An Overview
Our Regulatory Proposal
2015 to 2020

ERGON ENERGY

To ensure we manage the distribution network efficiently, Ergon Energy is regulated under the National Electricity Rules (NER) by a national regulator, the Australian Energy Regulator (AER). It is the AER's role to set the amount of money we're allowed to collect for the use of our electricity network. These network charges make up approximately half of the retail 'price' of electricity in Queensland.

To assist the AER in making the decisions it needs in determining our revenue allowance for 2015 to 2020, we have provided them with our future investment plans as a Regulatory Proposal. After considering our proposal and public submissions, the AER will publish a draft Distribution Determination. This will be available for further consultation in May 2015.

We have engaged with our customers to help inform our proposal and are confident, with the AER's support, that our investment plans will enable us to deliver the best outcome for regional Queensland into the future.

How to read our Regulatory Proposal

Ergon Energy's Regulatory Proposal is presented in a number of documents to make it easier for our different stakeholders to access the information they need.

This document, **An Overview Our Regulatory Proposal**, provides the context for the proposal and an overview of the price impacts and the broader customer benefits, along with the highlights of how we plan to deliver them. A summary of a range of other specific regulatory matters under consideration by the AER are also provided.

It is supported by four documents that explore our core challenges more deeply. These are noted in the relevant sections. There is also a forecast expenditure summary for each key category of expenditure, and various other reference documents.

The document, Ergon Energy Regulatory Proposal 2015 to 2020, fully addresses the regulatory requirements of the proposal for the AER.

These and a suite of other documents are available at www.ergon.com.au/futureinvestment

Our Regulatory Proposal and refreshed service commitments are about delivering...

PEACE OF MIND

CHOICE AND CONTROL

FOR THE BEST POSSIBLE PRICE

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Welcome

Thank you for taking the time to consider Ergon Energy's future investment plans.

In line with our strategic goal for a sustainable and affordable electricity supply for our customers, our plans are all about delivering on our service commitments for the best possible price, and powering the Queensland economy.

Our Regulatory Proposal should keep any increases to what we charge (in aggregate) for the use of the network – the part of the bill we are responsible for as a distributor – below inflation over the next five years. We are forecasting our distribution revenue to be $1,717 million in 2019-20. This is lower than our anticipated 2014-15 revenue of $1,753 million.[1]

We have done a lot already to achieve this outcome.

With consumption falling for the first time in 2010-11, in parallel with peak demand flattening, we took prudent steps to reduce our capital investment program and focus on our efficiency and effectiveness as an organisation. This along with our growing demand management capability has supported a reduction of more than 20% in our total expenditure when compared to our regulator's approved allowances for 2010-15. As a result we were able to reduce our revenue requirement by $99 million and absorb the cost of Cyclone Yasi and Oswald. Looking forward into 2015-20, we expect to reduce our overall expenditure by a further 11% on top of the reductions we have already achieved in the current period.

Together these outcomes, coupled with a drop in our financing costs, have delivered the positive, sustainable revenue requirement we have put forward in our Regulatory Proposal for 2015-20. If we are able to maintain and grow efficient energy consumption, then we should see a positive influence on network prices.

If we had not acted proactively, and financing costs had not dropped, customers would have been facing another double digit increase in network charges as we moved into the next regulatory control period.

We are also optimistic, as the AER works through its revenue determination, that the finance market parameters around the cost of capital will continue to improve relative to the assumptions in our proposal. This will deliver even better outcomes for customers in terms of what we ultimately charge.

Of course, we know it is not all about price. We appreciate that our customers value the peace of mind they receive from a safe and dependable service, and that they also increasingly want greater choice and control in their energy supply solutions.

If we had not acted proactively... customers would have been facing another double digit increase in network charges as we moved into the next regulatory control period.

It's about getting the balance right.

This has been at the centre of our discussions with our customers throughout the preparation of our Regulatory Proposal. I trust you find we have been listening and that our investment plans are customer informed.

We are confident, with our regulator's support, that our proposal will enable us to power economic prosperity in regional Queensland and support the objectives of The Queensland Plan.

Ian McLeod

Chief Executive

1. Nominal dollars. The DUOS revenue calculations between 2015-16 and 2019-20, exclude the forward revenues from metering services, which have been reclassified.

Ergon Energy in profile

Ergon Energy provides electricity to a population of 1.5 million people – with around 725,000 customer connections.

We service regional Queensland – from the expanding coastal population centres to some of the state's most remote communities. Two thirds of our customers are supplied through our rural network.

OUR ROLE AND PRICING REGULATION

Ergon Energy plays a role in each of the four elements of the electricity supply chain. We are both a distributor and a retailer, and we play relatively minor roles in generation and transmission.

This document is about our plans for the nationally regulated functions of the distribution side of our business. In the Regulatory Proposal we have put forward the information we believe the AER should consider in determining the revenue allowance for our distribution business for the five-year period from 2015 to 2020.

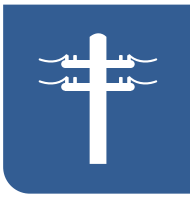
These revenues are designed to recover the costs of the essential electricity distribution services we provide to our customers. The revenue allowance is used by the AER to set what we can charge for the use of the network, which is passed through to customers as part of their electricity bill.

The AER does not regulate retail electricity prices. Our retail customers benefit from the Queensland Government's notified retail prices, which are determined by the Queensland Competition Authority (QCA). The AER is also not responsible for the regulation of the generation or distribution arrangements for our isolated communities.

ELECTRICITY SUPPLY CHAIN

GENERATION
A range of energy sources (coal-fired, biomass, gas, hydro and wind) is used by private and government-owned operators to generate Queensland's electricity.

TRANSMISSION
The transmission network consists of lines that carry electricity from the point of generation over long distances and feed it into the distribution network.



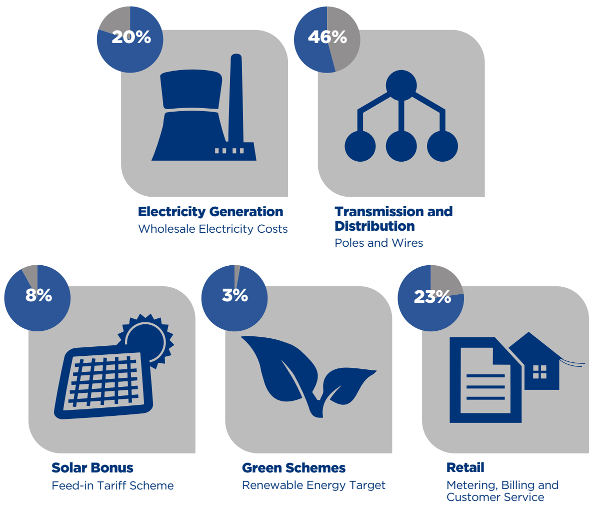
DISTRIBUTION
Distribution lines then carry electricity directly to Queensland's homes and businesses.

RETAIL
Electricity is purchased through the retailers, who also provide a range of other customer services.

WHAT MAKES UP THE PRICE?

For 2013-14, an average quarterly electricity bill for a residential customer in regional Queensland was $435. At $4.77 a day, this is 2.7% of Queensland's median household income.[2]

The cost of transporting electricity (both distribution and transmission) makes up the largest part of the bill. Retail costs, then electricity generation are the next largest. The carbon tax was passed on in 2013-14; however, this has since been removed (a 9.4% decrease in consumption charge of Tariff 11). The other costs are associated with the Queensland Government's Solar Bonus Scheme and the Renewable Energy Target[3]



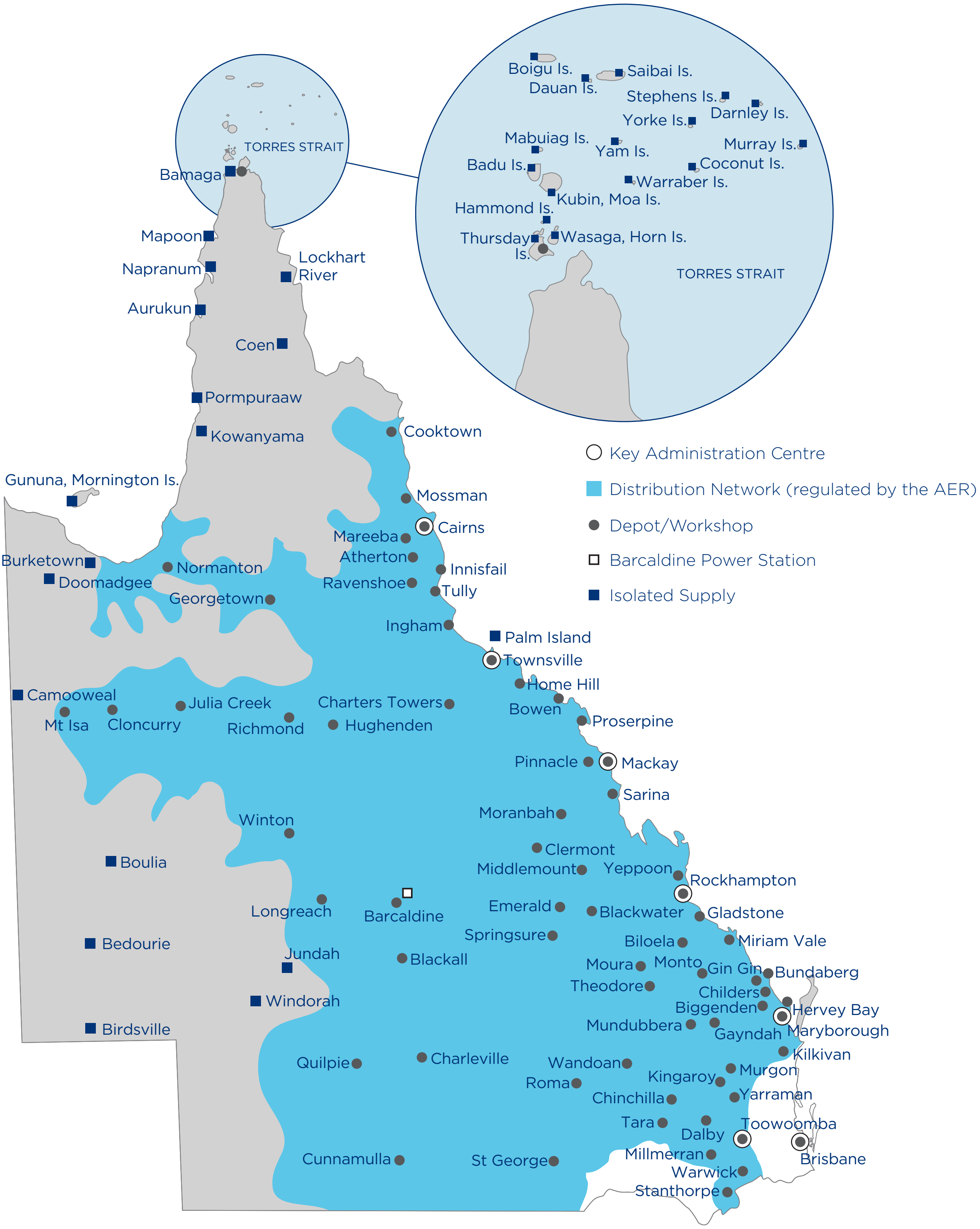
2 The average residential bill is based on Ergon Energy Queensland Pty Ltd accounts, excluding households with solar energy systems installed. Australian Bureau of Statistics Queensland median weekly household income ($1,235 per week).

3 Cost components and percentages are based on QCA publication of electricity prices www.dews.qld.gov.au/energy-water-home/electricity/prices

OUR SERVICE AREA

Ergon Energy supplies electricity across a service area of more than one million square kilometres – across 97% of the state of Queensland.

Our electricity distribution network – a regulated asset base valued at over $10 billion – has 371 major substations, over 160,000 kilometres of powerlines and around one million power poles.



Listening to our customers

In order to best develop our future investment plans and prioritise appropriately, we asked our customers and other stakeholders what they expected from us.

This has been part of an ongoing conversation with our customers and the communities we serve (both as an electricity distributor and as a retailer). The understanding we've gained, especially over recent times, has helped inform our decision making throughout the development of our Regulatory Proposal.

OUR ENGAGEMENT APPROACH

To ensure our investment proposals are aligned with the long-term interests of our customers, we implemented a coordinated, multi-channel customer/community engagement program. Our aim has been to give customers and other stakeholders the opportunity to express their views and concerns and provide input on our expenditure proposals and priority investments. We also used this engagement process to help us critically assess our customers' 'willingness to pay' for different service standards. Our efforts have also helped us build a better understanding in the community of the challenges facing Ergon Energy and the industry.

In planning our engagement approach we looked at our different stakeholder groups' capacity to engage, the impact of different elements on them, and their areas of influence. This process was undertaken by looking at the key areas where we were making decisions in the preparation of the Regulatory Proposal and working through how best to consult with customers and stakeholders across our broad regional footprint.

Our engagement program for the Regulatory Proposal over the past eighteen months has included direct customer engagement – supported by information sharing online – as well as a significant customer research program. There has also been substantial Board, Chief Executive and senior management commitment to both regional stakeholder and peak body engagement.

To build on our understanding of what our customers want from our electricity distribution network we also undertook an in-depth look at the different segments that make up our customer base. We will continue using these insights to ensure our future network investments are targeted and that our service offering meets customers' expectations.

