PRICING PROPOSAL

1 JULY 2016 – 30 JUNE 2017

essential energy

MODIFICATION HISTORY

Version	Date	Description
1	6/05/2016	Original version

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Attachment 1	Network Price List 2016-17: http://www.essentialenergy.com.au/content/electricity-network-pricing-and-information
Attachment 2	Essential Energy Streetlighting price list: http://www.essentialenergy.com.au/content/electricity-network-pricing-and-information
Attachment 3	Price Schedule for Ancillary Network Services http://www.essentialenergy.com.au/content/electricity-network-pricing-and-information
Attachment 4	Price Schedule Type 5 and 6 meters http://www.essentialenergy.com.au/content/electricity-network-pricing-and-information

1 BACKGROUND

1.1 Background

The Australian Energy Regulator (AER) has responsibility for the economic regulation of Distribution Network Service Providers (DNSP's) in New South Wales and requires Essential Energy to publish an Annual Network Prices Report. This report establishes a process of price notification and review by AER for annual price changes.

The Annual Network Prices Report complies with the requirements of Essential Energy's undertaking made to the AER under section 59A of the National Electricity Law (the Undertaking) (which can be found on our website at www.essentialenergy.com.au/networkpricing). This prices report is based on the *AER Final Decision Essential Energy distribution determination 2015-16 to 2018-19* (the determination), the *Electricity DNSP's annual information reporting requirements*, section 6.18 of the *National Electricity Rules* (the Rules) and specifically addresses the following:

- Prices for network distribution services
- Forthcoming changes in network prices
- Compliance with the regulatory arrangements relating to limits on price and revenue movements
- Impacts of the proposed changes on customers
- Pricing principles and the allocation of costs
- Expected levels of service and projected capital expenditure.

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1.2 Our Proposal

Essential Energy is proposing an overall increase in average prices for network services from 1 July 2015 of 3.6 per cent nominal. The increase in prices for network services is driven by Distribution Use of System increases predominantly due to an under recovery of revenues. However these increases are partially offset by a reduction in Transmission Use of System (TUoS) revenue.. There are also small changes in jurisdictional scheme amounts for the NSW Climate Change Fund (CCF) and the Queensland Solar Bonus Scheme (QSS) – each component is discussed in further detail in this report.

Essential Energy is continuing with our current residential block tariff that has three different rates for various levels of consumption, with higher levels of consumption being charged at lower prices. Our small business general supply tariff will still include two different rates for various levels of consumption, with higher levels of consumption being charged at lower prices.

The number of prices applicable to new connections, and the number of prices classed as obsolete and not available to new connections will not change. An alternate demand tariff is still available to customers who consume more than 160MWh and are therefore required to be on a demand based tariff. This tariff continues to be provided as an alternative for customers with poor load factor whose operations would otherwise see them penalised for using load for short periods during peak demand times.

As decided in the AER Framework and Approach process, metering services for type 5 and 6 meters are now classified as Alternative Control Services. In line with this, charges relating to the provision and maintenance of type 5 and 6 meters are charged as a separate charge from general tariffs. The costs of providing these metering services have been extracted from our standard control services and DUoS tariffs and will be charged as a separate metering tariff. Fees for customer specific services are now also classified as Alternative Control, these were formerly known as Miscellaneous and Monopoly Fees. This is further detailed in section 6 of the report below.

1.3 Our Network

Essential Energy is responsible for building, operating and maintaining Australia's largest electricity network. Our distribution network serves approximately 844,000 customers. Geographically, our footprint covers 95 per cent of NSW, as shown in Figure 1, from humid coastal environments in the north coast region, through semi-arid desert in the far west, alpine peaks in the south and a grain belt that crosses central NSW from north to south.

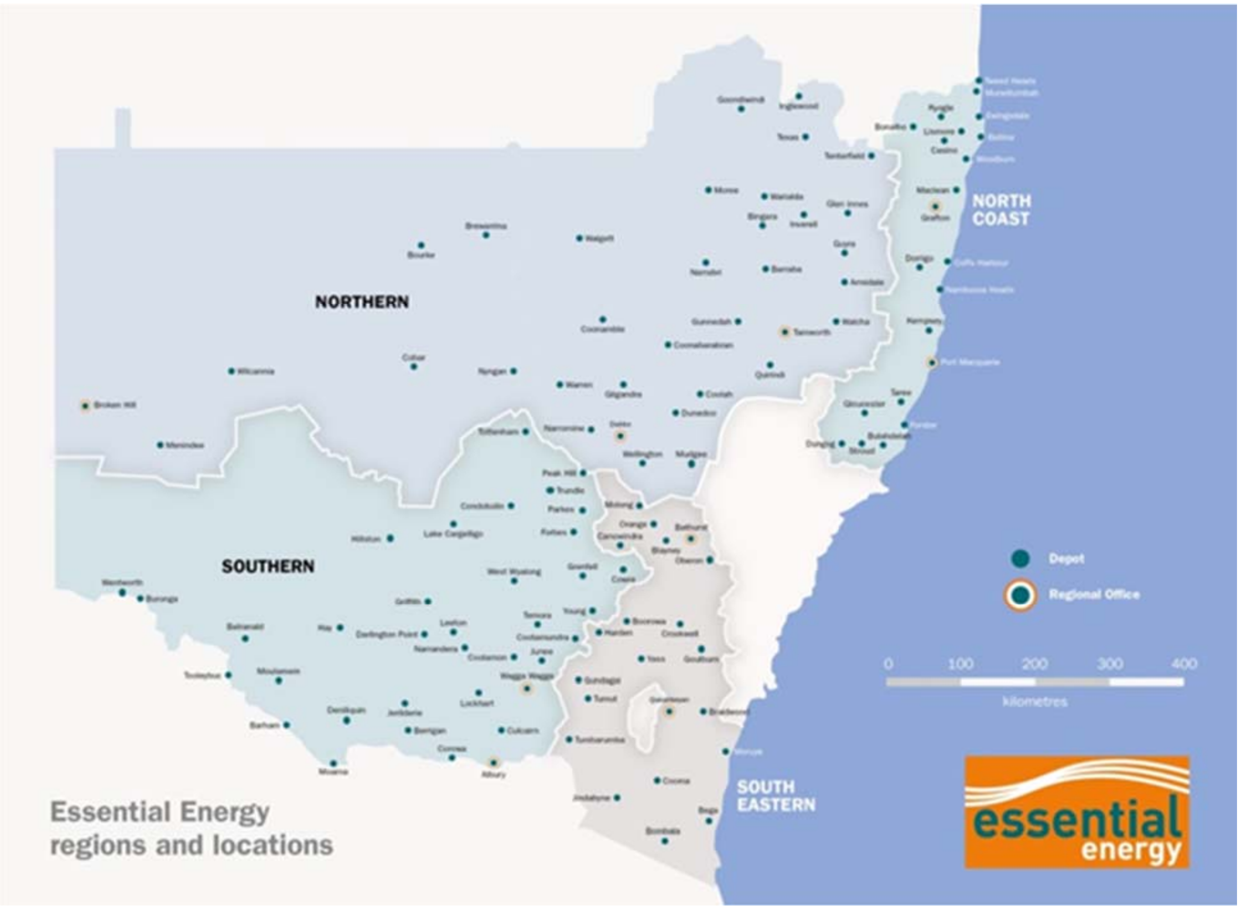


Figure 1 Essential Energy's distribution area

A vast network spread across a range of environments presents unique and ongoing challenges. Essential Energy's core focus is on ensuring the safe, affordable and reliable delivery of essential services to homes and businesses across rural and regional NSW. We are committed to delivering better value for our customers by reducing our costs without compromising safety or services.

Essential Energy's infrastructure includes approximately:

- 200,000 kilometres of power lines and cables
- 1.4 million power poles
- 150,000 streetlights
- 135,000 substations
- 400 zone substations

Essential Energy's core responsibility is the operation, maintenance and investment in electricity network infrastructure to ensure the safe, efficient and reliable delivery of essential services to homes and businesses across rural and regional NSW. We are committed to making a serious and sincere effort to deliver better value for our customers by reducing our costs without compromising safety or services.

Our electricity distribution network is funded through a distribution network revenue determination made by the AER in accordance with the National Electricity Law (NEL) and the Rules economic regulatory framework. The current determination was provided by the AER on 30 April 2015 and covers the 2015-16 to 2018-19 period.

Essential Energy focuses on three key outcomes:

> **Safety -** Improve the safety performance for our employees, contractors and the community.

> **Reliability -** Maintain the reliability, security and sustainability of the network.

> **Sustainability -** We will ensure our business is sustainable by making it efficient, affordable and competitive so that it can meet future challenges.

1.4 How our Network Transports Electricity

It is important that customers and stakeholders understand the electricity supply chain. We believe this will help them provide informed feedback on the plans and priorities of Essential Energy. The NSW electricity supply sector involves generation, transmission, distribution and retail sellers. Figure 2 below outlines the electricity supply chain and highlights the components associated with distribution asset management.

