Energex

Annual Pricing Proposal

1 July 2017 to 30 June 2018

energex

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Version control

Version	Date	Description
v.1	31 March 2017	Pricing Proposal submitted to the AER for approval.
v.2	4 May 2017	Revised Pricing Proposal updating the 2016-17 weighted average DUoS revenue for the ICC in Section 3.3.3 (Tables 3.3 and 5.1), and correcting an inconsistency in the calculation of the side constraint formula in Section 3.3.4 (Tables 3.4 and 3.5).

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1 Introduction

1.1 Background

On 30 June 2016, Energex Limited (Energex) became a subsidiary of Energy Queensland Limited which is the holding company for both Energex and Ergon Energy Corporation Limited (Ergon Energy). Energex is the Distribution Network Service Provider (DNSP) that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to 1.4 million domestic and business connections, delivering electricity to a population base of around 3.4 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

1.2 Purpose

This document is Energex's Annual Pricing Proposal for 2017-18 (Pricing Proposal). In accordance with clause 6.18.2(a)(2) of the National Electricity Rules (the Rules),[1] it is submitted for approval to the Australian Energy Regulator (AER) at least three months before the commencement of the regulatory year (that is, before 31 March 2017). The AER approves prices for services it classifies as Direct Control Services.

This Pricing Proposal has been prepared for the third year of Energex's 2015-20 regulatory control period and is the first to be submitted to the AER under the new regulatory arrangements set out in Chapter 6 of the Rules. Under the new arrangements, Energex's Pricing Proposal must demonstrate compliance with the Rules, Energex's 2017-20 Tariff Structure Statement (TSS) approved by the AER,[2] the AER's Final Decision Energex Determination 2015-16 to 2019-20 (Final Decision)[3] and the Final Framework and Approach (F&A)[4] for Energex and Ergon Energy.

The purpose of this Pricing Proposal is to:

- set out the proposed tariff classes, tariffs and charging parameters developed under the TSS that will enable Energex to recover its allowed revenue for the year commencing 1 July 2017 and ending 30 June 2018
- demonstrate compliance with the regulatory requirements
- provide network charges for 2017-18
- provide updated indicative price levels for each tariff and for each of the remaining regulatory years.

[1] The National Electricity Rules, Version 89.
[2] A copy of Energex's 2017-20 Tariff Structure Statement and associated Explanatory Notes can be found on Energex's website: https://www.energex.com.au/home/our-services/pricing-And-tariffs/business-customers/pricing-publications.
[3] AER, Final Decision Energex determination 2015-16 to 2019-20, October 2015.
[4] AER, Final Framework and approach for Energex and Ergon Energy Regulatory control period commencing 1 July 2015, April 2014.

1.3 Classification of services

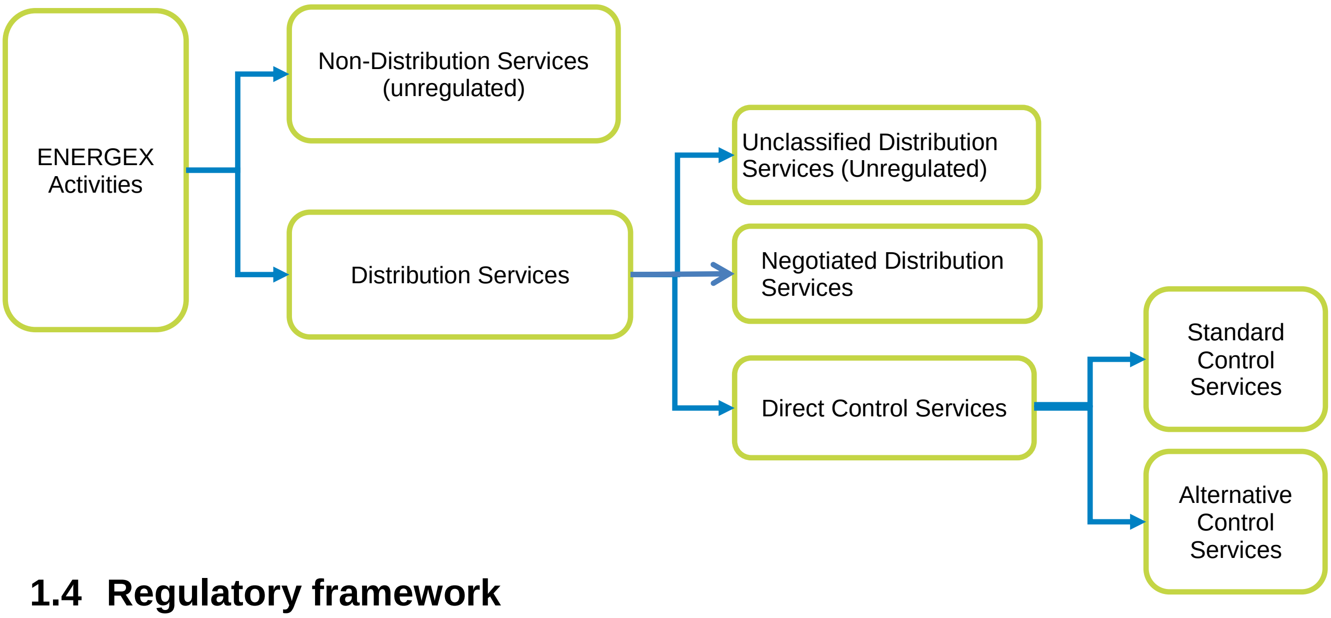
The AER determines how Energex's distribution services are classified and in turn the nature of economic regulation. This is important as it determines how prices will be set and how revenue is recovered from customers.

In the F&A issued in April 2014 and confirmed in the Final Decision, the AER classified Direct Control Services as Standard Control Services (SCS) or Alternative Control Services (ACS). Services classified as SCS relate to the access and supply of electricity using Energex's poles and wires (distribution system) to customers. Specifically, they include network services (e.g. construction, maintenance and repair of the distribution system), some connection services (e.g. small customer connections) and Type 7 metering services.[5] The AER applies a revenue cap form of control to SCS.

ACS are services provided by Energex to specific customers mostly charged on a 'user pay' basis and, therefore, do not form part of the SCS or distribution use of system (DUoS) revenue allowance. ACS include services such as Type 6 metering services,[6] public lighting services,[7] an increasing number of connection services, and ancillary services. Energex's ACS are charged on a limited building block price cap, price cap or quoted price basis, depending on the services. More information about ACS is included in Chapter 4 of this Pricing Proposal.

This Pricing Proposal refers to the tariff classes and tariffs for those distribution services classified as Direct Control Services as shown in Figure 1-1.

Figure 1-1 Classification of Energex's distribution services



1.4 Regulatory framework

As a DNSP, Energex is subject to economic regulation by the AER under the National Electricity Law (the Law) and the Rules. Under the Law and the Rules, the AER is responsible for regulating the revenues Energex can earn, and the prices Energex can charge its customers for the provision of network services.

[5] Type 7 metering refers to unmetered connections where usage is estimated (includes public lighting and traffic lights).
[6] Type 6 meters are manually read accumulative meters which only record total electricity usage.
[7] The conveyance of electricity to street lights remains a SCS, while services relating to the prevision, construction and maintenance of street lighting assets have been classified by the AER as ACS.

1.4.1 Distribution determination

In October 2015, the AER released its Final Decision on Energex's Determination for the 2015-20 regulatory control period. The annual revenue to be recovered by Energex from customers is lower than that recovered in the previous regulatory control period, mainly as a result of a lower cost of debt. This decline in allowable revenue is, however, partially offset by additional amounts mainly stemming from the jurisdiction scheme amounts which comprise the Queensland Solar Bonus Scheme and the AEMC levy payments which have been added to Energex's revenue as an adjustment. The revenue approved in the Final Decision forms the basis of Energex's prices provided in Appendix 1 of this Pricing Proposal.

1.4.2 Tariff structure statement

In November 2014, amendments to the Rules changed the framework in which tariffs for Direct Control Services are developed. Included in these new arrangements were new obligations for DNSPs to:

- develop a TSS that outlines the network tariff structures that it proposes to apply over the entirety of the regulatory control period[8]
- develop prices that better reflect the costs of providing services to customers so that they can make informed decisions about how they use electricity.

The AER approved Energex's TSS for the 2017 to 2020 period on 27 February 2017.[9]

The TSS interfaces with Energex's Pricing Proposal, and each Pricing Proposal must be consistent with the approved TSS. The TSS will apply to Energex for the first time in 2017-18.

As much of the content in the TSS about adherence to the pricing principles and tariff development is directly relevant to the 2017-18 prices, several sections of this Pricing Proposal therefore refer to the TSS for further information.

1.4.3 Pricing objective and principles

In accordance with clause 6.18.5(a), Energex's objective is to ensure that the tariffs charged for 2017-18 in respect of the provision of Direct Control Services reflect Energex's cost of providing these services. More specifically, Energex's tariffs are set in a manner that is consistent with the pricing principles as outlined in clauses 6.18.5(e) to (j) of the Rules. The pricing principles require Energex to demonstrate that:

- the revenue expected to be recovered from a tariff class lies between the stand alone and avoidable cost (clause 6.18.5(e)(1) and (2))
- tariffs must be based on the long-run marginal cost (LRMC) of providing the service (clause 6.18.5(f))
- the revenue expected to be recovered from each tariff must reflect Energex's total efficient costs (clause 6.18.5(g)(1))

[8] Under the transitional arrangements, the initial TSS will cover only the last three years of the 2015-20 regulatory control period (1 July 2017 to 30 June 2020).
[9] AER's Final Decision on Energex's 2017-20 TSS is available on the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/energex-tariff-structure-statement-2017.

- the revenue received from all the tariffs should enable Energex to recover its total annual revenue (TAR), as set by the AER in the 2015-20 Determination (clause 6.18.5(g)(2))
- tariffs are set in such a manner that minimises distortions to the price signal resulting from complying with the LRMC pricing principle (clause 6.18.5(g)(3))
- it has considered the impact of tariff changes on customers (clause 6.18.5(h))
- tariff structures are set in a manner that can be understood by customers (clause 6.18.5(i))
- the tariffs comply with the Rules and all applicable regulatory instruments (clause 6.18.5(j)).

Detailed information about Energex's application of, and compliance with, the pricing principles with respect to SCS tariffs is set out in Chapter 3 of this Pricing Proposal. For ACS, compliance is discussed in Chapter 4.

1.4.4 Queensland Government cap on fee based services

The Queensland Government has historically set maximum price caps to apply to a subset of Energex's services through Schedule 8 of the Electricity Regulation 2006. Since the price caps are imposed through legislation, they take precedence over the ACS prices approved by the AER.

It should be noted that the proposed ACS prices included in this Pricing Proposal have been derived under the price setting requirements outlined in sections 1.4.1, 1.4.2 and 1.4.3 above. These prices, if subject to the maximum price caps in Schedule 8, may be higher than those charged to customers.

1.5 Summary of changes

Energex is proposing a number of changes to its SCS and ACS for 2017-18. These changes are summarised in Table 1-1 and Table 1-2 below.

Table 1-1 SCS tariff changes

Tariff class	Proposed tariff changes
SAC	The introduction of an optional cost reflective time-of-use (ToU) demand based tariff for small businesses (NTC7100 – Business Demand). This new tariff is part of the implementation of Energex's tariff reform set out in the TSS. Further information is provided in Section 2.2.
CAC	The introduction of a ToU demand based tariff for the 11kV customers (NTC7400 – Demand ToU 11kV). It is the default tariff for new 11kV Line customers and is offered on a voluntary basis for all existing 11kV Line customers. The tariff is not accessible to new and legacy 11kV Bus customers. This new tariff is part of the implementation of Energex's tariff reform set out in the TSS. Further information is provided in Section 2.2.

Table 1-2 ACS tariff changes

Services	Changes
Fee based services	Following Power of Choice, a number of ACS services will be amended on 1 December to reflect the start of contestability in metering services for all customers. Further information is provided in Section 5.3.2.

Energex's network charges for existing and newly introduced tariffs for 2017-18 are included in Appendix 1.

1.6 Structure of this document

The structure of this Pricing Proposal is set out in Table 1-3 below.

Table 1-3 Pricing proposal structure

Chapter	Title	Overview
2	Standard Control Services: Tariff classes and tariffs	Sets out the tariff classes and tariffs for SCS, and the charging parameters for each tariff.
3	Standard Control Services: Network tariff levels	Sets out Energex's approach to calculating network charges and provides details on the weighted average revenue for SCS tariff classes, and compliance with side constraints for 2017-18.
4	Alternative Control Services: Tariffs	Sets out for 2017-18 the list of ACS and corresponding price levels in accordance with the pricing principles set out in the Rules and regulatory requirements.
5	Other compliance	Demonstrates Energex's compliance with the regulatory requirements which are relevant to both SCS and ACS, and have not been covered in previous chapters.
	Appendices	Provides additional supporting information.

1.7 Supporting network pricing documents

In addition to this Pricing Proposal, Energex publishes a number of related network pricing documents, some of which have been created with a view to assist network users, retailers and interested parties understand the development and application of network tariffs, ACS prices and connection charges. These documents are outlined in Figure 1-2 below and are available on Energex's website.