OUR FOUR PHASES OF ENGAGEMENT

PHASE 1:
INVITE STAKEHOLDERS TO BE INVOLVED AND BUILD ON ENGAGEMENT (COMMENCED JULY 2013)

The engagement program was launched at a stakeholder event in Townsville, with the approach and timeline outlined on our web site. Specific briefings then commenced with our Customer Council, as well as with regional community leaders.

PHASE 2:
UNDERTAKE CUSTOMER RESEARCH (COMMENCED AUGUST 2013)

Our existing research was reviewed, before a sophisticated service/cost trade-off research study was developed and undertaken. This allowed customer views across different segments and geographical areas to be actively considered in the development of the final proposal.

PHASE 3:
VALIDATE OUR SERVICE COMMITMENTS AND DIRECTION OF INVESTMENT PLANS (APRIL TO AUGUST 2014)

Engagement activity was undertaken to validate the direction of the proposal, supported by the release of our refreshed service commitments, as well as our research findings and a range of other updates.

PHASE 4:
PRESENT THE REGULATORY PROPOSAL (SEPTEMBER TO NOVEMBER 2014)

Advanced presentation of the Regulatory Proposal was undertaken, allowing customers and other stakeholders to review and assess the key building blocks of our expenditure and the potential price impacts. This engagement is continuing. We are also encouraging participation in the AER's engagement activities through the final stages of the process.

By listening to our customers we have built a clear understanding of the service attributes valued by our customers.

We understand the level of concern in the community about rising electricity prices. We also understand that our customers still want the peace of mind that comes from having a safe, dependable electricity service and they are increasingly seeking greater choice and control around their energy supply solutions.

WHAT OUR CUSTOMERS SAID TO US

Peace of mind from a safe, dependable service

Our customers do not want us to compromise on safety. They see electricity reliability as important and recognise that it has improved. They are no longer looking for higher reliability standards (except in areas where reliability is still poor).

They value our local presence, and our disaster response, and see investing in the network's resilience to severe weather as important. Our customers are looking for improvements in the delivery of new connections, including solar connections.

We are seen as a good corporate citizen, with responsibilities around electrical safety, emergency management, local employment and apprenticeships, energy conservation, minimising the impact of new electricity infrastructure on the community, and community participation.

A future of greater choice and control

A significant proportion of our customers feel they have done all they can to reduce their usage and save on their bill, and others are investing in technologies, such as solar and battery storage, as a means to control costs.

Our customers want us to look to a future where customers are empowered with new technologies and options for their electricity supply solutions. They want us to consider transitioning towards a 'smart' network. While a number of key customer segments indicate they need more information to fully understand the benefits of 'smart meters' (advanced electronic or interval meters), they see value in receiving information to help them manage their energy needs.

"Yes, we are very concerned about the increased cost of electricity..."

Source: Service/Cost Trade-off Research; online survey.

Customers also want more options around how they connect to our network. They find tariffs complex, and want simplicity, but they are looking for options and incentives to help them save on their bill.

Our customers increasingly want to be informed on energy-related matters.

Whilst not forming part of our engagement on the Regulatory Proposal itself, many customers also said they are also looking for choice in their retailer.

Best possible price, best overall value

The cost of electricity is a significant issue for our customers with affordability concerns rising as sharply as prices have risen. While our customers generally do not understand what has driven prices up, they expect Ergon Energy to respond as part of our role as the face of the industry in regional Queensland.

Our residential customers want prices to stabilise and our business customers see price relief as a key objective – they are no longer willing to pay more for further service improvements. The customer experience, reliability of supply and our corporate responsibility performance, however, remain important to our customers' value perceptions.

FOR MORE INFORMATION ABOUT OUR ENGAGEMENT PROGRAM GO TO OUR SUPPORTING DOCUMENTATION ONLINE.

Our understanding of what our customers expect from us has helped us refresh our strategic direction and commitments to our customers across regional Queensland, which in turn has helped inform the expenditure categories in our Regulatory Proposal.

OUR SERVICE COMMITMENTS

PEACE OF MIND

1. **Our goal is for our safety performance to stand with the best in our industry... to be Always Safe.**
2. **We'll maintain recent overall improvements in power supply reliability... and continue to improve the experience of customers who are suffering outages well outside our standards.**
3. **We'll be there after the storm, prepared and with the resources to respond to whatever Mother Nature delivers.**
4. **We'll meet our guaranteed services commitments. If we don't, we'll pay you.**

CHOICE AND CONTROL

5. **We're looking to the future – and evolving the network to best support customer choice in economic electricity supply solutions.**
6. **We'll make it easier for you to contact us, whether by phone, Facebook, or Twitter, and provide you with the information you need, when and how you need it.**
7. **We'll play our part in powering the economy by making it easier to connect to the network.**

FOR THE BEST POSSIBLE PRICE

8. **We're targeting to reduce what we charge for the use of our network in 2015-16, and keep increases overall in network charges under inflation for the next five years.**

Our progress, the challenge ahead

Our plans are focused on continuing to give our customers a safe, dependable service and increasingly, greater choice and control as our industry and the marketplace evolves. Our challenge is to deliver this while taking the pressure off electricity prices.

Before considering our investment plans, it is useful to have an insight into the progress we have made in meeting our customers' expectations, as well as the cost drivers and the other challenges our people face in meeting our customers' expectations – both those that are unique to Ergon Energy and common to the industry.

A SAFE, DEPENDABLE SERVICE

Reliability concerns largely addressed

In 2004 the Queensland Government's Electricity Distribution Service Delivery (EDSD) Review led to the introduction of reliability standards that became increasingly stringent. By 2009 network performance was not keeping up – and we had to invest above what was allowed for reliability improvement in the current period (2010-15) to meet customer and stakeholder expectations.

Over the last five years the performance of the network has significantly improved.

In 2014 – for the first time since 2008 – we achieved all six reliability performance targets within the Minimum Service Standards (MSS) set by the QCA. Whilst weather conditions always play a part in reliability outcomes, this significant achievement is a result of a substantial investment in network improvements over the past decade, and the dedication of our people.

With the cost of electricity now such a significant issue for our customers, and given our improved performance, we no longer consider reliability improvement investment of this scale warranted. Our customers are now generally satisfied with the supply standards they receive.

We now see our challenge being to maintain reliability standards overall, while continuing to address areas of the network that are underperforming. Around 7% of our customers are supplied by sections of the network that are well outside the performance standards.

Our position also reflects changes to our Distribution Authority, which was modified in line with our customers' expectations in July 2014. MSS levels were flat-lined to 2010-11 levels, our network security planning criteria obligations were revised, and an improvement program obligation was introduced for our worst performing lines.

The challenges associated with our network

The challenges our people face in meeting the reliability expectations of our customers are associated with the environment we operate in, the scale and customer density of our service area, and the design of the network.

Our people are dedicated to serving regional Queensland. They live and work in the communities we serve, and they understand the challenges.

A range of harsh environments

Our network area is subject to wide-ranging and sometimes extreme environmental and climatic conditions, so we expect to experience volatility in network performance from season to season and year to year.

To reduce the impact of weather and climatic conditions on network performance requires a significant operational response capability (people, property and fleet) throughout the state. It also requires prudent investment in network resilience, and in asset renewal, appropriate for the rate of degradation experienced by specific asset components.

DURATION OF OUTAGES CONTINUES TO TREND DOWN

The average duration of outages across our network reduced by 41% and the frequency by 34% from 2010. Meeting our customers' expectations, and our legislated standards, has driven a substantial investment in reliability improvement.

In our tropical north, where the 'wet' season is renowned, the network has a greater rate of power pole deterioration, and is exposed to high rates of vegetation growth, allowing trees to grow rapidly towards the lines. In our central region our network can experience a range of conditions from periods of high grass/bush fire risks, to years where wide spread flooding impacts both the asset and our operations.

In our southern region, the local weather patterns regularly expose the network to high levels of lightning activity and powerful storm cells. In fact, the entire coastal strip of our service area experiences extreme and destructive storm events, often on a scale not seen anywhere else in Australia.

These major events require a resource intensive and rapid emergency response. In recent years we have responded to numerous major weather events, the biggest being Cyclone Yasi in February 2011, and each time we have improved our response capability, as well as our Emergency Response Plans.

The size and customer density of our service area

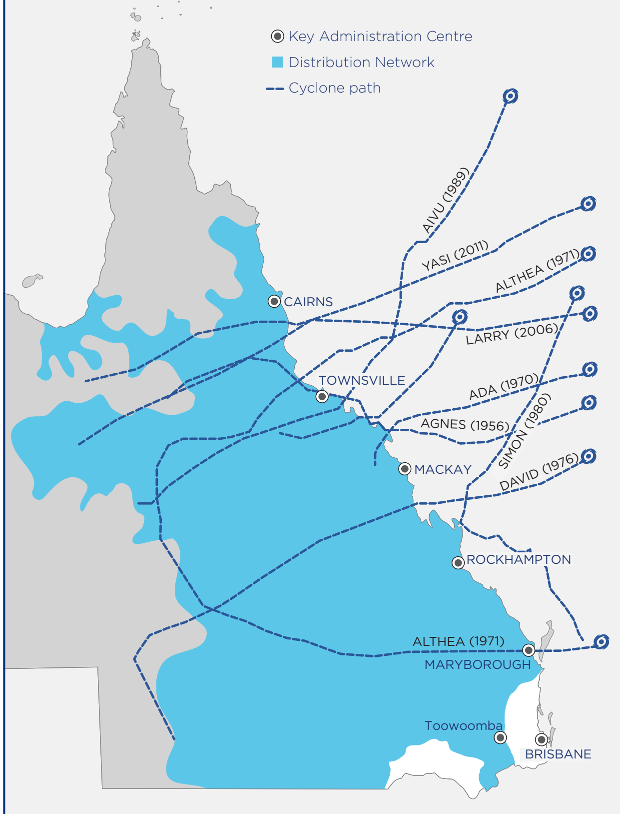
The way the network has developed, and the way it is operated and managed today, has been driven by an ongoing commitment to meeting the needs and expectations of our customers, wherever they are in regional Queensland.

While our customers make up only 7% of the National Electricity Market, we service an area that is by far the largest single distribution area in the market. Due to the dispersed population of regional Queensland, our network has developed with one of the lowest customer densities per kilometre in Australia – five customers per kilometres overall and on our network west of the Great Dividing Range this drops even lower.

This has clear implications for both the investment required per customer, and the way we operate. It can make network and non-network costs look higher than other distributors in areas like property and fleet, which are needed to gain access to the assets (for emergency response, pole inspections, vegetation management, etc.).

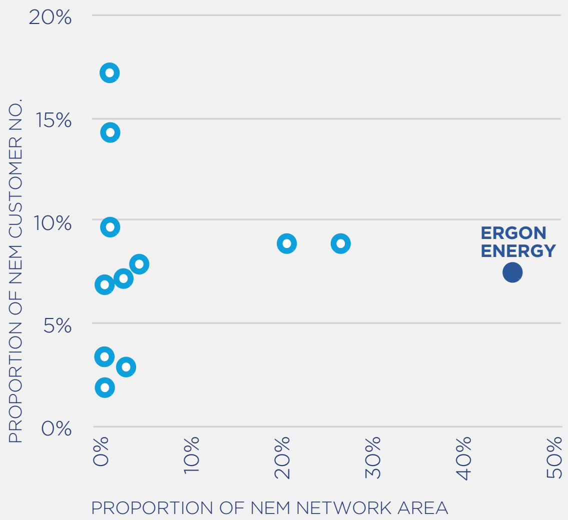
Ergon Energy's service area is over six times the size of Victoria – and we have a dispersed, varied customer base, as well wide-ranging and sometimes extreme environmental and climatic conditions.

EXPOSURE TO CYCLONES



Over the past half century, our service area has seen the destructive force of ten major cyclones. Most recently the network has had to stand up to the impacts of cyclones Yasi and Oswald, a mini tornado in Townsville, and several major wide spread flooding events, to name a few.

HOW ERGON ENERGY COMPARES TO OTHER DISTRIBUTORS



Our service area is by far the largest distribution area in the National Electricity Market (NEM). However, proportionally our customer base is small.

Source: Huegin Ergon Energy Expenditure Benchmarking.

FOR MORE INFORMATION ABOUT HOW ERGON ENERGY COMPARES GO TO OUR SUPPORTING DOCUMENTATION ONLINE.

The design of the network

Our vast service area, our history, our customer profile and our operating conditions have led to a broad range of design, maintenance and operations solutions. However, there are two specific network features that set the Ergon Energy network apart.

Firstly, our network features relatively large amounts of subtransmission assets compared to the other Australian distribution networks. This type of network is more costly to build and maintain than lower voltage networks.

Secondly, the network is largely radial in design. This means critical components of the network are widely dispersed with limited interconnectivity. Without the 'meshing' available to urban networks, there are limited options available when responding to faults or growth in demand. Much of this rural radial network consists of Single Wire Earth Return (SWER) lines with limited capacity and redundancy – at over 65,000 kilometres, we have one of the largest SWER networks in the world, much larger than anywhere else in Australia.

The demand profile and forecast for regional Queensland

A changing growth scenario

Between 2005 and 2009 Queensland was experiencing high economic growth. As a result demand on the network peaked above our forecasts. This and a recommendation that was adopted following the 2004 EDSD Review, which saw the introduction of more stringent 'N-1' network planning obligations around security of supply, led to substantial network investment.

Due to a combination of factors, including the impact of the Global Financial Crisis (GFC) on the Queensland economy, the rate of growth in electricity demand slowed significantly over the course of 2010 and 2011. Peak demand at this time was also impacted by cyclone events, milder summer temperatures, and changes to energy consumption.