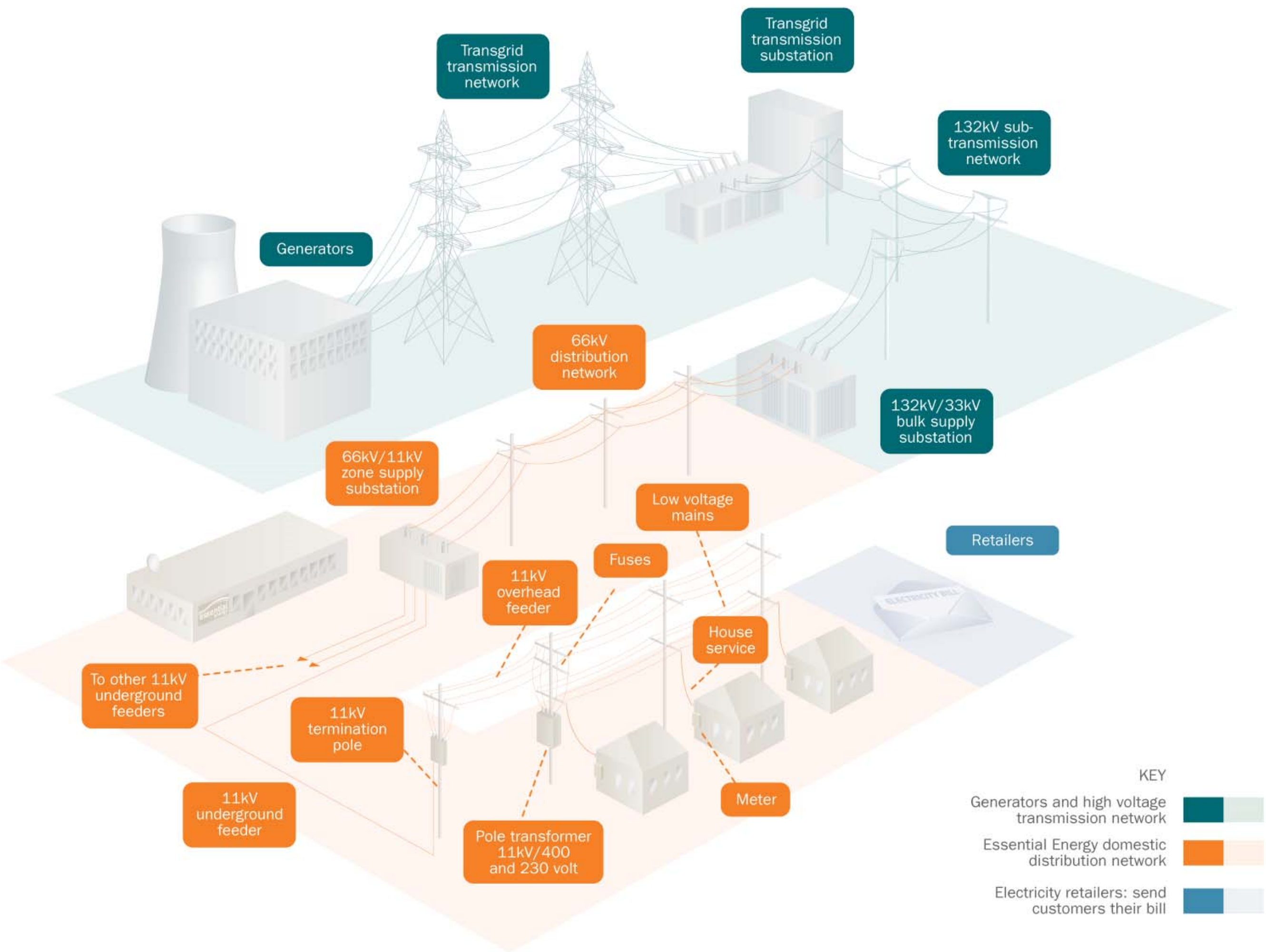


Figure 2 Electricity supply chain

1.5 Network Investment and Challenges

In its Revised Regulatory Proposal, Essential Energy proposed a capital expenditure program of $2,531 million and $2,331 million to operate and maintain Essential Energy's electricity network and services for the 2014-19 period. These expenditure programs were developed consistent with our corporate objectives of safety, reliability and affordability in the long term interests of our customers.

Unfortunately, the AER's final determination rejects much of the information we provided in our revised regulatory proposals. There has been a substantial reduction in revenue driven by movements in the weighted average cost of capital (WACC) and operating expenditure compared to our revised regulatory proposal. The WACC has been reduced by 2.11 per cent, operating expenditures by almost $700 million or 30 per cent, and capital expenditure by $175 million or seven per cent. This has resulted in a 25 per cent reduction in allowed revenues compared to our revised regulatory proposal. Essential Energy was successful in its merits review appeal of many of these reductions, but now are awaiting the outcomes of an AER judicial appeal against this merits review decision.

These unprecedented reductions made by the AER in its final decision will make the next three years extremely challenging for Essential Energy if upheld at the judicial appeal. We are continually assessing the AER's final determination against our priority to operate a safe, reliable and affordable network in the long term interests of our customers.

PRICES FOR NETWORK DISTRIBUTION SERVICES

Essential Energy provides network distribution services to all electricity customers connected within our distribution area. Customers may choose any retailer.

Network distribution services are those services performed by Essential Energy to provide access to our power supply network. Those services are principally the ownership, planning, design, construction, operation and maintenance of the electricity distribution network - consisting of equipment such as poles, wires and substations - to supply a safe and reliable power supply.

The conditions under which these network services are provided can be found on Essential Energy's website – summary of customer rights, obligations and entitlements – www.essentialenergy.com.au/content/summary-of-customer-rights-entitlements-and-obligations

Network prices are a use of system charge for the use of Essential Energy's electricity distribution network and also include a charge for the use of the transmission system.

Network prices are subject to annual review in accordance with pricing determinations by the AER. The Network Price List is available on Essential Energy's website – www.essentialenergy.com.au/content/electricity-network-pricing-and-information

The network price list contains network prices effective from 1 July 2016. There are additional price lists for Ancillary Network Services (formerly known as Miscellaneous and Monopoly Fees), Metering Charges for type 5 and 6 meters and streetlighting effective from 1 July 2016.

Network access is under the terms and conditions contained within our Deemed Standing Connection Contract and Standing Offers. A Negotiation Framework is also available where specific contractual conditions are required. This information is also available on Essential Energy's website – www.essentialenergy.com.au/content/electricity-network-pricing-and-information

Network distribution services are classified as either standard control or alternative control. This report focuses on standard control services supplied by Essential Energy but also refers to the alternative control services of Ancillary Network Services (formerly Miscellaneous and Monopoly Fees), Type 5 and 6 Metering charges and Streetlighting charges.

2 FORTHCOMING CHANGES IN NETWORK TARIFFS

Essential Energy is proposing an average increase in our prices for network distribution services of 3.6 per cent. This is in line with the revenue allowed by the AER for the 2016-17 year as part of the determination received in April 2015. Essential Energy remains concerned that this level of revenue is not sufficient to safely operate and maintain its network and that the reliability of our network may be compromised. The determination is now subject to judicial review.

Essential Energy is not proposing any changes to:

1. the number of prices applicable to new connections
2. the number of prices classed as obsolete and not available to new connections

Essential Energy has prepared this proposal in accordance with Essential Energy's undertaking made to the AER under section 59A of the National Electricity Law (the Undertaking) and the Rules. The Undertaking is available on Essential Energy's website at www.essentialenergy.com.au/networkpricing. All changes proposed are within the limits on price movements set out in the determination and are discussed further throughout this document.

3 RULE REQUIREMENTS

Clause 6.18.2(b)(5) of the NER requires that a pricing proposal set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.

The nature and basis of any variation or adjustment to our tariffs that could occur during the course of 2016-17 is set out in the Undertaking. The Undertaking is in place for the 2016-17 year only, and therefore this annual prices report does not address the remaining years of the 2015-16 to 2018-19 regulatory control period beyond this, as the outcomes of the appeals processes are still to be determined.

4 REGULATORY COMPLIANCE

4.1 Overview

This annual network prices report explains how Essential Energy's prices meet the regulatory arrangements, including limiting revenue to an allowed amount and providing for the recovery of transmission related payments and other pass through costs. Further detail on each of these items is contained below.

4.2 Revenue Cap

Charges for network distribution use of system (DUOS) prices are regulated in accordance with a revenue cap mechanism. In the previous regulatory period prices were set under a weighted average price cap (WAPC) which restricted the (weighted) average change in Essential Energy's prices to a limit (the 'X-factor') determined by the AER. For the current regulatory period prices are regulated under a revenue cap meaning that prices are set to recover a specified amount of revenue. There is also a mechanism to include any under or over recovery of DUOS from previous years.

For the 2016-17 year the AER have set the total allowed revenue (TAR) of $924 million for Essential Energy. However taking into account the adjustment of over recovered revenue in 2015/16 the DUOS revenue to be recovered is only $920 million. Revenue for the 2015-16 year is estimated to be over recovered by $6.4million due to higher consumption levels than forecast. This mechanism is demonstrated in table 2 below.

Table 2 DUoS unders and over account

Financial year ending	t (forecast) 2017
Revenue from DUoS Charges	919,867
Revenue from other standard control services	0
Total Standard Control Revenue	**919,867**
Less TAR for the relevant year	923,250
Smooth revenues (ARt)	924,086
DMIA carryover	(835)
Approved pass throughs (pass through)	0
(Under)/over recovery for regulatory year	-4,219
DUoS unders and overs account	
Nominal WACC	6.59%
Opening balance	4,083
Interest on opening balance	273
(Under)/over recovery for regulatory year	(4,219)
Interest on (under)/over recovery for regulatory year	(137)
Closing balance	0

Assuming the same level of energy consumption this DUoS revenue recovery implies an average increase in nominal price terms for distribution prices for 2016-17 of 10.3 per cent, including a CPI of 1.51 per cent.

As part of the annual price setting process, the AER was provided with all supporting calculations and information to demonstrate compliance with the revenue cap control mechanism.

4.3 Transmission-related cost recovery arrangements

The AER allows Essential Energy to recover transmission-related costs by setting transmission cost recovery (TUoS) prices to recover:

- Transmission charges paid to transmission network service providers
- Avoided TUoS payments to embedded generators calculated in accordance with the Rules
- Inter-distributor transfer payments to other network distribution businesses

The determination requires Essential Energy to demonstrate compliance with transmission cost recovery requirements. As part of the 2016-17 price approval process, the AER has been provided with the expected cost of transmission related payments. Essential Energy develops transmission cost recovery prices, using the methodology outlined in section 7 of this report, to recover the expected cost of transmission-related payments.

Essential Energy will also be recovering avoided TUoS payments to generators who have advised they will be supplying energy into our Network. As this effectively represents less transmission from Transgrid's network Essential Energy is required to pay avoided TUoS to the generators under section 5.5 of the Rules.

The total transmission revenue Essential Energy requires in 2016-17 has decreased by 16.2 per cent from the revenue forecast amount to be recovered for 2015-16. Expected transmission revenue and expense for 2016-17 is summarised in Table 3 below.

