Ergon Energy Regulatory Proposal 2020-25

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Contents

Executive Summary

We exist to provide electricity distribution services to our fellow Queenslanders. Over the past year, we have engaged our community stakeholders, our customers, and our industry partners to better understand what they need, value and expect from us. We have heard loud and clear that our customers want us to 'safely deliver affordable, secure and sustainable energy solutions'. This Regulatory Proposal details how we will deliver these outcomes from 1 July 2020.

In parallel, we have engaged the Australian Energy Regulator (AER) on how it regulates our distribution services. This Regulatory Proposal broadly accepts and applies the AER's Framework and Approach paper and its Guidelines for how it sets our revenues, including for determining the rate of return we can earn on the assets we use to provide our distribution services. With the AER's approval, we include the Mount-Isa Cloncurry network in this proposal.

Safety

Safety continues to be the priority for Ergon Energy. We prioritise the safety of our communities, customers and employees above all else. Many of our proposed investments focus on maintaining or, where relevant, improving our safety outcomes. Since Our Draft Plans, a more detailed risk assessment has driven an increase to the Ergon Energy replacement capital expenditure forecast for safety driven projects in 2020-25. Looking further ahead, we see real opportunities from our technology investment program to deliver on our commitment to continuously improve the safety of the community and our people while driving down costs.

Affordability

Affordability is our customers' primary concern. Our distribution network charges make up around one-third of a typical retail electricity bill in Queensland. This Regulatory Proposal commits us to doing everything we can to reduce our distribution network charges and, in turn, customers' bills. It provides a 4.5% real reduction in distribution network charges from 2019-20 to 2020-21 for our residential customers on their existing default tariff and our small business customers.

Under its Uniform Tariff Policy, the Queensland Government supports regional Queenslanders by using a Community Service Obligation to ensure our customers pay similar prices for their electricity as customers in South East Queensland. After this subsidy, our average residential customer will receive a 10.3% real reduction in distribution network charges from 2019-20 to 2020-21 on their legacy default network tariffs. For a small business customer, this reduction will be 11.4%.

These reductions are in addition to the on average 7% annual reductions we have delivered residential and small business customers every year since 2015. This does not account for jurisdictional schemes which may factor into customer network charges[1]. Customers may see further savings should they choose to opt-in to one of our new cost reflective tariffs, some of which may require a digital meter.

We will also deliver network tariff reforms that are equitable and offer additional savings, value and choice to reward customers for their role in the energy transformation underway in Queensland. We

[1] Total network charges comprise distribution network charges, transmission network charges and jurisdictional schemes.

will make changes while managing potential impacts on our customers, especially the most vulnerable in our society.

Security

Our customers have told us that they are generally satisfied with the power reliability we deliver. We will maintain our recent improvements in reliability, while targeting expenditure savings and improving outcomes where network outages are outside of our service standards. We will:

- deliver sustainable investment that avoids a boom-bust cycle and manages our aging assets through maintenance and targeted replacement
- continue to 'be there after the storm' so that our communities can recover quickly after any disruptive storms or natural disasters, and
- promote community and staff safety, by leveraging innovative solutions to continue the transition to an intelligent grid, enabling and leveraging the growth of distributed energy resources – including grid-scale and small solar generators, and energy storage solutions.

Sustainability

Our customers have told us they want greater choice and control over their energy solutions so that they can better manage their individual usage and associated costs, and better support action on climate change.

We will work more closely with our customers to enable them to realise the potential value emerging from today's transforming energy world, and to ensure the whole community benefits from today's and tomorrow's technologies.

Over time, we are gradually transforming our networks into an intelligent grid so that our communities and customers can leverage the many benefits of digital transformation, distributed energy resources and emerging technologies, like solar, battery storage and electric vehicles, as well as the next generation of home and commercial energy management systems. This means we will no longer simply manage network costs; we will also work hard to provide communities and customers with the ability to adopt technologies, while saving money and delivering digitally smarter and more resilient networks that are safe by design.

Snapshot of our proposal

The key aspects of Ergon Energy's Regulatory Proposal for the 2020-2025 regulatory control period are summarised below.

Table 1 Forecast summary 2020-21 to 2024-25

	2020-21	2021-22	2022-23	2023-24	2024-25
Standard control services					
Forecast expenditures ($M, Real $2020)					
Net capex	531.22	543.06	562.09	547.45	551.69
Opex (including debt raising costs)	377.77	371.58	367.00	362.06	357.17
Opening RAB ($M, Nominal)	11,634.09	12,011.43	12,392.06	12,791.20	13,174.68
Revenue Requirements ($M, Nominal)					
Return on Capital (WACC 5.46%)	635.08	652.08	669.02	686.74	703.37
Regulatory Depreciation	172.47	195.07	211.20	225.20	248.37
Incentive Schemes and other Revenue Adjustments	1.13	1.16	1.20	1.23	1.27
Corporate Tax Allowance (Gamma 0.585)	27.78	28.20	27.71	28.84	31.43
Annual Revenue Requirements (smoothed)	1,241.59	1,271.63	1,302.41	1,333.93	1,366.21
X Factor (note - positive value reduces revenues) (%)	9.44%	0.00%	0.00%	0.00%	0.00%
Demand - Forecast 50POE (MW)	2,560	2,596	2,601	2,580	2,574
Customer numbers	793,543	805,579	817,768	830,035	842,485
Forecast energy consumption (GWh)	13,849	13,882	13,917	13,945	13,979
Key positions					
Service Classification	We broadly accept the AER's proposed service classification as set out in the Final Framework and Approach (F&A) paper				
Control Mechanisms	We accept the AER's control mechanism decision as set out in the F&A paper, namely: • Revenue cap for standard control services, and • Price cap for alternative control services.				
Incentive schemes	We accept the proposed application of the following incentive schemes as set out the F&A paper: • Efficiency benefit sharing scheme • Service target performance incentive scheme • Capital Expenditure Sharing Scheme • Demand Management Incentive Scheme, and • Demand Management Innovation Allowance Mechanism.				
Nominated pass through events	We nominate the following additional pass through events: • Insurance cap event • Insurer's credit risk event • Terrorism event, and • Natural disaster event.				
Contingent projects	We have not proposed any contingent projects				
Alternative control services					
Metering services	We will continue to provide legacy (Type 6) metering services in the 2020-25 regulatory control period as customers transition to smart meters.				
Public lighting services	We are introducing new light-emitting diode (LED) tariffs to encourage the uptake of LED technology.				

Note: Net capex equals gross capex less capital contributions.

The communities we serve, our customers and other stakeholders, want an affordable, secure and sustainable electricity supply today, and into the future.

To deliver this for Queensland we are committed to listening and acting on their feedback and continuing to engage as we move forward.

Ergon Energy has responsibility for the distribution of electricity to 97% of the geographic area of Queensland. We provide distribution services to 752,909 domestic and business connections.

To ensure we get it right for the region, we welcome feedback on our Regulatory Proposal. This proposal has been presented for the AER to assist them in determining the revenue we are allowed to recover from our customers for the use of the network from July 2020.

Customer Commitments

Our plans are being guided by our overarching Customer Commitments to realise significant reductions in distribution network charges, continue to ensure the safety of our distribution network, and modernise the network in order to realise the potential value of emerging technologies.

The electricity industry is transforming as we and our customers embrace new technologies to manage energy use and costs, and support action on climate change. This requires us to redefine customer value, while proactively driving digital transformation that will bring down costs and offer new services to customers.

We have achieved a lot, but we know there is still a way to go on the journey.

We are being as transparent as possible and are clearly justifying how we spend the money that ultimately comes from customers for using our distribution networks.

We trust you can see your feedback in our plans and we look forward to hearing more from you as the AER reviews our proposal.

1. About us and this Regulatory Proposal

Key Messages

- **We provide our distribution services to 752,909 households and businesses, across a geographic area that accounts for 97% of Queensland.**
- **This is our Regulatory Proposal that details our proposed revenues for our next regulatory control period, 1 July 2020 to 30 June 2025. It has been deeply informed by the views and preferences of our communities and customers.**
- **We welcome our customers and other stakeholders' feedback on this Regulatory Proposal to inform our future plans and the Australian Energy Regulator's decision-making.**

We provide electricity distribution services to households and businesses throughout Queensland with the exception of the South-east corner. We are proudly part of Energy Queensland, a Queensland Government owned company.

We are the only provider of many distribution services in our service area. Because of this, the revenues and prices that we charge as a distribution network service provider (DNSP) are regulated by the AER to ensure that we provide our distribution services efficiently.

The AER is the economic regulator of electricity distribution services in all Australian states and territories, other than Western Australia. It regulates in accordance with the National Electricity Law (NEL) and National Electricity Rules (NER). Its role is to set the revenues we can recover from our customers for providing our distribution services and to approve the manner in which we can recover those revenues through our charges.

The AER does this by making Distribution Determinations that typically cover five-year periods. In April 2015, the AER made its Distribution Determination for our current regulatory control period, 1 July 2015 to 30 June 2020 (2015-20 regulatory control period).

This is Ergon Energy's Regulatory Proposal for our next regulatory control period, 1 July 2020 to 30 June 2025 (2020-25 regulatory control period). It has been deeply informed by the views and preferences of our communities and customers through our extensive engagement program. The AER will make its Distribution Determination for this period in April 2020.

1.1 Our electricity distribution service area

Ergon Energy has responsibility for the distribution of electricity to 97% of the geographic area of Queensland. Our assets comprise the 'poles and wires' that deliver electricity in a safe and reliable manner to homes and businesses.

We provide our distribution services to 752,909 households and businesses. We must maintain enough capacity in our distribution network to supply every household and business on the days when electricity demand is at its maximum, no matter where they are.

Figure 1 – Geographic coverage

Our service area is split into three geographic regions consistent with the DNSP boundaries:

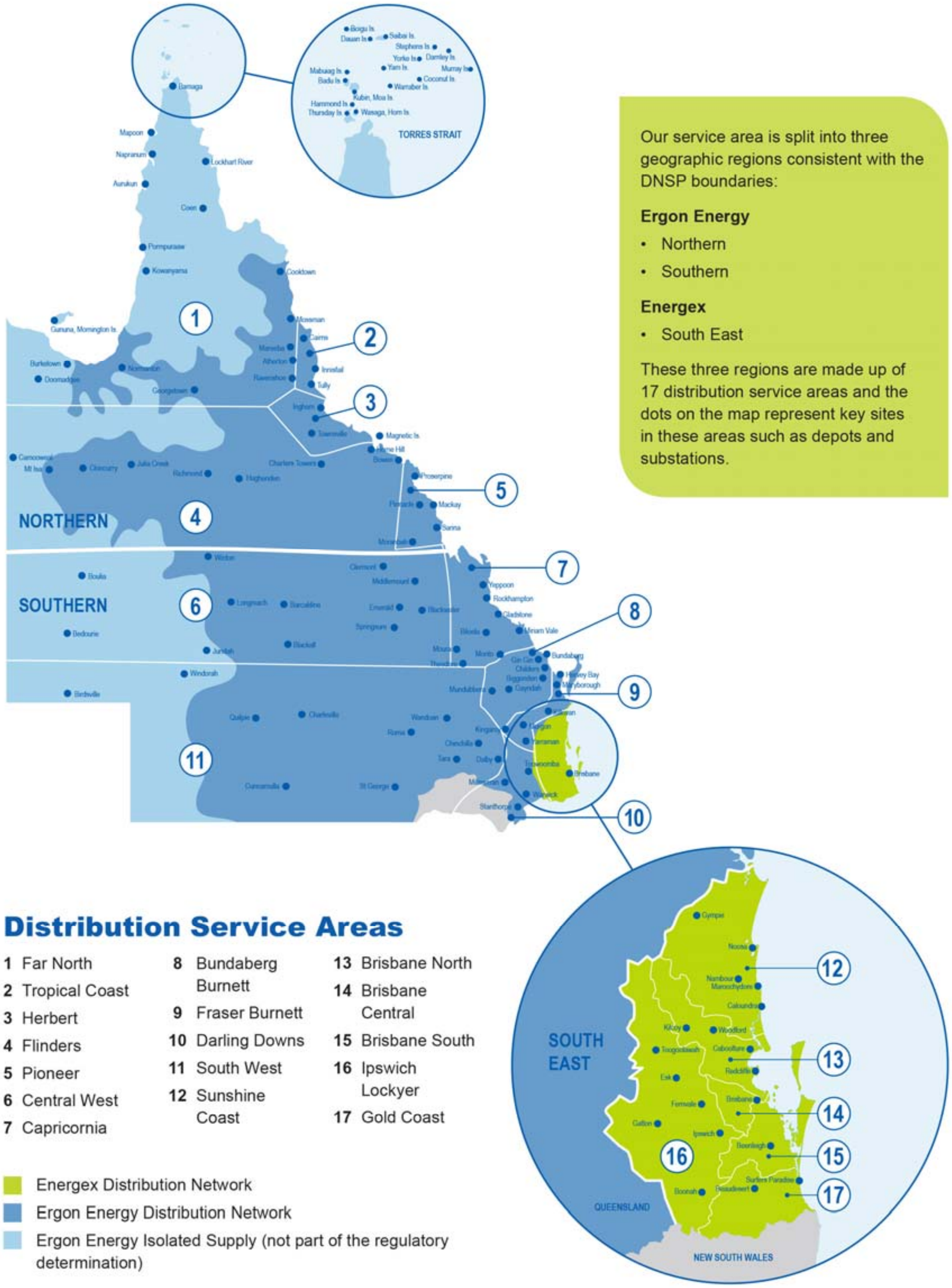
Ergon Energy

- Northern
- Southern

Energex

- South East

These three regions are made up of 17 distribution service areas and the dots on the map represent key sites in these areas such as depots and substations.



Distribution Service Areas

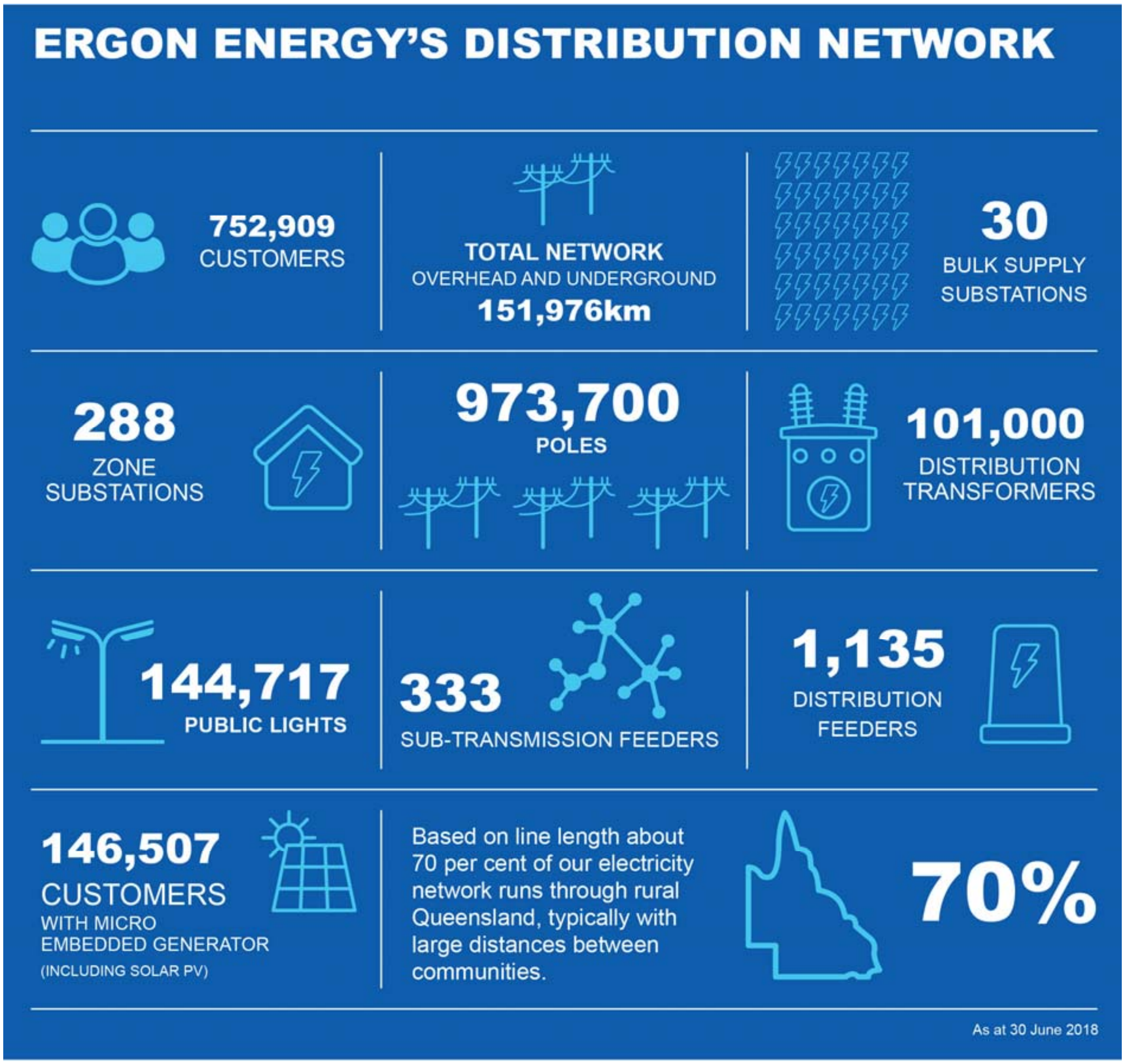
1 Far North
2 Tropical Coast
3 Herbert
4 Flinders
5 Pioneer
6 Central West
7 Capricornia
8 Bundaberg Burnett
9 Fraser Burnett
10 Darling Downs
11 South West
12 Sunshine Coast
13 Brisbane North
14 Brisbane Central
15 Brisbane South
16 Ipswich Lockyer
17 Gold Coast

- Energex Distribution Network
- Ergon Energy Distribution Network
- Ergon Energy Isolated Supply (not part of the regulatory determination)

We operate in a challenging environment. Some of the distinguishing features of our operating environment compared with other Australian electricity DNSPs are that we have:

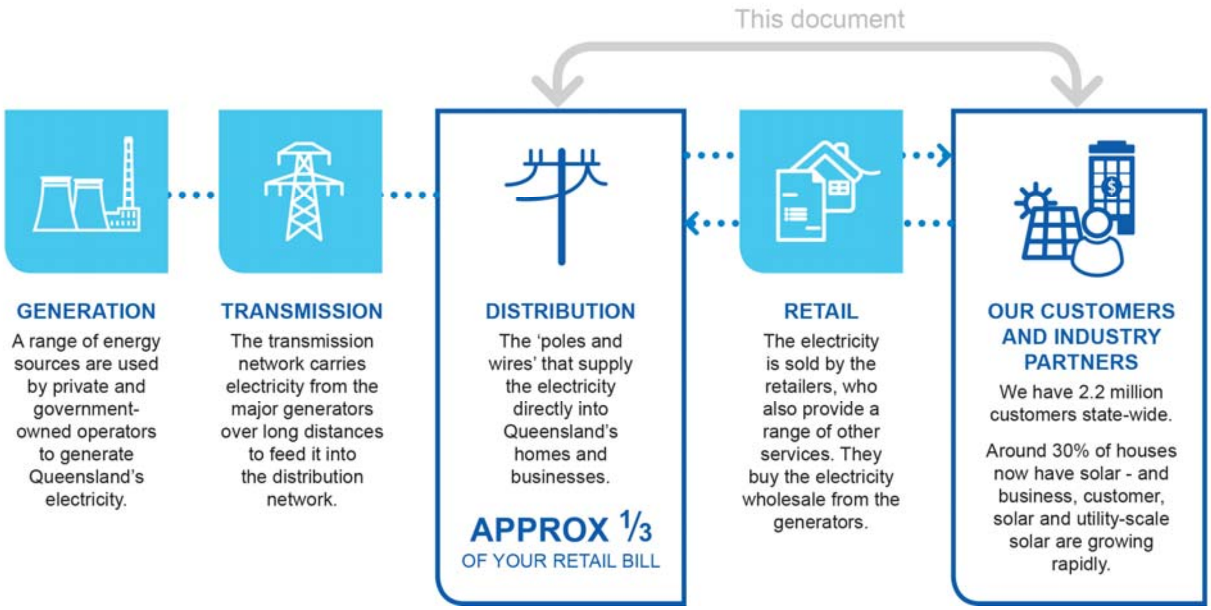
- a high probability of severe weather and extended storm seasons
- stringent vegetation management requirements, and
- high uptake of photovoltaic (PV) solar systems.

Figure 2 Scope of services



Our distribution network charges make up about one third of the typical retail 'price' of electricity in Queensland – the other bill components include generation, transmission and retail costs.

Figure 3 The Queensland electricity industry



1.2 Managing our network in a time of change

The electricity supply industry is in a state of rapid change, as distributed generation and storage technologies become competitive against the cost of producing electricity via large remote generators and transporting it through the transmission and distribution network. Our electricity network must also adapt to the increasing uptake of PV solar systems, batteries and other emerging technologies at homes and workplaces. We must also be ready for the anticipated uptake of electric vehicles and provide intelligent grid capabilities in response to customer expectations.

We are working hard to ensure our network is flexible in order to respond to this evolution of the electricity market. We intend our network to be able to manage the two-way flow of electricity, with the embedded intelligence needed to ensure this is achieved in a safe and reliable manner. The network of the future will require new and upgraded management systems and processes while ensuring that we can make the most use of our existing infrastructure, thereby keeping downward pressure on electricity prices.

Our management of the network today is providing for the future and achieving lower electricity charges through:

- innovation, prudency and efficiency
- improved customer connections processes and the support of customer choice
- operational excellence, and
- engagement with our customers.

Our priority starts with the safe and reliable operation of our network. With this, we are improving our network by using new technologies ourselves and by enabling our customers to connect new technologies. Our use of technologies will make it easier for customers to connect to, and use, our network and will enable us to make better use of our existing assets.

1.3 Our Regulatory Proposal

This Regulatory Proposal is structured as follows:

- **Part A – Introduction** covers the journey we have been on to prepare this Regulatory Proposal, including our engagement with customers and other stakeholders and our acceptance of the AER's positions in its Framework and Approach (F&A) paper.
- **Part B – Standard Control Services (SCS)** explains our proposed building blocks, which form the AER's decision making framework to determine our annual revenue allowance for our SCS for 2020 to 2025. It also details:
  - the AER's incentive schemes which encourage us to deliver our services efficiently
  - how we would recover the costs of particular uncertain events that may occur in the 2020-25 regulatory control period, and
  - our indicative distribution network charges and typical customer bill changes between the 2015-20 and 2020-25 regulatory control periods.
- **Part C – Alternative Control Services (ACS)** outlines our proposals for our metering, public lighting and ancillary services.
- **Part D – Other matters** provides information on several related matters, including our approach to confidential information and the assurance and certification we must provide, including the key assumptions supporting our expenditure forecasts.

Further information about our future investment plans is available in supporting documents we have submitted to the AER with this Regulatory Proposal.

After considering this Regulatory Proposal and public submissions, the AER will publish its draft Distribution Determination. This will enable further consultation before the AER makes its Final Determination, which will set the basis of our charges for our distribution services for the five years from 1 July 2020.

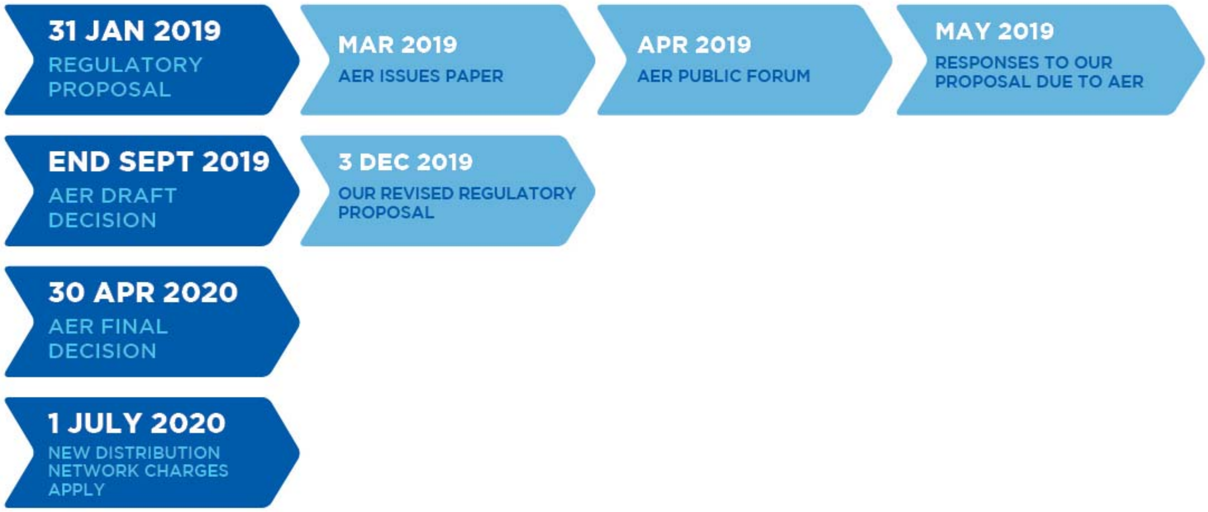
1.4 Next steps and on-going consultation

The AER will consult on our Regulatory Proposal and will publish its draft Distribution Determination by September 2019. We will then submit a Revised Regulatory Proposal to the AER by December 2019. The AER will also consult on its draft Distribution Determination and our Revised Regulatory Proposal before publishing its final Distribution Determination by April 2020. We encourage our communities and customers to make submissions to the AER as part of its consultation processes.

After the AER publishes its Distribution Determination, we will prepare our distribution network charges for the 2020-21 regulatory year, commencing 1 July 2020.

In the meantime, we will continue to engage with our customers and other stakeholders on this Regulatory Proposal, including through our Customer Council and our website, www.talkingenergy.com.au, where all of our existing consultation material is available. Questions can also be directed to us via regulatoryproposal@energyq.com.au

Figure 4 Next steps



1.5 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Corporate strategy	1.001	EGX ERG 1.001 Corporate strategy JAN19 PUBLIC
2020-25 Regulatory Proposals highlights	1.002	EGX ERG 1.002 2020-25 Regulatory Proposals highlights JAN19 PUBLIC
2020-25 Regulatory Proposal	1.004	ERG 1.004 2020-25 Regulatory Proposal JAN19 PUBLIC
An Overview Our Regulatory Proposals 2020-25	1.005	EGX ERG 1.005 An Overview Our Regulatory Proposals 2020-25 JAN19 PUBLIC
Capex and Opex Objectives, Criteria, and Factors in Chap 6 of NER	1.006	EGX ERG 1.006 Capex and Opex Objectives, Criteria, and Factors in Chap 6 of NER JAN19 PUBLIC
Network and non-network document hierarchy	1.007	EGX ERG 1.007 Network and non-network document hierarchy JAN19 PUBLIC
Document Register	1.008	EGX ERG1.008 Document Register JAN19 PUBLIC
Talkingenergy.com.au content (e.g. factsheets)		

2. Listening and responding to our customers

Key Messages

- **Our customers want us to listen to and act on their feedback and easily show how their feedback has informed our decisions.**
- **Our customers want us to provide affordable, secure and sustainable electricity.**
- **We will continue to engage our customers and other stakeholders throughout 2019 and 2020 as the AER finalises its decision for our distribution services for the 2020-25 regulatory control period.**

2.1 Our engagement program

2.1.1 What we have done

Over the past year, we have actively listened to our community stakeholders, our customers, and our industry partners to better understand what matters to them as we plan our distribution services for the 2020-25 regulatory control period. Our engagement program has included Customer Council Working Group meetings, regional Community Leader Forums, extensive qualitative and quantitative residential and business customer research, an online engagement capability through www.talkingenergy.com.au, and a significant schedule of business-as-usual engagement activities.

Our engagement program delivered rich and constructive feedback around all elements of our service offering, and our future challenges in providing our distribution services. The insights gained have informed our strategic direction, our asset management approach, our investment priorities, our proposed network tariff reforms and a range of other considerations in this Regulatory Proposal and our Tariff Structure Statement (TSS).

Further information on our engagement program is available in our 2020 and Beyond Community and Customer Engagement Report.

Figure 5 An overview of our engagement program

2.1.2 What we have heard

Our customers, communities and other stakeholders expect us to engage regularly with them in a transparent and meaningful manner. They want us to listen to and to act on their feedback and to show how it has informed our decisions. We involved our stakeholders in developing our approach to these documents and have continued through to submission to the AER.

We published 'Our Draft Plans 2020-25' for public consultation in September 2018. We subsequently published the additional submissions and feedback that we received. We have reflected this feedback in our approach to preparing this Regulatory Proposal and our TSS.

We remain committed to engaging and evolving our approach up to, and beyond, the AER's Distribution Determination in April 2020.

We heard a clear message through our engagement process that our customers want us to 'safely deliver affordable, secure and sustainable energy solutions'. This is our purpose and the central driver of this Regulatory Proposal and our TSS.

Figure 6 Our purpose

We have reflected these elements into a set of customer commitments.

2.1.3 What we will deliver

OUR CUSTOMER COMMITMENTS

SAFETY FIRST

Our number one priority is safety – our commitment is to the people and communities who we work with and support every day. We aspire to be an industry leader in health, safety, environment and cultural heritage.

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 for 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 peace of mind with a safe, reliable electricity supply, and the knowledge that we'll be there 'after the storm'.

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

Enabling your use of new and emerging technologies and providing easier access 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.

2.2 Safety

Safety is our overarching commitment to our communities, customers and employees. This is a non-negotiable element of our investment plans and how we work. New technology will help to improve safety and performance, while managing affordability.

2.2.1 What our customers want

Our engagement program highlighted that stakeholders recognise the importance of safety and they:

- recognise the dangers of electricity and that, if it is not managed appropriately, our distribution network presents a physical risk to our staff and the public
- are generally happy with the current safety of the network as well as our approach to maintaining safety for our communities, customers and staff, and
- recognise the value of investing in new technologies, such as low voltage monitoring devices, which can enhance customer safety.

2.3 Affordability

The cornerstone of this Regulatory Proposal is a commitment to do all we can to take the pressure off electricity prices by continuing to drive down our cost of distributing electricity. We understand the impact of retail electricity prices on the cost of living and of doing business.

2.3.1 What our customers want

Our engagement program highlighted that affordability remains a core concern for many customers:

- Our customers generally do not consider distribution charges separately to their retail electricity bill. They want the industry as a whole to deliver electricity price relief, without compromising the safety, security and reliability of supply they receive or customer service standards
- In general our customers are looking for price relief in order to reduce the cost of living and improve business competitiveness. Affordability is particularly important for customers facing financial hardship
- Our customers want price relief to be front ended in the early years of the 2020-25 regulatory control period
- For some customers, the rise in the cost of electricity in recent years has increased expectations around their electricity supply and the service experience we deliver
- Our stakeholders want us to demonstrate how our expenditure is prudent and efficient, including by:
  - showing what efficiencies and customer benefits have been achieved to date and what is planned as part of our ongoing business transformation program
  - ensuring our programs and contracts deliver best value, and
  - recovering costs over the lifetime of our assets' use, rather than in the year we incur the costs.
- Our stakeholders support tariff reform and greater cost reflectivity but are concerned about customer impacts and transition issues. They expect us to ensure equity of access to electricity, and

- Our customers want a trusted advisor to provide independent impartial advice, electricity usage data and tools to help them make informed choices in their energy use, behaviours and pricing plans. Stakeholders understand that we have a role to play here.

2.3.2 What we will deliver

10.3%

average residential customer on legacy default network tariff (after Uniform Tariff Policy)

In direct response to clear feedback received around the impact of retail electricity prices on the cost of living, our Regulatory Proposal will deliver a 9.44% reduction in revenue from 2019-20 to 2020-21. Compared to the current regulatory control period (2015-20), the next regulatory control period (2020-25) will see an 8% reduction ($492 million in real $2019-20) in Ergon Energy's overall smoothed revenue requirement.

This translates into at least a 4.5% real reduction in distribution network charges for the average residential customers from 2019-20 to 2020-21 on their existing tariff. This does not account for jurisdictional schemes which may factor into customer network charges. Customers may see further savings should they choose to opt-in to our cost reflective network tariffs, some of which may require a digital meter. For the average small business customer, in order to help address the impact of price rises on business competitiveness, it will deliver at least a 4% real reduction from 2019-20 to 2020-21. An average residential customer in Ergon Energy's region is a household who consumes 5,000 kWh of energy per annum. Similarly an average small business customer in regional Queensland is a small business who consumes around 7,500 kWh of energy per annum.The legacy tariffs (which are the existing default tariffs) are the Flat Residential Tariffs and the Flat Small Business Tariff.

Table 2 details our tariffs for residential and small business customers. The legacy tariffs (which are the existing default tariffs) are the Flat Residential Tariffs and the Flat Small Business Tariff.

Table 2 Forecast reduction in distribution network charges between 2019-20 to 2020-21[2]

Tariff	Average Residential Customer	Average Small Business Customer
	Real 2020	**Real 2020**
Legacy	4.5%	4.5%

Larger reductions in distribution network charges are being proposed in Energex's distribution area (South East Queensland). It is worth noting that Energex's network tariffs are used by the Queensland Competition Authority (QCA) to set the Queensland Government's *regulated* retail prices for regional Queensland which are then applied to electricity retail bills. Under this Uniform Tariff Policy, the Queensland Government subsidise the difference through Community Service Obligation payments to support regional Queenslanders, ensuring they pay similar prices for their electricity as customers in South East Queensland. After this subsidy, our average residential customer will receive a 10.3% real reduction in distribution network charges from 2019-20 to 2020-21. For a small business customer, this reduction will be 11.4%.

In addition to these savings, we are proposing network tariff reforms to offer customers additional choices and savings. We explain these reforms in our TSS.

2.3.3 How we will deliver it

Key initiatives in this Regulatory Proposal that will reduce distribution network charges and increase

[2] The real figure represents 2020 dollars, adjusted to incorporate an allowance for inflation.

customer affordability include:

- Reflecting the underspend against the AER's capex allowance in the 2015-20 regulatory control period into our opening regulatory asset base (RAB) in 2020. This is discussed in section 3.2.3
- Reducing our total operating expenditure (opex) on SCS from $2,027 million to $1,835 million (inclusive of debt raising costs)
- Making greater use of distributed energy resources (DER) and demand side initiatives, with transparent pricing for when these investments can reduce the need for investment in our network
- Applying the AER's 2018 Rate of Return Instrument to derive a rate of return estimate of 5.46% in 2020-21, compared with a forecast 5.98% in 2019-20
- Applying a revenue reduction in year one of the 2020-25 regulatory control period, with annual increases thereafter based on inflation, and
- Delivering network tariff reforms that are equitable and offer additional savings, value and choice that will reward customers for their role in Queensland's energy transformation.

2.4 Security

2.4.1 What our customers want

Our engagement program highlighted that stakeholders recognise the importance of security of supply. They:

- value how we keep the lights on and restore services after severe weather events. Overall, our customers want us to maintain, but not to improve, reliability performance. The exception is for the mainly rural and remote customers currently who are currently receiving below standard service
- are generally happy with the resilience of our distribution network, our operational readiness and our timely restoration of services after storms and other emergencies
- want better communication around power outage notifications – both planned and unplanned (e.g. text communication), and
- want us to continue insuring our assets cost effectively, particularly for major events (e.g. storms).

2.4.2 What we will deliver

We will ensure our distribution network remains secure and reliable, so that electricity is there when our customers need it. We will maintain the recent improvements in power reliability, while targeting expenditure savings and improving outcomes where network outages are outside of our service standards. Table 3 shows that we have out-performed our network reliability standards in 2017-18 – the most recent year where data is available at the time of submitting this Regulatory Proposal. Section 3.3 provides further information about the trend in our reliability service performance in the 2015-20 regulatory control period and compares it to earlier periods.

Table 3 Network performances standards

	2017-18 (Overall)	Minimum Service Standards		2017-18 (Unplanned)	STPIS Targets*	
Average length of outages – minutes (System Average Interruption Duration Index)						
Urban	124.82	149	✓	84.55	126.73	✓
Short Rural	318.23	424	✓	234.56	317.06	✓
Long Rural	891.29	964	✓	681.58	742.47	✓
Average number of outages per customer (System Average Interruption Frequency Index)						
Urban	1.490	1.98	✓	1.233	1.503	✓
Short Rural	2.708	3.95	✓	2.253	3.019	✓
Long Rural	5.551	7.40	✓	4.539	5.348	✓

** STPIS = Service Target Performance Incentive Scheme as detailed in section 3.3.*

2.4.3 How we will deliver it

Our proposed expenditure program will maintain our safety and security performance while:

- delivering sustainable investment that avoids a boom-bust cycle and manages our aging assets through maintenance and targeted replacement, and
- achieving improved community and staff safety, by leveraging innovative solutions to continue the transition to an intelligent grid, enabling and leveraging the growth of DER – including grid-scale and small solar generators, and energy storage solutions.

Key safety and security initiatives in this Regulatory Proposal include:

- implementing new network monitoring technologies to improve safety related to low voltage shocks associated with service lines. We will also ensure safety by design with improved capability to sense and predict safety issues. This will improve power quality, outage management and identification and network operation in a high DER future
- meeting discrete areas of strong growth across our network, including from solar and other emerging technologies. An example is reinforcing supply to Planella through key augmentation (augex) projects to meet pockets of demand growth
- maintaining the resilience of our network and response capability, while targeting expenditure savings
- addressing increasing risks around cyber security and data privacy
- continuing to improve outcomes where network outages are outside the standard
- evaluating further communications about planned and unplanned outages
- making better use of data and analytics, and providing digital services to our customers; such as by providing more transparent information on load growth and network reliability impacts to ensure our network continue to meet customer expectations, and
- maintaining our insurance and self-insurance policies.