We also reduced demand through various initiatives aimed at constrained areas of the network. As we entered 2014-15, the fifth and final year of the period, we surpassed our five-year demand management target, delivering 126MVA in demand reductions, which deferred or avoided $644 million in capital investment.

Our demand forecasts

For the coming regulatory control period, we are forecasting growth in system-wide peak 'summer' demand within a band of 1.3% to 1.5% for each year over the five years.

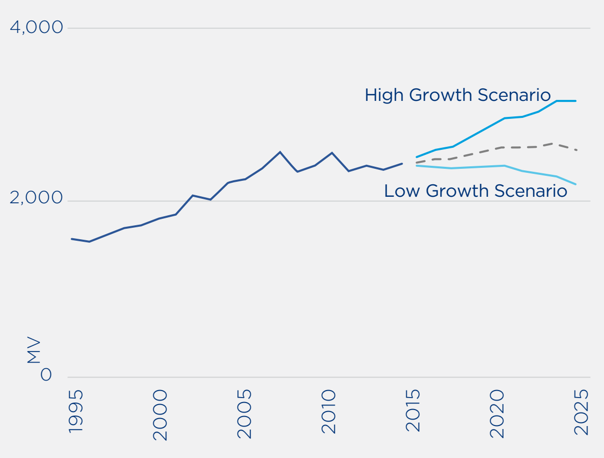
However, we are planning to invest conservatively in response to softening conditions and use the low economic growth demand scenario to inform our network investment decisions.

In addition to considering system-wide demand, we investigate a regions' customer profile and local economic conditions. In some areas of our network we are anticipating demand growth of over 4% a year through the period.

We also look at the load at the distribution level. The dominant driver of augmentation investment in the 'poles and wires' relates to existing constraints on the network, and the need to manage future growth and penetration of solar energy systems. Modelling has been undertaken of the entire network to ensure we consider each feeder line's limitations, load profile and any associated risks in our overall expenditure forecasts.

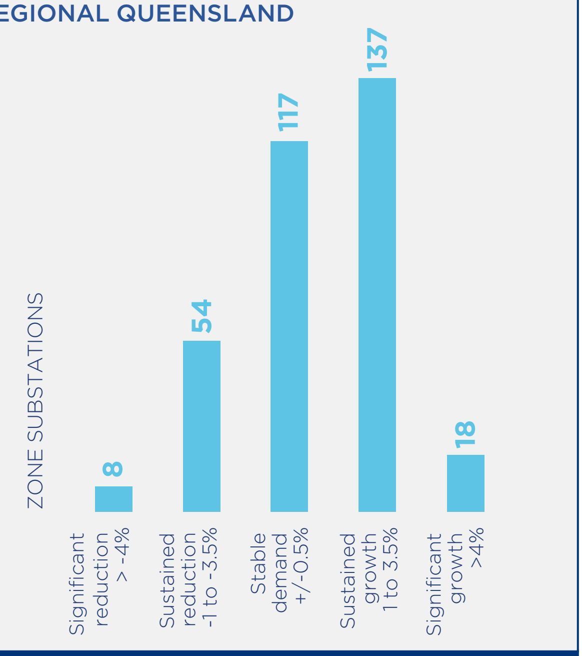
Ultimately, it will be our challenge to manage the demand that eventuates within the allowance set through the AER's distribution determination.

OUR NETWORK DEMAND FORECAST



Over recent years demand growth has slowed with the system-wide peak demand relatively steady. Record temperatures across the state in early January 2014 pushed the 2013-14 coincident peak to 2,441MW, as our customers brought air conditioning load online.

SUMMER DEMAND GROWTH ACROSS REGIONAL QUEENSLAND



While overall we are expecting a low growth scenario, over the next five years over 45% of our zone substation will still experience sustained or high growth, both in general load and new connections.

A CHANGING INDUSTRY AND MARKETPLACE

The take up of solar and emerging technologies

We anticipate that the rise in electricity prices over recent years, and advances in technology, will continue to drive industry and marketplace change, especially in the area of alternative energy supply solutions.

More than one in six households now have solar. Despite declines in government incentives, our customers' intent to purchase or expand on their current solar energy systems remains high. Solar energy exports, together with renewable energy from the sugar industry (bagasse) and other sources, are already contributing over 10% of the electricity for our main grid. To add to this, energy storage and electric vehicles are emerging as potential game changers. Electric vehicles could account for around 20% of vehicle sales in Australia by 2020, rising to around 45% of sales by 2030.[4]

In 2013, Ergon Energy participated in the CSIRO's special inquiry into what the future of the gird may look like, together with more than 35 other industry stakeholders. While trends in consumer choices, technology, government policy and commercial responses will ultimately decide the future, the forum was able to form a view on some of the possible future scenarios. They have been presented here simply to illustrate the level of industry wide change underway. Our view is that a hybrid of these futures across regional Queensland will deliver the best outcome for our customers, the Queensland economy and the environment.

To date we have kept up with the rate of solar connections and the network is operating well in most cases. However, the rate of technology and market change will continue to have both technical and economic implications. We are focused on ensuring these 'customer technologies' support positive, equitable outcomes for our customer base as a whole.

We are facing significant industry-wide change, both in the choices our customers are making around their electricity supply options, and in the new technologies available to us to supply our customers' power-supply needs efficiently and effectively.

The challenge of a dynamic bi-directional network

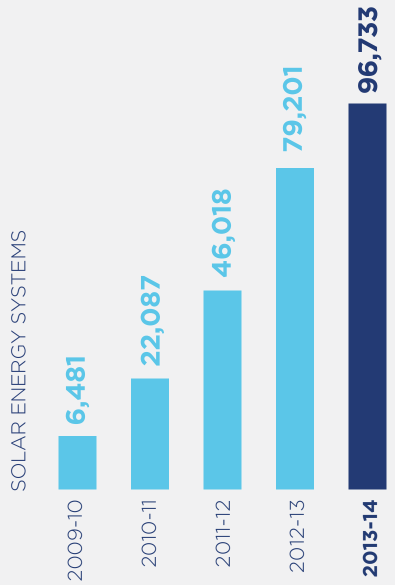
By and large, today's electricity network is currently geared to a one-way supply from the power station through the 'poles and wires' into our customers' premises.

Increasing the amount of two-way supply, such as when a customer with solar energy feeds energy back into the grid, requires us to invest to modernise the distribution network, and to manage the growing volume of data involved efficiently.

This data will be critical to our efforts in effectively planning, engineering and operating the network to avoid voltage issues and to deliver on our customers' expectations.

We have already begun to respond to these technical challenges by integrating operational technology with our more traditional network management capabilities in order to optimise business processes, enhance decision making, reduce costs and lower risks.

CUSTOMER TAKE UP OF SOLAR IS CONTINUING



Over recent years there has been a dramatic jump in customers across our network choosing solar as part of their electricity supply solution; more than 16% of homes now have solar, and support for this technology is continuing.

4 AECOM, Impact of electric vehicles and natural gas vehicles on the energy markets, June 2012. p iii.

POSSIBLE SCENARIO FUTURE SCENARIOS

In examining the 'mega-shifts' reshaping the electricity system, the CSIRO highlighted four diverse potential scenarios in their report, Change and Choice: the Future Grid Forum's analysis of Australia's potential electricity pathways to 2050, available at www.csiro.au/future-grid-forum

Set and forget

Consumers sign up to voluntary demand control schemes

Appliances can be automated to adjust their power use when certain conditions are met. This could be determined by a price point or a time of system stress. Consumers do not play an active role in demand control but rely on utilities for the solutions to integrate and operate the schemes.

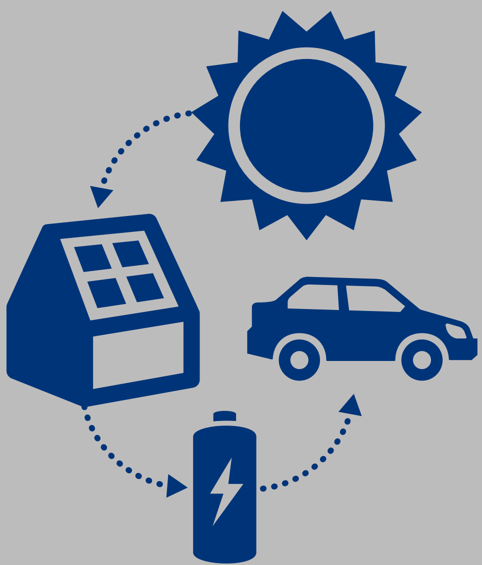
The rise of the prosumer

CUSTOMER CENTRIC MODEL
Where customers consume, trade, generate and store electricity

Consumers become involved in designing products for their own needs.

Moving away from a one-way relationship, the network becomes a platform for transactions. Service providers compete to integrate and facilitate these transactions.

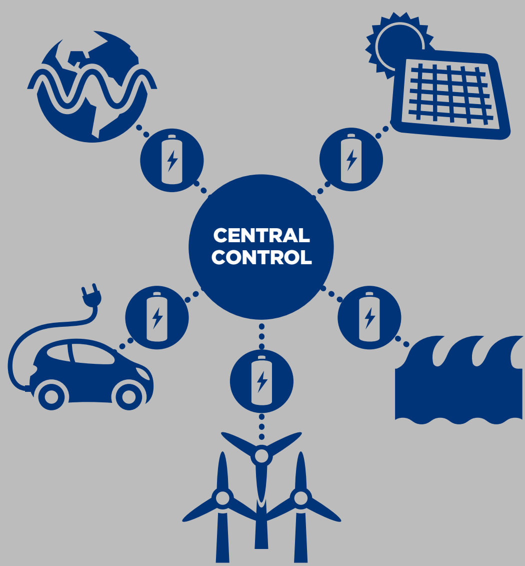
Leaving the grid



Around a third of consumers completely disconnect from the grid

Using a combination of gas generation, solar panels, storage and energy efficiency.

Renewables thrive



Storage plays a large role in all aspects of the electricity system.

Storage supports a 100% share of renewables in centralised power supply by 2050, high electric vehicle uptake (37% by 2050) and strong demand control.

The way our customers are utilising the network is changing

Over the past decade there has been a major shift in the way our customers utilise the electricity network.

Strong economic growth in the early 2000s, coupled with the take up of air conditioning (and other appliances), led to a rapid increase in demand for electricity during peak usage periods. In more recent times however, while peak demand has remained high, the economic slowdown, the growing take up of solar energy and the focus on energy efficiency (as electricity prices have risen) have led to an overall drop in electricity use.

This means Ergon Energy's network, which has been heavily invested in to respond to the growth in demand during peak times (which can occur for only a few days a year), is now not being used as effectively as it could be outside peak times. In addition, the change to consumption levels is putting upward pressure on prices.

To respond to this we have been focusing on addressing the utilisation of our assets. We are looking to respond to future growth with demand management solutions rather than building more network. Managing and even encouraging energy consumption, without placing additional stress on the network or costly infrastructure investment, is critical to ensuring electricity is affordable to all going forward.

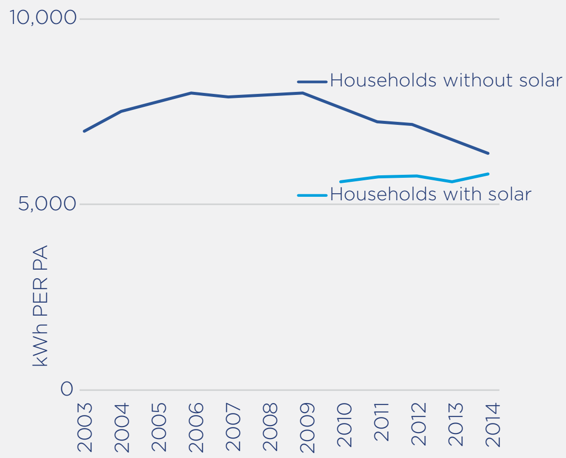
Facilitate a more effective market...value from every interaction

As an industry our challenge is to work with our customers to collectively make the most prudent and cost-effective investments in electricity supply solutions. To do this we need to foster competition and the innovation that will come with it and empower customers with choice and control.

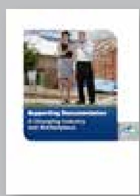
To enable this, we have been aligning our business model, organisational structure and business processes to one of a provider of essential infrastructure that links buyers and sellers of energy services. We see the future of the network as being an open access platform enabling an effective market for distributed energy and other energy-related solutions.

Our success in this rapidly shifting energy environment, especially the increasing complexity of the future distribution model, will require new skills and a material shift in the culture of the organisation. This challenge has seen us refresh our people strategy, and place it at the heart of the organisational transformation underway. We will need to leverage off technological advances over the coming years to build an agile, information-enabled organisation. We also need to maintain a strategic focus on increasing the effectiveness of our leadership and on industrial reform.

AVERAGE HOUSEHOLD ELECTRICITY USE DOWN[5]



Average household energy consumption across regional Queensland is falling. This drop, which is being exaggerated by the households who are sourcing their electricity from solar energy systems, is pushing up the unit cost of electricity.



FOR MORE INFORMATION ABOUT OUR CHANGING INDUSTRY AND MARKETPLACE GO TO OUR SUPPORTING DOCUMENTATION ONLINE.

5 Ergon Energy Queensland Pty Ltd accounts on a combination of regulated tariffs, excluding households with solar energy systems installed. The second trend line shows households with solar energy systems installed.

OUR JOURNEY TO THE BEST POSSIBLE PRICE

Driving efficiencies and effectiveness

As we moved into the 2010-15 regulatory control period we became acutely aware of the need to deliver greater efficiencies and network value to address the impacts of the developing 'price storm'.

