in at the start of the period, we have a general incentive to provide our services at less than the forecast costs and keep the difference until the end of the regulatory period. In the following period, we share the benefits of efficiencies with our customers.

This general incentive framework is complemented by a suite of guidelines, models and incentive schemes, including, amongst others, the:

- Efficiency Benefits Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS), which encourage us to pursue efficiency improvements in OPEX and CAPEX and share them with customers
- Service Target Performance Incentive Scheme (STPIS) which encourages us to set, maintain or improve service performance

- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM), which encourage us to pursue non-network options
- RIT-D, which requires us to undertake a cost-benefit analysis and consult with stakeholders before undertaking major investments
- Ring-fencing Guideline, which requires us to separate our regulated services from contestable services.

On 5 June 2020, the AER published its Final Distribution Determination for Energex for the 2020-25 regulatory control period, commencing 1 July 2020 to 30 June 2025. More information regarding Energex's allowed revenues and network prices can be found on the AER's website (www.aer.gov.au).

2.4 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)
- Network Investment Process.

2.4.1 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).

2.4.2 Asset Management Policy

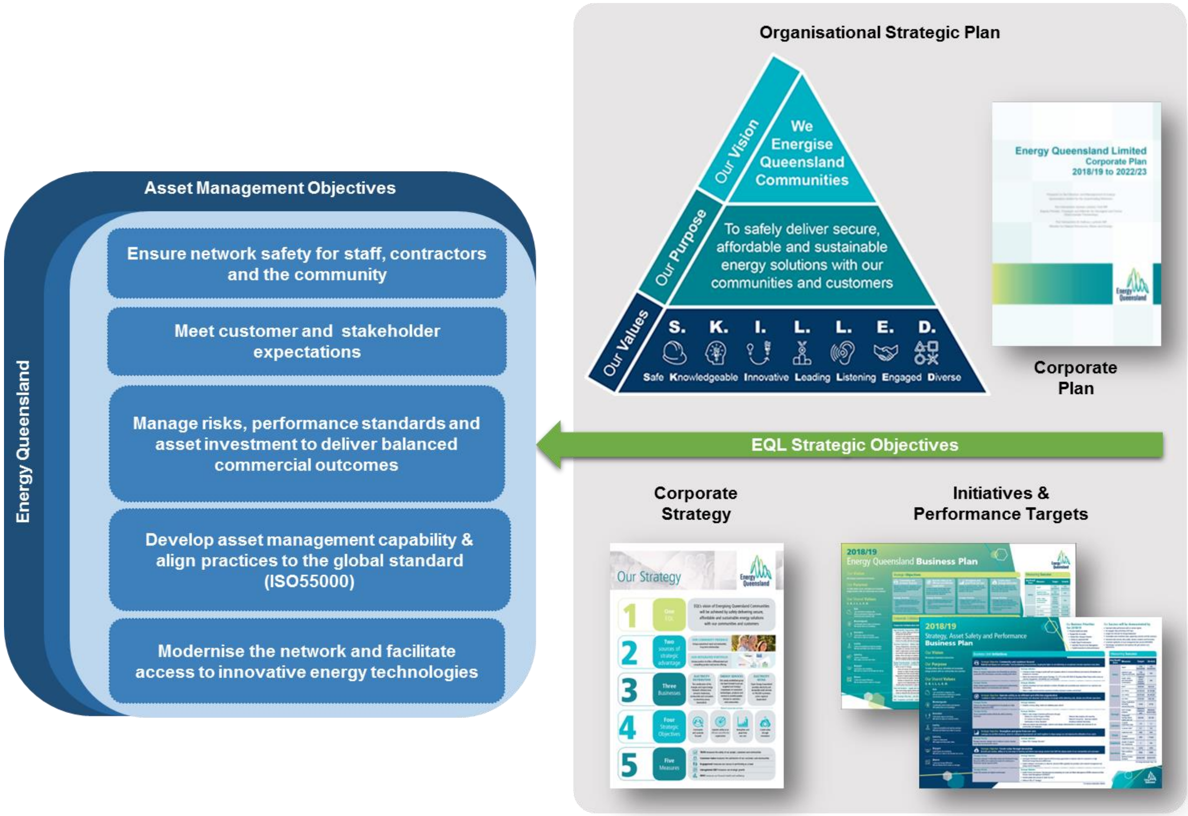
The asset management policy provides the direction and broad framework for the content and implementation of Energex's asset management strategies, objectives and plans. The policy directs Energex to undertake requirements associated with safety & people, meeting customer needs, and the commitment to 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.

2.4.3 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 4. 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 4 – SAMP translates Corporate Objectives to Asset Management Objectives



2.4.4 Investment Process

2.4.4.1 Corporate Governance

Energex has a four governance process to oversee future planning and expenditure on the distribution network as shown in Figure 5.

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 5 – 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 Works Program 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 Operational Delivery which is a corporate key performance indicator (KPI) that, with monthly performance reporting for key projects, informs the Executive and Board. Quarterly Program of Work updates are provided to the Board
4. **Project and Program Approval:** Network projects and programs are overseen by senior management and subject to an investment approval process, requiring business cases to be approved by an appropriate financial delegate.

2.4.5 Network Risk Management and Program Optimisation

Management of risk is a crucial foundation for effective asset management and an integral part of ISO 55000 Asset Management suite of standards. Energy Queensland's Network Risk Management Framework ensures we apply a consistent approach to the assessment of network risks. It aligns with AS/NZS ISO 31000:2009 Risk Management - Principles & Guidelines and with Energy Queensland's Portfolio Risk Management Framework. Energy Queensland continuously reviews inherent and emerging network risks to ensure optimisation of our projects and programs.

Network risk is assessed according to the following five risk categories:

- Safety
- Environment
- Legislated Requirements
- Customer Impacts and
- Business Impacts.

Risk assessment involves development of credible scenarios that may lead to a specific risk consequence. This is followed by estimation of the likelihood of occurrence and subsequent development of a risk rating for each scenario. Projects and programs of work are then considered for inclusion in the program of work on a priority basis to deliver appropriate network-wide risk mitigation. Energex Network optimises its program of work to balance the inherent risk should some programs not proceed, it considers; cost and funding constraints, resourcing availability, performance targets and other project drivers including fulfilment of strategic objectives.

2.4.6 Further Information

Further information on our network management is available on the Energex website:

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

Chapter 3

Community and Customer Engagement

- Overview
- Our Engagement Program
- What We Have Heard
- Our Customer Commitments

3 Community and Customer Engagement

3.1 Overview

To ensure we're meeting the unique and diverse needs of our communities and customers we invest in engaging with our customers and other stakeholders on their expectations, concerns and ideas.

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-focused solutions. Across our Group we operate a coordinated, multi-channel community and customer engagement and performance measurement program. These conversations, and the focus they provide, are fundamental to creating real long-term value for our customers, our business, and Queensland.

Most recently we have refreshed our understanding and prioritisation of the economic, social and environmental and governance topics that matter most to our different stakeholders – building on our extensive engagement undertaken previously and ongoing in 2019-20 around the network businesses' investment plans and our Regulatory Determination for 2020-25, and our network tariff reform program.

Our engagement efforts continue to influence the asset management strategies and investment plans in this report and help to align our future thinking with the long-term interests of our communities and customers.

This chapter provides an overview of these engagement activities and describes how they enable us to put our communities and customers at the heart of everything we do. More information is available in our Annual Report and the 2020 and Beyond Community and Customer Engagement Report published with our Regulatory Proposals.

3.2 Our Engagement Program

3.2.1 Customer Council and other Forums

Through Energy Queensland's Customer Council, as our flagship listening forum, we gain a customer perspective to emerging energy-related issues and potential solutions to deliver on their needs and expectations. We also have a wider group of customer and community representatives who have participated in engagements around our Regulatory Determinations and tariff reforms. This group met with us over the previous year, while we were revising our plans, to explore the decision remaining open for consideration and, at the same time, continue to build their capacity to understand our industry and its regulatory framework.

We also have a Major Customer Forum, Public Lighting Forum and Agricultural Forum to discuss topics relevant to specific customer groups.

3.2.2 Working with Industry Partners

We engage actively with our industry partners, both strategically and operationally.

The Energy Charter, of which we are one of 21 signatories, continues to provide a platform for collaboration with organisations from across the energy industry, building accountability across the supply chain and improving customer outcomes.

Direct engagement and service relationships with the different energy retailers who operate across the Queensland market remains critical to delivering for our customers.

Our industry engagement also includes state-wide forums to listen and share knowledge with electrical contractors, solar supplier/installers and property developers. These channels of communications are increasingly important to us as we move forward.

3.2.3 Community Leader Engagement

To better connect with our communities and ensure we are effective in our service delivery, we have 17 established operational areas across the state. Each area has a locally-based manager who build relationships with our local community stakeholders and understand the areas unique concerns.

This has been particularly important this year in managing our operational response to the COVID-19 pandemic, especially in our First Nations communities.

To support local stakeholder engagement, we also host Board stakeholder events regionally to ensure we keep in touch with our communities' expectations. While suspended with COVID-19, they provide an important means for our Directors, the Executive and a wide group of managers and decision-makers to interact with local stakeholders and customers.

3.2.4 Online Engagement

We continue to use our digital engagement platform, www.talkingenergy.com.au, with around 2,000 people registered for updates and engagement.

The site has proven to be an effective tool to interact with targeted stakeholders, as well as a channel to reach a wider audience as we engage on key energy topics and issues.

It has been especially useful of recent times to engage on technical matters, like changes to standards, as a single place to engage with stakeholders from across Queensland.

3.2.5 Our Customer Research Program

To improve the customer experience, as part of our Voice of the Customer program, we survey customer satisfaction following the key service interactions for each customer group, from our residential customers right through to major customer, electrical contractors, electricity retailers and key stakeholders. This is reported as the Customer Index for the Group.

This feedback mechanism is also supported by a program of additional market research activities that tracks both customer and community sentiment and enables deep exploration on specific topics.

A key annual survey is the Queensland Household Energy Survey. Funded by Energex and Ergon Energy Network in conjunction with Powerlink Queensland, in late 2019 this survey captured feedback from over 4,500 Queensland households. It tracks energy use and energy efficiency behaviours, and the take up of emerging energy-related technologies. This survey also tracks customer perceptions and overall attitudes to electricity prices and power supply reliability.

Through the Queensland Chapter of the Thriving Community Partnership (TCP), we collaborated this year with other corporate, not-for-profit and government partners in a Disaster Planning and Recovery Collaborative Research Project that explored the opportunities for positive change in our disaster response when the community is most vulnerable.

This year's research builds on the in depth research undertaken, both qualitative research (deliberative forums and focus groups) and quantitative research, to inform our Regulatory Determination, and the asset strategies and future works programs outlined in this report.

We will continue to track how satisfied our customers and the wider community are with our services, and the level of trust they have in us to do the right thing.

3.3 What We Have Heard

Through our engagement activities we continue to hear the following key messages:

- Safety should never be compromised – and it is an area where we could be 'smarter'

- Electricity affordability remains a concern for many customers – both from a cost of living and a business competitiveness perspective
- Our communities and customers value how we go about keeping the lights on, especially our response to severe weather events and other natural disasters
- Our customers want greater choice and control around their energy solutions
- Interest in renewables and growing concerns around climate change is fuelling customer and community expectations around the transition to a low carbon economy
- The impact of the COVID-19 restrictions and subsequent recession has brought ‘energy inclusion and vulnerability’ and ‘economic development and jobs’ to the foreground.

3.3.1 Safety First

There is recognition across our communities and customers of the dangers of electricity, and that if the network is not appropriately managed it presents a risk to our communities and employees. We are expected to be vigilant, and to always make safety our priority.

Community education on electrical safety awareness is seen as important, especially around natural disasters.

Our customers expect that we continue to adopt technology and process improvements to look for smarter ways to deliver improved safety outcomes.

Health concerns around the COVID-19 pandemic, especially in our First Nations communities, continue to have implications for our operational response.

3.3.2 More Affordable Electricity

Pricing

Electricity affordability remains the core concern for many of our customers, both from a cost of living and a business competitiveness perspective. Earlier increases in electricity prices, despite recent tariff relief, continues to have a detrimental effect on the value our customers place on the service we deliver.

Customers generally do not consider distribution network charges separately to their retail electricity bill. They are simply looking to the industry as a whole to deliver electricity price relief, without comprising the safety, security or reliability of supply or customer service standards.

The desire for greater control, in order to manage or moderate their bill, is driving much of the disruption across the industry.

We track price and affordability perceptions, and while we were encouraged by progress this year prior to the economic impact of the COVID-19 pandemic, in the [Queensland Household Energy Survey,] electricity bills remained the top household cost concern among regional Queensland households and third next to fuel and health costs for households in the South East.

Network Tariffs

Our customers are looking for network tariffs that offer simplicity, savings, value and choice, and that reward them for their role in energy transformation.

Many stakeholders recognise that network tariff reform is needed to respond to the changes in the market and to deliver sustainable charges for the future. However, more engagement is required to progress the reforms put forward in our Tariff Structure Statements.

Many customers would be willing to reduce their electricity use during peak times on the network, if rewarded. They recognise that there is an increasing opportunity to achieve this with emerging technologies. However, any reforms would need education awareness and support.

Fairness

It is clear that we have a corporate responsibility in providing an essential service to do all we can to address electricity affordability, and to deliver to all Queenslanders whether 'coast or bush'.

There is concern around the ability of some to respond to the changes taking place in the industry. Together, we need to ensure everyone benefits equitably from solar and other emerging technologies and that vulnerable segments of the community are not left behind.

From a network tariff perspective, being 'fair and equitable' is both about minimising cross subsidies and managing the social and economic impact of any move to more cost reflective pricing. There is also a need for a trusted advisor to provide independent impartial advice, and to help customers make informed choices in their energy use and behaviours.

3.3.3 A Secure Supply – Keeping the Lights On

Emergency Response

Queenslanders know that storms, cyclones, bushfires, floods and other disasters are beyond anyone's control. Feedback confirms that we respond well when these events occur and that our contribution is important to communities in getting them back up and running quickly.

We have largely had support for the way we managed our response state-wide to the COVID-19 pandemic. Safety was our priority, as we followed government advice to minimise the risk of exposure to our crews, customers and the wider community, while continuing to deliver a reliable electricity supply across Queensland. There was and remains heightened community sensitivity to residential power outages with more people working (at times even schooling) from home.

As part of Queensland's economic recovery, there are currently heightened expectations around the delivery of key capital projects going forward – the timely delivery to support economic development, maximising employee utilisation and where appropriate engaging local contractors/suppliers.

TCP's Research Project interviewed residents and small business owners impacted by the 2019 North

Queensland Monsoon to map their experiences leading up to, during, immediately after and in the months following the disaster. The report highlights the 'gatekeeper' role electricity plays to action before and after a disaster; how the communications across the journey influence response and recovery; and provides a range of other insights.

Reliability

Our communities and customers value having a reliable and consistent electricity supply and particularly appreciate our ability to quickly and safely restore services after weather events.

Most of our customers are satisfied with the current reliability standards delivered through our networks and do not necessarily value greater investment for higher reliability. However, some customers, especially those in the more rural and remote areas of our network, consider they are poorly serviced.

Power outages have a range of immediate customer and broader economic impacts. The quality of supply is also important to some customers.

76%*

are satisfied with the reliability of supply. This benchmarks above national average, despite ongoing supply challenges.

*Energy Consumers Australia Energy Consumers Sentiment Survey June 2020.

Customer Experience

Expectations around customer experience are shifting, and generally increasing, especially around notifications around issues such as power outages.

Feedback received through our Voice of the Customer program and our Customer Index has shown steady improvement over the last three years, with a notable uplift in customer satisfaction over the last 12 months from 6.7 in 2018-19. The above target result of 7.1 out of 10 for 2019-20 (target 6.7) was supported by service improvements across the Group.

Many see outage updates and restoration times as important as preventing the initial outage. Knowing we need to provide this information in ways that work for all saw us launch improvements to our Customer Self Service Portal, which allows customers to subscribe to receive a SMS and email notification for planned and unplanned outages. Since launching the SMS notification, over 20,000 customers have signed up for the service across Queensland. We are continuing to promote this service and monitor satisfaction.

Generally our stakeholders support us in using technology to improve efficiency and reduce costs, but we note that the scale of our digital transformation program is significant and that this creates some stakeholder concerns around potential business and service disruption.

3.3.4 A Sustainable Future

Network as an Enabler

The way our customers source and use energy, and monitor their energy needs, is rapidly changing. As new technologies are embraced to manage energy use and costs, and to support action on climate change the industry is transforming. Our customers recognise that new technology is important to a modern network and support initiatives that enable their choices and reduce costs.

Our customers expect us to be able to facilitate and accommodate integration of renewables, battery storage and electric vehicles into the network, without creating risks to network security, supply quality or performance.

During 2019-20, the number of applications for the connection of large-scale (>30kW) renewable energy generating systems to our networks grew again.

Our connection teams also supported an escalating number of rooftop solar system connections to our network, with the strongest growth in the South East. There are now over 600,000 solar energy systems connected to our network across the state.

Managing solar on the network and keeping voltages within statutory limits is challenging. Across the Energex network, there has been a 14% increase in voltage complaints.

87%*

said it was important that we modernise our electricity networks to continue to enable customers to take up new technologies.

* Future Energy Survey.
Q: How important is it that we modernise our electricity networks to continue to enable customers to take up new technologies? 'Don't know' excluded.

Our most recent insights from the December 2019 Queensland Household Energy Survey confirm that customers intend to adopt further rooftop solar – indicating that solar penetration could increase to 48% in the next 3-5 years, with 65% possible in the future.

Queenslanders have embraced more energy efficient behaviours over the last decade, however, attempts to reduce electricity use have declined. This appears to be related to the increase in solar penetration.

The survey confirmed that decreasing battery system prices is making them more attainable for Queenslanders. The number of customers with batteries has grown dramatically over the past year, with over 7,000 now installed. However, the intention to purchase battery storage in the next three years has dropped, especially in regional Queensland, with concerns around return on investment. Despite this, we expect around 150,000 energy storage systems to be in use by 2030.

Additionally, the survey tracks customer intention to go off-grid. Outback households are more likely to be considering this for the future. The reasons are largely around cost and price, but also the desire for self-sufficiency and to protect the environment.

While Electric Vehicles (EV) are still niche, the survey indicated a tipping point is approaching. By mid-year there were 2,300 fully electric Battery Electric Vehicles (BEVs) and almost 1,100 Plug-in Hybrid Electric Vehicles (PHEVs) on Queensland's roads. With a number of new, more affordable vehicle models scheduled for release over the coming year, the trend towards greater EV adoption is expected to continue.

There is a strong expectation that we will innovate and create a future-focused network to support our commitments and customers' lifestyles.

Our stakeholders are concerned with our ability to 'predict the future' given the level of change and potential impacts on the electricity grid combined with our long-life asset profile.

Collaboration

Our customers, communities and other stakeholders, expect us to engage with them in a transparent, meaningful manner on a regular basis.

Only two-fifths of Queenslanders in Energy Consumers Australia's Sentiment Survey June 2020 are confident the market will provide better value for money outcomes in the future. While there has been some improvement here, trust and relationships need to be rebuilt.

53%*

are confident that the energy market will provide better supply and cost outcomes through technology advances.

*Energy Consumers Australia Energy Consumers Sentiment Survey June 2020.

There is a strong desire to engage and work with us to realise the benefits from today and tomorrow's emerging technologies, and the valuable role the network provides in the energy transformation.

Education and awareness are seen as important. Customers need to be informed to take advantage of emerging technologies and participate in the market. Vulnerable customers must not be left behind – information is important to removing barriers to participation.

There is strong interest in collaborating around non-network alternatives and support for continuing existing demand management. Our demand management program is viewed positively, with our stakeholders expecting us to collaborate with, and provide incentives to, customers and the supply chain to assist in demand management delivery and uptake.

This collaboration is being outworked by Ergon Energy and Energex's Demand Side Engagement Strategy, which seeks to inform and include customer and non-network service provider participation to address any network limitations. We have a variety of means to which stakeholders become informed about network limitations and express interest and indicate ability for participation on non-network solutions.

Connections

Reasonable, clear timeframes and costs for connections are critical to Queensland's economic development. Customers are seeking a simplification of our connection process, and for continued equitable support of embedded generator connections. They have told us that network connections need to be timely, simpler and cost-reflective – there remains support for our efforts to align our service offering across Queensland. Customers also expect that we adapt to their changing preferences on connecting to our network.

3.4 Our Customer Commitments

As part of our planning process for our Regulatory Determination, we responded to the above community and customer insights with a set of commitments for 2020 and beyond. Our Customer Commitments, provided on the following page, continue to prioritise our investment plans, including the strategies and specific investments reflected in this report.

OUR CUSTOMER COMMITMENTS

SAFETY FIRST

Our priority is to be *Always Safe* – to show leadership in health, safety and wellbeing across our industry and the broader community.

AFFORDABLE

We continue to look for ways to make electricity more affordable across our networks, and to advocate for the reforms needed for a bright energy future all Queenslanders.

PRICING

To help take the pressure off electricity prices, we'll continue to drive down the cost of distributing the electricity across Queensland.

NETWORK TARIFFS

Our tariff and other reforms will be transparent, fair and equitable. We'll continue to show leadership in the energy transformation – with reforms that help to realise the potential value of emerging technologies.

FAIRNESS

We recognise the need to support our customers and communities, especially during times of vulnerability. We are committed to delivering responsibly on what really matters so that no-one is left behind and our communities grow stronger.

SECURE

We're here 24/7 to keep the lights on – providing the peace of mind of a safe, reliable electricity supply, and from knowing that we'll be there 'after the storm'. We're here to make life easy.

EMERGENCY RESPONSE

We'll be there after the storm, prepared and with the resources to safely respond to whatever Mother Nature delivers. And work closely with others in emergency response.

RELIABILITY

We'll maintain recent improvements in power reliability – and continue to improve the experience of those being impacted by outages outside the standard.

SERVICE PROMISE

We'll strive to find new ways to provide a great customer experience – to make it easy. And we'll meet our Guaranteed Service Levels – if we don't, we'll pay you.

SUSTAINABLE

Making it easier to connect to the network – we give you as much control as you choose for your energy solutions with information and more sustainable choices.

NETWORK AS AN ENABLER

We're looking to the future and evolving the network to best enable customer choice in their electricity supply solutions. We'll innovate to integrate solar, batteries and other technologies with the network in a way that is cost effective and sustainable.

COLLABORATION

We'll engage with you and provide you with the information you need, when and how you need it, to support sustainable energy choices.

CONNECTIONS

We'll make it easier and more timely to connect to the network, helping you from beginning to end, with an aligned state-wide service offering and further system improvements.

Chapter 4

Strategic Forecasting

- Forecasting Assumptions
- Substation and Feeder Maximum Demand Forecasts
- System Maximum Demand Forecast

4 Strategic Forecasting

Forecasting is a critical element of Energex's network planning and is essential to the planning and development of the electricity supply network. Growth in peak demand is not uniform across the State of Queensland, therefore electrical demand forecasts are used to identify emerging local network limitations and network risks needing to be addressed by either supply side or customer-based solutions. Peak demand 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.

A brief summary of the methodology and assumptions underpinning Energex's peak demand forecasts has been provided in this Chapter.

A Strategic Forecasting Annual Report is also available which details:

- Further discussion on the methodology and assumptions applied in the peak demand forecasts and also including:
  - minimum demand forecasts
  - energy purchases and energy sales forecasts
  - Distributed Energy Resources forecasts (solar PV, electric vehicles and battery storage systems).
- Economic and demographic forecasts and commentary relating to population growth, GSP and the Queensland economic outlook.

4.1 Forecast Assumptions

There are a number of factors which influence forecasts of peak demand, including the uptake of energy efficient appliances, adoption of solar PV, and customer response to electricity prices and tariffs. Assumptions used in the development of the peak demand forecasts are discussed in the following sections.

4.1.1 Economic Growth

COVID-19 has had a progressive impact on our network over the course of the year. While the system level peak demand, zone substation, and feeder level forecasts have been updated this year, there was not enough (post COVID-19) econometric data available at the time of the forecasts' construction to be able to incorporate expected COVID-19 impacts.

The level of economic growth is a major driver of many forecasts, and we primarily use Gross State Product (GSP). Queensland's economy experienced a high of 5.5% in 2011-12 followed by a decline in growth rates for the following three years. 2017-18 saw a resurgence in GSP to 3.7% buoyed by improvements in both private (e.g. mining) and Government investment and global commodity prices.

The Queensland economy will be in a recession in the short term, predominantly impacted by the COVID-19 event. External sources have forecast that the Queensland economy may fall marginally (in the range between -0.1% ~ -0.3%) in the 2019-20 financial year, and a further decrease between -0.4% ~ -2.7% in the 2020-21 financial year, as a result of the unprecedented COVID-19 impacts. As the

COVID-19 impacts fade away, a strong recovery is expected to occur over the following two years. In the longer term, there is considerable divergence in forecasts around the strength of the State economy. However, the underlying economic conditions remain solid, and the business activities will be 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, and the favourable international commodity prices.