2.5 Sustainability

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

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

2.5.1 What our customers want

Our engagement program highlighted the importance of sustainability to our customers. They:

- recognise that new technology is important to a modern distribution network. They expect us to explain how we use new technology and how they benefit from it
- want us to be an enabler of new customer technologies but not necessarily a leader (e.g. in the adoption of electric vehicles)
- want us to protect legacy load under control to manage network demand
- expect us to partner with the market in devising customer solutions to manage network demand into the future
- expect us to collaborate with, and provide incentives to, customers and the supply chain to assist in demand management delivery and uptake
- want connections to be timely and simple and for us to align our service offering across Queensland
- want greater choice, equity and user-pays outcomes for connections
- expect us to facilitate the integration of renewables into our distribution network, and
- want us to enable energy efficiency options and new technologies - including in public spaces (e.g. Light Emitting Diode (LED) and smart public lighting).

2.5.2 What we will deliver

Our goal is to enable our network to facilitate the interconnection of new technology for the benefit of our customers and communities. This will enable our communities and customers to leverage the many benefits of digital transformation, DER and emerging technologies, such as solar, battery storage and electric vehicles, as well as the next generation of energy management systems. We will do this by:

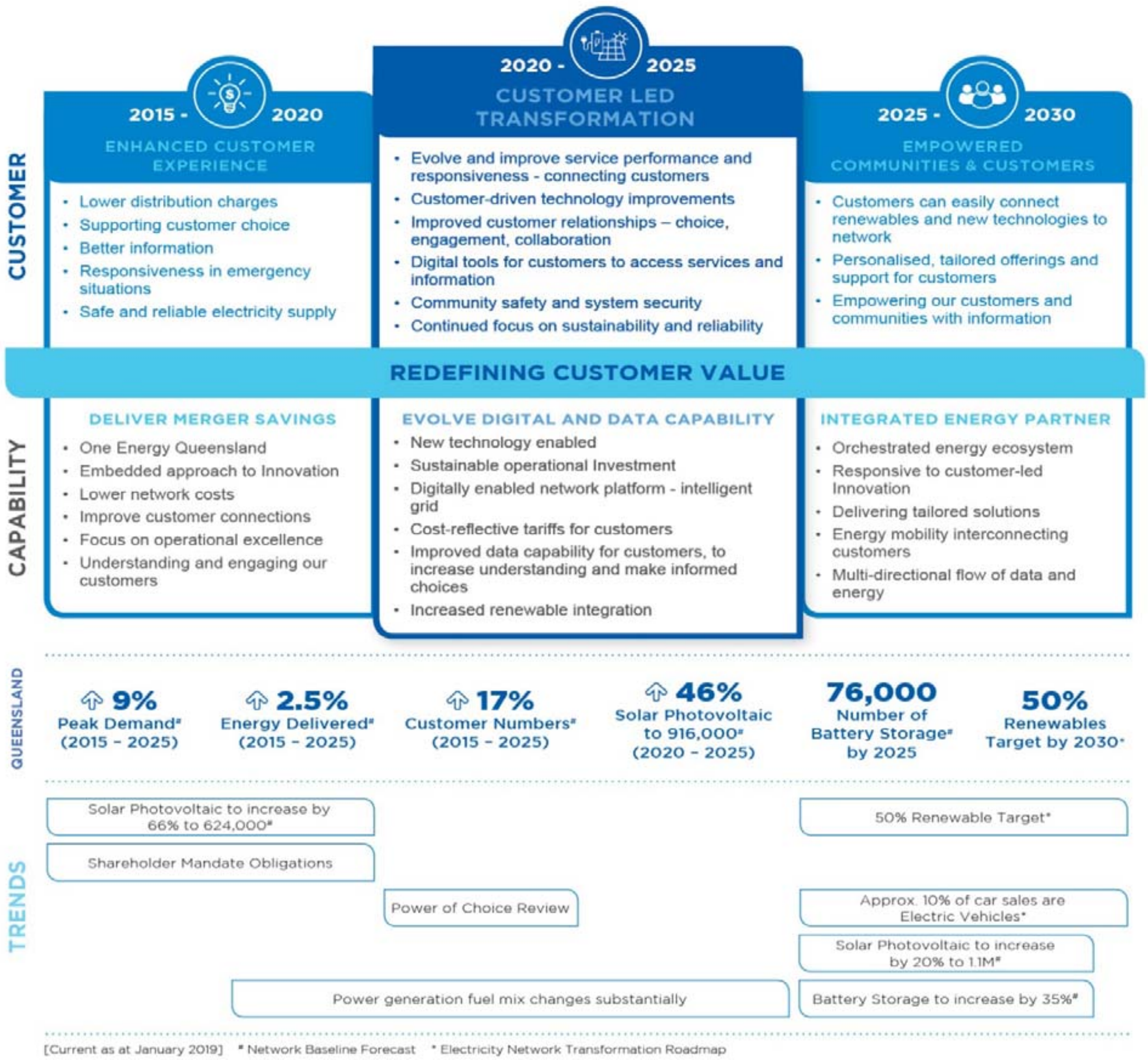
- continuing to collaborate and leverage customer-side investment, both to offset network expenditure and to improve overall service outcomes
- making it easier and quicker to connect to the network with an aligned state-wide service offering and further system improvements
- continuing to transform our network into an intelligent grid to leverage digital transformation and effectively integrate the growing range of DER
- evolving our network to best support customer choice in electricity supply solutions by integrating solar, batteries and other technologies into the network in a cost effective and sustainable way, and

- ensuring safety by design with improved capability to sense and predict safety issues, such as broken neutrals[3]. Greater levels of visibility of our network will improve power quality, outage management and identification and network operation in a high DER future.

Our task ahead is to work with our customers to realise the network value in the energy transformation and to ensure the whole community benefits from today's and tomorrow's emerging technology. We are committed to deliver on what really matters so that no one is left behind, and our communities grow stronger.

Figure 7 represents the journey that we are undertaking, building from the 2015-20 regulatory control period to position ourselves to have the capability to continue to serve customers effectively in a world of growing renewables, while addressing the increasing digitalisation of energy technology solutions with increased information being made available to our communities and customers.

Figure 7 Redefining customer value



[3] Broken neutral: A broken wire in a customer's service cable which results in unsafe voltages on earthed metallic objects in the customer's premises

2.5.3 How we will deliver it

We will continue to work with our stakeholders in the 2020-25 regulatory control period to realise the value emerging from today's transforming energy technology. Key sustainability initiatives in this Regulatory Proposal include:

- supporting and enabling emerging technologies and devices
- supporting load control as a tool to manage network demand
- collaborating with customers and partners to assist with demand management and delivery. We anticipate continuing these activities in the 2020-25 regulatory control period
- refining and aligning our proposed connection policies as far as is practicable to provide greater consistency in the provision of connection services across Queensland
- supporting and enabling the integration of renewables into the network, particularly where it makes prudent financial and delivery improvements for customers and communities, and
- working with our customers to develop a strategy to enable transition to LED technology and smart controllers. This includes new tariffs, funding arrangements and standards.

2.6 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Customer Engagement Summary - 2020-25 Regulatory Proposals	2.001	EGX ERG 2.001 Customer Engagement Summary - 2020-25 Regulatory Proposals JAN19 PUBLIC

3. What we have delivered in the 2015-20 regulatory control period

Key Messages

In the 2015-20 regulatory control period, we:

- **maintained a secure electricity network and responded quickly to storms and severe weather events**
- **promoted greater energy choice and control over energy solutions**
- **better understood customers' requirements and future needs and subsequently instituted initiatives to improve customers' experience**
- **are projecting to underspend our total capex and opex allowances by $523 million, or 8.5%, while continuing to meet reliability and customer service performance outcomes**
- **implemented safety enhancements through new technologies**
- **leveraged a range of low-cost options to support renewables across 30% of detached houses across Queensland**
- **used our demand management expertise to support the way our customers are using our network.**

Figure 8 details what we have delivered in the 2015-20 regulatory control period, against the three key outcomes that customers most value – affordability, safety and security and sustainability.

Figure 8 What we have delivered in the 2015-20 regulatory control period[4]

LOWER NETWORK PRICES

- Since June 2015, distribution network charges for households and small businesses in Queensland have fallen on average by 7% percent per annum. At the same time, however, there have been significant increases in wholesale energy prices, so these savings have largely not been visible to our customers in the electricity bills they receive from their retailers
- We have worked hard to reduce our costs to be able to deliver our lower distribution network charges
- We forecast underspending the AER's total capex and opex (totex) allowance by $320 million in the current regulatory period for Energex and $523 million for Ergon Energy (real $2020)[10]. A key contributor to this underspend has been improvements in delivery
- This will translate into lower distribution network charges for customers in the next period and thereafter
- As augmentation expenditure (augex) drops off, replacement expenditure (repex) is an increasing percentage of total spend. During high growth periods, aging assets are replaced to deliver increased capacity

SAFE AND RELIABLE ELECTRICITY SUPPLY

- The safety of our communities, customers and staff is paramount. We have taken a range of steps to improve the safety of our assets including embedding a common approach to risk, driving a stronger focus around asset safety and continuing trials of new technology to improve safety outcomes
- Despite delivering significant savings, we have provided high reliability and customer service performance outcomes to our customers
- Our reliability performance over the past two regulatory period has generally (with only a few exceptions) been stable, or progressively improving, and has been at, or has exceeded, the Minimum Service Standards in our Distribution Authorities issued by the Queensland Government
- Our contact centre performance has remained stable and has been exceeding our service targets
- We have delivered safety enhancements through new technologies like LiDAR and online condition monitoring to managing our large network

SUSTAINABILITY

- We are at the forefront in integrating distribution renewable energy and other technologies into the grid – with 30% of detached houses across Queensland, and more and more businesses, now benefitting from rooftop solar connected into the grid
- We are using our expertise in demand management to help us respond to the changing way our customers are using the network
- This will reduce demand on our network in the long-term and so reduce average future prices as a result of lower costs by and minimising regulated asset base growth
- We have leveraged a range of low cost options to support the 30% renewables. We are now at a point that investment will be required to achieve greater percentage of renewables

[4] The underspend is expressed in real 2020 dollars which incorporates inflation and real escalation up to 2020.

3.1 Network bill impacts

We have focussed on reducing the distribution component of our customers' electricity bills in the 2015-20 regulatory control period.

Since the commencement of our first TSS on 1 July 2017, we have begun introducing cost-reflective network tariffs to our suite of network tariffs. These tariffs include time of use consumption and time of use demand tariff structures that more accurately signal customers' usage of the network at times of peak network usage. We have also continued to listen to customer feedback on our existing network tariffs and the new cost reflective network tariffs. This feedback has been valuable in informing the suite of network tariffs in our TSS for the 2020-25 regulatory control period.

3.2 Our financial performance

3.2.1 Energy Queensland's joint savings

In the 2015-16 Mid-Year Fiscal and Economic Review, the Queensland Government announced our merger with Energex under the banner of Energy Queensland. The merger was accompanied by a clear intent to achieve cost reductions and efficiencies in opex and capex (totex) in the two regulated network businesses to the benefit of customers. The merger took effect from 1 July 2016.

Notwithstanding the reductions already targeted for the two businesses in their 2015-20 Regulatory Proposals and the AER's associated Distribution Determinations, in order to improve further on the baseline an additional totex target of $562 million net of implementation costs in nominal terms over four years (2016-17 to 2019-20) was formalised for the two business. These further targeted savings were against the forward estimates at that time, which approximated the regulatory expenditure allowance over the period to 2019-20.

We refer to the reductions achieved in these four years as "post-merger" savings to distinguish them from those already achieved by the two businesses in 2015-16.

The combined entity has been successful in achieving the savings' target through a combination of approaches, including:

- scale benefits
- re-negotiations with suppliers
- selection of, and adoption of, best practice across the two entities
- reconsideration of work practices and scheduling, and
- a general re-examination of planned spend to ensure it is prudent and efficient.

Some of these savings were envisaged and planned through formal savings' initiatives (which we call roadmaps) while other opportunities presented themselves after the merger. The external environment was also not static, and the businesses had to respond to changing requirements to ensure the continued safe and reliable operation of the network, some of which reduced and some of which increased the actual cost base.

It is not practical, and in some instances may be misleading, to attribute cost reductions to any of these individual internal or environmental factors, actions or decisions outlined above in isolation. In order to measure the achievement of the reduction target as objectively as possible against a stable baseline, we use the AER's 2015-20 totex allowance to monitor our progress. The reduction in cost compared to the AER's allowance is partially offset by implementation costs, and we use the term "net" savings to describe this measure.

In 2018-19, Energy Queensland expects to achieve approximately $93 million in nominal terms of post-merger net savings across its two network businesses. For ourselves and Energex, Energy

Queensland expects to achieve cumulative post-merger net savings of $579 million by the end of 2019-20, which exceeds the initial estimate of $562 million.

In addition, we and Energex achieved reductions before the merger. Energy Queensland expects to achieve totex savings against the regulatory allowances for the 2015-20 regulatory control period of over $735 million across the two businesses, net of implementation costs. Achieving these savings ambitions is a fundamental element of Energy Queensland's financial strategy. Table 4 provides a summary of the post-merger savings during the current regulatory control period.

Table 4 Energex and Ergon Energy post-merger net savings over the 2015-20 regulatory control period

Consolidated Group ($M, Nominal)	Target	2017-18 Estimated Actuals	2018-19 Plan	2019-20 Plan	Total
AER SCS Totex Allowance		1,913.0	1,939.0	1,979.0	7,789.0
SCS Totex Actual / Target		1,707.0	1,795.7	1,798.8	7,022.5
Total Savings		**206.0**	**143.3**	**180.2**	**766.5**
Opex savings		35.0	53.3	71.4	189.7
Capex savings		171.0	90.0	108.8	576.8
Implementation and Redundancy costs		39.0	50.6	54.3	187.9
EQL net savings compared to AER	**562.0**	**167.0**	**92.7**	**125.9**	**578.6**

Totals may not add due to rounding.

Achieving these savings enables us to operate and maintain our electricity distribution network in a manner that is efficient while delivering on safety and reliability standards. The savings achieved through the merger have flowed predominantly to capex, whereas the associated restructuring costs have reduced the profit of the organisation.

Savings in capex will flow into the next regulatory control period via an opening Regulatory Asset Base (RAB) that will be lower than it would be otherwise, which in turn lowers network prices. Customers will also benefit from us having a lower opex base year and through the expected adjustments made under various regulatory incentive schemes. We expect the merger savings to be sustained throughout the 2020-25 regulatory control period, although we are reflecting further savings into this Regulatory Proposal.

Table 4 details the post-merger savings that we have made, or expect to make, across Energex and Ergon Energy against the AER approved opex and capex allowances over the 2015-20 regulatory control period.

We have achieved the post-merger opex savings through:

- reducing spending on building new network assets or replacing old network assets by adopting enhanced network technologies and asset management strategies
- unit rate improvement for the delivery of projects through optimising crew size, work program, depot management, resources and productivity improvements
- better procurement price outcomes in network equipment, field service contract, corporate service contract corporate real estate consolidation and sublease
- improving asset strategies and standards and balancing network risk and customer outcomes
- removing the duplication in the corporate overhead functions, and
- process and labour utilisation improvements.

3.2.2 Ergon Energy's opex

Table 5 details our actual opex performance against the AER's allowance (excluding debt raising costs) for the 2015-20 regulatory control period.

Table 5 Actual opex compared with AER allowance

$M, Real $2020	2015-16	2016-17	2017-18	2018-19	2019-20	Total
AER opex allowance	371.87	378.29	384.60	392.55	399.93	1,927.23
Actual / estimated opex	425.19	377.82	401.14	379.77	372.51	1,956.43
Variance from allowance	**53.32**	**-0.46**	**16.54**	**-12.77**	**-27.42**	**29.20**

Totals may not add due to rounding. Both AER allowance and actual/estimated opex include debt raising costs.

We are projecting to overspend the AER's opex allowance for the 2015-20 regulatory control period by $29.2 million in real 2019-20 terms. Significantly, in this financial year (2018-19) and the next (2019-20) financial year we will underspend the allowance by $40.2 million. This means that our base year opex that we use to forecast our opex for the 2020-25 regulatory control period will be lower than it would have been if we spent up to the AER's allowance. This is discussed further in chapter 6.

The main drivers of our opex performance over the 2015-20 regulatory control period, and the above variances, are the:

- Savings from our merger with Energex, discussed above
- Introduction of new rapid inspection technologies for overhead and ground plant to cover the complete network which reduces "traditional" inspection techniques, needs and costs. Examples include:
    - Thermal imaging of low voltage pillars, and
    - LIDAR analysis of overhead conductors
- Reduction in the program units of aerial inspections through better use of data to target specific assets and environmental conditions
- Collaborative engagement with councils on removal of inappropriate trees, and
- Alignment of condition assessments, delivery timeframes and process improvements in inspection and defect management areas.

3.2.3 Ergon Energy's network capex

Table 6 details our actual network capex performance against the AER's allowance for the 2015-20 regulatory control period.

Table 6 Actual network capex compared with AER allowance

$M, Real $2020	2015-16	2016-17	2017-18	2018-19	2019-20	Total
AER capex allowance (network)	856.99	777.75	720.40	683.29	673.00	**3,711.43**
Actual / estimated capex (network)	737.89	621.72	571.55	625.47	602.33	**3,158.96**
Variance from allowance	**-119.11**	**-156.02**	**-148.85**	**-57.82**	**-70.68**	**-552.48**

Totals may not add due to rounding.

We are projecting to underspend the AER's network capex allowance for the current period by $552.5 million. This means that we will start the 2020-25 regulatory control period with a lower RAB than if we spent to the AER's allowance. The main drivers for our network capex performance over the 2015-20 regulatory control period, and the above variances, are:

- savings from our merger with Energex, discussed above

- reduced connections capex due to lower than forecast volumes and costs of customer-initiated work, and
- lower augmentation capex due to lower than forecast peak demand growth.

We are committed to continuing to build on the improvements throughout the 2015-20 regulatory control period through:

- internal labour improvements in field delivery
- materials and contract savings due to merger savings
- contract renegotiations
- economies of scale, and
- continuing demand management activities.

These improvements are included in our opex and capex forecasts in chapters 6 and 7 respectively.

3.2.4 Ergon Energy's non-network capex

Table 7 details our actual non-network capex performance against the AER allowances. We are projecting to underspend the AER's non-network capital allowance for the current period by $114.3 million. This means that we start the 2020-25 regulatory control period with a lower RAB than if we spent to the AER's allowance. The main drivers for our non-network capex performance over the 2015-20 regulatory control period, and the above variances, are:

- lower fleet and equipment capex through life-extension strategies of light and commercial vehicles
- life extension of plant refurbishment to Australian Standard guidelines
- significant reductions in Information Communication Technology (ICT) storage costs
- life extension of end user hardware, and
- opex leasing of mobile in-field devices.

Table 7 Actual non-network capex compared with AER allowances

$M, Real $2020	2015-16	2016-17	2017-18	2018-19	2019-20	Total
AER capex allowance (non-network)	163.60	114.38	102.79	88.29	77.49	**546.56**
Actual / estimated capex (non-network)	120.04	91.84	59.94	84.74	75.71	**432.27**
Variance from allowance	**-43.57**	**-22.54**	**-42.85**	**-3.55**	**-1.78**	**-114.29**

Totals may not add due to rounding.

3.3 Our service performance

We deliver our services to meet regulated target levels of electricity reliability (frequency of outages), responsiveness to restore power when outages occur (duration of outages), and customer call centre performance. We have two types of targets:

- **Total outages/interruptions (planned and unplanned) or system minimum service standards (MSS)** that we are required under our Distribution Authority to use our reasonable endeavours to meet. The MSS are set and administered by the Queensland Government's Department of Natural Resources, Mines and Energy (DNRME).
- **Unplanned outages/interruptions or Service Target Performance Incentive Scheme** targets that incentivise us to maintain or improve our service performance where customers

are willing to pay. We either earn financial rewards or pay penalties based on our performance relative to average historical levels. The AER sets the STPIS targets based on our five-year historical performance, with the reward or penalty being applied annually as tariffs are established.

- Table 8 shows our STPIS performance over the 2015-20 regulatory control period.

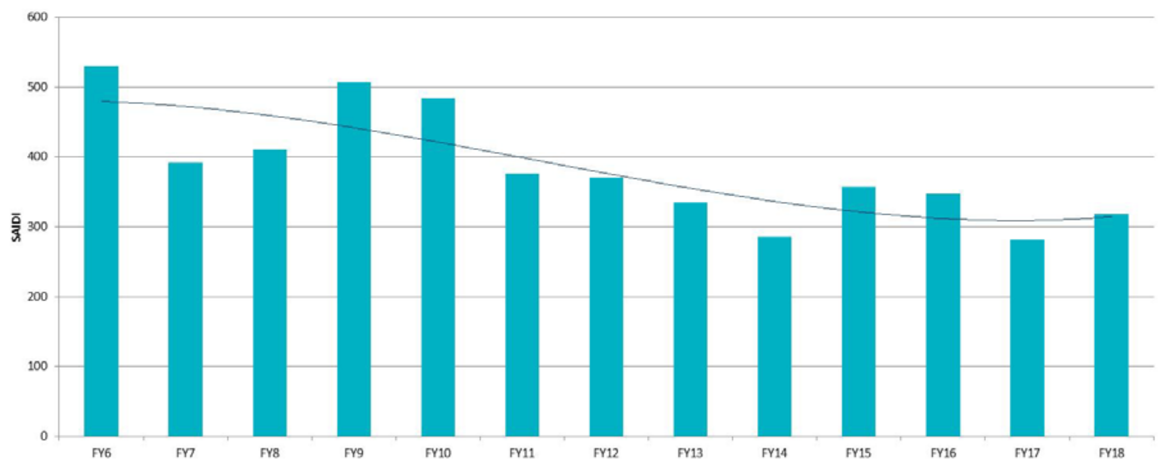
Table 8 Actual and Forecast Service Performance (STPIS)

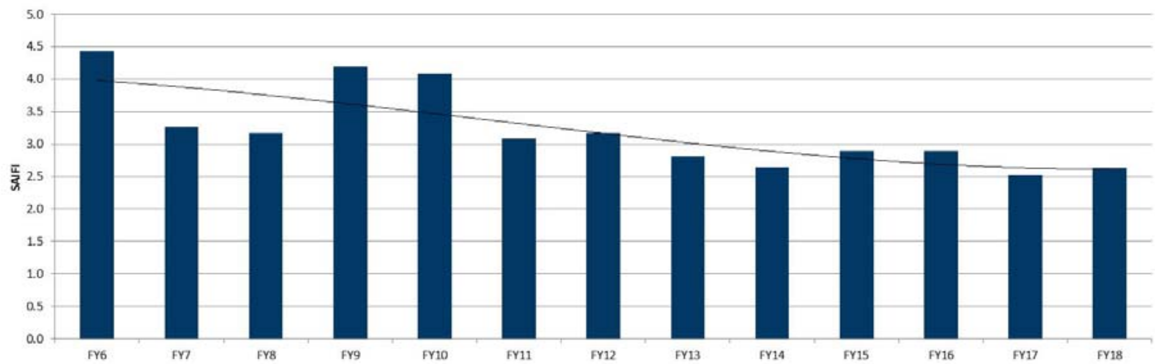
	2015-16	2016-17	2017-18	2018-19	2019-20
Unplanned SAIDI (minutes)					
Urban Distribution	94.61	79.43	93.57	91.62	91.62
Short Rural Distribution	276.78	213.14	231.38	245.02	245.02
Long Rural Distribution	821.75	624.48	681.58	735.05	735.05
Unplanned SAIFI (Interruptions)					
Urban Distribution	1.07	0.92	1.26	1.11	1.11
Short Rural Distribution	2.59	2.26	2.25	2.44	2.44
Long Rural Distribution	6.03	4.89	4.54	5.33	5.33
Customer service (% answered in 30 seconds)					
Telephone answering	79.49	80.20	79.64	80.24	80.24

** SAIDI = System Average Interruption Duration Index, * SAIFI = System Average Interruption Frequency Index*

Since the inception of MSS in 2005-06, as shown in Figure 9, our overall average outage duration and frequency (SAIDI and SAIFI) have improved between 40% and 41% (depending on the feeder type).

Figure 9 Improvement of SAIDI and SAIFI since the inception of MSS targets





3.4 Other customer performance

Following the 2004 Electricity Distribution and Service Delivery Review's recommendations, the Queensland Government introduced a Guaranteed Service Level (GSL) scheme initially under our Distribution Authority and later through the Queensland Electricity Industry Code (now the Queensland Electricity Distribution Network Code).

GSLs are a means of providing some financial recompense for poor service and reliability experienced by individual customers. The GSLs are intended to work in combination with the MSS targets to ensure that a minimum level of average network reliability is maintained, while recognising instances when individual customers receive poor service outcomes.

The current GSL scheme came into effect on 1 January 2005 and requires us to pay customers when the level of service that they receive for defined measures falls below specified levels. The GSL measures relate to:

- wrongful disconnections
- late connections
- late reconnections
- late attendance for hot water supply failure
- late attendance for appointment
- insufficient notice of planned interruption
- long interruptions, and
- frequent interruptions.

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We continue to use our best endeavours to automatically make GSL payments where service levels are not met. For the 2014-15 to 2017-18 financial years, 49,251 GSLs were paid out at a cost of $4.9 million. Table 9 shows our GSL volumes and payments between 2014-15 and 2017-18.

Table 9 GSL 2014-15 to 2017-18

$M, Real $2020		2014-15	2015-16	2016-17	2017-18	Average
Appointments	**Vol**	1,378	892	157	160	**647**
	$	71,812	50,860	8,949	9,120	**35,186**
Connection	**Vol**	241	70	28	61	**100**
	$	36,556	8,874	7,052	12,363	**16,212**
Hot Water	**Vol**	8	1	1	1	**3**
	$	520	57	57	57	**173**
Planned Interruption	**Vol**	2,609	1,988	1,323	1,381	**1,826**
	$	82,108	66,070	52,352	48,085	**62,154**
Reconnection	**Vol**	78	32	4	23	**35**
	$	6,760	4,985	456	2,107	**3,577**
Reliability – Duration	**Vol**	5,220	6,342	3,445	22,693	**9,425**
	$	542,841	722,988	392,730	2,587,002	**1,061,391**
Reliability - Frequency	**Vol**	290	58	143	57	**137**
	$	30,108	6,612	16,302	6,498	**14,880**
Wrongful Disconnection	**Vol**	275	125	103	64	**142**
	$	35,750	17,666	14,626	9,088	**19,283**

The significant increase in the volume of reliability-duration GSLs in 2017-18 is a result of a storm event in the Bundaberg Burnett Region on the 7 November 2017. The storm event resulted in a total of 12,904 GSLs.

Major weather events are a common occurrence in Queensland, and often cause significant damage to electricity network infrastructure and/or extended interruptions to supply for some customers. Despite our best efforts to plan and maintain the electricity network cost-effectively to meet customers' expectations for high levels of reliability, such extreme events and their consequences are outside our control. The MSS recognises this by excluding them from assessment of performance interruptions which commence on Major Event Days (MEDs). This is also recognised in the STPIS, which accounts for the impacts of MEDs in reliability indices used by the AER to assess network performance.

The QCA is currently consulting on the GSLs to apply for the 2020-25 regulatory control period. In this Regulatory Proposal we have assumed the current GSLs apply. To the extent the QCA makes amendments to the scheme, this will be reflected in our Revised Regulatory Proposal in December 2019.

4. Our response to AER's framework and approach paper

Key Messages

We broadly accept the AER's final F&A paper, including its proposed:

- **service classification**
- **control mechanisms for SCS and ACS, and**
- **application of the Efficiency Benefit Sharing Scheme (EBSS), the Capital Expenditure Sharing Scheme (CESS), the Demand Management Incentive Scheme (DMIS), STPIS, and the Demand Management Innovation Allowance Mechanism(DMIAM) for SCS.**

We note the AER's intention to apply:

- **its Expenditure Forecast Assessment Guideline to assess our capex and opex forecasts for the 2020-25 regulatory control period, and**
- **forecast depreciation to determine the RAB at the start of the subsequent regulatory control period.**

4.1 Overview

On 30 July 2018, the AER published its final F&A paper for Energex and Ergon Energy for the regulatory control period commencing 1 July 2020. This is the first step in the Distribution Determination process and sets out the AER's proposed approach on the:

- classification of distribution services
- application of incentive schemes
- application of the Expenditure Forecast Assessment Guideline, and
- calculation of regulatory depreciation.

The F&A paper also sets out the AER's decision on control mechanisms.

We were broadly supportive of the AER's preliminary F&A paper, and we also support the final F&A paper given that it is in large part consistent with the preliminary F&A paper. Our primary concern in our response to the preliminary F&A paper was the proposed increase in STPIS revenue at risk from ±2 per cent to ±5 per cent. The final F&A paper for the 2020-25 regulatory control period accepts our position that a high-powered STPIS is not required in Queensland at the present time, and retains the current ±2 per cent revenue at risk.

The F&A paper was finalised during the consultation on the AER's Service Classification Guideline and revised STPIS, which were subsequently published in September and November 2018, respectively. Both mechanisms necessitate adjustments to the service classification and the formulae which give effect to control mechanisms in the F&A paper. Indeed, we note that the AER indicated in the F&A paper that the publication of the Service Classification Guideline would constitute a material change in circumstances necessitating adjustments to the service classification in the F&A paper.

We outline below our response to the F&A paper together with our consideration of the Service Classification Guideline and the revised STPIS.

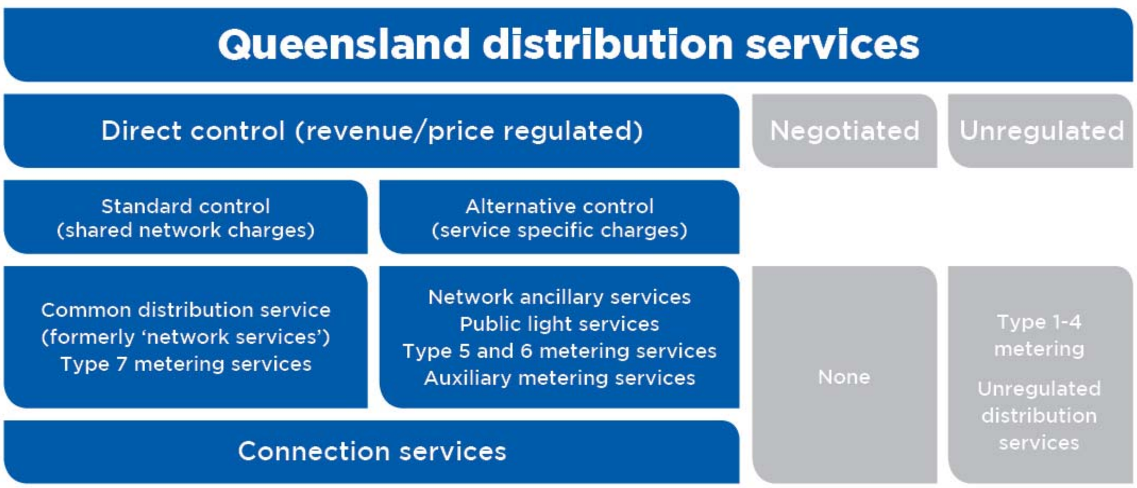
4.2 Service classification

Service classification determines which of our distribution services will be subject to regulation, how we will recover our costs, and our ring-fencing obligations, over the regulatory control period. For these reasons, it is one of the central decisions made by the AER in a Distribution Determination. Under the NER, the AER may:

- classify our distribution services as direct control services, and further as SCS or ACS. These services are subject to direct regulatory oversight by the AER through revenue and/or price controls
- classify distribution services as a negotiated distribution service. These services are subject to a more light-handed form of regulatory oversight through a negotiating framework, and
- not classify a distribution service. These services are not subject to regulatory oversight.

Figure 10 summarises our service classification proposal for the 2020-25 regulatory control period. Attachment 4.004 provides our detailed proposed 2020-25 Queensland distribution service list.

Figure 10 Our proposed classification of Queensland distribution services



4.2.1 Application of the Service Classification Guideline

In developing our service classification proposal, we have had regard to the F&A paper and the Service Classification Guideline. The F&A paper sets out, amongst other things, the AER's proposed service groupings, descriptions and classifications for the 2020-25 regulatory control period. The Service Classification Guideline also sets out the AER's proposed approach to service classification in a Distribution Determination. It is a new instrument introduced in the NER in December 2017 to improve the clarity, transparency and predictability of the distribution service classification process.

Ideally the Service Classification Guideline would have been applied during the F&A process, ensuring alignment between the two mechanisms. But, as noted previously, when the AER finalised the F&A paper for the 2020-25 regulatory control period, it was still in the process of developing the Service Classification Guideline. While the F&A paper incorporates many aspects of the AER's proposed approach to service classification set out in the Service Classification Guideline, there are differences between the two mechanisms, the most significant being in connection services.

The Service Classification Guideline proposes a fundamentally different classification framework for connections to that in the F&A paper, to improve clarity and consistency. We consider that the AER's connections framework outlined in the Service Classification Guideline is practical and will promote clarity and consistency in connection services across all jurisdictions. However, it triggers service classification changes from the F&A paper particularly for our small customer connections. These are currently classified as SCS in Queensland and as such our small customers do not typically pay upfront charges for their connections. By contrast, the Service Classification Guideline reclassifies these connections as ACS.

We acknowledge that the proposed service classifications in the F&A paper and the Service Classification Guideline are not binding on us in preparing our Regulatory Proposal or on the AER in making its Distribution Determination. Nevertheless, we submit that the proposed service classifications in the F&A paper must be given primacy. The F&A paper process is an important step in the Distribution Determination process and the service classification considerations during this process significantly shaped the development of our Regulatory Proposal and engagement with our customers. This is because the service classification affects many other aspects of our Regulatory Proposal, for example, our forecast RAB, opex, capex and our annual revenue requirements.

When the Service Classification Guideline was finalised, we were in the process of finalising our Regulatory Proposal based on the service classification in the F&A paper. More importantly, our customer engagement on Our Draft Plans (and connection policies) applied the service classifications in the F&A paper. Therefore, our service classification proposal adopts the service classifications of connection services in the F&A paper and we assume that the current regulatory arrangements will continue in the 2020-25 regulatory control period. However, we have endeavoured to apply the service groupings and descriptions provided in the Service Classification Guideline. The remainder of this section summarises our proposal for each of the other service groups.

4.2.2 Common distribution service

This is the bundled distribution service provided to customers that use the shared distribution network. The activities included under the common distribution service grouping in the Service Classification Guideline are largely consistent with the F&A paper, except for bulk supply point metering. In the Service Classification Guideline, bulk supply point metering is included in the common distribution service group but is a separate service under the metering services group in the F&A paper. We support the Service Classification Guideline decision and have adopted it in our proposed service list.

Further, we support the classification of common distribution services as direct control services and additionally as SCS because these are monopoly activities which benefit all customers. This is consistent with the Service Classification Guideline and the F&A paper.

4.2.3 Network ancillary services

These are services that are closely related to the common distribution service which are typically requested by specific customers and therefore attract customer specific charges. The services and descriptions/activities in the service classification guideline and F&A paper are largely consistent. We have adopted the Service Classification Guideline groupings and descriptions with the following exception:

- Inspection and auditing services: In relation to this service group, we retained the activities listed in the F&A paper, which included two additional activities relating to our requirements under sections 219 and 220 of the *Electrical Safety Regulation 2013* (Qld) for after-hours examination of consumer mains, mains switchboard, and electrical installations.

We support the classification of network ancillary services as direct control services and additionally as ACS because these are customer specific services and we can attribute the costs to the customers requesting the services. This is consistent with the Service Classification Guideline and the F&A paper.

4.2.4 Metering services

The metering services grouping involves activities relating to the measurement of electricity supplied to and from customers through the shared distribution system. We support the services and descriptions/activities under the metering services group in the Service Classification Guideline, which are in part consistent with the F&A paper. The Service Classification Guideline only includes a subset of the services included in the F&A paper, so in addition to adopting the Service Classification Guideline service groups, we propose to retain the following additional services provided in the F&A paper:

- Type 5 and 6 meter installation and provision (prior to 1 December 2017). This service reflects that we will continue to recover the capital costs associated with our legacy meters installed prior to 1 December 2017 in the 2020-25 regulatory control period
- Emergency maintenance of failed metering equipment not owned by the distributor (contestable meters). This service relates to power outages caused by an external metering provider's metering equipment
- Third party requested outage for purposes of replacing meter. This service relates to requests from a retailer or metering coordinator to isolate power at a customer’s premises to facilitate the replacement of the existing metering installation by an external metering provider, and
- Ergon Energy’s Mount Isa – Cloncurry supply network metering services, which reflect that the Mount Isa – Cloncurry supply network is exempt from Power of Choice. These include:
    - Type 5 and 6 meter installation and provision
    - Types 5 and 6 meter maintenance, reading and data services, and
    - Additional auxiliary metering services.