We had previously undertaken a whole-of-business 'get fit' efficiency drive through 2005 to 2010, but could see that if we did not take further action our customers would be facing unsustainable price increases.

We could see the scale of the price impact building from past network investment needed to meet growth, as well as a result of government renewable energy policies. In addition, the slowdown in demand in the early part of the current regulatory control period, around 2010-11, and falling consumption (partly due to the rapid take up of disruptive technologies like solar) was increasingly becoming a price issue. At the same time, the GFC led to rising concerns in the community generally about the cost of living.

This saw us, as an organisation, focus sharply on the efficiency and effectiveness of our operations.

In the latter half of 2011, Ergon Energy adopted a strategic goal to limit increases to average network charges to less than the CPI over the medium to longer term.

This led us to undertake a critical review of our operating model and associated organisational accountabilities, and 'right size' the organisation in line with the reduced works program. We reduced the workforce by 645 employees (to 4,415 employees) from the June 2012 peak of 5,060, when we were resourced for an anticipated growth in demand.

Savings have also been achieved through productivity improvements in vegetation management, line inspection and pole defect management. These and other efficiencies have been supported by an investment in new technologies, like the remote observation, automated modelling and economic simulation capability, known as ROAMES. Throughout recent years, we have also been working with our south east Queensland counterpart, Energex, to deliver greater efficiencies.

Together these efforts have delivered improvements in our maintenance costs compared to our asset base, and our operational expenditure per kilometre of line.

Ensuring prudent investment

We have also looked hard at our network planning standards. As we entered the current period, peak demand was still forecast to rise on average by 3.4% a year, and we were expecting record demand for new connections. We were also facing substantial investment in order to achieve the network security planning criteria.

To respond we intensified our investigations into alternative methods for achieving the long-term security of supply and reliability and we continued progressing our customer demand management programs. Demand-side solutions are now proving to be a cost-effective response to demand growth, and offsetting or deferring costly expenditure in major electricity infrastructure.

In the 2005-10 period we invested above our regulatory allowance to keep up with demand and progressively meet 'N-1 security standards'. However, with the slowdown in demand growth and affordability concerns identified, we questioned the reasonableness of the network security planning criteria set following the EDSD Review.

This questioning led to a formal review of our standards, in the middle of the regulatory control period, as part of the Queensland Government's ENCAP Review. Through this process, with the support of our government shareholders, we were able to develop a proactive response to addressing affordability. We then acted quickly to change our planning criteria following the relaxation of requirements through the review.

In terms of the financial outcome, our response, together with the slowdown in demand, allowed us to reduce our expenditure for 2010-15 by $709 million, from the original AER allowance. We were able to pass this benefit, incorporated into the ENCAP Review, back to customers by reducing our allowed network charges by $99 million over the remainder of the period.

We also absorbed the costs of major storm events, like Cyclone Yasi and Oswald, rather than seeking to increase prices by passing on these costs to consumers. Our estimate indicates these events cost us over $120 million.

Since the ENCAP Review was finalised, additional expenditure reductions of around $1 billion were identified. We are expecting to spend 22% less than the total expenditure allowance for the five years to July 2015.

Taking the pressure off prices

Our success in reducing expenditure means lower distribution charges for customers in 2015-16.

If we had not acted prudently and our investment, operating and financing costs remained at AER determined levels over the 2010-15 period, our customers would have been facing another substantial increase of over 12% in 2015-16 in these charges. Instead, customers will benefit from our company-wide initiatives to reduce expenditure in the current regulatory period and our commitment to drive expenditure even lower in the next period.

Instead of increasing prices, our efforts to reduce costs mean that what we charge for the use of our network will fall. Over the course of the 2015-20 period, our forecast for our distribution charges are lower than what we are currently charging (2014-15). This holds true even until 2020. This price path is a dramatic turnaround from what was experienced from 2007 to now.[6]

We recognise our journey is not over in taking the pressure off prices. Delivering on our plans, and achieving the customer savings, will be challenging, but we believe it is what our customers are asking for. The reduction in revenues shown are supported by a commitment to reduce our total capital and operational expenditure by a further 11% and our overhead costs[7] by at least 15%, when compared against our actual and expected performance in 2010-15[8].

Changed financial market conditions also support price reduction

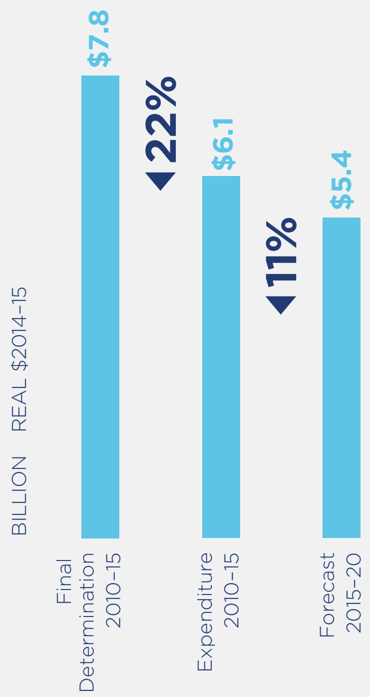
Our efforts to bring down our costs have been enhanced by a reduction in the cost of capital since our revenue allowance was last determined in 2010.

Like any business we need to make a fair return on what has been invested to ensure the business is sustainable. This is determined by forward looking market rates of financing similar businesses.

As rates are forward looking, we expect that the AER will update these rates early next year. To the extent that market rates (like the cost of debt) fall relative to the assumptions in our proposal, we fully expect the AER will make appropriate changes to our cost of capital.

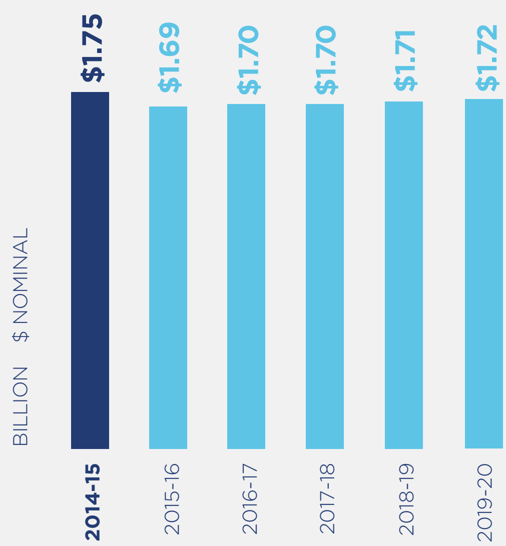
FOR MORE INFORMATION ABOUT OUR JOURNEY TO THE BEST POSSIBLE PRICE GO TO OUR SUPPORTING DOCUMENTATION ONLINE.

WE HAVE REDUCED OUR TOTAL EXPENDITURE DRAMATICALLY



As a result of changes to our capital program and a company-wide efficiency drive, our total expenditure for the 2010-15 period is likely to be at least $1.7 billion or 22% below the level approved by the AER. We believe we can reduce our expenditure further, by another 11% in 2015-20.

DISTRIBUTION USE OF SYSTEM REVENUE DOWN



We have been able to reduce our revenue requirements. This could see us charging customers less in five years' time than what we are charging now – our Distribution Use of System revenue of $1,753 million in 2014-15, is forecast be $1,717 million in 2019-20.

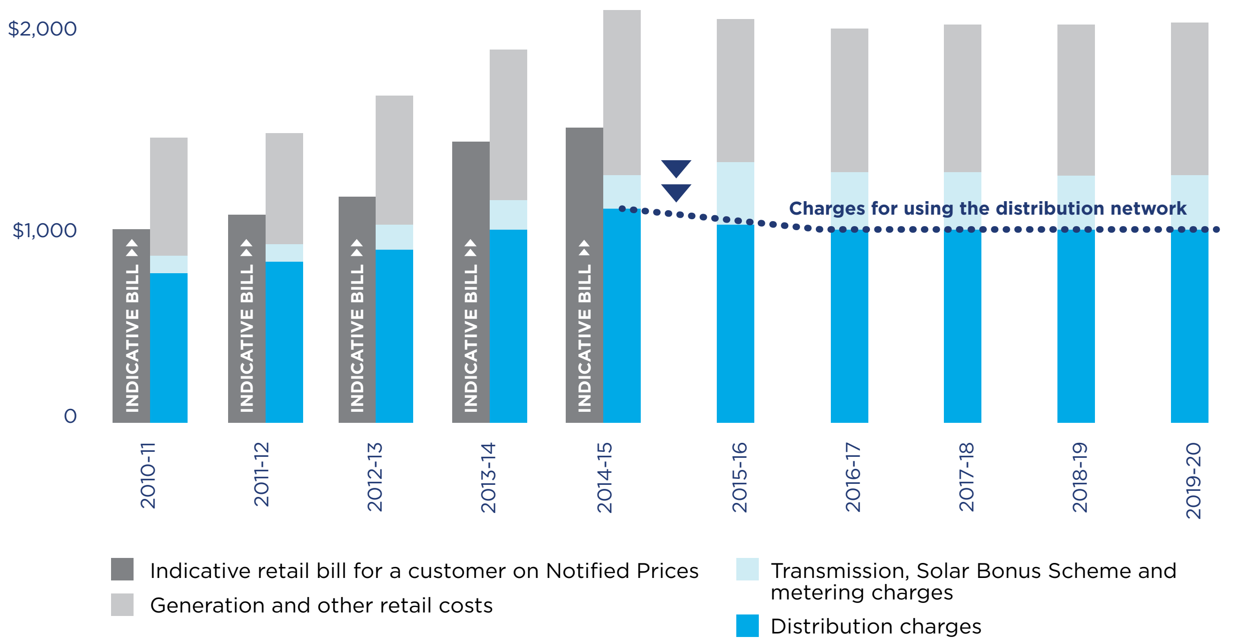
Note: forward revenues exclude reclassified metering services.

6 Based on revenue cap calculations, not inclusive of FiT recoveries or default metering services. Refers to the total DUOS revenue to be recovered from customers in a financial year. Individual circumstances may differ depending on consumption, demand or revenue allocation.

7 Excluding some non-discretionary overhead costs.

8 Proposed reduction is in common dollar (real 2014-15) terms.

PLAYING OUR ROLE IN STABILISING PRICES AS A DISTRIBUTOR

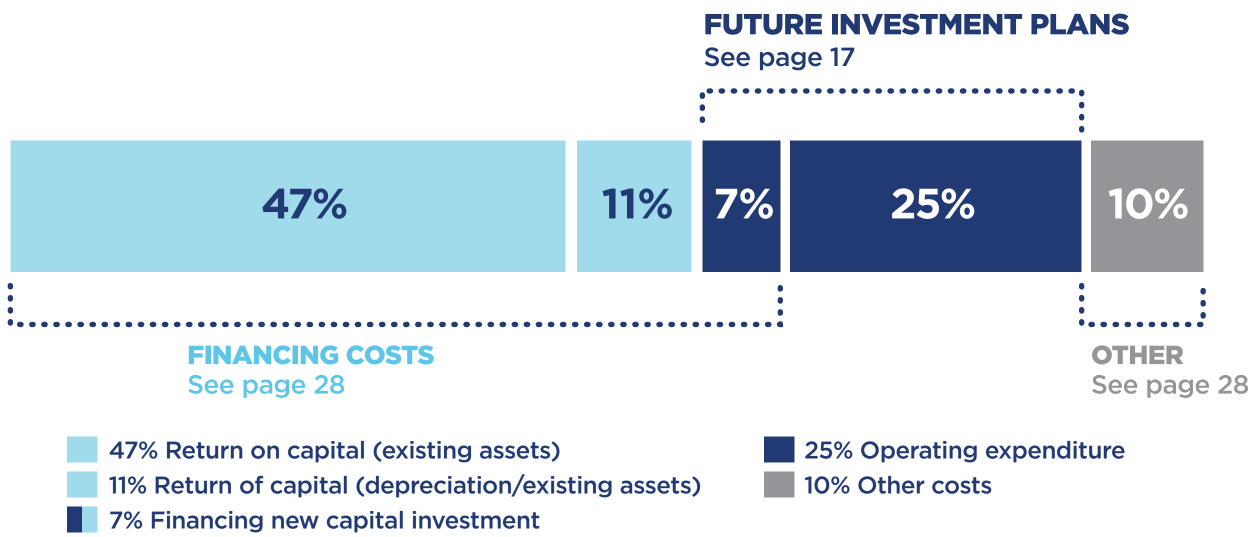


What do our forecasts mean for our customers? This graph shows a reduction for a typical annual residential customer using 4,091kWh per annum of around 6% in 2015-16 in the Distribution Use of System charge passed on to the customer's retailer.

An indicative price stack and trend has been shown in nominal dollars to illustrate all of the charges that are allocated to an average electricity bill for a residential customer on a market retail contract. Forward forecasts are indicative only.

The majority of residential customers in regional Queensland, however, benefit from the Queensland Government's notified retail tariffs, which are determined by the QCA. This means the actual retail bill is subsidised in line with the Queensland Government's Uniform Tariff Policy. The historical INDICATIVE BILL shows the retail bill for the customer on these Notified Prices. For further information on how regulated retail tariffs are determined go to www.dews.qld.gov.au/energy-water-home/electricity/prices. For further detail on our 'best possible price' commitment refer to page 25.

WHAT MAKES UP OUR REVENUE REQUIREMENTS?