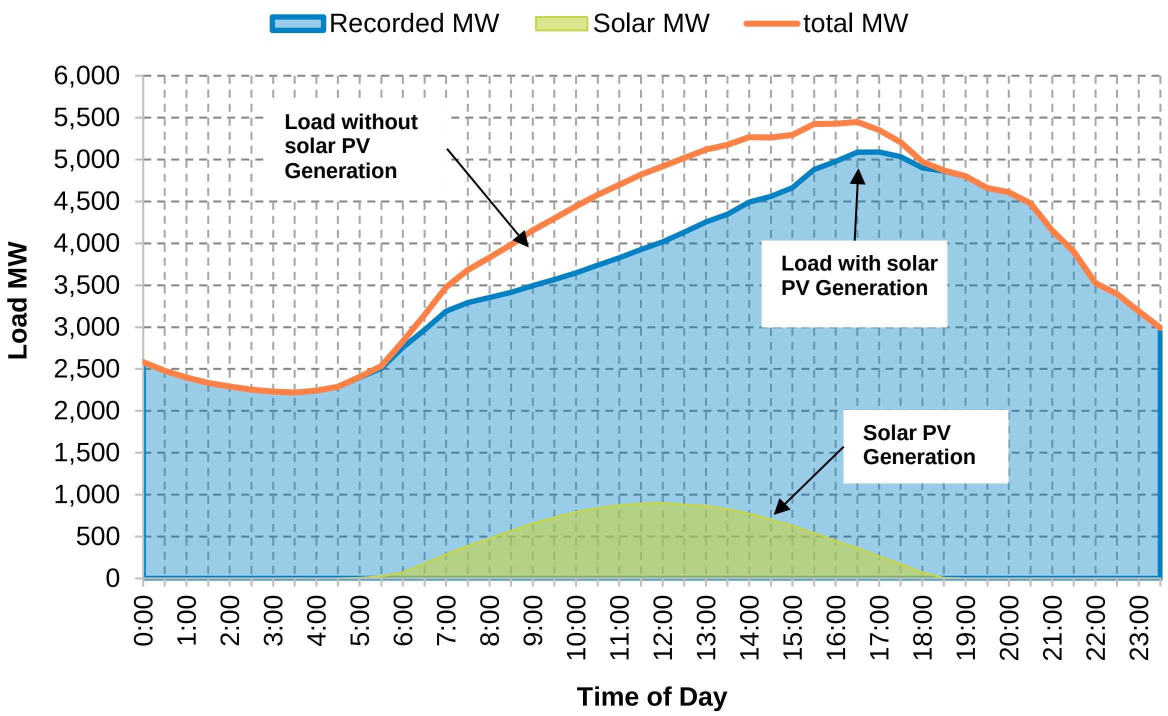
The current forecasts are based on underlying assumptions:

- GSP measures the aggregate economic activities throughout the whole rather than parts of Queensland
- The new liquefied natural gas (LNG) plants in central Queensland are pushing up the state economy, as a whole, to a lesser extent as the construction phase has shifted to production export and has limited impact on economic growth in SEQ or many other regional areas
- 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.

4.1.2 Solar PV

Figure 6 illustrates the impact that solar PV has on the Energex summer system peak demand. The 2019-20 Energex summer system peak of 5,069MW occurred at 5.00pm on Monday, 3 February 2020 and it was estimated that solar PV reduced the peak by almost 369MW at that time. Without PV generation, it is estimated that the peak would have occurred at 4.30pm and been over 500MW higher than the recorded 5.00pm peak. 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 6 – System Demand – Solar PV Impact, 3 February 2020



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

4.1.3 Electric Vehicles and Energy (battery) Storage

Mainstream uptake of electric vehicles (EVs) and Plug-in Hybrid electric vehicles (PHEVs) has the potential to increase energy and demand forecasts in the future. Similarly, customer interest in energy storage systems (batteries of various kinds) is increasing with the number of known energy storage systems in the Energex network being approximately 4,027 as of June 2020.

Energex's forecasting model is based on the peak day profile for residential, commercial and industrial customers, with the marginal impact of EVs, batteries and solar PV incorporated into that profile.

4.1.4 Temperature Sensitive Load

Temperature sensitive loads such as air-conditioning and refrigeration are major drivers of peak demand load on the network. The most extreme loads seen on the network over a year are typically driven by a combination of hot (and usually humid) weather conditions during times of high industrial and commercial activity.

Several weather stations are required to capture the variability of weather conditions across the network. Weather data for Amberley, Archerfield and Brisbane Airport is sourced from the Bureau of Meteorology (BOM), based on their representativeness of the weather in key population regions and the quality of their extended weather history.

The zone substation forecasting methodology also utilises weather data, with a process to identify the most relevant weather station to relate to a zone substation's load. Further details of the substation forecasting process are detailed below.

4.2 Substation and Feeder Maximum Demand Forecasts

The forecasting process predicts where extra capacity is needed to meet growing demand, or new assets are required in developing areas. 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. The bottom-up substation peak demand forecast is reconciled with the system level peak demand forecast, after allowances for network losses and diversity of peak loads. This process accounts for drivers which only become significant at the higher points of aggregation (e.g. economic and demographic factors), while also enabling investment decisions to be based on local factors. Hence, individual substation and feeder maximum demand forecasts are prepared to analyse and address limitations for prudent investment decisions.

The take-up of solar PV is continuing as electricity prices rise and the cost of solar PV falls, and the emerging influence of electric vehicles and battery storage systems is also incorporated at the system and substation levels of forecasting.

Balanced against this general customer trend, the forecasts produced post-summer 2019-20 have provided a range of demand growth rates, with many established areas remaining static while other areas like the northern Gold Coast, and the southern Sunshine Coast growing strongly. 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.

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 2020-25 period, the percentage compound growth rates of zone substations were as follows:

- 20% of zone substations have an annual compound growth rate at or below 0%
- 20% of zone substations have an average annual compound growth rate greater than 2%
- 10% of zone substations have an annual compound growth rate exceeding 5%.

The ten-year substation peak demand forecasts are prepared at the end of summer (and may also be updated post winter) to enable appropriate technical evaluation of network limitations for both existing and proposed substations. The forecasts are developed using data from historical peak demands, weather, photovoltaic installations, electric vehicles, battery storage systems, as well as economic and demographic data via the system demand forecasts. Independently produced forecasts for economic variables and photovoltaic installations, electric vehicles and battery storage systems uptake (by the SA2 level) are also sourced from Deloittes and the CSIRO respectively.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demands, and there has been a significant increase in PV for C&I premises over the last couple of years. While this will provide benefits for those parts of the network which peak during times of significant PV generation, there are many other areas of the network which peak later in the afternoon/evening, where the impact of PV generation on the peak may either be limited or non-existent.

4.2.1 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. Energex also incorporates feedback from the regional planning engineers to review, discuss and validate growth rates and temperature-corrected starting points for the new forecast.

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 which incorporates a Monte Carlo simulation to produce a distribution for 10 PoE and 50 PoE values. Larger block loads are incorporated (after validation for size and timing by the planning engineers) along with growth rates (with care taken to avoid double counting block loads and growth) to produce a forecast of the future load at each zone substation for the following ten years for summer and winter.

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 zone substation forecast is then reconciled with the independent system demand forecast and calibrated as required.

This approach has the advantage of incorporating uncertainty relating to weather events into the forecasting methodology.

Specifically, the ten-year substation demand forecasts are prepared by:

- Validating uncompensated substation peak demands are determined for the most recent summer period
- Regressing minimum and maximum temperature at three BOM weather stations against substation daily maximum demand, with the best-fit relationship used to determine the substation's probability of exceedance distribution
- Using demand variability to determine the 50 PoE and 10 PoE values if the substation's load does not demonstrate a significant temperature – demand relationship
- Reviewing historical variations from forecast to identify modelling inaccuracies or project/load transfers, block load variations
- Calculating starting values for apparent power (MVA), real power (MW) and reactive power (MVAr) for four periods – summer day, summer night, winter day and winter night
- Analysing demographics, preparing customer load profiles, and checking against customer connections and changes in population growth
- Incorporating the expected impact and growth in solar PV, battery storage, and plug-in EVs at the substation level
- Reviewing and validating the size and timing of new block loads, and load transfers with the planners, and applying same to the forecast starting value
- Aggregating the zone substation forecast peak demands to their parent bulk supply and transmission connection points for the distribution system coincident time

- Reconciling the total aggregated zone substation demand with the independently produced system demand forecast, to ensure that economic and demographic factors only evident at the system level, can be incorporated into the zone substation forecasts.

An important part of the modelling process is the careful review of the accuracy of the previous substation peak demand forecasts to identify and resolve any systematic errors or biases in the forecasting approach. It should be noted that the substation forecast modelling tool can differentiate between approved and proposed projects in the process.

4.2.2 Transmission Feeder Forecasting Methodology

A simulation tool is used to model the 110kV and 132kV 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 zone substation, bulk supply and connection point 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.

4.2.3 Sub-transmission Feeder Forecasting Methodology

Forecasts for sub-transmission feeders are produced for a five-year window aligning with the capital works program. Sub-transmission forecasts identify the anticipated maximum loadings on each of the sub-transmission feeders in the network under a normal network configuration.

Modelling and simulation is used to produce forecasts for the sub-transmission feeders. The traditional forecasting approach of linear regression of the historical loads at substations is not applicable, since it does not accommodate the intra-day variation. The modelling approach enables identification of the loading at different times of day to equate to the line rating in that period. A software tool models the 33kV sub-transmission network. The simulation tool has built-in support for network development which provides a variable simulation timeline that allows the modelling of future load and projects into a single model.

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 the SIFT. Eight models are produced, each containing forecast load for the different seasons. These include summer day, summer night, winter day and winter night, combined with 10 PoE or 50 PoE peak load. This enables the identification of worst-case risk period for each season.

4.2.4 Distribution Feeder Forecasting Methodology

Distribution feeder forecast analyses carry additional complexities in comparison to sub-transmission feeder 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 11kV 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, battery storage systems, electric vehicles, 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 Queensland Government Statistician's Office spatial population projections, combined with Energex's customer number forecasts to determine customer growth rates
- The forecast for solar PV systems, battery storage and EV from EQL's scenario modelling DER forecast is used as one of the growth drivers at distribution feeder level
- The temperature data, used to model the impacts of weather on maximum demand, is supplied by Weather Zone, which sources its data from the Bureau of Meteorology. This is used to determine approximate 10 and 50 PoE load levels
- Further forecast information is obtained from discussions with current and future customers, local councils and government.

4.3 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 substation peak demand forecast ('bottom-up') is reconciled with the system level peak demand forecast ('top-down'), 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)
- Solar PV generation (source: customer installation data)
- Load history (source: corporate SCADA/metering database.

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 the SIFT forecasting system)
- Forecast growth rates for organic growth (calculated by the SIFT forecasting system)
- System maximum demand forecasts.

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

4.3.1 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 November to March temperature data that excludes days with average temperature at selected weather stations that are below the set levels (for example, Amberley mean temperatures < 22.7C and daily maximum temperature < 30C). 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
- 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
- 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:

- 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 30 years of temperatures
- System forecasts, obtained from modelling a temperature-corrected multivariate regression model using economic, demand management, and distributed energy sources (DER, such as solar PV uptakes).

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.

The system peak demand forecast model incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

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

The total price component incorporated into the latest model aims to capture the response of customers to the increasing price of electricity.

In applying the above methodology, a system-level ten-year 50 PoE and 10 PoE maximum demand forecast is derived. The results of the forecasts are compared in Figure 7. Demand management load reductions are included in the forecast.

The Energex system peaked at 5,069MW on 3 February 2020 with Amberley reaching a maximum temperature of 39.1 degrees Celsius. While the result is lower than last year's peak of 5,086MW, on a temperature corrected basis or 50 PoE level, the system peak demand is still expected to increase over time. Table 2 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.

Figure 7 – Energex Peak Demand Forecast

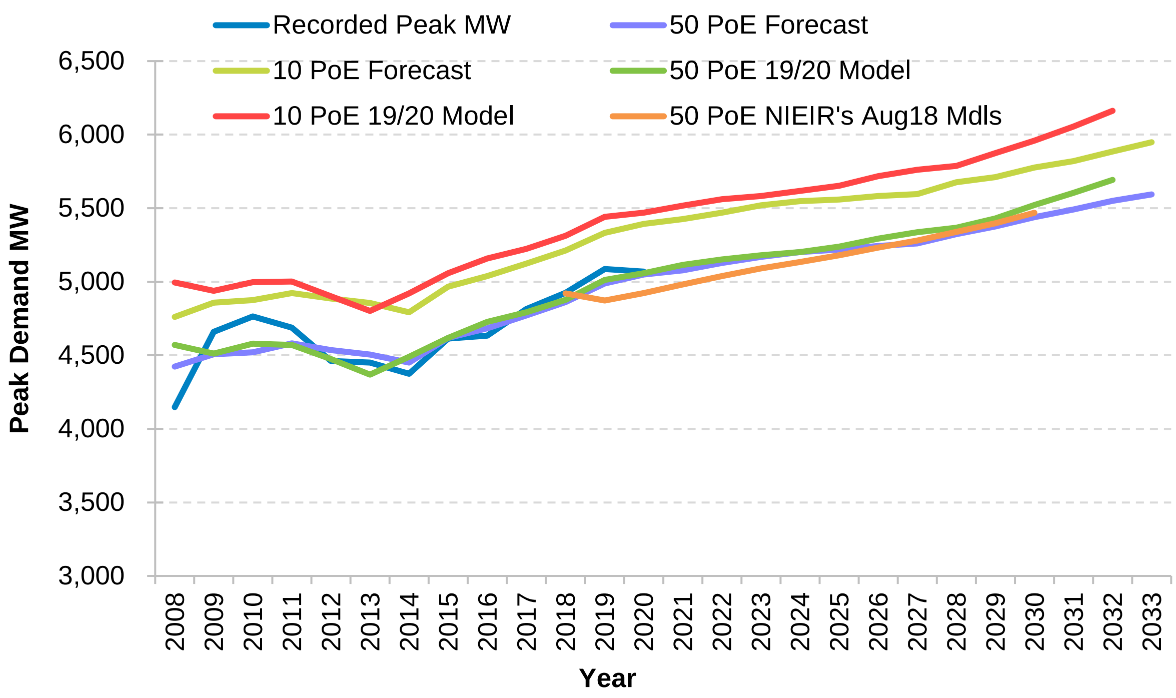


Table 2 – Actual Maximum Demand Growth – South-East Qld

Demand	2015-16	2016-17	2017-18	2018-19	2019-20
Summer Actual (MW) [1]	4,633	4,814	4,926	5,086	5,069
Growth (%)	0.4%	3.9%	2.3%	3.3%	-0.4%
Summer 50% PoE (MW)	4,684	4,771	4,862	4,988	5,050
Growth (%)	1.4%	1.8%	1.9%	2.6%	1.2%
	2015	**2016**	**2017**	**2018**	**2019**
Winter Actual (MW)	3,891	3,657	3,458	3,643	3,748
Growth (%)	10.1%	-6.0%	-5.4%	5.3%	2.9%
Winter 50% PoE (MW)	3,761	3,775	3,655	3,716	3,748
Growth (%)	0.7%	0.4%	0.4%	1.4%	0.9%

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

Table 3 lists the maximum demand forecasts over the next five years.

Table 3 – Maximum Demand Forecast (MW) – South-East Qld

Forecast [1, 2]	2020-21	2021-22	2022-23	2023-24	2024-25
Summer (50% PoE)	5,077	5,127	5,170	5,201	5,220
Growth (%)	0.2%	1.0%	0.8%	0.6%	0.4%
Summer (10% PoE)	5,425	5,470	5,519	5,547	5,558
Growth (%)	0.6%	0.8%	0.9%	0.5%	0.2%
	2020	**2021**	**2022**	**2023**	**2024**
Winter (50% PoE)	3,791	3,802	3,815	3,829	3,848
Growth (%)	1.1%	0.3%	0.3%	0.4%	0.5%
Winter (10% PoE)	3,928	3,938	3,954	3,967	3,987
Growth (%)	1.2%	0.3%	0.4%	0.3%	0.5%

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 2019-20.

2 The demand forecasts include the impact of the forecast economic growth as assessed in May 2020.

The forecast of solar PV generation at the time of summer peak demand is shown below in Table 4. 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.

Table 4 – Contribution of Solar PV, EVs and Battery Storage Systems to Summer System Peak Demand

	2021	2022	2023	2024	2025	2025	2027	2028
Solar PV Capacity impact on System Peak Demand (MW)	-421	-449	-479	-336	-359	-381	-402	-422
Electric Vehicle Load impact on System Peak Demand (MW)	2	4	7	13	22	34	49	68
Battery Storage Systems Load impact on System Peak Demand (MW)	-6	-9	-16	-35	-55	-75	-90	-104

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

The table above lists the modelled impacts of PV, EV and Batteries on system peak demand. 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 relatively small. 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). Battery storage is expected to 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 5

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
- Network Planning – Assessing System Limitations

5 Network Planning Framework

5.1 Background

Energex has a network development planning framework to ensure solutions, addressing network limitations and risks, are optimal to meet current and future requirements.

There are several definitions essential to the understanding of Energex's network planning philosophy. Reliability of supply is the probability of a system performing adequately under normal 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 thermal 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 planning standard for sub-transmission networks which takes into account the Value of Customer Reliability (VCR) 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 the criteria defined in the Distribution Authority (CBD, Urban, Rural) and the appropriate Safety Net target is assigned to associated network elements
- Plant and power line thermal 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 is utilised to optimise investment timing and
- Specific security requirements of large customer connections that are stipulated under the relevant connection agreements.

The application of the COS 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) against the 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 the COS is 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.

5.2 Planning Methodology

5.2.1 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
- 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.

5.2.2 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 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 a preferred development option
- Undertake regulatory public consultations for projects as required, and carry out detailed evaluation upon receipt of any alternative solutions from the registered participants/ proponents
- 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 applicable for the projects having credible options of more than $6 million.

5.3 Key Drivers for Augmentation

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

In general, these factors impact demand growth, plant thermal rating limitations, load transfer capabilities and asset condition which, combined with planning and security criteria, risks and security of supply, network performances, non-traditional solutions and overall economics of potential investment are embedded in network planning process.

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 4. 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 risks that need to be addressed by either network or non-network based solutions. These 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.

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 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
    - 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 and Energex's environmental assumptions. 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
- Underground cables are rated in accordance with IEC 60853 and IEC 60287 supported by Energex's environmental assumptions.

Load Transfer Capability

Energex's COS 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 using load flow studies, taking into account the thermal ratings and voltage stability of the network. For example, the load transfer capability at a substation level in an urban network 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 Chapter 8. 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.

5.4 Network Planning Criteria

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

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

- Deterministic approaches (e.g. N-1, N-2, etc.)
- Probabilistic (risk-based) approaches.

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
- **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 different options and benefits are considered for each project with the lowest present cost option being selected for progression. All investments are risk ranked and prioritised for consideration against Energex's budget and resource levels, with some network risks managed operationally.

5.4.1 Value of Customer Reliability

In December 2019, the AER published the results of an investigation into the value that NEM customers place upon reliability.

According to the AER Review, the VCR:

> *" seek to reflect the value different types of customers place on reliable electricity under different conditions. As such, VCRs are useful inputs in regulatory and network investment decision-making to factor in competing tensions of reliability and affordability. Importantly, VCR is not a single number but a collection of values across residential and business customer types, which need to be selectively applied depending on the context in which they are being used "*

Components in the calculation of VCR include:

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

The first three factors are combined to calculate the 'annualised probability-weighted Unserved Energy (USE)' in MWh. The last factor, customer mix, is combined with the AER 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 60 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.

5.4.2 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 outlined in the Distribution Authority address this issue by providing a set of "security criteria" that set an upper limit to the customer consequence (in terms of unsupplied load) for a credible contingency event in the Energex network as shown in Table 5. Energex is required to meet the restoration targets defined in Schedule 3 of Energex's Distribution Authority "…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 5 – Service Safety Net Targets

Feeder Type	Demand Range	Allowed Outage Duration to be Compliant
CBD	No outage Compliant	No outage Compliant
Urban – Following an N-1 event	>40MVA	No outage Compliant
	12 - 40MVA	30 minutes Compliant
	4 - 12MVA	3 hours Compliant
	<4MVA	8 hours Compliant
Short Rural – Following an N-1 event	>40MVA	No outage Compliant
	15 - 40MVA	30 minutes Compliant
	10 -15MVA	4 hours Compliant
	<10MVA	12 hours Complaint

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.

A Safety Net review of the network's sub-transmission feeders with zone and bulk supply substations are performed annually to 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.

5.4.3 Distribution Networks Planning Criteria

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

Target Maximum Utilisation (TMU) is used as a trigger for potential application of non–network solutions or capacity improvements for the 11kV 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 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 more dense Brisbane CBD areas where high reliability is critical and thus the loss of a single feeder should not affect supply.

Urban Feeders

An Urban Feeder in the security criteria is 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 80% utilisation under system normal conditions at 50 PoE.

Following the loss of a feeder, utilising 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 Safety Net criteria.

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

Short Rural Feeders

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

5.4.4 Consideration of Distribution Losses

Distribution losses refer to the energy loss incurred in transporting energy across the distribution network. They are represented by the difference between energy purchased and energy sold. Energex includes all classes of market benefits (including network losses) in its analysis that it considers to be material for all projects, including those under the RIT-D and those projects where there is a material difference in losses between options.

5.5 Voltage Limits

5.5.1 Voltage Levels

Energex's HV distribution network consists of 4 different voltage levels. Table 6 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 6 – System Operating Voltages

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

5.5.1.1 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 22kV. 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 22kV, the Queensland Electricity Regulations (QER) specifies steady-state (i.e. excluding transient events such as transformer energisation) 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 7 details the standard voltages and the maximum allowable variances for each voltage range from the relevant QER and National Electricity Rules.

Table 7 – Maximum Allowable Voltage

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

The values in Table 7 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.

5.5.1.2 Transmission and Sub-transmission Voltage Limits

Target voltages on bulk supply substation busbars are 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 are 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 may be required 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 COS.

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.

5.5.1.3 Distribution Voltage Limits

Target voltages on zone substation busbars are set by Energex as relevant. These zone substation busbars are operated with either LDC, or with a fixed voltage reference or automatic 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 7, 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 8 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 8 – Steady State Maximum Voltage Drop

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

5.5.1.4 Low Voltage Limits

Typically, LV network voltage is managed by a combination of real time voltage control at the zone substation 11kV busbar to control the voltage regulation along the 11kV 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 may be 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, it is required to reduce the voltage drop through the transformer and LV circuits typically by uprating or installing a new transformer and reconfiguring the LV network. Low Voltage Regulators (LVR) and Statcoms may also provide an additional reinforcement option.

5.5.2 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 132kV, 110kV or 33kV 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 11.2kV in urban areas and 11.3kV 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 4.2.3 and are also reported in the limitations tables contained in Appendix D.

5.5.3 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%
- Rural Substations 102.7%.

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

At present, there are 11kV 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.

5.5.4 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, 11kV 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 LDC or 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
- Installation of targeted transformer monitoring devices in response to network LV changes and PV installations.

5.6 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 5.9.

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 9 lists design fault level limits that apply at Energex installations.

Table 9 – Energex Fault Level Limits

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

While Table 9 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.

5.7 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, Energex 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 2020.

5.8 Large Customer Connections, including Embedded Generators

Energex is committed to ensuring that, where technically viable, Large Customer Connections (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/our-services/connections/major-business-connections

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

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

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

5.9 Joint Planning

5.9.1 Joint Planning Methodology

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

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. Joint Planning follows the same principles and considerations outlined in Sections 5.2 in developing proposed solutions and engaging with stakeholders.

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
- Network stability to ensure consistency with relevant standards.

5.9.2 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.

5.9.3 Joint Planning with Powerlink

In the past 12 months Energex has actively engaged with Powerlink on the following joint planning studies. These limitations have network drivers that have a notional target date in the forward planning period (2020-21 to 2024-25), as summarised in Table 10.

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 10 – Joint Planning Activities Covering 2020-21 to 2024-25

Energex Works Estimated Cost ($ M)	Project Description	Indicative Timing	2019 DAPR Reported Timing	Comments
0.4 – 1	Sumner Upgrade 110/11/11 kV transformer protection (Energex Project)	Jun-21	Jan-21	
1 – 2	Molendinar Upgrade 110/11/11 kV transformer protection (Energex Project)	Jul-21	Oct-20	Part of a program to upgrade backup protection reach
1 – 2	Bundamba Upgrade 110/11/11 kV transformer protection (Energex Project)	Feb-21	Jul-20	Part of a program to upgrade backup protection reach
1 – 2	Abermain Replace secondary systems (Powerlink Project)	Jun-30	Dec-20	Subject to RIT-T
1 - 2	Redbank Plains 110 kV Replace primary plant (Powerlink Project)	Jun-24	Dec-24	Subject to RIT-T

5.9.4 Joint Planning with other DNSP

There were no specific joint planning network investigations necessary between Energex and other DNSPs during 2019-20. 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.