Table 3 Transmission use of system unders and overs account ($'000)

Financial year ending	t (forecast) 2017
Revenue from TUoS charges	240,479
Less total transmission related payments	248,694
Transmission charges to be paid to TNSP	228,665
Inter-distributor payments	17,201
Avoided TUoS payments	2,828
(Under)/over recovery for regulatory year	(8,215)
TUoS unders and overs account	
Nominal WACC	6.59%
Opening balance	7,957
Interest on opening balance	525
(Under)/over recovery for regulatory year	(8,215)
Interest on (under)/over recovery for regulatory year	(266)
Closing balance	**0**

4.4 Consumer price index

The CPI used in setting prices for 2016-17 is 1.51 per cent, the December four quarter all major cities CPI as published by the Australian Bureau of Statistics. The method of calculating this CPI is provided by the AER in the determination.

$$\Delta CPI_t = [\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}}] - 1$$

Figure 3 CPI calculation

4.5 Climate change levy

Legislation requires Essential Energy to contribute $65.9 million to the climate change fund in 2016-17. Essential Energy is permitted to collect this contribution from its customers through network prices and is required to take into account an under or over recovery from previous years. It is also a requirement that only 25 per cent of this contribution is collected from residential customers.

Expected climate change fund revenue and expense for 2016-17 is summarised in table 4 below.

Table 4 Climate change levy unders and overs account ($'000)

Financial year ending	t (forecast) 2017
Revenue from Climate Change Fund Recovery (CCF) Tariffs	65,433
Climate Change Fund Payments	65,886
Audited opening balance of trans (unders)/overs account	
CCF unders and overs account	
Nominal WACC	6.59%
Opening balance	439
Interest on opening balance (365 days)	29
(Under) / over recovery for financial year	(454)
Interest charged on (under)/over recovery for financial year	(15)
Closing balance of Climate Change Fund (unders)/ overs account	0

4.6 Queensland Solar Bonus Scheme

Legislation requires Essential Energy to pay eligible customers an amount for their solar export. Prior to 1 July 2013 these amounts were rebated by the QLD Department of Energy and Water Supply. However Essential Energy was advised that they would no longer reimburse these amounts and encouraged us to recover these amounts through alternative means. As this scheme is a designated jurisdictional scheme under the Rules, Essential Energy is recovering the amount paid to these customers back through tariffs in a similar manner to the Climate Change Fund.

Expected Queensland Solar Bonus Scheme revenue and expense for 2016-17 is summarised in table 5 below.

Table 5 Queensland Solar Bonus Scheme unders and overs account ($'000)

Financial year ending	t (forecast) 2017
Revenue from Queensland Solar Scheme Recovery (QSS) Tariffs	639
QSS Payments	951
Audited opening balance of (unders)/overs account	
QSS unders and overs account	
Nominal WACC	6.59%
Opening balance	302
Interest on opening balance (365 days)	20
(Under) / over recovery for financial year	(312)
Interest charged on (under)/over recovery for financial year	(10)
Closing balance of Climate Change Fund (unders)/ overs account	0

5 IMPACT OF FORTHCOMING CHANGES TO NETWORK TARIFFS

This section demonstrates the impact of the forthcoming changes in Network Tariffs on typical customers' bills, including disclosing forecast average prices (based on typical account categories).

Table 6 demonstrates the average impact of the proposed prices to the residential and business customer classes. Displayed below are the average increases expected for each of the consumption types for residential and business network prices. These include standard supply, time of use, controlled load, and demand network prices for business customers.

Table 6 Average increases for residential and non-residential customers

		Average annual MWh	Average annual current account	Average annual proposed account	Average change per customer	Average increase (%)	Average current c/kWh	Average proposed c/kWh
Residential	DBT	5.0	$752.08	$798.67	$46.60	6.2%	15.04	15.97
	Time of Use	8.54	$945.75	$978.48	$32.73	3.5%	11.08	11.46
	Controlled Load 1	2.20	$85.09	$82.12	-$2.97	-3.5%	3.87	3.73
Non Residential	DBT	10.64	$1,797.66	$1,899.63	$101.98	5.7%	16.89	17.85
	Time of Use	52.77	$7,157.51	$7,479.52	$322.01	4.5%	13.56	14.17
	Controlled Load 2	2.08	$132.16	$131.06	-$1.10	-0.8%	6.34	6.29
	Demand	546.60	$54,921.26	$56,610.38	$1,689.12	3.1%	10.05	10.36

The average residential customer connected to a declining block tariff, without controlled load, in Essential Energy's distribution area will see an increase of approximately $46.60 or 6.2 per cent for the 2016-17 year based on an annual consumption of 5 MWh.

The average small non-residential customer connected to a continuous/block tariff in Essential Energy's distribution area will see an increase of approximately $101.98 or 5.7 per cent for the 2016-17 year based on an annual consumption of 10.64 MWh.

A typical residential customer living in Essential Energy's distribution area would generally be connected to the following network prices:

> BLNN2AU: Residential Declining Block Tariff

> BLNC1AU: Residential controlled load 1

Table 7 below provides an analysis of the impacts of price decreases for a low usage customer and a typical usage customer.

Table 7 Impact of price decreases for typical residential customers of Essential Energy

Customer type	% controlled load	2015-16 Quarterly network bill	2016-17 Quarterly network bill	Change in quarterly network bill
Low usage (3,500 kWh)	35%	$139.61	$144.58	$4.97
Typical usage (6,500 kWh)	35%	$192.21	$201.21	$9.01

A typical small non-residential customer operating in Essential Energy's distribution area would generally be connected to the following network price:

> BLNN1AU: General Supply Declining Block Tariff

Table 8 below provides an analysis of the impacts of price movements for a customer that consumes 20 MWh per annum and a customer that consumes 40 MWh per annum.

Table 8 Impact of price decreases for typical non-residential customers of Essential Energy

Customer type	2015-16 Monthly network bill	2016-17 Monthly network bill	Change in Monthly network bill
20 MWh	$260.90	$276.88	$15.97
40 MWh	$498.31	$480.03	-$18.28

The examples provided above for typical residential and small non-residential customers all fall within the Low voltage – Energy tariff class. Table 9 below shows the expected movement in the average rate for each of Essential Energy's tariff classes for DUoS charges.

Table 9 Impact of price increases for each tariff class (c/kWh)

Tariff class	2015-16		2016-17	
	Forecast Revenue $'000	Forecast avg rate c/kWh	Forecast Revenue $'000	Forecast avg rate c/kWh
Low voltage - Energy	618,881	11.09	683,271	12.24
Low voltage - Demand	152,713	6.76	168,024	7.44
High voltage - Demand	41,807	4.82	45,998	5.31
Subtransmission	12,477	0.48	13,728	0.53
Unmetered	8,040	5.45	8,846	5.99
Total average		**$10.34**		**$11.41**

Attachment 1 provides a full price list by tariff class for 2016-17 network charges.

5.1 Network price increases 2016-17 to 2018-19

The distribution X factor for 2016-17 is 0.21%, reflecting a real decrease in prices from 2015-16. Due to the Undertaking being in place for one year, and the appeals processes in progress, prices and distribution X factors for the remainder of the 2015-16 to 2018-19 regulatory control period are unknown. The 2016-17 X factor forms part of the determination for NSW DNSPs, and together with changes in CPI provide for the change in revenue from one year to the next that is allowed under a revenue cap. Price changes will also be subject to increases in transmission charges, jurisdictional scheme amounts and the recovery for CPI is also allowed under the revenue cap formula.

Essential Energy has provided prices for 2016-17 consistent with the Undertaking. The reduction in revenue delivered by the AER in the determination results in significant reductions in operating and capital expenditure which Essential Energy believes are not sustainable. Pending the outcomes of the appeals processes, the X factors and prices for 2016-17 are in place for one year only under the terms of the Undertaking.

The forecasts of CPI, the Climate Change Fund and recoveries of transmission related costs are likely to change over the regulatory control period and cannot be determined with certainty. Distribution X – factors may also change depending on the outcomes of the appeals processes or if there is a pass through event.

6 ALTERNATIVE CONTROL SERVICES

Alternative control services are those that are provided by distributors to specific customers. They do not form part of the distribution use of system revenue allowance provided in the determination. As these services are provided to specific customers we recover the costs of providing alternative control services through a selection of fees, most of which are charged on a 'user pays' basis.

6.1 Type 5 and 6 metering charges

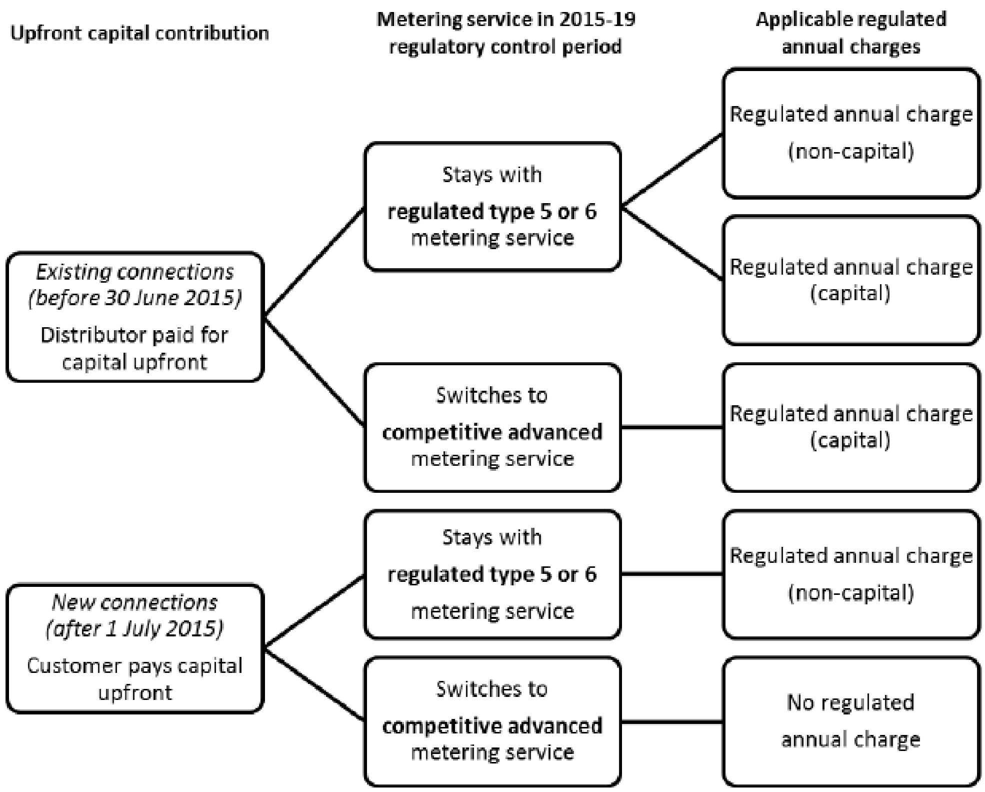
The AER have classified type 5 and 6 metering services as alternative control services starting from 1 July 2015. The control mechanism for alternative control metering services will be caps on the prices of individual services. This means that the costs relating to the provision and maintenance of type 5 and 6 meters have been removed from standard control services and will be recovered through a separate metering charge from customers.