By far the biggest component of our revenue requirement is the financing cost associated with the $10.1 billion already invested in the regulated network – the return on capital and the return of capital (depreciation). Around a third of our revenue requirement relates to our future investment plans – for the additional financing costs associated with the new capital investment we have planned for 2015-20 (return on capital and the return of capital) and the expenditure required for operating and maintaining the network and running the business. We also have to recover a range of other costs, such as corporate income taxes and other adjustments.

Our future investment plans

In developing our Regulatory Proposal for 2015-20, we have looked at our service commitments to regional Queensland, and used these to help inform our capital and operational investment plans.

In this section we provide an overview of these plans, highlighting the areas of expenditure that will help us deliver on our service commitments.

AN OVERVIEW OF OUR FORECAST EXPENDITURE

Ergon Energy undertakes both capital and operational expenditure.

Our capital expenditure includes both 'system capex' and 'non-system capex'. System capex involves building and renewing the network, the poles and wires, and the other infrastructure we need to supply the power.

Non-system or non-network related 'capex' covers investment in fleet vehicles, property (offices and depots), tools and equipment.

Our operating expenditure covers our day-to-day operation and maintenance of the network, and other costs for activities like our customer service functions and alternative solutions for meeting electricity demand.

Our overheads are allocated and incorporated into our capital and operating costs, through the Cost Allocation Methodology approved by the AER.

CAPITAL EXPENDITURE

ASSET RENEWAL

To maintain the safety and reliability of the network we need to continually refurbish and replace assets as required. We have made big strides in understanding the state of the network and targeting this investment to deliver the greatest value.

AUGMENTATION FOR GROWTH (CORPORATION INITIATED)

While demand for electricity has stabilised, we are still planning investment in areas of the state that are experiencing ongoing economic growth, largely associated with the resource sector.

NEW CONNECTIONS (CUSTOMER INITIATED CAPITAL WORKS)

Overall we expect requests for new or upgraded connections to remain relatively stable. We have developed robust forecasts across all of the connections categories, from new commercial or industrial connections to metering.

RELIABILITY AND OTHER TARGETED IMPROVEMENTS

We are targeting investment here where we know the network is not meeting our customers' expectations (as reliability has improved we've been able to cut this expenditure).

To respond to the changing needs of our customer, we are also progressively investing in new operational technologies that will allow us to better manage the network.

OTHER NON-NETWORK ASSETS

In order to service our vast area we also invest in fleet, property, equipment and tools. This is critical to maintaining our response capability day-to-day and in times of natural disaster when the strength of our regional presence is critical.

OPERATING EXPENDITURE

NETWORK MAINTENANCE

We are continuing routine asset inspection and maintenance programs. Clearing vegetation from around powerlines also remains a priority, both from a safety and reliability perspective. In addition, this expenditure category covers our outage/emergency response efforts.

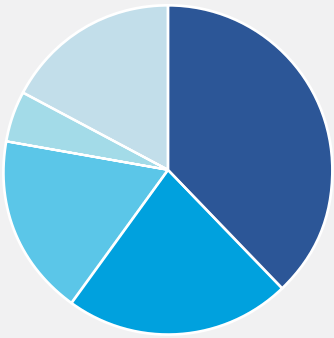
NETWORK OPERATIONS

This expenditure is for monitoring and controlling the network, and other systems, 24 hours a day, 7 days a week. Our investment in operational technologies will provide greater automation of the network and help manage these costs into the future.

OTHER OPERATING COSTS

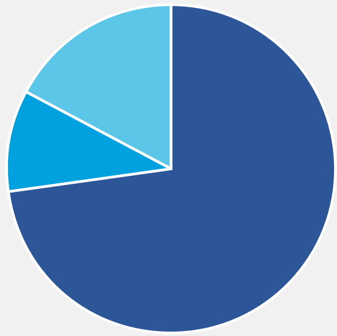
These range from managing service requests, from our customer contact centre to our service order dispatch teams, to other non-network activities. We are increasing our operating expenditure on alternative non-network solutions to better manage demand on the network, and looking at a new form of cyclone insurance cover.

OUR CAPITAL INVESTMENT PROFILE 2015-20 – $3.6 BILLION



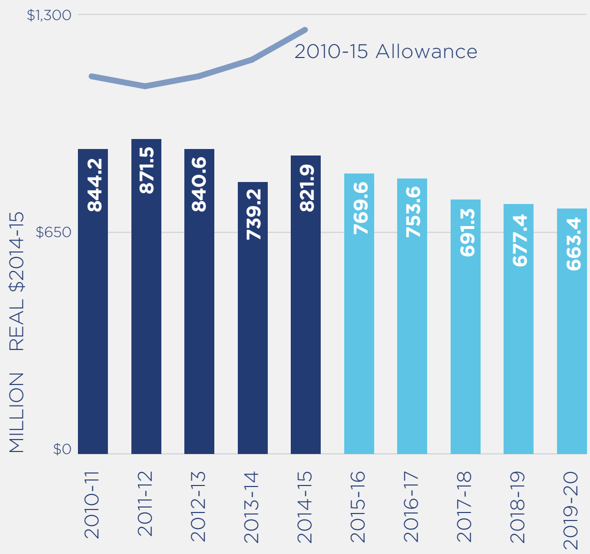
We plan to invest $1.4 billion in asset renewal to maintain the network. Our forecasts, both for demand across the different areas of our network and for new customer connections, are driving another $1.4 billion in investment. We also plan to invest $166 million in reliability and other targeted investments. Our non-network investment, including property and fleet, is down compared to the previous period to $603 million.

OUR OPERATING COSTS 2015-20 – $1.8 BILLION



In operating the network, maintenance is our largest cost – $1.3 billion over the five year period. We have achieved efficiencies in vegetation management, line inspection and pole defect management. At the same time we are increasing expenditure in alternative non-network solutions, as a more cost effective way to address network demand than capital investment.

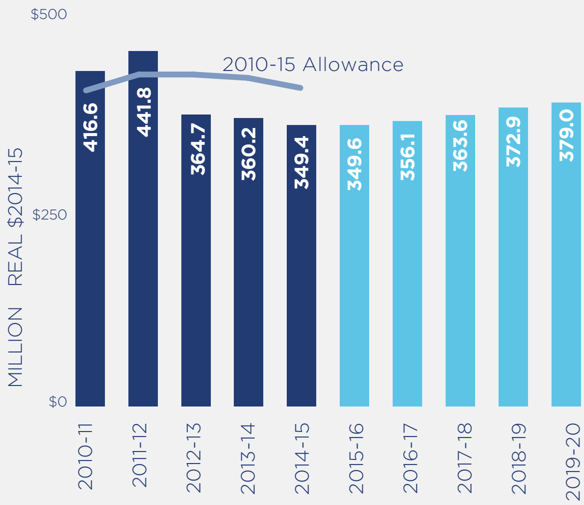
CAPITAL PROGRAM DOWN FROM 2010-15 ALLOWANCE



Due to a very different growth profile to what was forecast at the time of the last determination, and the low growth economic scenario we are using for our forward planning, our capital expenditure will be lower in 2015-20 – totalling $3.6 billion.

Changes have also occurred to the classification of services. The trend shown is for our Standard Control Services.

OUR OPERATING COSTS WERE REDUCED MID-PERIOD



We have achieved substantial efficiencies over recent years, which have placed us well to deliver savings as we move into 2015-16. The targets we have set for our operating costs are a challenge and will require significant reductions in costs in the future to deliver. We are looking to technology-based capabilities to support greater efficiencies moving forward.

FOR MORE INFORMATION ON OUR PLANS WE HAVE FORECAST EXPENDITURE SUMMARIES FOR EACH CATEGORY OF EXPENDITURE AVAILABLE ONLINE.

DELIVERING ON OUR SERVICE COMMITMENTS FOR 2015-20

PEACE OF MIND

Always Safe

Ergon Energy is committed to ensuring the safety of our customers, the community, employees and contractors.

Our operational response to network incidents remains central to minimising safety risks. We have two operational control centres, and a central communications system centre, which monitor the network and our other systems 24 hours a day, 7 days a week.

We are continuing our routine asset inspection and management program of lines and associated infrastructure. Managing trees around the powerlines also remains a key preventative safety measure. Greater efficiencies are being achieved in this area through smarter technologies like the remote observation capability, ROAMES.

Our Community Electrical Awareness Safety Plan will continue to educate the community about safe practices.

Improving our safety in the workplace for our people also remains a priority. This will see an ongoing investment in control measures around potential life threatening risks, a focus on reducing dangerous electrical events, a risk mitigation program around our network switching operations, and continuing safety leadership and other targeted safety training (including driver safety).

Targeting investment to address safety risks

To maintain the safety (and reliability) of the network we have a significant asset refurbishment and replacement program. Over recent years we've gained a better understanding of the network and addressed significant issues. However, we have more work to do and have proposed a number of specific safety-related asset renewal programs in our Regulatory Proposal. We don't want to risk the network deteriorating, or safety problems to arise in the future.

We have a significant investment planned to replace ageing copper lines across our network, which have in the past led to dangerous electrical events.

We are also planning further investment in the protection and control equipment across our substations and distribution lines, in order to better ensure we adequately protect the community, our people, and the network itself from faults. This will include continuing to add sensitive earth fault protection to our high voltage feeder lines and addressing a safety issue associated with our older zone substations and how the auxiliary power is supplied for use in the substation itself.

The proposals around our operational technology investment will also support network operations in delivering positive safety outcomes.

In our proposal we are also seeking an allowance to help maintain appropriate standards of environmental performance. We are progressively addressing oil separation and containment requirements at our transformer sites.

We are focused on being responsive to the changes taking place in our operating environment and being more effective across all areas of our delivery. To do this, we're helping our employees, like Raj Prasad, with the skills development, the tools, and the information and technology support required to carry out their work safely, efficiently and effectively.

Our commitment: Always Safe

Our goal is for our safety performance to stand with the best in our industry... to be Always Safe.

Our aim is to reduce asset-related public shocks, dangerous electrical events, and serious electrical incidents to as low as reasonably practical. This commitment is about managing the network to best ensure public safety. It also extends to building community awareness of safe practices around electricity infrastructure, and when using electricity in the home.

Our goal will also see us take the organisation's work, health and safety performance into the top quartile of the benchmarking undertaken annually by the Energy Networks Association (ENA).

Reliability and quality of supply

At the core of our expenditure proposal is our commitment to ensuring we meet our customers' reliability and quality of supply expectations, and our Minimum Service Standards.

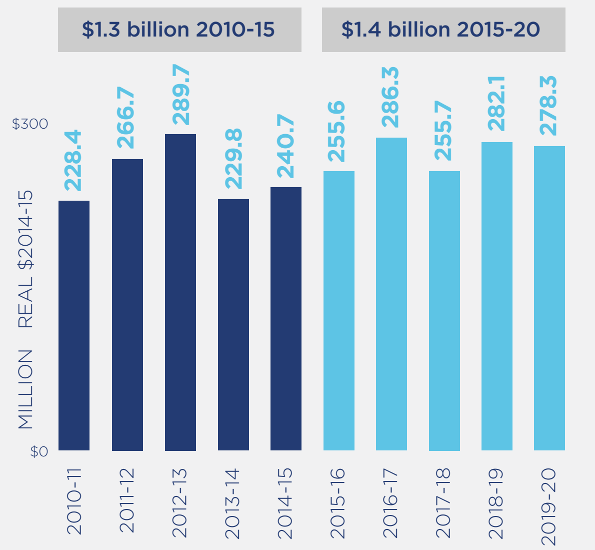
Invest with a better understanding of the condition of the network

Our asset renewal approach is aimed at reducing the risk of faults (both from a reliability and safety perspective) for the lowest whole-of-life cost. To do this efficiently we are continuing our investment in our condition monitoring capability to give us a better understanding of the state of the network.

> **"... there has been a very marked improvement over the last 10 years... I would not be prepared to accept a decrease in that high standard."**
>
> Source: Service/Cost Trade-off Research; online survey.

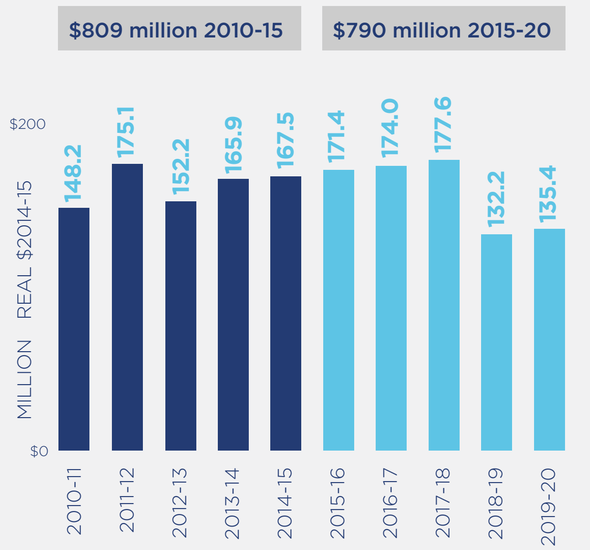
We are planning a significant replacement or refurbishment investment across our substation and powerline assets, and also for a range of other obsolescent technologies (including our radio communication network).

ASSET RENEWAL CRITICAL FOR SAFETY AND MAINTAINING SERVICE STANDARDS



We have made improvements in our data and information systems, inspection and condition monitoring regimes and our understanding of asset management solutions. This has allowed us to defer significant expenditure, and achieved other efficiencies in our asset management techniques. This has allowed us to divert funds for emerging safety risks, like the replacement of ageing copper powerlines and the old style, open wire or uninsulated services that go from the pole to the house.