5.9.5 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:

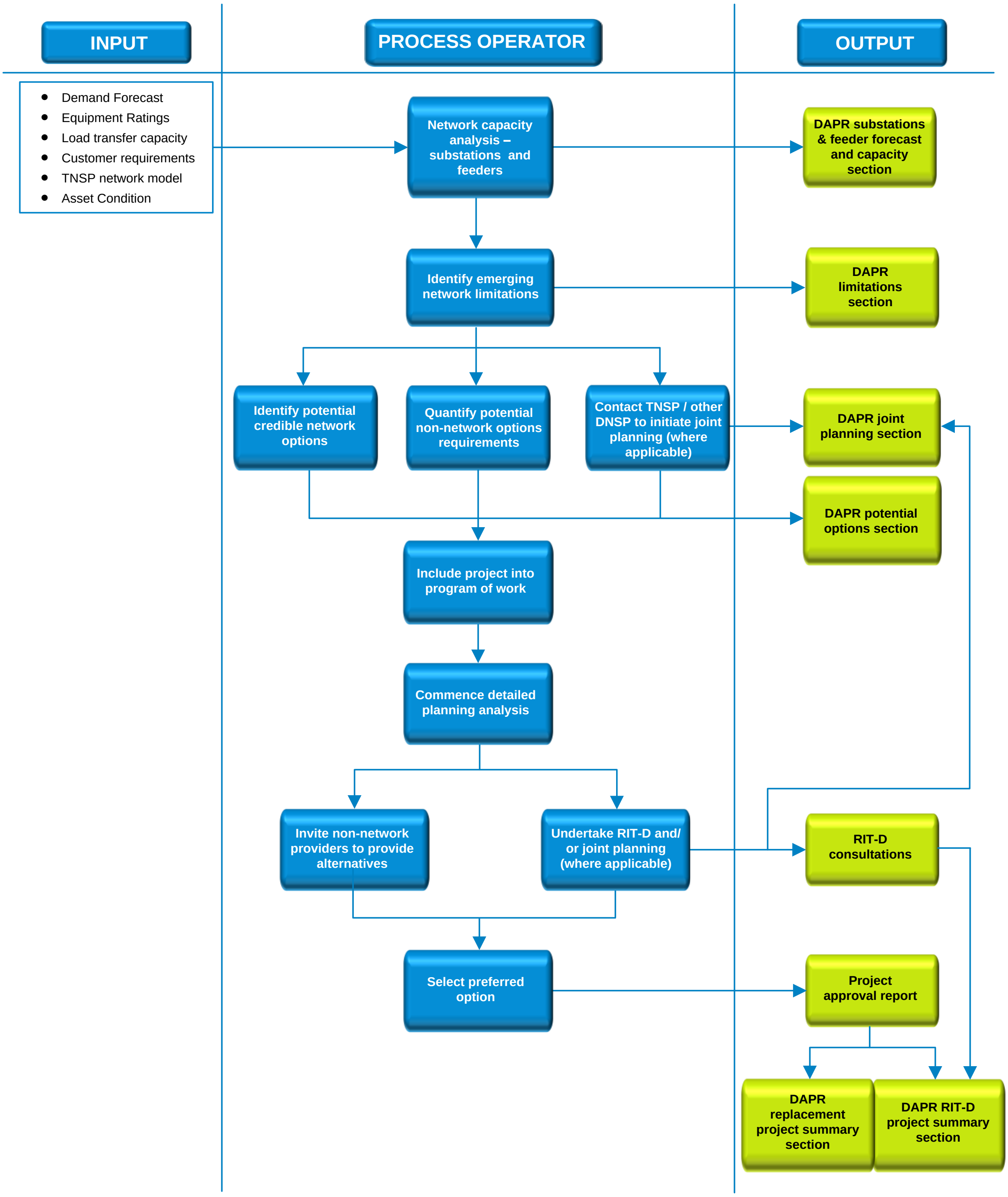
DAPR_Enquiries@energex.com.au

5.10 Network Planning – Assessing System Limitations

5.10.1 Overview of Methodology to Assess Limitations

The methodology shown in Figure 8 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 8 – System Limitations Assessing 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.

5.10.2 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 4.3.1.

5.10.3 Transmission and Sub-transmission Feeder Analysis Methodology Assumptions

Based on the forecasting methodology described in section 4.2.2 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.

Energex reviews and analyses these load flow results using additional data not contained in the model 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 outcome of the analysis would trigger further investigations and identification of potential solutions to address the limitations.

5.10.4 Distribution Feeder Analysis Methodology Assumptions

The 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
- 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 11kV 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.

5.10.5 Fault Level Analysis Methodology Assumptions

Energex performs fault level analysis for switchgear at all 132kV, 110kV, 33kV and 11kV buses as well as 33kV and 11kV 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 33kV and 11kV 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
- All loads and capacitors are switched out of service.

For the 11kV 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
- Fault levels are only calculated at nodes within the model with results showing individual line segments contribution to the fault.

Chapter 6

Overview of Network Limitations and Recommended Solutions

- Network Limitations – Adequacy, Security and Asset Condition
- 11kV Primary Overcurrent and Backup Protection Reach Limits
- Summary of Emerging Network Limitations
- Regulatory Investment Test (RIT-D) Projects
- Emerging Network Limitations Maps

6 Overview of Network Limitations and Recommended Solutions

6.1 Network Limitations – Adequacy, Security and Asset Condition

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 5.9.1. Limitations affecting either network will be investigated jointly and follow the RIT-T or RIT-D process to ensure prudent solutions are adopted.

6.1.1 Bulk and Zone Substation Capacity Limitations

For each bulk and zone substation, a separate summary forecast of load, capacity and limitations has been produced for summer and winter based on the Customer Outcome Standard. These results are contained in Appendix E. Appendix D outlines the network limitations that have been identified through this process.

6.1.2 Transmission, Sub-transmission and Distribution Feeder Capacity Limitations

For each transmission, sub-transmission feeder and distribution feeder, a separate summary forecast of load, capacity and available load transfers for summer and winter has also been produced, and the results are also contained in Appendix E. Feeder limitations are identified using the simulation models and processes as described in section 4.2.2 and section 5.10.3. 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.

6.1.3 Asset Condition Limitations

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 2.4. These projects can be found in Appendix D Substations Limitations and Proposed Solutions Part B, and Transmission and Sub-transmission Limitations and Proposed Solutions Part B.

6.1.4 Fault Level Limitations

Energex performs fault level analysis for switchgear at all 132kV, 110kV, 33kV and 11kV buses as well as 33kV and 11kV 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’s detailed analysis did not identify any additional switchgear fault rating limitations in comparison to the 2019 DAPR.

Table 11 below summarises the identified limitations across the Energex network for the DAPR period.

Table 11 – Summary of Substation and Feeder Limitations

Asset Type		Limitation Type		
		Capacity	**Asset Condition**	**Fault Level**
Limitations with Proposed Solutions	Bulk Substation	0	1	0
	Zone Substation	4	20	0
	Transmission Feeder	0	0	0
	Sub-transmission Feeder	4	5	0
	Distribution Feeder	4	0	0
Limitations not Addressed	Bulk Substation	1	0	0
	Zone Substation	1	0	0
	Transmission Feeder	1	0	0
	Sub-transmission Feeder	7	0	0
	Distribution Feeder	35	0	0

6.2 11kV Primary Overcurrent and Backup Protection Reach Limits

Energex engaged with a consultant to undertake a review of the existing protection settings of 11kV 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 11kV feeder primary protection reach to further improve network safety and increase network transfer tie capabilities.

Six percent of the total Energex 11kV feeders have been identified for potential improvements and is currently being addressed through protection setting changes, installation of 11kV pole mounted reclosers (PMR) and fuses, and 11kV 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. Approximately a quarter of these projects have moved into construction, and a quarter are approved and have moved into detailed design. The remaining projects are programmed for approval over the next 3-4 years.

6.3 Summary of Emerging Network Limitations

Appendix D provides a summary of proposed committed work 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.

6.4 Regulatory Investment Test (RIT-D) Projects

6.4.1 Regulatory Investment Test Projects – In Progress and Completed

As per the National Electricity Rules clause 5.17.3, and detailed further in Section 2.2 of the RIT-D Application Guidelines (December 2018), a RIT-D proponent is not required to apply the RIT-D for projects where the estimated capital cost of the most expensive potential credible option is less than the RIT-D cost threshold (as varied in accordance with a 'RIT-D cost threshold' determination). The RIT-D cost threshold is $6 million.

The following approved projects shown in Table 12 have credible options greater than the RIT-D cost threshold of $6 million. As such, the Final Project Assessment Reports for these projects are published in the Energex website under Current Consultations.

Table 12 – In Progress and Completed RIT-D Projects

Project Name	RIT-D Forecast/Actual Completion[1]
Caloundra Network Limitation	Qtr 4 2021
Coomera/Pimpama Network Limitation	Qtr 3 2021
Kilcoy Network Limitation	Qtr 3 2021
Logan Village Network Limitation	Qtr 3 2021

[1] Dates correct as at November 2020.

6.4.2 Foreseeable RIT-D Projects

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 13.

Table 13 – Potential RIT-D Projects

Project Name	RIT-D Commencement[1]
Kallangur Network Limitation	Qtr 2 2021
MLY Replace 33kV and 11kV isolators	Qtr 2 2021
Nudgee Network Limitation	Qtr 3 2021

[1] Dates correct as at November 2020.

6.4.3 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.

6.5 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/daprmap2020

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

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

Chapter 7

Demand Management Activities

- What is Demand Management
- How is Demand Management integrated into the Planning Process
- Energex's Demand Side Engagement Strategy
- What has the Energex DM Program Delivered over the last year
- What will the Energex DM Program deliver over the next year
- Key Issues Arising from Embedded Generation Applications

7 Demand Management Activities

Demand Management (DM) is part of our suite of solutions for network management which may be used instead of, or in conjunction with, investments in network infrastructure to ensure an optimised investment outcome.

7.1 What is Demand Management

In the context of electricity networks, DM is the act of modifying demand and/or electricity consumption, for the purpose reducing or delaying network expenditure (i.e. removing or delaying an underlying network constraint). This definition recognises that DM need not be specific to removing networks constraints only at times of peak demand. Rather that network support opportunities also include retirement or replacement of an aging asset; redundancy support during equipment failure; minimum demand and associated issues with voltage, system frequency and power quality management; managing diverse power flows and system security issues. In response to growing DER in the network, DM must evolve to include management of these customer assets to optimise end-to-end investment.

DM can also be particularly valuable when there is uncertainty in demand growth forecasts, as DM does not lock in long-term irreversible investment. In these situations, DM can provide considerable 'option value' and flexibility.

DM solutions are also known as non-network solutions as they provide an alternative to network based solutions. In the Energex and Ergon Energy context, DM involves working with our customers and DM providers to modify demand and/or energy consumption to reduce operational costs or be an alternative to capital expenditure. The more capital expenditure that can be deferred or avoided, the greater the savings to our customers.

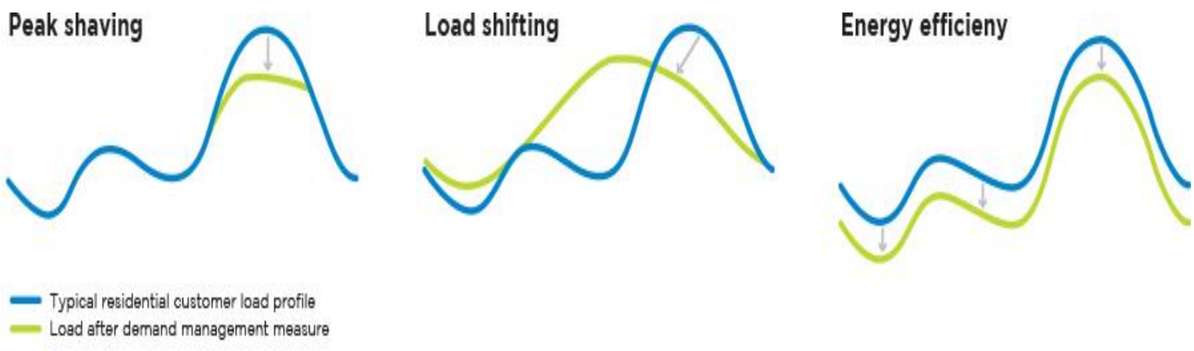
DM must be deployed to match the temporal (i.e. how often and what duration) and spatial (i.e. what level of the network and how many customers are affected) nature of the network constraint. As more DER is connected to our network, the temporal and spatial nature of network constraints will change. As such, our DM capability will need to adapt to suit these new and emerging network constraints.

There are three major DM approaches as outlined in the Table 14 and shown in Figure 9.

Table 14 – DM Approaches

DM Approach	Description	Type of DM
Peak shaving	Reducing peak period (e.g. using onsite generation)	Demand response
Load shifting	shifting demand to other time of the day when networks are less constrained (e.g. load control tariffs). Load shifting can be used to manage peak demand and minimum demand.	Demand Response
Energy efficiency	Use less electricity to perform the same task.	Energy efficiency

Figure 9 – DM Approaches



7.2 How is Demand Management integrated into the Planning Process

The planning process as outlined in Chapter 5 includes the identification of network constraints and the assessment of DM solutions (refer Figure 10 and Figure 11). When a network constraint is identified, a screen of non-network options is completed to determine if DM solutions offer credible options. Where a screening test finds that a non-network option may provide an efficient alternative solution (by partially or fully addressing the constraint), market engagement and investigation of possible DM solutions is initiated.

'In market' engagement activity depends upon forecast expenditure, size and timing of the constraint. Where total capital expenditure of the most expensive credible option is greater than $6 million, a RIT-D is undertaken (refer to Figure 10). For the list of projects that required a RIT-D assessment over the last year refer to section 6 and RIT-D consultation information available on the Energex website.

Where the forecast capital expenditure for the most credible option is less than $6 million, opportunities for credible non-network solutions are developed by gauging interest and ability of service providers and customers to participate. This can be done by publishing network constraints (Target Areas) online using incentive maps or inviting proponents to respond to a Request for Proposal (RFP). Refer to section 7.4.2 and Target area locations on the Energex website.

Where a non-network solution is selected, a contract is established with the customer to provide permanent (energy efficiency) or point in time (when required) demand response. Measurement and verification is undertaken to determine the response achieved. The verified change in demand becomes an input into the forecast and the planning process.

Figure 10 – Non Network Assessment Process for Expenditure >$6M (RIT-D)

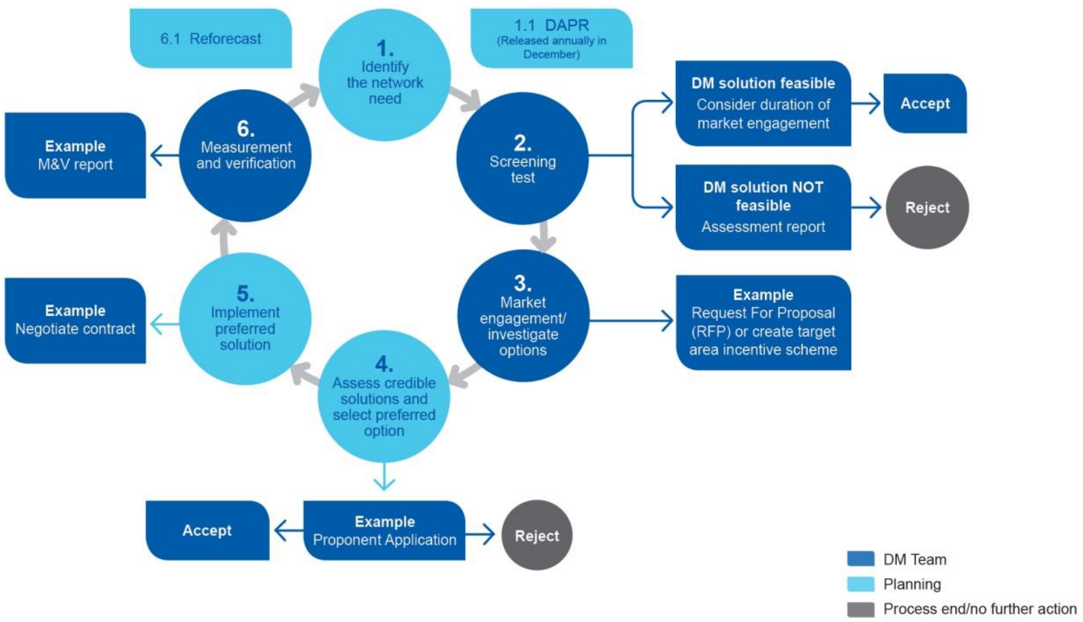
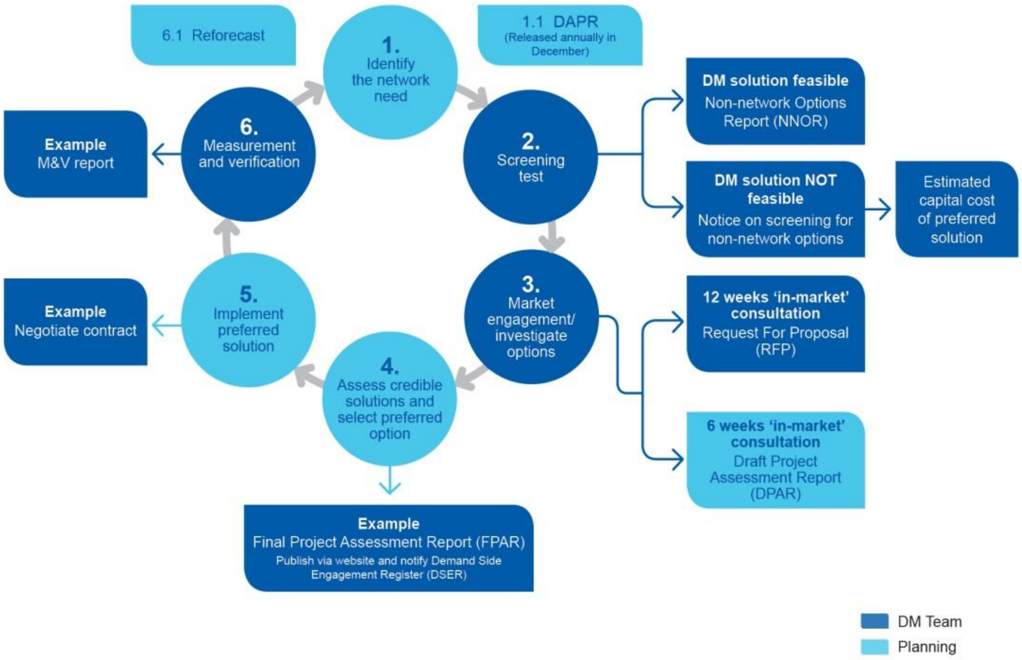


Figure 11 – Non Network Assessment Process for Expenditure <$6M



7.3 Energex's Demand Side Engagement Strategy

The Energex Demand Side Engagement Strategy (DSES) communicates how Energex engages with customers and non-network providers on the supply of credible demand side solutions to address system constraints and lower costs for customers in the network distribution areas. The DSES remains our commitment to:

- embed demand side engagement and non-network screening of network constraints into the distribution planning process
- identify and transparently provide details of Energex network constraints to customers and non-network service providers in consistent, simple and easy to understand terminology;
- identify and incentivise non-network solutions for broad based and targeted areas, engaging stakeholders and third party providers, as outlined in the Energex Demand Management Plan
- provide adequate time, support and mechanisms for stakeholders to engage, respond and participate in non-network solutions
- deliver and report non-network solutions that prevent, reduce or delay the need for network investment.

A copy of the DSES can be found on our website.

7.4 What has the Energex DM Program delivered over the last year

Four key initiatives were delivered by the DM Program in 2019-20:

- Broad based
- Targeted
- DM Development
- DM innovation.

7.4.1 Broad based DM

This initiative is available to residential and small business customers across the whole network. Demand reductions can occur across the whole network, rather than just in a local area with a network constraint. Broad based DM delivers direct control of loads during periods of extreme demand or emergency response. This capability is called up through our Summer Preparedness Plan (refer to section 9.3.1) to minimise interruptions during summer season extreme weather conditions.

Incentives are provided to customers who enrol their PeakSmart air conditioners or connect their appliances to load control tariffs. Incentives are also given to industry partners who install PeakSmart enabled air conditioners. For more information on PeakSmart visit our website.

7.4.2 Targeted DM

This initiative is available to customers and DM providers who can deliver DM solutions in specific areas of the network identified as having future network constraints (refer sections 6.1 Sub-transmission Feeder Limitations, 11kV Distribution Feeder Limitations and Appendix F. Market engagement is undertaken to seek DM solutions from customers and DM providers. Incentives are provided to customers or DM providers to provide DM solutions.

In 2019-20, 'in market' engagement for DM solutions occurred in three Target Areas across the region. Our Target Area maps provide online information on the network constraint and DM solution required for these areas. Verified customer and service provider DM solutions in these areas, which met technical, time and cost requirements were incentivised to deliver demand reductions. In addition, one embedded generation contract was maintained to provide a non-network solution during the 2019-20 year.

7.4.3 DM Development

This initiative drives continuous improvement of existing initiatives and enabling future DM capability. This included promoting DM through:

- inputting and being involved in a range of market and industry consultations, forums and development of standards, and will continue to support the long-term development of DM capabilities
- continuing to influence DM related standards and policies. One of the standards integral to the Energex DM is the suite of AS/NZS 4755 standards, which outline demand response capabilities for residential appliances. Work is close to completion with Standards Australia on a new standard AS 4755.2 which will cover "demand response systems" that do not require the individual physical elements defined in AS/NZS 4755.1. 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

- 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
- supporting tariff reform by informing customers of associated DM opportunities. This will allow customers to make more efficient decisions about their energy investments and energy use, leading to better utilisation of the network.

7.4.4 DM Innovation

The initiative supports future energy choices and DM capabilities that reduce long term network costs. A suite of innovative trials and projects to test and validate DM products and processes are funded via Demand Management Innovation Allowance Mechanism (DMIAM). These trials and projects are often started in response to emerging network challenges and opportunities (refer to chapter 6).

A DMIAM annual report is developed each year that summarises current and completed projects. The latest report can be found on our website: DMIAM Annual Report

7.5 What will the Energex DM Program deliver over the next year

Annually, Energex publishes a Demand Management Plan which includes our strategy for the next five years. Our strategy is to:

- Ensure efficient investment decision making
- Incentivise customer efficiency
- Active customer response enablers
- Manage two-way energy flows
- Transform supply at the fringe of grid
- Invest in innovation.

This plan explains our approach for delivering the Demand Management Program for Queensland and represents the initiatives and activities for the next financial year including the promotion of non-network solutions. Demand Management Plan 2020-21

As part of our initiative to drive continuous improvement of existing initiatives and enabling future DM capability, the DM Program will support the uptake of new tariffs, as outlined in the 2020-25 Tariff Structure Statement. A key action for 2020-21 will be the commencement of capacity tariff research.

Capacity tariffs will be explored and trials developed as part of a range of solutions to address the network challenges associated with the integration of large amounts of Distributed Energy Resources (DER) into the network. An example of a capacity tariff is one that has fixed charge, a capacity charge based on agreed use of the network, and a volume charge.

During this year, research and development of capacity tariff options will be undertaken, taking into account network requirements and customer impacts. Following appropriate stakeholder engagement and consultation, a field trial is expected to be designed to assess market response to capacity tariffs in Queensland, from both network and key stakeholders (i.e. Retailer and customer) perspective.

Further information on our DM program and the promotion of non-network options are detailed on our Positive Payback website pages.

7.6 Key Issues Arising from Embedded Generation Applications

The volume of solar PV applications continues to increase. Energex continues to focus on improving efficiency and satisfying customer experiences. The continued focus on the revision of processes, together with additional training for technical staff continues the path to developing a more customer-centric approach.

Key issues for large embedded generation include:

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

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

7.6.1 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 2019-20 the number of connection enquiries received is shown in Table 15. For micro EG 30kW or less (mainly solar PV), there is no connection enquiry phase i.e. all connection requests are processed as applications.

Table 15 – Embedded Generator Enquiries

Connection Enquiries	Number 2019-20
Embedded Generator (EG) Connection Enquiries – Micro EG 30kW or less	Not applicable
Embedded Generator Connection Enquiries >30kW Low Voltage	962
Embedded Generator Connection Enquiries >30kW High Voltage	38

7.6.2 Applications to Connect Received

In 2019-20 the number of applications to connect is shown in Table 16.