Figure 1-2 Supporting network pricing documentation

Tariff Structure Statement

- Sets out the proposed tariff classes, tariffs and tariff structures for the 2017-20 period
- Details how the proposed tariff classes, tariffs and tariff structures comply with the pricing principles
- Describes the tariff setting process for SCS and ACS
- Provides details on Energex's tariff assignment policy
- Provides indicative prices for the 2017-20 period for SCS and ACS
- Approved by the AER in February 2017, following stakeholder consultation.

Pricing Proposal

- Sets out the proposed tariff classes, tariffs and charging parameters developed under the TSS that will enable Energex to recover its allowed revenue for 2017-18
- Demonstrates compliance with the regulatory requirements
- Provides 2017-18 network charges for SCS and ACS
- Provides updated indicative price levels for each tariff and for each of the remaining regulatory years (provided in a separate Indicative Price Schedule)
- Submitted to the AER annually.

Information Guide

- Sets out the basis upon which Energex's revenue cap for SCS is recovered from various customer groups through network tariffs
- Outlines Energex's tariffs and charges for SCS and ACS for 2017-18
- Assists customers and retailers by providing eligibility criteria for assigning customers to tariff classes and tariffs, and product codes.

User Guides

- Provide an introduction to the current nework tariffs for each customer group
- Published annually and updated as required.

Connection Policy

- Sets out the circumstances in which a retail customer or real estate developer may be required to pay a connection charge for the provision of a connection service
- Details how Energex calculates the capital contributions to be paid.

2 Tariff classes and tariffs for Standard Control Services

RULE REQUIREMENT
Clause 6.18.2 Pricing Proposals (b) A pricing proposal must: (2) set out the proposed tariffs for each tariff class that is specified in the Distribution Network Service Provider's tariff structure statement for the relevant regulatory control period. (3) set out for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates. Clause 6.18.2 Tariff classes (b) Each customer for direct control services must be a member of 1 or more tariff classes. (c) Separate tariff classes must be constituted for retail customers to whom standard control services are supplied and retail customers are supplied.

This section details Energex's tariff classes, tariffs and tariff structures for SCS in accordance with the TSS.

2.1 Energex's tariff classes

Under chapter 10 of the Rules, tariff classes are defined as 'a class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs'. All customers who take supply from Energex for Direct Control Services are a member of one or more tariff classes (clause 6.18.3(b)). Consistent with Clause 6.18.3(c) of the Rules, Energex assigns retail customers receiving SCS to one of the tariff classes shown in Table 2-1.

Energex's tariff classes group retail customers on the basis of their usage, voltage level and nature of connection in accordance with clause 6.18.4(a)(1) and (2) of the Rules. Further, in accordance with clause 6.18.3(d) of the Rules, Energex's tariff classes group retail customers together on an economically efficient basis as to avoid unnecessary transaction costs.

Finally, in accordance with clause 6.18.4(a)(3) of the Rules, Energex does not make reference to customer's export load in assigning customers to tariff classes.

For 2017-18, Energex has applied the tariff classes detailed in the TSS. These are listed in Table 2-1 below.

Table 2-1 Tariff classes for 2017-18

Tariff class	Eligible customers
Individually Calculated Customers (ICC)	Customers are assigned to the ICC tariff class if they are coupled to the network at 110 kV or 33 kV. Customers with a network coupling point at 11 kV may also be assigned to the ICC tariff class if: • the customer's electricity consumption is greater than 40 GWh per year at a single connection; and/or • the customer's demand is greater than or equal to 10 MVA; and/or • the customer's circumstances mean that the average shared network charge becomes meaningless or distorted. ICC tariffs are based on: • the actual dedicated connection assets utilised by the customer; plus • the customer's specifically identified portion of the shared distribution network utilised for the electricity supply, including common and non-system assets.
Connection Asset Customers (CAC)[1]	Customers with a network coupling point at 11 kV who are not assigned to the ICC tariff class are allocated to the CAC tariff class. CAC tariffs are based on: • the actual dedicated connection assets utilised by the customer; plus • average charges for use of the shared distribution network, including common and non-system assets.
Standard Asset Customers (SAC)	All customers connected at LV are classified as SACs. SAC tariffs are based on: • average charges for dedicated connection assets; plus • average charges for use of the shared distribution network, including common and non-system assets.

Note:
1. In circumstances where a customer's connection point does not have the appropriate metering to access tariffs within the tariff class to which they are assigned, the customer may be temporarily assigned to a tariff within the SAC tariff class.

2.2 Tariffs and tariff structures for primary tariffs

Each tariff class consists of a number of individual tariffs that are established on the same basis as the tariff class. In grouping customers with similar usage and connection to the network, Energex ensures that there are not an excessive number of tariffs. In doing so, Energex minimises transaction costs that may be incurred as a result of customers switching between tariffs and managing the provision of an excessive number of tariffs.

Each tariff comprises a combination of charging parameters which are used to recover network costs. In developing its network tariffs, Energex has ensured that they provide signals to network users about the efficient use of the network. Finally, in accordance with clause 6.18.5(i), Energex's network tariff structures have been developed so that they can be easily understood by customers.

Details of Energex's rationale for its network tariffs, tariff structures and implementation approach for the 2017-20 period are outlined in the TSS and accompanying Explanatory Notes.

The tariffs for SCS for 2017-18 and their structures included in Table 2-2 to Table 2-7 below are consistent with the TSS.

Table 2-2 Tariffs and tariff structures for customers connected at 33kV and above

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
ICC (NTC1000)	Customers in the ICC tariff class are assigned to this tariff.	Supply charge	Unit: $/day (these charges vary for each customer).	Default tariff.
		ToU usage charge	Unit: c/kWh Peak and off-peak timeframes defined in Table 2-8.	
		Demand charge	Unit: $/kVA/month Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[1]	
		Capacity charge	Unit: $/kVA/month.	

Note:
1. The average power used during the 30 minute period is used to calculate demand.

Table 2-3 Tariffs and tariff structures for customers connected at 11kV

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
11kV Bus (NTC4000)	Customers with a network coupling point at an 11 kV zone substation bus via a dedicated 11 kV feeder that is not shared with any customer.	Supply charge	Unit: $/day (these charges vary for each customer).	Default for customers with an 11kV bus configuration.
		Usage charge	Unit: c/kWh Quantity: Peak and off-peak timeframes are defined in Table 2-8.	
		Demand charge	Unit: $/kVA/month Quantity: Maximum kVA	

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
			demand measured over a 30 minute period during the billing period.[1]	
11kV Line (NTC4500)	Customers with a network coupling point at an 11 kV feeder shared with other customers.	Supply charge	Unit: $/day (these charges vary for each customer).	Grandfathered on 1 July 2017.
		Usage charge	Unit: c/kWh. Quantity: Peak and off-peak timeframes defined in Table 2-8.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[1]	
HV Demand (NTC8000)	Previously, this tariff was allocated to 11 kV customers with energy less than 4 GWh per year and demand less than 1 MVA. From 1 July 2017, new customers with these characteristics are allocated to either NTC7400 – Demand ToU 11 kV if they share an 11 kV feeder with other customers or to NTC4000 – 11 kV Bus if they have an 11 kV bus configuration.	Supply charge	Unit: $/day (these charges vary for each customer).	Grandfathered since 1 July 2015.
		Usage charge	Unit: c/kWh. Quantity: Peak and off-peak timeframes defined in Table 2-8.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[1]	
EG – 11kV (NTC3000)	Previously, this tariff was allocated to customers who were predominantly generation customers with a generation capacity greater than 30 kVA. From 1 July 2017, new customers with these characteristics are allocated to	Supply charge	Unit: $/day (these charges vary for each customer).	Grandfathered since 1 July 2015.
		Usage charge	Unit: c/kWh. Quantity: Peak and off-peak timeframes defined in Table 2-8.	
		Demand charge	Unit: $/kVA/month Quantity: Maximum kVA	

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
	either NTC7400 – Demand ToU 11 kV if they share an 11 kV feeder with other customers or to NTC4000 – 11 kV Bus if they have an 11 kV bus configuration.		demand measured over a 30 minute period during the billing period.[1]	
Demand ToU 11kV (NTC7400)[2]	Cost reflective ToU demand tariff for customers with a network coupling point at 11 kV feeder shared with other customers.	Supply charge	<u>Capital:</u> Unit: $/day/$M of non-contributed asset value (NCCAV). Quantity: NCCAV ($M) and number of days in billing period. <u>Operating and maintenance</u>: Unit: $/day/$M connection asset value (CAV). Quantity: NCCAV ($M) and number of days in billing period.	Tariff offered from 1 July 2017 on a voluntary basis for all existing 11kV Line customers on legacy tariffs. This tariff will become the default tariff from 1 July 2017 for new customers that share an 11kV feeder with other customers.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Peak Demand charge	Unit: $/kVA/month. Quantity: Maximum kilowatt demand measured as a single peak over a 30 minute period during charging window defined in Table 2-9.	
		Excess demand charge	Unit: $/kVA/month. Quantity: The maximum of: • Zero, • Maximum kilowatt demand measured as a single peak over a 30 minute period outside the peak charging windows defined in Table 2-9, minus the	

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
			peak demand quantity as described above.[1]	

Notes:

1. The average power used during the 30 minute period is used to calculate demand.
2. Proposed new tariff.

It should be noted that connection assets are the assets required to connect an electrical installation to the shared network, and are all the assets from the connection point back up to and including the network coupling point.

Dedicated connection assets are generally for the sole use of a single connection and are typically not shared by multiple connections. In circumstances where the network coupling point, and/or identification of dedicated connection assets, is unclear or contested, Energex will consider other information, including but not limited to, the customer's metering point to make a determination about the network coupling point.

Table 2-4 Tariffs and tariff structures for LV customers with consumption greater than 100 MWh/year

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
Large Demand (NTC8100) Small Demand (NTC8300)	Tariffs available to LV customers with consumption greater than 100 MWh per year. Customers with consumption less than 100 MWh per year may voluntarily access these tariffs. Customers must have appropriate Type 1-4 metering to access these tariffs.	Supply charge	Unit: $/day. Quantity: Days in billing period.	NTC8100: Optional tariff. NTC8300: Default tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[1]	

Note:

1. The average power used during the 30 minute period is used to calculate demand.

Table 2-5 Tariffs and tariff structures for residential customers

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
Residential Flat (NTC8400)	This tariff is the default tariff for residential customers regardless of their size and cannot be used in conjunction with Residential	Supply charge	Unit: $/day. Quantity: Days in billing period.	Default tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing	

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
	ToU (NTC8900).		period.	
Residential ToU (NTC8900)	This tariff is available to residential customers regardless of their size and cannot be used in conjunction with Residential Flat (NTC8400). Customers must have a ToU capable meter to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period. Peak, shoulder and off-peak timeframes defined in Table 2-8.	
Residential Demand (NTC7000)	This tariff is available to residential customers regardless of their size and cannot be used in conjunction with Residential Flat (NTC8400). Customers must have appropriate Type 1-4 metering to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kW/month. Quantity: Maximum kilowatt demand measured as a single peak over a 30 minute period during peak charging window defined in Table 2-9.[1] For the first 12 months on this tariff, eligible customers' chargeable demand will be capped. Terms and conditions are provided in Appendix 3.	

Note:

1. The average power used during the 30 minute period is used to calculate demand.

Table 2-6 Tariffs and tariff structures for LV business customers with consumption less than 100 MWh/year

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
Business Flat (NTC8500)	This tariff is the default tariff for business customers with consumption less than 100 MWh per year.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Default tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
Business ToU (NTC8800)	This tariff is available to business customers with consumption less than 100 MWh per year. Customers must have ToU-capable metering installed to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period. Peak and off-peak timeframes defined in Table 2-8.	
Business Demand (NTC7100)[1]	This tariff is available to business customers with consumption less than 100 MWh/year and cannot be used in conjunction with Business flat (NTC8500). Customers must have appropriate Type 1-4 metering to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff offered from 1 July 2017.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kW/month. Quantity: Maximum kilowatt demand measured as a single peak over a 30 minute period during peak charging window defined in Table 2-9.[2]	

Notes:

1. Proposed new tariff.
2. The average power used during the 30 minute period is used to calculate demand.

2.3 Tariffs and tariff structures for secondary tariffs

Load control tariffs are secondary tariffs for residential customers which can only be used in conjunction with a primary tariff in the SAC tariff class.

Energex's tariffs, tariff structures and implementation for load control tariffs are outlined in Table 2-7 below.

Table 2-7 Tariffs and tariff structures for load control tariffs

Tariff	Tariff structure	Charging parameter	Implementation
Super Economy (NTC9000)[1] Economy[1] (NTC9100)	Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	Optional secondary tariff.
Smart Control[2] (NTC7300)	Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	Optional secondary tariff in conjunction with the residential demand tariff, NTC7000 – Residential Demand.

Notes:
1. This tariff cannot be used in conjunction with NTC7000.
2. Proposed new tariff.