AUGMENTATION TARGETED TO LOCAL GROWTH



In our plans we have funds allocated to 23 major subtransmission level projects that are already progressing, and another 29 new projects. In addition, we are planning 47 distribution level projects. All new projects have been planned based on forecast loads associated with the low economic forecast for Queensland.

Our commitment: Reliability and quality of supply

We'll maintain recent overall improvements in power supply reliability... and continue to improve the experience of customers who are suffering outages well outside our standards.

This means our customers living in our urban centres will experience on average less than two power outages per year, with an average time without supply of 2.5 hours per year (planned and unplanned outages).

For the majority of our customers, who live in our smaller rural communities, we'll aim to keep power outages on average down to four per year, and the average time without supply to seven hours per year. For our more remote areas, we'll aim to keep power outages on average to 7.4 per year, with the average time without supply to 16 hours.

This is in line with our commitment to the Queensland Government's Minimum Service Standards (MSS).

The second part of our commitment reflects our focus on monitoring and, where practical, improving the reliability of supply of the sections of the distribution network that are consistently performing poorly. We report publically on this program in our Distribution Annual Planning Report.

As well as reliability, we also remain committed to proactively addressing quality of supply, in accordance with the technical standards. Power quality encompasses such issues as under and over voltage, voltage sags and swells, momentary interruptions, harmonics and voltage flickers.

Ongoing improvements are also being made across our asset inspection, preventative and corrective maintenance programs.

We will continue to monitor reliability outcomes as we move forward.

Continue to address poor network performance

We have allocated expenditure to address the performance of up to 45 feeder lines that are consistently underperforming.

To best target efforts towards our customers who are consistently experiencing supply interruption duration well beyond the Minimum Service Standards, we will review reliability outcomes annually, along with the solutions that are most cost effective.

We also plan to continue installing power quality monitors across the network so that we can proactively address momentary outages and voltage issues. Around two thirds of our distribution feeder lines are now monitored for power quality. Our proposal is to invest in a further 1,120 power quality monitors and an additional 100 power quality analysers.

Prioritise our investment in the network to deliver the best value

Augmentation investment is critical to avoiding the potential for network limitations that could impact security of supply, and ultimately reliability performance.

We have enhanced our demand forecasting and governance protocols to be as prudent as possible in this area of investment in the network. Over the next five years we plan to invest $790 million to build or augment the network – much of this investment will be in the areas of Central and Southern Queensland.

In these regions we service some of Queensland's largest energy users. Several of these resource companies are developing or proposing to develop LNG fields in the Darling Downs and west of Clermont, and demand is expected to be driven upwards as local service centres grow to supply accommodation and support industries. Port development is also expected to add considerable load.

Our planned augmentation works are both at the subtransmission level and the distribution level.

At the substation level, we are applying new network planning criteria, which consider the customer value of the investment from a reliability perspective and applies a safety net based on the potential impact of a single event. We will continue to assess this approach as we move forward to best balance our customers' expectations around reliability and price.

At the distribution level, in addition to addressing localised demand, we are forecasting augmentation investment to specifically deal with voltage-driven constraints and conductor clearance issues. We are planning 47 new feeders and major feeder capacity upgrades.

Using demand management as a more cost effective solution

We are looking to build on our demand management success, and increasingly use non-network alternative solutions – from an embedded generation response to more innovative projects – as a more cost effective way to respond to constraints on the network.

We are planning to invest $60.5 million in demand management over the period to achieve targeted reductions of 80MVA in demand. This is considered a key strategic capability for supporting the proposed reducing capital works forecast for the 2015-20 period. Our reduced capital works program is not possible without the forecast risk mitigation support from demand management activities.

Our disaster management and storm response

Our emergency response capability

Our Regulatory Proposal supports the maintenance of a strong outage and emergency response capability.

We have a significant workforce of skilled, professional personnel to respond to day-to-day emergencies, as well as access to additional external resources to help us respond following major natural disasters. We have demonstrated the strength of this capability through our response to category 5 Cyclone Yasi, which brought devastation to north Queensland in 2011, as well as countless other events across our service area.

In preparation for each storm season, we will continue to routinely review our summer preparedness and improve our emergency management response capability.

Our expenditure in non-network assets across our vast service area, including our investment program in property, fleet, equipment and tools, remains critical to our people in delivering our emergency response. They also have access to a significant mobile generation and substation capability.

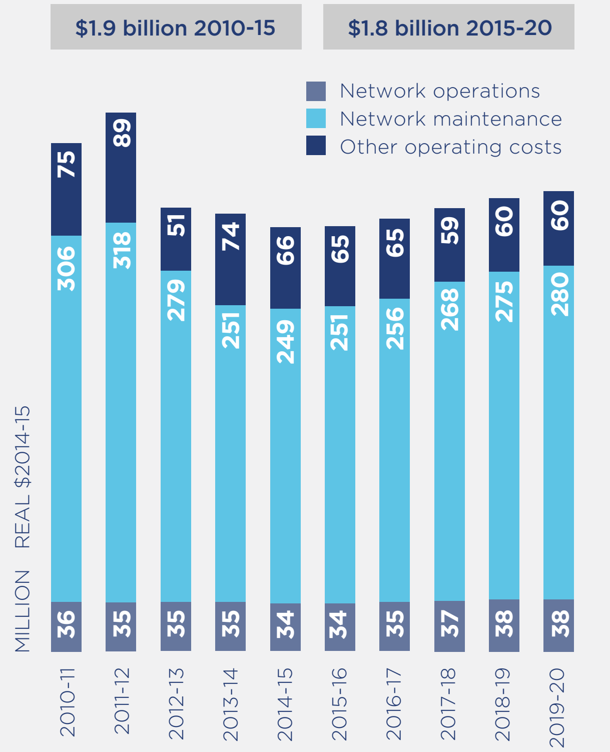
Our commitment: Disaster management and storm response

We will be there after the storm, prepared, and with the resources to respond to whatever Mother Nature delivers.

While we are unable to guarantee the lights will stay on during cyclones and other major weather events, we can reassure the community that we are prepared and ready to deal with these events. We see this as a core corporate responsibility.

This area of our service sees us engage both locally and at the state-government level to ensure an integrated emergency management response.

SERVICE DELIVERY BECOMES MORE EFFICIENT



We are committed to driving efficiencies, without compromising on our service standards, especially our Guaranteed Service Levels. We have recently shifted our new operating model to focus our delivery on the service commitments outlined in this document. We have achieved efficiencies through this, as well as significant productivity improvements across a range of our operational delivery areas.

To better target our response, our people are also now supported by the remote observation capability of ROAMES, which can provide a rapid aerial damage assessment following a major event.

Our summer storm safety communications program will also continue, and we'll ensure our contact centre has the capacity to handle the call load following a major event when our customers need us the most (see Communications).

We have a state-wide workforce at the ready to meet our customers' expectations during and after a major event – to ensure we can deliver when we are needed we have 69 operational depots and two control centres linked to two customer contact centre sites.

Improving our resilience to storms

Our focus on enhancing the resilience of the network to the impact of storms is continuing through our asset refurbishment and replacement programs, and through targeted initiatives. For example, we are installing 'spreaders' (insulated rods) as a cost effective solution to prevent lines clashing during high winds and retrofitting fuses to protect against electrical overload.

Safeguarding our customers from the cost

To financially safeguard us, and our customers, we have incorporated a new cyclone insurance proposal in our plans. While in the past the excessive costs of insurance meant we have effectively been self-insured or relied on pass through event mechanisms, the insurance market has changed. Drawing on overseas experiences, we believe it is now more prudent to take out insurance to ensure our customers are not exposed to what could potentially be a significant price shock impact if one or more of Queensland's coastal population centres was devastated by a major cyclone.

Meeting our customers' service expectations

Our operational costs include dedicated teams to manage customer service requests, from our customer contact centre to our field service teams.

To ensure a consistent service standard these teams will increasingly be supported by system technology investment.

We are currently progressing the roll out of Field Force Automation to transform how Ergon Energy manages all service order requests from new connections to final meter reads. This system effectively automates the dispatch of customer service and fault response work via mobile devices, which crews will use in the field to allow consistent, improved customer service and greater efficiencies.

Our commitment: Meeting service expectations

Ergon Energy aims to meet a high level of customer service satisfaction.

Where, despite our best efforts, a customer is not happy with our service and makes a complaint, we'll respond promptly and appropriately. At least 90% of complaints will be responded to within two working days, and 75% will be resolved within five working days.

We also have Guaranteed Service Levels across our key service areas, including connections; reconnections; wrongful disconnection; hot water supply; appointments; notification of planned interruptions; duration and frequency of interruptions.

We'll meet these commitments. If we don't, we'll pay you.

For more information, visit www.ergon.com.au/your-home/connections/guaranteed-service-levels

CHOICE AND CONTROL

Our future focus

Develop an intelligent grid to support the safe two-way flow of power

In order to respond to the needs of our customers, and a changing industry and marketplace, we are progressively developing a 'smarter' grid and creating an open access platform that enables distributed energy resources and other applications to easily connect with our network to enhance customer choice.

We plan to be proactive, with investment in improving our real time data on network status, which will support better operational management decisions. For example, through a phased approach, we plan to communication-enable three quarters of our high voltage regulators by 2020, and where practical use intelligent communicating switches and protection devices, as well as active monitoring throughout the distribution network.

This approach is necessary to support the change in the way customers are using the network. It will also allow us to achieve greater network utilisation (and potentially defer or avoid costly network investment) and create general operational efficiencies. This capability, coupled with other voltage management initiatives, is particularly important in ensuring we can manage the network voltage issues associated with a higher penetration of solar energy systems.

We estimate there will ultimately be around 800,000 smart devices located throughout the network as more and more standard network components include this capacity off the shelf and they are installed at the premise.

To take advantage of this smart technology, we are targeting investment in new operational technology capabilities. This includes further investment in our distribution and outage management system, our 'SCADA' control system and demand management system, as well as in telecommunications infrastructure.

We are also planning to establish a dedicated, fully integrated network operations centre that will enable us to efficiently deal with the complexity and volume of information that will be available from the myriad intelligent electronic devices located across the network.

Reform network tariffs to provide choice, and ensure long term network viability

We have begun restructuring the way we charge for the use of the network. This will provide greater choice and equity, and ensure we maintain a viable network for the benefit of all our customers and the economy. While not part of the Regulatory Proposal 2015-20, the network tariff reform path we started in 2013 will continue into the next regulatory control period, through an ongoing engagement process, with our ultimate goal of giving customers choice as to when and how they use our network, with effective price signals that optimise the use of the network, and ultimately take the pressure off prices.

Some of the new tariff options may require advanced metering, which can record interval data and ultimately communicate with our systems. While we are not seeking regulatory funding or planning a large roll out of these meters as part of our metering strategy, the number of electronic meters in use across the network will increase through our business-as-usual meter replacement program. We are, however, seeking funding to implement a system that will allow us to configure these electronic meters and ripple receivers, more cost effectively in the field. This will be critical as the proportion of electronic meters grows and tariff reform progresses.

Our commitment: Future focus

We are looking to the future – and evolving the network to best support customer choice in economic electricity supply solutions.

We are committed to shaping our services to meet our customers' evolving needs.

We are increasingly taking on the role of a provider of essential infrastructure that connects buyers and sellers of energy services, and allows all participants – customers, generators, or those storing energy and managing demand – to get value from the network. We see the future of our network business being in distribution, connection, and market facilitation.

Engaging with our customers

Maintain the capability of our Contact Centre

Ergon Energy maintains a high tech, well-resourced contact centre across two sites in order to manage high volumes of phone enquiries and the risks associated with being exposed to major storm events – we receive over 1.5 million customer calls every year, with around 500,000 relating to the distribution element of the business. Our total call handling capability, both in person and through our Interactive Voice Recognition service, is approximately 30,000 calls per hour.

The contact centre's technology platform is currently being replaced to meet current industry standards. This will deliver both greater efficiencies and enhanced customer outcomes as we move into the next five-year period. The new platform supports the management of multiple contact types (phone, email, web, social media, etc.) in an integrated way, as well as the introduction of new self-service options.

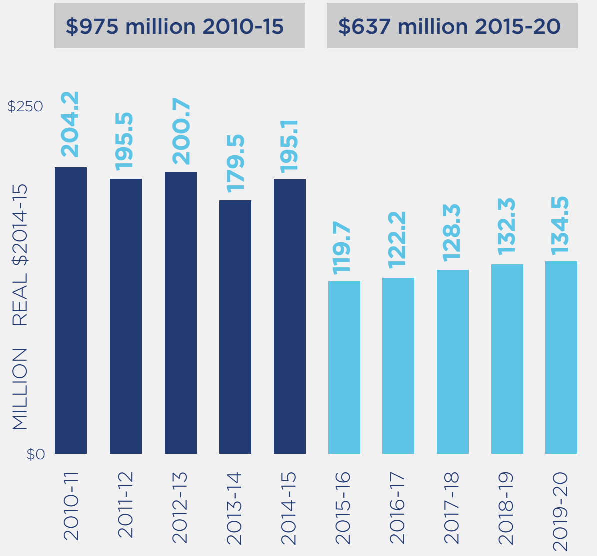
We will also be looking for ways to keep our customers better informed about outages by using the 'real time' information available from the growing level of 'smarts' in the network. Most recently we developed an online Outage Finder, which visually displays planned and unplanned outage information and restoration times across our network, and also progressed our social media engagement.