We support the service classification in the service classification guideline and F&A paper:

- Type 1 to 4 metering activities being unregulated
- Type 5 to 6 metering installation related services being classified as ACS, and
- Type 7 metering services being classified as SCS.

4.2.5 Public lighting services

These services relate to the provision of public lighting typically to local government councils and road operators. We support the Service Classification Guideline service description of public lighting, which is consistent with the F&A paper. We also support the ACS classification for public lighting. This is a continuation of current regulatory arrangements in the 2020-25 regulatory control period.

4.3 Control mechanisms

4.3.1 Forms of control

Control mechanisms impose constraints on the revenues we earn or the prices that we charge (or both), in the provision of direct control services (i.e. SCS or ACS). They ensure that we only earn what the AER has allowed. The NER provide for several control mechanisms including revenue caps and price caps. In its F&A paper, the AER decided to retain the following control mechanisms in the 2020-25 regulatory control period:

- revenue cap for SCS, and

- caps on the prices of individual services for ACS.

We accept the AER's decision in the F&A paper.

4.3.2 Formulae for control mechanisms

Under the NER, in making a Distribution Determination, the formulae that give effect to the control mechanisms must be as set out in the F&A paper unless the considers that a material change in circumstances justify departing from the formulae in the F&A paper. As noted above, the publication of the revised STPIS necessitates changes to formulae that give effect to the revenue cap for SCS which are set out in the F&A paper. Therefore, we propose to vary from F&A paper's control formulae for SCS. Our proposed formulae are outlined in Attachment 4.003.

4.4 Incentive schemes

The NER provides several incentive schemes designed to encourage us to maintain and improve service levels, pursue capex and opex efficiencies and demand management. We accept the application of the STPIS, EBSS, CESS, DMIS and DMIAM over the 2020-25 regulatory control period, as proposed in the F&A paper. We have had regard to incentive schemes in chapter 11 and Attachment 11.001.

4.5 Expenditure forecast assessment guideline

We note the AER's intention to apply its Expenditure Forecast Assessment Guideline to assess our capex and opex forecasts for the 2020-25 regulatory control period. We have had regard to this guideline in preparing our opex and capex forecasts in chapters 6 and 7 respectively.

4.6 Depreciation

We note and support the AER's intention to apply forecast depreciation to determine our RAB at the start of the subsequent regulatory control period, commencing on 1 July 2025. We agree that, in combination with the proposed application of the CESS, this approach will maintain incentives for us to pursue capex efficiencies.

4.7 Single Regulatory Proposal

We have received approval from the AER to submit this Regulatory Proposal for both our primary network and our network at Mount Isa - Cloncurry in accordance with the provisions of clause 6.2.4 of the NER.

4.8 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Control mechanisms	4.001	EGX ERG 4.001 Control mechanisms JAN19 PUBLIC
Expenditure forecasting method	4.002	EGX ERG 4.002 Expenditure forecasting method JUN18 PUBLIC
Response to Preliminary Framework and Approach	4.003	EGX ERG 4.003 Response to Preliminary Framework and Approach MAY18 PUBLIC
Service Classification	4.004	EGX ERG 4.004 Service Classification JAN19 PUBLIC

Part B – Standard Control Services

5. Demand Forecast

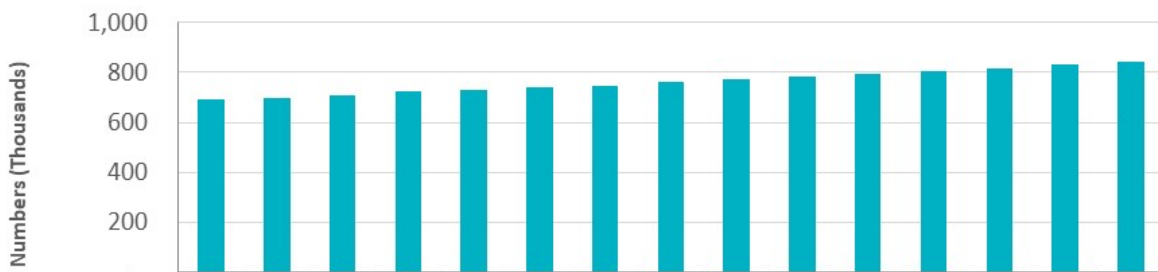
Key Messages

- **We expect our customer numbers to increase by 7.68% over the 2020-25 regulatory control period, based on connecting more than 60,000 new customers.**
- **Our network experienced record levels of peak demand in the summers of 2017 and 2018.**
- **We expect our average annual growth in peak demand to be 0.4% in the 2020-25 regulatory control period – this is relatively flat compared with our recent history, although we expect localised areas of the network will continue to experience higher growth. Consequently, we expect augmentation capex to be relatively low for the 2020-25 regulatory control period.**
- **Our modelling approach is being improved. In 2018, ACIL Allen identified several improvements to our modelling methodology. We have engaged Energeia to assist us with the recommendations.**
- **We are managing the uncertainty associated with new and emerging DER and their impact on our network and peak demand.**

5.1 Overview

We expect our customer numbers to increase by 7.68% over the 2020-25 regulatory control period, based on connecting more than 60,000 new customers. This steady growth is illustrated in Figure 11.

Figure 11 Customer numbers



	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
	2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)				
Customer Numbers	689	699	710	722	728	739	746	760	771	782	794	806	818	830	842

While customer growth remains strong, we expect our peak demand growth to be considerably below our historical highs. We expect average annual peak demand growth of 0.38%. Figure 12 illustrates our flat demand forecast. This is a key driver of the capacity that our network must safely and reliably deliver. Consequently, we expect augmentation expenditure to be relatively low for the 2020-25 regulatory control period.

We use temperature corrected demand forecasts at 10% and 50% Probability of Exceedance (POE), depending on whether we are assessing our network under system normal conditions or with elements of plant out of service (N-1) respectively. This helps use the appropriate level of risk to the network scenario. POE10 and POE50 is the temperature corrected demand, corresponding to one year in ten and one year in two (average summer or average winter) conditions.

Figure 12 Demand and Energy trends

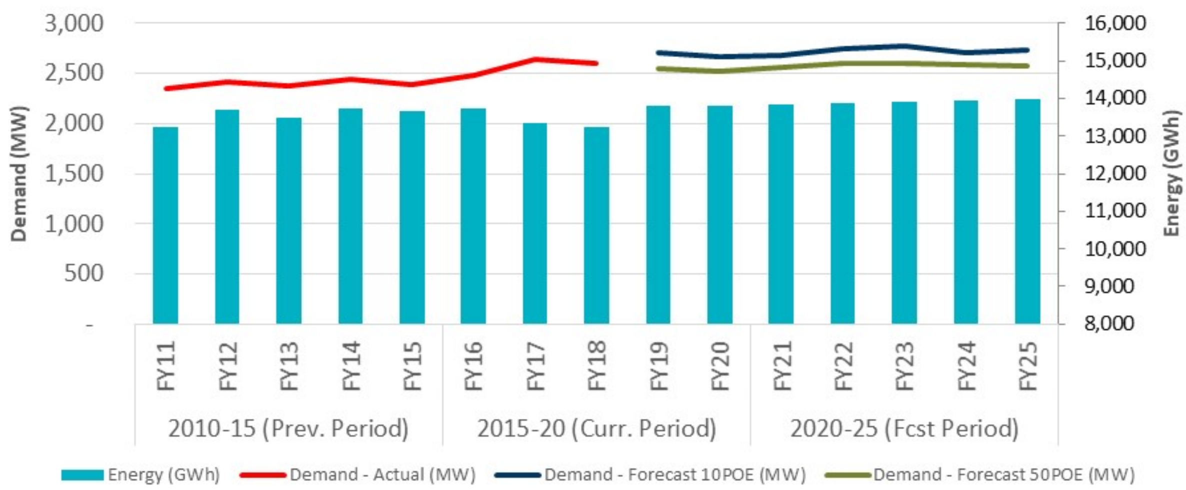


Table 10 provides the historical information presented in Figure 12.Table 11 provides the estimated and forecast information.

Table 10 Historical Demand and Energy

	2010-15 (Prev. Period)					2015-20 (Curr. Period)		
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18
Demand - Actual (MW)	2,349	2,417	2,380	2,441	2,382	2,481	2,637	2,597
Energy - Actual (GWh)	13,227	13,692	13,496	13,716	13,656	13,747	13,332	13,243

Table 11 Estimated and Forecast Demand and Energy

	2015-20 (Curr. Period)		2020-25 (Forecast Period)				
	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Demand - Forecast 10POE (MW)	2,709	2,666	2,679	2,740	2,766	2,711	2,735
Demand - Forecast 50POE (MW)	2,550	2,526	2,560	2,596	2,601	2,580	2,574
Energy - Forecast (GWh)	13,792	13,820	13,849	13,882	13,917	13,945	13,979

5.2 Our customer numbers forecasting approach

We use stepwise regression models to forecast residential customer numbers (national meter identifier counts) and apply the Queensland population as the major driver. The estimated coefficient of the population, together with the forecasted population increases are used to forecast annual changes of residential customer numbers. We typically use population forecasts provided by independent parties such as Deloitte Access Economics.

We apply similar methodologies to forecast non-residential customer number, but use Gross State Product (GSP) or log-GSP, rather than population, as the key driver.

5.3 Our peak demand forecasting methodology

We employ a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts. Our forecasts use validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Demand reductions, delivered via load control tariffs, are included in these forecasts. This provides us with accurate forecasts on which to plan.

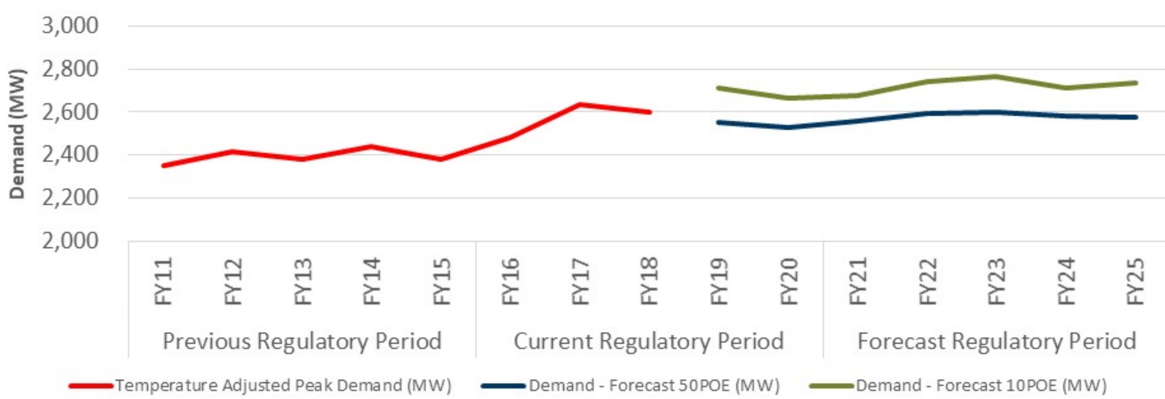
At the end of each summer, we review and update the temperature-corrected system summer peak demand forecasts and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution network. For consistency, the system level peak demand forecast is reconciled with the bottom-up substation peak demand forecast after allowances for network losses and diversity of peak loads. It is the bottom-up substation and feeder demand that drives distribution network investment.

We engage with our regional planning engineers to review, discuss and agree upon growth rates and temperature-corrected starting points for each forecast. We incorporate non-network alternative solutions and other known and anticipated changes in local demand and supply of electricity. It is the local knowledge of planners in the absence of well-defined economic and demographic drivers that ensure the best forecast outcomes at the level of individual zone substations.

For forecasting and network impact analysis, we are currently increasing the granularity of inputs to improve our spatial modelling of zone substation and feeder level demand. We are introducing a tariff scenario simulation, allowing improved accuracy at the localised network level of customer load patterns, tariff selection, and DER adoption. These outputs, in particular, the DER spatial forecasts, will be incorporated into the annual zone substation peak demand forecast from next year, which will in turn flow into expenditure decisions.

Greater detail about the methodology applied to peak demand forecasting at all levels of the network, from transmission to sub-transmission to zone-substations to distribution feeders, can be found in the Distribution Annual Planning Report, chapter 5 (Network Forecasting), section 5.3 (Substation and Feeder Maximum Demand Forecasts). Figure 13 shows our actual annual peak demands for the past 7 years along with our 50% and 10% probability of exceedance forecasts for the period through to 2025.

Figure 13 Actual and Forecast Demand



In 2018, we engaged ACIL Allen to review our adoption of their forecasting methodology, from which they made a number of recommendations. Subsequently, we engaged Energeia to develop a strategic implementation roadmap of these recommendations. Seven recommendations were grouped into three priority areas:

- regionalisation of the existing forecasting solution to match the zones in place for asset planning
- improvement of the method by which DER impacts are modelled in the forecasting process, and
- improvement of the method for weather normalisation and sensitivity of forecasts.

While implementation of these recommendations will take some time, they do not impact the validity of our current forecasting methodology as used for this Regulatory Proposal.

5.4 Our electricity delivered forecasting methodology

Our approach for forecasting electricity delivered is a combination of statistically-based time series analysis, multi-factor regression analysis, and the application of extensive customer knowledge and industry experience. Regression models and consultant reviews are used to substantiate the forecasts, which are separately formulated for residential and non-residential customers, in alignment with their respective network tariffs.

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

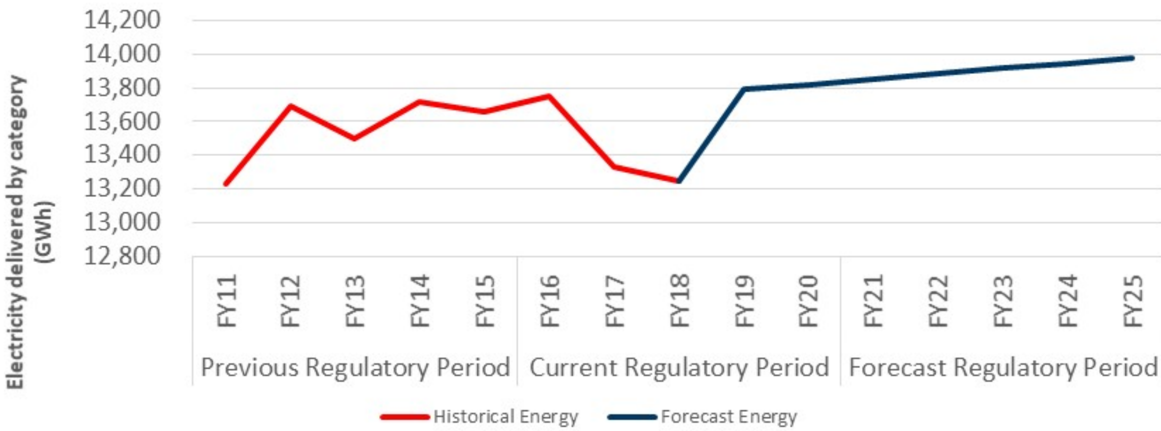
Each category is affected by different underlying drivers for growth. For example, population and income growth are generally of greater significance in driving electricity use in the residential category, whereas growth is more important in the commercial category. Given these sensitivities, we treat the different categories independently, rather than taking a more generalised approach that results in some loss of useful information. Our methodology results in a more robust forecast.

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

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

Forecasts for consumption growth are related to expected changes in GSP and the trend in changing average consumption. Electricity delivered is predicted to grow at an average of 0.4% per annum over the 2020-25 regulatory control period. Figure 14 provides a graphical representation of this electricity growth.

Figure 14 Total Electricity Delivered



5.5 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Demand Review Energy Queensland	5.001	EGX ERG 5.001 ACIL ALLEN Demand Review Energy Queensland APR18 PUBLIC
Demand Forecast Summary Recommendations	5.002	EGX ERG 5.002 Demand Forecast Summary Recommendations JAN19 PUBLIC

6. Operating Expenditure forecasts

Key Messages

- **Our forecast total opex for the 2020-25 regulatory control period is $1,835 million. This is $44.66 million higher than what we included in Our Draft Plans ($1,790 million) that we published in September 2018.**
- **We have adopted the AER's preferred Base-Step-Trend (BST) approach to developing our forecast opex, other than for debt raising costs where we have adopted category specific forecasts.**
- **Our proposed base year is 2018-19 – we have estimated this amount for use in this Regulatory Proposal. We forecast our opex will be $13 million below the AER's allowance for this year, reflecting the cost reductions achieved since the merger of Energex and Ergon Energy under the Energy Queensland banner.**
- **Even before making adjustments for restructuring costs, ongoing post-merger savings, and the application of our AER-approved Cost Allocation Method (CAM), our base year is efficient when tested against the econometric models considered in the AER's 2018 Annual Benchmarking Report.**
- **We recognise that we can achieve further cost reductions. We are proposing a productivity saving of 14% over the regulatory control period, or 2.58% per annum, based on a top-down management initiative targeting a 10% saving in Energy Queensland indirect costs, and a 3% improvement in our program or works over the 2020-25 regulatory control period. Together, our management-led savings equates to $223.4 million of cost savings over the 2020-25 regulatory control period.**
- **We are not proposing any step changes.**

6.1 Overview

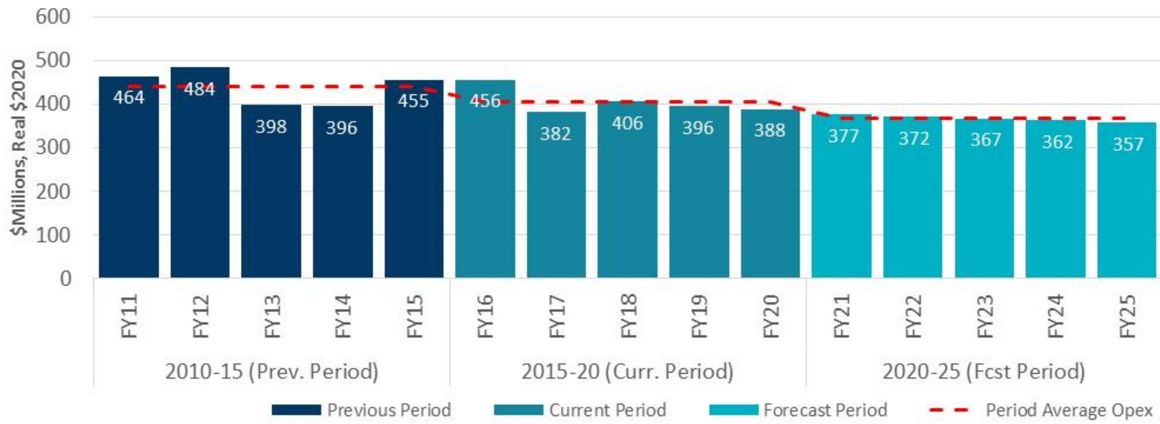
Our opex associated with managing the network includes inspections, maintenance and vegetation management, emergency response and other non-network costs, such as customer service/call centres, fuel and technical trade training that we need to deliver our distribution services.

We forecast the opex required to deliver our SCS as an input to our revenue requirements for the 2020-25 regulatory control period using the AER-preferred BST approach.

Our opex forecast must comply with the NER requirement for us to submit a prudent and efficient opex forecast that is consistent with maintaining the quality, reliability and safety of the network and network services. We must meet the service obligations in our Distribution Authority and the Queensland Electricity Distribution Network Code as well as our customers' reasonable expectations that we should maintain the safety and reliability of our distribution services.

Our actual and forecast opex for each year of the 2010-15, 2015-20 and 2020-25 regulatory control periods are shown in Figure 15.

Figure 15 Historical and forecast opex (includes debt raising costs)



Note: Previous and current period data is presented on a like for like basis (adjustments for CAM, classification of services and reporting) with forecast period, so AER allowance is not comparable.

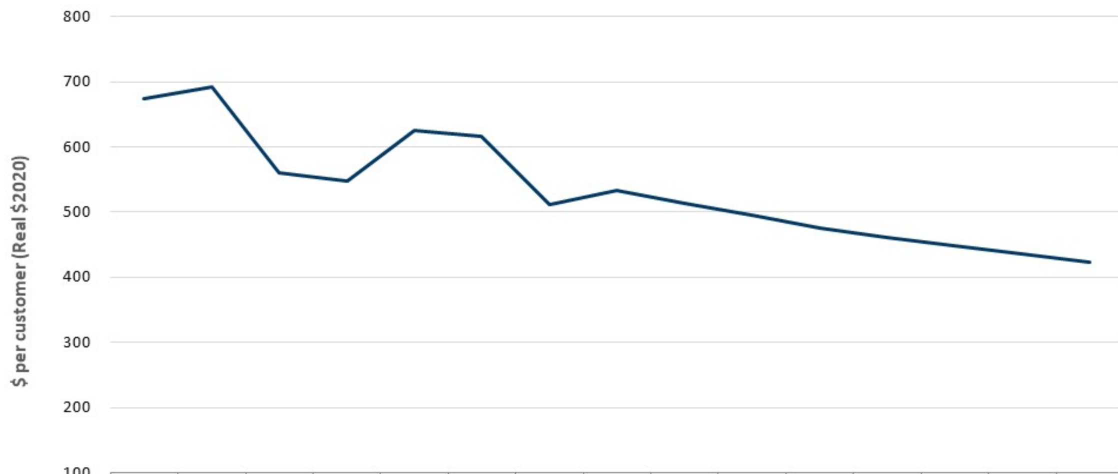
Table 12 compares our Regulatory Proposal opex with the opex included in our Draft Plans, and outcomes from the previous (2010-15) and current (2015-20) regulatory control periods.

Table 12 Opex comparison (includes debt raising costs)

$M, Real $2020	2010-15	2015-20	2020-25
Regulatory Proposal		2,286.45	1,834.64
AER Final Decision Allowance	2,243.16	1,927.23	
Actual/forecast	2,534.88	1,956.43	
Draft Plan			1,760.85
% change over 2015-20 forecast			-6%

We expect our actual and estimated opex to be over the AER's opex allowance for the 2015-20 regulatory control period by $29.2 million. However, our opex is declining and we expect to underspend the AER's opex allowances in the final two regulatory years of the current regulatory control period (i.e. 2018-19 and 2019-20) by a total of $40.2 million. We expect our opex to continue to trend downwards in the 2020-25 regulatory control period, as we set ambitious targets following our merger with Energex to further reduce our distribution network charges for the benefit of our customers. Figure 16 highlights the significant actual and planned reduction in our opex costs on a per customer basis.

Figure 16 Opex (excluding debt raising costs) per customer



	Period	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24
		2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)			
Opex Per Customer	673	692	560	548	625	616	512	534	513	496	475	461	449	436	424

6.2 What we have heard from our customers

In developing our opex plans for the 2020-25 regulatory control period, we have considered how best to address the feedback we have received from our customers outlined in chapter 2 and explained further in our 2020 and Beyond Community and Customer Engagement Report. In particular:

- customers recognise the value of investing in new technology and that it is important to have a modern network that enables customer technology solutions
- overall, our customers want us to maintain, but not to improve, reliability performance. The exception is for the mainly rural and remote customers currently who are currently receiving below standard service
- customers want better communication around power outage notifications – both planned and unplanned (e.g. text communication), and
- our future opex will include expenditure on demand management capabilities and collaboration with the market on new solutions seen to better manage the network into the future.

6.3 The nature and drivers of our opex

Our Expenditure Forecasting Methodology that we submitted to the AER in June 2018 explained that we have six opex categories, which are described in Figure 17 below.

Figure 17 Categories of opex

RIN Category	Service Description
Vegetation management	• Planned programs and reactive maintenance activities in managing vegetation to provide a safe and reliable network
Maintenance	• Inspection programs to detect potential defects requiring remedial response. • Maintenance plans to ensure delivery of supply, reliability, security and safety objectives.
Emergency response	• Works undertaken after a failure of an asset to either restore the network to a state in which it can perform its required function or render the installation safe • Repair of damaged equipment and all storm-related repairs.
Non-network	• Expenditure relating to IT and communications assets, non-network buildings and property assets, fittings and fixtures, and other non-network assets
Network overheads	• Overhead costs including the provision of network, control and management services that cannot be directly identified with a specific operational activity (eg. network management, planning, network control and operational switching personnel, quality and standards functions, network billing, customer services, demand side management, levies etc.)
Corporate overheads	• Provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity (eg. executive management, legal, HR, finance, debt raising etc)

The key drivers of our opex include:

- security, performance and reliability needs of customers
- inspecting and maintaining assets to ensure that they are operating safely and efficiently over their lifetimes
- meeting legislative requirements
- responding to storm and severe weather events to restore supply
- meeting growth in our network as measured by the number of connected customers, line length and the ratcheted maximum demand of our customers
- actively managing vegetation near our assets, and
- addressing aging infrastructure and asset-related safety hazards.

Our opex forecast is our response to these drivers so that, together with our capex forecast, we manage our overall network risk and deliver the service performance outcomes that our customers expect and value.

Ergon Energy's expenditure forecasting process systematically consider the trade-offs between opex and capex through various ways including design and maintenance standards, equipment specification, options analysis of replacement capex and demand management programs. This approach ensures that the efficient trade-off between opex and capex has been considered at both an individual component level (e.g. equipment specification), a project level (e.g. replacement decisions) and a network level (e.g. our demand management programs). Details of the opex-capex trade-offs are set out in Attachment 4.002.

6.4 Key opex assumptions

Table 13 details the key assumptions underpinning our opex forecasts. These have been endorsed by our Directors.

Table 13 Key opex assumptions

Issue	Assumption
1. Structure and ownership	Our opex forecasts are based on our current company structure and ownership arrangements.
2. Legislative and regulatory obligations	Our opex forecasts are based on our current legislative and regulatory obligations and our Distribution Authority.
3. Service classification and ring-fencing	We will apply the service classification in the AER's F&A paper and the current ring-fencing arrangements will not change materially.
4. Customer preferences and expectations	The preferences and expectations of participants revealed through our stakeholder engagement program accurately reflect those of our customers generally.
5. Addressing customer concerns about affordability	Our opex forecasts have particular regard for the affordability of electricity supply and appropriately respond to our customers' concerns.
6. Service outcomes	We will maintain, but not improve, our average system-wide service outcomes, consistent with clause 6.5.6(a) of the NER.
7. Forecast opex	Our opex forecasts are required to deliver the safety, reliability and customer outcomes set out in our Regulatory Proposal.
8. Customer numbers	Our customer numbers forecast provides an appropriate approach for determining our opex rate of change.
9. Cost allocation	Our CAM provides an appropriate basis for attributing and allocating costs to, and between, our distribution services.
10. Inflation	Our forecast inflation is reasonable and reflects the inflation-related costs that we will incur.
11. Opex base year	The financial year 2018-19 is an appropriate base year for our opex forecast and, subject to our proposed adjustments, is reasonably representative of our recurrent prudent and efficient future opex requirements.
12. Opex trend assumptions	Our forecast changes in input costs, output growth and productivity are reasonable and appropriately reflect the trend in our future opex, given our (adjusted) opex base year.
13. Cost pass through and contingent projects	The AER will approve our nominated pass through events and we will not have any contingent projects.

Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6.2.1(6) of the NER, as discussed in section 16.4 of this Regulatory Proposal.

6.5 AER requirements and approach

Under the NER, the AER must either accept or not accept our forecast opex for the 2020-25 regulatory control period in this Regulatory Proposal. The AER must accept our forecast opex if it is satisfied that the forecast reasonably reflects the opex criteria in clause 6.5.6 of the NER.

The AER indicated in its F&A paper that it intends to have regard to the following assessment / analytical tools set out in the Expenditure Forecast Assessment Guideline in reviewing our opex forecasts:

- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis, and
- cost benefit analysis and detailed project reviews.

The AER's need to consider benchmarking arises from the opex factors in clause 6.5.6 of the NER, which include, amongst other things, the most recent annual benchmarking report and the benchmark opex that would be incurred by an efficient DNSP over the regulatory control period. Section 0 discusses benchmarking and Attachment 6.004 addresses how we comply with the opex factors.

6.6 Our opex forecasting approach

We have used a BST approach to forecast our opex for the 2020-25 regulatory control period, except for our debt raising costs. This is consistent with the approach that we proposed in our Expenditure Forecasting Methodology that was submitted to the AER on 29 June 2018 and the AER's preferred approach for forecasting opex, as detailed in its Expenditure Forecast Assessment Guideline.

A BST approach involves forecasting opex at an aggregate level, rather than preparing individual forecasts for each category of opex. The BST approach involves the following stages:

- Nominating a base year
- Applying adjustments to remove non-recurrent and other expenditure from the base year
- Applying rate of change adjustments to the adjusted base year opex for:
    - growth in labour and non-labour prices
    - growth in output, and
    - productivity improvements
- Applying step changes.

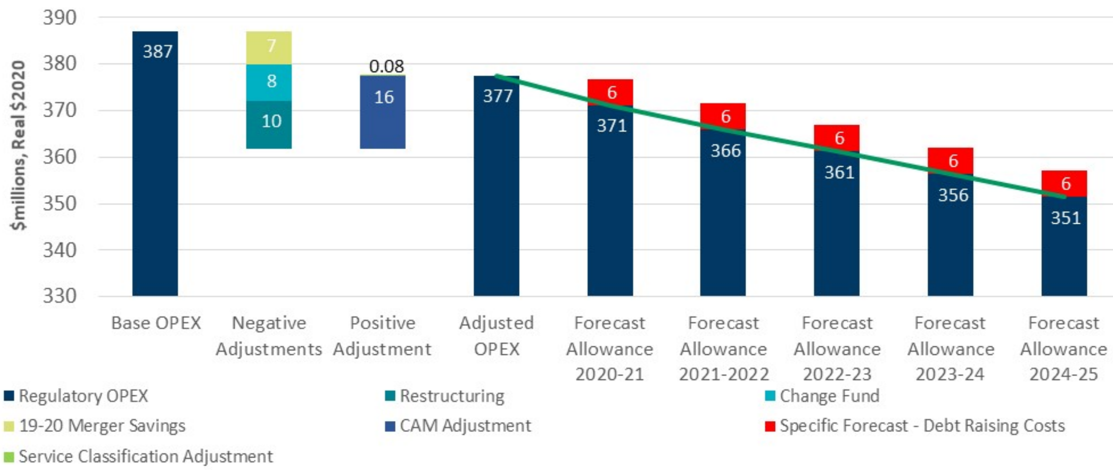
Our forecast opex for the next period is 9.5% below what we expect to spend in the current period.

We are not forecasting any step changes and, to the extent that we incur any over the 2020-25 regulatory control period, we will need to achieve offsetting cost savings, except in the case of pass through events, which we discuss in section 12.2.

For our forecast debt raising costs, we applied the year-on-year benchmark method, as explained in section 6.11. This is because actual debt raising costs in our base year are not necessarily representative of future costs and may not reflect benchmark costs – we have therefore removed debt raising costs from our base year. In forecasting our debt raising costs, we used the post-tax revenue model (PTRM) to forecast the incremental costs for each year of the 2020-25 regulatory control period and add them to the output of the BST method.

Figure 18 illustrates the build-up of our opex forecast for the 2020-25 regulatory control period, which shows that our opex will continue to trend down over the 2020-25 regulatory control period. Table 16 provides a detailed numerical breakdown of our opex forecast.

Figure 18 Forecast opex



6.7 Base year

6.7.1 Choice of base year and base year adjustments

We selected 2018-19 as our base year because it represents a realistic expectation of the efficient and sustainable on-going opex that is required to provide our SCS in the 2020-25 regulatory control period. We chose 2018-19 because:

- It continues the well-accepted regulatory practice of using the most recent year for which audited data is available by the time of the final Distribution Determination. Choosing a prior year would require significant adjustments to ensure that it reflects our current and future expected base opex. This would include removing merger and other efficiency savings realised since the prior year and the 2018-19 year
- It is the first year where our operations – and associated costs – largely reflect a harmonised approach following the establishment of Energy Queensland and our merger with Energex. Choosing a prior year would require significant adjustments to reflect the incomplete nature of the business merger savings. We have incorporated expected 2019-20 savings into our forecast to ensure that they are passed on to our customers, and
- We have achieved efficiencies over the 2015-20 regulatory control period through the merger savings achieved in Energy Queensland. Therefore, our 2018-19 opex base year estimate is below the efficient opex forecast determined by the AER for the 2015-20 regulatory control period.

We note that the AER deemed that it was appropriate to use revealed costs to set our opex allowances for the 2015-20 regulatory control period, which meant that it was appropriate also to apply the EBSS to this period. Our forecast underspend in the final two regulatory years of the current regulatory control period against the AER's allowance shows that we are responding appropriately to the incentives under the AER's EBSS.

We have had to estimate our 2018-19 opex for use in this Regulatory Proposal, as actual data is not available at this time. We will update our base year opex forecast in our Revised Regulatory Proposal in response to the AER's draft Distribution Determination, by which time our actual 2018-19 opex will be known.

We have made the following adjustments to our opex base year:

- Added $15.8 million for changes in our CAM and service classification.
- Deducted $25.4 million for:
  - Non-recurring costs (i.e. change costs that we incur to improve our business), and
  - Post-merger savings expected in 2019-20.

These adjustments reduce our opex base year from $387 million to $377 million. Our 2018-19 opex base year does not include any forecast provisions. We propose to remove changes in provisions from our actual 2018-19 base year opex when we update our base year for actual opex in our Revised Regulatory Proposal.

6.7.2 Forecast base year opex

Table 14 details our forecast opex base year, including adjustments, for the 2020-25 regulatory control period.

Table 14 Forecast base year opex

$M, Real $2020	2020-21
Pre-adjustments base year opex	387.09
Adjustment for cost allocation	15.73
Adjustment for service classification changes	0.08
Removal for one off costs (non-recurring and restructuring)	-18.13
Reduction for expected merger savings in 2019-20	-7.27
Post adjustments base year opex	377.50

6.7.3 Recent AER benchmarking

The AER released its Annual Benchmarking Report for electricity DNSPs in December 2018, which shows that we have improved our relative benchmark performance, as measured against other DNSPs in the National Electricity Market (NEM), and we are now in the middle group of efficient networks in terms of opex efficiency in 2017. In particular, the AER's 2018 Benchmarking Report shows that:

- We achieved a 7% multilateral total factor productivity improvement (MTFP) in 2017 and were recognised by the AER as one of the three most improved DNSPs.[5] We improved our ranking to 6th of the 13 DNSPs (from 8th in 2016).
- We improved our efficiency in 2017 based on the multilateral partial factor productivity (MPFP) analysis. After taking into the account of differences in operating environments, the AER concluded that we are amongst the middle group of efficient networks in terms of opex efficiency in 2017 and over the past six years.[6]

[5] AER, Annual Benchmarking Report, Electricity distribution network service providers, November 2018, pages iii

[6] Ibid, page 20

The AER's 2018 benchmarking report provides limited guidance on how it intends to use benchmarking in assessing our opex forecasts. However, in its November 2018 draft Distribution Determination for the NSW DNSPs, the AER's assessment of base year opex was based on the results of the following economic benchmarking models — Cobb-Douglas stochastic frontier analysis, Cobb-Douglas least squares econometrics, Translog stochastic frontier analysis and Translog least square econometrics. These are presented in Figure 5.1 of page 31 of the AER's 2018 Annual Benchmarking Report. We welcome the AER's latest approach of relying on a broad range of evidence, which we consider to be preferable to the AER's previous approach of relying solely on the results of its Cobb-Douglas stochastic frontier analysis model.

As we have a challenging operating environment, the assessment of Operating Environment Factors (OEFs) will play an important role in the AER's benchmarking. The AER's 2018 benchmarking report provides limited guidance on how it intends to account for OEFs in its benchmarking models. However, we understand from its approach for the NSW DNSPs that the AER will apply an OEF adjustment for us consistent with its Distribution Determination for our 2015-20 regulatory control period. On this basis, our OEF adjustment would be 26.2%.

A 26.2% OEF adjustment would account for OEFs that are relevant to us but are excluded from the economic benchmarking models presented in the latest annual benchmarking report, such as sub-transmission, division of responsibility for vegetation management, severe weather events, network accessibility, taxes and levies and termite exposure. Other factors accounted for in this 26.2% OEF adjustment include building regulations, capitalisation practices, competition from mining, corrosive environments, cultural heritage, environmental regulations, grounding conditions, occupational health and safety regulations, planning conditions, proportion of 11Kv and 22Kv lines, rainfall and humidity, skills required by different DNSPs, solar uptake, termite exposure, topography, traffic management, asset age, bushfires, environmental variability, private power poles, and transformer capacity owned by customers.