The terms and conditions for secondary tariffs can be found in Appendix 2 of this Pricing Proposal.

2.4 Time of Use charging timeframes

The charging timeframes for ToU usage and ToU demand tariffs are included in Table 2-8 and Table 2-9 below.

Table 2-8 ToU usage charging timeframes

Tariff	Network Tariff Code	Charging timeframes	Weekdays[1]	Weekends
Residential ToU	NTC8900	Off-Peak	10pm – 7am	10pm – 7am
		Shoulder	7am – 4pm, 8pm – 10pm	7am – 10pm
		Peak	4pm – 8pm	No peak
Business ToU	NTC8800	Off-Peak	9pm – 7am	Anytime
		Peak	7am – 9pm	No peak
ICC, CAC	NTC1000 NTC4000 NTC4500 NTC8000 NTC3000	Off-Peak	11pm – 7am	Anytime
		Peak	7am – 11pm	No peak

Note:
1. Include government specified public holidays.

Table 2-9 ToU demand charging windows

Tariff	Network Tariff Code	Charging timeframes	Workdays[1]	Weekends
Residential ToU	NTC7000	Off-Peak	8pm – 4pm	Anytime
		Peak	4pm – 8pm	No peak
Business ToU	NTC7100 NTC7400	Off-Peak	9pm – 9am	Anytime
		Peak	9am – 9pm	No peak

Note:
1. Workdays are weekdays but exclude government specified public holidays.

2.5 Tariff assignment policies

Energex's policies and procedures for the assignment and reassignment of customers to tariff classes and tariffs have been developed in accordance with the principles and provisions set out in the AER's Final Decision. These policies and procedures are contained in the TSS as per clause 6.18.1A of the Rules.

In addition, the Final Decision requires Energex's Pricing Proposal to set out a method of how it will review and assess the basis on which a customer is charged, where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile. Energex's compliance with this requirement for SCS tariff classes and tariffs is set out below and also in the TSS.[10]

Review of the charging basis

Energex periodically reviews the assignment of customers to tariff classes and tariffs to ensure customers are assigned to the correct tariff class and tariff. For large customers connected at the 11kV network and above, demand and volume characteristics are reviewed annually, while connection assets and network configurations are reviewed periodically or on request.

The decision making for tariff class and tariff re-assignment is similar to that used for the assignment of customers to tariff classes and tariffs set out in the TSS. Indeed, consistent with 6.18.4 of the Rules, Energex ensures customers with similar characteristics are treated equitably by specifically taking into account the nature and extent of their usage, and the nature of their connection to the network. Energex's detailed procedures for the re-assignment of customers to tariff classes and tariffs can be found in Section 5.3 and Appendix 3 of the TSS.

For customers with demand levels that fluctuate frequently, Energex may apply a reasonable tolerance limit on tariff thresholds to mitigate frequent tariff re-assignment, and subsequently limit customer impact.

Finally, it should be noted that customers requesting a tariff re-assignment are allowed only one free of charge tariff change per 12 month period. This ensures transaction costs are contained and pricing signals are not distorted by constant changes.

[10] AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control mechanisms, October 2015, page 28.

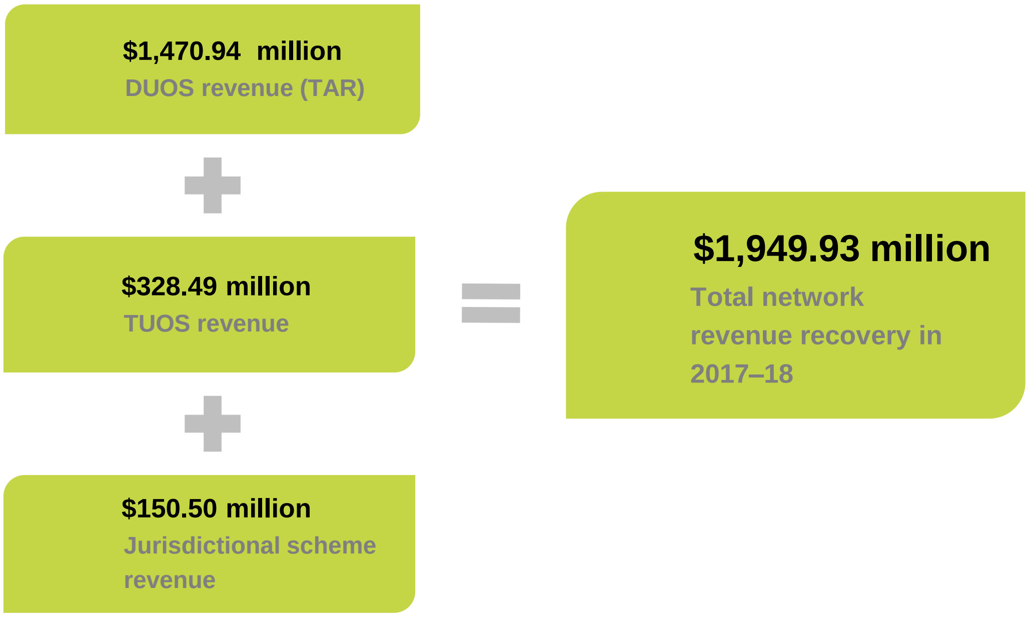
3 Tariff levels for Standard Control Services

This chapter sets out how Energex has developed its 2017-18 network charges for SCS in compliance with the regulatory requirements in Chapter 6 of the Rules.

3.1 Total Revenue Requirement for 2017-18

In 2017-18, the total revenue that Energex will need to recover from network users is approximately $1,949.93 million as shown in Figure 3-1. Detailed calculations are provided in Table 3-1.

Figure 3-1 Summary total network revenue for 2017-18



Energex's SCS are regulated under a revenue cap form of control determined by the AER in the Final Decision.[11]

The amount to be recovered by Energex through its network charges is known as the Total Annual Revenue (TAR). The TAR, which reflects Energex's smoothed expected revenue plus other annual adjustments, will be approximately $1,470.94 million in 2017-18. This is 2.09 per cent below what Energex expects to recover from network users in 2016-17.

When calculating the TAR for 2017-18, Energex has applied the revenue cap formulae set out by the AER in its Final Decision:

[11] AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanisms, October 2015.

Figure 3-2 Revenue cap formulae

1. $TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ i=1,…, n and j=1,…,m and t=1,…,5
2. $TAR_t = AR_t \pm I_t \pm B_t \pm C_t$ t=1,…,5
3. $AR_t = AR_{t-1}(1+\Delta CPI_t)(1-X_t)(1+S_t)$

Where:

AR_t is the annual smoothed expected revenue for 2017-18.

AR_{t-1} is the annual smoothed expected revenue for 2016-17.

ΔCPI_t is the annual percentage change in the ABS CPI All groups, Weighted Average of Eight Capital Cities, from the December quarter in 2015 to the December quarter in 2016.

X_t is the X-factor for 2017-18 as determined in the Post Tax Revenue Model (PTRM).

S_t is the service performance factor determined in accordance with the STPIS requirements to be applied in 2017-18.

TAR_t is the total annual revenue in 2017-18.

p_t^{ij} is the price of component j of tariff i in 2017-18.

q_t^{ij} is the forecast quantity of component j of tariff i in 2017-18.

I_t is the final carryover amount from the application of the DMIS from the 2010-15 distribution determination. This adjustment to the allowed revenue was only applicable in the 2016-17 Pricing Proposal and is no longer relevant.

B_t is the annual percentage change from the sum of:

- The under-recoveries in DUoS charges in 2014-15. This adjustment is no longer applicable from 1 July 2017.
- Any under or over recovery of actual revenue collected through DUoS charges in regulatory year t-2 (i.e. 2015-16).

C_t is the sum of the feed-in tariff (FiT) pass-through amounts relating to the 2014-15 regulatory year. This adjustment does no longer apply from 1 July 2017.

Table 3-1 below details the TAR calculation for 2017-18. The TAR is based on a building block approach, which includes:

- Each of the regulated cost components which form part of the annual smoothed expected revenue, namely: regulatory depreciation, return on capital, operating expenditure and tax allowance.
- Adjustments for carry-overs, incentive payments and pass-throughs.

In addition to the TAR, Designated Pricing Proposal Charges (DPPC)[12] and jurisdictional scheme amounts, including FiT payments made under the Solar Bonus Scheme (SBS) and the AEMC levy, are also recovered from customers.

The calculation of the TAR for 2017-18 is presented in Table 3-1 below.

[12] Transmission network charge previously known as Transmission Use of System (TUoS).

Table 3-1 2017-18 Total Revenue calculations

Component	Amount ($m)	Comments/reference
(a) Annual Revenue (AR_{t-1})	**$1,248.22**	2016-17 annual smoothed expected revenue as per the amount in the approved 2016-17 Pricing Proposal.
(b) Consumer Price Index (CPI_t)	1.48%	Annual percentage change in the CPI All Groups, Average of Eight Capital Cities from the December quarter in 2015 to the December quarter in 2016 as published on the Australian Bureau of Statistics (ABS) website.
(c) X Factor (X_t)	-19.56%	X factor for 2017-18 updated as a result of the annual return on debt update, as determined by the AER.
(d) STPIS (S_t)	-3.37%	S-factor determined in accordance with the STPIS requirements. Includes 2014-15 and 2015-16 STPIS. It is based on Energex's annual performance for 2014-15 and 2015-16 against STPIS which resulted in S-factors of 2% and 1.5% respectively.
Impact on Revenue	***$215.25***	Impact = (a)x(1+(b))(1-(c))(1+(d))-(a)
Annual Smoothed Expected Revenue 2017-18 (AR_t)	**$1,463.47**	
Adjustments:		
DMIS carryover amount (I_t)	N/A	No longer applicable.
DUoS 2015-16 under recoveries (B_t)	$7.47	Under recovery for 2015-16. Further information is provided in Section 3.3.2.
Capital contributions under recoveries (B_t)	N/A	No longer applicable.
Solar Bonus Scheme (SBS) FiT payment pass-through (C_t)	N/A	No longer applicable.
Total Annual Revenue (TAR)	**$1,470.94**	
Further adjustments:		
Jurisdictional Schemes	$150.50	Queensland SBS Jurisdictional Scheme for 2017-18 and AEMC levy amounts for 2017-18.
DPPC	$328.49	Transmission cost to be recovered in 2017-18.

Component	Amount ($m)	Comments/reference
Total Revenue Requirement[1]	**$1,949.93**	Total revenue that Energex will need to recover in 2017-18.

Note:
1. Due to rounding, individual components may not sum to the total.

3.2 Revenue allocation

Energex allocates costs to tariff classes and tariffs using the Distribution Cost of Supply (DCOS) model.

Energex's TAR is first allocated to the Energex cost groups:

- Network (system) – directly attributable costs associated with the provision of network connection and distribution services that are attributable to a single customer or group of customers. Network costs are allocated between connection assets and shared network assets based on the replacement cost of assets.
- Common services – costs associated with those system assets that benefit the system as a whole and are not directly related to any single customer or group of customers. Assets included in this category are reactive plant, load control, control centres and communications.
- Non-system – these costs include items such as corporate support and customers services, IT and communications, motor vehicles and occupancy costs that are not directly attributable to the operation and maintenance of the network but which are associated with network service delivery.

These costs combined with jurisdictional schemes and DPPC are assigned to SCS tariff classes:

- ICC
- CAC
- SAC.

A description of Energex's tariff classes is included in Chapter 2 of this Pricing Proposal.

Figure 3-3 below illustrates how Energex's 2017-18 TAR and revenue adjustments flow to the tariff classes.

Figure 3-3 2017-18 Revenue allocation flowchart

Total Annual Revenue (TAR)[1]
$1,470.9 m

Regulatory Depreciation		Return on Capital		Operating & Maintenance Costs	
$114.4 m		$865.4 m		$435.6 m	
plus Tax	$4.5 m	plus Tax	$33.9 m	plus Tax	$17.1 m
$118.9 m		**$899.3 m**		**$452.7 m**	
8.1%		61.1%		30.8%	

Distribution Cost of Supply Categories[1]		
System	Common Services	Non-system
$1,384.8 m	$15.9 m	$70.3 m

Other	
Jurisdictional schemes	DPPC
$150.5 m	$328.5 m

Allocated Costs[1]		
Individually Calculated Customers (ICC)	Connection Asset Customer (CAC)	Standard Asset Customer (SAC)
DUoS $39.2 m	DUOS $122.7 m	DUOS $1,309.1 m
DPPC $31.2 m	DPPC $45.9 m	DPPC $251.4 m
Jurisdictional schemes $3.0 m	Jurisdictional schemes $12.1 m	Jurisdictional schemes $135.4 m

Expected Revenue[1]		
Individually Calculated Customers (ICC)	Connection Asset Customer (CAC)	Standard Asset Customer (SAC)
DUoS $39.2 m	DUoS $122.7 m	DUoS $1,309.1 m
DPPC $31.2 m	DPPC $45.9 m	DPPC $251.4 m
Jurisdictional schemes $3.0 m	Jurisdictional schemes $12.1 m	Jurisdictional schemes $135.4 m

Note:
1. Due to rounding, individual components may not sum to the total

3.3 Distribution charges

3.3.1 Recovery of DUoS charges from generators

RULE REQUIREMENT

Clause 6.1.4 Prohibition of DUOS charges for the export of energy

(a) A Distribution Network Service Provider must not charge a Distribution Network distribution use of system charges for the export of electricity generated by the user into the distribution network.