An ongoing commitment to engagement

We will continue making improvements to our customer and community engagement approach.

A priority is being placed on understanding and responding to our customers evolving energy needs, as new technologies emerge. We will continue to track what our customers value, monitor service expectations, and adapt to the different engagement preferences of our various customer and stakeholders segments.

CHANGE TO THE CLASSIFICATION OF NEW CONNECTIONS IMPACTS EXPENDITURE PROFILE



We are anticipating the rate of new connections to remain relatively stable in the coming years. The drop shown in 2015-16 simply reflects changes in the classification of some of our new connection services – an estimated $385 million of large customer initiated capital works are now considered Alternative Control Services and, as such, are not shown in the Standard Control Service expenditure forecasts here.

An ongoing investment will be made in community participation in the decision making process around new infrastructure proposals and, wherever reasonable and cost-effective, on responding to concerns or proposals raised.

We see demand-side engagement as a key component to our strategy for addressing rising electricity prices. Ergon Energy's approach includes engaging early on with stakeholders, customers and non-network providers on the supply of demand-side solutions to identify the most cost effective solution to network supply problems.

Our commitment: Engaging with our customers

We'll make it easier for you to contact us, whether by phone, Facebook, or Twitter, and provide you with the information you need, when and how you need it.

We'll continue to look for ways to improve the interaction experience with our contact centre.

Our aim is to meet our customers' expectations (maintaining satisfaction levels above 85%) with a priority on delivering a high grade of service. Our aim is to ensure greater than 77.3% of unplanned outage enquiries/ emergency calls are answered in 30 seconds, and 70% of all general enquiries (distribution) are answered in 120 seconds.

We'll also continue to build our expertise and capacity to engage online. We see great opportunities here in communicating real-time updates on the progress of a local power restoration and in increasing the self-serve options available to our customers.

When we have to work on the network, we guarantee we'll notify customers at least two business days before the planned interruption – and with more time whenever we can.

We'll also continue to strive to empower customers with the information they need to engage on energy-related matters, and increase the effectiveness of our overall stakeholder engagement strategy.

We will continue to be proactive in engaging with the communities we serve to ensure we are able to meet our corporate responsibilities, and listen to concerns to minimise the social, environmental and local economic impact of our decision making.

New connections

Maintain robust forecasting of new connection works

Overall we are anticipating demand for new connections to remain relatively stable in accordance with regional Queensland's economic forecasts. We expect this to apply at the macro level to the following key customer segments: domestic and rural; commercial and industrial; subdivisions; street lighting; metering; and services.

Having said this, the timing and scale of new connections at a local level can be uncertain owing to changes in local economic circumstances.

This area of our service is driven solely by customers requesting new or upgraded connections. Ergon Energy is obliged to connect customers to the network, where practical to do so. Our Regulatory Proposal includes a new Connection Policy, which sets out, amongst other things, the contribution a customer is required to make towards the cost of connection.

Our aim in forecasting our costs has been to balance the need to ensure we can respond in a timely way to the level of demand without unnecessary scaling up of our resources and adding costs.

We have a team dedicated to engaging our larger customers who are driving the major infrastructure projects across the state, most notably in the resources sector. The customer intelligence that this team gathers supports the forecasting and management of the demand for major customer connections. After transitioning last period, these projects are now predominantly considered an Alternative Control Service, which are paid for by the individual customer.

"The focus should be on sustainability in the long term, both in terms of financial sustainability, the ability to meet the community's expectations..."

Source: Service/Cost Trade-off Research; online survey.

Support greater choice in how connections are undertaken

We will continue to support real estate developers in undertaking their own electricity infrastructure design and construction works. We'll also explore opportunities to expand the choices available. The contestability of these works is allowing developers to take greater control of their costs and the timing of necessary works. This service, however, is still being offered by Ergon Energy and resourcing requirements have been established based on the works forecasts.

We plan to maintain the Developer Reference Group, which was established to work collaboratively with real estate development industry representatives to resolve issues relating to policies and processes around developers' design and construct options.

Our commitment: New connections

We'll play our part in powering the economy by making it easier to connect to the network.

To do this, we'll continue to make improvements to our policies, standards and practices in relation to new connections and customer-initiated network upgrades.

We'll continue to provide assistance to our large customers when choosing the connection option that best suits their needs (whether that is to build, own and operate, or build and transfer) and to support the development of a competitive connections market in regional Queensland.

For real estate developers undertaking their own 'developer design and construct' projects (for residential, rural, commercial and industrial subdivisions), our service promises are outlined in a dedicated New Connections for Developers Charter.

We also recognise our customers are seeking ongoing service delivery improvement for the smaller, less complicated connections and network upgrades, where the works are performed by Ergon Energy as part of our network connection service. For these projects, our aim is to meet the service standards set out in our Network Connection Application Guidelines.

BEST POSSIBLE PRICE

Our engagement has shown that customers generally appreciate the best possible price is not always the lowest possible price. We are seeking sustainable outcomes, which address affordability concerns now without impacting prices or sacrificing safety or service reliability in the future.

Right across the business we are continuing to look at our own efficiency and effectiveness, from how we plan, operate and maintain our network, to how we deliver our support services, and undertake our interactions with customers and others in the market.

Smarter use of the network we already have

In the current period, technology and a focus on demand management has allowed us to move our investment planning approach from being largely based on building more or bigger 'poles and wires' solutions, to a focus on finding the best, most cost-effective solution. Our delivery of 126MVA demand reductions, to date, over the current period is a clear demonstration of the capability developed in this area. This is equivalent to removing the demand of 36,000 houses or the demand of a regional city the size of Bundaberg.

We plan to strengthen this capability by progressively expanding the automation within the network. This will enable us to adopt emerging 'smart' technologies in the future that will optimise our ability to efficiently deliver the power supply needs of regional Queensland.

Operating as efficiently as we can

To support further efficiencies, over the next five-year period, we'll be implementing new technology-based capabilities, including better information and decision-making tools.

We are currently investing in management systems to enable efficiencies – this covers organisational performance information systems, as well as the systems that manage finance, human resources, safety and procurement. An investment is also continuing to be made in our spatial data and Geographic Information System to enable continued support, while delivering functional improvements.

Facilitate a more effective market and foster contestability

To take the pressures off price, we are being active in facilitating a more effective market, one that empowers customers with choice and control.

Our proposals will allow us to increasingly act as an open access 'platform' for new economic and sustainable energy solutions as they emerge. They will help us provide the essential infrastructure (and the required operational technologies), as well as the information, services, rules, standards and protocols that link the buyers and sellers of energy services.

Through the right pricing signal and control, we believe an effective market will encourage energy use at the right time, at the right price, and unlock the economic value of the network for all, improving its utilisation and lowering the price of the services we offer.

Our commitment: Best possible price

We're targeting to reduce what we charge for the use of our network in 2015-16 – a significant part of our customers' electricity bill – and keep increases overall in these network charges under inflation over the next five years.

Our target is at the centre of our Regulatory Proposal, which we have submitted to the AER, for the next five-year regulatory control period.

We have applied our best possible price commitment to the costs we control, and pass on to a customer's retailer, as regional Queensland's electricity distributor.

Instead of increasing prices, our commitment to reduce costs means that what we charge overall for the use of our network will fall, by around 3.5% in the first year. Over the course of the 2015-20 period, our forecast for our distribution charges are lower than what we are currently charging in 2014-15. This commitment holds true even until 2020.

Even with the inclusion of metering service charges, our combined network charges are reduced and forecast increases are overall below CPI.

The actual price impact on individual customers will vary based on energy consumption and tariff class, as well as the approach the QCA takes in setting Notified Prices in the future, and the impact of network tariff reforms. See example on page 16.

To the extent that our financing costs and cost of capital continue to improve relative to the assumptions in our proposal, we expect even better outcomes for customers in terms of what we ultimately charge to build, operate and maintain our electricity network.

CUSTOMER BENEFITS AND THE RISK SUMMARY

CUSTOMER BENEFIT	RELATED RISKS
Our approach to safety	
• Our goal is for our safety performance to stand with the best in our industry... to be Always Safe. • Our expenditure on renewal, maintenance and network operations is focused on managing safety risks.	• Unforseen safety related issues or damage caused by weather events may arise in the next period that may result in the reprioritising of expenditure towards addressing them or lead to passing on cost increases in the period following.
A reliable, quality electricity supply	
• We'll maintain recent overall improvements to power supply reliability... and continue to improve the experience of customers who are suffering outages well outside our standards.	• Further reductions to the expenditure proposals, seasonal weather conditions or delivery delays (due to significant weather related events/reprioritisation of expenditure) may impact the reliability performance in some areas. • Improvements in the areas of the network currently requiring attention will need to be prioritised based on the level of available funds. • We will be monitoring the impact of the changes to the way we are managing security of supply to ensure they do not impact on reliability in the longer-term.
Our disaster management and storm response	
• We'll be there after the storm, prepared and with the resources to respond to whatever Mother Nature delivers.	• If approved, the operational resourcing levels outlined in our proposal will maintain our current outage and emergency response capability.
Meeting service expectations	
• We'll meet our guaranteed services commitments. If we don't, we'll pay you.	• As expectations around choice and control evolve, our service standards, especially in the connections and communications area may need to be reviewed.
A future of customer choice	
• We're looking to the future – and evolving the network to best support customer choice in economic electricity supply solutions.	• We have made assumptions on the rate of industry change in our planning, and the market reforms needed to support it. If the market reforms are ineffective, and/or the rate that customers' take up new technologies or the type of technology that emerges is significantly different, our ability to respond could be limited.
Open, helpful communications	
• We'll make it easier for you to contact us, whether by phone, Facebook, or Twitter, and provide you with the information you need, when and how you need it.	
Timely new connections	
• We'll play our part in powering the economy by making it easier to connect to the network. • We're making it easier to transition to new energy efficient street lighting technology.	• Our forecasts are based on softer economic growth conditions and the need to ensure we can respond in a timely way to the demand for new connections. A significant jump in economic activity through the five-years, however, could impact delivery times for new connections, and absorb capital expenditure allocations from other areas.
The best possible price	
• We're targeting to reduce what we charge for the use of the network in 2015-16, and keep increases overall in network charges under inflation for the five years. • By separating metering service charges from our network charges, we are supporting customer choice in providers.	• Network charges are only one part of a customers' bill. Other costs will also influence what a customer pays. Adjustments to incentive schemes, or rate of return adjustments could increase or decrease revenue requirements. • For customers on regulated retail prices (Notified Prices) the actual price impact of Ergon Energy's Regulatory Proposal will depend on the approach the QCA takes in setting prices in the future. • The financial target we have set is a challenge. We will require significant reductions in costs in the future to achieve it. There is a risk that further reductions would not be sustainable, and may affect service delivery and the safety of the network.

Other details in our Regulatory Proposal

The previous section explained our expenditure plans around our core function of electricity distribution. Our Regulatory Proposal also details a range of other specific matters under consideration by the AER, including:

- **the way we classify and charge for our different services**
- **our revenue requirements and the building blocks**
- **how the Solar Bonus Scheme, and other costs are to be recovered**
- **the pricing methods for different Alternative Control Services**
- **the approach proposed for our metering services**
- **our approach to public lighting services.**

THE WAY WE CLASSIFY AND CHARGE FOR OUR SERVICES

Ergon Energy provides a number of different services. The service that is incorporated within the customer's bill relates to access and supply of electricity. However, a number of other user specific and asset specific charges are separately regulated. The AER determines how all of our regulated services are classified. This is important as it determines how prices will be set and how charges are recovered from our customers.

Standard Control Services are associated with the access and supply of electricity to customers. Since these services are relied on by all customers, the costs form part of the electricity bill for all customers. With the exception of metering services (discussed in this section) and other small changes, the services subject to Standard Control Service arrangements are consistent with current arrangements.[9]

The AER will place controls on the amount of revenue we can collect for Standard Control Services (as a revenue cap) consistent with the arrangements in the National Electricity Rules. The AER will determine the cap on revenue each year, as well as how Ergon Energy will propose prices consistent with the revenue cap, taking into account adjustments allowed for matters such as inflation, incentive schemes, any under or over recoveries from previous years, or any cost pass-through amounts.

OUR REVENUE REQUIREMENT AND THE BUILDING BLOCKS

The total revenue requirement proposed in our Regulatory Proposal for our Standard Control Services is $7,622 million. We have minimised our revenue requirement through our reduced expenditure forecasts and the anticipated lower capital financing costs. However, at the same time, due to regulatory changes that come into effect in the next period, the $7,622 million appears as an escalation above the previous requirement of $7,113 million.

This is largely due to an accounting change in the regulatory treatment of capital contributions, which means we can no longer keep the value of contributed assets in our asset base and deduct the value of capital contributions from our revenue requirement upfront. The upfront revenue deduction compensated customers for the value of contributed asset, which were recovered over time. Under the new regulatory requirements, the contributed assets are no longer included in the asset base and therefore no upfront revenue deduction is required. As we don't recover these contributed asset values over time, the apparent uplift associated with the removal of the upfront revenue deduction should not be interpreted as an increase in charges.

In our Regulatory Proposal we have presented our revenue requirement for our Standard Control Services under a number of building blocks. These are illustrated, showing the value of each compared to what was allowed for in the current period.

Return on capital – the capital already invested in the network, and the financing costs associated with that capital, has the greatest impact on prices. The value of the return on capital is determined by multiplying the value of the asset base by an efficient, forward-looking benchmark rate of return.