Table 16 – Embedded Generator Applications

Connection Applications	Number 2019-20
Embedded Generator Connection Applications – Micro EG 30kW or less	49,325
Embedded Generator Connection Applications >30kW Low Voltage	492
Embedded Generator Connection Applications >30kW High Voltage	22

7.6.3 Average Time to Complete Connection

In 2019-20 the number of applications received and connected took an average time to complete as shown in Table 17.

Table 17 – Embedded Generator Applications – Average Time to Complete

Connection Applications	Average time to complete 2019-20
Embedded Generator Connection Applications – Micro EG 30kW or less	28 business days
Embedded Generator Connection Applications >30kW Low Voltage	180 business days
Embedded Generator Connection Applications >30kW High Voltage	86 business days

Note: Typically, there are no applications for connection of large renewable generation to Energex' transmission and sub-transmission networks

Chapter 8

Asset Life-Cycle Management

- Approach
- Preventative Works
- Line Assets and Distribution Equipment
- Substation Primary Plant
- Substation Secondary Systems
- Other Programs
- De-Rating

8 Asset Life-Cycle Management

8.1 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 based on the “so far as is reasonably practical” principle. If elimination of a safety risk is not practical, our responsibility is to mitigate risks based on the same principle.

Energex’s approach to asset life-cycle management, including:

- Achieving its legislated safety Duty
- Delivering customer services and network performances to meet the required standards
- 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
- 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.

8.2 Preventative Works

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

8.2.1 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 2.4. 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
- 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.

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.

8.2.2 Asset Condition Management

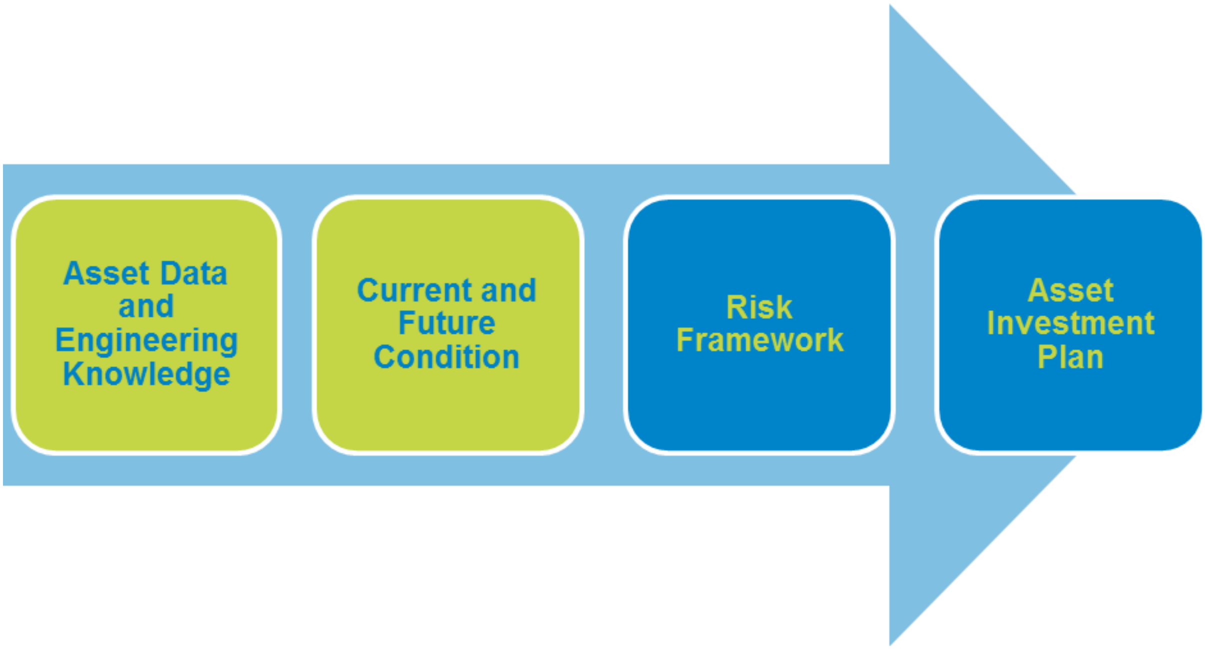
The processes for inspection and routine maintenance of Energex's assets are well established and constantly reviewed. Energex uses its asset management system to record and analyse asset condition data collected as a part of these programs. Formal risk assessments are conducted for all asset classes, 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. This technique is currently used for Substation Power Transformers, Circuit Breakers and Instrument Transformers as well as Underground Cables of 33kV and above.

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

Figure 12 – Process to Create Asset Investment Plan



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.

8.3 Line Assets and Distribution Equipment

8.3.1 Pole and Tower Refurbishment and Replacement

Poles and towers are inspected periodically as required by Queensland legislation. Poles require very little maintenance except for removal of vegetation and termite and bacteria barrier treatments, normally carried out during the inspection process. The majority of pole replacement is driven by well-established inspection programs used to identify severe structural strength degradation. Structural strength is determined in accordance with AS 7000.

A small volume of poles are also replaced when undertaking reconductoring programs as an efficient means of work delivery. Poles replaced under reconductoring programs will be either identified as approaching end of life based on asset criteria or as a result of mechanical design requirements to support the new conductor.

Targeted pole replacement programs make up the small remainder of the forecast. This program is estimated, based on a combination of criteria that identify assets approaching end of life and that present a high risk in the event of in-service failure. The criteria used are a combination of pole type, age, location, previous strength assessment and/or the period the pole has been nailed. Risk is largely determined by the location, with priority being given to replacement in high risk areas such as the vicinity of schools and public amenities.

Pole nailing is a mid-life refurbishment method intended to restore ground line structural strength lost due to below-ground bacterial degradation and is applied based upon inspection outcomes. To date, pole staking achieves an average of 15 years additional asset life. Historical, staking volumes have been used to forecast future staking volumes.

8.3.2 Pole Top Structure Replacement

Pole top structure condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed through asset inspection and defect identification processes. The majority of pole top replacements are driven from the inspection and defect management process and are funded through OPEX for the Energex network. Replacements funded through OPEX are not detailed in this document.

The majority of pole top structure replacements funded through REPEX based programs are replaced as part of conductor and pole replacement programs. High risk aging populations of pole top structures, specifically crossarms, are replaced through targeted replacement programs and contribute to the overall REPEX replacement volume. Crossarms flagged to be replaced as part of targeted replacement programs are combined with other assets to identify sections of the network that present higher risk in order to determine prioritisation of replacements.

8.3.3 Overhead Conductor Replacement

Overhead conductor condition is difficult to assess in-situ as current visual inspection methods can only identify surface defects. Conductor age, type, construction, environment and in-service performance history are used as proxies for condition. Energex employs a data driven refurbishment software tool to identify overhead conductor operating at beyond its expected technical life based on the replacement criteria documented in the AMP – Overhead Conductors. At-risk conductor is then field assessed by subject matter experts during project scoping to validate the corporate data and assess the asset in service. The number of splices/joints identified in each span is used as an indicator of in-service condition.

3/12G galvanised steel (SC/GZ) and small diameter hard drawn bare copper (HDBC) conductor have been identified and confirmed as prone to failure due to corrosion and mechanical fatigue caused by reduced stranding and cross sectional area. These populations contribute significantly to the in-service failures and defects observed on the Energex network. Refer to the Asset Management Plan for a comprehensive breakdown of the installed population, current levels of service and current and emerging technical issues.

Due to the geographically dispersed nature of the network, populations of conductor are subject to different operating environments and failure modes. Targeted programs are therefore aimed at known problematic conductor types and initially focused on those installed in populated, coastal regions where the likelihood of in service asset failure is considered greater. Remaining aged populations are managed through routine inspection programs with ongoing monitoring of conductor failure rates and performance metrics.

The prioritised scope of HV and LV distribution overhead conductor reconductoring is:

- All hard drawn bare copper 7/0.104” imperial and smaller aged 70+
- All galvanised steel 3/12 imperial conductor aged 55+
- Small diameter ACSR imperial conductor aged 70+.

Additionally, this approach has identified at risk 33kV conductor operating at or beyond its technical life based on condition, which presents a significant safety risk to electricity workers and the general public.

8.3.4 Underground Cable Replacement

Energex employs Condition Based Risk Management (CBRM) to forecast the retirement of underground cables greater than or equal to 33kV. Asset condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each cable within this population. This begins with a “Health Index” (HI) developed to represent asset condition. A higher HI value represents a more degraded asset, with corresponding higher likelihood of failure. In turn, this reflects as a higher likelihood of inability to achieve the basic customer energy delivery service. Energex considers assets for replacement when HI reaches 7.5. The Energex risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

In general, distribution and low voltage cables are replaced upon identified defect or ultimate failure.

Underground cable assets are inspected periodically, as required by Queensland legislation. At transmission and sub-transmission voltages, routine maintenance monitors the electrical condition of the cable over sheaths and sheath voltage limiters, the performance of pressure feeds, the accuracy and condition of pressure gauges and alarm systems and the physical condition of the above ground structures and terminations. At distribution voltages, periodic inspections check the external condition of distribution cable systems including link pillars, link boxes and service pillars to ensure equipment remains in an acceptable condition.

Energex has initiated the following proactive, targeted programs aimed at known problematic underground distribution assets:

8.3.4.1 Underground Network Demand Replacement

CONSAC (Concentric Neutral Solid Aluminium Conductor) is a legacy aluminium sheathed paper insulated LV cable installed on the network during the 1970's. The aluminium sheath also serves as the neutral conductor in this cable construction. The aluminium sheath is susceptible to corrosion which can lead to open circuit of the neutral and therefore can pose a significant safety risk.

8.3.4.2 Corrosion of Cast Iron Cable Potheads

Cast iron potheads are an obsolete legacy cable termination used to transition from the underground to overhead system. Each core of a multicore cable is terminated through porcelain bushings contained in a cast iron box. A dielectric material, such as hydrocarbon oil or asphalt, is used to fill the box. Corrosion of the outer casing leads to water ingress and potential catastrophic failure of the termination. Due to data quality issues, small populations of these terminations exist and are to be replaced upon discovery.

8.3.5 Customer Service Line Replacement

Service replacement programs include works as part of an ongoing strategy to ensure compliance with statutory regulations relating to the condition assessment of customer services. Public shocks are required to be reported to the Electrical Safety Office and are monitored against corporate performance targets. This asset class is narrowly performing at an acceptable level against these metrics due to ongoing proactive replacement programs.

8.3.6 Distribution Transformer Replacement

Distribution transformers are inspected periodically as required by Queensland legislation. Distribution transformers require very little maintenance except for removal of vegetation and animal detritus. They are reactively replaced, due to either electrical failure or poor condition as assessed by ground based inspection. It is generally considered uneconomical to refurbish distribution transformers, and they are routinely scrapped once removed. Replacement is with modern equivalent units.

8.3.7 Distribution Switches (including RMUs) Replacement

These assets are inspected periodically as required by Queensland legislation. All assets require basic cleaning maintenance such as removal of vegetation and animal detritus. HV switches require some mechanical maintenance, mostly related to moving parts. Oil filled RMUs require some maintenance related to cleaning of oil sludge. SF6 gas filled switches and RMUs require little other maintenance.

LV and HV switches, fuse assets and RMUs are replaced reactively, either on electrical failure or on poor condition as assessed by ground based inspection. Problematic asset types are proactively replaced by targeted programs.

Some refurbishment of components outside of sealed gas chambers is undertaken where economical to do so on in-service assets. It is generally considered uneconomical to refurbish LV and HV switches, fuse carriers and RMUs once removed, and they are routinely scrapped. Replacement is with modern equivalent units.

8.4 Substation Primary Plant

8.4.1 Power Transformer Replacement and Refurbishment

Asset condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each individual transformer. This begins with a "Health Index" (HI) developed to represent asset condition. A higher HI value represents a more degraded asset, with corresponding higher likelihood of failure. In turn, this reflects as a higher likelihood of inability to achieve the basic customer energy delivery service. Energex considers assets for replacement when HI reaches 7.5. The Asset Management Plan documents the basis of the condition analysis and derivation of health index. Energex employs CBRM modelling to identify the poorest condition assets. The oldest substation transformers in the population that have exceeded their technical life are also considered as potential candidates for replacement to avoid an unsustainable build-up of very aged assets. The Energex risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

8.4.2 Circuit Breaker, and Switchboard Replacement and Refurbishment

Substation circuit breakers and reclosers condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each individual substation asset. This begins with a "Health Index" (HI) developed to represent asset condition. A higher HI value represents a more degraded asset, with corresponding higher likelihood of failure. In turn, this reflects as a higher likelihood of inability to achieve the basic customer energy delivery service. Energex considers assets as potential candidates for replacement when HI reaches 7.5. The Asset Management Plan for Circuit Breakers and Reclosers documents the basis of the condition analysis and derivation of the HI, using CBRM modelling to identify the poorest condition assets. The Energex risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

8.4.3 Instrument Transformer Replacement and Refurbishment

Instrument transformer's condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each individual substation asset. A more degraded asset has a corresponding higher likelihood of failure. This has adverse implications on network protection as well as staff and public safety. In turn, this reflects as a higher likelihood of inability to achieve the basic customer service delivery and a safe network for the Queensland community. Energex considers assets for replacement based on assessed end of technical life, condition and risk. The Energex risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

Where practical, timing of replacement is coordinated with other necessary works occurring in the substation to promote works efficiencies.

8.5 Substation Secondary Systems

8.5.1 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 damage to plant and 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, standalone projects for replacement of the obsolete protection schemes are undertaken.

8.5.2 Substation DC Supply Systems

Outcome of a battery failure inside a substation can lead to high safety consequence such as serious injury to Energex personnel and reliability risk consequences such as complete loss of control and protection at a substation. Maintaining the operational reliability of substation DC services is paramount.

Batteries are inspected and tested annually. As the batteries degrade with use and time, component elements are replaced upon failure, while complete battery banks and chargers are replaced on age.

8.6 Other Programs

8.6.1 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 cause of 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 treat vegetation on all overhead line routes. The cycle times are managed based on species, growth rates and local conditions
- Reactive spot activities to address localised instances where vegetation is found to be within clearance requirements and is unable to be kept clear until the next cycle - or has been reported for action by customers.

Energex works cooperatively with local councils to reduce risk of vegetation contacting powerlines.

8.6.2 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. All but 20 known defects have been assessed and rectified at the end of June 2020 with the remainder to be completed by the end of 2020.

The next LiDAR overhead network clearance survey will commence in August 2020 on a three-year cycle. During this cycle, an algorithm to compensate the effect of temperature on conductor sag will be trialled and applied to ensure compliance at 35°C ambient temperature.

8.7 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.

Chapter 9

Network Reliability

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

9 Network Reliability

9.1 Reliability Measures and Standards

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

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

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

- System Average Interruption Frequency Index (SAIFI). This reliability performance index indicates the average number of occasions the system is interrupted during the reporting period.

9.1.1 Minimum Service Standard (MSS)

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

The reliability limits are prescribed in Energex's Distribution Authority, No. D07/98, 30 June 2014. Energex is required to use all reasonable endeavours to ensure that it does not exceed the SAIDI and SAIFI limits set out in the Distribution Authority for the relevant financial year. Circumstances beyond the distribution entity's control are generally excluded from the calculation of SAIDI and SAIFI metrics.

Under Energex's Distribution Authority (DA), exceedance of the same MSS limit in three consecutive financial years is considered a 'systemic failure' and constitutes a breach. The MSS limits for the regulatory control period in Schedule 2 of the Distribution Authority remain flat up to 2025. In October 2019, the DNRME issued the revised DAs for Ergon Energy and Energex with the above recommendations materialised in the respective areas.

9.1.2 Reliability Performance in 2019-20

The normalised results in Table 18 highlight a favourable performance against MSS for all of Energex's network performance measures in 2019-20.

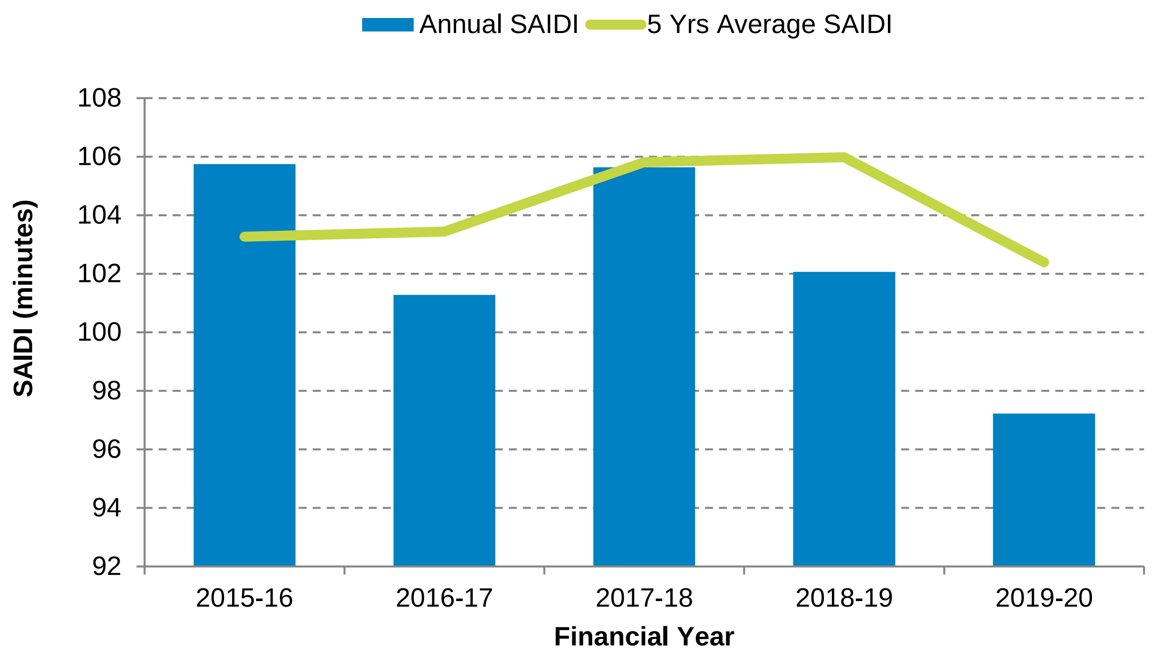
Table 18 – Performance Compared to MSS

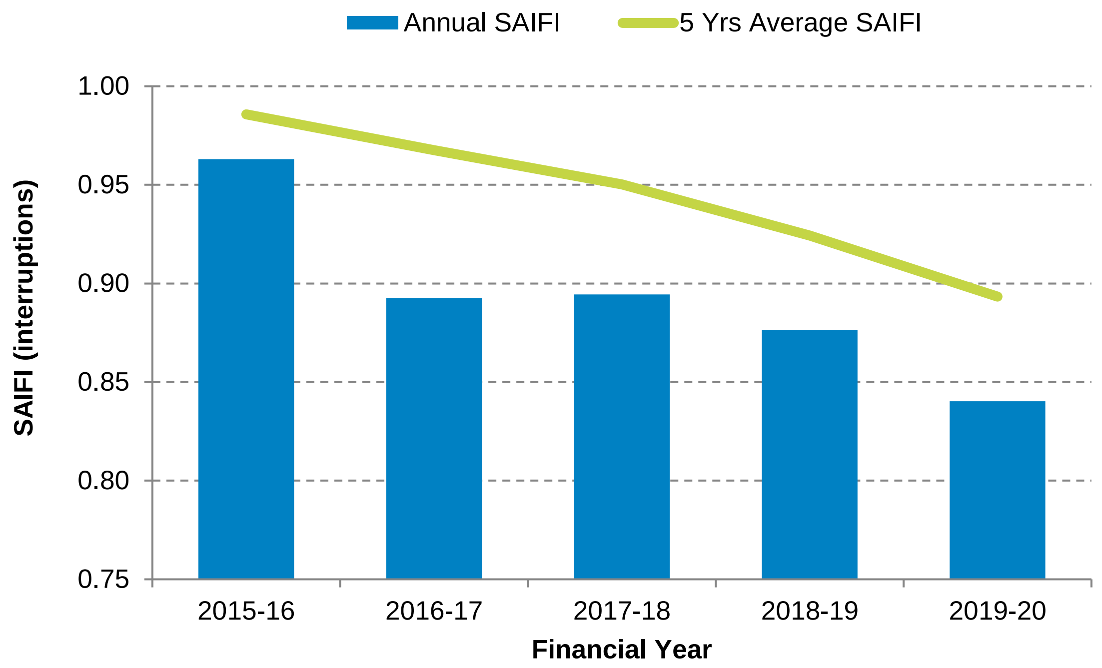
Normalised Reliability Performance		2018-19 Actual	2019-20 Actual	2015-20 MSS
SAIDI (mins)	CBD	2.132	5.001	15
	Urban	70.575	70.473	106
	Short Rural	178.883	159.195	218
SAIFI	CBD	0.0141	0.0227	0.15
	Urban	0.6423	0.6220	1.26
	Short Rural	1.4423	1.3463	2.46

In 2019-20, Energex reliability of supply was favourable to the Distribution Authority's MSS limits for all performance measures.

Figure 13 depicts the five-year rolling average reliability performance for both SAIDI and SAIFI at whole of regulated network level, which demonstrate continual improvement. The overall network performance outcomes for 2019-20 had favourable reliability outcomes for all measures. The performance trends indicate the optimal performance capability of the network without further reliability specific investment on its infrastructure. Energex's overall reliability performance continues to show improvement in MSS since 2010-11 with both the duration and frequency of overall outages reducing by 11.9% and 30.1% respectively. This is a reflection of the targeted investment made during the last two regulatory control periods towards achieving the regulated MSS standards.

Figure 13 – Network SAIDI and SAIFI Performance Five-year Average Trend





9.1.3 Reliability Compliance Process

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. There is, however, no capex allocated specifically to achieve these internal targets.

The internal targets are used as the reference for tracking performance during a year and to put necessary operational measures in place where required and feasible.

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 11kV feeders, as Energex's 11kV network is the highest contributor to its SAIDI and SAIFI results. By creating projects around individual 11kV feeders, the performance of each feeder can be analysed, and the improvement work 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.

9.1.4 Reliability Corrective Actions

As shown in Table 18, Energex met its MSS reliability targets during 2019-20. 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.

9.2 Service Target Performance Incentive Scheme (STPIS)

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

The AER's STPIS provides a financial incentive for our organisation to maintain and improve our service performance for our customers. The scheme rewards or penalises a DNSP, in the form of an increment or reduction on Annual Revenue Requirement, for its network performance relative to a series of predetermined service targets. The applicable revenue change is applied in the third year from the regulatory year when the performance outcomes are measured.

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

The incentive rates for the reliability of supply performance parameters of the STPIS are primarily based on the value that customers place on supply reliability (the VCR), energy consumption forecast by feeder type and the regulatory funding model.

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

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

Energex's 2019-20 Performance RIN's response included completed templates (and relevant processes, assumptions and methodologies) relating to reliability performance reporting under the STPIS.

More information on Ergon Energy's and Energex's recent RIN submissions can be found on the AER's website https://www.aer.gov.au/networks-pipelines/network-performance

9.2.1 STPIS Results

The normalised results in Table 19 highlight a favourable year end performance against STPIS for all of the network categories in 2019-20. As this table presents average duration and the frequency of unplanned supply interruptions, lower numbers indicate stronger results and less interruption to our customers' electricity supply.