The AER's determination approves two types of metering service charges:

- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising of two components:
    - capital—metering asset base (MAB) recovery
    - non-capital—operating expenditure and tax.

These new charges are summarised in the diagram below and can be seen in more detail in Attachment 4 Price Schedule Type 5 and 6 meters

Figure 3 Metering annual charges



The schedule of metering tariffs is provided below in table 11

Table 11 Metering Tariff Charges for 2016-17

	Pre-30 June Connections - Maintenance		Pre-30 June Connections - Capital		Post-1 July Connections - New Meters - Maintenance	
Metering Service Charge Tariff Class	**Bill Print Description**	**Annual Charge**	**Bill Print Description**	**Annual Charge**	**Bill Print Description**	**Annual Charge**
Residential Anytime	MSC MAINT - ANYTIME	$23.01	MSC CAPITAL - ANYTIME	$9.54	MSC NM MAINT - ANYTIME	$15.29
Residential TOU	MSC MAINT - TOU	$31.61	MSC CAPITAL - TOU	$9.54	MSC NM MAINT - TOU	$20.37
Small Business Anytime	MSC MAINT - ANYTIME	$23.01	MSC CAPITAL - ANYTIME	$9.54	MSC NM MAINT - ANYTIME	$15.29
Small Business TOU	MSC MAINT - TOU	$31.61	MSC CAPITAL - TOU	$9.54	MSC NM MAINT - TOU	$20.37
Controlled Load	MSC MAINT - CONTROLLED LOAD	$6.94	MSC CAPITAL - CONTROLLED LOAD	$4.34	MSC NM MAINT - CONTROLLED LOAD	$4.88
Solar (gross meter)	MSC MAINT - SOLAR	$31.10	MSC CAPITAL - SOLAR	$8.71	MSC NM MAINT - SOLAR	$19.92

6.2 Ancillary Network Services

Ancillary network services (ANS) are non-routine services distributors provide to individual customers on an 'as needs' basis. These services were part of standard control and called 'miscellaneous' and 'monopoly' services in the previous regulatory period.

ANS may be a 'fee-based service' for tasks that are performed routinely and are based on a labour rate and a set time to perform the task, or a “quoted service’ which are once off and specific to a particular customer's request. The cost of these services will depend on the actual time taken to perform the service however with the hourly rate set, the longer it takes the distributor to perform the service, the more the customer will pay.

A full listing of ANS and their fees is provided as Attachment 3 Price Schedule for Ancillary Network Services.

6.3 Public Lighting

Public lighting continues to be classified as an Alternative Control Service in this regulatory control period.

A full listing of public lighting charges is provided as Attachment 2 Essential Energy Streetlighting Price List.

7 PRICING PRINCIPLES AND COST ALLOCATION

Costs of the shared distribution network are characterised by economies of scale leading to large and lumpy investments, which occur at irregular intervals and generally have long lives. From a purely economic efficiency perspective, prices should reflect the marginal cost of providing customers with access to the electricity network. The long run marginal cost (LRMC) approach to pricing achieves economic efficiency by signalling the future cost of the next increment of network asset investment. Network prices would in this case send an economic signal to customers of the costs of the next increment of load and provide locational signals for future investment.

Essential Energy strives to send customers accurate network price signals, which reflect the marginal costs of supply. However, the LRMC approach to pricing is difficult to implement. Also, network pricing based on economically efficient marginal costs do not recover the long run average costs, except where there is network congestion. This creates a significant tension between economically efficient prices and prices necessary for the commercial sustainability of the distributor.

A practical approach to minimising distortions is to recover the gap between marginal and average costs in a manner which does not vary between locations, contains a fixed component - and to the extent that a variable component is necessary - includes both energy and demand components. Electricity prices for the great majority of customers are averaged in a conventional distributed cost of supply model as detailed below. Large individual customers and standard customer classes receive average network prices consisting of combinations of energy and demand price structures.

Essential Energy has developed a cost of supply allocation and tariff structure model (‘CoS Model’) that is used to allocate the appropriate network costs that are to be recovered from network customers through network use of system charges. The CoS Model has been designed to provide a transparent and defendable allocation of network costs based on pricing principles and the methodology and pricing strategies described in this document.

7.1 Network prices based on incremental and stand-alone cost principles

There are two principles that can be used to test for cross subsidisation in monopoly services.

> Stand-alone costs

  Cross subsidisation exists when customers pay more for a service than the costs another firm would incur if it served those customers on a stand-alone basis.

> Incremental costs

  Cross subsidies do not exist when the revenues received for a service is less than the stand-alone cost, or are greater than the incremental or marginal cost of providing the service. The incremental cost test is appropriate when the goal is to show that prices for services are not ‘unfair’.

The range of prices that lies between incremental cost and stand-alone cost is known as the subsidy-free pricing zone. Cross subsidisation occurs when prices lie outside this zone. Essential Energy has developed a marginal cost and standalone CoS model for this purpose. This document provides details of the methodology used, incremental cost and standalone cost of supplying network distribution services to customers connected to Essential Energy's network.

7.2 Network prices based on fully distributed cost principles

Network costs are largely fixed and sunk, and due to the meshed nature of electricity distribution networks, pricing must involve a substantial degree of averaging.

For these reasons, Essential Energy's approach to allocating costs to customers is primarily founded on equity considerations, where there is some degree of averaging present in the calculation of standard network prices for the majority of customers belonging to general customer classes.

Essential Energy has adopted the average or fully distributed cost approach for the allocation of the revenue requirement. Network revenue as a cost is allocated to standard customer classes based on the use of network assets, with prices averaged by customer class. This pricing policy is driven mainly by equity considerations. It is applied to individual prices for large customers and standard published network prices.

We believe this average allocation approach best reflects the manner in which costs are incurred by customer classes and provides equitable and reasonably efficient outcomes.

7.3 Network customer classes

Distribution services are provided to a range of tariff or customer classes. Segregation of customers by class is commonly carried out to assess their relative impact on network costs.

7.3.1 Standard customer classes

All but the largest Essential Energy customers have network prices that are averaged for their customer class. Different customer classes have different consumption profiles and therefore impact differently on network costs. Customer classes have been established taking into consideration historical pricing structures, existing metering and the cost effectiveness of metering options and connected voltage level.

Historically, customer classes have been grouped according to end use such as residential, business, commercial, or industrial purposes. However, network costs are not necessarily driven by the end use of electricity but rather by the voltage of supply, the capacity being held in readiness for demand and the time of day that this demand occurs.

The assets required to provide network distribution services to each customer class is a major cost driver. Customer segmentation is carried out in different ways, largely dependent upon the availability of detailed cost information. It has been possible, to some degree, to segregate network costs by voltage level. Therefore, Essential Energy's customer classes vary in accordance with the voltage level at which electricity is taken from the network.

Essential Energy also offers controlled load services.

The definitions of network customer classes are detailed in section 7.12.2 below and can also be found in Essential Energy's Network Price List upon approval by the AER. This list is updated each year or as required in consultation with the AER.

7.3.2 Site specific customer class

For large customers, Essential Energy may provide a Site Specific Customer (SSC) price which is cost reflective network pricing applicable to the location of the customer's supply point.

The SSC process is a cost allocation mechanism based on the structure of the present network using a fully distributed cost of supply analysis and is a reasonable assessment of long run incremental pricing for the individual assets through which energy is transported to the individual customer. The SSC approach fulfils the requirements for an equitable sharing of past and future costs. This price comprises an allocation of the costs associated with only those assets used by the customer. The calculation of SSC charges involves analysis of the network to which the customer is connected to determine the allocation of asset-related revenue recovery in proportion to the peak utilisation of the relevant assets. SSC is assessed annually to allow the application of new prices by 1 July each year.

7.4 Overview of network pricing methodology

Essential Energy has separated each network price into a DUoS price for providing distribution use of system services to distribution customers and a separate TUoS price. The methodology adopted by Essential Energy for setting network prices is summarised as follows:

1. Project total network revenue requirements (total network cost) for the upcoming year taking into account distribution revenue derived from the determination, the cost of transmission related payments, transmission under and over recovery balance, climate change levy and the forecast growth in the network.
2. Model fully distributed costs.
3. Model the long run marginal and stand-alone cost of supply to each customer class to establish the 'subsidy free zone'. The long run marginal cost of supply to customer classes is based on the usage of the network and other network services and the impact on future capital expenditure made by each customer class. The stand-alone cost of supply is based on establishing an alternative source of supply to the customer class.
4. Assess the existing network prices to establish whether they fall between the marginal and stand-alone cost of supply.
5. Establish medium term price paths to move existing network prices steadily toward the subsidy free zone, whilst complying with the economic regulatory arrangements of the Determination and Essential Energy's medium term network pricing strategy to progressively equalise prices across the network.

7.5 Calculation of annual revenue requirements

The first stage in the process involves calculating Essential Energy's total revenue requirements based on the cost of providing network distribution services.

The form of economic regulation affects the annual revenue that Essential Energy is able to receive for the provision of network services and the setting of prices. DUoS are regulated by the AER under a Revenue Cap. The Revenue Cap operates by restricting Essential Energy's proposed revenue to a limit – the TAR- determined by the AER.

To set the TAR for the Revenue Cap the AER undertook a cost building block analysis to determine the notional revenue requirement for each year of the regulatory control period for Essential Energy. The building block approach sets the base revenue and has been assessed on the basis of a wide range of indicative factors including network operations, asset valuation, commercial risks, appropriate cost of capital, relative levels of efficiency, and reliability and quality of supply.

The AER also made extensive use of benchmarking to determine what they felt were efficient expenditure levels for Essential Energy.

7.6 Network cost drivers

The costs drivers of owning and operating Essential Energy's electricity distribution network are predominantly driven by asset related costs. Other drivers include customer related, demand related and energy related cost drivers and common service costs.

It is appropriate to allocate and recover costs, to some degree, from customer classes in accordance with these cost drivers as discussed below.