In accordance with clause 6.1.4(a), DUoS charges will not be incurred for the export of electricity generated by the user into the distribution network. Generators who are net importers of electricity will receive network charges only for their use of the network related to electricity import. Where customers are net generators, and are exposed to kVA based demand charges, their export consumption will be ignored in the calculation of the charges.

3.3.2 DUoS unders and overs account

As part of the requirements of the Final Decision, the AER requires Energex to maintain a DUoS unders and overs account in its annual pricing proposal to ensure Energex does not recover any more or less than the TAR for any given year. The AER requires Energex to provide entries in its DUoS unders and overs account for the most recently completed regulatory year (t-2) and the next regulatory year (t). For this Pricing Proposal, year t-2 is 2015-16 and year t is 2017-18.[13]

In addition, the Final Decision requires Energex to achieve a closing balance as close as practicable to zero in its DUoS unders and overs account in each forecast year in the annual pricing proposal. In other words, the AER's Final Decision requires the total 2015-16 DUoS under recovery to be passed through in the 2017-18 TAR.

The AER requires the amounts used in Table 3-2 for the most recently completed regulatory year (t-2) (i.e. 2015-16) to be audited. Energex believes this requirement has been met as a consequence of the audit by Queensland Audit Office (QAO) of Energex's statutory financial statements and annual regulatory information notice. Amounts for the next regulatory year (t) are forecast amounts. The unders and overs account is detailed in Table 3-2.

Table 3-2 DUoS unders and overs account ($'000)

Unders/overs account element	2015-16 Year t-2 (actual)[1]	2017-18 Year t (forecast)[1]
Revenue from DUoS charges	1,559,680	1,470,943
Adjustment for Go Energy revenue unrecovered	-254	
(A) Revenue from DUoS charges	1,559,425	1,470,943
(B) Less Total Annual Revenue for the relevant year	1,566,074	1,470,943
+ Annual revenues (AR)	1,153,298	1,463,469
+ Demand Management Incentive Scheme carryover amount		
+ Sum of under/over recoveries (Bt) =	158,162	7,474
+ Capital contributions	47,278	
+ DUoS revenue under/over recovery approved	110,884	
+ Sum of pass through adjustments (Ct) =	254,614	
+ Feed-in tariff cost pass throughs	254,614	
+ Approved pass through amounts		

[13] AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanisms, October 2015, page 17.

Unders/overs account element	2015-16 Year t-2 (actual)[1]	2017-18 Year t (forecast)[1]
(A minus B) Under/over recovery of revenue for regulatory year	**-6,649**	**0**
DUoS Unders and Overs Account		
Nominal WACC t-2 (per cent)	6.01%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	0	-7,474
Under/over recovery of revenue for regulatory year	-6,649	7,474
Interest on under/over recovery for 2 regulatory years	-825	N/A
Closing balance	**-7,474**	**0**

Note:
1. Due to rounding, individual components may not sum to total.

The DUoS under recovery amount to be recovered in 2017-18 includes the unpaid revenue resulting from Go Energy's voluntary administration in April 2016. Energex recognised a doubtful debt of $254,373. Once the revenue determined by the administrators is finalised, Energex will conduct a true-up to ensure it does not recover any more or any less revenue than it is allowed to.

3.3.3 Forecast weighted average revenue

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(4) set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year.

The Weighted Average Revenue (WAR) for SCS tariff classes for 2016-17 and 2017-18 is outlined in Table 3-3.

Table 3-3 Expected weighted average DUoS revenue by tariff class

Tariff class	Current regulatory year 2016-17[1] ($m)	Relevant regulatory year 2017-18[1] ($m)	Change in weighted average revenue
ICC	$40.00	$39.19	-2.03%
CAC	$120.74	$122.67	1.59%
SAC	$1,351.97	$1,309.09	-3.17%
Total[2]	**$1,512.72**	**$1,470.94**	**-2.76%**

Notes:
1. Revenue excludes GST.
2. Due to rounding, individual components may not sum to the total.

3.3.4 Side constraints

RULE REQUIREMENT

Clause 6.18.6 Side constraints on tariffs for standard control services

(a) This clause applies only to tariff classes related to the provision of standard control services.

(b) The expected weighted average revenue to be raised from a tariff class for a particular regulatory year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding regulatory year in that regulatory control period by more than the permissible percentage.

(c) The permissible percentage is the greater of the following:

(1) the CPI-X limitation on any increase in the Distribution Network Service Provider's expected weighted average revenue between the two regulatory years plus 2%;

Note: The calculation is of the form (1 + CPI)(1 - X)(1 + 2%)

(2) CPI plus 2%.

Note: The calculation is of the form (1 + CPI)(1 + 2%)

(d) In deciding whether the permissible percentage has been exceeded in a particular regulatory year, the following are to be disregarded:

(1) the recovery of revenue to accommodate a variation to the distribution determination under rule 6.6 or 6.13;

(2) the recovery of revenue to accommodate pass-through of designated pricing proposal charges to retail customers;

(3) the recovery of revenue to accommodate pass-through of jurisdictional scheme amounts for approved jurisdictional schemes; and

(4) the recovery of revenue to accommodate any increase in the Distribution Network Service Provider's annual revenue requirement by virtue of an application of a formula referred to in clause 6.5.2(1).

FINAL DECISION REQUIREMENT

Energex's revenues must be consistent with the total annual revenue formulae and side constraint formulae in Attachment 14, page 13.

Under the Rules and the requirements set out by the AER in its Final Decision, Energex is required to demonstrate that the expected WAR from DUoS to be raised from a tariff class for year (t) will not exceed the side constraint formula in Equation 3-1 below.

In determining whether the permissible percentage threshold has been exceeded, Energex has applied the requirements set out in clause 6.18.6(d) of the Rules and has excluded the following:

- the recovery of revenue relating to pass through costs
- the recovery of revenue relating to the pass through of DPPC
- the recovery of revenue relating to the pass through of jurisdictional schemes
- the recovery of revenue reflecting the annual update in the cost of debt.

Equation 3-1 Side constraint formula

$$\frac{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_t^{ij} q_t^{ij})}{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_{t-1}^{ij} q_t^{ij})} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\times(1+S_t)+I_t^{'}+B_t^{'}+C_t^{'}$$

where each tariff class has "n" tariffs, with each up to "m" components, and where:

d_t^{ij} is the proposed price for component 'j' of tariff 'i' for year t.

d_{t-1}^{ij} is the price charged for component 'j' of tariff 'i' in year t–1.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory t-1 divided by the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-2.

X_t is the X factor for each year of the 2015–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 - rate of return [of the AER's Final Decision] - calculated for the relevant year. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

S_t is the s-factor determined in accordance with the STPIS for regulatory year t.

$I_t^{'}$ is the annual percentage change from the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016–17 pricing proposal.

$B_t^{'}$ is the annual percentage change from the sum of:

- any under or over-recoveries relating to capital contributions from 2013–14 and 2014–15
- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 as calculated using the method in Appendix A [of Attachment 14 of the AER's Final Decision].

$C_t^{'}$ is the annual percentage change from the sum of adjustments related to:

- feed-in tariff pass through amounts relating to 2013-2014 and 2014-2015
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events.

With the exception of the CPI, X factor and S factor, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the total annual revenue formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t).

The values used to calculate the side constraint percentage for 2017-18 as per the formula in Equation 3-2 are provided in Table 3-4.

Table 3-4 2017-18 values used in the side constraint formula

Component	Values
ΔCPI_t	1.48%
X_t	-19.56%
S_t	-3.37%
$I_t^{'}$	0.00%
$B_t^{'}$	0.49%
$C_t^{'}$	0.00%
Permissible percentage	**20.08%**

Table 3-5 below confirms that Energex's expected WAR to be raised from each tariff class for 2017-18 year is below the percentage allowed by the side constraint formula above (i.e. the permissible percentage threshold of 3.28%).

Table 3-5 Compliance with side constraint formula

Tariff class	Calculated percentage change between 2016-17 and 2017-18	Permissible percentage change
ICC	-1.37%	20.08%
CAC	1.59%	20.08%
SAC	-3.17%	20.08%

3.3.5 Avoidable and stand alone costs

RULE REQUIREMENT

Clause 6.18.5 Pricing Principles

(e) For each tariff class, the revenue expected to be recovered should lie on or between:

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

(2) a lower bound representing the avoidable cost of not serving those retail customers.

In accordance with clause 6.18.5(e) of the Rules, the revenue expected to be recovered from each tariff class should lie on or between the bounds of stand alone and avoidable costs.

The stand alone cost for a tariff class is the theoretical cost of building and operating a network designed solely for that tariff class.

The avoidable costs are the costs which would be avoided, should Energex not provide distribution services to a particular tariff class, assuming all other tariff classes continue to be served.

By requiring revenue from a tariff class to be below stand alone costs and above avoidable costs, and by collecting no more than the total allowable revenue for the year, Energex ensures it recovers efficient costs for its services.

Energex's approach to estimating the stand alone and avoidable costs for each tariff class is as follows:

- Lower bound test (avoidable cost) - includes the cost of non-contributed connections and the operating and maintenance (O&M) costs for that connection. The daily supply charge for the customer includes these costs, making it the floor price.
- Upper bound test (stand alone cost) – includes the infrastructure and O&M costs for upstream assets shared across multiple customers and tariff classes. In the case of smaller network customers connected at the LV network, the allocated cost will be well below stand alone costs as the costs for HV assets are shared with larger customers.

Details of Energex's approach to calculating the avoidable and stand alone costs is outlined in Chapter 2 of the TSS.

Table 3-6 below confirms that Energex's total revenue for 2017-18 from each tariff class falls between the stand alone and avoidable cost estimates.

Table 3-6 Demonstration of compliance with stand alone and avoidable cost test for 2017-18

Tariff class	Avoidable cost ($)	2017-18 Revenue ($)	Stand alone costs ($)
ICC	$11,994,072	$39,190,244	$43,184,310
CAC	$13,867,838	$122,667,077	$138,977,347
SAC	$59,274,143	$1,309,086,164	$1,366,411,090
Note: 1. The figures above are GST exclusive.			

3.3.6 Long run marginal cost

RULE REQUIREMENT

Clause 6.18.5 Pricing Principles

(f) Each tariff must be based on the long run marginal cost of providing to which it relates to the retail customers assigned to that tariff, having regard to:

(1) the costs and benefits associated with calculating, implementing and applying that method as proposed;

(2) the additional costs likely to be associated with meeting demand from customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the network;

(3) the location of customers that are assigned to that tariff and the extent to which costs vary between different locations in the network.

Chapter 2 of the TSS and chapter 6 of the TSS's Explanatory Notes set out the methodology used by Energex to calculate LRMC and the approach adopted when applying LRMC to its SCS tariffs.

LRMC values for 2017-18

Table 3-7 provides the LRMC values for each voltage level for 2017-18. These figures are based on those included in the 2017-20 TSS, escalated using the estimated forecast CPI.

Table 3-7 Undiversified LRMC values by voltage levels for 2017-18

Voltage level	$/kVA/month	$/kW/month	c/kWh peak energy	c/kWh energy
110/33 kV	$4.963			
11 kV Bus	$7.569			
11kV Line	$10.176			
LV business		$10.689	2.649	1.261
LV residential		$10.689	10.594	1.261
Note: 1. The figures are exclusive of GST.				

Application of LRMC in tariff setting

The LRMC values have been incorporated in the demand charge parameter of the demand based tariffs as it is considered the most suitable mechanism to signal the cost of future network augmentation. For the tariffs without a demand charge parameter, LRMC has been allocated to the peak usage charge of ToU usage tariffs (ie Residential ToU (NTC8900) and Business ToU (NTC8800)) and flat usage charge of the anytime usage tariffs (ie Residential Flat (NTC8400) and Business Flat (NTC8500)).

For the newly introduced cost reflective tariffs, the demand charging parameter has been set to the full LRMC value from the first day they are offered. In contrast, recognising the impact of tariff reform on customers, legacy tariffs will gradually be transitioned to cost reflectivity.

3.3.7 Response to price signal

RULE REQUIREMENT

Clause 6.18.5 Pricing Principles

(g) The revenue expected to be recovered from each tariff must:

(1) reflect the DNSP's total efficient costs of serving the retail customers that are assigned to that tariff

(2) when summed with the revenue expected to be received from all other tariffs, permit the DNSP to recover the expected revenue for the relevant services in accordance with the applicable distribution determination

(3) comply with (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).

Clause 6.18.5(g) requires that Energex recovers its efficient costs in a way that minimises distortion to the price signal. For each tariff, Energex meets this requirement by identifying a tariff charge parameter that will be used to signal LRMC (see Section 3.3.6 above for further details) and recovering the residual revenues through other tariff charge parameters.