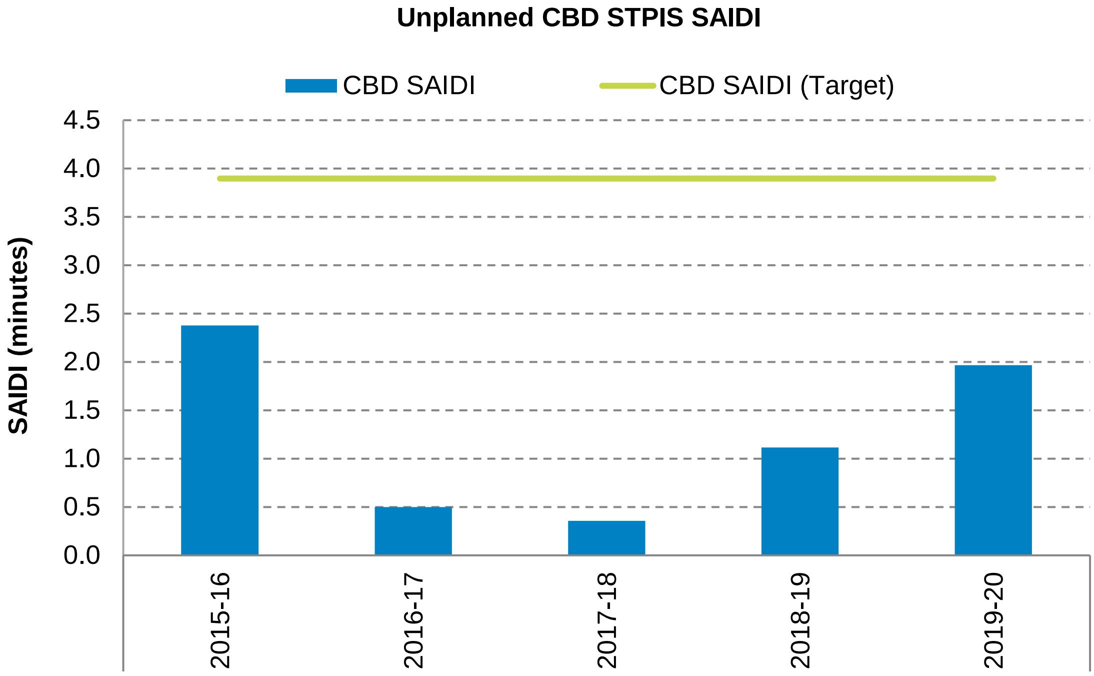
Table 19 – Performance Compared to STPIS

Normalised Reliability Performance		2018-19 Actual	2019-20 Actual	2015-20 STPIS
Unplanned SAIDI (mins)	CBD	1.120	1.968	3.897
	Urban	45.590	51.815	60.118
	Short Rural	126.850	122.868	114.475
Unplanned SAIFI	CBD	0.0030	0.0131	0.0352
	Urban	0.5590	0.5597	0.9081
	Short Rural	0.7690	1.2367	1.8747

In 2019-20, Energex's reliability of supply outperformed the unplanned performance targets under the Australian Energy STPIS for all six measures. Our overall reliability unplanned performance has improved since the inception of STPIS in 2010 with both the duration and frequency of overall unplanned outages reducing by 7.0% and 30.5% respectively.

Figure 14, Figure 15 and Figure 16 depict the STPIS targets and results for the 2015-20 period. The actuals are the normalised values (i.e. exclusions are applied as per Clause 3.3 of the STPIS).

Figure 14 – STPIS CBD SAIDI / SAIFI Historical, Actuals



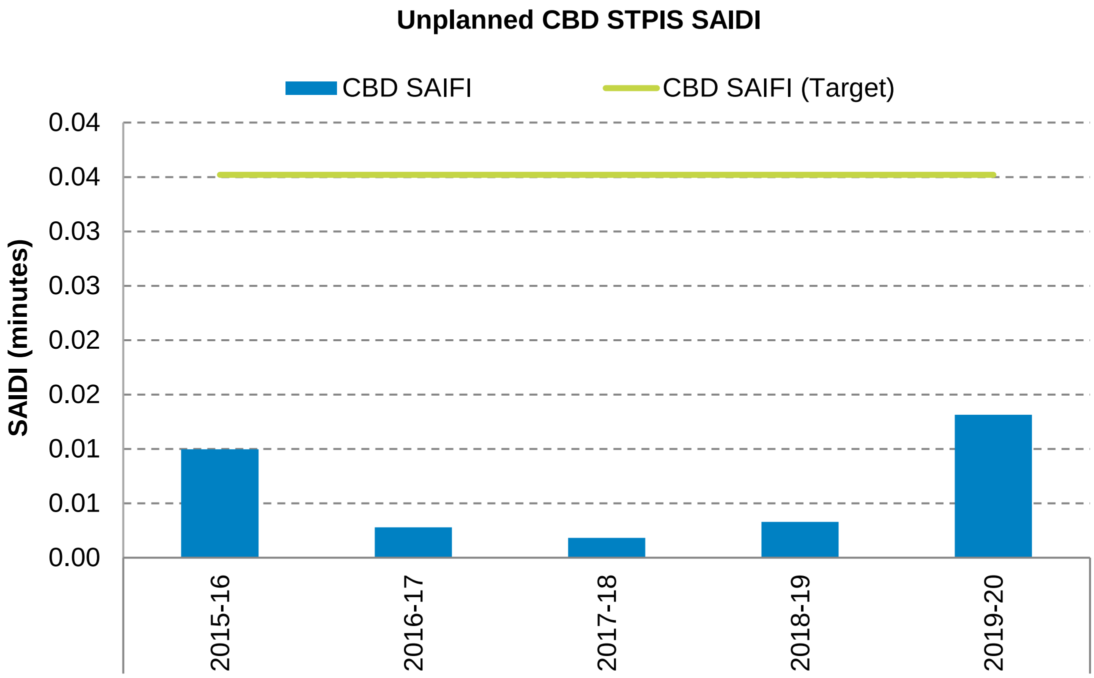


Figure 15 – STPIS Urban SAIDI / SAIFI Historical, Actuals

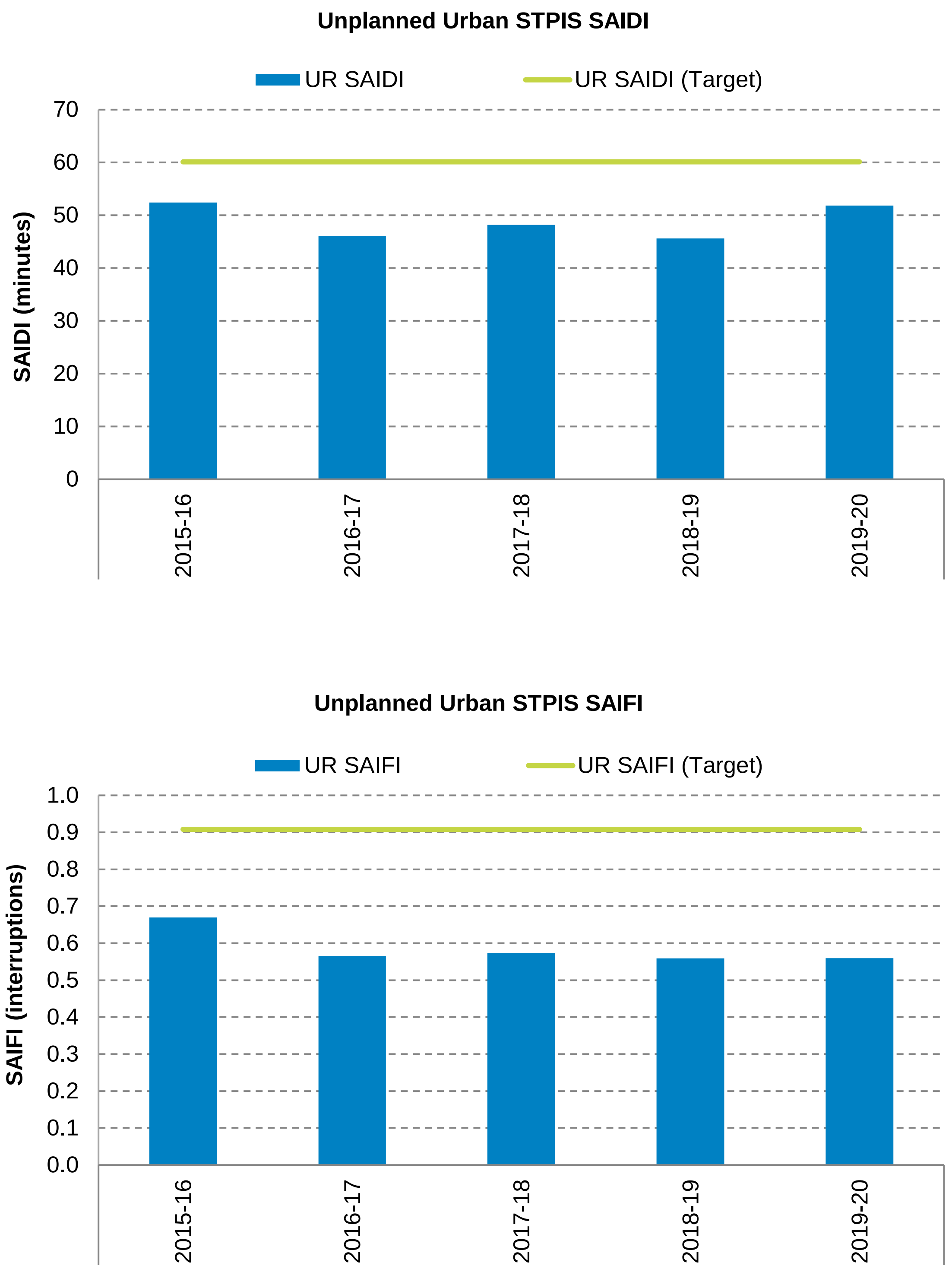
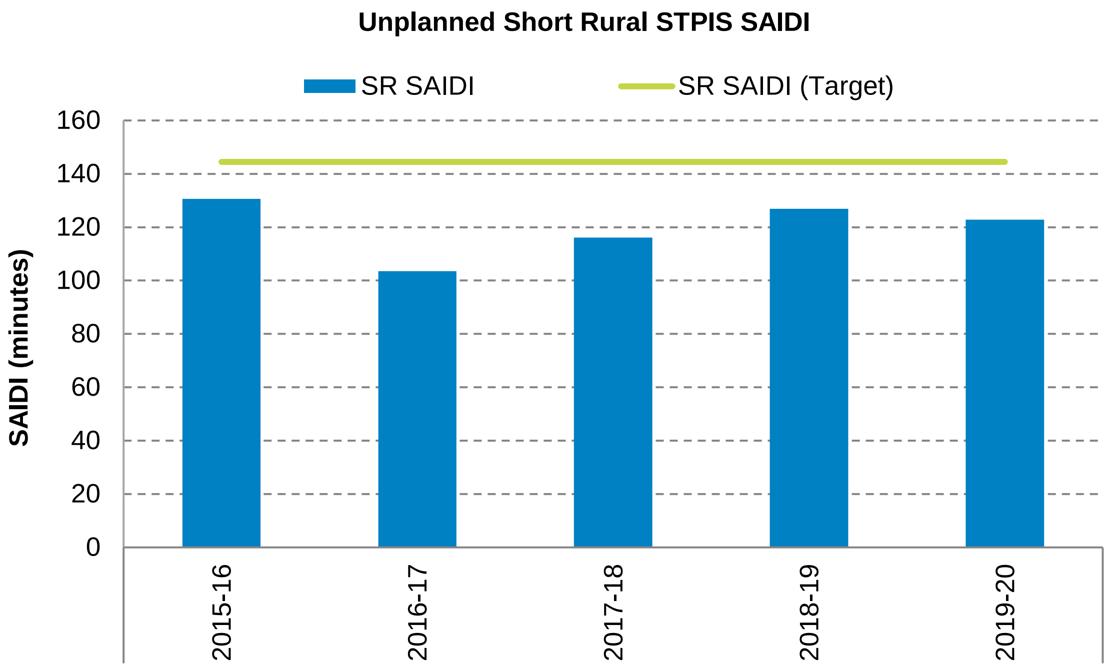
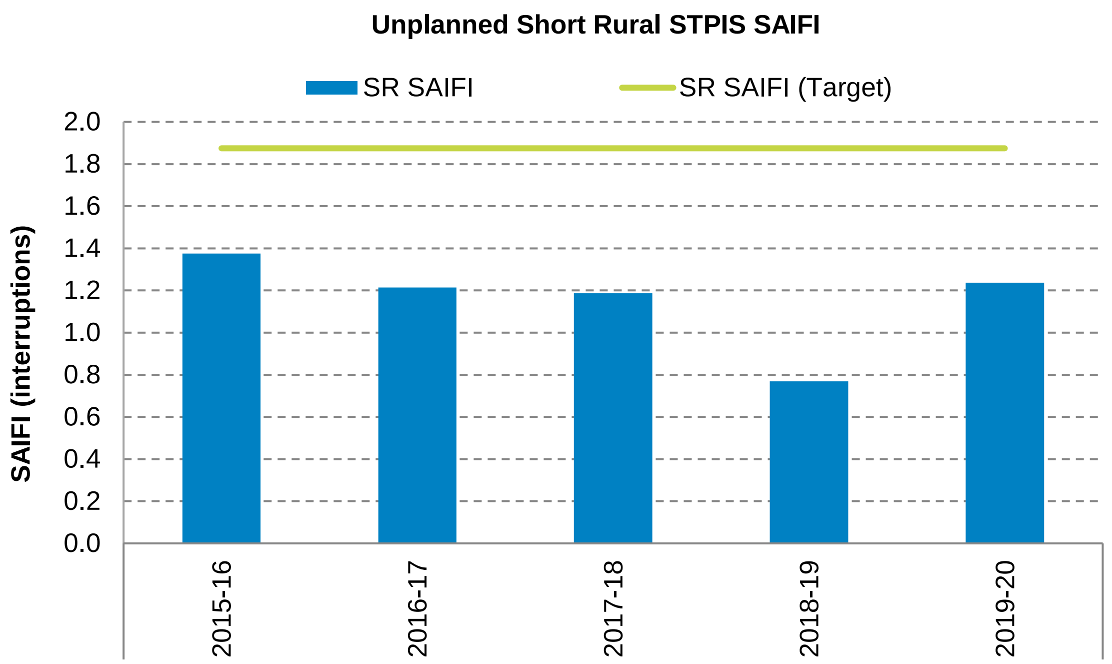


Figure 16 – STPIS Short Rural SAIDI / SAIFI Historical, Actuals





9.3 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
- Bushfire Risk Management Plan.

The current version of the Summer Preparedness Plan and Bushfire Risk Management Plan are available on Energex's website (https://www.energex.com.au/about-us/company-reports,-plans-and-charters).

During the reporting period the Energex distribution network was exposed to five severe storms impacting the network and subsequently requiring an increased level of response from field and support groups. These severe storms impacted a total of 115,440 customers. The South East network was also exposed to heatwave conditions and was impacted by several bushfires, the most significant bushfire was experienced in Tewantin, impacting 33 customers and requiring the replacement of 12 poles.

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.

9.3.1 Summer Preparedness

Energex conducts annual preparations prior to each summer storm season to provide Queensland with a reliable network that minimises 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.

9.3.2 Bushfire Management

Energex reviews and updates the Bushfire Risk Management Plan annually. The plan is published in August each year and contains a list of programs and 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.

9.3.3 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.

9.4 Guaranteed Service Levels (GSL)

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

GSLs are applied by the type of feeder supplying a customer with limits appropriate to the type of GSL as outlined below in Table 20. Some specific exemptions to these requirements can apply. For example, we do not need to pay a GSL for an interruption to a small customer's premises within a region affected by a natural disaster (as defined in the EDNC).

Table 20 – GSL Limits Applied by Feeder Type

EDNC	GSL	CBD feeder	Urban feeder	Short rural feeder
Clause 2.3.3	**Wrongful disconnections** (Wrongfully disconnect a small customer)	Applies to all feeders equally		
Clause 2.3.4	**Connections** (Connection not provided)	On business day agreed with customer. Applies to all feeders equally		
Clause 2.3.5	**Reconnections** (Reconnection not provided within the required time)	If requested before 12.00pm - same business day. Otherwise next business day		
Clause 2.3.6	**Hot Water Supply** (Failure to attend the customer's premises within the time required concerning loss of hot water supply)	Within one business day		
Clause 2.3.7	**Appointments** (Failure to attend specific appointments on time)	On business day agreed with customer. Applies to all feeders equally		
Clause 2.3.8	**Planned Interruptions** (Notice of a planned interruption to supply not given)	4 business days as defined in Division 6 of the NERR under Rule 90 (1). Applies to all feeders equally		
Clause 2.3.9(a)(i)	**Reliability – Interruption Duration** (If an outage lasts longer than...)	8 hours	18 hours	18 hours
Clause 2.3.9(a)(ii)	**Reliability – Interruption Frequency** (A customer experiences equal or more interruptions in a financial year)	10	10	16

9.4.1 Automated GSL Payment

The EDNC requires that a DNSP use its best endeavours to automatically remit a GSL payment to an eligible customer. Customers receive the payment for most GSLs within one month of confirmation. However, in the case of Interruption Frequency, the GSL payments will be paid to the currently known customer once the requisite number of interruptions has occurred. Table 21**Table 21** shows the number of claims paid in 2019-20.

Table 21 – GSLs Claims Paid 2019-20

GSL	Number Paid	Amount Paid
Wrongful Disconnection	23	$3,266
Connection of Supply	693	$197,166
Customer Reconnection	26	$2,451
Hot Water Supply	1	$114
Appointments	88	$5,016
Planned Interruptions	423	$14,252
Duration of Interruption	1,349	$153,786
Frequency of Interruption	0	$0
Total	**2,603**	**$376,051**

9.5 Worst Performing Distribution Feeders

In accordance with Clause 11 of the Distribution Authority No. D07/98, Energex continues to monitor the worst performing distribution feeders on its distribution network and report on their performance. Under the authority, Energex is also required to implement a program to improve the performance outcomes for the customers served by the worst performing distribution feeders.

In October 2019 the worst performing feeder improvement program criteria set out in Clause 11.2(c) of the Distribution Authority No. D07/98 were amended and are outlined below:

<u>Clause 11. Improvement Programs</u>

(c) The worst performing feeder improvement program will apply to any distribution feeder that meets the following criteria:

> *(i) The distribution feeder is in the worst 5% of the network's distribution HV (high voltage) feeders, based on its three-year average SAIDI/SAIFI performance; and*
>
> *(ii) The distribution HV feeder's SAIDI/SAIFI outcome is 200% or more of the MSS SAIDI/SAIFI limit applicable to that category of feeder.*

The list of our worst performing distribution feeders, as defined by Clause 11.2(c) of the Distribution Authority No. D07/98 up to June 2020, has been provided in Appendix G. Energex's worst performing distribution feeder assessment for 2019-20 is summarised below:

- 4% of Energex's distribution feeders meet the worst performing feeder improvement program criteria based on 3 year average performance up to June 2020 (71 distribution feeders in total – 2 CBD, 15 Urban and 54 Short Rural)

- The 71 distribution feeders meeting the worst performing feeder improvement program criteria supply 2.51% of the Energex's customer total
- 47 of the reported worst performing distribution feeders have carried over from the list from the 2018-19 reporting period.

Table 22 below shows the comparative average, minimum and maximum 3-year averages of SAIDI/SAFI for the reported worst performing distribution feeders across the feeder categories for 2019-20.

Table 22 – 2019-20 Worst Performing Feeder List – Current Performance (2019-20)

	3 Year Average Feeder SAIDI (mins)			3 Year Average Feeder SAIFI (int.)		
	Minimum	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Urban	283.44	905.05	5,593.40	2.61	7.53	34.10
Rural	439.53	903.01	9,485.48	5.35	12.61	69.25

9.5.1 Details of worst performing distribution feeders reported for 2019-20

CBD feeders

- The change to Clause 11.2(c) of the Distribution Authority No. D07/98 has resulted in the inclusion of the CBD feeder category for the first time. Two feeders in the CBD category have met the worst performing distribution feeder SAIDI criteria. Both feeders are single customer feeders.

Urban feeders

- The Urban worst performing distribution feeder list consists of 15 feeders. From the total of 15 feeders 13 met the worst performing distribution feeder SAIDI criteria and 8 feeders met the SAIFI criteria, with 6 feeders meeting both the SAIDI and SAIFI criteria. Six of the feeders are single customer feeders
- Seven Urban feeders identified under the SAIDI criteria have improved their performance from the previous year.

Short Rural feeders

- The Short Rural worst performing feeder list consists of 54 feeders. From the total of 54 feeders 49 met the worst performing distribution SAIDI criteria and 12 the SAIFI criteria, with 7 feeders meeting both criteria. Five of the feeders are single customer feeders
- Twenty-six Short Rural feeders identified under the SAIDI criteria have improved their performance from the previous year.

A full report on Energex's worst performing distribution feeders based on 2019-20 performance is available in Appendix G.

Consistent with the 2015-2020 regulatory term, Energex only sought limited capex for the worst performing feeder improvement program from the AER for the 2020-25 regulatory control period. We are ensuring that the investment in the worst performing feeder improvement program is prudently spread across different feeders that meet the Distribution Authority No. D07/98 improvement program

Clause 11 criteria.

The reliability improvement solutions identified from the worst performing distribution feeder reviews conducted in the 2015-20 regulatory period have mainly included moderate capital investment options and we expect this to continue in this regulatory period. 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 distribution feeders during 2020-21.

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

1. Improved network operation by:
   - investigating to determine predominant outage cause
   - implementing reliability or operational improvements identified through the investigation of any unforeseen major incidents
   - improving fault-finding procedures with improved staff-resource availability, training and line access
   - improving availability of information to field staff to assist fault-finding, which could include communications, data management and availability of accurate maps and equipment
   - planning for known contingency risks until permanent solutions are available
   - improving and optimising management of planned works.
2. Prioritisation of preventive-corrective maintenance by:
   - scheduling asset inspection and defect management to poorly performing assets early in the cycle
   - scheduling worst performing distribution feeders first on the vegetation management cycle
   - undertaking wildlife mitigation (e.g. birds, snakes, possums, frogs) in the vicinity of worst performing distribution feeders.
3. Augmentation and refurbishment through capex by:
   - refurbishing or replacing ageing assets (for both powerlines and substations).

9.6 Safety Net Target Performance

Energex's Distribution Authority DO7/98 (DA) describes the performance reporting obligations against service Safety Net targets. Supply interruption events over 2019-20 have been reviewed in detail to identify any instances where the actual restoration performance may not have achieved the service Safety Net targets set out in Schedule 3 of the Distribution Authority (as described in Section 5.4.2). There were no network events in the 2019-20 period where the customer safety net targets were breached.

Chapter 10

Power Quality

- Quality of Supply Process
- Customer Experience
- Power Quality Supply Standards, Codes Standards and Guidelines
- Power Quality Performance in 2019-20
- Power Quality Ongoing Challenges and Corrective Actions

10 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.

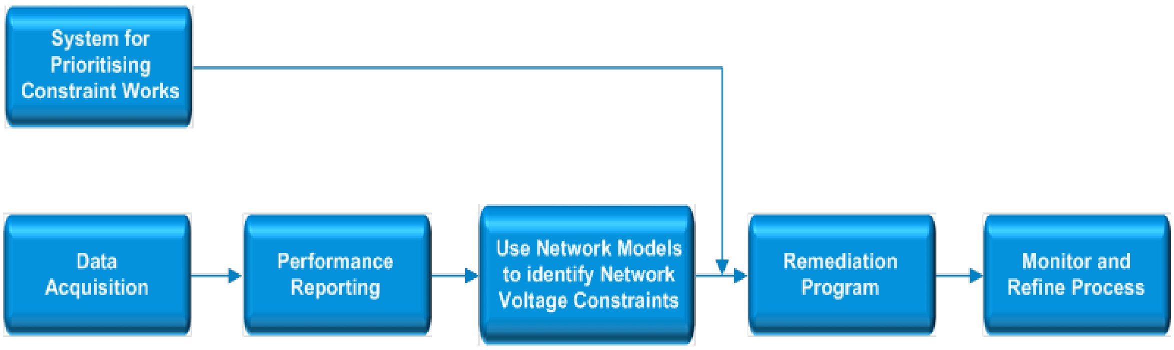
10.1 Quality of Supply Processes

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 17 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
- Measuring results to refine the network model and remediation options.

Figure 17 – 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.

10.2 Customer Experience

Energex has been traditionally tracking 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 18 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 shows a slight decline.

Figure 18 – Quality of Supply Enquiries per 10,000 customers

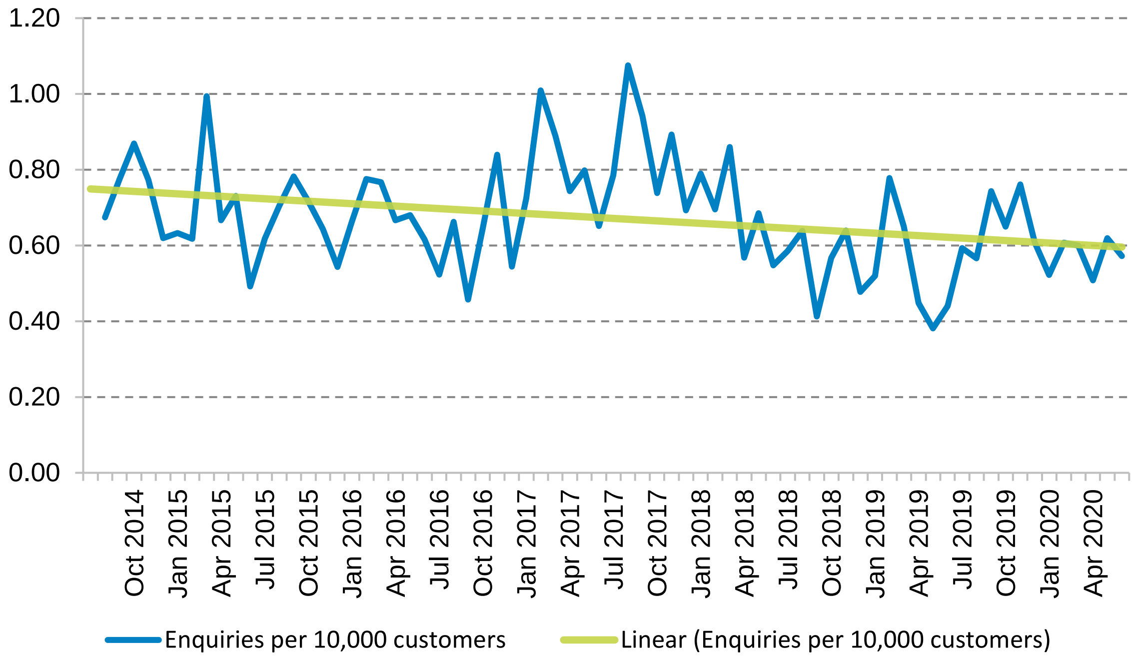


Figure 19 shows a breakdown of the enquiries received by the reported symptoms over the last 12 months, with the largest identifiable category, at 46%, related to solar PV issues. These are usually associated with customer installations where solar PV inverters could not export without raising voltages 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 20 shows the number of Quality of Supply enquiries received from 2015–2020. The QoS enquiries can mainly be categorised into low voltage, voltage swell, voltage spike, solar PV related and other queries. Solar PV related queries have continued to dominate the QoS queries for the last five years, and this clearly indicates growing number of PV system connected on the distribution network.