7.6.1 Asset related cost driver

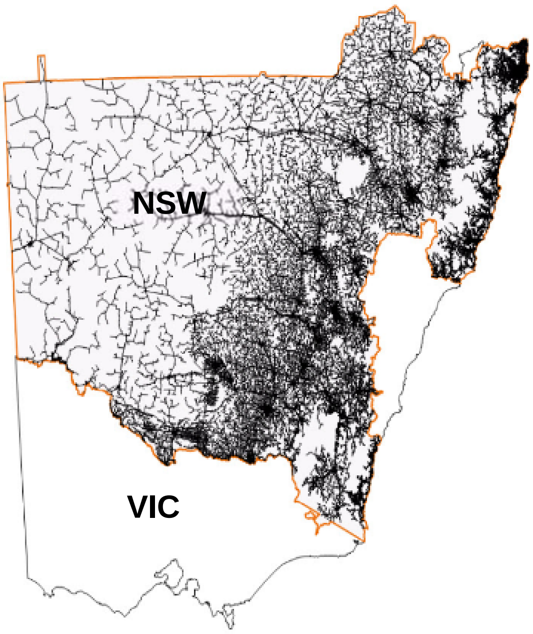
Essential Energy's network is unique in terms of the geographic area it covers, the terrain it traverses, the vegetation that grows within it and the diversity of weather that passes over it. The scale of assets required to ensure the network physically reaches customers in the most far reaching corners of NSW is like no other network in Australia.

It is critical to understand the scale of assets Essential Energy must manage. It is also important to acknowledge that the majority of costs associated with electricity distribution are not driven by the number of customers or their demand on the network. Rather, network costs are driven by the number of assets required to deliver electricity to each customer. Whether there are 50 customers connected to one pole or 50 poles connecting one customer, each asset needs to be inspected, safely maintained, and replaced at the end of its life.

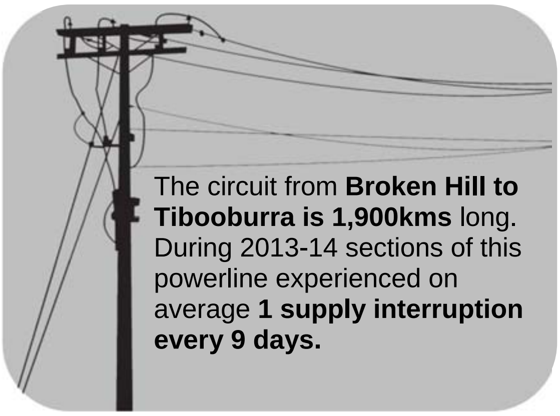
The scale of the network plays a major role in the drivers of cost to deliver network services.

The map adjacent demonstrates that the majority of the population on the network is on the East Coast and at a few major regional cities further inland. However, the network still needs to be available to customers throughout NSW.

The combined area of regional Victorian businesses Powercor and AusNet Services networks fits into the Essential Energy network area more than three times.



A vast network spread across a range of environments presents unique and ongoing challenges:



The circuit from **Broken Hill to Tibooburra is 1,900kms** long. During 2013-14 sections of this powerline experienced on average **1 supply interruption every 9 days.**

A radial network

Essential Energy's network is largely radial. This means many of our customers are supplied through one powerline and power can't be re-routed or switched to restore power during supply interruptions. It is often difficult to locate and repair radial line faults due to the distance needed to travel to find the fault on the network, often in adverse weather conditions.

Rural powerlines typically supply much more sparsely populated areas and carry lower loads along very long sections. The longer the feeder gets, the greater the difficulty in maintaining power quality and exposure to environmental factors increases. Essential Energy's network is 80 per cent rural powerlines.

Varying environmental and weather conditions

The weather is one thing no one can control yet it is often the cause of unplanned supply interruptions. Windy conditions along the coast contribute to salt build up on insulators resulting in failures. Timber power poles in the North Coast region are prone to increased fungal decay as a result of higher humidity when compared to Victoria and South Australia.

West of the Dividing Ranges, the rural lines traverse open rolling terrain with scattered vegetation. This exposes our network to storms and associated lightning strikes, which often cause damage to our assets. With vegetation, dry land and lightning, comes bushfires. Bushfire prone areas make up a large portion of our network.

15,409 lightning strikes per year on the network.

Over 900 times the number of strikes experienced by CitiPower.

Accessing our network

During 2013-14, our fleet travelled 61 million kms - equivalent to driving around Australia 4,200 times.

On average, one Essential Energy depot maintains a network area 42 times the size of CitiPower's entire network

Travelling across regional and rural NSW can be dramatically different to utilising an urban road. Traffic is not an issue, but access and distance are. Sending our field crews out can impose many challenges, adding time to a journey to restore power or maintain our assets.

Crews often need to utilise access roads that have sometimes not been driven on for years. Often roads are gravel or dirt and after rain can remain impassable for weeks.

Wildlife and vegetation often inhibit access. Crews need to be careful when driving at dusk, during the night and dawn to ensure they reduce the chance of an accident. Fallen trees across roads and access trails often need to be cleared.

The knowledge of our employees at a local level with regards to roads, access paths and the location of network assets is an advantage in identifying the location of faults and finding the right route to get to them.

A large portion of our network cannot be accessed in a standard vehicle meaning a 4WD fleet is required on a daily basis. In alpine areas, we utilise all-terrain vehicles and ski-doos to access the network during snow season. In coastal areas and during floods, we sometimes need to utilise watercraft or helicopters to access the network.

Managing vegetation

Vegetation management is Essential Energy's largest single operating expense, after labour. The costs of managing vegetation around the network are driven by the size of the geographic area the network covers, the volume of trees requiring trimming and the extent to which trees need to be trimmed.

Essential Energy has on average more trees to maintain per span due to a longer average span length than most distributors. The longer a span is the greater clearance zone required to account for blow out of conductors in high wind conditions.

Managing vegetation around the network:

- Reduces the risk of bushfires ignited as a result of contact between vegetation and network assets.
- Reduces the number of reliability performance issues as a result of vegetation contacting the network.
- Reduces the number of outages during storms as a result of trees and branches falling onto powerlines. When a tree falls on a powerline it can sometimes force that powerline to the ground and create a safety issue through the increased risk of electrocution.

1,067,238 spans on Essential Energy's network are in designated high bushfire zones. The typical clearance zone is 4 metres.

196,736 of AusNet Services spans are in high bushfire zones.

Managing a network of this nature requires an efficient level of capital and operating expenditure that is commensurate with the assets it needs to maintain.

Essential Energy's network is unique in terms of the vast geographic area it covers, the environments it is exposed to and the comparatively low number of customers it serves.

Our assets traverse an area three times larger than Victoria to serve customers right across NSW, while adhering to the requirements of the *NSW Electricity Supply Act* (1995)

The costs of operating a network of this nature are driven by the number of assets and their locations, not simply the number of customers or demand on the network.

7.6.2 Customer related cost driver

These costs relate to the individual customer and as such the number of customers drives some costs. The individual cost can vary with the size of the customer but not necessarily in proportion to energy or demand requirements. Customer related costs cover the maintenance of service connection equipment (such as metering, load control receivers and service lines) and the 'administrative' costs arising from the connection of a customer to the network such as meter reading, billing, collection, price setting and network-related customer account management. For standard customer classes these costs are averaged across all customers and are generally reflected in the Network Access Charge (Service Availability Charge) of the standard network prices.

7.6.3 Demand-related cost driver

The capacity of a distribution network is developed to serve the demand for electricity that customers impose upon it. The available capacity of the network is driven by the diversified demand-related usage of the low voltage system (not including service mains), distribution substations and of the higher voltage distribution and sub-transmission networks. Customer loads have an incremental effect on the overall and local diversified load pattern.

The demand served by the network is the most important driver of costs in the provision of network services containing the bulk of the direct asset-related costs (see section 6.6.1). They are often referred to as maximum demand-related costs. It consists of the costs of financing and constructing the asset and maintenance of plant and equipment necessary to supply the cumulative demand of customers. These costs are principally fixed, proportional to the size of the peak demand supplied.

Network augmentation to increase capacity takes place at different levels throughout the network - subtransmission, high voltage, low voltage mains and substations. The need to augment the network arises when the power flow exceeds the capacity available in that part of the network.

At higher level voltages, augmentation of the network is necessary from time to time, to maintain adequate supply capacity and to maintain quality and reliability standards. Investment in the capacity of the network is achieved by a series of discrete, incremental augmentations and extensions. However, augmentation usually involves the provision of lumpy expensive network assets that have long lives. The cost of providing a given overall network capacity is made up of the sum of many of these augmentations in separate parts of the network.

Where demand is measured these costs can be directly applied, but for installations with energy only metering, it is common to regard energy consumption as a surrogate for demand, particularly for those standard customer classes with a predictable and relatively limited range of load profiles.

Demand related costs are distributed between all those customers who utilise the network so that each is allocated an equitable share according to their contribution to the total demand-related costs. Essential Energy uses a mathematical process called the "Method of Intercepts" to allocate demand-related costs according to the relative contribution per customer class to the network maximum demand.

7.6.4 Energy related cost driver

These costs tend to be less influenced by a customer's capacity requirements. They include costs which are related to the utilisation of the network and include the costs of general operation and maintenance of the shared network and referred costs such as transmission charges and demand management payments. These costs are most equitably allocated according to the amount of energy used by the customer (kilowatt hours consumed).

7.6.5 Common service costs

These costs relate to the provision of corporate services which are provided internally in support of network distribution services and other business units and cannot be reliably allocated by any one of the above four cost drivers. In order to carry out a fully distributed cost analysis, these costs are distributed according to one, or a combination, of the above drivers.

7.7 Network price components

Essential Energy's network prices contain the following price components, also referred to as charging parameters.

7.7.1 Demand charges

The demand imposed by larger customers has a more direct and significant impact on future network costs than smaller customers. The diversity of demand is more significant for smaller customers. It is therefore appropriate that larger customers should have pricing based on measured demand or supply capacity where the costs recovered through the demand charge represent those that could be directly impacted by the customer's demand on the network.