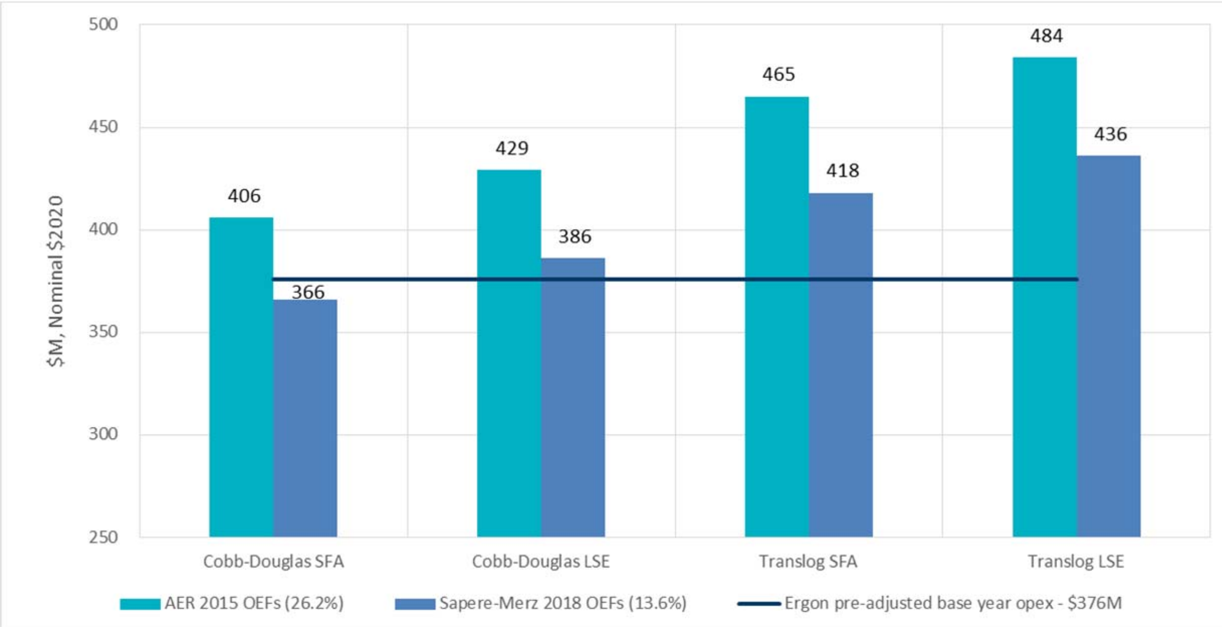
The AER is currently consulting further on how OEFs can be quantified. It published a report by Sapere-Merz in September 2018, which assesses three OEFs that are relevant to us – being sub-transmission, taxes and levies and termite exposure. We note that this is a limited subset of the OEFs previously considered by the AER in 2015. The illustrative OEF adjustment proposed for these three OEFs is 13.6%.

In our view, Sapere-Merz's report significantly underestimates the OEFs adjustments that are necessary to explain the vast differences in the operating environment of the different DNSPs in the NEM. We were therefore pleased to see that the AER is using its 2015 assessment of OEFs as the basis of its draft Distribution Determination for NSW distributors, rather than the OEF adjustments presented by Sapere-Merz. However, we understand it may be because Sapere-Merz's work includes only a limited subset of relevant OEFs and is too preliminary and illustrative at present. Our view is confirmed by recent work undertaken for us by Frontier Economics (Attachment 6.009) that sets out a framework for assessing OEFs and highlights some of the limitations with the Sapere-Merz's work.

We have cross-checked our pre-adjustments base year opex of $387.1 million with the AER's latest economic benchmarking models described above to see if there is any evidence that our opex is materially inefficient. Our cross-check used both the AER's 2015 OEF adjustment of 26.2% as well as the preliminary and conservative Sapere-Merz OEF adjustment of 13.6%.

As Figure 19 shows, the AER's most recent economic benchmarking analysis indicates that our pre-adjustments base year opex of $387.1 million is efficient, and that there is no justification for the AER to make a further base year efficiency adjustment. This is true even under the highly conservative OEF adjustment of 13.6%, which covers only three of our many relevant OEFs.

Figure 19 Cross-check of Ergon Energy's proposed base year opex with the AER's latest economic benchmarking models



Note: The horizontal blue line shows Ergon Energy's pre-adjusted Base Year Opex expressed in FY2020 (mid-year) dollars of $376 million. Converted to year end dollars and adding the expected change from 2018-19 to 2019-20 gives the $387.1 million shown in Table 14. A description of each econometric model specification is included in the Frontier Economics report. Source: Frontier Economics benchmarking report at Attachment 6.002.

Figure 19 shows that the range of estimated efficient opex from the AER's four economic benchmarking models for various model specifications is:

- between $406 million and $484 million, when an OEF adjustment of 26.2% is used; and
- between $366 million and $436 million, when a conservative OEF adjustment of 13.6% is used.

In summary, this analysis indicates that our proposed 2018-19 base year opex is prudent and efficient for the safe and reliable provision of our SCS.

Further detail on how our base year opex compares to economic benchmarks is included in the Frontier Economics report at Attachment 6.002 and discussed in Attachment 6.003.

6.7.4 Category analysis benchmarking

We note that our initial category analysis benchmarking indicates:

- indirect costs and maintenance costs are not materially inefficient compared to other Australian DNSPs, and lower than some
- emergency response costs appear higher than for some DNSPs, primarily because of the severe weather that we can face across a broad network coverage area and subsequent mobilisation of resources to respond to our customers restoration expectations
- vegetation management costs appear comparable with other DNSPs after adjustments for operational factors.

Attachment 6.003 provides more details on our economic and category analysis benchmarking and why our opex base year is efficient.

6.8 Rate of change – price

Our base year opex reflects the current prices of our cost inputs. The BST approach adjusts this base year opex to account for forecast real changes in input costs over the 2020-25 regulatory control period.

Our trend adjustments have taken the average of the real labour escalator forecasts from BIS Oxford and Deloitte Access Economics (DAE), being 0.85% on average per year over the 2020-25 regulatory control period. We commissioned BIS Oxford to provide us with real labour escalator forecasts and adopted the DAE forecasts used by the AER in its draft Distribution Determination for the NSW distributors, expecting that the AER will commission DAE labour forecasts for Queensland in due course.[7]

We have applied a labour cost escalator of 0.26% on average per annum to reflect our management commitment to improve our program of works by 3% over the 2020-25 regulatory control period. This will be achieved by the digitisation of our business processes, delivering improved work scheduling and improved corporate processes.

As recognised in past AER decisions, using a labour (or wage) price index as we propose builds in some assumed labour productivity. We have not sought to quantify this but it adds to our proposed top down management savings.

We have not included any real material cost escalators in our forecast.

Table 15 details the forecast average annual change in cost for each year of the 2020-25 regulatory control period.

Table 15 Forecast price growth 2020-21 to 2024-25

Per cent	2020-21	2021-22	2022-23	2023-24	2024-25
BIS Oxford real labour forecast	0.50%	0.80%	1.30%	1.40%	1.40%
Deloitte Access Economic real labour forecast	0.06%	0.57%	0.83%	0.84%	0.84%
Average real labour forecast	0.28%	0.68%	1.07%	1.12%	1.12%
Less 3% management commitment (productivity)	0.59%	0.59%	0.59%	0.59%	0.59%
Adjusted real labour forecast (62% weight)	-0.31%	0.09%	0.47%	0.52%	0.52%
Real other forecast (38% weight)	0.00%	0.00%	0.00%	0.00%	0.00%
Price growth	-0.19%	0.05%	0.28%	0.31%	0.31%

6.9 Rate of change – outputs

Our base year opex reflects our current outputs. The BST approach adjusts this base year opex to account for forecast output levels over the 2020-25 regulatory control period.

We have included an allowance in our opex forecast for the impact of output growth in the 2020-25 regulatory control period, consistent with the AER's standard approach. This reflects the fact that delivering greater outputs costs more to operate and maintain.

We have applied the output change measures and respective weightings in the Economic Insights report[1] released with the AER's 2018 benchmarking report, including for the impact of economies of

7 AER – NSW DETERMINATIONS – Draft Decision – opex model – September 2018_0 - Excel, Input | rate of change.
[1] Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, 10 August 2018

scale. The four output growth measures are set out in Table 16. These are weighted to calculate the average output growth shown (in bold) in the same table. The weights used to calculate that average are shown in Table 17.

Table 16 Forecast output growth 2020-21 to 2024-25

Per cent	2020-21	2021-22	2022-23	2023-24	2024-25
Output Measures					
Customer numbers	1.42%	1.51%	1.50%	1.49%	1.49%
Circuit length	1.06%	0.50%	0.50%	0.50%	0.50%
Ratcheted maximum demand	1.06%	0.85%	0.62%	0.00%	0.00%
Energy	0.21%	0.24%	0.25%	0.20%	0.24%
Average Output Growth (using the average weights in Table 17)	**1.13%**	**1.13%**	**1.07%**	**0.92%**	**0.92%**

Table 17 Output weights by economic model

Per cent	SFA CD	LSE CD	LSE TLG	MPFP	Average
Output Measures					
Customer numbers	70.80%	67.56%	51.48%	31.00%	55.21%
Circuit length	16.80%	11.81%	13.86%	29.00%	17.87%
Ratcheted maximum demand	12.40%	20.63%	34.66%	28.00%	23.92%
Energy	0.00%	0.00%	0.00%	12.00%	3.00%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Note: The labels for the four models shown are abbreviated: 'SFA' means Stochastic Frontier Analysis; 'CD' means Cobb Douglas; 'LSE' means Least Squares; 'TLG' means Translog; and 'MPFP' means Multilateral Partial Factor Productivity. These terms are explained further in the Economic Insights report.

6.10 Rate of change – productivity

We have delivered significant efficiencies in our opex over the 2015-20 regulatory control period, as we discussed in section 3.2, and are committed to pursuing further savings in the 2020-25 regulatory control period. We have also removed expected incremental merger savings from 2018-19 to 2019-20 from our base opex (as shown in Table 14) even though we have not benefited from these yet.

We are proposing a positive productivity saving based on the Energy Queensland top-down management initiative of 10% total indirect cost savings, and other targeted cost reductions, which results in an overall productivity saving of 14% over the 2020-25 regulatory control period, or 2.58% per annum, as set out in Table 18.

In this way, the savings will be progressively achieved through a structured program delivered throughout 2020-25. We expect that, because of our targeted productivity savings, we will at least maintain our relative performance as benchmarked against our peers, with an aspiration to improve.

Table 18 Forecast productivity 2020-21 to 2024-25

Per cent	2020-21	2021-22	2022-23	2023-24	2024-25
Productivity saving	2.58%	2.58%	2.58%	2.58%	2.58%

In its recent decisions, the AER has applied a zero per cent productivity factor based on recent productivity trends and advice from Economic Insights. However, we note that in its November 2018 draft decision paper on "Forecasting productivity growth for electricity distributors", the AER foreshadowed its intention to use an opex productivity growth forecast of 1% for its next Distribution Determinations for each DNSP. Our proposed productivity savings over the regulatory control period should be considered instead of (rather than additional) to that considered by the AER. Our targeted productivity assumption of 14% over the regulatory control period is based on our assessment of being able to achieve the resulting level of opex and continue to deliver services that our customers expect which meets our regulatory obligations. That assumption is based on information available to us at the time we submit this Regulatory Proposal, including the status of the AER's review of productivity which is not expected to be completed until after we submit.

If circumstances change between the dates of this Regulatory Proposal and when we submit our Revised Regulatory Proposal – including following the AER's findings on productivity and its draft determination – we reserve the right to reassess whether our proposed productivity assumption enables us to deliver the services that our customers expect from us while meeting our regulatory obligations, and if necessary, amend our targeted productivity assumption in our Revised Regulatory Proposal. Our assessment will also include the impact of the AER's Draft Decision on other aspects of our Regulatory Proposal including whether we are able to make the investments necessary to achieve these productivity improvements. Our views on how the AER should determine the productivity factor are set out in our submission to the AER on this matter.

6.11 Specific or category forecasts

Debt raising costs are the costs of issuing debt, including the costs of maintaining an investment credit rating needed to issue this debt. We estimated the debt raising costs using the method adopted by the AER in its recent Distribution Determinations, as set out in the PTRM. We propose a debt raising cost unit rate of 8.05 basis points.

The calculation of our debt raising costs is set out in section 9.3.1. Table 19 sets out our forecast debt raising costs based on 8.05 basis points.

Table 19 Forecast debt raising costs 2020-21 to 2024-25

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Debt raising costs	5.62	5.66	5.71	5.75	5.79	28.53

Total may not add due to rounding.

6.12 Our opex forecast

Table 20 details our BST forecast opex over the 2020-25 regulatory control period, which is a summation of the above components.

Table 20 Forecast opex, 2020-21 to 2024-25

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Base	387.09	387.09	387.09	387.09	387.09	1,935.43
Net Base Year Adjustments	-9.59	-9.59	-9.59	-9.59	-9.59	-47.94
Output Growth	4.34	8.92	13.56	17.76	22.20	66.77
Price Growth	-0.72	-0.52	0.60	1.90	3.27	4.53
Productivity Growth	-9.91	-19.98	-30.36	-40.86	-51.58	-152.69
Step Changes	0.00	0.00	0.00	0.00	0.00	0.00
Debt raising costs	5.62	5.66	5.71	5.75	5.79	28.53
Total	**376.83**	**371.57**	**367.01**	**362.06**	**357.17**	**1,834.64**

Note: Totals may note add due to rounding.

6.13 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Demand Management Plan	6.001	EGX ERG 6.001 Demand Management Plan JUN18 PUBLIC
Benchmarking independent expert report	6.002	EGX ERG 6.002 Frontier Economics Benchmarking independent expert report JAN19 PUBLIC
Base Year Opex Overview	6.003	EGX ERG 6.003 Base Year Opex Overview JAN19 PUBLIC
Cost allocation method	6.004	EGX ERG 6.004 Cost allocation method NOV18 PUBLIC
Escalations independent expert report	6.005	EGX ERG 6.005 BIS Oxford Economics Escalations independent expert report JUN18 PUBLIC
Escalations independent expert report	6.006	EGX ERG 6.006 Deloitte Access Economics Escalations independent expert report JUL18 PUBLIC
Opex forecast – SCS	6.008	ERG 6.008 Opex forecast – SCS JAN19 PUBLIC
OEFs independent expert report	6.009	EGX ERG 6.009 Frontier Economics OEFs independent expert report JAN19 PUBLIC

7. Capital expenditure forecasts

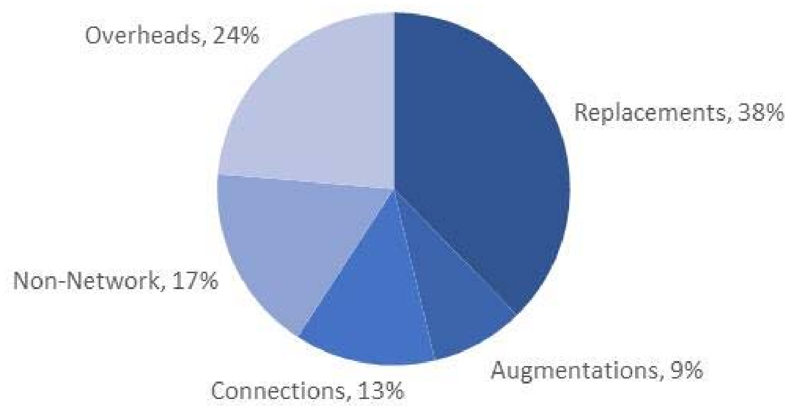
Key Messages

- **Our proposed capex for the 2020-25 regulatory control period is $2,905 million and is line with our estimated capex of $2,843 million for the current regulatory control period.**
- **We are committed to investing capital prudently and efficiently on behalf of customers. Our capex focus for the 2020-25 regulatory control period is to deliver:**
  - **A no-compromise approach to community and staff safety, leveraging innovative solutions that enable continuous improvement**
  - **Sustainable investment to avoid the historical boom-bust cycle and associated future bill shocks, appropriately manage aged assets, and maintain our reliability and security standards while continuing to find cost efficiencies in investments**
  - **Investments which support the transition to the future by evolving the network to best enable customer choice in their electricity supply solutions, such that we can integrate solar, batteries and other technologies with the network in a way that is cost effective and sustainable, whilst incorporating non-network alternatives, and**
  - **Prudent investment in fit-for-purpose non-network assets to support our staff in efficiently delivering services to our customers.**
- **Our replacement capex (repex) will form the largest component of our proposed system capex as we continue to responsibly replace and upgrade poor condition assets informed by a mature risk management approach.**
- **Our connections capex forecast reflects our most recent lower expenditure levels. We expect that connections capex levels will remain at these levels for the foreseeable future as we unwind from the mining boom.**
- **Our augmentation capex (augex) forecast reflects the changing nature of our network, with an overall reduction in expenditure despite ongoing peak demand and customer growth. We are focusing on augmenting key localised growth areas, and investing to support the transition to an intelligent grid in areas such as network control and monitoring**
- **Our non-network ICT investment will enable the continued transformation of our business and support the delivery of opex savings. We will benefit from the increased functionality embedded within new software packages**
- **Our investment in fleet and property assets enables us to deliver services to our customers in line with community and customer expectations of value for investment through targeted programs to support optimal lifecycle, asset risk and functional operations**
- **We have forecast our capitalised overheads using the BST approach applied to opex.**

7.1 Overview

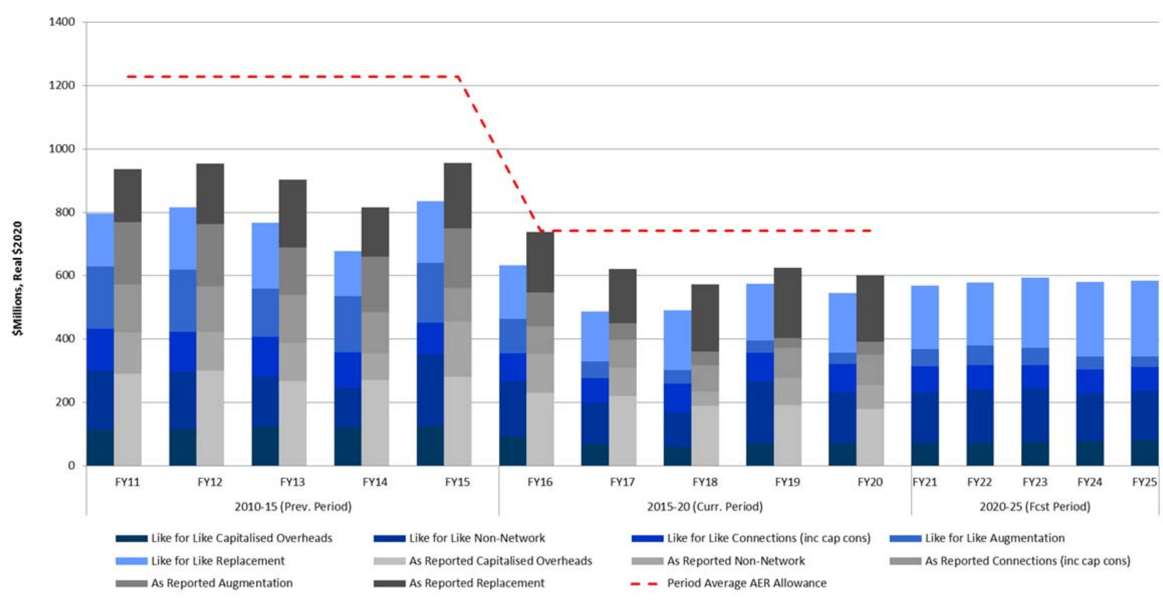
Figure 20 details our forecast capex over the 2020-25 regulatory control period. Figure 21 shows trends in our gross capex by category over the 2010-15, 2015-20 and 2020-2025 regulatory control periods.

Figure 20 Forecast capex category proportions



Note: Totals may not sum to 100% due to rounding

Figure 21 Capex trends compared to AER allowance



Note: Previous and current period data is presented on a like for like basis (adjustments for CAM, classification of services and reporting) with forecast period, so AER allowance is not comparable.

The data supporting Figure 21 is provided in Table 21 and Table 22.

Table 21 Capex trends compared to AER allowance – previous and current regulatory control periods

$M, Real $2020	2010-15 (Prev. Period)					2015-20 (Curr. Period)				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20
As Reported Replacement	166.34	190.58	214.35	157.24	205.72	191.00	173.01	212.34	222.90	210.27
As Reported Augmentation	196.16	197.75	150.34	175.54	190.08	107.49	52.45	41.48	30.98	40.95
As Reported Connections (inc cap cons)	153.10	144.22	151.13	128.62	103.95	87.58	87.24	84.36	95.11	95.50
As Reported Non-Network	128.79	122.72	121.19	84.54	176.48	122.67	89.13	45.05	84.74	75.71
As Reported Capitalised Overheads	291.02	299.18	266.82	270.61	279.41	229.15	219.89	188.32	191.74	179.89
Period Average AER Allowance	1,227.50	1,227.50	1,227.50	1,227.50	1,227.50	742.29	742.29	742.29	742.29	742.29
Like for Like Replacement	168.37	196.80	209.79	142.64	194.88	170.72	159.06	189.15	179.75	187.54
Like for Like Augmentation	196.16	197.75	150.34	175.54	190.08	142.28	132.02	41.48	38.36	35.58
Like for Like Connections (inc cap cons)	129.93	123.83	125.36	113.65	97.79	88.88	75.95	91.78	89.04	89.32
Like for Like Non-Network	189.22	183.60	158.80	127.13	227.70	174.10	132.12	109.58	196.44	161.37
Like for Like Capitalised Overheads	113.30	114.18	123.50	118.22	125.40	92.10	67.60	58.14	70.48	70.48

Table 22 Capex trends compared to AER allowance – forecast regulatory control period

$M, Real $2020	2020-25 (Fcst Period)				
	FY21	FY22	FY23	FY24	FY25
Like for Like Replacement	200.13	199.65	221.34	234.16	239.13
Like for Like Augmentation	55.53	61.52	56.14	42.32	33.00
Like for Like Connections (inc cap cons)	79.33	76.75	72.77	73.02	74.04
Like for Like Non-Network	162.88	168.57	169.91	153.40	157.50
Like for Like Capitalised Overheads	70.94	72.04	73.93	76.59	80.09

Figure 21 presents our actual capex for our 2010-15 regulatory control period, forecast actual capex for the current 2015-20 regulatory control period and our capex forecast for 2020-25 regulatory control period. It shows that we are forecasting:

- A 27.0% reduction in our capex in the 2015-20 regulatory control period from the 2010-15 regulatory control period

- Our capex will be 16% below the AER's allowance in the 2015-20 regulatory control period, and
- Our capex in the 2020-25 regulatory control period will be:
  - o 6% above our estimated capex in the current period
  - o 22% below the AER's allowance in the current period, and
  - o 25% below our actual capex in the 2010-15 regulatory control period.

These trends reflect the fact that we had sustained real growth in our capex between 2005 and 2015, largely in response to increased reliability standards, which contributed to strong growth in our RAB. This is shown in Table 23.

Table 23 Capex trends by category

$M, Real $2020	2010-15	2015-20	2020-25
Replacement	912.49	886.23	1,094.41
Connections (incl capital contributions)	590.56	434.98	375.91
Augmentation (incl Reliability)	909.87	275.36	248.51
Capitalised Overheads	594.60	358.82	373.60
Total System	3,007.52	2,069.74	2,092.43
ICT	239.52	364.05	367.21
ICT - Direct Capex	-	-	210.12
ICT- Capitalised Indirect Expenditure	-	-	157.09
Fleet & Equipment	292.69	200.31	224.80
Fleet & Equipment - Direct Capex	-	-	160.67
Fleet & Equipment - Capitalised Indirect Expenditure	-	-	64.14
Property	354.25	209.25	220.26
Property - Direct Capex	-	-	128.55
Property - Capitalised Indirect Expenditure	-	-	91.71
Total Non-network	886.45	773.61	812.27
Total Gross Capex	**3,893.97**	**2,728.99**	**2,904.70**
Closing RAB	**11,134.53**	**11,548.55**	**12,027.04**

Note: Totals may not add due to rounding. Previous and current period data is presented on a like for like basis (adjustments for CAM, COS and reporting) with forecast period, so AER allowance is not comparable.

Our capex performance has been compared against our peers in many studies, including by the AER's annual benchmarking reports. These reports show that our capex in 2017 has reduced by more than any other DNSP (except for Ausgrid) over this last 10 years. We have also had the largest underspend of any DNSP over its most recently completed regulatory control period. The AER's 2018 Annual Benchmarking Report examines the capital MPFP of electricity DNSPs over the period

2006 - 2017. This considers the productivity of the DNSP's use of overhead lines and underground cables (split into distribution and sub-transmission) and transformers. The AER's analysis shows that we have remained relatively stable in the middle band of DNSPs over this period.

Our capex trend reflects our long-term commitment to reducing our capex in a sustainable manner for the benefit of our customers. Our merger with Energex has made an important contribution to this trend.

7.2 The nature and drivers of our capex

Our main categories of capex from our June 2018 Expenditure Forecasting Methodology that support the delivery of our network services are shown in Figure 22.

Figure 22 Categories of capex

RIN Category	Expenditure Category Elements	Service Description
Replacement expenditure (Repex)	Corporation initiated replacement & refurbishment of network assets.	• maintaining the existing level of supply and standard of service by replacement or renewal of assets that are no longer capable of delivering their designed purpose.
Connections (Connex)	Customer initiated capital works to deliver services to: • Connect residential customers to the network; upgrade existing connections; and provide service to connect small scale embedded generation (PV)	• timely and cost efficient connection of new customers to the distribution network and/or changes to existing small customer connections.
Augmentation expenditure (Augex)	Corporation initiated capital works to reinforce or grow the network to increase: • Capacity • Reliability • Power Quality; and • Secondary Systems	• maintaining the existing level of supply and standard of service by addressing increases in peak demand, additional load, fault levels, reliability and power quality requirements within the network, including the purchase of operational land and easements
Non-network	ICT Motor vehicles Buildings and property Other	• capex not directly related to the construction or replacement of system assets but which supports the operation of the regulated network business
Capitalised network overheads	Network overheads	• Overhead costs including the provision of network, control and management services that cannot be directly identified with a specific activity
Capitalised corporate overheads	Corporate overheads	• Provision of corporate support and management services by the corporate office that cannot be directly identified with specific activity

- **Repex** – driven by:
  - o the need to maintain and where relevant improve safety outcomes for our communities, customers and employees
  - o equipment replacement due to age and condition where maintenance or repair is no longer practical, or cost effective and the asset is at end of life
  - o overhead distribution network (these are the 'poles and wires' you can see, rather than the ones that are underground) where the greatest network risk exposure resides

  - addressing poor condition assets and emerging asset related safety hazards, and
  - transitioning to a more proactive replacement approach for sustainable asset management and safety outcomes.
- **Connection expenditure (connex)** – driven by:
  - customer connections performed in accordance with our Connection Policy and capital contributions framework
- **Augex** – driven by:
  - network expansions or additions i.e. a new substation or feeder to support new customer growth
  - innovative technology investment to enable an intelligent grid and improved asset utilisation while meeting customers' increasing network capacity needs through choice in solutions such as solar energy, batteries, and electric vehicles
  - obligations to address reliability of worst performing feeders, and
  - obligation to maintain power quality and supply voltages.
- **Non-network expenditure (Property, ICT, Fleet and Equipment)** – driven by:
  - business needs to deliver our program of work, and
  - investing in appropriate systems and tools to efficiently run our business and deliver services to our customers.
- **Overheads** – comprising capitalised corporate overheads and network overheads
  - corporate overheads cover the provision of corporate support and management services by the corporate office that cannot be directly attributed to specific services, and
  - network overheads cover the provision of network, control and management services that cannot be directly attributed to specific services.

Our capex forecast is our response to these drivers so that, together with our opex forecast, we manage our overall network risk and deliver the service performance outcomes that our customers expect.

7.3 What we have heard from our customers

In developing our capex plans for the 2020-25 regulatory control period, we have considered how best to address the feedback we have received from our customers. As discussed in chapter 2, we heard that we need to:

- manage asset, staff and community safety as an expectation of our role
- ensure investment is prudent to minimise increases to the RAB, particularly in an uncertain energy future
- prioritise collaboration with our customers, communities and other market participants in developing solutions
- continue to transform our network to enable new technology and customer choice
- ensure that we manage a sustainable program to avoid boom and bust cycles and subsequent customer impacts, and
- continue to use new technology to deliver efficiencies.

We have sought additional ways to expand our demand management plans in light of the positive customer feedback on these initiatives and the desire to see more of them. We have also provided additional clarity about where we are investing in demand management and where it has been used in project outcomes.

We presented our high-level investment drivers and forecasts as part of our customer engagement program, in order to provide information and invite feedback on our thinking so far. In these presentations, we included a number of case studies including:

- The replacement of the end of life Childers-Gaydah 66kV line and proposed replacement project
- The replacement of the end of life Mossman substation and proposal to reconfigure, reduce and consolidate the network configuration as part of the replacement
- The use of Non-Network solutions such as the Emerald Solar Farm to provide reactive support and defer the need to upgrade the sub-transmission network, improving customer outcomes and reducing growth in RAB
- The use of new technology such as Real Time Capacity Monitoring to extract maximum use from our assets and minimise new expenditure
- Customers supported our proposed approaches. More detail on these and other specific investment activity we are proposing is available in our supporting documentation.

7.4 Key capex assumptions

The key assumptions underpinning our capex forecasts are detailed in Table 24.

Table 24 Key capex assumptions

Issue	Assumption
1. Structure and ownership	Our capex forecasts are based on our current company structure and ownership arrangements.
2. Legislative and regulatory obligations	Our capex forecasts are based on our current legislative and regulatory obligations and our Distribution Authority.
3. Service classification and ring-fencing	We will apply the service classification in the AER's F&A paper and the current ring-fencing arrangements will not change materially.
4. Customer preferences and expectations	The preferences and expectations of participants revealed through our stakeholder engagement program accurately reflect those of our customers generally.
5. Addressing customer concerns about affordability	Our capex forecasts have particular regard for the affordability of electricity supply and appropriately respond to our customers' concerns.
6. Service outcomes	We will maintain, but not improve, our average system-wide service outcomes, consistent with clause 6.5.7(a) of the NER.
7. Forecast capex	Our capex forecasts are required to deliver the safety, reliability and customer outcomes set out in our Regulatory Proposal.
8. Demand	Our base case network peak demand forecast provides an appropriate basis for our network augmentation forecast.
9. Customer numbers	Our customer numbers forecast provides an appropriate approach for determining our capex rate of change.
10. Cost allocation	Our CAM provides an appropriate basis for attributing and allocating costs to, and between, our distribution services.
11. Unit rates/standard estimates	Unit rates/standard estimates are used in the development of our bottom up forecasts where appropriate.
12. Real cost escalations for	Our real cost escalations used for our capex forecasts are reasonable and reflect prudent

Issue	Assumption
capex	and efficient costs.
13. Inflation	Our forecast inflation is reasonable and reflects the inflation-related costs that we will incur.
14. Current period capex	We will deliver our forecast capex in the remainder of the current period, which will provide an appropriate basis for our capex program in the next period.
15. New Connection Policy	We will apply our new Connection Policy.
16. Cost pass through and contingent projects	The AER will approve our nominated pass through events and we will not have any contingent projects.

Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6.2.1(6) of the NER. We are not submitting any restricted asset applications under c6.4(b).2 of the NER. We have not included any expenditure for a restricted asset as per c6.5.7(b)(5) of the NER.

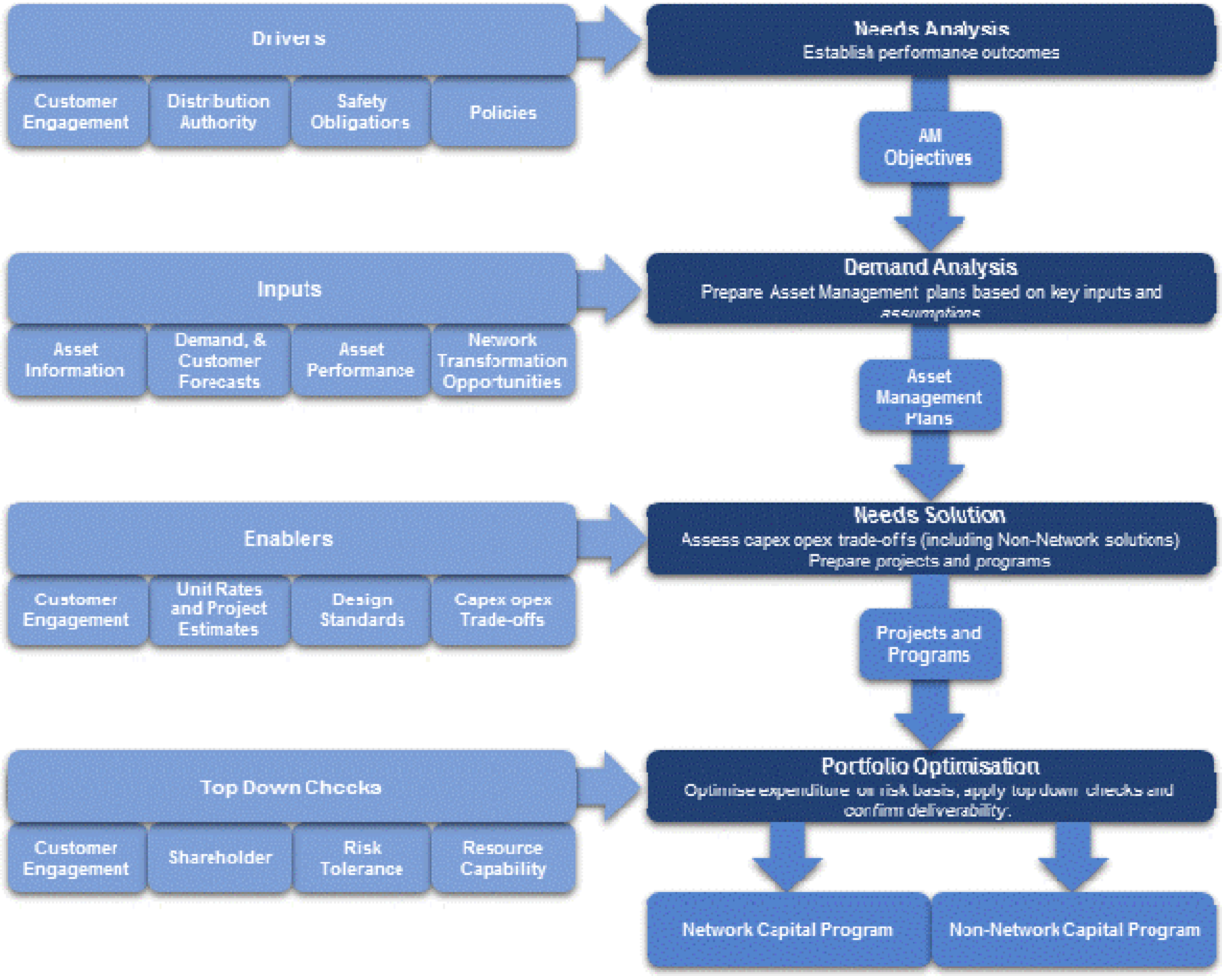
7.5 Our expenditure forecasting methods

Our capex forecasting methodology that was detailed in our June 2018 Expenditure Forecasting Methodology was used to develop a capex program on a project by project basis that meets our network requirements, customer expectations and community needs. We assessed individual projects for non-network alternatives (NNA). Where we have identified an efficient NNA project, network projects have been deferred, cancelled or reconsidered. We have reconciled our forecast against NER requirements and network risk profile tolerances to ensure prudent and efficient investment.

This general approach is illustrated in Figure 23 and includes the following steps:

- **Needs Analysis** – establish network performance outcomes to deliver organisational targets, including in areas such as safety performance, responsibilities to the environment, financial outcomes and commitments to customers, as well as obligations to the community
- **Demand Analysis** – critically review key inputs such as asset condition information, network demand growth and new technology against established performance outcomes to determine area requiring intervention
- **Needs Solutions** – prepare capital projects and programs that address the identified needs. This step includes capex opex trade-offs and investigations of non-network solutions with the potential to defer the timing of major projects
- **Portfolio Optimisation** – reconcile projects and programs against top-down expenditure targets and optimise having regard for a tolerable network risk profile.

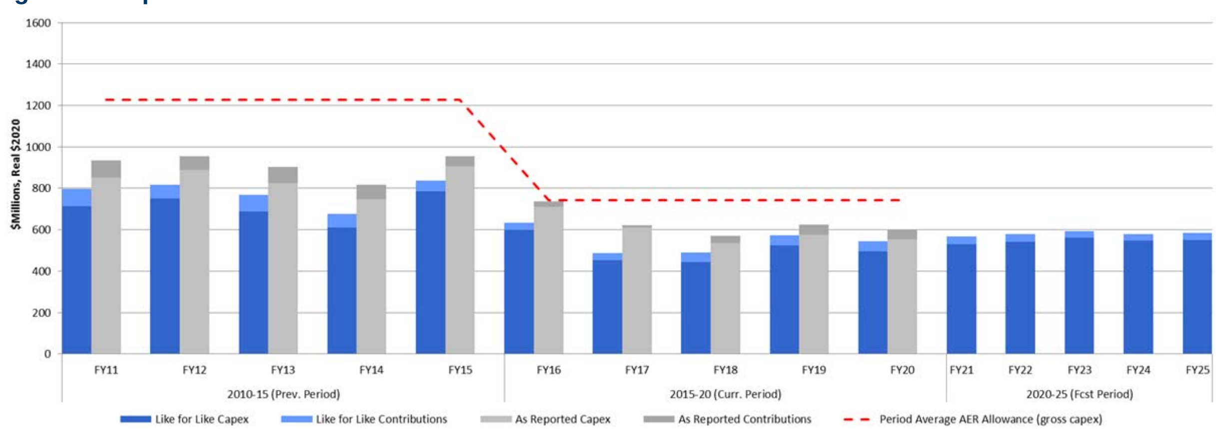
Figure 23 Capex forecasting process



7.6 Our forecast capex

Figure 24 shows our capex trend over the 2010-15, 2015-20 and 2020-25 regulatory control periods in order to provide context for our capex forecast – it shows gross capex (i.e. including assets that are funded by customers through capital contributions) and net capex (i.e. excluding capital contributions). In the following sections we explain and justify our forecasts for each capex category.