Figure 19 – Power Quality Voltage Categories

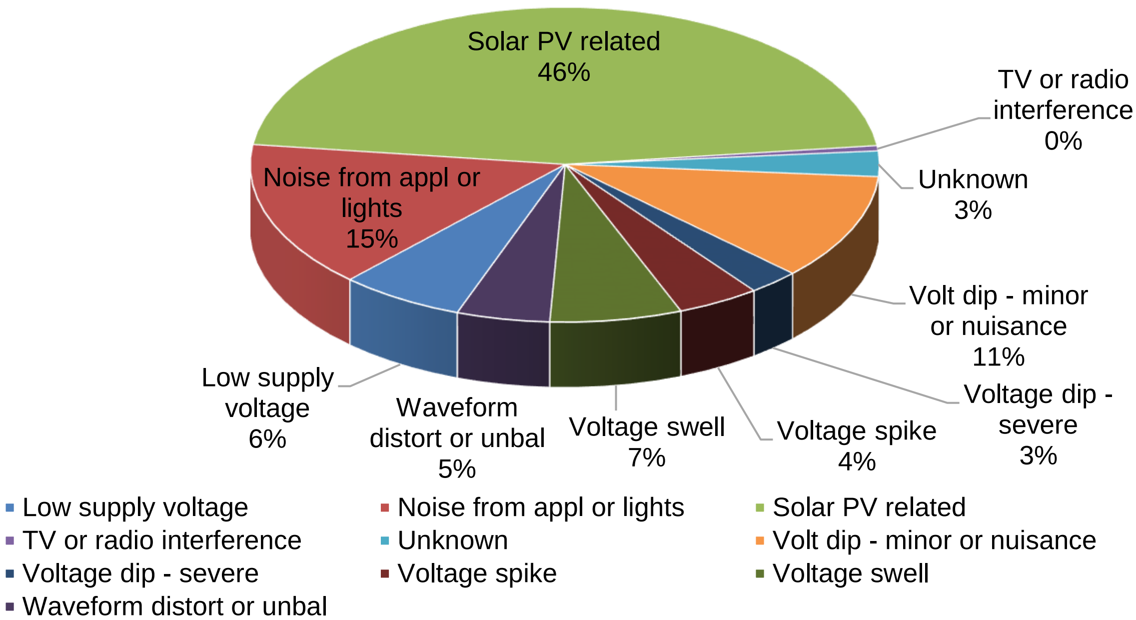


Figure 20 – Quality of Supply Enquiries per Year

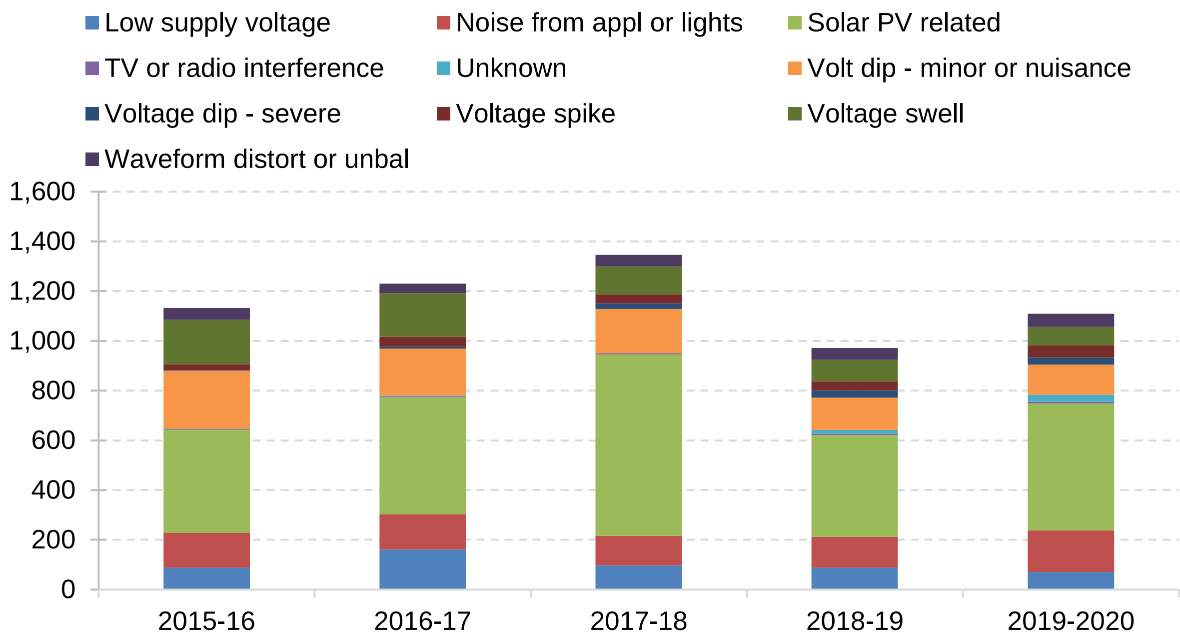
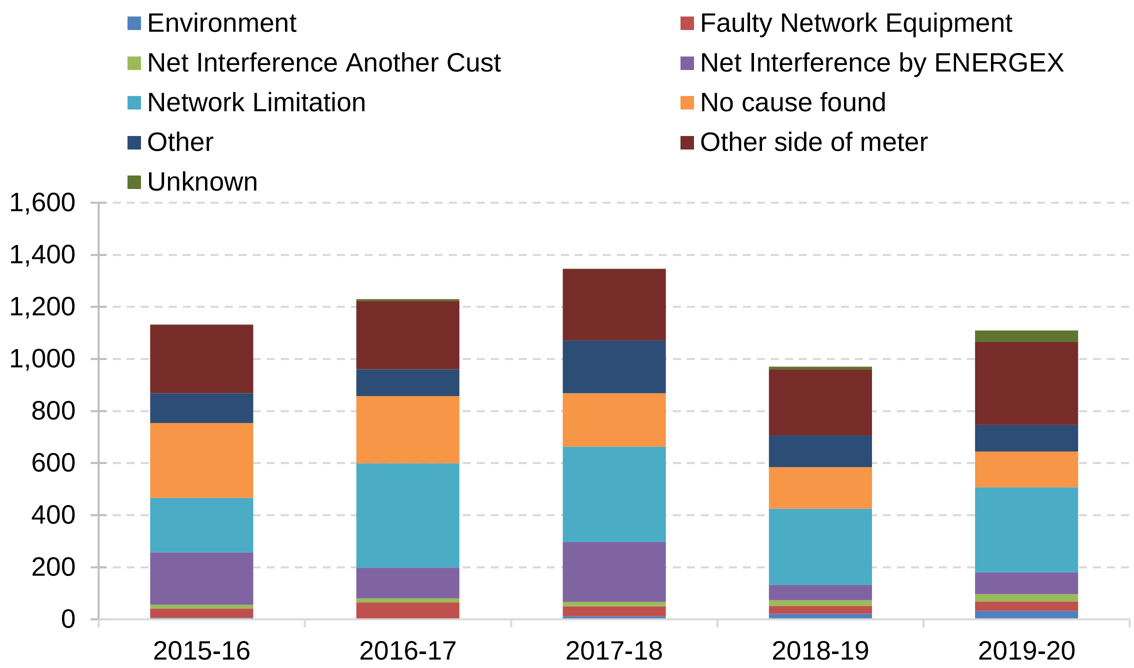


Figure 21 shows the causes at close out for resolving the Quality of Supply queries from 2015-2020. The plot shows that network limitations play an important role in close out of supply queries. Due to network limitations, QoS queries may not always have complete resolution. Network and customer safety however is always ensured.

Figure 21 – Quality of Supply Enquiries by Type at Close Out



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

Some of the requirements under the regulations/rules are listed below and further defined in Table 23, Table 24, Table 25 and Table 26.

- **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 22kV or less is specified in the Electricity Regulations S13
- **Voltage Fluctuations**: An 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**: An NSP must use reasonable endeavours to design and operate its network to ensure that the effective harmonic distortion at any point in the network

is less than the compatibility levels defined in Table 1 of Australian Standard AS/NZS 61000.3.6:2001

- **Voltage Unbalance**: An 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 23 – Allowable Variations from the Relevant Standard Nominal Voltages

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

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

Table 24 – Allowable Planning Voltage Fluctuation (Flicker) Limits

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

Table 25 – Allowable Planning Voltage Total Harmonic Distortion Limits

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

Table 26 – Allowable Voltage Unbalance Limits

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

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

The Power Quality Planning Guideline and the Standard for Transmission and Distribution and Planning are joint working documents 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.

10.4 Power Quality Performance in 2019-20

10.4.1 Power Quality Performance Monitoring

Processes for power quality (PQ) 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 23,000 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 11kV and LV network.

Each of the PQ monitors contributes to give an indication of the state of the network for PQ parameters. The monitor data is downloaded daily, recorded, accessed and presented based on 10 minute averages. PQ reports are presented in various ways to identify potential network issues that may need urgent investigation and resolutions. The majority of PQ monitors are installed on the terminals of the distribution transformers with a quantity installed at the end of long the LV feeders due to difference in load during the evening and rise in voltage during the day depending on the amount of solar along the feeder.

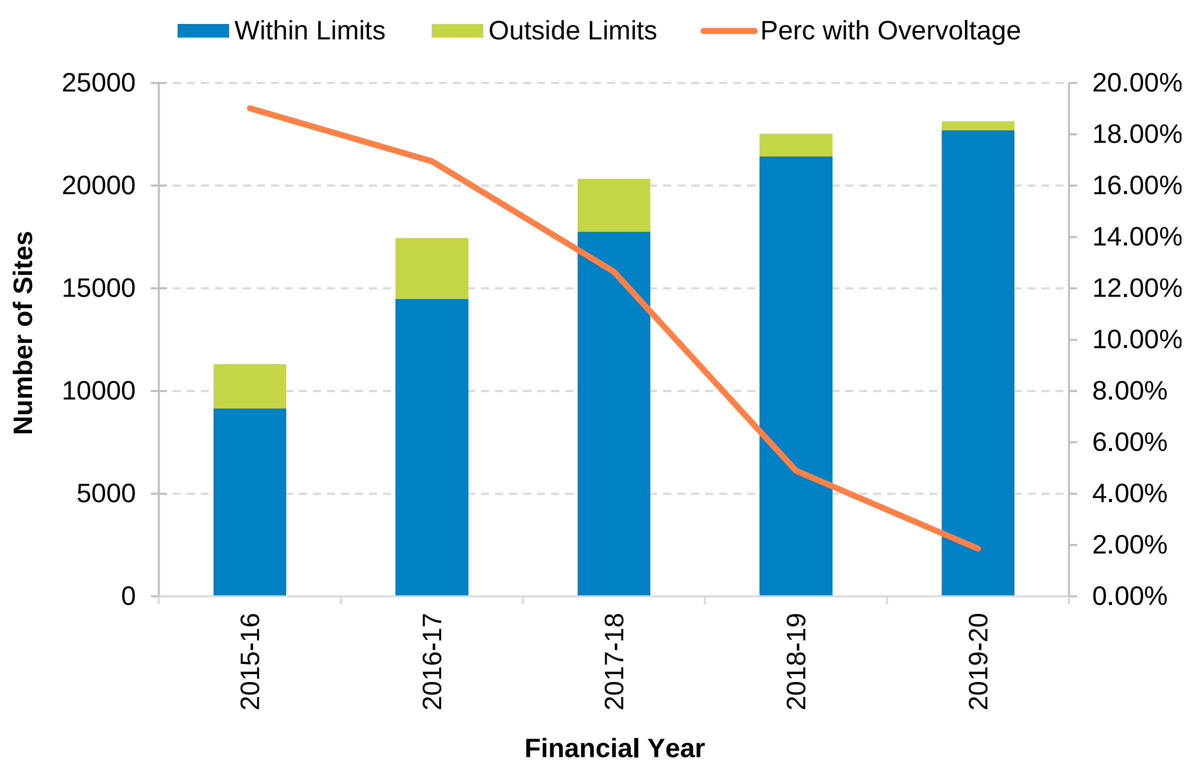
10.4.2 Steady State Voltage Regulation - Overvoltage

The number of monitored sites that reported overvoltage outside of regulatory limits of 253V was 1.86% for 2019-20. This means 1.86% of the monitored sites recorded an exceedance of the upper limit for more than 1% of the time based on 10 minute averages. This is significant improvement from the 19-20 year. The change to the 230V standard is primary reason for the reduction. Figure 22 Figure 22 shows the number of monitored sites that have recorded over-voltage conditions for the last 5 years and percentage of overvoltage sites for each year. This is the fifth consecutive year that improvement has occurred to reduce the number of sites with overvoltage issues.

The take-up of solar PV is substantially greater in South East Queensland than in Southern states and regional Queensland 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. 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.

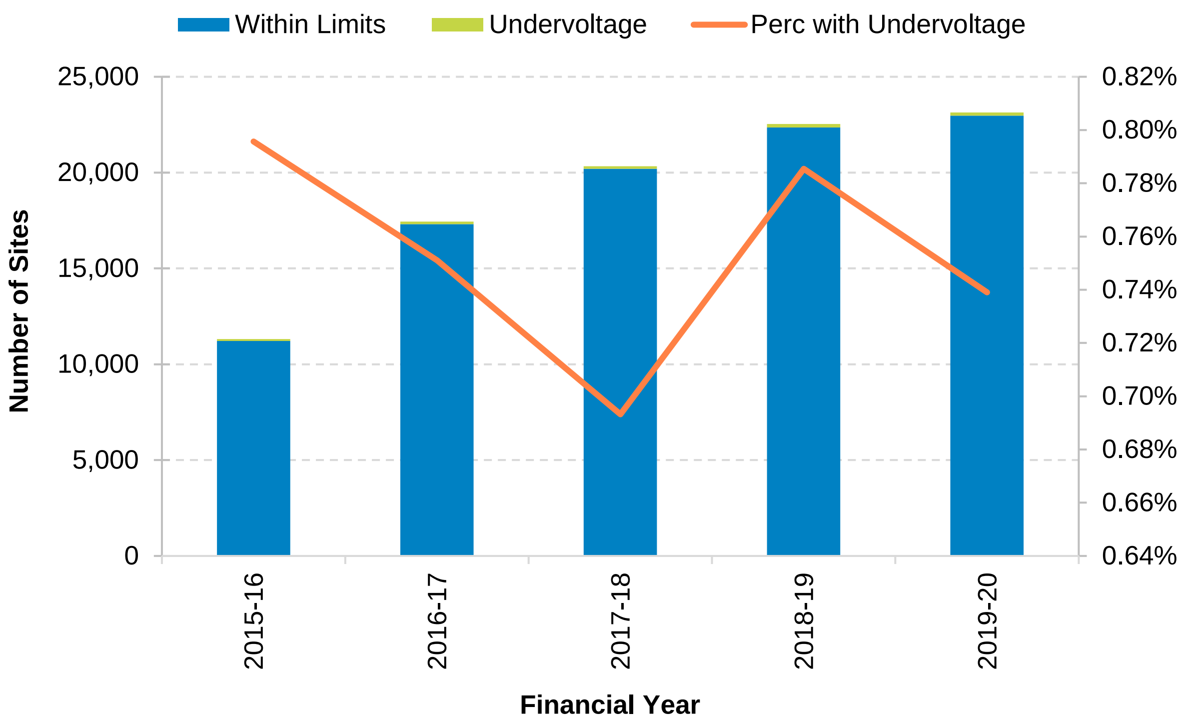
Figure 22 – Overvoltage Sites



10.4.3 Steady State Voltage Regulation – Under Voltage

The change to 230V sees the lower limit for low voltage move to 216.2V. The number of monitored sites that recorded under voltage outside of regulatory limits of 216.2V was 0.74% for 2019-20. This means 0.83% of monitored sites recorded an exceedance of the lower limit for more than 1% of the time based on 10 minute averages. Figure 23 shows the number of monitored sites that have recorded under-voltage conditions for the last 3 years. There has been a slight decrease from the 2018-19 year.

Figure 23 – Under Voltage Sites

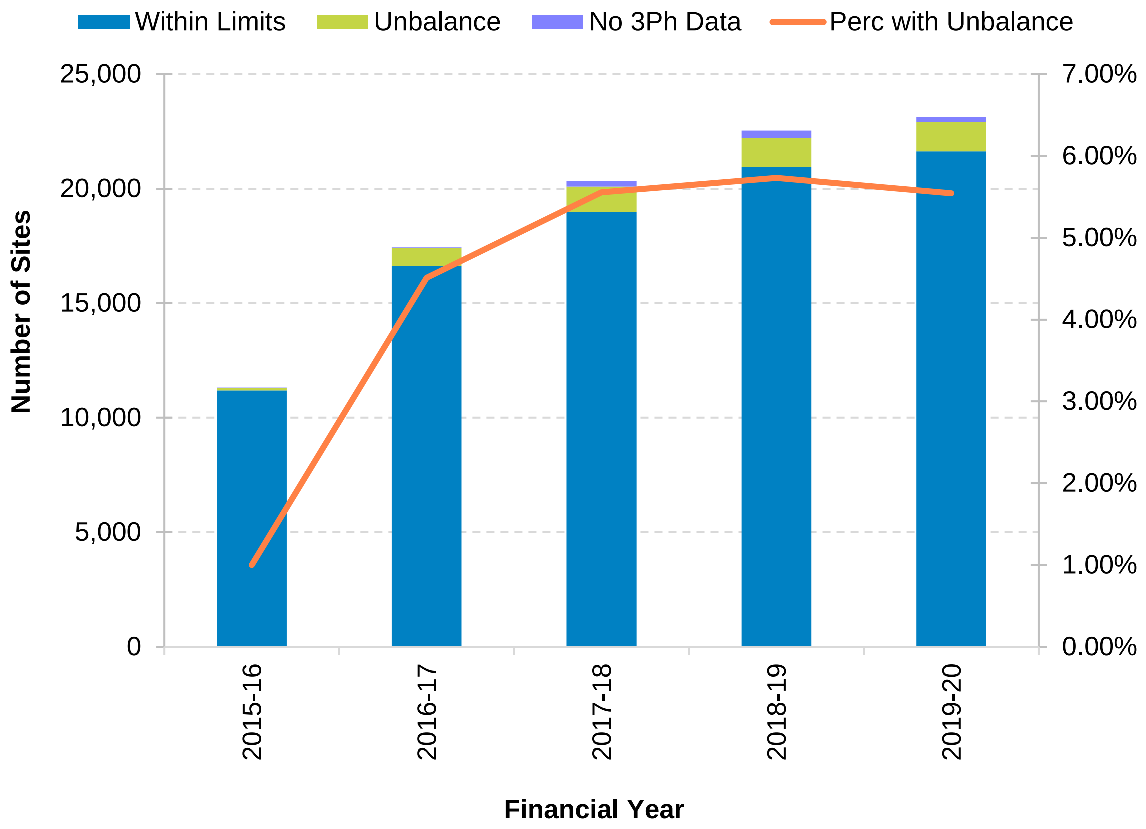


10.4.4 Voltage Unbalance

Data from the 3-phases shows that 5.4% of these sites were outside of the required unbalance standard of 2.5% during 2019-20. Figure 24 shows the number of sites that have recorded unbalanced conditions for the past five years.

The unbalance is mainly due to the increase in the number of monitors being installed at the end of the long LV feeders. Typically these feeders have a high percentage of solar systems, during the daylight periods there is greater unbalance as the solar systems are not typically balanced across the LV network.

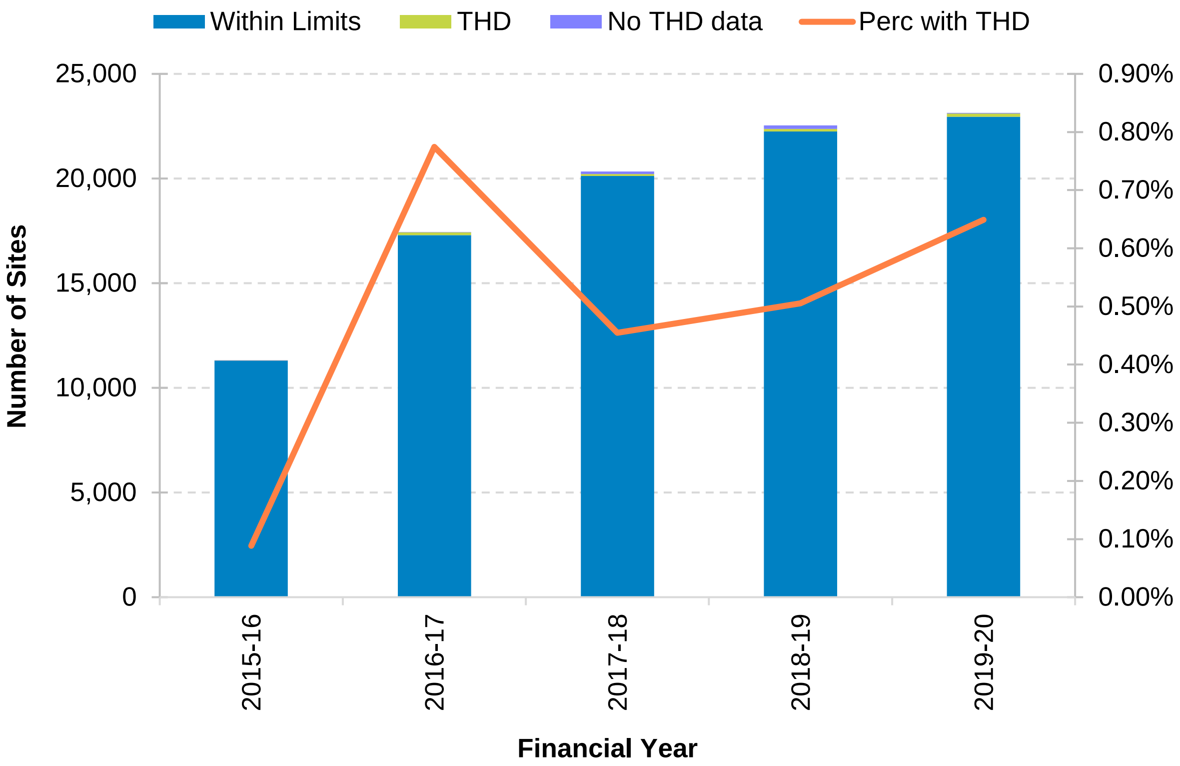
Figure 24 – Voltage Unbalance Sites



10.4.5 Harmonic Distortion

Total harmonic distortion (THD) is a measure of the impurity of the supply voltage and is primarily due to customer loads. Data from monitored distribution transformers was analysed for THD and this is displayed in Figure 25 for the 5 past years . The graph shows that 0.55% of monitored sites had THD that exceeded the 8% threshold stipulated in Australian Standards. This is a slight increase from the 2018-19 figure. 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 25 – Total Harmonic Distortion Sites



10.5 Power Quality Ongoing Challenges and Corrective Actions

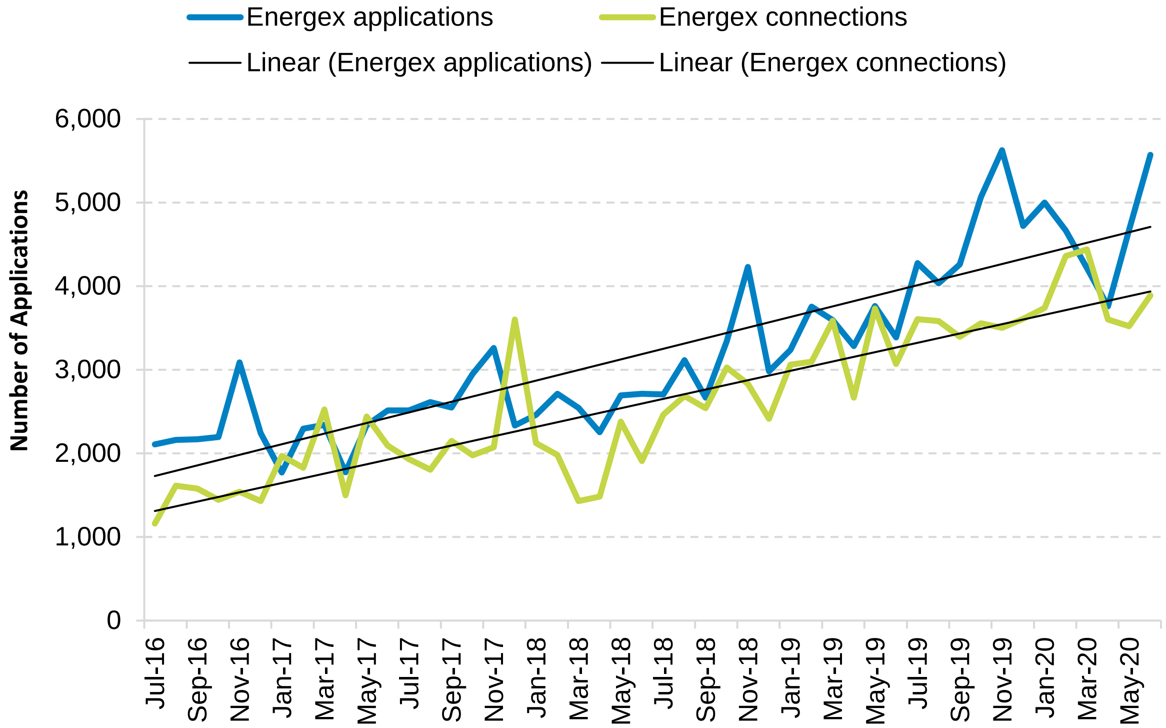
During 2019-20 Energex voltage management strategy focussed on the impacts on low voltage customers. In 2019, Energy Queensland finalised the Customer Quality of Supply Strategy which covers the LV areas of the Power Quality strategy for Energex and Ergon Energy. It covers the changing network connections 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 (EV's).