Demand based prices provide the customer with a clear signal relating to the benefits of load management to improve their average load and avoid short duration load peaks. Customer load factors can vary considerably from mining customers, with load factors in the range of 0.7-0.9, to irrigation loads with annual load factors less than 0.3. The load factor is a measure of how "peaky" a load is and therefore the nature of the demand placed on the network. A load factor of 1 indicates a constant flat load, which therefore uses the network in a consistent fashion regardless of the time of day or season. The $/kWh or per unit network charge for a customer with a low load factor would be significantly greater than for high load factor customers. Poor load factor customers on a demand price would, as a consequence, need to alter their usage patterns, if feasible, to minimise costs. Customers with typical load factors will generally find the standard demand time of use price results in a much lower average network charge.

Customers' loads consume both real and reactive power and as such the maximum demand is metered in kVA to reflect the customer's power factor. Customers on a demand based price can achieve significant savings by improving their power factor to as close to unity as possible to minimise the kVA demand. For smaller customers the cost of reactive compensation is less economic, and signalling of kW demand would be appropriate. For smaller customers, the time of use energy acts as a reasonable surrogate for the demand.

The factor, which drives augmentation, is the coincidental demand at different levels of the network. However, there are issues arising from attempting to pass on a coincident demand-related price signal, such as:

- The coincident demand is dependent upon the actions of a group of customers rather than the actions of an individual
- A coincident demand charge can only be calculated after the event, when all customer contributions are known
- The coincident demand at different levels in the network each will have a different impact upon future costs
- The coincident demand carries with it a significant degree of complexity in terms of incorporation into the network billing system.

For these reasons, it is more appropriate for the customer's recorded non-coincident demand to be used to determine the demand charge.

7.7.2 Energy charges (network usage charges)

Where a customer does not have a meter capable of recording demand, the metered energy consumption, either in the form of a single anytime energy rate or as a time of use energy rate, provides the only means of signalling future augmentation costs to the customer.

Energy based charges are most commonly on an anytime basis with a single rate as most domestic and small business meters presently only record consumption in this form.

The peak and shoulder components of the time of use price provide a reasonable surrogate for the signalling of the costs of demand during those time periods that drive investment in the network.

7.7.3 Network access charges (fixed charges)

Most network prices have a fixed Network Access Charge, which is independent of the demand and energy supplied. Fixed charges are non-discretionary in nature and represent the means of cost recovery for those costs which are fixed and reflect the costs that vary due to customer numbers. They are unrelated to actual consumption.

The Network Access Charge is associated with the provision of the following network services, which are fixed in terms of costs:

- Maintenance of assets dedicated to the customer's supply such as connection and metering assets, low voltage assets and for larger customers, the substation circuit breaker and instrument transformers used for metering
- Customer related operation and maintenance costs such as the 24 hour/7 day control centre, emergency and technical response crews
- Billing and account processing
- The distribution substation and high voltage power.

The Network Access Charge does not fully recover the fixed costs of some customer classes.

7.8 Fully distributed cost of supply modelling

Once the total annual revenue allowed is determined, then it must be apportioned to customers connected to the network.

Due to the meshed nature of the electricity distribution networks and largely fixed and sunken nature of costs, pricing must involve a substantial degree of cost averaging. Essential Energy has adopted the fully distributed cost approach to allocate all network costs to each network customer class and large network customers based on the assets required to serve the customers and their usage of network distribution services. This approach is largely based on current costs, with new capital investment rolled into the regulatory asset base. We believe this general principle best reflects the manner in which costs are incurred by general customer classes and provides equitable and reasonably efficient outcomes.

Fully distributed cost of supply modelling involves three fundamental steps:

1. The determination of the total network revenue requirements/costs for the networks business to provide the desired standard of network distribution service
2. The allocation of network costs to separate asset categories (cost pools) within classes of network distribution services
3. Conversion of cost pools to usage-based network prices for different individual customers and classes of customers, based on factors such as voltage level and their use of the distribution system (load shape) to determine cost reflective prices. The structure of these prices varies for customer classes as outlined in the previous section.

7.8.1 Allocation of network costs to asset cost pools

Electricity may be supplied directly to a single large customer or indirectly to a homogeneous class of customers such as low voltage customers. There is dedicated connection equipment associated with each customer and to varying degrees each customer makes use of the shared distribution network assets. If the assets are for the sole use of one customer, then the cost allocation process is straightforward as all costs are totally attributable to that customer. However, when assets are shared, such as the shared distribution network, then the task is more difficult in allocating costs in an equitable and consistent manner between customers.

The cost components of a customer using the distribution system relate to those portions of the network, and as such asset groups, which are being used. The model allocates the network cost components into separate cost pools, which have varying cost drivers or inputs. The cost pools generally reflect the different voltage levels of the network.

The model takes as inputs the following quantities:

- The total distribution network cost and transmission related payments
- Optimised network asset values for each asset class and each individual subtransmission element
- Operating and maintenance costs for each asset class and each individual subtransmission network element

- Depreciation allowances and the effective return on capital for each asset class and each individual subtransmission network element
- Connectivity of subtransmission elements
- Forecast customer numbers, energy consumption and demand
- Load profile characteristics for individual customers and major customer classes.

An intermediate stage in the cost allocation process to the derivation of desired network prices is the separation of the network into several asset categories.

7.8.2 Network asset categories (cost pools)

In order to apportion the total revenue required to network elements, network assets are first subdivided into several asset categories. The cost of supply model apportions the allowable network revenue as a cost into "cost pools" for these various major asset classes of the network.

Network assets are segregated into several asset categories based on voltage level:

- Distribution network assets

Distribution network assets are all the assets between the transmission point of connection and the distribution connection assets supplying a customer or group of customers. All the customers connected to the distribution network share these assets to a greater or lesser extent:

- Sub-transmission network mains – overhead and underground mains
- Zone substations
- High voltage distribution network mains – overhead and underground distribution
- Distribution substations
- Low voltage network mains - overhead and underground.

The cost of these asset categories comprises operation and maintenance, depreciation and a return on the capital employed.

- Connection assets

Customers are connected at all voltages within Essential Energy's network, either directly to substations or embedded within the network. Connection assets (also referred to as exit assets) are those fully dedicated to a customer, or group of customers, at their point of connection to the network where power exits the network. Examples of these include service lines, metering and where applicable instrument transformers, load control or circuit breakers in a zone substation supplying a single large customer. The costs associated with these assets form the basis for the Network Access Charge.

- Common service assets

Common service assets are those that benefit all customers and which cannot be reasonably allocated on an individual network asset basis. Common service assets are subdivided into the following asset categories:

- Network common service assets include system control and communication systems, voltage regulators and reactive plant providing voltage support, spare parts, land and buildings not associated with lines or substations. Network common service includes network management and support costs
- Controlled load common service assets include off-peak load management equipment such as load control signal generators and injection plant
- Corporate common service assets include an allocation to the networks business of those assets and costs associated with the management and administration of the total business.

A customer connected to the high voltage network would be allocated a share of the costs from the transmission, sub-transmission mains, zone substations, high voltage distribution mains, and connection assets cost pools and those common service assets, which provide high voltage support. It is for this reason that prices vary with connected voltage level. The average network price that a typical customer may experience will increase with connections at lower voltages. A typical customer connected at high voltage will generally have an average price which is lower than a typical low voltage customer.

7.9 Cost allocation to asset categories

In a fully distributed cost model, the annual revenue requirement is determined for each of the above asset categories (cost pools) using similar principles to that applied by the AER in the determination. That is, each network "cost pool" is assigned an asset-related cost (asset depreciation and a return on the assets employed) and efficient operating costs as follows:

Allocation to cost pool = operating costs + return of capital + return on capital + cost of tax.

Where information is available, the direct costs of an asset category or individual element are directly attributed to that asset cost pool. Amounts related to allocated 'indirect' costs as well as the returns required on the optimised values of assets are calculated and stored for each asset category or element.

In some cases, average unit operating cost (particularly maintenance cost per kilometre for network mains and maintenance cost per asset value for sub-transmission substations) is used to determine the elemental costs.

If the above process is carried out for each of the asset categories listed above, then the sum of the annual revenue requirements for all of the asset categories, plus the allocation of shared corporate common services, would equal Essential Energy's regulated distribution revenue requirements for that year, not including pass-through costs such as transmission related costs.

The relative proportions of operating costs and asset returns vary with each asset class due to the differences in asset values, depreciated life and operating expenditure requirements.

7.9.1 Asset related costs

Prior to calculating any asset-related returns, the value of assets financed by capital contributions is deducted from the total value of each asset category. Assets financed by capital contributions are not subject to a rate of return or depreciation charge, and only efficient maintenance and operation costs are recovered for these assets through network charges.

To arrive at an asset-related return for a particular asset category, the ODRC (excluding contributed assets) is multiplied by Essential Energy's effective regulated rate of return to arrive at the return on assets for that asset category. To this is added the depreciation charge, based on the ODRC valuation and effective asset lives, to arrive at the total asset-related return for that asset category.

7.9.2 Conversion of cost pools to usage-based network prices

Once the costs have been determined for each of the shared asset categories, the next step is to apportion them to individual major customers and standard customer classes.

In this case the utilisation of these assets for the individual large customer or customer class is matched with the costs assigned to those assets. A technique called the "Method of Intercepts" is fundamental to the shared network cost allocation process and is used to determine the contribution or impact of each on the demand that must be met by the network. This process utilises load profiles derived from estimates or samples.

The following steps provide an overview of the process that is used by Essential Energy to apportion the annual revenue requirement for shared network assets to nodes in the network.