This means that for cost reflective tariffs available on 1 July 2017 (i.e. NTC7000, NTC7100 and NTC7400) the revenue shortfall will be recovered from the fixed and usage charges. For these tariffs, the demand charge parameter is solely used to signal the efficient usage of the network.

It should also be noted that for legacy tariffs some residual revenues are recovered from the same tariff charge parameter that signals LRMC. In 2017-18 Energex will continue to transition the legacy tariffs so that the charging parameters conveying the price signal get closer to the LRMC based value.

Further details on this matter are provided in the section 2.4.2 of the TSS.

3.3.8 Tariff simplicity

RULE REQUIREMENT

Clause 6.18.5 Pricing Principles

(i) The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to:

(1) The type and nature of those retail customers; and

(2) The information provided to, and the consultation undertaken with those retail customers.

The structures of Energex's tariffs have been developed in consideration to the feedback received as a result of the ongoing engagement with customers and stakeholders as part of the development of its TSS. Energex considers that its tariffs strike the right balance between cost reflectivity and customers' ability to understand and respond to the pricing signals.

Further details are provided in the TSS and associated Explanatory Notes.

3.4 Designated Pricing Proposal Charges

RULE REQUIREMENT
Clause 6.18.2(b)(6) Pricing proposals
A pricing proposal must set out how designated pricing proposal charges are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year.

Under the Rules, Energex is able to recover transmission-related costs associated with:

- the use of Powerlink's transmission network to deliver high voltage electricity from generators to Energex's distribution network
- avoided transmission (TUoS) charges paid to eligible EGs
- payments made to other DNSPs for the supply of distribution services.

These costs are recovered from customers through designated pricing proposal charges (DPPC), or TUoS charges, which form part of Energex's network tariffs.

In accordance with clauses 6.18.2(b)(6) and 6.18.7(b) the DPPC amount to be passed on to customers must not exceed the estimated amount of the DPPC adjusted for any over or under recovery.

Furthermore, Energex does not recover DPPC charges through its revenue requirement, jurisdictional scheme or from other DNSPs (clause 6.18.7(d)).

3.4.1 DPPC expenses

3.4.1.1 DPPC paid to TNSPs (Powerlink)

Powerlink charges Energex at the Transmission Connection Point level. Their charges comprise both daily supply and variable charges, namely:

- Entry/Exit Connection Price ($/month)
- Capped Customer TUoS Usage Price: Usage Capacity Price ($/kW/month of nominated demand plus $/kW/month average demand)
- Customer TUoS General Prices: General Energy Charge (c/kWh of historical energy)
- Transmission Customer Common Service Prices: Common Service Energy Price (c/kWh on historical energy).

Energex is also currently charged by Powerlink for the entry and exit of services provided at the 110kV network from Rocklea to Archerfield. Clause 11.39.7 of the NER provided that Energex could recover these costs as DPPC up until 30 June 2015.

The AER has advised Energex that these charges can continue to be recovered as DPPC from 1 July 2015, on the basis that when the transitional arrangement under clause 11.39.7 of the Rules expired, the charges became a prescribed service from that time and therefore qualified as DPPC.

3.4.1.2 Avoided customer TUoS charges

RULE REQUIREMENT	
Clause 5.5 Access arrangements relating to Distribution Networks	
(h)	**A Distribution Network Service Provider must pass through to a Connection Applicant the amount calculated in accordance with paragraph (i) for the locational component of prescribed TUoS services that would have been payable by the Distribution Network Service Provider to a Transmission Network Service Provider had**

the Connection Applicant not been connected to its distribution network ('avoided charges for the locational component of prescribed TUoS services').

(i) To calculate the amount to be passed through to a Connection Applicant in accordance with paragraph (h), a Distribution Network Service Provider must, if prices for the locational component of prescribed TUOS services were in force at the relevant transmission network connection point throughout the relevant financial year:

(1) determine the charges for the locational component of prescribed TUOS services that would have been payable by the Distribution Network Service Provider for the relevant financial year:

(i) where the Connection Applicant is an Embedded Generator, if that Embedded Generator had not injected any energy at its connection point during that financial year;

(ii) where the Connection Applicant is a Market Network Service Provider, if the Market Network Service Provider had not been connected to the Distribution Network Service Provider's distribution network during that financial year; and

(2) determine the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the Distribution Network Service Provider, which amount will be the relevant amount for the purposes of paragraph (h).

Payments associated with avoided TUoS to EGs by Energex reflect the avoided costs of upstream transmission network reinforcement. In accordance with the Rules, to calculate the avoided TUoS payments for EGs, Energex will:

(a) Determine the charges for the locational component of prescribed DPPC services that would have been payable by Energex had the EG not injected any energy at its connection point during that financial year.

(b) Determine the amount by which the charges calculated in (a) exceeds the amount for the locational component of prescribed DPPC services actually payable by Energex.

(c) Credit the value from (b) to the EG account.

For 2017-18, avoided TUoS payments will generally be remitted in the form of a lump sum payment after 30 June 2018, similar to previous years.

Since avoided TUoS does not solely impact on the TNCP to which the EG is connected and the benefits of avoided TUoS relate to all customers, the recovery of the avoided TUoS payments made to EGs has been assigned to all tariff classes.

The total amount in avoided TUoS payments made to EGs in 2017-18 is included in Table 3-9.

3.4.1.3 Payment to other DNSPs

In contingency circumstances, Essential Energy (the DNSP in northern New South Wales) provides supply from its Terranora Substation to Energex's Kirra Zone Substation. Under this arrangement, Essential Energy requires Energex to pay for the use of its assets.

The charges established by Essential Energy in respect of this arrangement are based on approved rates for each month in which the alternate supply is utilised. These costs have been incorporated into the costs for the Mudgeeraba TNCP and are consequently passed through to users. The amount to Essential Energy paid in 2017-18 is included in Table 3-9.

3.4.2 Recovery of DPPC (revenue)

Where administratively efficient, the forecast DPPC will be passed on to customers in the same form of price structure as it is received.

For ICCs, Energex's network tariffs preserve the economic signals present in the structure of the DPPC as the charges are based on the relevant transmission connection point. This provides the greatest cost-reflectivity for these customers and is a feasible method for calculating charges since the number of such customers is relatively small.

DPPC charges for CAC tariffs are based on average DPPC charges. This provides a significant degree of cost-reflectivity for this group of customers while recognising the practical difficulties of calculating individual charges for each customer connected at the 11 kV network.

DPPC cost amounts are allocated to SAC tariffs proportionally based on a mixture of average monthly maximum demands and volumes, and recovered from the same tariff structure as DUoS charges (fixed charge, maximum demand and/or volume charge). However, for the newly introduced residential demand tariff (NTC7000 – Residential Demand) and small business demand tariff (NTC7100 – Business Demand), Energex will not recover DPPC from the fixed charge parameter, but rather from the demand charging parameter to strengthen the network LRMC signal.

A forecast of the DPPC is provided to Energex by Powerlink in March each year, allowing Energex to develop tariff components for recovery of the anticipated costs.

The network charging parameters applied to each tariff for the recovery of DPPC are detailed in Table 3-8 below.

Table 3-8 DPPC recovery from tariff charging parameters

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameters							
			Daily supply charge ($/day/ $M-CAV)	Daily supply charge ($/day/ $M-NCCAV)	Daily supply charge ($/day)	Monthly maximum demand charge ($/kVA/ month)	Monthly maximum demand charge ($/kW/ month)	Excess demand ($/kVA/ month)	Usage charge flat (c/kWh)	Usage charge ToU (c/kWh)
ICC	ICC	1000			✓	✓[1]				✓[2]
CAC	EG 11 kV	3000[3]			✓	✓				✓
	11 kV Line	4500			✓	✓				✓
	11 kV Bus	4000			✓	✓				✓
	HV Demand	8000[3]			✓	✓				✓
	Demand ToU 11kV	7400[4]				✓		✓	✓	
SAC	Demand Large	8100			✓	✓			✓	
	Demand Small	8300			✓	✓			✓	
	Business Flat	8500			✓				✓	
	Business ToU	8800			✓					✓

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameters							
	Business Demand	7100[4]					✓		✓	
	Residential Flat	8400			✓				✓	
	Residential ToU	8900			✓					✓
	Residential Demand	7000[5]					✓		✓	
	Solar FiT	9900		N/A						
	Super Economy	9000							✓	
	Economy	9100							✓	
	Smart Control	7300[5]							✓	
	Unmetered	9600							✓	
	Notes: 1. Monthly maximum demand charge for ICCs is the locational charge as published by Powerlink and consists of the nominated demand plus average demand multiplied by rate. 2. Usage (volume) charge for ICCs is a combination of general and common charge as published by Powerlink. 3. These tariffs will no longer be offered to new customers from 1 July 2015. 4. Cost reflective tariff offered from 1 July 2017. 5. Cost reflective tariff offered since 1 July 2016.									

The total DPPC revenue received is indicated in Table 3-9 below.

3.4.3 DPPC unders and overs accounts

FINAL DECISION REQUIREMENT

Energex must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from DPPC and associated payments in accordance with Appendix B of Attachment 14.

In accordance with the Rules and the requirements set out in the Final Decision, Energex is required to provide amounts for the following entries in its DPPC unders and overs account for the most recently completed regulatory year (t-2) and the next regulatory year (t). For this 2017-18 Pricing Proposal, year t-2 is 2015-16 and year t is 2017-18.

The unders and overs account is detailed in Table 3-9 below.

In proposing variations to the amount and structure of DPPC for a given regulatory year (t), Energex will achieve a zero expected balance on the DPPC unders and overs account at the end of each regulatory year in the regulatory control period.

The AER requires the amounts used in the table below for the most recently completed regulatory year (t-2) (i.e. 2015-16) to be audited.[14] Energex believes this requirement has been met as part of the statutory or regulatory account audits certified by Queensland Audit Office (QAO).

DPPC amounts for the regulatory year (t) are forecast amounts.

Table 3-9 DPPC unders and overs account

Unders/overs account element	2015-16 actual ($'000)	2017-18 forecast ($'000)
(A) Revenue from DPPC charges	454,085	328,485
(B) Less DPPC related payments for regulatory year =	446,611	328,485
DPPC charges to be paid to TNSP	432,723	335,997
Avoided TUoS payments	496	521
Inter-distributor payments[1]	352	370
DPPC revenue under/over recovery approved	13,040	-8,402
(A minus B)Under/over recovery for regulatory year	**7,474**	**0**
Unders and Overs Account		
Nominal WACC t-2 (per cent)	6.01%	N/A
Nominal WACC t-1 (per cent)	6.04%	N/A
Opening balance	0	8,402

[14] AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanisms, October 2015, page 19.

Unders/overs account element	2015-16 actual ($'000)	2017-18 forecast ($'000)
Under/over recovery of revenue for regulatory year	7,474	-8,402
Interest on under/over recovery for 2 regulatory years	928	N/A
Closing balance[2]	**8,402**	**0**

Notes:

1. Payments to Essential Energy for the supply from its Terranora Substation to Energex's Kirra Zone Substation.
2. Due to rounding, individual components may not sum to total.

3.5 Jurisdictional schemes

RULE REQUIREMENT

Clause 6.18.2(b) Pricing proposals

A pricing proposal must:

> **(6A) set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts;**
>
> **(6B) describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.**

Clause 6.18.7A Recovery of jurisdictional scheme amounts

> **(a) A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider's jurisdictional scheme amounts for approved jurisdictional schemes.**

Energex is subject to two jurisdictional schemes: SBS and the AEMC industry levy.

Under the SBS, Energex is required to allow customers to connect their qualifying small solar PV generators to its distribution network so that they can export their surplus electricity generated from solar PV systems. Energex is obliged to make FiT payments to customers through the operation of clause 44A of the Electricity Act 1994 (QLD).

Customers who joined the scheme before 10 July 2012 and continue to meet eligibility requirements are paid 44 cents per kWh for surplus electricity fed into the grid. Those customers will continue to receive a FiT payment at this rate until 30 June 2028. The cost of the FiT incentives required under the SBS is funded by electricity consumers within each distribution area.

Since 22 March 2016, Energex's Distribution Authority (DA) requires Energex to pay a new industry levy covering the Queensland's funding commitment to the AEMC for the work it performs under the Law. Subsequently, the AER approved Energex's application to treat the AEMC levy as a jurisdictional scheme under clause 6.18.7A of the Rules on 26 April 2016.

Energex confirms that there have been no amendments to its jurisdictional schemes since they were approved and, therefore, clause 6.18.2(b)(6B) does not apply to this Pricing Proposal.

3.5.1 Forecast of jurisdictional scheme amounts

The estimated jurisdictional scheme amount to be recovered in 2017-18 is $150.5 million. It comprises $150.3 million in SBS FiT payments (inclusive of $17 million in over recovery) and $0.16 million in AEMC levy.

The approach used by Energex to determine its forecast jurisdictional scheme amounts is set out in the section below.