10.5.1 Low Voltage Networks

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 continues to require on-going work to ensure the PQ parameters are maintained within limits and to ensure neutral currents are limited. The Customer Quality of Supply Strategy for 2020-25 has identified the need for further monitoring of the LV network.

Figure 26 shows that the number of solar applications and connections has continued to increase each year for the past 4 years. The continued increase of solar PV shows that continual vigilance and expenditure will be required throughout the network to ensure it remains compliant with the relevant PQ standards. 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.

Figure 26 – Solar PV Applications and Connections



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 solar 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.

10.5.2 Planned actions for 2020-25 Regulatory Period

Energex will continue to have a focus on voltage management for low and medium voltage network issues identified through PQ data analysis. This will be further supported by determining suitable methods to monitor and rectify the network to ensure compliance continues. Typical rectification of voltage and PQ issues could include the installation of Statcoms, switched capacitor, Low Voltage Regulator (LVR) and On Load Tap Changers (OLTC).

Chapter 11

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

11 Emerging Network Challenges and Opportunities

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

11.1 Solar PV

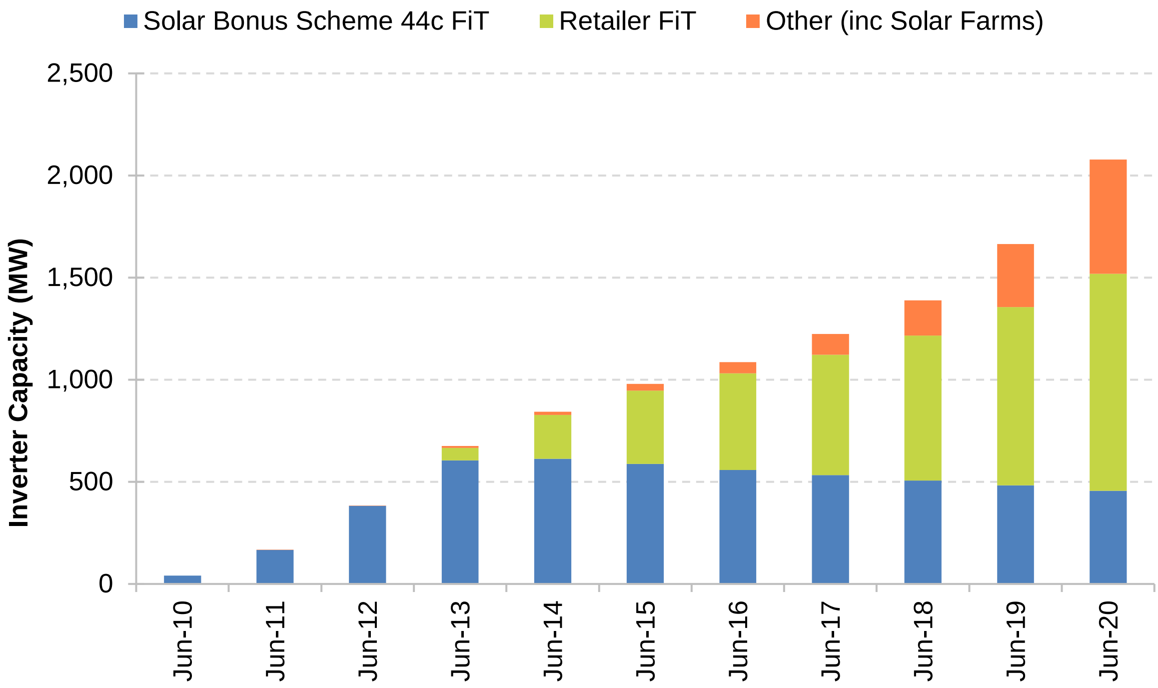
11.1.1 Solar PV Emerging Issue and Statistics

In Energex's network, 40% of detached houses have a solar PV system connected, with an average inverter capacity of around 3.8kVA. The rapid uptake of solar PV has changed the way power travels through the network, from a purely one-way to bi-directional energy flow. The impact is greatest in the LV network and creates a number of system design and operational challenges.

The growth rate in solar PV connection volumes has trended upwards in 2019-20. An average of around 4,100 new systems with a combined capacity of around 34MW, and average capacity of 8.4kVA, were connected per month. Energex now has a total of 440,383 PV systems connected (at June 2020) with an installed capacity of 2,078MW, the majority of which are installed on residential rooftops.

Figure 27 shows the increase in installed solar PV inverter capacity, including small- and medium-scale PV systems. Over the past 12 months, the volume of connections increased by around 13%, and the PV capacity increased by around 25%. The growth in the number of small and medium-scale PV systems is leading to a large number of distribution transformers with high solar PV penetration, and almost 20% of 11kV feeders having experienced reverse power flows during the middle of the day.

Figure 27 – Grid Connected solar PV System Capacity by Tariff as at June 2020



[1] Australian PV Institute, "Mapping Australian Photovoltaic Installations". Accessed 07/08/20, Available: https://pv-map.apvi.org.au/animation

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 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.

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 3kVA to a mandatory dynamic volt-var, volt-watt response mode for all small inverter energy systems. 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. At excessive voltages, the volt-watt mode ramps down active power output to minimise nuisance tripping. 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 swings, unbalance and less nuisance tripping.

Energex had approximately 510 Quality of Supply enquiries in 2019-20 related to solar PV, predominantly resulting from high voltages. This volume represented a 25% increase from the previous year, highlighting the challenges that the increase in the number of PV systems is presenting.

Figure 28 shows the daily load profile of North Maclean zone substation (located south of Brisbane) for ten consecutive years in the shoulder season as the penetration of solar PV systems on this substation has grown. The trend of reducing net load on the feeder during daylight hours is apparent.

Figure 28 – Impacts of Solar PV on North Maclean Zone Substation

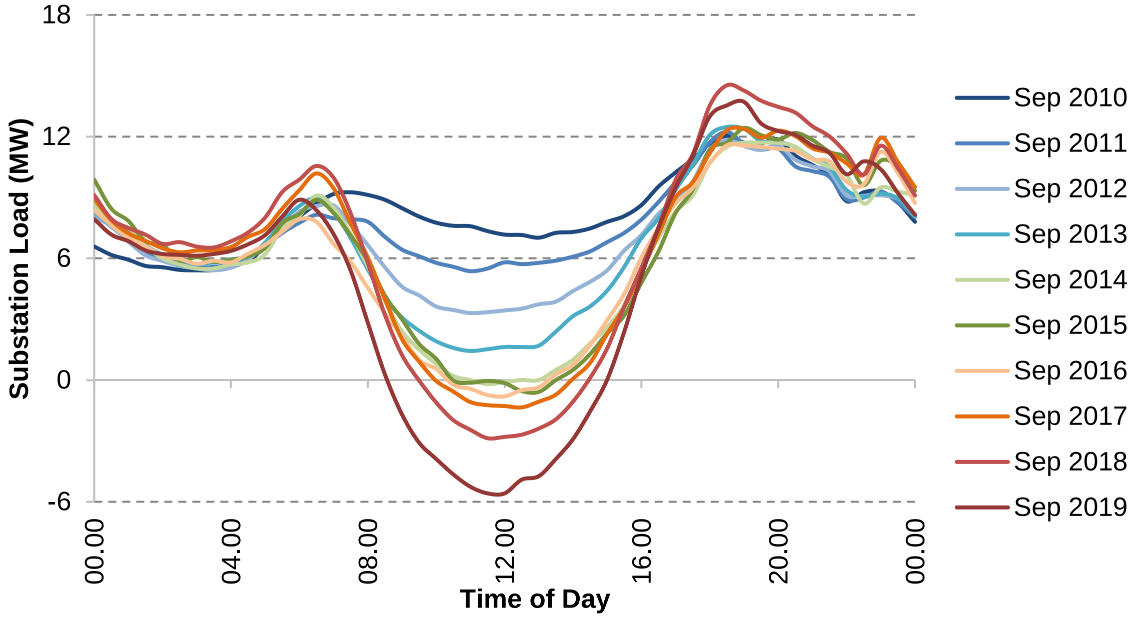


Figure 29 and Figure 30 shows the uptake of solar PV across the Energex network based on zone substation supply areas. Figure 29 indicates the total number of customers in each zone who have solar PV installed and Figure 30 indicates the total installed capacity in the same areas. The five zone substation areas with the highest numbers have been highlighted on each map.

Figure 29 – Number of customers with Solar PV by Zone Substation

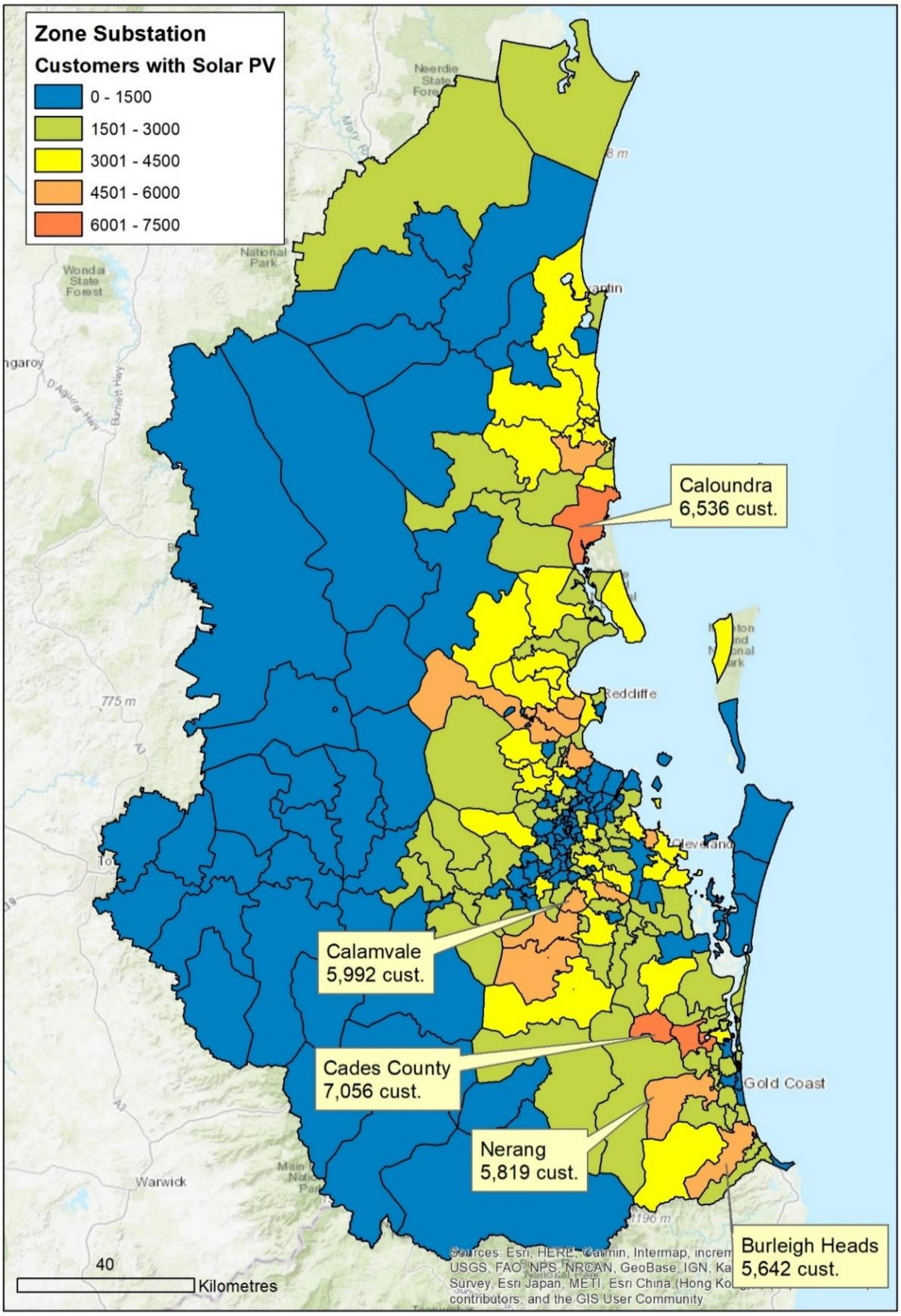
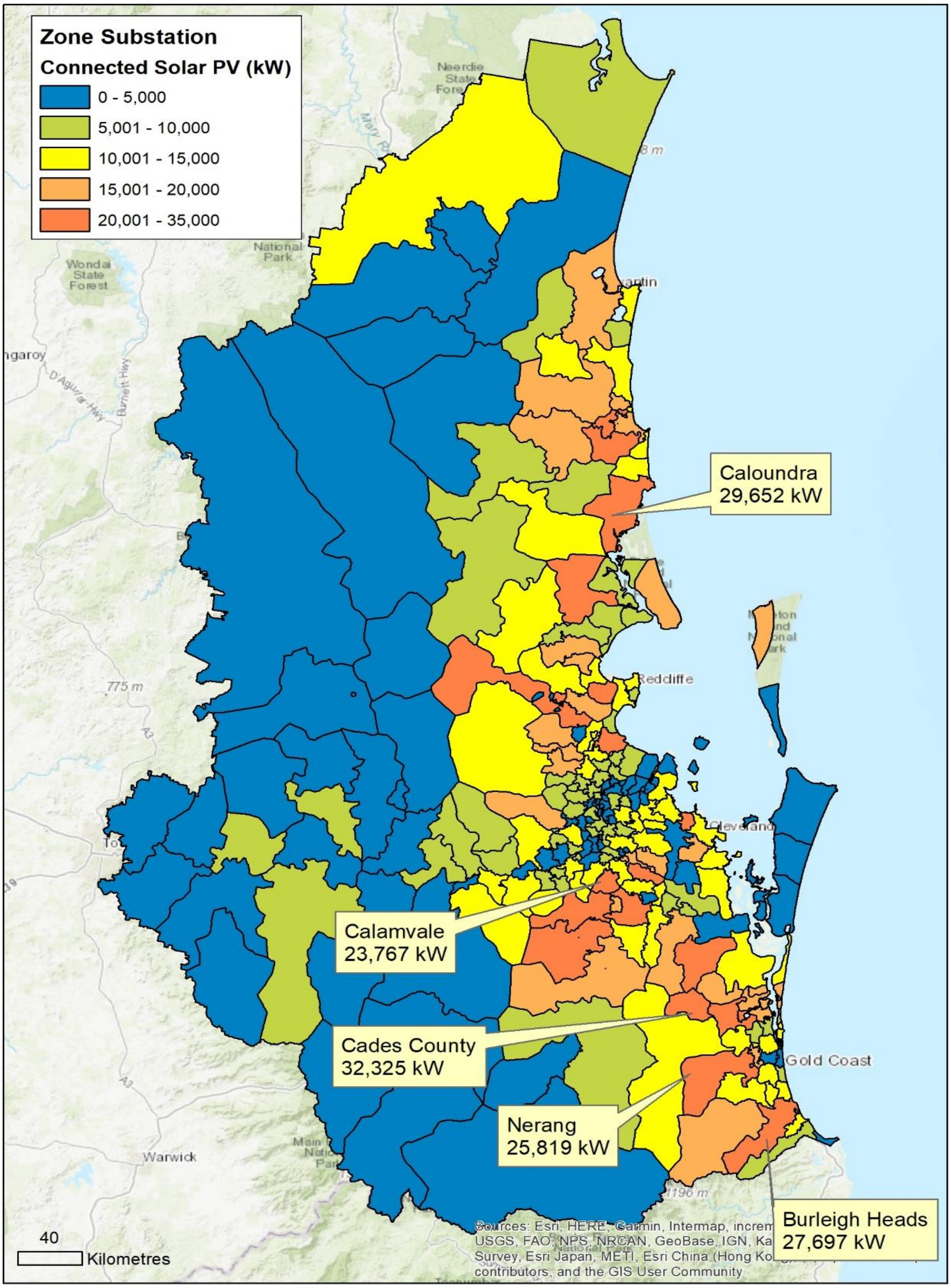


Figure 30 – Installed Capacity of Solar PV by Zone Substation



11.1.2 Solar PV remediation options

A range of traditional, new technology and non-network solutions as shown in Table 27 are used to address network limitations associated with increasing PV penetrations at the LV, MV and zone substation levels. The most cost-effective solution and the PV penetration at which it is required will be site specific and overtime several solutions may be implemented to maximise PV hosting capacity.

Table 27 – Remediation options for increasing penetrations of solar PV

	Network Solutions	Non-network solutions
Increasing Solar PV Penetration	1. Change transformer tap 2. Phase balance PV & load	I. Update zone substation AFLC schedules
	3. Upgrade distribution transformer capacity	**Coordinated via LV DERMS**
	4. Install additional distribution transformer &. reconfigure LV area 5. Re-conductor LV mains 6. MV upgrade where multiple LV networks impacted 7. New technology (LV Regulator, Statcoms, Voltage Regulating Distribution Transformer)	II. Implement Dynamic Operating Envelopes on new DER III. Procure non-network load/generation shifting service from the market

11.2 Strategic Response

11.2.1 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 Networks Australia 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 Grid Roadmap 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 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.

11.2.2 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 distributed energy resource (DER) connection standards.

In February 2020 the small Inverter Energy Systems (IES) and LV standards were updated to align with the National DER Connection Guidelines from Energy Networks Australia (ENA). Using the guidelines improves transparency and consistency in standards requirements between distribution networks in Australia. As more distribution networks make the move towards using the guidelines, Energex will seek to work with other jurisdictions to create greater alignment to improve outcomes for customers, industry and networks.

As part of the work to deliver standards to the connection guidelines, Energex worked collaboratively with other distributors to develop nationally supported uniform power quality response mode settings (volt-var, volt-watt) which enable the management of higher penetrations of DER. These settings have been included in our standards, taking advantage of advanced inverter technology to provide positive customer outcomes.

In July 2020 the Small IES and LV standards were updated to align with Energex's new Connection Policy. The Connection Policy delivered new aligned Model Standing Offer connections between Energex and Ergon Energy, the assessment criteria were reviewed for alignment and with modern engineering principles to deliver increased hosting capacity for DER exports.

Energex has also delivered an update to its joint HV connection standard for DER, aligning with the National DER Connection Guidelines with Ergon Energy which:

- Introduces clear DER communication requirements along with cyber security to ensure safe, reliable management of a distributed grid
- Introduces various measures to help network security and resilience by adopting best practice requirements.

11.3 Electric Vehicles

The charging of Plug-in Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs) creates a new class of electrical load that could have significant impacts on the low voltage electricity network and upstream aspects of the electricity supply chain. EVs are already popular overseas, so while still forming an emerging industry in Australia, their numbers are expected to grow dramatically in Queensland as their purchase costs decrease, availability increases, and more charging infrastructure is deployed.

The growth in EV numbers also presents us opportunities to collaborate with relevant stakeholders to create customer access to optimal private and public charging solutions based on the affordability and convenience priorities of EV owners. If EV owners increasingly charge their vehicles outside network peak demand periods, this will enhance network utilisation, reduce customer charging costs and deliver many other significant benefits to our business and society. 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.

In the 12 months to 30 June 2020, the volume of plug-in EVs registered in Queensland increased by 80% to more than 3,400 vehicles. More than 90% of those EVs are in south-east Queensland. However, EVs still only account for 0.12% of all registered cars in Queensland, and 1.0% of cars sales over the previous 12 months. Battery storage capacity of currently available PHEVs and BEVs is in the range of 12kWh (e.g. Mitsubishi Outlander PHEV) to 100kWh (e.g. Tesla Model S [BEV]). A 120kW Tesla Supercharger is capable of charging the Model S battery from 20% to 80% capacity in around 30 minutes. Ultra-fast charging stations are rated up to 350kW.

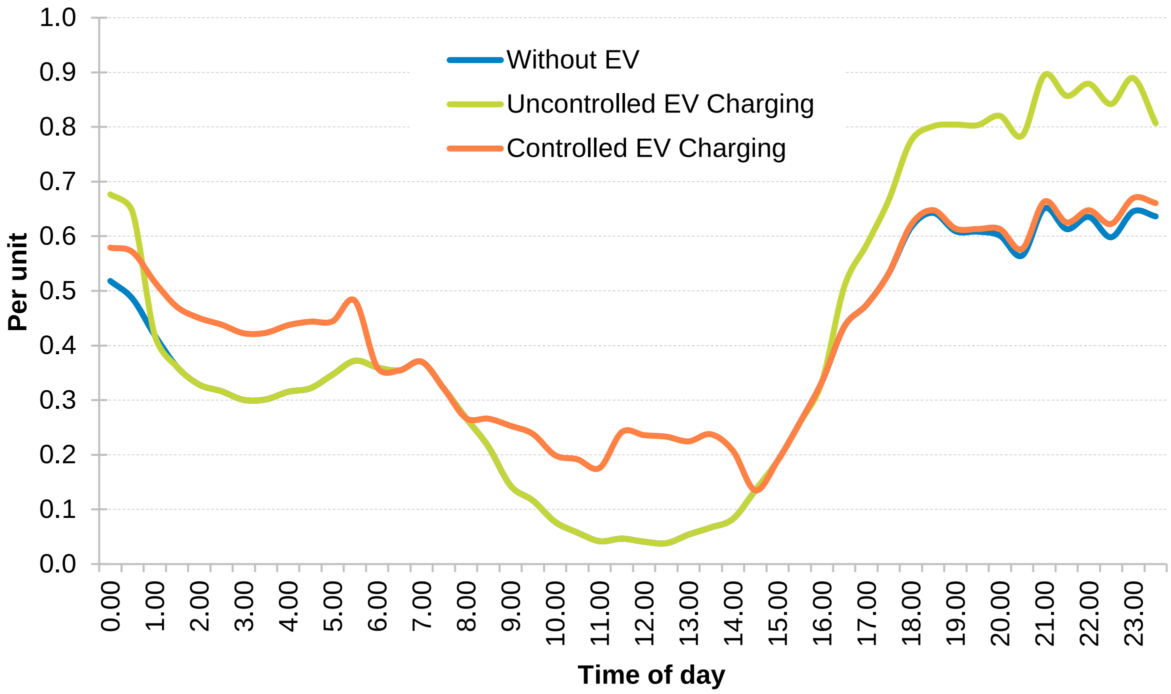
Energex aims to lower relevant barriers to EV ownership and better understand and capitalise on EV charging. To help achieve this, we have developed a Network Electric Vehicles Tactical Plan, a summarised version of which is available on our website: https://www.energex.com.au/manage-your-energy/smarter-energy/electric-vehicles-ev

The tactical plan outlines the key actions our network business will take over the next one to two years to prepare for EVs.

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 31Figure 31 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.

Figure 31 – Impact of Controlled and Uncontrolled EV Charging on a Residential Feeder



11.4 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 BESSs to a real-world environment in customers' premises. Our trials and tests have continued our engagement with the energy storage market on standards, safety and connection requirements. We recognise the potential for BESSs to provide network benefits (addressing peak demand and/or power quality issues) and customer benefits; however, we also recognise the barriers to effectively utilising this developing resource.