It is through this building block that our efforts to reduce our capital expenditure program – both over recent years and as we move forward – are supporting our target to reduce what we charge for the use of the network. In addition, customers will benefit from a lower rate of return, thanks to an anticipated lower market cost of capital.

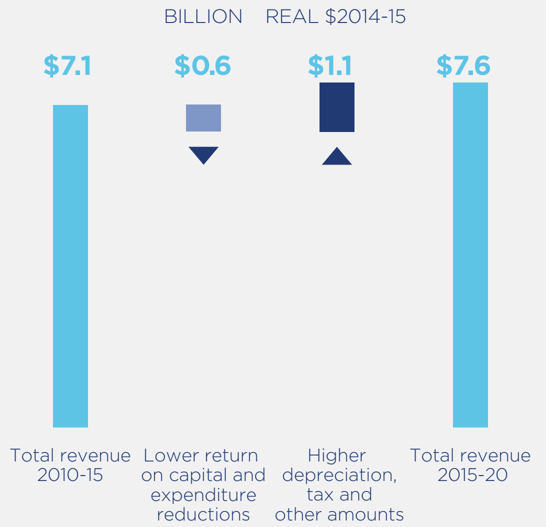
Return of capital – this depreciation element recognises that as a business we need to recover the cost of capital over the useful life of each asset. It is effectively a regulatory depreciation allowance associated with our regulated asset base.

Operating expenditure – as discussed earlier, this amount is what we believe is efficient and prudent, and necessary to maintain the safety, quality, reliability, security of the distribution network. It has been largely forecast using a base-step-trend approach.

Tax allowance – this corporate income tax allowance is calculated using the revenue forecast, the standard Australian Tax Office corporate tax rate, and the value of distributed tax credits (gamma). Ergon Energy pays this to the Queensland Government as a tax equivalent payment.

9 See the AER's Framework and Approach paper available at www.aer.gov.au/node/20186

OUR TOTAL REVENUE REQUIREMENT



The total revenue requirement proposed in our Regulatory Proposal is $7,622 million (compared to $7,113 million in the previous period).

We have been able to reduce our revenue requirement by $509 million, thanks to the reductions we have been able to achieve in our expenditure forecasts and lower anticipated financing costs. However, changes to the treatment of capital contributions, which was previously treated separately to the Standard Control Service revenue, as well as a range of other elements (including the tax liability, carry forward revenue and shared asset adjustments) have lifted the total revenue requirement.

The increase in tax shown is associated with a change to the regulatory treatment of capital contribution and gifted assets.

This revenue allowance is then adjusted each year for:

Incentive schemes – this is the revenue that comes from the various regulatory incentive schemes (both carried forward from the current period, and anticipated and then adjusted as we move through the next period). These schemes are aimed at incentivising, in a small way, efficient investment decisions and operational expenditure, balanced with appropriate performance standards.

Cost pass through – a cost pass through can occur when a predetermined type of event occurs that materially increases or decreases our costs. In these circumstances, the AER may approve a revenue adjustment. In our proposal we have specified the following as possible pass through events:

- natural disaster event
- insurance cap event
- insurance event
- retail separation event
- isolated networks separation event.

HOW DOES THE AER MAKE AN APPROPRIATE ALLOWANCE FOR OUR FINANCING COSTS?

The AER recognises that network businesses need to finance both past and future investment. They assume that an efficient network business would borrow 60% of the required funds and raise the remaining 40% from equity. The 'weighted average' of the relative costs of this debt and equity is known as the Weighted Average Cost of Capital or the WACC.

A sound estimate of the rate of return is vital to meeting the long-term interests of consumers. If the rate of return is set too low, sourcing the funds necessary for future network investment may be difficult and network performance standards may decline. On the flip side, if the rate of return is set too high, compared to market conditions prices could be unnecessarily inflated.

The AER must set the rate of return based on an efficient, forward-looking benchmark for finance costs, rather than the actual costs to individual businesses. This incentivises network businesses to finance their business as efficiently as possible.

Being forward looking, the AER will ultimately apply a WACC commensurate with the most up to date financial market information at the time of its determination. In the meantime, the WACC in our Regulatory Proposal should only be considered a placeholder. We have analysed the past 12 months of market information on the cost of debt in order to represent what the future WACC might look like. We have also proposed inputs and methodologies that we think best meet the requirements in the National Electricity Rules around estimating an appropriate rate of return, including some departures from the AER's guidelines.

The placeholder WACC of 8.02% in our Regulatory Proposal is a reduction on the current period's 9.72% WACC, and the 8.50% of the period before the current one (under the regulation of the Queensland Competition Authority 2005-10). This is reflective of current market conditions and supports our commitment to reducing what we charge for the use of the network in 2015-16, and keeping increases overall in network charges under inflation for the five years.

Our placeholder WACC is below the AER's last decision for the NSW Distribution Network Service Providers of 8.10%. Other AER regulated businesses have put forward rates of return in 2014 that vary between 7.58% and 9.10%.

Under and over recoveries – As actual electricity sales, and therefore revenue recovery, varies each year, we inevitably either over collect or under collect our revenue cap. To ensure we only recover our allowed revenue, adjustments are made to our revenues and prices in future years to account for any actual under or over recoveries. In 2015-20, we have accommodated a carry forward of under-recovery of revenues related to the previous period.

HOW THE REVENUE WE REQUIRE TO BUILD, OPERATE AND MAINTAIN THE ELECTRICITY NETWORK IS CONSIDERED AND CHARGED AS PART OF THE BILL.

FINANCING AND DEPRECIATION | TAXES AND OTHER COSTS

	Return on Capital	Return of Capital	Operational Expenditure	Tax Allowance	Increments/ decrements
2015-20 PROPOSED	**$4,151m**	**$839m**	**$1,882m**	**$576m**	**$174m**
2010-15 ALLOWANCE	$4,582m	$791m	$2,055m	$349m	($657m)

Revenue Requirement

Revenue Requirement

Adjustments
- CPI adjustment
- Cost of debt adjustment
- Incentive scheme
- Transitional revenue
- Cost pass through
- Under and over recoveries

Distribution Use of System Charge (Revenue Cap)

- Distribution Use of System Charges (DUOS)
- Alternative Control Services – Metering Charges
- Feed-in Tariff Charges
- Transmission Use of System Charges (TUOS)

Network Use of System Charges

- Network Use of System Charges (NUOS)
- Electricity Generation
- Green Schemes
- Retail Costs & Headroom

Retail Electricity Bill

SOLAR BONUS SCHEME, TRANSMISSION AND OTHER COSTS ARE BUNDLED IN WITH OUR CHARGES

Other costs are added to what we charge for the use of our network and passed through to the customer through the retailer, as shown in the diagram on page 30 under Network Use of System. The AER determines how we incorporate these additional costs to our network charges in our annual prices.

One of the additional cost items is the Queensland Solar Bonus Scheme (SBS) charges or the Feed-in Tariff. This scheme pays eligible customers for the surplus electricity generated from solar energy systems that is exported back into the electricity grid. Under the *Electricity Act 1994* (Qld) distributors are required to pay the amount credited to eligible customers through the Feed-in Tariff.

Ergon Energy intends to continue to recover payments made under the SBS by passing through these costs to all customers based on a two-year lag between the year in which the payments are made, and the year in which the prices are collected. For example, in our 2014-15 prices to retailers, amounts were factored in to recover the under-recovery of actual Feed-in Tariff payments made in the 2012-13 year. We would like to continue a similar approach in relation the SBS charges in 2015-20.

PRICING METHOD FOR DIFFERENT ALTERNATIVE CONTROL SERVICES

Alternative Control Services are also subject to direct controls on revenues and price. However, for these services the AER has more flexibility in how it calculates and controls prices compared to Standard Control Services. Many of these services are requested or relate to a specific customer, and therefore the customer directly benefiting from the service is either charged a fixed fee or a quoted price. Other services relate to a particular asset or class of assets, which can be distinguished from the meshed distribution network (metering and public lighting services).

The method of pricing for our Alternative Control Services is provided on the next page.

The classification of some of these services has changed (noted with an *) – with some being unbundled from our Distribution Use of System Charge for the first time. For more information please refer to the AER's Framework and Approach Paper.[10]

The AER does not place controls on the prices or revenues from our Type 1 to 4 metering services, watchman lighting services, the distribution services provided in isolated community networks, our emergency recoverable works and high load escorts. As these services are not regulated by the AER, they are not covered in the Regulatory Proposal.

10 See the AER's Framework and Approach paper available at www.aer.gov.au/node/20186

OUR APPROACH TO METERING SERVICES

The most significant change of classification is for our 'default' metering services. Ergon Energy is responsible for the installation, reading and maintenance of basic electricity meters for small to medium business and residential customers. These are the meters that measure the electricity that goes into a property, which allow electricity retailers to bill their customers.

Currently, the cost of our metering service is bundled together with all of the other costs associated with the use of the electricity network – it is not a separate item on the customer's electricity bill.

The AER has decided to separately classify default metering services with a longer-term view of enabling metering services to be opened up to competition. A change in the classification of this service requires us to create the separate charge for metering services.

The majority of our customers have a basic accumulation meter. This change covers the cost of providing these meters, as well as related meter reading and operations.

We propose to recover the existing and annual costs for this service through a daily charge per premises. Prices for a standard (primary) meter will be capped at $85 in 2015-16 (different charges will apply multi-phase or secondary meters) and falling to $79 by the end of the period. A transfer fee will apply where customers no longer want Ergon Energy to provide the default meter service. Some up-front costs will be required for upgraded meter services at the customers' request.

OUR APPROACH TO STREET LIGHTING SERVICES

If a street light is owned by Ergon Energy, 10% of the efficient costs of owning and maintaining the asset are charged to the customers as a public lighting service with the remainder paid by the Queensland Government via the Community Service Obligation. Ergon Energy manages an asset base of more than 155,000 public lights that illuminate roads managed either by a local government authority or the Queensland Government's Department of Transport and Main Roads.

Over the past 18 months we have undertaken significant engagement on this area of our service – on the accuracy of our asset data and billing, on our service level standards, and our approach to emerging lighting technology. To improve the quality and accuracy of our public lighting asset records we have undertaken a statewide geo-spatial audit of street lighting assets. This engagement has informed our public street lighting strategy.

Our strategy is driving the proactive management of public lighting performance to agreed standards; the development of better information systems to more efficiently and transparently manage public lighting assets; and the transition to LED (light emitting diode) technology to reduce costs.

METHOD FOR PRICING	METHOD OF PRICING FOR ALTERNATIVE CONTROL SERVICES
Additional charges for services provided to certain customers	**Type 5 and 6 metering installation, provision, maintenance, reading and data services***
Fixed prices for work undertaken by Ergon Energy at the request or initiation of a customer or retailer	**Connection application services (selected)*** **Temporary connection** **Connection management services (post connection) (selected)** **Accreditation of alternative service providers and approval of their designs, works and materials (selected)***
Quoted prices for work undertaken by Ergon Energy at the request or initiation of a customer or retailer	**Connection application services (selected)*** **Pre-connection consultation services*** **Large customer connections (i.e. design and construction of connection assets for large customers)** **Commissioning and energisation of large customer connections*** **Real estate development connection*[11]** **Removal of network constraint for embedded generator*** **Connection management services (post connection) (selected)** **Accreditation of alternative service providers and approval of their designs, works and materials (selected)*** **Auxiliary metering services*** **Ancillary network services (selected)*** **Provision, construction and maintenance of public lighting[12]**
Additional prices for Local Councils and the Queensland Government Department of Transport and Main Roads	**Provision, construction and maintenance of public lighting** **Emerging public lighting technology***

OUR APPROACH TO STREET LIGHTING SERVICES (CONTINUED)

We have determined the revenue required to provide public lighting services to our customers. The basis of our proposed revenue allowance is calculated using a limited building block methodology common with Standard Control Services. This revenue requirement is allocated on a causal basis to major and minor lights.

In developing the revenue requirement that is the basis for these charges, we have made every effort to deliver efficiencies, in line with our stakeholder expectations.

Our revenue requirement for public lighting is expected to increase by 5%. The majority of this increase is accounted for by an increase in the tax allowance. We forecast growth of public lights in regional Queensland of approximately 1.6% per annum over the next five years.

The proposed prices show a real decrease in 2015-16 between 9.9% and 10.9%. Thereafter it is proposed that prices vary by CPI + 0.60%.

The revenue requirements and pricing impact of the other Alternative Control Services are provided in our Regulatory Proposal at www.ergon.com.au/futureinvestment

11 While there has been a change in classification, real estate developers will continue to fully fund the connection costs.

12 Removal/rearrangement of public lighting assets only.

Have your say

This overview covers the highlights of our Regulatory Proposal 2015-20 and our service commitments to regional Queensland.

For further information go to:

www.ergon.com.au/futureinvestment

Our proposal has been informed by our engagement efforts over the past 18 months. We trust we have shown we are listening, and provided you with a better understanding of our Regulatory Proposal.

You can provide feedback on our plans directly to us by emailing futureinvestment@ergon.com.au

Or you can submit your feedback to the AER. For details on how to do this go to www.aer.gov.au

The AER will be holding a public forum in December 2014 and inviting submissions on our proposal. After considering the information in our proposal, along with stakeholder submissions, the AER will publish a preliminary Distribution Determination (scheduled for April 2015). Further stakeholder consultation will then take place in May 2015. Feedback at this stage will be considered in any revisions to our proposal.

The AER will then make their final determination in October 2015 on our revenue allowance for the five-years from 2015 to 2020.

Ergon Energy Corporation Limited ABN 50 087 646 062

ergon.com.au