Figure 24 Capex trends



The data supporting Figure 24 is provided in Table 25 and Table 26.

Table 25 Capex trends compared to AER allowance – previous and current regulatory control periods

$M, Real $2020	2010-15 (Prev. Period)					2015-20 (Curr. Period)				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20
As Reported Capital Contributions	84.0	64.6	78.3	67.8	48.8	27.9	10.0	36.5	48.2	48.3
As Reported Capex	851.4	889.8	825.5	748.8	906.9	709.9	611.7	535.0	577.3	554.1
Period Average AER Allowance (gross capex)	1227.5	1227.5	1227.5	1227.5	1227.5	742.3	742.3	742.3	742.3	742.3
Like for Like Capital Contributions	84.0	64.6	78.3	67.8	48.8	35.3	33.8	45.1	48.2	48.3
Like for Like Capex	712.9	751.5	689.5	609.4	787.1	632.8	533.0	445.1	525.9	496.0

Table 26 Capex trends compared to AER allowance – forecast regulatory control periods

$M, Real $2020	2020-25 (Forecast Period)				
	FY21	FY22	FY23	FY24	FY25
Like for Like Capital Contributions	38.3	35.5	32.0	32.0	32.1
Like for Like Capex	530.5	543.1	562.1	547.5	551.7

7.7 Replacement capex

During the 2010-15 regulatory control period, we invested slightly above our regulatory allowances as we undertook major restoration works associated with Cyclones Yasi (2011), Anthony (2012), Oswald (2012), and then flooding around the Bundaberg and other areas in our southern region. This replacement of assets due to weather damage rather than end of life increased the risk profile across the entire network.

We are now taking a more proactive approach to replacing aging assets. As such, our repex is forecast to be above the regulatory allowance in the current regulatory control period. We have focused on the sustainable removal of aged, poor-condition assets to maintain expected network performance for our customers and safety to the community.

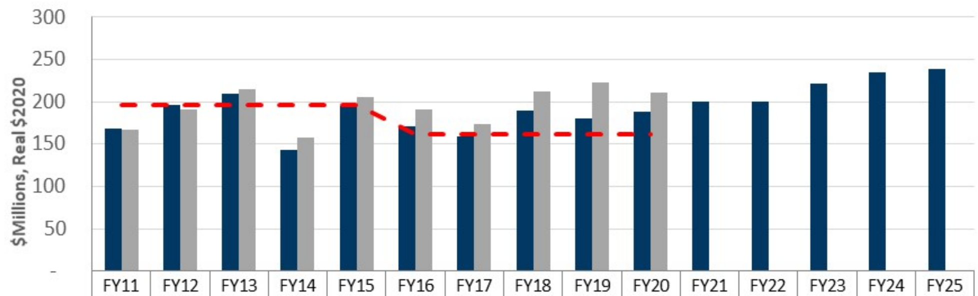
Even with this proactive approach, risk across the network has continued to increase due to the age profile of our assets. This is a major driver of our repex forecast for 2020-25. The proposed investment program for 2020-25 will remain targeted, based on analysis of the condition and performance of specific assets. There are significant asset populations that are now entering the wear out failure phase of the asset lifecycle.

Reactive replacement of assets is now proving to be no longer economic. For example there were 12 separate projects over five years that delivered like for like replacement at Blackwater substation. While each investment was the lowest cost option at the time, this approach did not provide an opportunity to optimise the substation configuration for long term customer needs and customers were exposed to ongoing poor service and safety hazards.

Our 2020-25 regulatory control period repex is expected to be consistent with our current level of investment, which will mean repex will form a large component (approximately 38%) of our proposed system capex program, as other capex categories reduce. Below we detail the investments we are proposing.

Figure 25 presents our repex trends and between 2010 and 2025. Table 27 reflects the sub-categories of forecast repex for the 2020-25 regulatory control period.

Figure 25 repex trends compared to allowance



	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
	2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)				
Like for Like Repex	168	197	210	143	195	171	159	189	180	188	200	200	221	234	239
As Reported Repex	166	191	214	157	206	191	173	212	223	210					
Period Average AER Allowance	197	197	197	197	197	162	162	162	162	162					

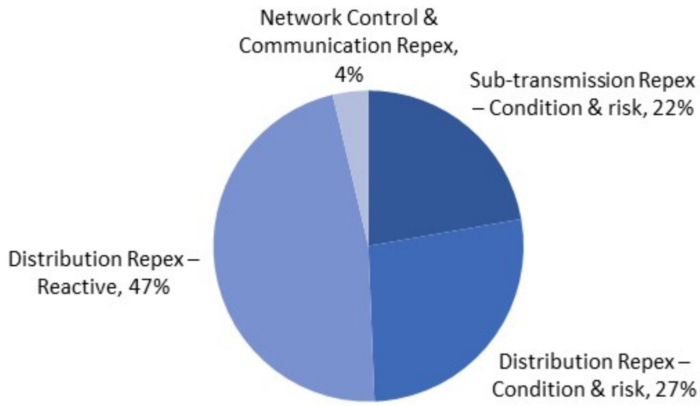
Note: We determined the average AER allowance by apportioning the AER's allowance across all capex categories based on our estimate of expected capex.

Table 27 Forecast repex sub-categories

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Sub-transmission repex – Condition & risk	35.70	34.07	49.90	59.21	64.32	**243.20**
Distribution repex – Condition & risk	50.20	53.00	60.84	66.34	66.78	**297.17**
Distribution repex – Reactive	101.96	102.45	102.52	102.92	103.64	**513.50**
Network Control & Communication repex	12.27	10.12	8.07	5.69	4.39	**40.54**
Repex Total	**200.13**	**199.65**	**221.34**	**234.16**	**239.13**	**1,094.41**

Note: Totals may not add due to rounding

Figure 26 Forecast repex sub-categories proportions



Note: Totals may not sum to 100% due to rounding

Our forecast repex for the 2020-25 regulatory control period is mainly driven by asset management objectives outlined in our Strategic Asset Management Plan at Attachment 7.090, as well as specific performance targets outlined in strategies and asset management plans included in Attachments 7.026-7.044. These include meeting our reliability and security of supply targets in our Distribution Authority, as well as safety, environmental, and regulatory obligations. As discussed in chapter 2, our no-compromise approach to community and staff safety has been well supported by customers.

Our repex programs are developed based on analysis of the condition and performance of assets (i.e. Condition and Risk), as well as historical demand driven from inspection and in-service failure (i.e. Reactive). We do not pursue like-for-like replacement of assets, but rather undertake condition and risk programs that are proactive in nature and target high-risk assets that are approaching the end of their lifecycle.

Reactive replacement programs are predominately driven by well-established inspection programs, which are used to identify assets at imminent risk of in-service failure and to manage asset condition where proactive replacement is not economical. The Reactive programs also include a small allocation for the cost of asset replacement due to in-service failures, which are typical in a distribution network.

Our proposed repex represents a balance of Condition and Risk, and Reactive, programs to provide a prudent means of achieving the asset management objectives.

7.7.1 Sub-transmission Replacement Expenditure – Condition & Risk

Most of our asset replacement programs for sub-transmission have been developed beginning with an analysis of the condition and health of assets in accordance with the Condition Based Risk Management (CBRM) methodology to identify individual assets nearing the end of their lifecycle. The scope and timing of replacement or refurbishment (life extension) is typically informed by risk assessments conducted to document risks associated with asset failure and to establish when it is no longer viable to retain these assets in service.

Replacing assets is considered based on network security standards and obligations. We also consider alignment with other network drivers, such as augex and connex, to ensure the final option is the most cost effective. We do not pursue like-for-like replacement, but test each investment decision against the future needs of the network. NNA options for replacement are investigated through the Regulatory Investment Test for Distribution (RIT-D) process, where the project exceeds the RIT-D investment threshold. There are several identified projects forecast in the 2020-25 regulatory control period that exceed this threshold. RIT-D processes will be performed for these projects.

The highest proportion of expenditure in this category is driven by major substation asset replacement with the bulk of this being 33/11kV transformers and 33kV circuit breakers.

7.7.2 Distribution Replacement Expenditure – Condition & Risk

We have developed the Condition and Risk distribution replacement programs based on our analysis of asset performance and risk. The major component of this capex is in the distribution line refurbishment programs, which include replacement of overhead conductor, poles and pole top structures that are approaching end of life. Assets that are identified as approaching end of life are prioritised according to risk and are bundled into logical packages of work to provide efficient delivery. Volumes of replacement works are determined based on the overall network risk exposure and considering the aging network trends. This ensures programs are prudent and continue to meet asset management objectives, particularly for community and staff safety and legislative obligations.

The other major component of the Condition and Risk distribution replacement program is the proposal to establish a capability in low voltage safety monitoring. This program utilises technology to provide near real-time network information to improve the management of safety risks to the community, maximise useful asset life and defer repex.

We presented our high-level repex drivers and forecasts to customer groups as part of our customer engagement program to provide information and invite feedback on our thinking so far. As part of those presentations, we included a number of case studies, including for:

- Overhead Conductor Replacement programs
- Pole Replacement program, and
- Low Voltage Safety Monitoring program.

Customer groups broadly supported this approach to deliver community safety outcomes. Our strategic proposal for low voltage safety monitoring device is outlined in Attachment 7.080.

7.7.3 Distribution Replacement Expenditure - Reactive

Our proposed Reactive distribution repex is driven primarily by the replacement of assets identified as being at end of life through routine inspection programs. Volumes of replacement under these programs are forecast based on historical demand, considering population trends such as age and asset quantity. Defects identified through inspection are prioritised based on risk and are bundled into efficient programs of delivery to minimise customer outages during rectification. The major drivers for capex in this category include replacement of wood poles, pole mounted plant and overhead services that are identified in our five-year cycle of overhead line inspection.

The Reactive distribution programs also include a demand-based allocation to replace assets as a result of in-service failure. Volumes of asset replacement in this category are forecast based on historical requirements and trends.

7.7.4 Network Control & Communication

Network control and communication replacement expenditure requirements are developed based on a combination of reactive, condition and risk driven programs.

Reactive replacement programs are predominately driven by in-service failures detected via continuous monitoring or inspection programs. These programs identify assets that have stopped operating, are no longer performing to specification, or are at imminent risk of failure. For some low risk asset classes, such as distribution transformer monitoring units, certain intelligent electronic devices used in the Supervisory Control and Data Acquisition (SCADA) system and many telecommunications line driver and switch units, only reactive replacement on a like-for-like replacement is used.

Condition and risk-based programs consider the condition, performance and risk of assets (including obsolescence) to identify assets approaching the end of life. Planning assessments are undertaken to determine the most appropriate solution to meet network requirements, including non-network alternatives. Due to the rapid pace of technology development, network solutions will often be based around modern equivalent assets. This includes replacing:

- analogue and electromechanical with digital (numerical) protection relays
- copper pilot wire for protection communication with fibre optic cables, and
- the Plesiochronous Digital Hierarchy (PDH) for the transportation of digital data on our networks with more efficient and robust Multiprotocol Label Switching (MPLS) network equipment.

7.7.5 AER repex model comparison

The AER has used its repex model to assess repex in its previous Distribution Determinations. It uses asset age profiles and expected asset lives to estimate future asset replacement expenditure. The optimal timing for asset replacement is not only reliant on age – other factors such as safety, environment, changes in defect rates, and obsolescence issues must also be considered. Nevertheless, the repex model provides for a useful check or comparison with our forecast repex requirements. We have a number of proactive asset replacement programs driven by emerging risks unrelated to the age of the assets, which are not fully captured in the repex model.

While we recognise there are limitations to the age-based approach inherent in repex modelling, it is one tool we use for a top-down challenge of our repex forecast using a bottom-up build. This is done both at an overall repex level and at an asset category group level where applicable, such as for poles.

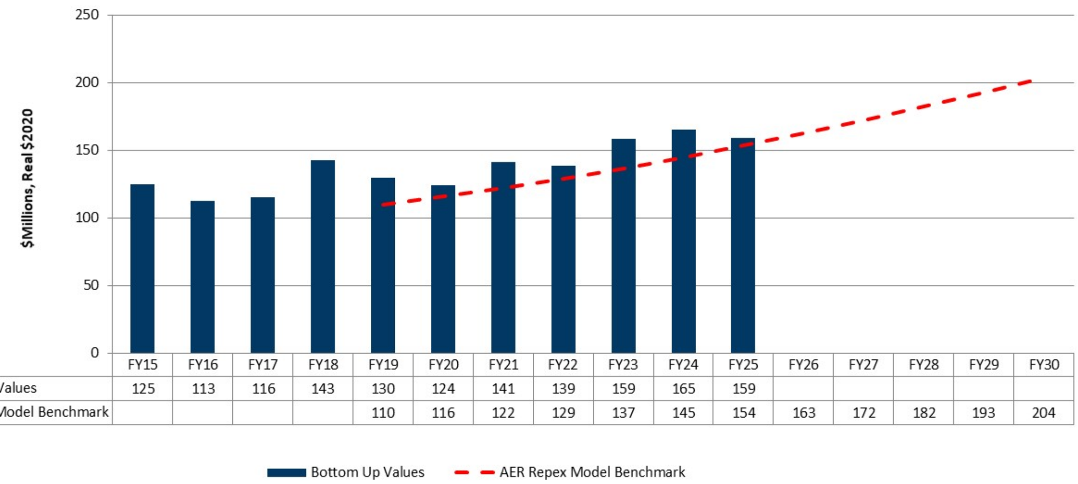
The AER assess repex based on 2 broad categories of assets:

- Assets that are capable of being modelled based on the AER Repex model. This includes 6 asset classes (poles, overhead conductor, underground cables, switchgear, transformers, and services). Often referred to as modelled repex these 6 categories make up 67% of the total Energex repex.
- Assets that are not well suited to the AER Repex model which comprises all remaining asset classes (e.g. network communication, control, and protection system assets, pole-top structure assets, and other miscellaneous items such as battery systems, fire systems, and fences).

Ergon Energy has engaged with the AER on several occasions to understand their application of repex modelling, such that Ergon Energy considers the same scenarios and utilises repex modelling in a similar manner.

Figure 27 compares the range of repex modelling scenario outcomes and the modelled components of our bottom-up repex forecast (and therefore excludes the un-modelled portion of our total repex shown in Table 27). The model projects an increasing trend in repex requirements; this is consistent with our increasing proportion of aged and end of life assets.

Figure 27 Modelled repex trends



	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Bottom Up Values	125	113	116	143	130	124	141	139	159	165	159					
AER Repex Model Benchmark					110	116	122	129	137	145	154	163	172	182	193	204

While our forecast is likely to be above the repex threshold, the underlying trend of the model, combined with our transition towards a more sustainable blend of proactive and reactive programs supports our view that our forecast represents a sustainable, prudent and efficient level of repex given the age and condition of our assets.

Similar to modelled repex assets, the repex forecast for un-modelled asset classes has been prepared in line with asset strategies and plans; and consistent with our risk frameworks and risk appetite. We are therefore confident the un-modelled portion of forecast repex also represents sustainable, prudent and efficient expenditure.

The proposed program is reflective of the commitment to constrain customer price impacts and continue to look for efficiencies in program delivery. It reflects a risk position which balances the achievement of asset management objectives and customer service levels.

Our repex Model Supporting Information in Attachment 17.029 outlines our response to repex model related requirements of Schedule 1 of the Regulatory Information Notice (RIN) and provides further details of the repex modelling scenarios we considered in comparison to our repex forecasts.

7.8 Augmentation capex

Our augex requirements have reduced significantly from our 2010-15 regulatory control period, following our investment to meet previous strict N-1 security criteria requirements established as part of the Electricity Distribution Service Delivery (EDSD) Review, and as revised through the 2011 Electricity Network Capital Program review.

Reduced security and reliability requirements following the move from deterministic to probabilistic security criteria as part of the 2014 Independent Review Panel, along with cost reductions following the merger and lower than forecast demand growth, resulted in reductions to augex requirements in the 2015-20 regulatory control period. This trend will continue in the 2020-25 regulatory control period. Augex is required to:

- address key areas of community development, population and demand growth

- support the continued connection of residential and commercial solar PV systems to the distribution network
- maintain network statutory and standard requirements and address our obligations outlined in our Distribution Authority pertaining to our safety net security criteria, MSS and worst performing feeder requirements, and
- provide additional functionality to support an intelligent grid through a range of network control and monitoring initiatives.

Figure 28 shows our augex trend over the 2010-15, 2015-20 and 2020-25 regulatory control periods, including against the AER's allowances. Table 28 provides a breakdown of our augex forecast for the 2020-25 regulatory control period and Figure 29 illustrates the shares of each sub-category for the period.

Figure 28 Augex trends compared to allowance

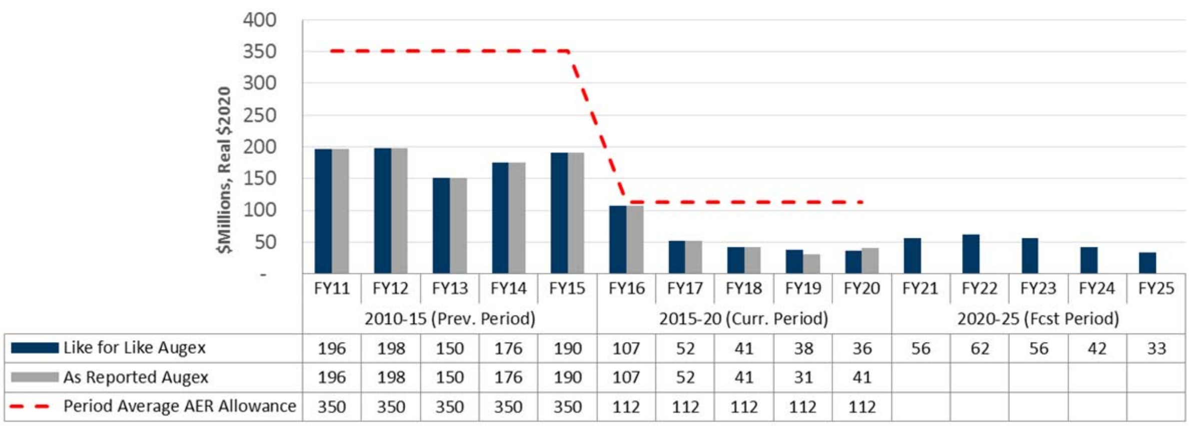
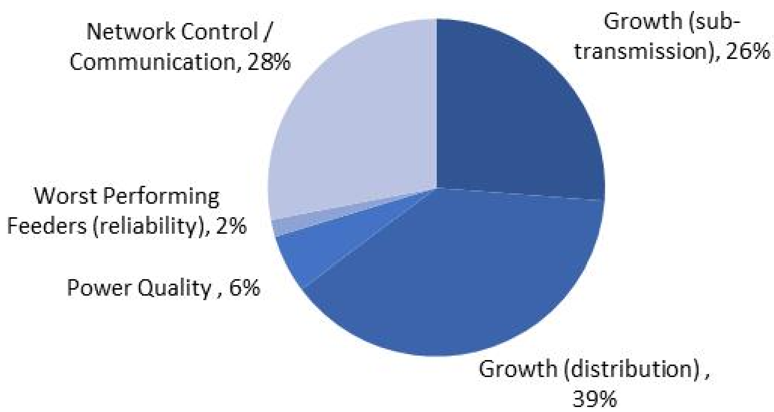


Table 28 Forecast augex expenditure sub-categories

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Growth (sub-transmission)	17.21	22.37	18.18	6.32	1.07	**65.16**
Growth (distribution)	19.25	19.09	19.06	19.10	19.22	**95.73**
Power Quality	3.27	3.20	1.95	2.40	3.04	**13.85**
Worst Performing Feeders (reliability)	0.62	0.89	0.89	0.89	0.81	**4.09**
Network Control / Communication	15.19	15.98	16.05	13.61	8.86	**69.69**
Augex Total	**55.53**	**61.52**	**56.14**	**42.32**	**33.00**	**248.51**

Totals may not add due to rounding

Figure 29 Forecast augex sub-categories proportions



Note: Totals may not sum to 100% due to rounding

In order to reduce our augex and to improve customer outcomes, we proactively seek demand management solutions by deploying initiatives to reduce peak demand and defer network investment. The successful use of demand management has resulted in us reducing our augex in the 2015-20 regulatory control period and we are forecasting this to continue in the 2020-25 regulatory control period. This has included us considering non-network solutions as a part of the routine planning process. However, where we are seeing community development and growth beyond our ability to defer load, network augmentation will be required in some instances.

The growth components of our augex (i.e. sub-transmission and distribution) are based on normal network condition demand forecasts and include a variety of network and non-network scenarios. Areas of high growth are included as part of demand management initiatives and all major investments are subject to a RIT-D and market test of alternative solutions. Documentation to support our major sub-transmission investment is provided with this Regulatory Proposal to show the need and benefits of the proposed solution.

We presented our high-level augex drivers and forecasts as part of the customer engagement program for information and feedback. As part of these presentations, we included several case studies, including:

- The non-network solution to secure supply to Emerald compared with establishing a second 66kV sub-transmission line, and
- establishing a zone substation at Ooralea in South Mackay to cater to significant forecast commercial, industrial and residential development, subject to a prior assessment of demand management solutions.

As a result of customer support and feedback, the Emerald and Ooralea non-network solution will be funded from our forecast opex in the 2020-25 regulatory control period.

Only a small number of larger, growth-related sub-transmission augex projects are forecast over the 2020-25 regulatory control period. The RIT-D process will be undertaken for each of these projects to canvass the market for an efficient non-network solution. Those of significance included in the forecast to meet security of supply requirements under safety net provisions of the Distribution Authority include:

- Airlie Beach and Whitsundays Security of Supply Reinforcement

- Establish Nikenbah to Point Vernon 66kV line, and
- Reinforce Supply to Burnett Heads

We forecast our distribution growth-related augex requirements using a combination of detailed engineering analysis that compares forecast demand to available capacity and the historical average rates of investment in this category.

Our distribution growth category contains augex driven by capacity, voltage and protection limitations on the distribution network and includes programs such as bushfire mitigation. As we have reduced the number of large sub-transmission investments, we have increasingly utilised distribution augmentation to help support areas of localised demand growth. Distribution growth-related augex requirements are forecast by referencing expenditure and demand to the 2015-20 regulatory control period and by assessing the continuation of programs such as bushfire mitigation, clearance defects and back-up protection. Efficient non-network solutions identified through the RIT-D process will be funded by a capex/opex trade-off.

For smaller sub-transmission augex projects, targeted demand management programs will be operated over the 2020-25 regulatory control period, where prudent and efficient.

A significant decrease has been applied to forecast distribution augex, based on delivering targeted demand management reductions to defer specific augex projects

More detail on the distribution growth component of the proposal is included in the supporting strategic proposal for distribution feeder augmentation (Attachment 7.092).

7.8.1 Worst Performing Feeders (reliability)

We must meet MSS targets set out in our Distribution Authority, which outlines feeder category-based reliability performance targets and also includes obligations to improve the reliability of the worst performing 11 kV feeders, in order to address the impact on these customers. We have assumed that the MSS for 2020-25 will continue to be flat-lined and, as such, the augex forecast for the 2020-25 regulatory control period has been based solely on addressing worst performing feeder obligations set out in the Distribution Authority. As the current MSS expires on 30 June 2020, the Government may set new targets with a consequential need for us to update our forecasts in our Revised Regulatory Proposal.

Our proposed worst performing feeder improvement program is also based on performance improvement on our network in the last ten years and customer feedback about their network reliability expectations. Our augex forecast for the worst performing feeder improvement program has remained in line with the 2015-20 regulatory control period.

More detail regarding our approach to network reliability is outlined in the Customer Reliability Strategy provided in Attachment 7.048, and the Worst Performing Feeder Strategic Proposal provided in Attachment 7.098.

7.8.2 Power Quality

Our proposed Power Quality and Solar Program seeks to maintain and improve the monitoring and reporting programs established during the 2015-20 regulatory control period. Addressing the power quality statutory obligations, this program is a key enabler of the increased penetration of solar PV and new technology connections. This program also includes remediation activities to address voltage non-compliances from solar or other customer or network issues. The forecast for 2020-25 has been developed by forecasting augex from the 2015-20 regulatory control period and considering the impact of strategies around enabling an intelligent grid and the efficiencies achieved from existing programs such as the 230V transition. The Customer Quality of Supply Strategy (Attachment 7.047) and the Strategic Proposal Power Quality (Attachment 7.095) contain more detail on this category.

7.9 Connections capex and customer contributions

We have an obligation to provide connection services to residential and commercial and industrial customers, real estate developments, unmetered supplies and embedded generators in our distribution area. Connection services comprise a range of activities required to connect new customers to the distribution network or modify connection assets and/or the network for existing customers. The activities may include the establishment or modification of assets dedicated to a customer (premises connection assets), extensions to, or augmentation of, the shared distribution network.

In providing connection services, we incur the costs of some connection activities and require customers to pay upfront or contribute to the costs for some connection activities. For this reason, our connections capex is made up of two parts:

- **costs that we incur or fund (net connections capex).** We roll these costs into our RAB and recover the costs through time via our network charges. Our net connection capex represents the investment required to connect new small customers (residential and small businesses customers) and to extend and augment the shared network to facilitate connections for all our customers.
- **costs incurred by customers (capital contributions).** Under our proposed connection policy and service classification, customers may be required to fund aspects of connections services either as cash contributions or gifted assets, depending on the size or type of customer (small or major) and/or aspect of the connections service (premises connections, extension or augmentation). In general, capital contributions are required from small customers – where their connections are uneconomic; and from major customers (including real estate developments, large embedded generators etc.) who are required to fully fund their dedicated connection assets as ACS.

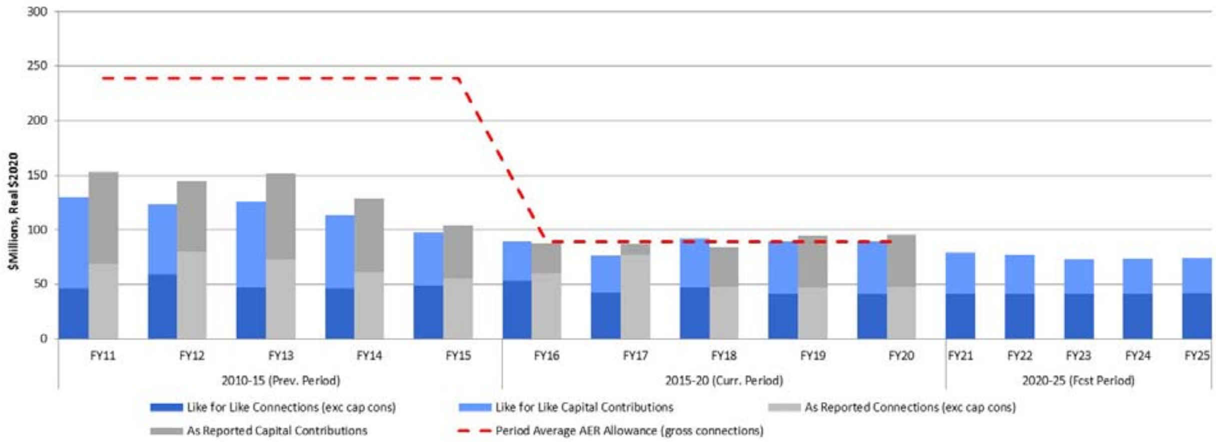
Both net connections capex and capital contributions are purely customer driven. They depend on the actions of our customers making decisions to either connect to our network or request services to modify their connections and/or the shared network. It is therefore inherently difficult to accurately forecast connections related capex.

Nonetheless, we consider that there is a strong correlation between connection works and economic activity. Our connections capex declined in the early part of this decade reflecting the impact of the Global Financial Crisis in our distribution area. Mining activity slowed, and despite the addition of a large number of large connections associated with renewable generation, our total connections capex has been declining. We expect to spend less on connections in the current regulatory control period compared to the 2010-15 regulatory period.

We consider that our best indication of connections capex for 2020-25 regulatory control period is our most recent observed expenditure levels. It is difficult to predict economic conditions. We have taken a conservative approach by using our most recent actual expenditure because it is at the lower end our actual expenditure since 2010. It is possible that connections capex could be materially higher in future if economic conditions markedly improve.

Figure 30 displays the trends in our historical and forecast connections capex and customer contributions.

Figure 30 Connections capex trends compared to allowance (including capital contributions)



The data supporting Figure 30 is provided in Table 29 and Table 30.

Table 29 Connections capex trend compared to allowance – previous and current regulatory control periods

$M, Real $2020	2010-15 (Prev. Period)					2015-20 (Curr. Period)				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20
As Reported Capital Contributions	84.0	64.6	78.3	67.8	48.8	27.9	10.0	36.5	48.2	48.3
As Reported Capex	69.0	79.6	72.8	60.9	55.2	59.6	77.2	47.8	46.9	47.2
Period Average AER Allowance (gross capex)	239.0	239.0	239.0	239.0	239.0	89.4	89.4	89.4	89.4	89.4
Like for Like Capital Contributions	84.0	64.6	78.3	67.8	48.8	35.3	33.8	45.1	48.2	48.3
Like for Like Capex	45.9	59.2	47.0	45.9	49.0	53.6	42.2	46.7	40.9	41.1

Table 30 Forecast connections capex

$M, Real $2020	2020-25 (Forecast Period)				
	2020-21	2021-22	2022-23	2023-24	2024-25
Like for Like Capital Contributions	38.3	35.5	32.0	32.0	32.1
Like for Like Capex	41.1	41.3	40.8	41.0	42.0

7.10 Non-Network capex

7.10.1 ICT

Change in ICT service delivery model

Before 2016, our and Energex's ICT services were provided by a jointly-owned subsidiary, SPARQ Solutions Pty Ltd (SPARQ). SPARQ's only customers were the entities within the two distribution network groups, including the unregulated entities. Given the program of work that SPARQ undertook was not split on an even basis, SPARQ used an "Asset Usage Fee" model to appropriately recover its costs against each of the entities in the groups. This incorporated depreciation of the assets constructed as well as interest based on borrowings required to fund the asset construction. Essentially, this was a "software as a service" model with the assets being owned by SPARQ.

Following the creation of Energy Queensland, SPARQ ceased being owned by the two DNSPs and became a 100% subsidiary of Energy Queensland. As part of this transition, the employees of SPARQ became employees of Energy Queensland.

Energy Queensland continues to use the Asset Usage Fee established by SPARQ for the current regulatory control period (2015-20). This treats ICT costs as an overhead in the DNSP businesses, and results in these costs being allocated across capex and opex projects. These costs are allocated without margin.

From the 2020-25 regulatory control period, Energy Queensland will allocate the assets in SPARQ at 1 July 2020 (and for new assets constructed after that date) to the fixed asset register, and RABs, of the appropriate entities in the group to which the relevant asset applies. Where assets are "shared" (i.e. they cannot be specifically assigned to one entity) the costs will be allocated through the CAM.

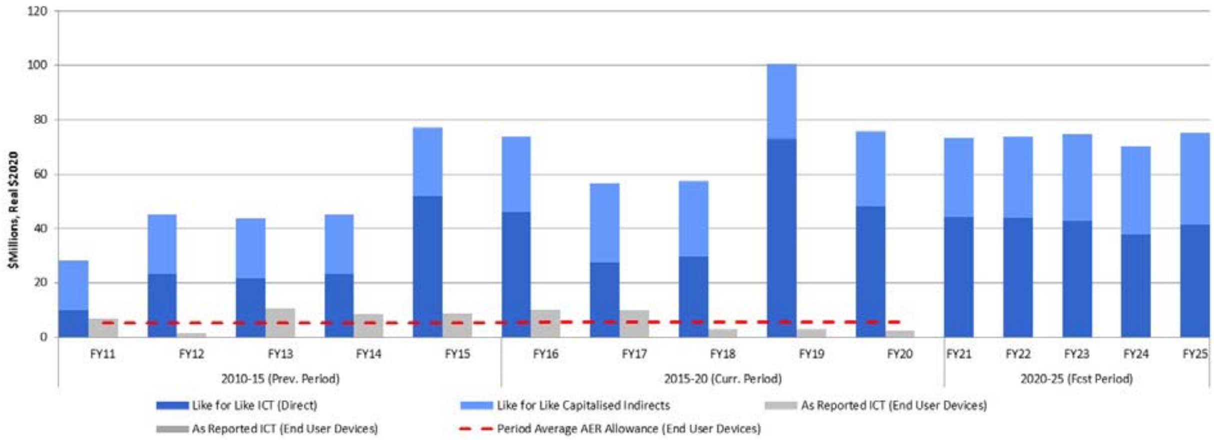
Assigning these assets means that the effective life is more accurately reflected in the accounts of the DNSP as the asset usage fee is not treated as an overhead and then, in some instances, is depreciated over a 40-year life. We consulted on this matter through our customer engagement program. There was support for assigning a useful life of ten years for those assets brought over at 1 July 2020, rather than five year as is normal for most ICT assets, as a way of lessening the impact on distribution network charges.

The major systems included in the assets being transferred into our RAB include the Unified Enterprise Resource Planning and Enterprise Asset Management (Unified ERP EAM) and the ICT & Digital Enterprise Building Blocks (DEBBs) Capital Works in Progress programs. These systems support sustainable and secure core systems and consistent work practices across several key business functions, and support Power of Choice (POC) and other market-based reforms.

Our ICT capex for the 2020-25 regulatory control period

Figure 31 provides our historical ICT capex against allowance and our forecast for the 2020-2025 regulatory control period.

Figure 31 ICT capex trends compared to allowance



The data supporting Figure 31 is provided in Table 31 and Table 32.

Table 31 ICT capex trend compared to allowance – previous and current regulatory control periods

$M, Real $2020	2010-15 (Prev. Period)					2015-20 (Curr. Period)				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20
As Reported ICT (End User Devices	6.9	1.4	10.8	8.4	8.6	10.0	9.8	2.9	2.9	2.5
Period Average AER Allowance (End User Devices)	5.4	5.4	5.4	5.4	5.4	5.6	5.6	5.6	5.6	5.6
Like for Like Capitalised Indirects	18.5	21.7	22.2	21.7	25.2	27.8	29.0	27.7	27.5	27.5
Like for Like ICT (Direct)	9.9	23.4	21.5	23.4	52.0	46.0	27.7	29.6	72.8	48.3

Table 32 ICT capex trend compared to allowance – forecast regulatory control periods

$M, Real $2020	2020-25 (Forecast Period)				
	2020-21	2021-22	2022-23	2023-24	2024-25
Like for Like Capitalised Indirects	28.8	29.9	31.9	32.6	34.0
Like for Like ICT (Direct)	44.4	43.9	42.8	37.8	41.3

We rely on efficient ICT systems and services to deliver our distribution services. We will focus on ICT as an enabler of business performance consistent with the following ICT strategic themes:

1. maintain systems for sustainability, security and operational safety
2. leverage ICT renewals for digital transformation, enabling joint productivity improvement targets
3. maintain efficient ICT performance in a rapidly changing technology environment, and

4. leverage innovative technologies and techniques for efficiency and customer service.

Energy Queensland will continue to maintain our ICT systems and capability consistent with established ICT asset lifecycle management practices. Upon renewal of key systems, we and Energex will consolidate and rationalise legacy applications with consistent best-practice business processes across the service regions.

This digital transformation will enable realisation of Energy Queensland's forecast 10% reduction in indirect costs and 3% improvement in program of work labour costs. This outcome will be achieved through process and capability optimisation, including:

- simplifying workflows and accuracy of data capture at source, reducing the need for rework
- improving data mastering, with reduced duplication and data synchronisation complexity
- aggregating workload across our and Energex's service areas for improved work throughput, consistency and resource utilisation
- improving analysis of network and non-network data for improved forecasting and planning
- continuously improving asset management through ISO55000 practices, with combined insights and network intelligence
- tailoring asset management and works program delivery to the local requirements of particular network segments
- reducing or deferring capex through better analysis of energy usage, targeting of demand management programs and use of non-network alternatives, and
- reducing complexity associated with support of highly aged, custom developed applications requiring specialist skills.

The planned ICT program will also enable a series of key non-financial outcomes, including:

- sustaining our and Ergon Energy's business systems and technology infrastructure for ongoing supportability, serviceability and security
- undertaking safety risk mitigation, including during emergency events, through accurate network data and consistent work practices across our and Energex's regions
- improving network operational resilience and continuity through Operational Control Centre (OCC) fail-over capability between our and Energex's regions
- continuing to apply necessary security controls for access to information related to critical infrastructure and privacy of customer data
- meeting the community's "open data" expectations for access to accurate and timely spatial data regarding the corporations' assets
- being able to respond to ongoing regulatory, compliance and technology changes, building upon the existing information intelligence architecture, and
- complying with all legislative and regulatory obligations, including market obligations, reporting obligations, safety requirements and conformance with prescribed standards.

We and Energex have reintegrated the ICT functions previously by SPARQ into the operational business functions in order to maintain efficient ICT performance. This efficiency is also enhanced through the prudent use of market services, cloud software and as-a-service hosting.

While ensuring the efficiency of ICT service delivery, we are maintaining our focus on the electronic security of our and Energex's ICT systems, information and infrastructure in an environment of increasing cyber risk.

Our proposed ICT investment is essential to support the transformation of our business and supports the delivery of our forecast opex and capex savings as we take advantage of new functionality that comes standard with the replacement systems shown in Table 33. This lower cost base flows through to lower revenue requirements and has enabled us to propose our real reductions in distribution network charges for our customers. We have provided supporting documentation for the material items in the attachments to this chapter.