SBS FiT payments to customers

Energex has established the forecast value of SBS FiT payments to be recovered in 2017-18 based on historical trends using actual SBS payments and information to 31 March 2017 and by applying the following formula:

Equation 3-3 Formula for calculation of forecast SBS payments

Forecast SBS payments are calculated as follows:

SBS FiT payments = feed-in tariff rate x estimated exported energy;

where estimated exported energy = forecast number of eligible systems x estimated annual exported energy per system.

Estimated exported energy is reviewed annually against actual outcomes to ensure continued accuracy of the estimate. Table 3-10 includes the values of the inputs used to estimate the 2017-18 SBS FiT payments.

Table 3-10 Forecast for 2017-18 SBS FiT payments

SBS FiT payment calculation	2017-18
Average export per system (GWh)	380.3
Export rate (c/kWh)	0.44
Solar FiT Payment ($M)	**$167.3**
Over recovery[1]	(17.0)
Total Solar Fit Payment ($M)	**$150.3**

Note:
1. Refer to Section 3.5.3 for further details.

Forecast of the AEMC Levy

The levy amount payable by Energex will be determined by the Queensland Government each financial year. Energex has been advised that the calculation of the levy for Queensland's DA holders will be set at five per cent of Queensland's total annual funding requirement for the AEMC. The apportionment between Energex and Ergon Energy will be done in accordance with the relative customer numbers reported to the Queensland Government each October for the preceding financial year. The AEMC Levy amount for 2017-18 is expected to be $162,694.

3.5.2 Recovery of jurisdictional scheme payments from tariffs and charging parameters

Payments made as jurisdictional schemes are excluded from the control mechanism formula set out for SCS, and therefore are not included in DUoS charges. To determine total revenue upon which Energex sets its prices, SBS FiT and AEMC levy payments have been added to the TAR as a revenue adjustment.[15]

The Final Decision does not stipulate any particular methodology or approach Energex should follow for the recovery of jurisdictional schemes from customers.

[15] As discussed in Section 3.1, DPPC is also added to TAR as a revenue adjustment.

The jurisdictional scheme payments are passed through to all customers in a cost reflective, efficient and equitable manner. Energex's allocation methodology is outlined below:

1) Jurisdictional scheme payments are allocated to all SCS tariffs proportional to the allocation of shared network revenues for each tariff.
2) Jurisdictional scheme amounts are then allocated to the tariff charging parameters in the following manner:
    a. Allocation to fixed charging parameter ($/day) based on the value of connection assets for each tariff.
    b. Allocation of the remaining amounts to the variable charging parameters - usage on a c/kWh basis.

For secondary load control tariffs, the recovery of jurisdictional schemes is through the usage charging parameter only.

The allocation of the jurisdictional schemes to network tariffs and charging parameters is presented in Table 3-11.

Table 3-11 Jurisdictional schemes recovery from tariff charging parameters

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameters							
			Daily supply charge ($/day/ $M-CAV)	Daily supply charge ($/day/ $M-NCCAV)	Daily supply charge ($/day)	Monthly maximum demand charge ($/kVA/ month)	Monthly maximum demand charge ($/kW/ month)	Excess demand ($/kVA/ month)	Usage charge flat (c/kWh)	Usage charge ToU (c/kWh)
ICC	ICC	1000			✓					✓
CAC	EG 11 kV	3000[1]			✓					✓
	11 kV Line	4500			✓					✓
	11 kV Bus	4000			✓					✓
	HV Demand	8000[1]			✓					✓
	Demand ToU 11kV	7400[2]			✓					✓
SAC	Demand Large	8100			✓				✓	
	Demand Small	8300			✓				✓	
	Business Flat	8500			✓				✓	
	Business ToU	8800			✓					✓

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameters							
	Business Demand	7100[2]			✓				✓	
	Residential Flat	8400			✓				✓	
	Residential ToU	8900			✓					✓
	Residential Demand	7000[3]			✓				✓	
	Solar FiT	9900		N/A						
	Super Economy	9000							✓	
	Economy	9100							✓	
	Smart Control	7300[3]							✓	
	Unmetered	9600							✓	

Notes:

1. These tariffs are no longer offered to new customers since 1 July 2015.
2. New cost reflective tariff offered from 1 July 2017.
3. Cost reflective tariff offered since 1 July 2016.

3.5.3 Jurisdictional scheme payments unders and overs account

RULE REQUIREMENT

Clause 6.18.7A Recovery of jurisdictional scheme amounts

Pricing Proposal

> **(b) The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a Distribution Network Service Provider's approved jurisdictional schemes adjusted for over or under recovery in accordance with paragraph (c).**
>
> **(c) The over and under recovery amount must be calculated in a way that:**
>
> **(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges;**
>
> **(2) ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and**
>
> **(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.**

FINAL DECISION REQUIREMENTS

To demonstrate compliance with the distribution determination applicable to it during the 2015-20 regulatory control period, Energex must maintain a jurisdictional scheme amounts unders and overs account in its annual pricing proposal in accordance with Appendix C of Attachment 14.

As part of the requirements set out in the Rules and the AER's Final Decision,[16] Energex is required to provide amounts for the unders and overs relating to jurisdictional schemes for the most recently completed regulatory year t-2, being 2015-16, and the regulatory year t, being 2017-18.

The unders and overs account is detailed in Table 3-12 below.

Table 3-12 Jurisdictional scheme amounts unders and overs account

Unders/overs account element	2015-16 actual ($'000)	2017-18 forecast ($'000)
(A) Revenue from jurisdictional schemes	202,184	150,499
(B) Less jurisdictional scheme payments for regulatory year =	187,078	150,499
+ SBS FiT payments	186,934	167,318
+ AEMC Levy payments	144	162
+ Jurisdictional scheme amounts revenue under/over recovery approved		-16,981
(A minus B)Under/over recovery for regulatory year	**15,106**	**0**
Jurisdictional scheme amount unders and overs account		
Nominal WACC t-2 (per cent)	6.01%	

[16] AER, Final Decision Energex Determination 2015-20 to 2019-20, Attachment 14 – Control Mechanisms, Appendix C, October 2015.

Unders/overs account element	2015-16 actual ($'000)	2017-18 forecast ($'000)
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	0	16,981
Under/over recovery of revenue for regulatory year	15,106	-16,981
Interest on under/over recovery for 2 regulatory years	1,875	N/A
Closing balance[1]	**16,981**	**0**
Note: 1. Due to rounding, individual components may not sum to total.		

3.6 Demand, energy and customer number forecasts

RULE REQUIREMENT

Clause 6.18.8(a)(3) Approval of pricing proposal

The AER must approve pricing proposal if the AER is satisfied that, among other things, all forecasts associated with the proposal are reasonable

In Energex's 2015-20 Regulatory Proposal, Energex provided the AER with details on the key drivers underpinning its demand and energy forecasts, and expected customer numbers throughout the 2015-20 regulatory control period.[17] These were also included in Section 4.3 of the Explanatory Notes accompanying the TSS.

Using the same methodology, the forecasts for 2017-18 use the most up to date assumptions and inputs to further refine and ensure greater accuracy to derive network charges for 2017-18. The forecast demand, energy and customer numbers for 2017-18 are included in Table 3-13.

Table 3-13 2017-18 demand, energy and customer number forecasts

Tariff class	ICC	CAC	SAC	Total
Average Demand (MVA)	406,738	811,829	1,611,110	**2,829,677**
Undiversified Average Maximum Demand (MW)	369,188	753,549	8,256,774	**9,379,510**
Volume (GWh)	1,974.1	3,732.3	15,245.2	**20,951.6**
Customer numbers	56	551	1,448,278	**1,448,885**
Notes: 1. Undiversified demand assumes all customers are utilising the network at the same time. 2. Maximum demand (MW) used to allocate costs to tariffs. 3. Demand in MW for small non-demand customers was derived from the volumes to which a specific load factor was applied.				

[17] Energex's Regulatory Proposal June 2015 to June 2020, November 2014.

3.7 2017-18 SCS charges

The proposed network charges for 2017-18 for all SCS tariffs are included in Appendix 1 of this Pricing Proposal.

4 Alternative control services

Services provided under the ACS framework are customer specific and/or customer requested services. These services may also have potential for provision on a competitive basis rather than by a single DNSP. ACS are akin to a 'user-pays' system. The whole cost of the service is paid by those customers who benefit from the service, rather than recovered from all customers.

ACS are either subject to a price cap (fee based services), whereby the price is set in accordance with specified service assumptions due to the standardised nature of the service, or a price on application (quoted services) where the service is of a nature and scope which cannot be known in advance.

4.1 ACS tariff classes

RULE REQUIREMENT

Clause 6.18.3 Tariff classes

(b) Each customer for direct control services must be a member of 1 or more tariff classes.

(c) Separate tariff classes must be constituted for retail customers to whom alternative control services are supplied

(d) A tariff class must be constituted with regard to:

(1) the need to group retail customers together on an economically efficient basis; and

(2) the need to avoid unnecessary transaction costs.

Clause 6.18.3(b) requires that each customer for ACS be a member of one or more tariff classes.

Aligning with the TSS, the ACS tariff classes for this Pricing Proposal are defined in Table 4-1.

Table 4-1 ACS tariff classes

Tariff class	Nature of services
Connection Services	Pre connection (other than general connection enquiry service). Connection (other than small customer connections). Post Connection (other than operating and maintaining connection assets). Accreditation/Certification.
Ancillary Network Services	Services provided in relation to the retailer of last resort. Other recoverable works.
Metering Services	Type 6 Metering Services. Auxiliary Metering Services.
Public Lighting Services	Provision, construction and maintenance of public lighting.

Tariff class	Nature of services
	Other public lighting. Emerging public lighting.

In accordance with clause 6.18.3(d)(1) and (2), the ACS tariff classes were developed having regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transaction costs. Compliance with this clause requires a balance between sending efficient price signals to individual customers and the cost of having too many tariff classes.

4.2 Control mechanisms

Energex's prices and/or pricing methodologies for ACS in 2017-18 have been developed in accordance with the AER's Final Decision and the TSS.

4.2.1 Control mechanism for price cap services

There are two main control mechanisms relevant for price cap ACS. The first approach is applied to public lighting services (provision, installation and maintenance) and metering services (Type 6) for which the initial value was based on a limited building block approach.

The charges for these services are developed using the following approach:

- a limited building block approach in the first year of the 2015-20 regulatory control period
- prices for the subsequent years will be determined in accordance with the control mechanism formula in Equation 4-1 and escalated from one year to the next based on changes in CPI and application of X and A factors (metering service charge).

The second price cap approach is applied to connection, ancillary network, auxiliary metering and other public lighting services and consists of the following two step process:

- a schedule of price capped ACS for the first year of the 2015-20 regulatory control period as approved by the AER in its Final Decision based on submitted service assumptions and proposed costings
- prices and rates for the subsequent years will be determined in accordance with the control mechanism formula in Equation 4-1 and escalated from one year to the next based on changes in the CPI and application of X factors which reflect changes in cost escalators and on-costs.

To calculate the prices for price cap services for 2017-18, Energex has applied the approved control mechanism formula in Equation 4-1.

Equation 4-1 Control mechanism formula for price cap services

$$p_t^i = p_{t-1}^i (1+\Delta CPI_t)\left(1-X_t^i\right) + A_t^i$$

Where:

p_t^i is the cap on the price of service in year t

p_{t-1}^i is the cap on the price of service in year t-1

ΔCPI_t is the annual percentage change in the ABS CPI All groups, Weighted Average of Eight Capital Cities from the December quarter in year t-2 to the December quarter in year t-1.

X_t^i is the X factor for service i in year t

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life.

In calculating the prices for 2017-18 price cap services, Energex used the CPI value of 1.48 per cent. Energex also applied the relevant X factors in accordance with the Final Decision.[18] These are summarised in Table 4-2 below.

Table 4-2 2017-18 X factors and escalations for price capped services

Service Description	X factor %	Escalation %[1]
Limited Building Block:		
Public Lighting	(0.98)	2.47
Metering Services Charge		
Non Capital Component	(2.00)	3.51
Capital Component	(1.00)	2.49
Price Cap (fee based services)	(0.61)	2.1
Upfront Meter Capital Charge		
Single phase one element	(0.37)	1.86
Single phase two elements	(0.37)	1.86
Multi-phase	(0.37)	1.86
Multi-phase with Current transformer	(0.37)	1.86

Note:

1. $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 where CPI is 1.48% and A_t^i is nil.

It can be noted that unlike SCS, the WACC is not updated annually to reflect changes in the cost of debt.

[18] AER, Final Decision Energex Determination 2015-20 to 2019-20, Attachment 16 – Alternative Control Services, Appendix A, October 2015.

4.2.2 Control mechanism for quoted services

Prices for quoted services are determined at the time the customer makes an enquiry. They reflect the individual nature of the service requested and vary based on the resources required to deliver the type of services requested. To develop the prices for quoted services in 2017-18, Energex applies the AER approved formula outlined in Equation 4-2. This formula includes cost parameters for different services which are representative of the efficient costs of providing and delivering the services.