7.9.3 SSC customer class

For those customers eligible for SSC pricing the following cost allocation process is used:

- The assets providing supply to the large individual customer are itemised and costs assigned (efficient operating costs, depreciation and return on asset) as a portion of the pool costs for the shared asset classes using the process described above. This enables the annual revenue requirement for each individual asset to be determined. Allocation is based on the optimised asset valuation of each asset category. Network common service costs are included in the allocation process as a component of the annual revenue requirement for each asset. All exit nodes from the sub-transmission network are identified as part of this process

> An annual load profile dissected into hourly demand periods is obtained for each node on the sub-transmission network. By summating the load profiles of customers downstream from each node either from estimates or samples, the load profile of that network node can be derived. Financial responsibilities for upstream assets can then be allocated in proportion to demands at each network node. In this way all of the operating costs, depreciation and return on assets for the sub-transmission network can be related to individual customers and/or customer classes. Hourly metered load data for each day of the previous year is used. This data is summarised to produce an average daily load curve for the node. The load curve is converted to a load duration curve by the software for the allocation process. The load profile of each large SSC customer is overlaid onto the load profile for the node. This identifies which customer contributes most to the peak periods and therefore drives the need for greater system capacity

> Costs are allocated using the "Method of Intercepts" process, which apportions the required revenue at shared nodes so that each customer bears an equitable portion of the input cost at that node. The method of intercepts may be thought of as producing a "flow rate" of annual revenue costs per hour per megawatt ($/hour/MW). This approach places an increasing value on the use of the network during periods of high demand. A load that has a high peak utilisation will receive a proportionally higher sharing of costs. This method is based on the fact that a customer not only has a maximum demand at a certain moment of time, but also a varying demand at other times, and that this varying demand, however small, is also making use of Essential Energy's supply facilities. That is, equal proportions of network costs are assigned to equal increments of load. The resulting cost allocation takes into account the proportion of use. Thus the sharing of annual revenue requirement is based not just on a proportion of the maximum demand but rather on an integrated function of both demand and duration

> The outcome is an annual demand-related cost at each node on the sub-transmission network that includes an allocated portion of all the upstream network costs, which are recovered in proportion to a customer's utilisation of the assets

> Customer-related costs are also determined for the dedicated connection assets. Customer dedicated assets are identified and costs, associated with these assets, are applied to the individual customer including operating and maintenance costs and a capital return. These costs are normally applied as a fixed charge. Dedicated assets paid for by customers do not attract a capital return

> Corporate common service costs are allocated to customers based on an average rate per kWh. A simple approach to cost sharing based on energy consumption is used for these cost components, as this quantity is easily measured or can be estimated for all customers supplied by the network

> For customers satisfying the criteria for individual customer pricing, the total cost at the customer's exit node is then calculated including transmission use of system, distribution network use of system (as per the method of intercepts allocation), common service and connection service components. This annual revenue requirement at the exit nodes for SSC customers is translated into price levels and structure.

7.9.4 Standard customer classes

For standard class customers the following process is used:

> The annual revenue allowance is allocated to asset cost pools in accordance with the process set out above. From these the costs assigned to SSC customers are deducted. Usage-based network prices are then derived for each of the asset cost pools, from the allocated costs and the energy consumption for each customer class. The forecast energy projections for each class are derived from readings of metering equipment for the previous year

> The cumulative usage-based prices (shared distribution use of system) for each standard customer class is derived by adding together the usage price for each asset category utilised down to the point of exit from the network for that particular class. That is, each customer class is allocated a usage based revenue allowance in accordance with the assets (sub-transmission, high voltage, distribution substation and low voltage) utilised

- Added to this shared distribution use of system charge is the transmission use of system, and the customer-related costs such as common service and connection service components which includes metering, service lines and load control receivers. A portion of these costs is recovered through the Network Access Charge
- Connection service costs are allocated on an average rate per kWh approach using standard charges for different customer classes. Where the connection assets have been provided by customers or are the subject of a capital contribution, the costs are adjusted accordingly.

The cumulative usage based prices generated for each customer class in this manner is reflective of the asset-related costs and operating costs which would be attributed to the customer loads connected at each voltage level.

7.9.5 Controlled load customer class

Due to the ability to control a customer's load to avoid system peaks, the allocation of network service charges to controlled load network prices does not include any demand component. However, the principal residential and business network price includes a demand cost allocation. The controlled load network price includes the cost of a customer's load control equipment and an allocation for the load control signal injection equipment.

7.10 Allocation of transmission network costs

Essential Energy's total revenue requirement incorporates transmission related payments. Transmission charges are a significant cost component for Essential Energy and are recovered as part of the total network charges levied on our customers.

Transmission related payments include:

- The cost of transmission related costs for use of transmission networks owned by TransGrid, Ausgrid and Powerlink
- Avoided TUOS payments to embedded generators calculated in accordance with the Rules
- Payments for network services to other distributors for inter-distributor transfers.

Transmission charges are not in a form that readily translates into network price structures. Essential Energy translates historical energy and kilowatt demand charges from transmission authorities into equivalent peak, shoulder and off-peak energy rates in order to allocate those charges to the network use of system tariffs.

Essential Energy allocates transmission charges to network prices using the following principles:

- The total TUOS allocated to network prices aligns with total expected transmission related payments to be made by Essential Energy
- Transmission charges are allocated to network prices in a way that reflects the cost drivers present in transmission
- The pass through of transmission charges and the structure of network prices have been aligned wherever possible by Essential Energy
- SSC customers have transmission charges allocated in a way that preserves the location and time signals of transmission pricing as per chapter 6 of the Rules. These charges are passed through as closely as possible to reflect the manner in which the charges are levied on Essential Energy
- Network prices for standard customer classes have transmission charges allocated on an average basis due to the difficulties associated with equitably allocating the general and common service fixed charge as a fixed network access charge, and passing through location price signals which cannot be preserved when the end price is applied to many customers within the network.

For larger customers connected in close electrical proximity to transmission connection points, transmission charges constitute the majority of the network price. It is therefore important that TUOS pricing is cost reflective and that the structure is mapped, as directly as possible, into network prices. For large customers with individual prices, the individual cost of transmission is directly assigned to the customer. The balance is allocated to standard customer classes.

Direct mapping to network prices for standard customer classes has not been possible due to the large fixed transmission charges that cannot be directly included in network price structures for these customers, which typically have a small fixed charge. More importantly, the customer's metering generally does not readily permit it. Due to these limitations, it is therefore not possible to pass the same transmission cost drivers through to all customers in the same format as they are provided to Essential Energy.

While the allocation of the large fixed charge component is reasonably discretionary, it has been apportioned between customer classes on the basis of their consumption. Allocation to customers in this way is a balance between equity and efficiency. Only the peak and shoulder energy component can be readily passed on to customers through distribution prices.

The transmission charges are allocated on their non time of use energy, peak and shoulder energy consumption, and/or demand and are added to the distribution network costs for each customer class. The intention of this mapping methodology is to preserve within the customer's price, to the extent possible, the cost drivers inherent in the transmission charge.

- Non-TOU price – the total transmission charge allocation for the class is divided by the total class consumption and added to the energy rate for the price. Average transmission charges would apply to smaller customers
- TOU price – the transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off peak consumption and added to the peak, shoulder and off peak energy rates. The transmission allocation relating to the fixed transmission component is added to the TOU energy rates Demand TOU price – the transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off peak consumption and added to the peak, shoulder and off peak energy rates. The transmission allocation relating to the fixed transmission component is added to the TOU energy rates.

The fixed component of the transmission charge was originally largely determined from an 'anytime' energy allocation of costs. This component is apportioned between individual customers and customer classes on the basis of their anytime energy consumption. Allocation to customers in this way is a balance between equity and efficiency. The allocation of the transmission demand charge using peak and shoulder energy is justified on the basis that in the long run, the augmentation of the transmission network - and hence future costs - is related to peak and shoulder utilisation of the network.

7.11 Incremental and stand alone cost allocation process

Essential Energy's cost of supply model assesses cost allocations to customer classes both on a LRMC and stand-alone basis. It is inappropriate for network distribution service charges to be below the incremental cost (or LRMC) of supply as it results in inefficient pricing signals. It is also inappropriate for charges to exceed that which the customer could pay for an alternative equivalent service, the stand-alone cost.

The stand-alone cost of supply is based on establishing an alternative source of supply to the customer class. Stand-alone costs are assessed by calculating the costs of various alternative supplies to our distribution network such as the construction of an alternative grid or the use of a community or individual generator. The lowest of the various stand-alone costs is chosen for the comparison.

Marginal costs are established by assessing the marginal component of the cost pools and allocating these costs to customer classes. This process takes into account the usage of the distribution network and other distribution network services and the impact on future capital expenditure made by each customer class. The LRMC of the distribution network is determined by separately identifying capacity related expenditure and averaging this over a forecast change in output (the Average Incremental Cost Approach).

The below steps are followed in the determination of Essential Energy's marginal costs:

1. Marginal cost components are allocated to the following cost pools:
    - Customer – marginal costs reflect the costs that vary due to additional customer numbers, i.e. building and maintaining the low voltage network, customer inquiries, and emergency response and outage restoration

- Demand – marginal costs accrue due to the customer's peak loading that contributes to network capacity requirements and augmentation
- Energy – marginal costs accrue due primarily to the structure of transmission charges

2. Growth related capital expenditure is allocated to the customer and demand cost pools based on forward estimates of average annual growth related network augmentation required over the next ten years
3. Asset renewal expenditure is based on forward estimates of average annual capital expenditure on asset refurbishment or replacement required to meet load growth. These assets would otherwise be unsatisfactory to supply existing loads
4. Capital expenditure for reliability and quality enhancement, and environmental, safety and statutory obligations are allocated to the customer and demand cost pools
5. Operation and maintenance marginal costs excluding administration and overheads are allocated to the customer and demand cost pools according to the relevant activity
6. Marginal transmission costs including both TransGrid, Ausgrid and Powerlink demand and energy charges are allocated to the relevant cost pools. The transmission fixed charges are not allocated as marginal costs
7. The allocation of the demand cost pool to customer classes is based on the asset utilisation by each class of customer
8. The allocation of the energy pool is based on energy consumption for each customer class
9. The customer cost pool is allocated according to a weighted customer value representing relevant customer servicing costs.

The network price for each customer class is then compared with the stand-alone costs and LRMC to determine if any cross-subsidisation exists.

Section 8 of this report demonstrates the relationship between current network prices and LRMC and stand-alone costs over a range of consumptions in each price class. The table and graphs show that network prices lie above the long run marginal cost of supply and below the lowest cost stand-alone alternative throughout the range of consumption.

7.12 Setting of price structures and levels

7.12.1 Factors considered

Final network prices and structures for standard network customer classes are established taking into consideration the following factors:

- Previous price structures and limits on price movements
- Nature and extent of their usage
- Nature of their connection to the network
- Cost effectiveness of metering requirements
- Demand management
- Simplicity

7.12.2 Network tariff classes

Essential Energy's network prices are separated into six broad categories that address the price setting principles listed above.