Table 33 List of systems planned for replacement in the 2020-25 regulatory control period

Category	Current System/Capability
Geo Spatial Support Capability	Smallworld/NFM
Operational Technology	Feederstat/Scada
Operational Technology	Ventyx Suite and Field Smart Systems
Data Management	PEACE
Tools	Network Design Tools
Tools	Distribution Forecasting
Customer Support	Customer Contact Technology
Knowledge Management	Consolidation of Information Storage Repositories
Customer Support	Customer Interaction Portals
Data Management	TOHT
Tools	Asset Inspection and Planning
Content Management	Document and Enterprise Content Management
Tools	Content Management and Collaboration
Customer Support	Customer Relationship Management
Tools	Network Management and Planning Support
Tools	Process Management Support
Security	Cyber Security Platform Consolidation
Tools	Internet Website Replacement

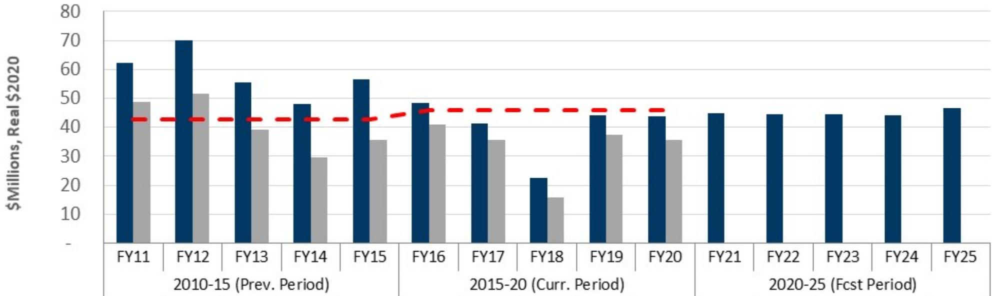
7.10.2 Fleet and Equipment

Investing in fleet assets enables us to deliver distribution services in line with community and customer expectations. We are forecasting stable fleet and equipment capex for the 2020-25 regulatory control period against the AER's allowance for the 2015-20 regulatory control period. This is due to a large proportion of the mobile elevated work platform and mobile generator fleets being due for replacement in the 2020-2025 regulatory control period. However, this is offset by an increased replacement cycle for light and light commercial vehicles, and life extension of suitable plant through refurbishment to Australian Standard guidelines.

We have provided our Fleet and Equipment Asset Management Strategies to the AER in support of our fleet and equipment forecasts. The aim of these strategies are to identify fleet and equipment assets which meet business requirements based on the principle of fit-for-purpose design considering safety, industry standards, business priorities and cost efficiency.

Replacement criteria for fleet and equipment assets are determined by considering the initial economical life expectancy (benchmarked to industry peers), asset condition at end of life and its potential to be economically and safely extended, industry safety and technology improvements, and regulatory constraints. Our targeted fleet and equipment investment supports the efficient delivery of our network program of work. Figure 32 shows the trend in our fleet and equipment capex over the 2010-15, 2015-20 and 2020-25 regulatory control periods, referenced against the AER's allowances.

Figure 32 Fleet capex trends compared to allowance



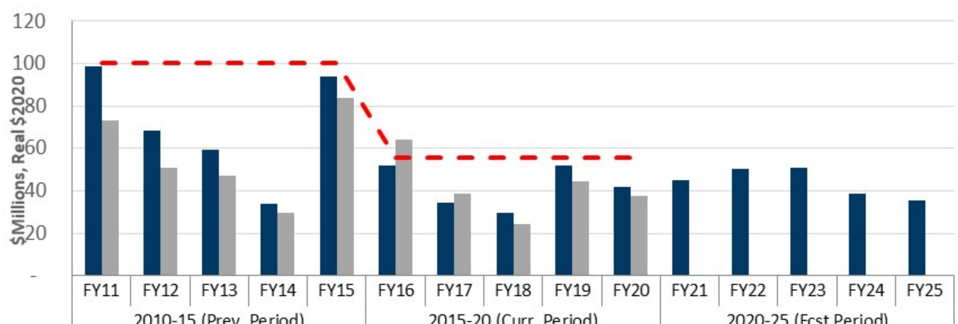
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
	2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)				
Like for Like Fleet and Equipment	62	70	56	48	57	49	41	23	44	44	45	45	44	44	47
As Reported Fleet and Equipment	49	52	39	29	36	41	36	16	38	36					
Period Average AER Allowance	43	43	43	43	43	46	46	46	46	46					

7.10.3 Property

We have provided our Property Strategy to the AER in support of our property forecast. The aim of this strategy is to deliver a safe and efficient, fit-for-purpose and customer-centric property portfolio. The property portfolio will support Queensland communities and customers by ensuring we have facilities in the right locations to enable the operation of a safe and efficient network.

Our property capex forecast aligns with the AER allowance in the current period on a like-for-like basis. We are bringing forward initiatives that will drive business benefits and lower costs in the long term. Figure 33 shows the trend in our property capex for the 2010-15, 2015-20 and 2020-25 regulatory control periods, referenced against the AER allowances.

Figure 33 Property capex trends compared to allowance



	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
	2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)				
Like for Like Property	99	68	60	34	94	52	34	30	52	42	45	50	51	39	36
As Reported Property	73	51	47	30	84	64	38	24	44	37					
Period Average AER Allowance	100	100	100	100	100	56	56	56	56	56					

7.11 Capitalised overheads

Consistent with our CAM, Energy Queensland categorises its overhead costs as follows:

- **Non-regulated overheads** relate to Energy Queensland's non-regulated services and are allocated to the non-regulated businesses, Retail and Yurika (that is, they are not included in our or Energex's costs).
- **Corporate overheads** include expenditure incurred for the following functions provided by Energy Queensland: finance, strategy and regulation and people and culture. These costs are allocated between the non-regulated businesses, ourselves and Energex.
- **Network overheads** are indirect costs incurred by ourselves and Energex, including the functions of network planning and project governance, quality and standards, network control and operational switching, and field support.
- **Non-network overheads** are indirect costs incurred by ourselves and Energex, including expenditure incurred to operate and maintain vehicles owned or leased (e.g. fuel, registration, vehicle maintenance), costs for property occupancy and facility management, and information communication and technology costs (e.g. major systems, software applications, data management, infrastructure services).

Once the indirect costs (being Network, Non-Network and Corporate overheads) have been allocated to ourselves and Energex they are then further allocated to the different services types (being SCS, ACS and unregulated services) based on a proportional allocation of direct spending consistent with our AER-approved CAM. The Opex Base Year Attachment 6.003 provides more detail on the allocation methods applied.

It is necessary to charge direct costs and indirect costs (overheads) that are directly attributable to constructing or readying an asset for use to ensure the value of constructed assets correctly reflects all costs incurred. Therefore, a portion of indirect costs allocated to SCS are capitalised based on our Capitalisation Policy and Capitalisation Manual.

This results in approximately 47-48% of our overhead costs being capitalised. We understand that there is a wide range of capitalisation approaches and outcomes across DNSPs in the NEM, with the amount of overheads capitalised ranging up to 50 per cent of overheads.

In developing our capitalised overhead forecasts for the 2020-25 regulatory control period, we have adopted the BST approach. This involves the following stages:

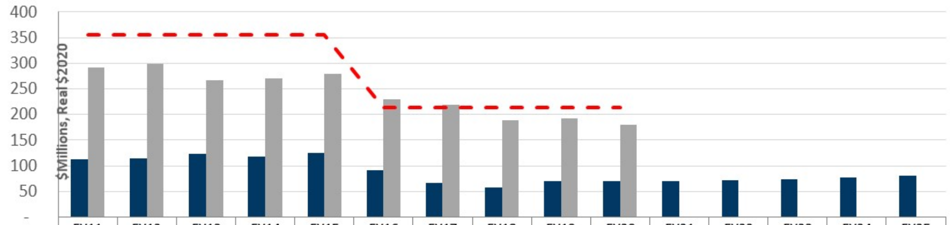
- nominating a base year
- applying adjustments to remove non-recurrent and other expenditure and expected post-merger savings to be delivered in 2018-19
- applying rate of change adjustments to the adjusted base year opex for:
  - Growth in labour and non-labour prices
  - Growth in output
  - Productivity improvements, and
- applying step changes.

Consistent with our opex forecast, we have:

- adopted 2018-19 as our base year capitalised overheads for the reasons set out in chapter 6
- removed from our 2018-19 capitalised overheads base year change fund and redundancies which are not part of the capitalised overheads. We have also removed expected savings to be delivered in 2019-20
- applied the same output growth and price growth that we applied to our opex forecasts as set out in chapter 6 but applied a slightly different productivity improvement factor to reflect targeted savings of 10% in overheads over the 2020-25 regulatory control period, and
- not proposed any step changes.

Figure 34 compares our forecast capitalised overheads for the 2020-25 regulatory control period with our actual overheads and AER allowances over the 2010-15 and 2015-20 regulatory control periods. Our capitalised overheads increase in line with our capex spending on a like-for-like basis.

Figure 34 Capitalised overheads trend compared to allowance



	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
	2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)				
Like for Like Capitalised Overheads	113	114	123	118	125	92	68	58	70	70	71	72	74	77	80
As Reported Capitalised Overheads	291	299	267	271	279	229	220	188	192	180					
Period Average AER Allowance	355	355	355	355	355	213	213	213	213	213					

7.12 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Equipment Asset Management Strategy	7.001	EGX ERG 7.001 Equipment Asset Management Strategy JAN19 PUBLIC
Fleet Asset Management Strategy	7.002	EGX ERG 7.002 Fleet Asset Management Strategy JAN19 PUBLIC
External Unit Rates Review	7.004	ERG 7.004 GHD External Unit Rates Review DEC18 PUBLIC
Unit Cost Methodology and Estimation Approach	7.005	EGX ERG 7.005 Unit Cost Methodology and Estimation Approach JAN19 PUBLIC
Cyber Security Strategy	7.006	EGX ERG 7.006 Cyber Security Strategy JAN19 PUBLIC
ICT Plan	7.007	EGX ERG 7.007 ICT Plan JAN19 PUBLIC
ID01 GIS Consolidation and Replacement	7.008	EGX ERG 7.008 ID01 GIS Consolidation and Replacement JAN19 PUBLIC
ID02 Network Operations Consolidation and Replacement	7.009	EGX ERG 7.009 ID02 Network Operations Consolidation and Replacement JAN19 PUBLIC
ID03 Field Force Systems	7.010	EGX ERG 7.010 ID03 Field Force Systems JAN19 PUBLIC

Name	Ref	File name
ID04 Customer Market Systems	7.011	EGX ERG 7.011 ID04 Customer Market Systems JAN19 PUBLIC
ID05 Design Tools	7.012	EGX ERG 7.012 ID05 Design Tools JAN19 PUBLIC
ID06 Distribution Forecasting Tools	7.013	EGX ERG 7.013 ID06 Distribution Forecasting Tools JAN19 PUBLIC
ID07 Customer Contact Technology	7.014	EGX ERG 7.014 ID07 Customer Contact Technology JAN19 PUBLIC
ID08 Information Repositories	7.015	EGX ERG 7.015 ID08 Information Repositories JAN19 PUBLIC
ID09 Service Interaction Portal	7.016	EGX ERG 7.016 ID09 Service Interaction Portal JAN19 PUBLIC
ID10 MDM	7.017	EGX ERG 7.017 ID10 MDM JAN19 PUBLIC
ID11 Asset Inspections and Planning	7.018	EGX ERG 7.018 ID11 Asset Inspections and Planning JAN19 PUBLIC
ID12 Document Management System	7.019	EGX ERG 7.019 ID12 Document Management System JAN19 PUBLIC
ID13ICT Mgt systems	7.020	EGX ERG 7.020 ID13 ICT Mgt systems JAN19 PUBLIC
ID14 ICT customer mgt	7.021	EGX ERG 7.021 ID14 ICT customer mgt JAN19 PUBLIC
ID15 Network Planning Tools	7.022	EGX ERG 7.022 ID15 Network Planning Tools JAN19 PUBLIC
ID16 Process Management System	7.023	EGX ERG 7.023 ID16 Process Management System JAN19 PUBLIC
ID17 Cyber Security System	7.024	EGX ERG 7.024 ID17 Cyber Security System JAN19 PUBLIC
ID18 Internet Websites	7.025	EGX ERG 7.025 ID18 Internet Websites JAN19 PUBLIC
Asset Management Overview, Risk and Optimisation Strategy	7.026	EGX ERG 7.026 Asset Management Overview, Risk and Optimisation Strategy JAN19 PUBLIC
Asset Management Plan - AFLC	7.027	EGX ERG 7.027 Asset Management Plan - AFLC JAN19 PUBLIC
Asset Management Plan - Circuit Breakers	7.028	EGX ERG 7.028 Asset Management Plan - Circuit Breakers and reclosers

Name	Ref	File name
and reclosers		JAN19 PUBLIC
Asset Management Plan - Communications Linear Assets	7.029	EGX ERG 7.029 Asset Management Plan - Communications Linear Assets JAN19 PUBLIC
Asset Management Plan - Control Systems	7.030	EGX ERG 7.030 Asset Management Plan - Control Systems JAN19 PUBLIC
Asset Management Plan - DC Supply Systems	7.031	EGX ERG 7.031 Asset Management Plan - DC Supply Systems JAN19 PUBLIC
Asset Management Plan - Distribution Transformers	7.032	EGX ERG 7.032 Asset Management Plan - Distribution Transformers JAN19 PUBLIC
Asset Management Plan - Instrument Transformers	7.033	EGX ERG 7.033 Asset Management Plan - Instrument Transformers JAN19 PUBLIC
Asset Management Plan - Operational Tech Environment	7.034	EGX ERG 7.034 Asset Management Plan - Operational Tech Environment JAN19 PUBLIC
Asset Management Plan - Overhead conductors	7.035	EGX ERG 7.035 Asset Management Plan - Overhead conductors JAN19 PUBLIC
Asset Management Plan - Pole Top Structures	7.036	EGX ERG 7.036 Asset Management Plan - Pole Top Structures JAN19 PUBLIC
Asset Management Plan - Poles and Lattice Towers	7.037	EGX ERG 7.037 Asset Management Plan - Poles and Lattice Towers JAN19 PUBLIC
Asset Management Plan - Protection Relays	7.038	EGX ERG 7.038 Asset Management Plan - Protection Relays JAN19 PUBLIC
Asset Management Plan - Ring Main Units	7.039	EGX ERG 7.039 Asset Management Plan - Ring Main Units JAN19 PUBLIC
Asset Management Plan - Services	7.040	EGX ERG 7.040 Asset Management Plan - Services JAN19 PUBLIC
Asset Management Plan - Substation Transformers	7.041	EGX ERG 7.041 Asset Management Plan - Substation Transformers JAN19 PUBLIC
Asset Management Plan - Switches	7.042	EGX ERG 7.042 Asset Management Plan - Switches JAN19 PUBLIC

Name	Ref	File name
Asset Management Plan - Telecommunications	7.043	EGX ERG 7.043 Asset Management Plan - Telecommunications JAN19 PUBLIC
Asset Management Plan - Underground cables	7.044	EGX ERG 7.044 Asset Management Plan - Underground cables JAN19 PUBLIC
Asset Management Policy	7.045	EGX ERG 7.045 Asset Management Policy JAN19 PUBLIC
Business Case - Life Extension Legacy Data Comms	7.046	ERG 7.046 Business Case - Life Extension Legacy Data Comms JAN19 PUBLIC
Customer Quality of Supply Strategy	7.047	EGX ERG 7.047 Customer Quality of Supply Strategy JAN19 PUBLIC
Customer Reliability Strategy	7.048	EGX ERG 7.048 Customer Reliability Strategy JAN19 PUBLIC
Distribution Annual Planning Report	7.050	ERG 7.050 Distribution Annual Planning Report DEC18 PUBLIC
Demand Management Strategy and Plan 2020-25	7.051	EGX ERG 7.051 Demand Management Strategy and Plan 2020-25 JAN19 PUBLIC
DM Customer Engagement Outcomes	7.052	EGX ERG 7.052 DM Customer Engagement Outcomes JAN19 PUBLIC
DM Outcomes 2015-20	7.053	EGX ERG 7.053 DM Outcomes 2015-20 JAN19 PUBLIC
Future Grid Roadmap	7.054	EGX ERG 7.054 Future Grid Roadmap JAN19 PUBLIC
Intelligent Grid Enablement Strategic Proposal	7.055	EGX ERG 7.055 Intelligent Grid Enablement Strategic Proposal JAN19 PUBLIC
Intelligent Grid Technology Plan	7.056	EGX ERG 7.056 Intelligent Grid Technology Plan JAN19 PUBLIC
Justification Statement - Circuit Breakers and Reclosers	7.058	ERG 7.058 Justification Statement - Circuit Breakers and Reclosers JAN19 PUBLIC
Justification Statement - Distribution Transformers	7.061	ERG 7.061 Justification Statement - Distribution Transformers JAN19 PUBLIC

Name	Ref	File name
Justification Statement - Instrument Transformers	7.063	ERG 7.063 Justification Statement - Instrument Transformers JAN19 PUBLIC
Justification Statement - Overhead Conductor	7.065	ERG 7.065 Justification Statement - Overhead Conductor JAN19 PUBLIC
Justification Statement - Pole Top Structures	7.067	ERG 7.067 Justification Statement - Pole Top Structures JAN19 PUBLIC
Justification Statement - Poles and Towers	7.069	ERG 7.069 Justification Statement - Poles and Towers JAN19 PUBLIC
Justification Statement - Return to Service	7.071	ERG 7.071 Justification Statement - Return to Service JAN19 PUBLIC
Justification Statement - Services	7.073	ERG 7.073 Justification Statement - Services JAN19 PUBLIC
Justification Statement - Substation Transformers	7.076	ERG 7.076 Justification Statement - Substation Transformers JAN19 PUBLIC
Justification Statement - Switches incl RMUs	7.077	ERG 7.077 Justification Statement - Switches incl RMUs JAN19 PUBLIC
Justification Statement - Underground Cables	7.079	ERG 7.079 Justification Statement - Underground Cables JAN19 PUBLIC
LV Network Monitoring Strategy	7.080	EGX ERG 7.080 LV Network Monitoring Strategy JAN19 PUBLIC
Planning Proposal - Garbutt	7.082	ERG 7.082 Planning Proposal - Garbutt JAN19 PUBLIC
Planning Proposal - Hermit Park	7.083	ERG 7.083 Planning Proposal - Hermit Park JAN19 PUBLIC
Planning Proposal - Cannonvale and Jubilee Pocket	7.084	ERG 7.084 Planning Proposal - Cannonvale and Jubilee Pocket JAN19 PUBLIC
Planning Proposal - Mossman Reinforcement	7.085	ERG 7.085 Planning Proposal - Mossman Reinforcement JAN19 PUBLIC
Planning Proposal - Childers -Gaydnah	7.086	ERG 7.086 Planning Proposal - Childers - Gaydnah JAN19 PUBLIC
Planning Proposal - Kilkivan	7.087	ERG 7.087 Planning Proposal - Kilkivan JAN19 PUBLIC
Planning Proposal - Meringandan	7.088	ERG 7.088 Planning Proposal - Meringandan JAN19 PUBLIC

Name	Ref	File name
Protection Augmentation Strategy	7.089	EGX ERG 7.089 Protection Augmentation Strategy JAN19 PUBLIC
Strategic Asset Management Plan	7.090	EGX ERG 7.090 Strategic Asset Management Plan JAN19 PUBLIC
Strategic Proposal - Distribution Feeder Augmentation	7.092	ERG 7.092 Strategic Proposal - Distribution Feeder Augmentation JAN19 PUBLIC
Strategic Proposal - LV Safety and Network Visibility	7.093	EGX ERG 7.093 Strategic Proposal - LV Safety and Network Visibility JAN19 PUBLIC
Strategic Proposal - Power Quality	7.095	ERG 7.095 Strategic Proposal - Power Quality JAN19 PUBLIC
Strategic Proposal - Protection Schemes	7.096	EGX ERG 7.096 Strategic Proposal - Protection Schemes JAN19 PUBLIC
Strategic Proposal - Worst Performing Feeder Program	7.098	ERG 7.098 Strategic Proposal - Worst Performing Feeder Program JAN19 PUBLIC
Strategic Proposal - Field Mobile Voice Comms - Coastal	7.099	ERG 7.099 Strategic Proposal - Field Mobile Voice Comms - Coastal JAN19 PUBLIC
Strategic Scope - Protection Relays	7.103	ERG 7.103 Strategic Scope - Protection Relays JAN19 PUBLIC
Strategic Scope - Back Up Reach Program	7.105	ERG 7.105 Strategic Scope - Back Up Reach Program JAN19 PUBLIC
Strategic Scope - CMS Expansion	7.106	ERG 7.106 Strategic Scope - CMS Expansion JAN19 PUBLIC
Strategic Scope - Comms Power Systems	7.107	ERG 7.107 Strategic Scope - Comms Power Systems JAN19 PUBLIC
Strategic Scope - Comms Site Infrastructure	7.108	ERG 7.108 Strategic Scope - Comms Site Infrastructure JAN19 PUBLIC
Strategic Scope - Control Room Enhancement	7.109	EGX ERG 7.109 Strategic Scope - Control Room Enhancement JAN19 PUBLIC
Strategic Scope - DC Supplies Duplication	7.111	EGX ERG 7.111 Strategic Scope - DC Supplies Duplication JAN19 PUBLIC
Strategic Scope - Demand Management Development	7.112	EGX ERG 7.112 Strategic Scope - Demand Management Development

Name	Ref	File name
		JAN19 PUBLIC
Strategic Scope - DMIA	7.113	EGX ERG 7.113 Strategic Scope - DMIA JAN19 PUBLIC
Strategic Scope - Fixed Voice Comms	7.114	ERG 7.114 Strategic Scope - Fixed Voice Comms JAN19 PUBLIC
Strategic Scope - Initiatives Broad Based	7.115	EGX ERG 7.115 Strategic Scope - Initiatives Broad Based JAN19 PUBLIC
Strategic Scope - Initiatives Targeted	7.116	EGX ERG 7.116 Strategic Scope - Initiatives Targeted JAN19 PUBLIC
Strategic Scope - Intelligent Grid Data Comms	7.117	ERG 7.117 Strategic Scope - Intelligent Grid Data Comms JAN19 PUBLIC
Strategic Scope - Network Capacity and Coverage	7.118	ERG 7.118 Strategic Scope - Network Capacity and Coverage JAN19 PUBLIC
Strategic Scope - Non-Network Alternatives	7.119	EGX ERG 7.119 Strategic Scope - Non-Network Alternatives JAN19 PUBLIC
Strategic Scope - Operational Tech Environment	7.122	ERG 7.122 Strategic Scope - Operational Tech Environment JAN19 PUBLIC
Strategic Scope - OT Environment enhancements	7.123	EGX ERG 7.123 Strategic Scope - OT Environment enhancements JAN19 PUBLIC
Strategic Scope - OT Meter Management	7.124	EGX ERG 7.124 Strategic Scope - OT Meter Management JAN19 PUBLIC
Strategic Scope - Physical Linear Media	7.125	ERG 7.125 Strategic Scope - Physical Linear Media JAN19 PUBLIC
Strategic Scope - Remote Terminal Units	7.129	ERG 7.129 Strategic Scope - Remote Terminal Units JAN19 PUBLIC
Strategic Scope - Secure Data Zone	7.131	EGX ERG 7.131 Strategic Scope - Secure Data Zone JAN19 PUBLIC
Strategic Scope - OT Security Environment Enhance	7.133	EGX ERG 7.133 Strategic Scope - OT Security Environment Enhance JAN19 PUBLIC
Strategic Scope - Totem Expansion	7.134	ERG 7.134 Strategic Scope - Totem Expansion JAN19 PUBLIC
Sub Transmission Major Project List	7.136	ERG 7.136 Sub Transmission Major Project List JAN19 PUBLIC
Business Case Property - Banyo Workshop	7.137	EGX ERG 7.137 Business Case

Name	Ref	File name
		Property - Banyo Workshop JAN19 PUBLIC
Business Case Property - Brisbane Office	7.138	EGX ERG 7.138 Business Case Property - Brisbane Office JAN19 PUBLIC
Business Case Property - Brisbane Training Facilities	7.139	EGX ERG 7.139 Business Case Property - Brisbane Training Facilities JAN19 PUBLIC
Business Case Property - Data Centre	7.140	EGX ERG 7.140 Business Case Property- Data Centre JAN19 PUBLIC
Business Case Property - Maryborough	7.141	EGX ERG 7.141 Business Case Property - Maryborough JAN19 PUBLIC
Business Case Property - Townsville Training Centre	7.142	EGX ERG 7.142 Business Case Property - Townsville Training Centre JAN19 PUBLIC
Property Services Strategy	7.143	EGX ERG 7.143 Property Services Strategy JAN19 PUBLIC
Property Strategic Asset Management Plan	7.144	EGX ERG 7.144 Property Strategic Asset Management Plan JAN19 PUBLIC
Capitalisation policy	7.146	ERG 7.146 Capitalisation policy NOV18 PUBLIC
Connection policy	7.148	ERG 7.148 Connection policy JAN19 PUBLIC
Connection Policy Overview	7.150	ERG 7.150 Connection Policy Overview JAN19 PUBLIC
Forecast Capex Model(s) and Methodology	7.154	ERG 7.154 Forecast Capex Model(s) and Methodology JAN19 PUBLIC

8. Regulatory asset base and depreciation

Key Messages

- **We are committed to placing downward pressure on the size of our RAB as part of our focus on continuing to make our electricity distribution services as affordable as possible for our customers.**
- **We propose an opening RAB as at 1 July 2020 of $11,634 million (nominal), calculated using the AER's Roll Forward Model (RFM).**
- **We propose retaining our approach of applying the "year-on-year tracking" method, which the AER has accepted for other DNSPs. This aligns the return of capital (i.e. depreciation) with the economic lives of our assets.**
- **We propose to use forecast depreciation to roll-forward the RAB at the start of the subsequent regulatory control period, consistent with the AER's F&A paper.**

8.1 Overview

8.1.1 Regulatory asset base

Our RAB reflects the value of the investments we have made to provide SCS but are yet to recover. It comprises assets of various economic lives – ranging from short life assets, such as ICT assets (with 5 to 10 year lives), to long-life assets such, as transformers and power lines (with 50 year lives). Under the NER, our RAB is updated annually by adjusting the RAB value from the previous year for:

- inflation (indexation), which increases the RAB
- new capex, which increases the RAB
- depreciation, which reduces the RAB, and
- asset disposals, which reduce the RAB.

The RAB is used to calculate two of the building blocks that make up our revenues – the return on capital (financing costs) and regulatory depreciation (payback of investments). Thus, it has a significant effect on customer charges.

We acknowledge that our RAB has increased significantly since 2005. This has been driven, in part, by our investment in the network to meet demand growth, replace aging assets and augment the network to meet mandated security standards. However, in recent years we have been reducing our capex as demand growth has slowed and security standards have changed. Our RAB is forecast to increase over the current and forthcoming regulatory control periods, but at a much slower rate than in the past.

8.1.2 Regulatory depreciation

Regulatory depreciation is an allowance through which we recover our network investments over the economic lives of our assets. When calculating the depreciation on existing assets at the commencement of the 2020-25 regulatory control period, we note that the AER considers that two approaches meet the requirements of the NER, namely:

- **The weighted average remaining life (WARL) approach**. This is the standard approach employed in the AER's PTRM. The approach pools or groups all past expenditure within an asset class and estimates a single WARL for the entire asset class. Straight-line depreciation is then calculated by dividing the pooled value by the WARL.

- **The year-by-year or period-by-period approach.** This is a novel method that was first adopted in the 2015-20 Distribution Determinations for SA Power Networks and ourselves. Unlike the WARL approach, the tracking approach does not pool all past capex within an asset class. Instead, capex for each year of a regulatory control period is 'tracked' and depreciated separately – either on a year-by-year basis or alternatively on a period-by-period basis. Remaining asset lives are irrelevant under this approach (except for the opening RAB values when the approach is first used – i.e. 1 July 2015). The approach is more complex but also more accurate than the WARL.

We propose continuing to apply the by-year or period-by-period tracking approach in the 2020-25 regulatory control period.

8.2 Establishing the opening RAB

Under the NER, the value of our RAB as at the commencement of the 2020-25 regulatory control period is a constituent element of the AER's Distribution Determination. We calculated the opening value in accordance with clause 6.5.1 and schedule 6.2 of the NER and using the AER's RFM. In summary, we have calculated the opening value at 1 July 2020 by rolling forward the value at the start of the 2015-20 regulatory control period, 1 July 2015, set by the AER in the 2015-20 Distribution Determination. The completed RFM is provided as Attachment 8.008. Table 34 summarises the calculations.

Table 34 Opening RAB as at 1 July 2020

$M, Nominal	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Opening RAB	9,872.98	10,232.91	10,505.53	10,827.56	11,169.17	
Straight-line depreciation	-435.77	-389.19	-395.16	-411.37	-425.14	
Indexation	166.71	151.04	200.56	189.48	251.31	
Capex	628.98	510.78	516.63	563.50	553.22	
Closing RAB	10,232.91	10,505.53	10,827.56	11,169.17	11,548.55	
Adjustment for previous regulatory control period					-68.42	
Legacy ICT assets					153.96	
Opening value as at 1 July 2020						11,634.09

Note: Totals may not add due to rounding.

Capex

In deriving the opening RAB, we used:

- our actual capex for the first three years of the 2015-20 regulatory control period as reported in our annual RINs, and
- forecast capex for the last two years of the 2015-20 regulatory control period. We will provide actual capex for the penultimate year, 2018-19, in our Revised Regulatory Proposal.

Under the NER, in deciding on the value of our opening RAB, the AER must produce a statement on the prudency and efficiency of capex rolled into RAB. The AER may exclude capex from being added to the RAB if we have:

- inefficiently overspent our capex allowances

- paid inflated margins to our related parties, and
- capitalised expenditure previously classified as opex.

Furthermore, the NER provides that the review period for such exclusions is the last two years of the 2010-15 regulatory control period and the first three years of the 2015-20 regulatory control period (i.e. 2013-14 to 2017-18). However, since the AER's Capital Expenditure Incentive Guideline was published in November 2013, the relevant review period for us is the four-year period from 2014-15 to 2017-18. Thus, we have used this four-year period to assess whether a reduction is required for our opening RAB. We note that over this period we:

- underspent our capex allowances
- did not include related party margins in our capex, and
- did not change our capitalisation policies to capitalise more expenditure.
- For these reasons, we do not consider that our opening RAB should be reduced.

Indexation

Consistent with the approach used in our control mechanism, we calculated indexation of our RAB for each year by applying the actual annual December to December All Groups CPI, Weighted Average of Eight State Capital Cities (published by the Australian Bureau of Statistics).

Depreciation

Consistent with the 2015-20 Distribution Determination, we roll-forward the RAB using the forecast depreciation approved by the AER for the 2015-20 regulatory control period.

Legacy ICT assets

As discussed in section 7.10.1, in the 2010-15 and 2015-20 regulatory control periods, our ICT services were provided by SPARQ which then formed part of Energy Queensland. We note that in the 2015-20 Distribution Determination the AER expressed concerns regarding our treatment of ICT costs particularly our 'off-balance sheet treatment' of ICT assets. The AER considered that it lacked transparency and made it difficult to assess our ICT costs against other DNSPs.

In light of the merger and the AER's previous concerns, commencing from 1 July 2020, we are proposing to capture all our ICT assets within our RAB. In transitioning to this approach, we propose to add our legacy ICT assets projected to be valued at $154 million into the RAB as at 1 July 2020. As per customer feedback, we also propose to assign an asset life of 10 years to these assets, which is longer than our 5 year standard life for our ICT assets. We consider that this will smooth the recovery of these legacy assets and limit distribution network charge shocks. Attachment 8.001 details how we derived the value of legacy ICT assets.

8.3 Forecast RAB

Our forecast RAB over the 2020-25 regulatory control period is set out in Table 35. We have derived the RAB values in accordance with the NER and using the AER's PTRM. In summary, we have taken the opening RAB value outlined in the previous section and:

- added forecast indexation (as discussed in section 8.4.2)
- added forecast capex (which is discussed in chapter 9)
- deducted straight-line depreciation (as discussed in section 8.4), and
- deducted forecast disposals.

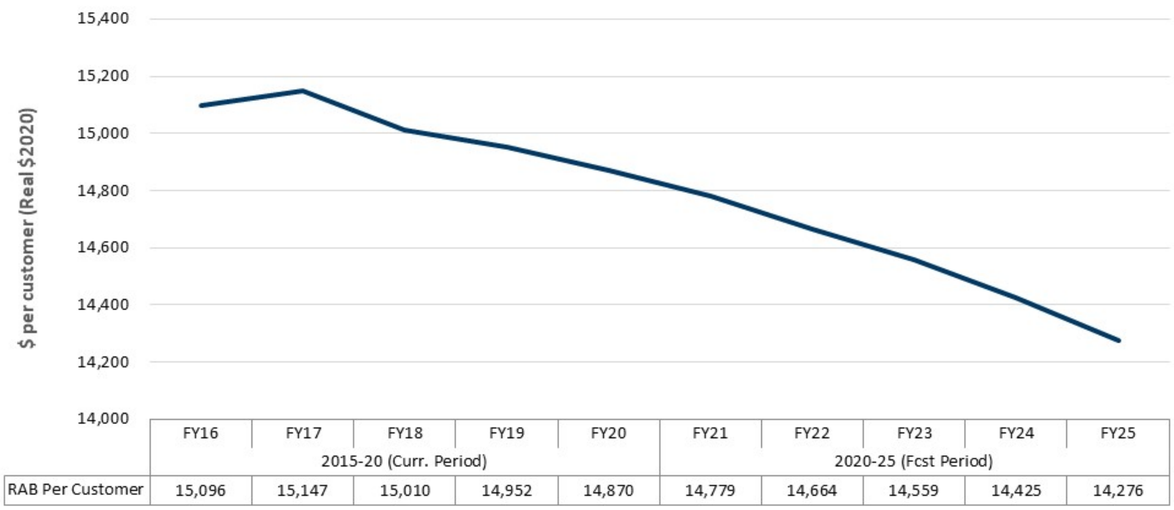
Table 35 Forecast RAB over the 2020-25 regulatory control period

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Opening RAB	11,634.09	12,011.43	12,392.06	12,791.20	13,174.68
Capex	549.81	575.70	610.34	608.68	628.16
Straight-line depreciation	-454.01	-485.74	-511.09	-534.75	-567.20
Indexation	281.54	290.68	299.89	309.55	318.83
Closing RAB	12,011.43	12,392.06	12,791.20	13,174.68	13,554.47

Note: Totals may not add due to rounding.

Figure 35 demonstrates the efforts made by Ergon Energy to improve the efficiency of its capital employed, resulting in a reduced RAB per customer.

Figure 35 RAB per customer trends



8.4 Forecast depreciation

Depreciation is the mechanism through which we recover our network investments typically over the economic lives of the assets. The current approach of the AER is to net off straight-line depreciation (which reduces the RAB) and indexation (which increases the RAB) and to refer to the net value as ‘regulatory depreciation’.

Our forecast regulatory depreciation schedules are provided as Attachment 8.006. Table 36 summarises the calculations.

Table 36 Forecast regulatory depreciation

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25
Straight-line depreciation	454.01	485.74	511.09	534.75	567.20
Indexation	281.54	290.68	299.89	309.55	318.83
Regulation depreciation	172.47	195.07	211.20	225.20	248.37

8.4.1 Depreciation methodology

The NER does not prescribe a method for calculating depreciation. Rather, clause 6.5.5 of the NER provides that the AER must use the depreciation schedules proposed by the DNSP to the extent that they conform to the following key requirements:

- the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.
- the sum of the real value of the depreciation that is attributable to any asset or category of assets must be equivalent to the value at which that category of assets was first included in the RAB for the relevant distribution system.

The AER's PTRM is configured to use the straight-line method as the default method for calculating depreciation. We have used this method in conformance with clause 6.5.5(b)(1) of the NER. We recognise that this approach may change in the future.

In calculating depreciation, the approach taken in the PTRM is to derive the total straight-line depreciation as the sum of:

- the depreciation on existing assets at the commencement of the regulatory control period (opening asset value) – based on their remaining asset lives, and
- the depreciation on forecast capex (new additions) over the regulatory control period – based on their standard asset lives.

As previously mentioned, we are proposing to continue to apply year-by-year tracking approach in calculating the depreciation on existing assets at the commencement of the regulatory control period. Therefore, our depreciation proposal for the 2020-25 regulatory control period is to:

- combine our all our pre-2015 assets, i.e. assets in existing assets at the commencement of the current regulatory control period (1 July 2015). In the 2015-20 Distribution Determination, these consisted of two groups being the pre-2010 assets and the 2010-2015 period capex. We have derived a value-weighted remaining life that is used to depreciate the combined pre-2015 assets going forward.
- depreciate actual and forecast capex for the 2015-20 regulatory control period separately using standard asset lives, and
- depreciate forecast capex for the 2020-25 regulatory control period using standard asset lives.

Table 37 sets out our proposed standard asset lives. We propose to use the same asset lives as approved by the AER in the 2015-20 Distribution Determination. We have reviewed the asset lives and do not consider that any changes are warranted at this stage.