The number of BESS installations continues to grow modestly, with around 4,000 BESS now connected to the Energex network. The average capacity of a home battery storage system is around 10kWh. Experience from the testing of current BESS available on the market suggests that there is opportunity for increased sophistication in the systems operation that would increase the potential value that the systems provide to the network and customer. Improved market signals would be required to stimulate these improvements.

BESS for network use continue to be developed, in particular focusing on the potential for energy storage in grid support and microgrid applications. We have developed battery monitoring systems for our BESS that are supporting existing infrastructure such as communications facilities to improve our asset management functions for these resources.

11.5 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 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.

11.6 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), bushfires, tropical cyclones, storms and storm surges, as well as changing sea levels. These events increase 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, as part of EQL, acknowledges and aligns with the Queensland State Government Pathways to a climate resilient Queensland, Queensland Climate Adaption Strategy 2017-2030 and now has a Low Carbon Future Statement and an Environmental Sustainability and Cultural Heritage Policy.

Energex proposes to mitigate the impacts of climate change on our network by:

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

Chapter 12

Information Technology and Communication Systems

- Information Communication and Technology
- Forward ICT Program
- Metering
- Operational and Future Technology

12 Information Technology and Communication Systems

12.1 Information Communication and Technology

12.1.1 Information Communication and Technology Investments 2019-20

This section summarises the material investments Energex has made in the 2019-20 financial year, relating to Information & Communications Technology (ICT) systems.

The key investment priority during the year was to progress programs within the Digital Enterprise Building Blocks (DEBBs) portfolio, with key milestones achieved in the following areas:

- Desktop Transformation Program
- Human Resource Employee Central Platform
- Financial and Procurement Services
- Health Safety and Environment
- Governance Risk and Compliance
- Enterprise Content Management.

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

Table 28 contains a summary of ICT investments undertaken in 2019-20. These include projects which commenced prior to this year and investments not completed by 30 June 2020. Further information on the scope of each initiative can be noted below.

Table 28 – ICT Investments 2019-20

Description	Cost $ M actual
Corporate Services	$34.08
Network Asset Management	$24.44
Network Operations	$9.35
Enterprise Services	$4.34
Customer, Market and Metering	$1.46
Infrastructure, Security and Devices	$9.03
Minor Applications Change and Compliance	$6.35
Total	**$89.05**

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).

Corporate Services

ERP Portfolio of Projects

Commencement of the planning and procurement phase for the replacement of Energex's Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) systems began in 2016-17 and continued throughout the regulatory period. Energex's core ERP/EAM system reached both technical and financial obsolescence in mid-2015. Renewal of the ERP systems with contemporary systems has enabled Energex to consolidate satellite applications. The initiatives encompass procurement, people, culture, safety, finance and planning, corporate services and works and asset management footprints. The program has been delivered through Energy Queensland Digital Enterprise Building Block Initiatives program. The sub programs delivered within this initiative encompass the following:

People, Culture and Safety:

- Replacement of systems and processes that support the core Human Resource, Payroll and Health, Safety and Environment (HSE) functionality. The new tools support core HR and Payroll, Performance, Recruitment, Training, Workforce Planning and HSE functions.
  - Solutions are helping 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.

Procurement and Finance Systems:

- Replacement of systems and processes that support procurement with a single unified Energy Queensland solution, including managing, sourcing, contract and supplier management, and buying processes
- Integrated processes and systems, both internally and externally, improving collaboration with stakeholders and suppliers
- An advanced source-to-settle solution with the ability to acquire goods and services from the community with simplicity, governance and affordability
- Enable common processes and standardised analysis and reporting to provide oversight and insights into organisational performance. This includes end-to-end purchasing; maintenance work execution (non-network); time capture and reporting; financial accounting and reporting; solution accessibility through internal network and mobile devices.

Network Asset Management

The Asset and Works Management (AWM) project is part of the Digital Enterprise Building Blocks and implementing a single system and process that supports the distribution business for Energex. The new tools will support lifecycle and financial management for assets through all stages of the asset lifecycle.

The Geographic Information System (GIS) Portal provides the capability to view all network data, maps and applications in a single environment and replaces legacy disparate solutions. This investment has resulted in improved visualization and data harmonisation and is an important step as we progress a fully unified GIS solution for Energy Queensland in the coming period.

Customer Market and Metering

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 2019-20 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.

This period also finalised enhancements and upgrades to the existing suite of market systems 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 Operations

The Network Operation Control systems provide the technology used to manage the distribution of electricity for Energex customers. During this period, planning has been occurring to deliver a consolidated, proven and modernised platform with consistent business processes for Energy Queensland. This will allow all of our teams to support each other seamlessly and maximise business continuity in times of significant events anywhere in Queensland. Investment to maintain Energex's existing solution and infrastructure was required this period to preserve the reliability of the current system in advance of the future consolidation.

Additional investment this period has resulted the development of an enhanced and consistent set of outage maps now available on Energex's website. This will be further enhanced through the, above mentioned, Unified DMS initiative with real-time visibility and improved monitoring and response times for Energex crews when electricity outages occur.

Enterprise Services

The Desktop Transformation program was initiated to improve technology to deal with evolving business needs, a distributed workforce, changing ways of working and an increasingly complex cyber security environment. Investment in this program has provided Energex users with the ability to securely connect and consume digital services and information via contemporary software solutions such as Microsoft Office, SharePoint and other collaboration tools, on current operating environments and devices. The implementation successfully completed in June 2020.

Infrastructure, Security and 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.

The modernisation of the corporate network fully enabling wireless access capability for all users at all Energex sites continued during 2019-20 extending to all regional Queensland sites including depots and substations that have historically not had wireless capability. Phase 1 and 2 have completed and Phase 3 to address requirements at Energy Queensland data centres is being planned.

Minor Applications Change and Compliance

This includes minor improvements and updates across the ICT systems footprint including; work force automation, market systems, knowledge management systems, and customer service systems which support Energex's business operations. Key investments in this area across 2019-20 included maintaining the security of the network, supporting working from home arrangements imposed by COVID-19 and ensuring compliance to regulatory imposed tariff reform changes.

Changes to systems to manage new rules coming into effect during this period include Fatigue Management Solutions, Apprentice Training Certification Tools and preparation for the introduction of an Online Payment Portal. These initiatives enhance the safety, security and wellbeing of both Energex customers and employees.

12.2 Forward ICT Program

As Energex looks toward the future, ICT systems and capability must be maintained for sustainability, cybersecurity, compliance and operational safety. Planned technology replacements will also be leveraged to enable the company's planned productivity improvement.

In the coming period, Energex will focus on ICT as an enabler of business performance consistent with the following ICT strategic themes:

- Maintain systems for sustainability, cybersecurity and operational safety
- Leverage ICT replacements for digital transformation, enabling Energex's productivity improvement targets
- Maintain efficient ICT performance in a rapidly changing technology environment
- Leverage innovative technologies for efficiency and customer service
- In the new regulatory period, commencing from 2020-21, the focus of the ICT Program for Energex will be the continuation of Energy Queensland's digital transformation through the consolidation and rationalisation of legacy applications with consistent best-practice business technologies and processes. Planned investment during this time has been grouped within a set of seven roadmap segments including:

Customer and Market Systems

- Asset and Works Management
- Distribution Network Operations
- Corporate Systems
- Cybersecurity, Productivity and ICT Support
- ICT Devices and Infrastructure
- Minor Change and Compliance.

A high level summary of potential ICT investment for the Distribution Business for the forward ICT Program is shown in Table 29. Emerging priorities and new technologies will result in ongoing prioritisation and may require adjustments dependent on the determination received. Forecasts have been grouped by initiative names as included in the ICT Plan for 2020-25.

Table 29 – ICT Investment 2020-21 to 2024-25

Initiative Name	2020-21 $M	2021-22 $M	2022-23 $M	2023-24 $M	2024-25 $M
Asset and Works Management	28.88	19.61	5.17	3.02	0.43
Distribution Network Operations	5.03	3.94	1.46	-	-
Customer and Market Systems	9.60	10.58	6.01	5.15	6.93
Corporate Systems	3.41	0.91	2.12	2.27	4.84
ICT Management Systems, Productivity and Cybersecurity	2.71	2.41	0.56	2.47	3.51
Infrastructure Program	6.08	6.92	7.05	7.78	7.67
Minor Applications Change	3.57	3.68	3.79	3.91	4.02
Grand Total	**59.28**	**48.06**	**26.16**	**24.60**	**27.40**

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). Forecasts are represented as $ Nominal values.

12.3 Metering

Energex is currently separating load control from metering, as it relates to network operation and network management. 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 Manual (QECM) and Queensland Electrical Metering Manual (QEMM), to ensure these align with the rollout of smart-ready meters in a contestable marketplace.

12.3.1 Revenue Metering Investments in 2019-2020

There were no revenue metering investments in 2019-20 due to Power of Choice legislation that prevents Energex from installing any new meters.

12.3.2 Revenue Metering Investments from 2020-21 to 2024-25

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

12.4 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 several 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.

12.4.1 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
  - 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
- 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; the following lists some of the specific items that were replaced:
  - Access Switch equipment at substations
  - Deployed new arrangements to account for the switch off of existing services as part of the NBN rollout
  - Replace a number of older PDH microwave radios.
- 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.

12.4.2 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.

Supervisory Control and Data Acquisition (SCADA)

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
- 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.

Other changes

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

- Recommenced the implementation of a new phone system to replace existing operator consoles
- Commenced a project to provide a common OT environment to allow the deployment of a common Distribution Management System (DMS) for Energex and Ergon Energy
- Continued replacement of various end of life components within the Data Centres, including the firewalls and other components.

Operational Security

Energex asset renewed the core firewalls and commenced consideration on how best to secure a combined Operational Technologies environment of Energex and Ergon. Additional threats were identified during the period and a range of mitigation activities has occurred.

Intelligent Grid Enablement

Over the next five years Energex plans to invest in the development of a smarter network for the future. The growth of DER in distribution networks, at both residential and commercial scales, requires Energex to consider new approaches for maximising DER hosting capacity.

In order to deliver sustainable outcomes for the network and choice for the customer, Energex plans on the delivering the following major capabilities:

- Low Voltage Management System – manages the various streams of data from the LV network and feeds this information into a constraint engine which determines the active network performance and limits, and then passes those values and subsequent constraint envelopes via an orchestration system to deliver the best outcome
- Demand Response System - this capability allows Energex to transition the existing and successful direct load control (AFLC) system to individually addressable load for network support
- Distributed Energy Resources Management System - this capability will allow Energex to interact with market participants, including Virtual Power Plants/Aggregators, for generation and load management, as well as directly with large scale distributed energy resources (DER) to enable efficient connections and network support now, and longer term
- Real Time Analytics - this capability will be used to actively manage the dynamic operational ranges across EQL's 140,000 Low Voltage networks. The insights gained will be able to automatically tune network performance.

LV Network Safety Monitoring Program

Safety by design is fundamental to Energex's network strategy, providing safe and reliable electricity residents and businesses across regional Queensland and is at the core of Energex's corporate values. Neutral integrity failures on the Low Voltage (LV) network are a significant cause of customer safety incidents. Energex is committed to customer safety imperatives and considers that the detection of neutral integrity failures is critical to mitigating customer safety risks. Energex is investing in developing a smart network monitoring device with neutral integrity monitoring capability which will be installed under a trial on selected customer premises throughout Queensland. The pilot program provides a foundation to enabling further investment by Energex over the 2020-2025 regulatory control period in equipment, systems and processes to detect neutral integrity failures through increased LV visibility. The data leveraged from this platform will feed into various applications including the LV Management System of the Intelligent Grid Enablement program. Currently a pilot is being deployed and then the wider program will commence in 2022. In 2019-20, Energex successfully proved the technology concept through a small-scale deployment and prepared the program deployment building blocks for a large-scale trial.

12.4.3 Investments in 2109-20

Table 30 summarises the SCADA and Communications investments for 2019-20.

Table 30 – Information Technology and Communication Systems Investments 2019-20

Project	Cost $ M actual
Telecommunications Network	
Telecommunications equipment replacement	$0.69
MPLS system implementation	$1.14
Fibre Cable installation	$2.14
P25 implementation	$2.03
Operational Systems	
Operator console replacement	$0.36
Common OTE	$0.16
SCADA and Automation Refurbishment / Replacement	$0.67
OT Security projects	$0.03
LV Network Safety Monitoring Program	$1.89
Total	**$9.12**

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. Forecasted data is subject to ongoing variation due to COVID 19 impacts. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

12.4.4 Planned Investments for 2020-21 to 2024-25

Table 31 summarises Energex's OT and associated Telecommunication planned investments for 2020-21 to 2024-25.

Table 31 – Operational Technology Planned Investments 2020-21 to 2024-25

Project	Cost $ M actual
Telecommunications Network	
Telecommunications equipment replacement	$14.79
MPLS system implementation	$3.64
Fibre Cable installation	$4.19
Comms Network Enhancements	$7.88
Operational Systems	
Security Enhancements	$3.93
SCADA and Automation Enhancement	$1.95
SCADA and Automation Refurbishment / Replacement	$6.94
OT Refurbishment / Replacement	$7.27
Control Room Enhancements	$0.90
Infrastructure Expansion	$3.74
Intelligent Grid Applications	$12.46
LV Network Safety Monitoring Program	$35.04
Total	**$102.73**

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. Forecasted data is subject to ongoing variation due to COVID 19 impacts. Energy Queensland is 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
Statcom	Static Synchronous compensator
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

Abbreviations	
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;	1.2 Network Overview 2.2 Electricity Distribution Network
2) a description of its operating environment;	3 Community and Customer Engagement 9.1 Reliability Measures and Standards 9.2 Service Target Performance Incentive Scheme (STPIS) 9.3 High Impact Weather Events 10.3 Power Quality Supply Standards, Codes Standards and Guidelines 11 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	5.2 Planning Methodology 5.3 Key Drivers for Augmentation 5.4 Network Planning Criteria 5.5 Voltage Limits 5.6 Fault Level 5.9 Joint Planning 5.10 Network Planning – Assessing System Limitations 8.2.2 Asset Condition Management 9.2.1 STIPIS Results and Forecast
(5) analysis and explanation of any aspects of forecasts and information provided in the Distribution Annual Planning Report that have changed significantly from previous	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**
forecasts and information provided in the 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;	4 Strategic Forecasting **Appendix E** Substations Forecast and Capacity Tables **Appendix F** Feeders Forecast and Capacity Tables
(2) load forecast:	4 Strategic 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)'

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**
	‘Mobile Plant Avail (MVA)’
(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;	6.5 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	9.2 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;	5.6 Fault Level
(ii) voltage levels;	5.5 Voltage Limits
(iii) other power system security requirements;	9.3 High Impact Weather Events Appendix C Network Security Standards
(iv) the quality of supply to other Network Users (where relevant); and	10.4 Power Quality Performance in 2019-20 11.1 Solar PV 11.2.2 Improving Standards for Increased DER Connections
(v) ageing and potentially unreliable assets;	8.1 Approach 8.2 Preventative Works 8.2.2 Asset Condition Management **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:	6.1.3 Asset Condition Limitations 8 Asset Life-Cycle Management **Appendix D** Network Limitations and Mitigation Strategies
(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	

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**
Report, an explanation of why this has occurred;	
(b2) for the purposes of subparagraph (b1), where two or more network assets are:	6.1.3 Asset Condition Limitations 8 Asset Life-Cycle Management **Appendix D** Network Limitations and Mitigation Strategies
(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;	

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**
(c) information on system limitations for sub-transmission lines and zone substations, including at least:	6 Overview of Network Limitations and Recommended Solutions 6.1 Network Limitations – Adequacy, Security and Asset Condition 5.5.2 Sub-transmission Network Voltage 6.1.2 Transmission, Sub-transmission and Distribution Feeder Capacity Limitations 6.3 Summary of Emerging Network Limitations 6.5 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;	6 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

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**
(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
(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	5.5.3 11 kV Distribution Network 6 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**
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:	6.1.2 Transmission, Sub-transmission and Distribution Feeder Capacity Limitations 6.3 Summary of Emerging Network Limitations 6.5 Emerging Network Limitations Maps **Appendix F** Feeders Forecast and Capacity Tables **Appendix D** Network Limitations and Mitigation Strategies
(1) the location of the primary distribution feeder;	6 Overview of Network Limitations and Recommended Solutions 6.5 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;	6 Overview of Network Limitations and Recommended Solutions 6.5 Emerging Network Limitations Maps

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 **Appendix F** Feeders Forecast and Capacity Tables
(iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation;	**Appendix D** Network Limitations and Mitigation 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:	6.4 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	**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**
connection charges and distribution use of system charges that have been estimated;	
(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;	6.4.2 Foreseeable RIT-D Projects
(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:	5.9 Joint Planning 6.4 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;	5.9 Joint Planning **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;	5.9 Joint Planning
(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	5.9 Joint Planning

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**
the timing (month and year) of the investment; and	
(3) where additional information on the investments may be obtained;	5.9 Joint Planning 5.9.5 Further Information on Joint Planning
(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:	
(1) a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning;	5.9 Joint Planning
(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	5.9.4 Joint Planning with other DNSP
(3) where additional information on the investments may be obtained;	5.9 Joint Planning
(j) information on the performance of the Distribution Network Service Provider's network, including:	9 Network Reliability 10 Power Quality
(1) a summary description of reliability measures and standards in applicable regulatory instruments;	9.1 Reliability Measures and Standards 9.2 Service Target Performance Incentive Scheme (STPIS) 9.4 Guaranteed Service Levels (GSL) 9.5 Worst Performing Distribution Feeders
(2) a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;	10.3 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;	9.1.1 Minimum Service Standard (MSS) 10.4 Power Quality Performance in 2019-20

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**
(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;	9.1.3 Reliability Compliance Process 9.1.4 Reliability Corrective Actions 10.5 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 subparagraphs (1) and (2); and	9.1.3 Reliability Compliance Process 10.1 Quality of Supply Processes
(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;	9.2 Service Target Performance Incentive Scheme (STPIS)
(k) information on the Distribution Network Service Provider's asset management approach, including:	2.4 Asset Management Overview
(1) a summary of any asset management strategy employed by the Distribution Network Service Provider;	2.4 Asset Management Overview 2.4.2 Asset Management Policy 8 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;	5.4.4 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	8 Asset Life-Cycle Management 11 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;	2.4.6 Further Information 1.6 DAPR Enquiries
(l) information on the Distribution Network Service Provider's demand management activities, including a qualitative summary of:	

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) non-network options that have been considered in the past year, including generation from embedded generating units;	7.4 What has the Energex DM Program delivered over the last year?
(ii) key issues arising from applications to connect embedded generating units received in the past year;	7.6 Key Issues Arising from Embedded Generation Applications
(iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; and	7.4 What has the Energex DM Program delivered over the last year?
(iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period;	7.5 What will the Energex DM Program deliver over the next year?
(2) a quantitative summary of:	
(i) connection enquiries received under clause 5.3A.5;	7.6.1 Connection Enquiries Received
(ii) applications to connect received under clause 5.3A.9; and	0 Applications to Connect Received
(iii) the average time taken to complete applications to connect;	7.6.3 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	12 Information Technology and Communication Systems 12.3 Metering 12.4 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:	6 Overview of Network Limitations and Recommended Solutions 6.5 Emerging Network Limitations Maps

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**
(1) sub-transmission lines, zone substations and transmission-distribution connection points; and	6 Overview of Network Limitations and Recommended Solutions 6.5 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.	6 Overview of Network Limitations and Recommended Solutions 6.5 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.	6 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.	5.4.2 Safety Net 9 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.	Safety Net Target Performance
DA 11 Improvement programs	
DA 11.2 Requirements	

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) 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;	9 Network Reliability 9.5 Worst Performing Distribution 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.	5 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 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.	5.4 Network Planning Criteria 9 Network Reliability 9.5 Worst Performing Distribution Feeders **Appendix G** Worst Performing 11 kV Feeders

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 and 2020 - 2025. 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>

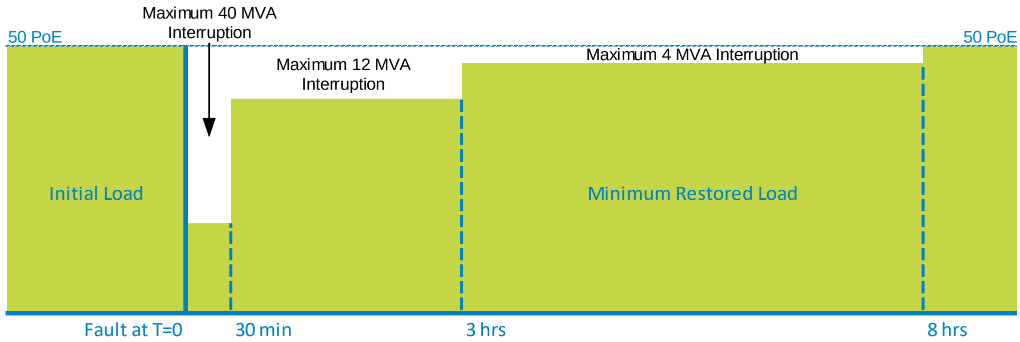
- Ensure that any single credible event does not result in a loss of customer supply.

</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.

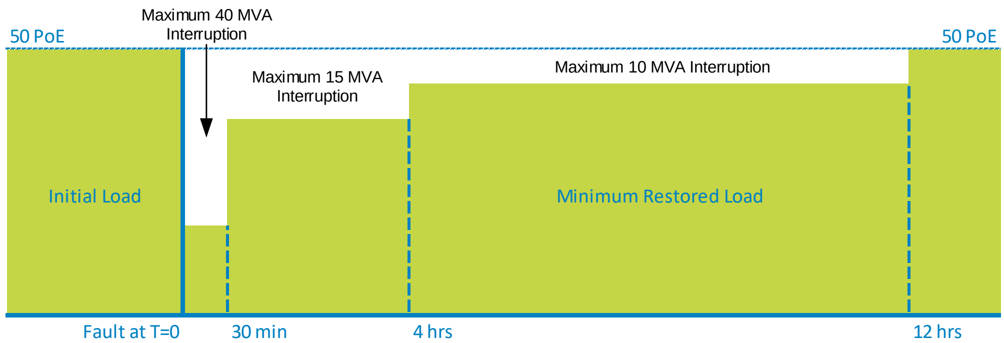
</td></tr>
<tr><td>Urban</td><td>

- 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 2019 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 2019 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:

- Substations Limitations and Proposed Solutions Capacity
- Substations Limitations and Proposed Solutions Refurbishment Part A
- Substations Limitations and Proposed Solutions Refurbishment Part B
- Transmission and Sub-Transmission Feeders Limitations and Proposed Solutions Capacity
- Transmission and Sub-Transmission Feeders Limitations and Proposed Solutions Refurbishment

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:

DAPR 2020

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:

DAPR 2020

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).

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 2019/20 starting values, and the winter forecasts are based on winter 2020 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 2019. 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, 2021 winter forecast includes all committed projects with a proposed commissioning date up to 1 June 2021, and the 2020/21 summer forecast includes all committed projects with a proposed commissioning date up to 1 December 2020.

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 offline.
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 2020/21 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 offline.
- **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 offline. 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:

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F.1 Supporting Notes on Feeders

The following sections list the 132 kV, 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, the 2021 winter forecast includes all committed projects with a proposed commissioning date up to 1 June 2021, and the 2020/21 summer forecast includes all committed projects with a proposed commissioning date up to 1 December 2020.

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 2020, and the 132 kV and 110 kV studies are based on the summer 2020/21 Queensland peak generation scenario[1].

Feeder capacities are shown for 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.

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.

F.2.1 Distribution (11 kV) Feeder Studies

For the 11 kV feeder studies, the 50 PoE and 10 PoE load forecasts are assessed based on the 2020 winter and 2019/20 summer starting values, and include some load transfers expected from approved project proposals as at June 2020. 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 ⇒ site does not meet security standard

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

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.
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.

Term	Definition
Raw LAR (A)	The amount of load exceeding ECC rating. (Load – ECC Rating)
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.2.2 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.

F.2.3 Available Transfers

As per the Customer Outcome Standard, there is an implied 4MVA of remote generation automatically available for feeders classified as Urban, and 10MVA for feeders classified as Rural. The load transfers shown in the forecast table have these values as their default values. Where under a contingency the load and these default transfers exceeds the ECC rating of the feeder, specific load transfers are calculated to determine whether a feeder meets the Customer Outcome Standard, or is a limitation.

Appendix G

Worst Performing 11 kV Feeders

Appendix G
Worst Performing 11 kV Feeders

The Worst Performing 11 kV Feeders contains the 2019/20 Worst Performing 11 kV Feeder. This is available in spreadsheet format via the following hyperlinks:

2019-20 Review of Worst Performing 11 kV Feeders

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

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