Equation 4-2 Formula for pricing quoted services

Price = Labour + Contractor Services + Materials + Capital Allowance + GST

where:

Labour is all labour costs directly incurred in the provision of the service, labour on-costs, fleet on-costs and overheads. The labour cost for each service is dependent on the skill level, travel time, number of hours and crew size required to perform the service.

Contractor services is all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service (e.g. traffic control, road closure permits).

Materials is the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

Capital allowance is a return on, and return of, capital for non-system assets used in the delivery of the service.

GST is Goods and Services Tax, where applicable.

The Final Decision sets out the approved hourly labour rates for 2015-16 to be utilised for the purpose of Equation 4-2. From 2016-17 onwards the base labour rates for 2015-16 will be escalated annually by $(1+\Delta CPI_t)(1-X_t^i)$. For 2017-18 the CPI value is 1.48 per cent and the X-factor is - 0.61 per cent, resulting in an escalation rate of 2.10 per cent as shown in Table 4-3. Other costs are determined at the time when the quote request is made.

Table 4-3 2017-18 X factor and escalation for quoted services

Service Description	X factor %	Escalation %[1]
Labour component of quoted services	(0.61)	2.10

Note

1. $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 where CPI is 1.48% and A_t^i is nil.

4.3 Charging parameters

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(2) set out the proposed tariffs for each tariff class that is specified in the Distribution Network Service Provider's tariff structure statement for the relevant regulatory control period.

(3) set out for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates.

In accordance with clause 6.18.2(b)(2) of the Rules, Energex's Pricing Proposal sets out the ACS tariffs which have been specified in Energex's approved TSS for the 2017-20 period. These tariffs are included in Appendix 1.

Clause 6.18.2(b)(3) of the Rules requires that Energex's Pricing Proposal sets outs the charging parameters utilised to calculate the charges for ACS connection, metering, public lighting and ancillary services. The charging parameters outlined in Table 4-4 below are consistent with the TSS.

Table 4-4 Charging parameters for ACS

Service	Charge	Charging parameter	Control mechanism formula
Connection services	Fixed charge	Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.2.1
	Quoted service	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver it.	Refer section 4.2.2
Metering services	Fixed charges	Metering services charge: ($) per day per tariff. Metering service charges differ by: • The type of metering service (primary, controlled load, solar PV); and • The type of cost recovery (capital, non-capital).	Refer section 4.2.1
		Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.2.1
	Quoted service	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver it.	Refer section 4.2.2
Public lighting services	Fixed charges	Fixed rate ($) per day per light.	Refer section 4.2.1
		Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.2.1
	Quoted service	Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.2.2
Ancillary services	Fixed charge	Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.2.1
	Quoted service	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver it.	Refer section 4.2.2

4.4 Compliance with pricing principles

Energex's ACS tariffs have been developed in accordance with the Rules and the TSS. Further details on Energex's compliance with the pricing principles are provided in the TSS.

4.4.1 Avoidable and stand alone costs

Clause 6.18.5(e) of the Rules requires that for each tariff class, the revenue expected to be recovered should lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class and a lower bound representing the avoidable cost of not serving those customers.

Energex's compliance with this pricing principle is set out in Section 6.3.2 of the TSS.

4.4.2 Long run marginal costs and response to price signals

Clause 6.18.5(f) of the Rules requires that Energex's customers requesting ACS be exposed to the future efficient costs of the services they seek and have the ability to respond by modifying their request.

The TSS provides that, because ACS are priced on a price path basis, an LRMC based pricing approach cannot be adopted. However, it can be noted that by virtue of being customer specific or customer driven services, ACS vary in accordance with the specific needs and requirements of customers who have the ability to respond to the efficient costs of these services.[19]

4.4.3 Price signal

Under the formula based approach, customers are sent signals about the true cost of the service that they are able to request. This helps ensure that customers will only use a service if they believe they will gain a larger benefit from the service than it costs Energex to provide that service in the long term. This helps ensure that ACS are provided to customers up to the point where the marginal benefits from using the service equals the marginal costs that use of the service imposes on Energex. This is consistent with economic efficiency.

In the case of quoted services, customers will have incentives to consider whether a different variant of the service may be preferable (e.g. customers can minimise the cost incurred for some services by choosing to have the service delivered during business hours, if applicable). This, too, is consistent with economic efficiency principles.

By their nature, most ACS are services requested by customers that vary according to the specific characteristics or circumstances of the customer. This suggests that customers have the ability and incentive to respond to cost reflective tariffs for these services.

4.5 Tariff assignment policies

In accordance with clause 6.18.1A of the Rules, Energex's policies and procedures governing the assignment and reassignment of customers to tariff classes and tariffs are included in Energex's TSS.

Prior to the provision of an ACS, Energex's customers will be assigned to the relevant tariff class based on the type of ACS required. Similar to the tariff class membership requirement

[19] Energex, 2017-20 Tariff Structure Statement, Section 6.3.1, page 40.

for SCS, ACS customers will not receive the service prior to being allocated to the appropriate tariff class.

4.6 Intra-period adjustments to ACS

On 1 December 2017, the AEMC's recommendations in the Power of Choice review will be implemented in Queensland. Under these new arrangements Energex will no longer be responsible for providing metering installations as they will become subject to contestability and will only provide metering services to existing regulated meters as long as they are in operation. As a result, in December 2017, a number of ACS services will be discontinued or have the metering provision component stripped out of the service with the remaining service components covering the services still performed by Energex. The revised ACS charges will be less than those approved by the AER as part of the pricing proposal process.

The list of services which will be amended and the proposed mechanism to calculate the charges in December 2017 are further detailed in Section 5.3.2 and Appendix 4 of this Pricing Proposal.

4.7 2017-18 ACS charges

The proposed charges for 2017-18 for all ACS tariffs are included in Appendix 1 of this Pricing Proposal.

5 Other Compliance

This chapter covers Energex's compliance with regulatory requirements which have not been covered in Chapters 2, 3 and 4 of this Pricing Proposal.

5.1 Customer impact

RULE REQUIREMENT

Clause 6.18.5 Pricing Proposals

(h) A DNSP must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraph (e) to (g) to the extent the DNSP considers reasonably necessary.

ICC and CAC tariffs comprise confidential site-specific charges, and consequently customer specific impact analysis is not included. However, general trends in ICC and CAC customer impacts between 2016-17 and 2017-18 are presented in Table 5-1. The average impact figures have been calculated based on the revenue Energex would recover using the 2017-18 approved rates relative to the revenue Energex would recover using the 2016-17 rates.

Table 5-1 Average customer impacts for the ICC and CAC tariff classes

Tariff Class	Impact	DUoS annual impact (%)	Jurisdictional schemes annual impact (%)	DPPC annual impact (%)	NUoS annual impact (%)
ICC	Average Impact	-1.37%	-16.84%	-30.06%	-16.81%
CAC	Average Impact	1.59%	-11.23%	-32.98%	-10.94%

In 2017-18, ICC and CAC customers will experience a significant decrease in their NUoS charges over the previous year with an average reduction of approximately 16.8 per cent for ICC customers and 10.9 per cent for CAC customers.

Analysis undertaken by Energex on the network price movements that may be experienced by customers on tariffs within the SAC tariff class is included in Table 5-2 below.

The network prices used for the analysis comprise total annual NUoS excluding GST. These NUoS prices are the AER approved prices for 2016-17 and the proposed 2017-18 prices included in this document (refer to Appendix 1) for AER approval.

To eliminate the impact of fluctuation in demand and energy between years, the same usage and demand profiles were used to calculate customers' bills for both 2016-17 and 2017-18.

Table 5-2 Customer impact scenarios for customers on SAC tariffs

Demand based tariffs	Usage / demand types	Usage MWh/year	Monthly demand (kVA/month)	2016-17 NUoS ($)	2017-18 NUoS ($)	Annual NUoS increase/ decrease ($)	Annual NUoS increase (%)
Demand Large – NTC8100	Lowest	1,107	309	$101,472	$90,653	-$10,819	-10.7%
	Typical	1,575	383	$126,113	$111,674	-$14,439	-11.4%
	Highest	2,140	492	$160,203	$141,176	-$19,027	-11.9%
Demand Small – NTC8300	Lowest	132	41	$15,411	$13,427	-$1,984	-12.9%
	Typical	217	71	$25,029	$21,819	-$3,210	-12.8%
	Highest	405	124	$42,797	$37,178	-$5,619	-13.1%
Volume based tariffs	**Usage type**	**Primary tariff - Usage (MWh/year)**	**Secondary tariff - Usage (MWh/year)**	**2016-17 NUoS ($)**	**2017-18 NUoS ($)**	**Annual NUoS increase/ decrease ($)**	**Annual NUoS increase (%)**
Business Flat – NTC8500	Lowest	1.7		$475	$434	-$41	-8.7%
	Typical	6.4		$1,062	$978	-$84	-7.9%
	Highest	17.6		$2,460	$2,276	-$184	-7.5%
Business ToU – NTC8800	Lowest	3.8		$720	$678	-$42	-5.8%
	Typical	21.4		$2,841	$2,724	-$117	-4.1%
	Highest	51.1		$6,406	$6,164	-$242	-3.8%
Residential Flat – NTC8400	Lowest	2.5		$474	$431	-$42	-8.9%
	Typical	4.0		$648	$585	-$63	-9.7%
	Highest	6.0		$881	$790	-$91	-10.3%
Business Flat – NTC8500 combined with Economy – NTC9100	Lowest	3.6	0.4	$751	$688	-$63	-8.4%
	Typical	9.2	1.1	$1,518	$1,397	-$121	-8.0%
	Highest	20.8	2.2	$3,073	$2,835	-$238	-7.8%
Residential Flat – NTC8400 combined with Super Economy – NTC9000	Lowest	2.7	1.3	$581	$530	-$50	-8.7%
	Typical	4.1	1.9	$782	$710	-$72	-9.2%
	Highest	6.1	2.5	$1,053	$951	-$102	-9.7%
Residential Flat – NTC8400 combined with Economy – NTC9100	Lowest	2.3	1.2	$567	$513	-$53	-9.4%
	Typical	3.6	1.8	$776	$698	-$78	-10.1%
	Highest	5.6	2.6	$1,086	$971	-$115	-10.6%

Demand based tariffs	Usage / demand types	Usage MWh/year	Monthly demand (kVA/month)	2016-17 NUoS ($)	2017-18 NUoS ($)	Annual NUoS increase/ decrease ($)	Annual NUoS increase (%)

Notes:

- Usage scenarios based on actual 2015-16 consumption data.
- Each tariff group contains only NMIs that have data for the full period.
- Customer impact for NTC8900 – Residential ToU and NTC7300 – Residential Demand is not included as usage scenarios could not be derived due to the very low number of customers on these tariffs.
- NTC9000 and NTC9001 are secondary tariffs, when combined with the primary tariff NTC8400, an overall net benefit to the customer may result.
- Low use customers belong to quantile 0.25; typical use customers belong to quantile 0.50; high use customers belong to quantile 0.75.
- For customers with a primary and secondary tariff, consumption scenarios at the secondary tariff are independent from those at the primary tariff. Therefore, any combination of low, typical and high use scenarios between the primary and secondary tariff can be formed. For example a residential customer with a typical usage at the primary tariff may have a low energy usage at the secondary tariff.
- For demand based tariffs, energy and demand levels are independent of each other. Any combination of low, typical and high energy and demand levels can be formed. For example a customer with typical energy usage may have a high demand.
- Solar tariffs NTC7500, NTC9900, NTC9700 and NTC9800 have been excluded from the dataset.

Table 5-1 and Table 5-2 show that customers across the spectrum are expected to experience a decrease in their NUoS charges in 2017-18 compared with their 2016-17 charges. This is largely due to adjustments in the demand and energy forecasts used for the development of the tariff levels, decreases in DUoS under-recoveries, the expiry of capital contributions under recoveries, and significant decreases in jurisdictional schemes and DPPC. Further details on these changes between 2016-17 and 2017-18 are provided in Section 5.2.

The estimated decreases in network charges identified in Table 5-1 and Table 5-2 above have not resulted in the need to vary the tariffs as allowed in clause 6.18.5(h). However, it should be noted that customer impact was considered in transitioning customers on legacy tariffs to cost reflectivity as permitted in clause 6.18.5(c). This matter is more fully discussed in the TSS and Section 6.3 of the associated Explanatory Notes.

5.2 Changes between regulatory years

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(8) describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the Rules and any applicable distribution determination.

This section outlines changes between 2016-17 and 2017-18, including:

- adjustments to TAR components
- changes to tariffs
- changes to the approach to price setting.

A summary of the annual adjustments is included in Table 5-3.