Table 37 Standard asset lives

Asset Class	Remaining asset lives in years (at 1 July 2015)	Standard asset life in years
Overhead Sub-Transmission Lines	33.00	55.00
Underground Sub-Transmission Cables	27.84	45.00
Overhead Distribution Lines	36.50	50.00
Underground Distribution Cables	47.86	60.00
Distribution Equipment	27.46	35.00
Substation Bays	32.34	45.00
Substation Establishment	32.56	60.00

Asset Class	Remaining asset lives in years (at 1 July 2015)	Standard asset life in years
Distribution Substation Switchgear	37.84	45.00
Zone Transformers	31.63	50.00
Distribution Transformers	27.38	45.00
Low Voltage Services	32.24	35.00
Communications – Pilot Wires	28.86	35.00
Generation Assets	27.32	30.00
Other Equipment	37.16	40.00
Control Centre - SCADA	4.30	7.00
Land & Easements (System) - combined	N/A	N/A
IT Systems	32.56	5.00
Office Equipment & Furniture	4.33	7.00
Motor Vehicles	7.51	10.00
Plant & Equipment	5.36	10.00
Buildings	36.67	40.00
Land & Easements - combined	N/A	N/A
Land Improvements	35.76	40.00
Metering	22.31	25.00
Communications	27.88	30.00
ICT Legacy Assets	-	10.00
Equity raising costs	43.98	47.86

8.4.2 Forecast inflation

We have calculated forecast inflation using the AER's preferred Reserve Bank of Australia (RBA) method. Our calculation is discussed in section 9.4.

8.5 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Integration of legacy ICT assets	8.001	EGX ERG 8.001 Integration of legacy ICT assets JAN19 PUBLIC
Modelling Architecture Summary	8.002	EGX ERG 8.002 Modelling Architecture Summary JAN19 PUBLIC
PTRM – SCS	8.004	ERG 8.004 PTRM – SCS JAN19 PUBLIC
RAB Depreciation Model	8.006	ERG 8.006 RAB Depreciation Model JAN19 PUBLIC
RFM – SCS	8.008	ERG 8.008 RFM – SCS JAN19 PUBLIC

9. Rate of return

Key Messages

- **We accept the outcomes of the AER's 2018 Rate of Return Instrument.**
- **We propose a rate of return of 5.46% for this Regulatory Proposal.**
- **We have applied the AER's preferred RBA method to forecast inflation.**
- **We have applied the AER's methodology for forecasting debt and equity raising costs.**

9.1 Overview

The rate of return is an estimate of the financing costs that we face to attract the funds we require to invest in the network. It is estimated as a weighted average of the return on equity and the return on debt as we generally acquire funds from two sources: equity from shareholders and debt from lenders.

As a capital-intensive business, the rate of return is a significant driver of our revenues (and customer charges). The return of capital building block, which is calculated by multiplying the rate of return and the value of the RAB, makes up more than 51% of our revenues.

Under the NEL, the AER's Rate of Return Instrument sets out how the AER calculates the rate of return and value of imputation credits. The Rate of Return Instrument is binding on the AER and network service providers in a regulatory determination. In December 2018, after an 18-month consultation process, the AER published its final 2018 Rate of Return Instrument, which applies to our Distribution Determination. We accept the outcomes of the development of the Rate of Return Instrument.

We have applied the Rate of Return Instrument to derive a rate of return estimate of 5.46%. This is a placeholder estimate that will be updated by the AER in its Final Distribution determination to reflect our nominated averaging periods that are used to estimate the risk free rate (for the return on equity) and the return on debt. Further, the rate of return will be updated annually during the 2020-25 regulatory control period as a result of the annual update of the return on debt under the trailing average approach.

9.2 Rate of return

As mentioned above, consistent with the Rate of Return Instrument, we propose a rate of return of 5.46% for this Regulatory Proposal. We have calculated this value using the formula in Clause 3 of the Rate of Return Instrument, which calculates the allowed rate of return as:

$$return\ on\ equity\ \times (1 - gearing\ ratio) + return\ on\ debt\ \times gearing\ ratio$$

Table 38 summarises the parameters used in our calculations.

Table 38 Rate of return

Parameter	Value
Return on equity	6.26%
Return on debt	4.92%
Gearing ratio	0.60
Rate of return	5.46%

9.2.1 Return on equity

We propose a return on equity of 6.26% for this Regulatory Proposal, consistent with the Rate of Return Instrument. In estimating the proposed value, we used the formula contained in Clause 4 of the Rate of Return Instrument, which estimates the allowed return of equity as:

$$risk\ free\ rate + equity\ beta\ \times market\ risk\ premium$$

Table 39 summarises the parameters used in our calculations.

Table 39 Return on equity

Parameter	Value	Basis
Risk free rate	2.60%	This is a placeholder estimate of the risk-free rate for the purpose of this Regulatory Proposal. The AER will calculate our actual risk-free rate using the method outlined in Clause 4 of the Rate of Return Instrument and the nominated averaging period we have proposed in Attachment 9.002.
Equity beta	0.60	As set in the Rate of Return Instrument
Market risk premium	6.00%	As set in the Rate of Return Instrument
Return on equity	6.26%	

9.2.2 Return on debt

The Rate of Return Instrument sets out that the return on debt is to be calculated using a trailing average portfolio approach following a 10 year transition from the on-the-day approach. We commenced our transition to the trailing average approach in the 2015-16 regulatory year, and we are therefore part way through the 10 year transition. Under the transition approach, the on-the-day return on debt estimated shortly prior to the commencement of the 2015-16 regulatory year is applied to:

- 100 per cent of the debt portfolio for the 2015–16 regulatory year
- 90 per cent of the debt portfolio for the 2016–17 regulatory year, with the remaining 10 per cent based on prevailing interest rates during the averaging period for 2016–17
- 80 per cent of the debt portfolio for the 2017–18 regulatory year, with 10 per cent based on prevailing interest rates during the averaging period for 2016–17, and 10 per cent based on prevailing interest rates during the averaging period for 2017–18
- 70 per cent of the debt portfolio for the 2018-19 regulatory year, with 10 per cent based on the prevailing interest rates during the averaging period for 2016-17, 10 per cent based on the prevailing interest rates during the averaging period for 2017-18, and 10 per cent based on the prevailing interest rates during the averaging period for 2018-19, and
- so on for the subsequent regulatory years.

Following the transition period, the return on debt will be calculated as simple average of the prevailing interest rates during our averaging periods over the previous 10 years.

Up to now, the AER has updated the return on debt for the first four years of transition period – 2015-16 to 2018-19. Therefore, we have forecast the return on debt applying to each regulatory year of the remainder of the transition period by applying the approach outlined above and also assuming that the prevailing interest rates estimated during the most recent averaging period, for the current 2018-19 regulatory year, apply for the remainder of the transition period. The following table sets out our actual return on debt estimates as determined by the AER to date and our proposed forecast return on debt estimates to 2024-25. Our calculations are set out in Attachment 9.002.

Table 40 Return on debt

Regulatory year	Prevailing interest rates during averaging period	Trailing return on debt	Basis
2015-16	5.01%	5.01%	Actuals as determined by the AER
2016-17	5.53%	5.06%	Actuals as determined by the AER
2017-18	5.11%	5.07%	Actuals as determined by the AER
2018-19	4.51%	5.02%	Actuals as determined by the AER
2019-20	4.51%	4.97%	Forecast
2020-21	4.51%	4.92%	Forecast
2021-22	4.51%	4.87%	Forecast
2022-23	4.51%	4.82%	Forecast
2023-24	4.51%	4.77%	Forecast
2024-25	4.51%	4.72%	Forecast

We anticipate that the AER's draft Distribution Determination will be updated to reflect the annual return on debt update for the 2019-20 regulatory year, and the AER's final Distribution Determination will reflect the annual return on debt update for the 2020-21 regulatory year, which is the first year of the 2020-25 regulatory control period.

Consistent with the Rate of Return Instrument, we accept that the rate of return will be updated annually over the 2020-25 regulatory control period. Furthermore, we accept the Rate of Return Instrument's proposed approach to estimating the annual prevailing interest rates in each year of the 2020-25 regulatory control period, particularly based on the following:

- a 10-year benchmark tenor
- BBB+ benchmark credit rating, which is implemented by adopting a weighted average of 1/3 A-rated and 2/3 BBB-rated curves
- Bloomberg, RBA, and Thomson Reuters curves as third party data sources
- extrapolation and interpolation methodologies for third party data sources, and
- the conditions for nominating averaging periods. Our nominated averaging periods for the 2020-25 regulatory control period are set out in a confidential Attachment 9.001.

9.3 Debt and equity raising costs

9.3.1 Debt raising costs

Debt raising costs are transaction costs incurred in raising and/or refinancing debt. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs. The Rate of Return Instrument does not deal with the calculation of debt raising costs. However, the AER has, over successive regulatory determinations, consistently applied a forecasting approach based on the Allen Consulting Group report, commissioned by the Australian Competition and Consumer Commission in 2004.

We propose to adopt this same approach, which involves:

- Calculating the benchmark bond size – currently set at $250 million, based on recent AER decisions, and
- Calculating the number of bond issues required to rollover the benchmark debt share (60%) of the RAB. Our opening RAB for the 2020-25 regulatory control period is approximately $12 billion. This implies that 28 bond issues are required to rollover the assumed debt share of $7 billion.
- Amortising the upfront debt issuance costs incurred using our nominal vanilla weighted average cost of capital (WACC) over a ten-year period. Our Regulatory Proposal uses the upfront costs adopted by the AER in several recent decisions and our proposed rate of return of 5.46%.
- Expressing the debt issuance costs in basis points per annum (bppa) as an input into the PTRM.
- Multiplying the rate by our projected RAB to determine the debt raising cost allowance.

Our proposed estimate of debt raising costs is 8.05 bppa, as set out in Table 41.

Table 41 Debt raising costs

Number of bonds	Value	1 bond issued	28 bonds issued
Amount raised	-	250.00	7,000.00
Arrangement fee	8.50	6.92	6.92
Bond Master Program (per program)	56,250.00	0.30	0.01
Issuer's legal counsel	15,625.00	0.08	0.08
Company credit rating	77,500.00	0.41	0.01
Annual surveillance fee	35,500.00	0.14	0.01
Up-front issuance fee	5.20	0.69	0.69
Registration up-front (per program)	20,850.00	0.11	0.00
Registration- annual	7,825.00	0.31	0.31
Agents' out-of-pockets	3,000.00	0.02	0.02
Total (bppa)	-	8.98	8.05

9.3.2 Equity raising costs

Equity raising costs are the transaction costs associated with raising new equity. These include legal fees, marketing costs and other transaction costs incurred in this process. The Rate of Return Instrument does not cover the estimation of equity raising costs. However, the AER has, over successive regulatory determinations, developed a well-accepted cash flow analysis approach to estimating equity raising costs. The estimated equity raising cost allowance (if any) is amortised over the weighted average standard life of new capex added to the RAB over the 2020-25 regulatory control period.

We have applied this approach and, based on our projected capex and cash flows, we do not forecast any equity raising costs.

9.4 Expected inflation

We propose to adopt the AER's preferred method for forecasting expected inflation – the RBA method. Clause 6.4.2(b)(1) of the NER requires the AER to specify in the PTRM a methodology that is likely to result in the best estimate of expected inflation. The AER's preferred method for estimating expected inflation is the RBA method, which is the 10-year geometric annualised average of the RBA's forecast headline rate for the two years ahead and the mid-point of the RBA target inflation band of 2% to 3% for eight years.

For the purpose of this Regulatory Proposal, we used a forecast of 2.42% based on the August 2018, RBA Statement of Monetary Policy as summarised in Table 42.

Table 42 Forecast inflation

Per cent	2018-19	2019-20	2020-21 to 2027-28	Geometric mean
Forecast inflation	2.00%	2.25%	2.50%	2.42%

9.5 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Averaging periods – rate of return	9.001	EGX ERG 9.001 Averaging periods – rate of return JAN19 CONFID
Rate of return	9.002	EGX ERG 9.002 Rate of return JAN19 PUBLIC

10. Estimated cost of corporate income tax

Key Messages

- **We accept the AER's Rate of Return Instrument value of imputation credits (gamma).**
- **Our forecast tax allowances set out in this Regulatory Proposal will likely reduce as a result of the AER's recently completed review of its regulatory tax approach.**

10.1 Overview

Our allowed revenues include a notional corporate income tax allowance. This represents an estimate of the cost of corporate income tax faced by a benchmark firm operating our business.

The corporate tax allowance is forecast using a standard tax calculation that considers our forecast taxable revenue and taxable expenses (depreciation, interest and opex), as well as the statutory corporate tax rate and the value of imputation credits (gamma).

Under the NEL, the AER's Rate of Return Instrument sets out the value of imputation credits. On 17 December 2018, the AER published its 2018 Rate of Return Instrument which applies in our Distribution Determination. We accept the value of 0.585 set out in the AER's Rate of Return Instrument.

We note that the AER recently reviewed its regulatory tax approach and published a final report on 17 December 2018. The final report recommends changes to the AER's approach. The changes that impact us (immediate expensing of certain capex and use of diminishing value method) require formal model changes to the AER's RFM and PTRM. Given that the AER is required to run a consultation process before amending the RFM and PTRM and the consultation will not be completed by the time our proposal is due, we have not accounted for the potential changes to the AER's tax approach in this Regulatory Proposal. Although we have not accounted for the potential changes, we expect that they will likely reduce the tax allowance forecasts – which will benefit our customers through lower prices. We will work with the AER as part of its consultation and the Distribution Determination as it looks to give effect to those changes.

10.2 Forecast corporate tax allowance

We have forecast our proposed corporate income tax allowance using the AER's PTRM. Our completed PTRM is provided as Attachment 8.004 and summarised in Table 43 below. The PTRM's corporate income tax allowance calculations are governed by Clause 6.5.3 of the NER, which specifies the following formula:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

Where:

- ETC_t is the estimated corporate income tax allowance for each regulatory year.
- ETI_t is an estimate of the taxable income for each regulatory year that would be earned by a benchmark firm operating our business (and providing SCS). This is calculated using the AER's PTRM.
- r_t is the expected statutory tax rate. We adopt the statutory tax rate of 30%.

- γ is the value of imputation credits. We adopt the AER's rate of return instrument value of 0.585.

Table 43 Forecast tax allowance

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Tax payable	66.94	67.95	66.78	69.50	75.74	**346.91**
Less: value of imputation credits	-39.16	-39.75	-39.07	-40.66	-44.31	**-202.94**
Net corporate income tax allowance	27.78	28.20	27.71	28.84	31.43	**143.97**

Note: Totals may not add due to rounding.

10.3 Forecast tax depreciation

Forecast tax depreciation is a key input in the estimating of our corporate income tax allowances. Under the Australian tax system, depreciation is a deductible expense. The regulatory calculation of tax depreciation depends on:

- The value of the regulatory tax asset base as at the commencement of the 2020-25 regulatory control period, i.e. 1 July 2020. We used the AER's RFM to derive the opening tax asset base as at 1 July 2020. Our completed RFM is provided as Attachment 8.008 and summarised in Table 44. We rolled forward the value of the tax asset base at 1 July 2015 set by the AER in the 2015-20 Distribution Determination. As outlined in section 7.10.1, we are proposing to add our legacy ICT assets into the RAB at 1 July 2020. Therefore, we have added a corresponding value to the tax asset base.
- The tax remaining asset lives used to calculate tax depreciation of on our opening tax base. We have adopted the weighted average remaining asset lives derived in the RFM. These are outlined in Table 45.
- The tax standard asset lives used to calculate tax depreciation on our new investments. We adopted the values provided in our 2017-18 Annual RIN. These values are consistent with the Australian Taxation Office's (ATO) approved lives.

Table 44 Opening tax asset base as at 1 July 2020

$M, Real $2020	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Opening tax asset base	6,240.43	6,617.07	6,842.86	7,088.41	7,384.16	
Capital expenditure	638.96	507.84	545.90	595.95	585.76	
Less: Tax depreciation	- 262.32	- 282.04	- 300.35	- 300.20	- 314.59	
Closing tax asset base	6,617.07	6,842.86	7,088.41	7,384.16	7,655.33	
Adjustment for legacy ICT assets					153.96	
Opening tax asset base as at 1 July 2020						7,809.29

Table 45 Tax asset lives

Asset Class	Standard asset lives in years	Remaining asset lives in years at 1 July 2020
Overhead Sub-Transmission Lines	45.00	22.37
Underground Sub-Transmission Cables	50.00	34.60
Overhead Distribution Lines	45.00	33.98
Underground Distribution Cables	50.00	36.00
Distribution Equipment	45.00	39.48
Substation Bays	40.00	32.74
Substation Establishment	40.00	29.83
Distribution Substation Switchgear	40.00	32.98
Zone Transformers	40.00	22.87
Distribution Transformers	40.00	26.47
Low Voltage Services	40.00	26.11
Communications – Pilot Wires	10.00	5.62
Generation Assets	15.00	11.97
Other Equipment	40.00	32.60
Control Centre - SCADA	10.00	5.61
Land & Easements (System) - combined	N/A	n/a
IT Systems	4.00	2.54
Office Equipment & Furniture	10.00	3.44
Motor Vehicles	13.50	9.24
Plant & Equipment	5.00	3.34
Buildings	40.00	30.80
Land & Easements - combined	N/A	n/a
Land Improvements	40.00	32.80
Metering	25.00	17.98
Communications	10.00	3.66
ICT Legacy Assets	-	10.00
Equity raising costs	-	-

11. Incentive schemes

Key Messages

- **We are responding to incentives to improve our service performance and cost efficiency**
- **We are entitled to revenue increments under the CESS and EBSS for efficiencies achieved in the current 2015-20 regulatory control period. However, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to not claim the potential revenue adjustment associated with these efficiency schemes in this Regulatory Proposal.**
- **We welcome the AER's proposal to continue to apply the EBSS, CESS, STPIS, DMIS, and DMIAM in the 2020-25 regulatory control period**

11.1 Overview

We operate under an incentive-based regulatory framework where we are encouraged to continuously improve efficiency. A key feature of this framework is that the AER sets the maximum revenue that we can recover from our customers over the course of the regulatory control period, thus encouraging us to provide our services at a lower cost than forecast by the AER.

In addition, the NER stipulates that the AER may, or must, develop a suite of incentive schemes to compliment the incentive-based regulatory framework. The incentive schemes encourage us to continuously improve our service performance, cost efficiency, and demand management. They include an EBSS, CESS, STPIS, DMIS, DMIAM, and the Small Scale Incentive Scheme (SSIS).

In the F&A paper for our regulatory control period commencing 1 July 2020, the AER proposed to apply the EBSS, CESS, STPIS, DMIS and DMIAM. We support the application of these schemes as we consider that they align our incentives with the long-term interests of our customers, thus promoting the National Electricity Objective. The AER did not specify a SSIS in the F&A paper; we support the AER's position.

> We only benefit under these incentive schemes if customers also benefit

We note that we are responding to incentives by outperforming our service performance targets, projecting capex and opex efficiencies and continuing to pursue demand management solutions in the current regulatory control period. We are entitled to revenue increments in the 2020-25 regulatory control period under the CESS and EBSS for efficiencies achieved in the current 2015-20 regulatory control period. However, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to not claim the potential revenue adjustment associated with these efficiency schemes in this Regulatory Proposal. In doing so, we believe we are presenting a balanced proposal focussed on our customer's key concerns of safety, affordability and security and sustainability. In the event the AER has any material concerns with our Regulatory Proposal in its Draft Determination, we will reassess our approach to efficiency schemes to ensure our Revised Regulatory Proposal continues to provide a balanced approach in the long term interests of our customers.

Attachment 11.002 outlines in detail our proposed approach to the application of each incentive scheme, while the remainder of this chapter summarises our acceptance of the application of the schemes in the 2020-25 regulatory control period.

11.2 Efficiency Benefit Sharing Scheme

The EBSS encourages us to pursue opex efficiency improvements and share these with customers. We retain approximately 30% of efficiency gains (or losses) and customers receive 70% under the scheme.

The EBSS is intrinsically linked to the revealed cost or BST forecasting approach, where our forecast opex is based on our actual opex from a recent nominated base year. The EBSS addresses two potential incentive problems arising from this forecasting approach:

- the incentive to increase opex in the base year to increase forecast opex, and
- the incentive to defer efficiency improvements until after the base year.

The use of the BST forecasting approach combined with the EBSS provides us with the same reward and penalty in each year of the regulatory control period.

Prior to the commencement of the next regulatory control period, the AER calculates our carryover amounts for opex efficiency gains (or losses) made in the current regulatory control period, and adds (or subtracts) these to (or from) our annual revenue requirements.

11.2.1 Carryovers from the 2015-20 regulatory control period

The EBSS currently applies in our 2015-20 regulatory control period. As set out in chapter 6, we have achieved efficiencies over the 2015-20 regulatory control period through the merger savings achieved in Energy Queensland. We project that our opex for the last two years of the current regulatory control period, which includes our nominated base year, will be below the efficient opex forecast determined by the AER for the 2015-20 regulatory control period. The lower opex will flow through to our forecast opex for the 2020-25 regulatory control period to the benefit of our customers.

As we are projecting significant opex savings at the end of the current regulatory control period, we are forecasting significant positive EBSS carryovers as a result, as set in the table below. The EBSS model, provided as Attachment 17.057, sets out the detailed calculations of the proposed EBSS carryovers.

Table 46 Proposed EBSS carryovers not claimed

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
EBSS	66.3	51.1	75.9	50.1	25.1	268.5

Note: Totals may not add due to rounding.

While we are entitled to recover the positive carryovers in the next regulatory control period as part of our annual revenue requirements, as we outlined above, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to not claim these potential revenue increments. We have not included these forecast carryovers in our forecast annual revenue requirements provided in chapter 13.

11.2.2 Application of the EBSS in the 2020-25 regulatory control period

In the F&A paper, the AER proposed to apply the EBSS in the 2020-25 regulatory control period. However, the AER indicated that the application of the EBSS is contingent on using the BST forecasting approach, which in turn, depends on the efficiency of our base year. We consider that our revealed costs provide an appropriate basis for determining our forecast opex. As previously mentioned, our 2018-19 opex base year estimate is below the efficient opex forecast determined by the AER for the 2015-20 regulatory control period and efficient compared to the AER's benchmarking models. We consider that we are responding appropriately to the incentives to reduce opex.

Therefore, we support the continued application of the EBSS in the 2020-25 regulatory control period.

We also support the opex adjustments allowed under version 2 of EBSS, namely adjustments for:

- approved pass through amounts or opex for contingent projects
- capitalisation policy changes
- categories of opex not forecast using a single year revealed cost approach for the regulatory control period. For the 2020-25 regulatory control period, we propose to exclude debt raising costs and DMIA, and
- inflation.

The table below sets out our proposed opex for the EBSS.

Table 47 Proposed EBSS opex for the 2020-25 regulatory control period

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Adjusted forecast opex	370.5	364.5	359.2	353.6	348.0	1795.8

Note: Totals may not add due to rounding.

11.3 Capital Expenditure Sharing Scheme

The CESS encourages us to spend capex efficiently over the regulatory control period by rewarding or penalising us for capex efficiency gains or losses respectively. Similar to the EBSS, we retain 30% of underspends (or overspends) and customers receive 70%. The AER's forecast capex is used as a proxy for efficient capex, and differences between forecast and actual capex approximate efficiency gains and losses.

11.3.1 CESS outcomes from the 2015-20 regulatory control period

The CESS currently applies in our 2015-20 regulatory control period. As we outlined in chapter 7, we are reducing our capex. We are projecting substantial capex savings in the 2015-20 regulatory control period and are forecasting even lower capex in the 2020-25 regulatory control period. The capex savings and reductions will ultimately limit our RAB growth and lower network charges over time.

The CESS revenue increments resulting from our capex savings are provided in following table. The CESS model, provided as Attachment 17.057, sets out the detailed calculations of the proposed CESS rewards.

Table 48 Proposed CESS payments not claimed

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
CESS	7.87	7.87	7.87	7.87	7.87	39.33

While we are entitled to recover the positive carryovers in the next regulatory control period as part of our annual revenue requirements, as we outlined above, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to not claim these potential revenue increments. We have not included these forecast rewards in our forecast annual revenue requirements provided in chapter 13.

11.3.2 Application of the CESS in the 2020-25 regulatory control period

In the F&A paper, the AER proposed to apply the CESS in the 2020-25 regulatory control period. We support the continued application of the CESS, together with the use of forecast depreciation in the 2020-25 regulatory control period.

11.4 Service Target Performance Incentive Scheme

The STPIS encourages us to maintain and improve service performance where customers are willing to pay. The AER's STPIS comprises two mechanisms:

- a service incentive factor (s-factor) where we are rewarded and penalised for better or worse performance against set targets via annual adjustments to our approved revenues, and
- a GSL payments scheme that provides payments directly to customers where certain levels of service are not met.

Currently, as a result of the operation of the Queensland GSL scheme, which is administered by the QCA, only the s-factor component of the STPIS applies to us.

In the F&A paper, the AER proposed to apply to continue to apply the STPIS in the 2020-25 regulatory control period. The STPIS has applied in Queensland since 2010 and we have consistently delivered great service performance for our customers as evidenced by our outperformance of STPIS targets. We therefore support the AER's proposal including the following aspects of the STPIS:

- retaining a revenue at risk of ±2%
- segmenting our network as urban, short-rural and long rural
- applying the following s-factor parameters:
    - reliability component: SAIDI and SAIFI
    - customer service component: telephone answering
- setting our performance targets based on our average performance over the past 5 years
- applying the methodology indicated in the national STPIS for excluding certain events from the s-factor calculations
- applying the methodology indicated in the national STPIS and the Australian Energy Market Operator's (AEMO) 2014 Value of Customer Reliability (VCR) study for calculating incentive rates, and
- excluding the GSL component of the STPIS.

Lastly, we note that on 14 November 2018, the AER published its revised STPIS. We support the application of the revised STPIS and have developed our STPIS targets and incentive rates largely consistent with revised STPIS as outlined in Attachment 11.008.

11.5 Demand Management Incentive Scheme and Innovation Allowance Mechanism

The NER provides for a demand management incentive framework to encourage us to pursue demand management (i.e. non-network solutions). In December 2017, the AER published the:

- new Demand Management Incentive Scheme, which is designed to encourage us to undertake efficient expenditure on relevant non-network options relating to demand management. The new scheme has three key elements:

- a cost uplift (of up to 50 per cent) on expected costs of efficient demand management projects
- a net benefit constraint, which ensures that incentive payments for any project do not exceed the project's expected net benefit
- an overall incentive constraint, which limits the total incentive in any year to 1 per cent of our annual revenues.

- revised Demand Management Innovation Allowance Mechanism (DMIAM), which provide us with funding for research and development (R&D) in demand management projects that have the potential to reduce long term network costs. The revised DMIAM is similar in design to the AER's current DMIA. It provides an ex-ante R&D allowance and any underspend of the allowance is returned to customers in the following regulatory control period.

In the F&A paper, the AER proposed to apply the new DMIS and the revised DMIAM. We support the AER's position. Further, consistent the revised DMIAM approach, we propose the following DMIAM allowances for the 2020-25 regulatory control period. The calculations are set out in the PTRM provided as Attachment 8.002.

Table 49 Proposed DMIAM allowances for the 2020-25 regulatory control period

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
DMIAM	1.10	1.11	1.11	1.12	1.13	5.56

11.6 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Application of Incentive Schemes	11.002	ERG 11.002 Application of Incentive Schemes JAN19 PUBLIC
STPIS Targets and Incentive Rates	11.008	ERG 11.008 STPIS Targets and Incentive Rates JAN19 PUBLIC
2020-25 Efficiency Benefit Sharing Scheme RIN template	17.057	ERG 17.057 2020-25 Efficiency Benefit Sharing Scheme RIN template JAN19 PUBLIC

12. Pass through events and contingent projects

Key Messages

- **In addition to the prescribed pass through events in the NER, we are nominating the following pass through events and definitions that have been previously accepted by the AER for other DNSPs: an insurance cap event; an insurer's credit risk event; a terrorism event; and a natural disaster event.**
- **We are not proposing any contingent projects.**

12.1 Overview

We operate in an uncertain environment where events outside of our control can materially change our costs over the 2020-25 regulatory control period. It is virtually impossible for us to estimate now the efficient costs of responding to such events; therefore, we exclude them from our forecasts. However, in limited circumstances, the NER allows for our revenues to be adjusted if and when such events occur over the course of the 2020-25 regulatory control period. The AER tests these applications and reviews our efficient costs at that time.

This ensures that customers only pay for costly events that actually occur and when the efficient costs can be estimated with reasonable certainty.

The mechanisms in the NER used to manage uncertainty comprise:

- Pass through events – which enable us to recover (or pass through) costs of defined, unpredictable, high costs events not provided for in the Distribution Determination. The NER prescribe the following events as pass through events for a regulatory control period:
    - a regulatory change event
    - a service standard event
    - a tax change event
    - a retailer insolvency event.

  In addition, we are allowed to nominate additional events as pass through events as part of our Regulatory Proposal. For the 2020-25 regulatory control period, we propose the following four nominated pass through events:
    - insurance cap event
    - insurer credit risk event
    - terrorism event
    - natural disaster event.
- Contingent projects – which enable us to recover the costs of significant network projects only after pre-defined trigger events occur. We have not identified any contingent projects for the 2020-25 regulatory control period.
- Capex reopeners – which enable us to seek a reopening of the Distribution Determination where an event occurs during a regulatory control period which requires us to undertake additional capex equivalent to five per cent or more of the RAB for the first year of the regulatory control period.

12.2 Proposed nominated pass through events

Table 50 below outlines our proposed nominated pass through events and their respective definitions for the 2020-25 regulatory control period. These events are consistent with the nominated pass through events approved by the AER in the current 2015-20 Distribution Determination. However, we have updated the definitions to be consistent with the AER's most recent regulatory determinations.

Table 50 Proposed nominated pass through events for 2020-25 regulatory control period

Proposed nominated event	Proposed definition for the 2020-25 regulatory control period
Insurance cap	An insurance cap event occurs if: • Ergon Energy make a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy, • Ergon Energy incur costs beyond the relevant policy limit, and • the costs beyond the relevant policy limit increase the costs to Ergon Energy in providing direct control services • For this Insurance Cap Event: o a relevant insurance policy is an insurance policy held during the 2020-25 regulatory control period or a previous regulatory control period in which Ergon Energy was regulated, and o Ergon Energy will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related body corporate of Ergon Energy in relation to any aspects of the network or Ergon Energy's business. • Note for the avoidance of doubt, in assessing an insurance cap event through application under rule 6.6.1(i), the AER will have regard to: o the relevant insurance policy for the event, and o the level of insurance that an efficient and prudent NSP would obtain in respect of the event.
Insurer credit risk	An insurer's credit risk event occurs if: • An insurer of Ergon Energy becomes insolvent, and as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, Ergon Energy: o is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or o incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer. Note: In assessing an insurer's credit risk event pass through application, the AER will have regard to, amongst other things, • Ergon Energy's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation. • In the event that a claim would have been made after the insurance provider became insolvent, whether Ergon Energy had reasonable opportunity to insure the risk with a different provider.
Terrorism	Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which: • from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear), and • increases the costs to Ergon Energy in providing direct control services.

	Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: • whether Ergon Energy has insurance against the event, • the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and • whether a declaration has been made by a relevant government authority that an act of terrorism has occurred.
Natural disaster	Natural Disaster Event means any natural disaster including but not limited to fire, flood or earthquake that occurs during the 2020-25 regulatory control period that increases the costs to Ergon Energy in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider. Note: In assessing a Natural Disaster Event pass through application, the AER will have regard to, amongst other things: • whether Ergon Energy has insurance against the event; and, • the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and • whether a relevant government authority has made a declaration that a natural disaster has occurred.

In proposing our nominated pass through events, the NER requires us to consider the nominated pass through events considerations, which are defined in chapter 10. [8] Furthermore, under the NER, the AER must consider these considerations in deciding whether or not to accept our proposal.[9] In summary, these considerations are:

- whether the event proposed is an event covered by the category of prescribed events in the NER
- whether the nature or type of event can be clearly identified at the time of the Distribution Determination
- whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event
- whether the relevant service provider could insure against the event, having regard to:
  - o the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms, or
  - o whether the event can be self-insured on the basis that:
    - ▪ it is possible to calculate the self-insurance premium, and
    - ▪ the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services.
- any other matter the AER considers relevant.

We note that, in successive determinations, the AER has sought greater consistency in relation to nominated pass through events and their respective definitions. In this regard, we consider that the AER's reasons for approving our four nominated events above remain appropriate for our 2020-25 regulatory control period, namely that:

- the events are not covered by the prescribed events specified in the NER

[8] NER clause 6.5.10(a)
[9] NER clause 6.5.10(b)

- the nature and type of these events can be clearly identified at the time of the determination and
- while a prudent service provider could take steps to reduce the likelihood and cost impacts of these events and could insure or self-insure against them, expenditure beyond a certain level aimed at completely eliminating the risk is likely to be imprudent or inefficient.

12.3 Application of pass through to SCS and ACS

- We propose that the prescribed and nominated pass through events set out above apply to both SCS and ACS. We consider that this is consistent with the NER, which refers to the provision of direct control services (i.e. both SCS and ACS) in relation to pass through events.

12.4 Contingent projects

As mentioned above, we do not propose any contingent projects over the 2020-25 regulatory control period.

13. Annual revenue requirements and X-factors

Key Messages

- **Our proposed ‘smoothed’ annual revenue requirements (or maximum allowed revenues) and X-factors, which include a reduction in our revenues and average distribution network charges in 2019-20, minimise any adverse impacts of the proposed changes and reflect our customers’ feedback to front-end reductions.**
- **Our proposed ‘smoothed’ total revenue requirement for the 2020-25 regulatory control period, for the five years 1 July 2020 to 30 June 2025, is $6,516 million (nominal). This amount reflects the efficient costs of providing our SCS and meeting the safety and service levels our customers expect and value. It prudently balances cost and price pressures in future regulatory control periods.**
- **This is $364 million lower compared with what we included in Our Draft Plan that we published in August 2018.**
- **We are proposing to not claim $303.9 resulting from our projected outperformance under the EBSS and CESS in the current 2015-20 regulatory control period.**

13.1 Overview

Under the NER, our annual revenue requirement (ARR) is calculated using a building block approach, which estimates our ARR as a build-up of the efficient costs that we face annually in providing SCS. The building blocks include:

- a return on capital allowance which represents benchmark financing costs of investing in our network. The return on capital is calculated as the rate of return (discussed in chapter 9) multiplied by our forecast RAB (discussed in chapter 8).
- a regulatory depreciation allowance which represents the payback of our investment in the network (discussed in chapter 8)
- an opex allowance, which represents the estimating costs of operating and managing the network (discussed in chapter 6)
- a corporate income tax allowance which represents an estimate of the cost of corporate income tax faced by a benchmark firm operating our business (discussed in chapter 10), and
- revenue adjustments which include adjustments for incentive schemes, shared assets etc.

The ARR is calculated using the AER’s PTRM. After calculating the ARR for each year of the regulatory control period, the ARRs are ‘smoothed’ to reduce significant variations in revenues (and ultimately network charges) from year to year. The smoothing of the ARRs is done via the X-factors, which equalise (in net present value terms) the unsmoothed ARRs and smoothed ARRs.