Low voltage – energy

This tariff class relates to customers with a low voltage connection to the network and are billed on usage. It includes the customer classes of:

- Residential block (previously continuous)

- Residential time of use
- Controlled load 1
- Controlled load 2
- Business block (previously continuous)
- Business time of use < 160 MWh

Low voltage - demand

This tariff class relates to customers with a low voltage connection to the network and are billed on usage and demand. It includes the customer classes of:

- Low voltage - average daily demand
- Low voltage – one rate demand
- Low voltage – three rate demand

High voltage - demand

This tariff class relates to customers with a high voltage connection to the network and are billed on usage and demand. It includes the customer classes of:

- High voltage - average daily demand
- High voltage – one rate demand
- High voltage – three rate demand

Subtransmission

This tariff class relates to customers with a subtransmission connection to the network and are billed on usage and demand. It includes the customer classes of:

- Subtransmission - three rate demand
- Cost reflective network customers

Inter distributor transfer

This tariff class relates to specific connection points between distributors

Unmetered

This tariff class relates to customers that do not have a meter and includes:

- Streetlighting usage charges
- Any other unmetered supply

Further information on Essential Energy's network price structures for standard customer classes can be obtained from the Network Price List. The Network Price List is available on Essential Energy's website at www.essentialenergy.com.au or on request.

7.12.3 Cost reflective network prices and cross subsidies

Some network prices do not reflect the fully allocated cost of providing the service. Essential Energy's fully distributed cost of supply model indicates that some prices are not cost-reflective.

The term 'cross-subsidy' is frequently used when discussing the level of cost reflectivity in prices. However, a large proportion of a network operator's costs are fixed, and allocation of fixed costs to various customer classes is an arbitrary process. Caution must therefore be taken when interpreting discussions of cross subsidies in network pricing which have been determined by this allocation of fixed costs to various customer classes.

It is important to understand the various interpretations of what constitutes a cross subsidy.

The generally accepted view is that cross-subsidies do not exist if the cost of providing a service exceeds its incremental cost.

Despite this very valid proposition, there are two significant issues for setting network prices that need to be taken into account:

> First, there is subjectivity in the definition of marginal costs for distribution network services. In the short run, marginal costs are negligible as energy losses are traded in the market. In the longer term, incremental costs would trend to average costs as per a fully distributed cost of supply of an optimised network.

> Second, network distribution assets are long lived and their cost recovery needs to be considered over an extended timeframe.

8 EXPECTED LEVELS OF SERVICE AND PROJECTED CAPITAL EXPENDITURE PROJECTS

Essential Energy's capital investment program for the 2016-17 year is forecast to be $XX million in accordance with the amounts provided for in the determination.

8.1 Capital expenditure projects

Capital expenditure is invested efficiently by Essential Energy to deliver the greatest benefit to all stakeholders. Our medium-term capital investment program is designed to meet targeted programs and to continue to improve the current levels of service to customers. Specifically the program takes into account the following factors:

> The needs of our customers and all other stakeholders

> Current and projected levels of service standards, including long-term network reliability across the network and the specific targeting of those parts of the network that are delivering the lowest service levels

> Forecasts of demand growth

> Condition and age of assets

> Regulatory, environmental and safety compliance requirements

> Non-system investment requirements

> Efficient alternatives to capital expenditure including efficient operating and maintenance expenditure, demand management, and new generation.

Essential Energy's $528 million capital investment program for 2016-17 includes $462 million for expenditure on system assets and $66 million for expenditure on non-system assets.

The following section outlines the major capital expenditure categories and provides a brief description of major capital expenditure projects planned for the 2016-17 financial year necessary to meet:

> Growth in demand and system augmentation requirements to maintain system performance and system security and quality of supply

> Asset replacement and renewal requirements to maintain system performance, safety and integrity of the network and to maintain overall system reliability

> Non-system investment requirements to support the operations of the distribution business.

8.1.1 Growth in demand and system augmentation

Growth related expenditure relates to investments that are required to ensure that the network has adequate capacity to meet demand. General distribution related reliability capital expenditure to maintain existing service levels are also included in this category together with compliance and demand management capital expenditure.

The determination reduced Essential Energy's expenditure in this area by 15 per cent from our revised regulatory proposal. In doing so, the AER stated:

Essential Energy's forecast to augment its high voltage network is overstated because it does not take into account the expected decline in spatial network growth. We reduced this forecast downwards to accurately reflect the forecast decline in network growth (using forecast customer connections rates as a proxy).[1]

However this does not take into account that Essential Energy's distribution network is operating at or near its maximum capacity in some areas. The strong growth areas include the major regional centres and the northern and southern coastal strips, the latter areas representing some of the fastest growing areas in the state. This reflects continued residential and commercial development, with expansion forecast to continue into the future. Over the medium term, Essential Energy will need to continue to expand and reinforce the network in these areas to meet continued growth in demand.

Capital projects to cater for growth for the 2016-17 year are being reviewed as a result of these reductions.

8.1.2 Asset renewal and replacement

A significant component of the overall network related capital program is the replacement and renewal of aged assets. Network assets have a finite life. Replacement and renewal investment ensures the timely replacement or refurbishment of network assets that have become unserviceable, that frequently fail in service, have significantly deteriorated to an unsafe or risky condition or where the present value cost of maintaining the asset exceeds the cost of replacement. Asset replacement expenditure increases gradually over time due to the ageing of the network. This trend is already evident and will continue through the current regulatory period. Where the condition of the assets has deteriorated and ongoing maintenance is not effective, system assets must be replaced.

Replacement is also driven by environmental, regulatory and industry safety compliance considerations. More than 40 per cent of Essential Energy's network assets are over 40 years old and are rapidly ageing. In the areas of the network west of the ranges, the network assets are generally older and the condition of some assets is increasingly requiring replacement in order to maintain the performance level of the network.

8.1.3 Non-system requirements

This category includes capital items that will be required to support the electricity distribution business including:

- Information systems development and computer hardware, software and upgrades, licences, plant and equipment relating to IT assets, and related expenditure required to operate the business. Expenditure in this area has been reduced significantly from the previous regulatory period
- Motor vehicles and plant
- Communication systems
- A number of other miscellaneous expenditures such as general office equipment, furniture, small plant and test equipment, and building and property works

Expenditure related to this category will ensure the continued efficient management and support of the electricity distribution business.

8.2 Expected levels of service for the coming year

Essential Energy is proud of the service standards achieved within a difficult and unique operating environment.

The SAIDI reliability performance objectives for 2016-17 for different components of the network are tabled below. SAIDI represents the total number of minutes on average that each customer installation connection to the distribution system (or to those components) is without a supply of electricity.

[1] AER, *Final Decision Essential Energy - distribution determination 2015−16 to 2018−19 April 2015 Overview*, p36

Table 12 SAIDI Reliability Performance Objectives for 2016-17 [2]

Component of distribution system	2016-17 SAIDI objective (minutes)
Urban feeders	68.47
Rural short feeders	212.94
Rural long feeders	419.43

Network reliability has improved significantly, in line with the current licence conditions. Compared with 2003, customers today experience approximately 75 minutes less interruption time per year. The frequency of interruptions has also decreased by approximately 30 per cent, to just under two outages per year. Our asset plan now aims to maximise our past investments and focus future investments so that our network performance can be maintained at those levels.

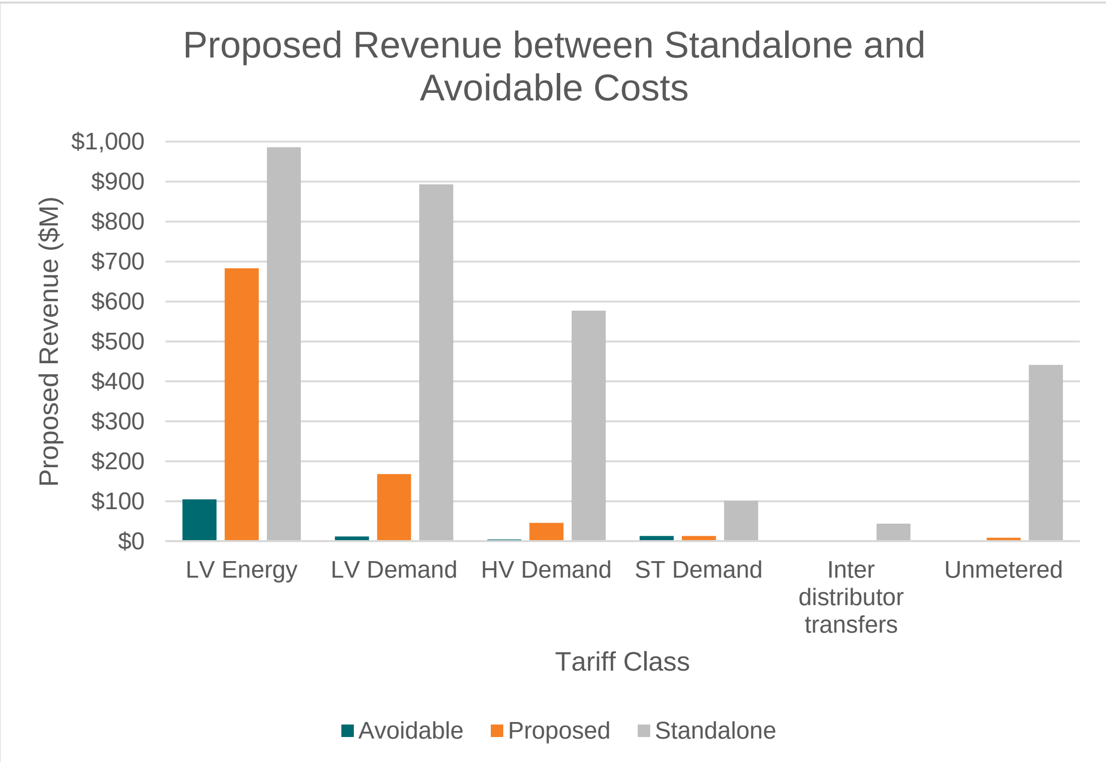
9 FULLY DISTRIBUTED COST COMPARISON

In accordance with Chapter 6 Part I of the Rules, Essential Energy is required to include in their pricing proposal each year a comparison of distributed costs. The proposal must show the tariff classes to apply for the relevant year and demonstrate that for each *tariff class*, the revenue expected to be recovered must lie on or between:

> an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and

> a lower bound representing the avoidable cost of not serving those retail customers.

The graph below shows that network prices lie above the avoidable cost of supply and below the stand-alone cost for each tariff class.



[2] AER, *Final Decision Essential Energy - distribution determination 2015−16 to 2018−19 Overview April 2015 Attachment 11*, p8