Figure 36 Regulatory building blocks

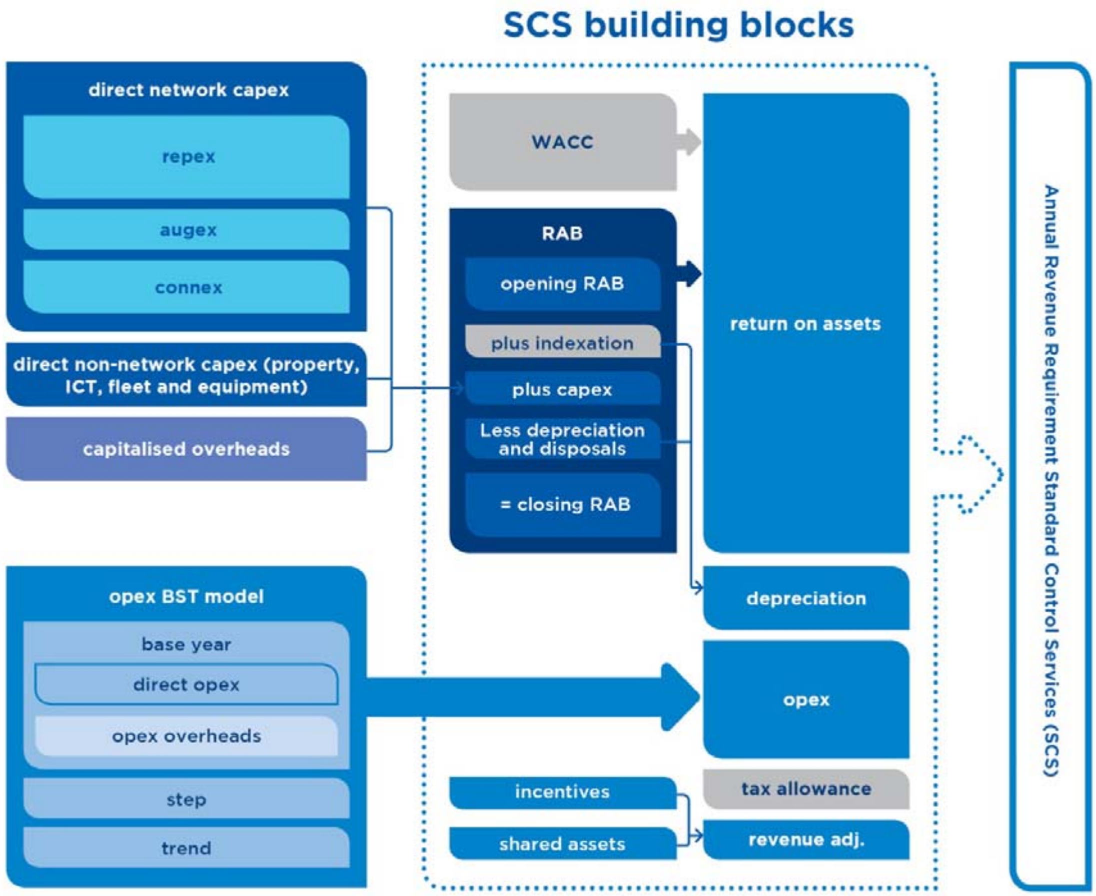
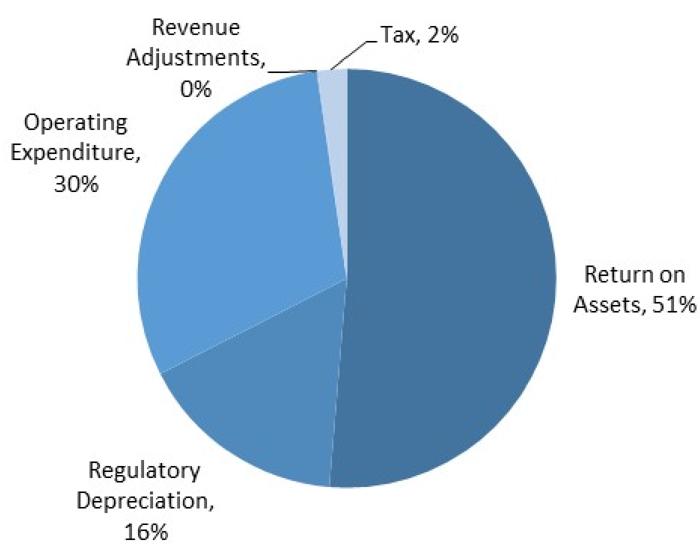


Figure 37 illustrates the approximate contribution each building block makes to one dollar of our revenue.

Figure 37 Contribution of each building block to SCS revenue



Totals may not add due to rounding

Table 51 shows our proposed ARRs and X factors for our SCS for the 2020-25 regulatory control period, which are the summation of the building blocks in Table 52. Our proposed X-factors show that we are proposing a real reduction of 9.44% in our revenues for the first year of the 2020-25 regulatory control period when compared to our expected revenues for the last year of the 2015-20 regulatory control period. Overall, we are proposing to recover $6,516 million over the 2020-25 regulatory control period.

Table 51 Forecast SCS revenue, 2020-21 to 2024-25

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Annual revenue requirement (unsmoothed)	1,223.37	1,266.28	1,303.44	1,340.41	1,386.97	6,520.47
X factors	9.44%	0.00%	0.00%	0.00%	0.00%	n/a
Maximum allowed revenue requirement (smoothed)	1,241.59	1,271.63	1,302.41	1,333.93	1,366.21	6,515.77

Totals may not add due to rounding

Importantly, our proposed X factors mean that forecast smoothed and unsmoothed revenue are within 3% of each other, which helps reduce any price distortions that may otherwise occur heading into the 2025-30 regulatory control period.

The detailed calculations are provided in our completed PTRM, which is provided as Attachment 8.002.

13.2 Annual revenue requirements

Table 52 shows the building blocks that make up our proposed ARRs and X factors for our SCS for the 2020-25 regulatory control period. Figure 38 shows the trends in our revenues over the 2015-20 and 2020-25 regulatory control periods, while Figure 39 shows this trend on a per customer basis.

Table 52 Forecast SCS revenue by building block, 2020-21 to 2024-25

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Return on capital	635.08	652.08	669.02	686.74	703.37	3,346.29
Regulatory depreciation	172.47	195.07	211.20	225.20	248.37	1,052.31
Opex (including Debt Raising)	386.91	389.78	394.30	398.40	402.53	1,971.91
Revenue adjustment	1.13	1.16	1.20	1.23	1.27	5.98
Corporate income tax	27.78	28.20	27.71	28.84	31.43	143.97
Annual revenue requirement (unsmoothed)	**1,223.37**	**1,266.28**	**1,303.44**	**1,340.41**	**1,386.97**	**6,520.47**
X factors	9.44%	0.00%	0.00%	0.00%	0.00%	n/a
Maximum allowed revenue requirement (smoothed)	**1,241.59**	**1,271.63**	**1,302.41**	**1,333.93**	**1,366.21**	**6,515.77**

Totals may not add due to rounding

Figure 38 SCS revenue trend

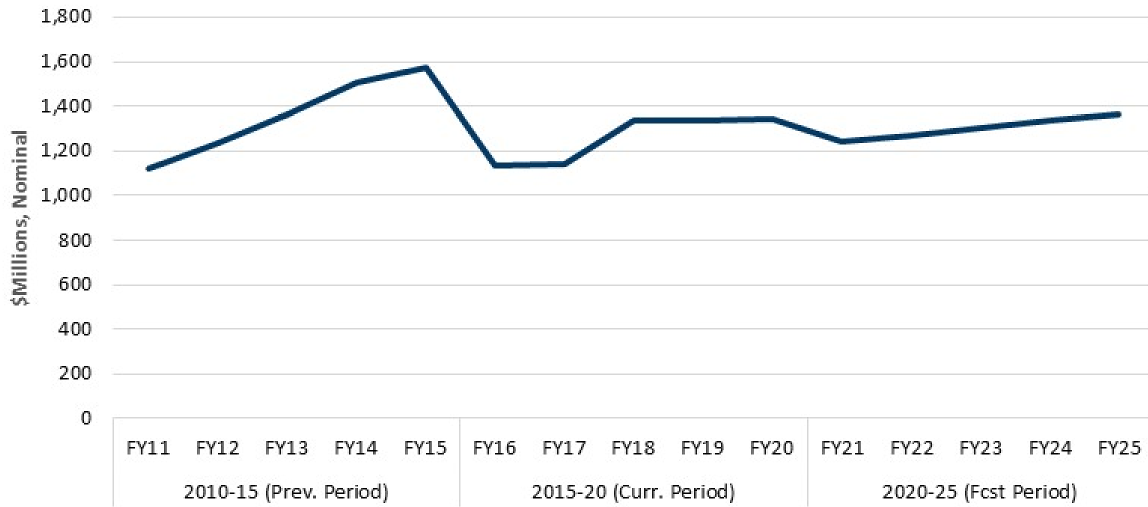
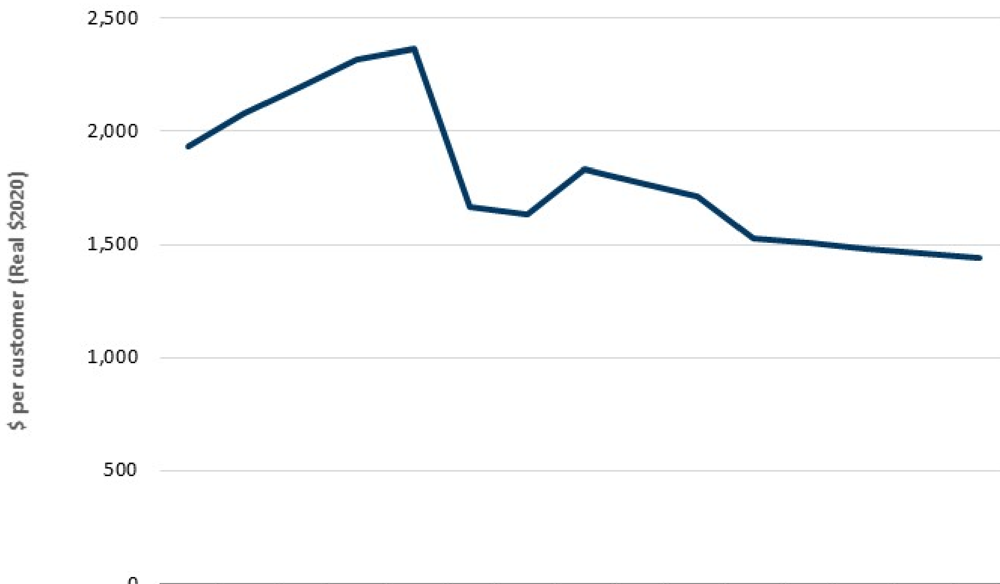


Figure 39 SCS revenue per customer



	2010-15 (Prev. Period)					2015-20 (Curr. Period)					2020-25 (Fcst Period)				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Revenue Per Customer Real	1,937	2,078	2,201	2,318	2,364	1,670	1,632	1,832	1,772	1,717	1,528	1,505	1,482	1,460	1,439

Table 53 compares our forecast and total revenue for the current and proposed regulatory control periods.

Table 53 Revenue comparison (Real, $2020)

Scheme	2015-20	2020-25	% Change
Total Revenue ($M)	6,554	6,061	
Average revenue per customer ($)	1,724	1,483	-14%

13.3 Revenue adjustments

As we noted in chapter 11, our ARR includes adjustments for incentive schemes. We are entitled to revenue increments under the CESS and EBSS for efficiencies achieved in the current 2015-20 regulatory control period. However, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to not claim the potential revenue adjustment associated with these efficiency schemes in this Regulatory Proposal. Table 54 below summarises our incentive scheme adjustments.

Table 54 Incentive schemes adjustment

Scheme	2020-21	2021-22	2022-23	2023-24	2024-25	Total
EBSS	66.33	51.09	75.94	50.07	25.08	268.51
CESS	7.87	7.87	7.87	7.87	7.87	39.33
DMIAM	1.10	1.11	1.11	1.12	1.13	5.56
Sub-total	**75.30**	**60.06**	**84.92**	**59.05**	**34.08**	**313.40**
Unclaimed EBSS	-66.33	-51.09	-75.94	-50.07	-25.08	-268.51
Unclaimed CESS	-7.87	-7.87	-7.87	-7.87	-7.87	-39.33
Total	**1.10**	**1.11**	**1.11**	**1.12**	**1.13**	**5.56**

Note: Totals may not add due to rounding.

We have made no revenue adjustments arising from control mechanisms for this period as per c6.4.3(a)(6) of the NER, but acknowledge that the AERs F&A paper provides for this.

13.4 Shared assets

The ARR must be reduced when annual unregulated revenues from the use of shared assets (i.e. those assets in the RAB that are earning both regulated and unregulated revenues) are expected to be greater than 1% of the total smoothed annual revenue requirement for that regulatory year.

The information provided in our RIN response demonstrates that the materiality threshold was not reached – the current forecast is 0.2%. As a result, no revenue reductions have been included for shared assets during the 2020-25 regulatory control period.

13.5 X Factors

In proposing our X-factors, we considered the requirement in the NER that the unsmoothed and smoothed ARR must be reasonably close. We note that in previous regulatory determinations the AER has considered a difference of about 3 per cent or less to be reasonable, and that during our customer consultations we received a clear message from customers seeking the front-loading of any tariff reductions. We have implemented the approach favoured by our customers and note that the forecast revenue difference of 1.5% is within the AER threshold.

14. Indicative distribution network charges and bill impacts

Key Messages

Our planned tariff designs respond to customer specific feedback, summarised as:

- **Fairer price structures that emphasis simplicity and clarity**
- **Provide customers greater choice and control in tariff selection**
- **Efficient tariffs leading to efficient investment – more affordable outcomes and downward pressure on network charges**
- **Awareness of customer impact when introducing new cost reflective tariffs**
- **Introduction of TEDI (Tariffs, Education, Dynamic Incentives and Information) to ensure a smooth transition**
- **Reduce and eventually eliminate cross-subsidies between and within customer classes**
- **Tariffs that fairly and equitably represent the cost accessing our network services.**

14.1 Our Network Pricing Principles

We understand how critical distribution network bill impacts are for customers and we have established clear principles by which we set network tariffs for our customers. These include:

- **Affordability** – ensuring we continue to put downward pressure on our component of customers' electricity bills through network tariffs that represent value for money
- **Economic efficiency** – our tariffs signal the economic costs of providing distribution services to the market
- **Customer impacts** – we manage changes that are expected to affect customer bills for example progressive deployment of changes to avoid bill shock
- **Simplicity and transparency** – we offer customers a clear and simple tariff structure
- **Flexibility** – we provide innovative tariffs that support customer choice and control
- **Fairness** – similar customers pay similar distribution network charges and charges reflect the impact of customer usage and technology decisions on network costs
- **Stability** – bills should remain reasonably predictable and avoid price shocks
- **Sustainability** – supports the energy trilemma strategy
- **Compliance** – our tariffs comply with all relevant regulations and the NER.

Following consultation with our customers discussed in chapter 2, we have prepared a set of indicative network tariffs that conform to the pricing principles in the NER and are based on the revenues set out in chapter 13 of this Regulatory Proposal. Our TSS sets out how we have complied with the pricing principles in the NER. Our indicative network tariffs embody the above principles and the clear feedback provided by customers on our proposed network tariffs and tariff structures for the 2020-25 regulatory control period. As discussed in chapter 2, this feedback was received through:

- a series of customer forums held throughout 2018,
- a formal customer survey; and

- feedback received via www.talkingenergy.com.au

The following section briefly summarises the expected distribution network bill impacts resulting from our indicative network tariffs for residential and small business customers. Please refer to Appendix A of our TSS for full list of our distribution network tariffs.

14.2 Customer Distribution Network Charges Impacts

As a result of the savings detailed in this Regulatory Proposal, we have been able to deliver real reductions in customers' distribution network charges from 1 July 2020.

For example, the average regional Queensland residential customer will see a real reduction in the distribution network component of their annual bill in 2020-21 of around 4% compared to 2019-20. This does not account for jurisdictional schemes which may factor into customer network charges[10]. Customers may see further savings should they choose to opt-in to one of our new cost reflective tariffs, some of which may require a digital meter.

Table 55 summarises the changes in residential tariffs and Table 56 summarises the small business tariffs.

Table 55 Residential Customer

Residential Tariff Description	% Change	$ Change
2019-20 Legacy to 2020-21 Legacy	-4.5%	-$31.50

Table 56 Small Business Customer

Small Business Tariff Description	% Change	$ Change
2019-20 Legacy to 2020-21 Legacy	-4.5%	-$44.92

[10] Total network charges comprise distribution network charges, transmission network charges and jurisdictional schemes.

14.3 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
2020-25 Tariff Structure Statement	14.002	ERG 14.002 2020-25 Tariff Structure Statement JAN19 PUBLIC
2020-25 TSS Explanatory Notes	14.004	ERG 14.004 2020-25 TSS Explanatory Notes JAN19 PUBLIC
2020-25 TSS Overview	14.007	ERG 14.007 2020-25 TSS Overview JAN19 PUBLIC
2020-25 LRMC Model	14.009	ERG 14.009 2020-25 LRMC Model JAN19 PUBLIC
Tariff Structure Statement 2020-25 Engagement Summary	14.010	EGX ERG 14.010 2020-25 TSS Engagement Summary JAN19 PUBLIC

Part C – Alternative Control Services

15. Alternative Control services

15.1 Overview

ACS are customer specific or customer requested services. In its F&A paper, the AER classified the following customer specific services / services group as ACS:

- Public lighting
- Type 6 Metering services
- Auxiliary metering services
- Connection management services
- Enhanced connection services, and
- Network ancillary services.

As discussed in chapter 6, we accept the AER's service classification of the above services as ACS. This chapter summarises our proposal for ACS as follows:

- Limited building block Type 6 metering services
- Limited building block public lighting services, and
- Fee-based and quoted services for the remaining ACS.

Our detailed proposals for ACS are provided in Attachment 15.006.

15.2 Type 6 Metering services

Metering Services - Key Messages

- **Under the Australian Energy Market Commission's (AEMC's) Power of Choice (POC), the provision of new and replacement meters is fully contestable and will be facilitated by retailers on behalf customers. We will no longer install new or replacement meters. The POC Reforms cover most of Queensland including all areas under the NER metering rules. There are some areas not covered by the NER and these areas are therefore designated as POC-exempt areas.**
- **We continue to provide Type 6 legacy metering services (i.e. the maintenance, reading and data services associated with the legacy meters) and to recover the capital costs of metering equipment installed prior to 1 December 2017.**

Our proposed total revenue requirement for metering services for the 2020-25 regulatory control period is $191.4 million (nominal).

Under the AEMC's PoC reforms, metering contestability came into full effect on 1 December 2017. This reform transferred the responsibility for the provision of meters to a Metering Coordinator (MC). New and replacement meters are now provided by competitive MCs and are chosen by customers in conjunction with their electricity retailer.

As the Responsible Person[11] as at 1 December 2017, we inherited the role of MC for customers with Type 6 meters and will continue to provide the following metering services:

- recovery of capital costs of Type 6 meters installed prior to 1 December 2017
- meter maintenance – works to inspect, test, maintain, repair and replace meters
- meter reading – quarterly or other regular reading of the meter, and
- meter data services – collection, processing, storage, delivery and management of metering data, remote or self-reading at difficult to access sites, provision of metering data from previous two years and ongoing provision of metering data.

We prepared our Meter Asset Management Plan (MAMP) in accordance with AEMO's requirements. This sets out our plan for the installation, replacement, testing and inspection of metering installations for which we are responsible. A copy of our MAMP is provided in Attachment 15.002.

We forecast that over the 2020-25 regulatory control period, there will be a churn or roll-off of 8% per annum of our Type 6 customers to contestable providers. However, the displaced meters remain part of our metering asset base.

We have adopted a limited building block approach to determine the revenue requirement for our metering services. We have applied the same rate of return for metering services as for SCS and we have adopted the AER's PTRM straight-line depreciation approach. Our forecast revenue for the 2020-25 regulatory control period is shown in Table 57.

Table 57 Forecast Metering Service Revenue

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Return on capital	4.51	4.36	4.18	3.95	3.66	20.66
Regulatory depreciation	6.13	6.86	7.62	8.40	8.66	37.66
Opex (including Debt Raising)	29.58	27.78	26.20	24.76	23.47	131.79
Revenue adjustment	-	-	-	-	-	-
Corporate income tax	0.20	0.22	0.24	0.36	0.36	1.38
Annual revenue requirement (unsmoothed)	**40.43**	**39.22**	**38.23**	**37.47**	**36.14**	**191.49**
X factors (Non-Capital)	-2.45%	0.00%	0.00%	0.00%	0.00%	n/a
X factors (Capital)	15.97%	0.00%	0.00%	0.00%	0.00%	n/a
Maximum allowed revenue requirement (smoothed)	**40.93**	**39.50**	**38.17**	**36.94**	**35.81**	**191.36**

Note: Totals may not add due to rounding.

We apply a price cap control mechanism for our ACS metering services, in the form of a daily metering services charge for each tariff. As for the 2015-20 regulatory control period, metering services' revenue will be recovered through the following tariffs:

- Primary tariffs
- Controlled load tariffs, and
- Solar tariffs.

[11] Clause 11.86.7 - On and from the effective date, a Local Network Service Provider that was the responsible person for a type 5 or 6 metering installation connected to, or proposed to be connected to, the Local Network Service Provider's network under clause 7.2.3(a)(2) of old chapter 7 or clause 9.9C.3 immediately before the effective date must be appointed as the Metering Coordinator by the financially responsible Market Participant.

Further, we have established separate price for capital and non-capital components of the metering services costs. This allows flexibility for separate service components to be removed when a customer appoints an alternative provider to deliver part of the Type 6 metering service. Metering services revenue will be recovered across the applicable tariffs in Table 58. Further information on the tariffs is set out in our TSS.

Table 58 Metering service tariffs

Cents per day, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Primary Tariff - Non- Capital Charge	10.698	10.957	11.222	11.494	11.772
Primary Tariff - Capital Charge	3.217	3.295	3.375	3.456	3.540
Controlled Load Tariff - Non- Capital Charge	3.934	4.029	4.126	4.226	4.328
Controlled Load Tariff - Capital Charge	1.183	1.211	1.241	1.271	1.302
Solar PV Tariff - Non- Capital Charge	2.660	2.725	2.791	2.858	2.927
Solar PV Tariff - Capital Charge	0.800	0.819	0.839	0.859	0.880

15.3 Public Lighting Services

Public Lighting Services - Key Messages

- **With customer support, we are forecasting 47% of our total public lighting portfolio to be LEDs by the end of the 2020-25 regulatory control period.**
- **We are proposing to introduce LED-specific public lighting tariffs for each of the four public lighting categories and a new public lighting tariff category (NPL4) for customers funding of NPL1 upgrades to LED luminaire and lamps.**
- **Our proposed total revenue requirement for public lighting services for the 2020-25 regulatory control period is $140 million (nominal).**

We have approximately 150,000 public lights connected to our distribution network throughout Queensland. Our major customers for public lighting are the 56 local government authorities (LGAs) in our distribution area and the Department of Transport and Main Roads (DTMR).

The key issue for the 2020-25 regulatory control period is the rate of roll out of LEDs across our distribution network. Based on feedback from customers, we are proposing a moderate acceleration of our LED replacement program to achieve a target of 47% LED penetration by 2020. For the 2020-25 regulatory control period, we will introduce LED specific tariffs to encourage the conversion to this new energy efficient technology. Combined with communication capabilities and smart city applications, public lights have the potential to be smarter, more environmentally friendly and can provide opportunities for customers to make savings in energy and network costs.

We have used a limited building block approach to determine annual revenue requirements. Consistent with our proposal to introduce separate tariffs for LEDs, we have prepared two separate PTRMs:

- a conventional public lighting PTRM covering the conventional Public Lighting Asset Base (PLAB), used to calculate the conventional public lighting tariffs, and

- a LED public lighting PTRM covering the LED PLAB, used to calculate the LED public lighting tariffs.

We have applied the same rate of return for public lighting services as for our SCS and have adopted the AER's PTRM straight-line depreciation. The tax allowance for public lighting is spread across both PTRMs.

Our total forecast public lighting revenue for the 2020-25 regulatory control period is provided in Table 53 for conventional lights and Table 60 Forecast LED Public Lighting Revenue for LEDs.

Table 59 Forecast Conventional Public Lighting Revenue

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Return on capital	4.32	3.84	3.29	2.63	1.88	15.96
Regulatory depreciation	6.11	6.30	6.36	6.21	5.49	30.48
Opex (including Debt Raising)	13.06	12.29	11.12	9.59	7.64	53.70
Revenue adjustment	-	-	-	-	-	-
Corporate income tax	-	-	-	-	-	-
Annual revenue requirement (unsmoothed)	**23.49**	**22.43**	**20.77**	**18.43**	**15.01**	**100.13**
X factors	0.00%	0.00%	0.00%	0.00%	0.00%	n/a
Maximum allowed revenue requirement (smoothed)	**24.96**	**23.55**	**21.41**	**18.65**	**15.22**	**103.80**

Note: Totals may not add due to rounding.

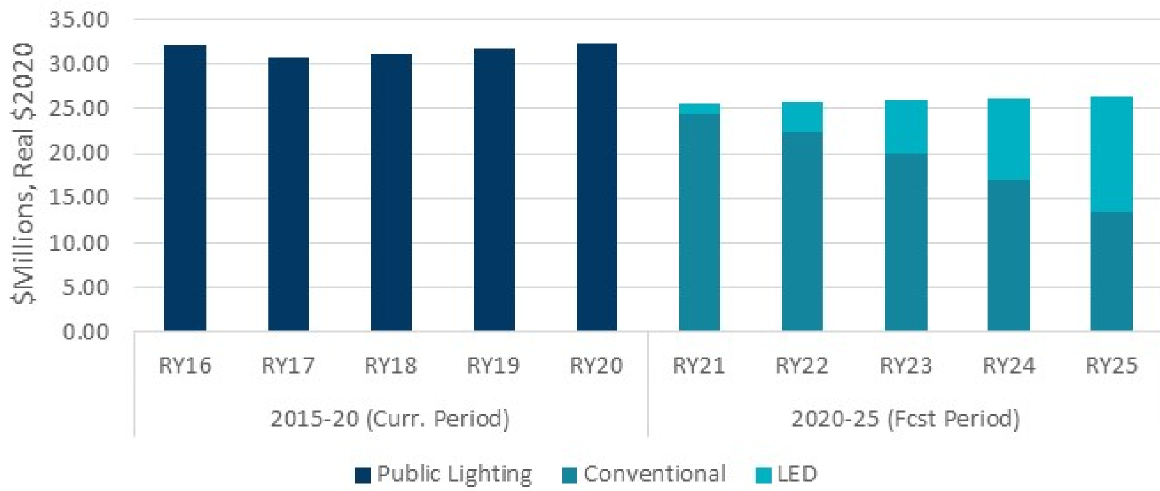
Table 60 Forecast LED Public Lighting Revenue

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Return on capital	0.34	0.97	1.66	2.45	3.32	8.74
Regulatory depreciation	0.37	0.98	1.83	2.95	4.30	10.43
Opex (including Debt Raising)	0.61	1.58	2.72	4.26	6.10	15.27
Revenue adjustment	-	-	-	-	-	-
Corporate income tax	1.00	0.99	1.01	1.03	1.05	5.08
Annual revenue requirement (unsmoothed)	**2.33**	**4.52**	**7.22**	**10.69**	**14.76**	**39.52**
X factors	0.00%	0.00%	0.00%	0.00%	0.00%	n/a
Maximum allowed revenue requirement (smoothed)	**1.22**	**3.46**	**6.47**	**10.13**	**14.49**	**35.78**

Note: Totals may not add due to rounding.

Figure 40 details the trend in our total public lighting revenue over the 2015-20 and 2020-25 regulatory control periods.

Figure 40 Total Public Lighting revenue



We have applied a price cap control mechanism, based on a dollar per lamp per day rate, to achieve the AARs. Public lighting services' revenue will be recovered across the applicable tariffs in Table 61 and Table 62 Forecast LED Public Lighting Tariffs. Further explanation is available in our TSS (Attachment 14.002).

Table 61 Forecast Conventional Public Lighting Tariffs

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25
NPL 1					
Major	0.780	0.799	0.819	0.840	0.861
Minor	0.479	0.491	0.503	0.516	0.529
NPL 2					
Major	0.449	0.460	0.471	0.483	0.495
Minor	0.295	0.302	0.310	0.318	0.326

Table 62 Forecast LED Public Lighting Tariffs

$M, Nominal	2020-21	2021-22	2022-23	2023-24	2024-25
NPL 1					
Major	0.815	0.836	0.857	0.878	0.900
Minor	0.492	0.505	0.517	0.530	0.543
NPL 2					
Major	0.399	0.409	0.419	0.430	0.441
Minor	0.261	0.267	0.274	0.281	0.288
NPL 4					
Major	0.710	0.728	0.746	0.765	0.784
Minor	0.440	0.451	0.462	0.474	0.486

15.4 Other Alternative Control Services

Other ACS - Key Messages

- **Fee based services are generally predictable in scope and do not vary greatly between customers or retailers, whereas quoted services depend on the scope of a customer or retailer's request. Prices can be set for fee-based services, but It is not practical to set individual fees for quoted services as the costs vary significantly on a project-by-project basis**
- **We are proposing changes to our service descriptions to improve clarity and consistency with Energex.**
- **We have based our prices on:**
  - **Internal labour rates approved by the AER for the current regulatory control periods and escalated to 2020-21**
  - **2020-21 costs for contractor costs, overheads and materials, and**
  - **Task time, crew size and labour type derived from historical practice and internal assessments.**

In addition to the Type 6 metering services and public lighting services, we accept the AER's proposal to classify the following other services as ACS:

- auxiliary metering services
- ancillary public lighting services
- connection management services
- enhanced connection services, and
- ancillary network services.

These services share the common characteristic of being non-routine services provided to an individual customer on an 'as needs' basis.

It is noted that the AER, has reclassified a number of specific network ancillary services from unregulated to ACS, including:

- network related property services
- provision of training to third party for network related access, and
- provision of security lights.

Unlike Type 6 metering services and public lighting services, where annual revenue requirements can be calculated using the limited building block, these other ACS will be based on a cost build-up approach.

The cost build-up approach used to determine the prices for these ACS is specified by the formula below:

Price = Labour + Contractor Services + Materials + Capital Allowance

Pricing arrangements will be fee-based, or quoted, depending on the characteristics of the service. Full details of the proposed fee and quoted services and indicative prices are as set out in our TSS for 2020-25 and the accompanying Explanatory Notes (Attachment 14.002 and Attachment 14.004 respectively).

15.5 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Meter Asset Management Plan	15.002	ERG 15.008 Capex forecast – ACS metering JAN19 PUBLIC
Asset Management Plan Public Lighting	15.003	EGX ERG 15.009 Fee-based and quoted services model – ACS JAN19 PUBLIC
Public Lighting Strategy	15.004	EGX ERG 15.009 Fee-based and quoted services model – ACS JAN19 CONFID
Alternative Control Services	15.006	ERG 15.011 Opex forecast – ACS metering JAN19 PUBLIC
Capex forecast – ACS metering	15.008	ERG 15.013 Opex forecast – ACS public lighting CON JAN19 PUBLIC
Fee-based and quoted services model – ACS	15.009	ERG 15.015 Opex forecast – ACS public lighting LED JAN19 PUBLIC
Fee-based and quoted services model – ACS	15.011	ERG 15.017 PTRM – ACS metering JAN19 PUBLIC
Opex forecast – ACS metering	15.013	ERG 15.019 PTRM – ACS public lighting CON JAN19 PUBLIC
Opex forecast – ACS public lighting CON	15.015	ERG 15.021 PTRM – ACS public lighting LED JAN19 PUBLIC
Opex forecast – ACS public lighting LED	15.017	ERG 15.023 RFM – ACS metering JAN19 PUBLIC
PTRM – ACS metering	15.019	ERG 15.025 RFM – ACS public lighting CON JAN19 PUBLIC
PTRM – ACS public lighting CON	15.021	ERG 15.027 RFM – ACS public lighting LED JAN19 PUBLIC
PTRM – ACS public lighting LED	15.023	EGX ERG 15.028 Metering pricing model - ACS JAN19 PUBLIC
RFM – ACS metering	15.025	ERG 15.030 Public lighting LED and Conventional Pricing model - ACS JAN19 PUBLIC
RFM – ACS public lighting CON	15.027	ERG 15.008 Capex forecast – ACS

Name	Ref	File name
		metering JAN19 PUBLIC
RFM – ACS public lighting LED	15.028	EGX ERG 15.009 Fee-based and quoted services model – ACS JAN19 PUBLIC
Metering pricing model - ACS	15.030	EGX ERG 15.009 Fee-based and quoted services model – ACS JAN19 CONFID

D – Other Matters

16. Other Matters

Key Messages

- **We support the AER's decision not to classify any distribution services as negotiated distribution services, as outlined in its F&A paper.**
- **Regardless, clause 6.8.2(c)(5) of the NER requires us to submit a negotiating framework as part of our Regulatory Proposal. Should the AER depart from the F&A paper and classify certain services as negotiated distribution services in the final determination, then the negotiating framework provided in Attachment 16.006 will apply.**
- **Our objective is to maximise the transparency of our Regulatory Proposal. We have therefore minimised the number of confidential documents that we have submitted to the AER.**
- **We have addressed the requirements of the AER's Confidentiality Guideline for the matters for which we are claiming confidentiality.**
- **Our directors have provided a certification statement for our key assumptions for capex and opex.**
- **Our Chief Executive has made a statutory declaration attesting to the information provided in our response to the AER's RIN.**

16.1 Negotiating framework

The AER's F&A paper did not propose any negotiated distribution services. We agree with the AER that none of our current services are suited to being classified as negotiated distribution services.

Nevertheless, in accordance with clauses 6.7.5 and 6.8.2(c)(5) of the NER, we are required to provide a negotiating framework outlining the process that we would follow in negotiating the terms and conditions of any prospective negotiated distribution services with other parties.

Our negotiating framework for the 2020-25 regulatory control period is provided in Attachment 16.006.

16.2 Jurisdictional Schemes

In accordance with the AER, we have excluded the costs of jurisdictional schemes from our forecasts as they do not form part of our ARR or distribution network charges.

16.3 Confidential information

In accordance with clause 6.14 of the NER and the AER's Confidentiality Guideline, we have completed a confidentiality template at Attachment 16.002 of this Regulatory Proposal that details the matters for which we are claiming confidentiality.

16.4 Governance, assurance and certifications

16.4.1 Certification statement

Schedules 6.1.1(5) and 6.1.2(6) of the NER require our directors to certify the key assumptions that underlie our capex and opex forecasts. Our key assumptions for:

- opex are set out in section 6.4, and
- capex are set out in section 7.4.

Our certification statement is provided as Attachment 16.003 to this Regulatory Proposal.

16.4.2 Statutory declaration by Chief Executive

The AER's Reset RIN requires an officer of Ergon Energy to make a statutory declaration attesting to the information provided in response to that notice.

The statutory declaration made by our Chief Executive is provided as Attachment 17.019 to this Regulatory Proposal.

16.4.3 Compliance checklist

We have completed a compliance checklist, which demonstrates how we have complied with the requirements of the NER and the RIN. This is provided at Attachment 16.004.

16.5 Supporting documentation

The following documents supporting this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Confidentiality template	16.002	ERG 16.002 Confidentiality template JAN19 PUBLIC
Key capex and opex assumptions certification	16.003	EGX ERG 16.003 Key capex and opex assumptions certification JAN19 PUBLIC
NER cross-reference compliance checklist	16.004	EGX ERG 16.004 NER cross-reference compliance checklist JAN19 PUBLIC
Negotiating framework	16.006	ERG 16.006 Negotiating framework JAN19 PUBLIC
Regulation and Legislation foreseen changes summary	16.007	EGX ERG 16.007 Regulation and Legislation foreseen changes summary JAN19 PUBLIC

16.6 Abbreviations

The following abbreviations are used in this Regulatory Proposal:

Acronym/Abbreviation	Meaning
$, nominal	These are nominal dollars of the day
$real2019-20	These are dollar terms as at 30 June 2020
2020-25 regulatory control period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
ACCC	Australian Competition and Consumer Commission
ACS	Alternative Control Service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
ATO	Australian Taxation Office
Augex	Augmentation capital expenditure
Bppa	Basis points per annum
BST	Base Step Trend
CAM	Cost allocation method
Capex	Capital expenditure
CBD	Central business district
CBRM	Condition Based Risk Management
CESS	Capital efficiency sharing scheme
Connex	Connections expenditure
CPI	Consumer Price Index
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
CWIP	capital works in progress
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
DEBBS	ICT & Digital Enterprise Building Blocks
DER	Distributed energy resources
DMIA	Demand management incentive allowance
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
DNRME	Department of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
EBSS	Efficiency benefits sharing scheme

Acronym/Abbreviation	Meaning
EDSD	Electricity Distribution Service Delivery
EG	Embedded generator
ENA	Energy Networks Australia
ENCAP	Electricity Network Capital Program
EV	Electric vehicles
F&A	Framework and Approach
FiT	Feed-in Tariff (Solar FiT) under the Queensland Solar Bonus Scheme
GSL	Guaranteed service level
GSP	Gross State Product
GWH	gigawatt hours
HV	High voltage
ICT	Information communication technology
JMTC	Joint Energex and Ergon Energy Market Transaction Centre
kV	kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	kilowatt hour
LCC	Large Customer Connection
LED	Light emitting diode
LV	Low voltage
MAMP	Meter Asset Management Plan
MAR	Maximum allowed revenue
MC	Metering coordinator
MED	Major event day
MPFP	Multilateral partial factor productivity
MPLS	Multiprotocol Label Switching
MSS	Minimum Service Standard
MTFP	Multilateral total factor productivity
MW	megawatt
MYFER	Mid-year fiscal and economic review
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective

Acronym/Abbreviation	Meaning
NER	National Electricity Rules (or Rules*)*
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NMI	National Metering Identifier
NNA	Non-network alternatives
NPL	Network Public Lighting
NSP	Network Service Provider
O&M	Operating and Maintenance Allowance (Opex)
OEF	Operating environment factor
Opex	Operating and Maintenance Expenditure
PDH	Plesiochronous Digital Hierarchy
PLAB	Public lighting asset base
POC	Power of Choice
POE	Probability of exceedance
Previous regulatory control period or previous period	Regulatory control period 1 July 2010 to 30 June 2015
PTRM	Post-tax revenue model
PV	Photovoltaic (Solar PV)
QCA	Queensland Competition Authority
R&D	Research and development
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Regulatory Proposal	Energex or Ergon Energy's proposal for the next regulatory control period submitted under clause 6.8 of the NER
Repex	Replacement capital expenditure
RFM	Roll forward model
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test - Distribution
RP-TSS Working Group	Regulatory Proposal - Tariff Structure Statement Working Group
SAC	Standard Asset Customers
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SBS	Solar Bonus Scheme
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Service
SPARQ	SPARQ Solutions

Acronym/Abbreviation	Meaning
SSIS	Small Scale Incentive Scheme
STPIS	Service target performance incentive scheme
TEDI	Tariffs, Education, Dynamic Incentives and Information
Totex	Total expenditure
TSS	Tariff Structure Statement
UDMS	Unified distribution management system
Unified ERM EAM	Unified Enterprise Resource Planning and Enterprise Asset Management system
VCR	Value of customer reliability
WACC	Weighted average cost of capital
WARL	Weighted average remaining life