Table 5-3 Summary of annual adjustments

Component / adjustment	2016-17 values	2017-18 values	Reason for change
CPI	1.69%	1.48%	Adjustment as per information published by the ABS – CPI All Groups, Average of Eight Capital Cities from the December quarter in 2015 to the December quarter in 2016.
X Factor	-2.09	-19.56%	X-factor updated in PTRM
Capital contributions	$17.40 m	N/A	No longer applicable from 2017-18.
STPIS	$65.00 m	$27.86 m	The S-factor for the year is 1.941%. It has been adjusted to reflect the previous year's S-factor.
DMIS Carry-over	$(5.24) m	N/A	Not applicable in 2017-18.
DUoS under recovery	$22.36 m	$7.47 m	DUoS under recovery for 2015-16 to be recovered in 2017-18.
SBS FiT payments pass-through	$219.55 m	N/A	No longer applicable from 2017-18.
Jurisdictional schemes	$180.78 m	$150.50	The value in 2017-18 relates to the forecast expected payments to be made in that year for the SBS and the AEMC levy as jurisdictional schemes. Also incorporates an over recovery of SBS from the 2015-16 year.
DPPC	$484.80	$328.49	The decrease in DPPC between 2016-17 and 2017-18 reflects the AER's Draft Decision on Powerlink's 2017-22 transmission revenue determination.

The difference between 2016-17 and 2017-18 for ACS services is limited to a change in the CPI values from 1.69 per cent to 1.48 per cent resulting in an average reduction in pricing levels.

It should also be noted that subsets to existing ACS will be introduced in 2017-18. These 'scaled down' services will be offered in addition to the original services, providing more options and a greater degree of cost reflectivity. Details on the adjusted services are provided in Table 5-4.

Table 5-4 New subsets of existing services

Category	Service description	Original service	Adjusted service	Reasons	Full service rate for 2017-18 (excl. GST)	Subset rate 2017-18 (excl. GST)
Customer initiated supply enhancement	Overhead service upgrade to single phase.	Single phase upgrade – business hours	Single phase upgrade (fuse only) – business hours	The original service involves both an upgrade to the fuse and also the overhead	$1,059.52	$183.88

Category	Service description	Original service	Adjusted service	Reasons	Full service rate for 2017-18 (excl. GST)	Subset rate 2017-18 (excl. GST)
		Single phase upgrade – after hours	Single phase upgrade (fuse only) – after hours	service line. It was identified that in some situations the service only involves a fuse upgrade. This subset is at a lower cost.	$1,377.99	$262.41
Meter Maintenance	Integrity verification as a result of a meter alteration – additional meter.	Business hours – No CT	Business hours – No CT – Additional meter	The original service is a charge per meter and includes travel to site. Where multiple meters per site exist need to be able to charge for additional metering without duplicating travel time. These rates have had travel time excluded from there calculation.	$133.43	$110.38
		After hours – No CT	After hours – No CT – Additional meter		$190.82	$157.51
		Anytime – No CT	Anytime – No CT- Additional meter		$190.82	$157.51
		Business hours – CT	Business hours – CT – Additional meter		$826.86	$694.05
		After hours – CT	After hours – CT – Additional meter		$1,179.96	$990.44
		Anytime - CT	Anytime – CT – Additional meter		$1,179.96	$990.44
Customer consultation or appointment	A visit to the customers premise to advise on electrical supply matters.	Complex	Simple	Reduce time allowed for a simple customer consultation or appointment.	$229.86	$104.71

5.3 Adjustments to tariffs within a regulatory year

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(5) 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.

5.3.1 Adjustments to SCS tariffs

Variations or adjustments to Energex's network tariffs may occur when ICC or CAC customers change their demand or request a change to their connection assets during the course of the year. In these circumstances, Energex will recalculate the customer's charge with the adjustment to the charge occurring at the next network bill. In the case of a new connection, Energex will create a new tariff.

In circumstances where Energex is required to make a change to its TSS during a regulatory control period as a result of an event outside its control which could not reasonably have been foreseen, Energex may request from the AER the right to amend its TSS in accordance with clause 6.18.1B of the Rules. If the AER is satisfied that the change to the TSS is warranted, Energex may be able to adjust the charge to the tariff in accordance with the revised TSS approved by the AER.

5.3.2 Adjustments to ACS tariffs

In November 2015, the Australian Energy Market Commission (AEMC) finalised its Competition in Metering and Related Services rule change (the "Power of Choice" rule change). Under the new arrangements, the provision of metering services will be further opened to competition, particularly in relation to small customers. As a result, the installation and delivery of metering services will become the responsibility of third party service providers. It should be noted that Energex will remain responsible for the maintenance of its existing fleet of Type 6 meters.

As a result of Power of Choice taking effect on 1 December 2017, Energex anticipates that amendments to certain ACS will have to be made, namely:

1) Certain services will need to be restructured into various charging components to reflect the possible permutations introduced by metering service contestability. These services, currently charged as a single charge, will on 1 December 2017 be broken down into components which will be allocated to the appropriate party. It is proposed that the subset of services continue to be offered as price cap services.
2) The cost of certain services which are currently charged to customers as part of their metering services charges will, following Power of Choice, be individually allocated to the customer. With metering contestability, these services will require separate charging to the retailer on behalf of their customers or to the metering provider. Energex proposes to classify these services as price cap services.
3) Certain services will cease come Power of Choice (e.g. installation of a new or replacement Type 5 or 6 meter).

It is proposed that the list of services and associated prices included in Energex's 2017-18 Pricing Proposal will not be reflective of the impact of Power of Choice. Energex will, however, publish an updated price schedule on 1 December 2017 to include the revised ACS charges.

It is important to note, that no new ACS are proposed to be created, and for the prices of the impacted services, which are to be levied from 1 December, to be equivalent to or less than the price for the 'fully inclusive' service approved by the AER as part of this Pricing Proposal.

The services assessed as being impacted by Power of Choice are listed in Appendix 4.

5.4 Difference between the current 2017-18 price levels and relevant indicative prices

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(7A) demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the relevant indicative pricing schedule, or explain any material differences between them.

The current 2017-18 price levels for SCS and ACS have been developed on the same basis as the indicative prices included in the TSS. However, the indicative prices prepared as part of the submission of the revised TSS in November 2016 were based on inputs which have since been updated.

5.4.1 Reasons for differences in SCS pricing levels

Attachment 1 provides a comparison in price levels between the 2017-18 indicative rates included in the TSS approved by the AER and the rates submitted as part of this Pricing Proposal. The differences are expressed as both absolute values and percentages.

The calculation of individual rates is impacted by a number of inputs which have been updated between the development of the TSS and the Pricing Proposal. The key changes include:

- the final TAR which has increased by $25.9 million or 1.8 per cent
- the forecast jurisdictional scheme revenue which has decreased by $23.8 million or 13.6 per cent
- the forecast DPPC revenue which has been revised by a $7.1 million increase or 2.2 per cent
- updated customer numbers, demand and volume forecasts by tariff.

The overall NUOS revenue impact (TAR, Jurisdictional Scheme and DPPC revenues) is an increase of $9.3 million or 0.5 per cent.

In addition, the overall forecast billable kVA demand has been adjusted upwards by 0.2 per cent and overall volume has decreased by 1.1 per cent. However, it should be noted that increases and decreases in forecast demand and energy vary across tariffs differently.

Tariff rate outcomes can be quite sensitive to changes in these inputs, particularly in the case of tariffs with relatively small customer and revenue allocations.

Furthermore, with the introduction of LRMC based cost reflective tariffs, and the associated progressive transition of legacy tariffs to 100 per cent LRMC based revenue recovery in their demand charge parameter, small variations in key inputs may have a magnified impact on the usage volumetric rate (c/kWh) which is used to recover the residual revenue after subtracting daily supply and demand charges.

When looking at the price level comparisons provided in Attachment 1, a degree of caution should be exercised as tariffs are to be considered as more than the sum of individual parameters and associated rates. Indeed, the rates of the charging parameters 'contribute' in varying amount to the overall NUOS revenue recovery at the overall tariff level. That is, each charging parameter within a tariff has a weighting (or percentage) of the overall NUOS revenue recovery. This means that a large percentage change on a specific charge parameter that only has a small weighting of overall NUOS revenue recovery will have a smaller impact on the overall cost outcome of the tariff than the increase on the single charge parameter would indicate. This is shown in the *Indicative Weighted % impact on total tariff NUOS* (refer column J in Attachment 1).

With respect to materiality, we have referenced a raw increase of greater than 10 per cent in an individual rate and greater than 1.0 per cent in the indicative weighted outcome as the threshold to explain differences.

5.4.2 Reasons for differences in ACS pricing levels

As shown in Attachment 1, the differences in pricing levels for ACS services between the TSS and this Pricing Proposal are not material. The changes reflect the adjustment to the CPI from 1.69 per cent to 1.48 per cent resulting in an average reduction in pricing levels of 0.21%.

5.5 Updated indicative pricing levels

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(d) At the same time as a DNSP submits a pricing proposal under paragraph (a), the DNSP must submit to the AER a revised indicative pricing schedule which sets out, for each tariff and for each of the remaining regulatory years of the regulatory control period, the indicative price levels determined in accordance with the DNSP's tariff structure statement and updated so as to take into account that pricing proposal.

The indicative prices for the 2018-20 period are provided in the accompanying update Indicative Pricing Schedule as noted in Attachment 2.

5.6 Publication of information about tariffs and tariff classes

RULE REQUIREMENT

Clause 6.18.9 Publication of information about tariffs and tariff classes

(a) A DNSP must maintain on its website:

(2) its current indicative pricing schedule

(3) a statement of the provider's tariff classes and tariffs applicable to each class

In accordance with clause 6.18.9(a), this Pricing Proposal is available on the Energex website.

Appendices

Appendix 1: Proposed network charges

A1.1 Prices for Standard Control Services

Table A. 1 SCS prices for 2017-18

Tariff class	Tariff	Tariff charge parameter	Unit	DUoS	Jurisdictional	DPPC	NUoS
CAC	**NTC3000** EG 11kV	Supply	$/Day	*Site specific prices are confidential*			
		Demand	$/kVA/month	10.065	0.000	1.326	11.391
		Usage off-peak	c/kWh	0.270	0.315	0.151	0.736
		Usage peak	c/kWh	0.270	0.315	0.151	0.736
	NTC4000 11kV Bus	Supply	$/Day	*Site specific prices are confidential*			
		Demand	$/kVA/month	7.266	0.000	1.326	8.592
		Usage off-peak	c/kWh	0.088	0.197	0.096	0.381
		Usage peak	c/kWh	0.088	0.197	0.096	0.381
	NTC4500 11kV Line	Supply	$/Day	*Site specific prices are confidential*			
		Demand	$/kVA/month	11.241	0.000	1.326	12.567
		Usage off-peak	c/kWh	0.270	0.315	0.151	0.736
		Usage peak	c/kWh	0.270	0.315	0.151	0.736
	NTC7400 Demand ToU 11kV	Supply – CAV	$/Day/$M - CAV	29.562	3.040	0.000	32.602
		Supply – NCCAV	$/Day/$M - NCCAV	66.493	6.838	0.000	73.331
		Peak demand	$/kVA/month	8.141	0.000	2.752	10.893
		Excess demand	$/kVA/month	1.628	0.000	0.550	2.178
		Usage flat	c/kWh	1.109	0.315	0.569	1.993
	NTC8000 HV Demand	Supply	$/Day	24.850	0.554	20.479	45.883
		Demand	$/kVA/month	10.728	0.000	2.505	13.233
		Usage flat	c/kWh	0.270	0.315	0.451	1.036
SAC	**NTC8100** Demand Large	Supply	$/Day	27.823	2.035	5.305	35.163

Tariff class	Tariff	Tariff charge parameter	Unit	DUoS	Jurisdictional	DPPC	NUoS
		Demand	$/kVA/month	14.811	0.000	2.666	17.477
		Usage flat	c/kWh	0.316	0.539	0.321	1.176
	NTC8300 Demand Small	Supply	$/Day	3.144	0.318	1.291	4.753
		Demand	$/kVA/month	17.399	0.000	2.580	19.979
		Usage flat	c/kWh	0.122	0.673	0.616	1.411
	NTC8500 Business Flat	Supply	$/Day	0.458	0.009	0.181	0.648
		Usage flat	c/kWh	9.402	1.078	1.108	11.588
	NTC8800 Business TOU	Supply	$/Day	0.458	0.009	0.181	0.648
		Usage off-peak	c/kWh	7.353	1.003	0.923	9.279
		Usage peak	c/kWh	11.146	1.521	1.283	13.950
	NTC7100 Business Demand	Supply	$/Day	0.431	0.000	0.000	0.431
		Peak demand	$/kW/month	6.449	0.000	2.119	8.568
		Usage flat	c/kWh	5.485	1.137	0.201	6.823
	NTC8400 Residential Flat	Supply	$/Day	0.406	0.009	0.065	0.480
		Usage flat	c/kWh	7.832	0.981	1.435	10.248
	NTC8900 Residential ToU	Supply	$/Day	0.406	0.009	0.065	0.480
		Usage off-peak	c/kWh	5.625	0.459	0.330	6.414
		Usage shoulder	c/kWh	7.224	0.589	1.435	9.248
		Usage peak	c/kWh	12.742	1.039	3.822	17.603
	NTC7000 Residential Demand	Supply	$/Day	0.371	0.009	0.000	0.380
		Peak demand	$/kW/month	5.989	0.000	1.968	7.957
		Usage flat	c/kWh	3.251	0.947	0.312	4.510
	NTC9000 Super Economy	Usage flat	c/kWh	4.382	0.468	1.165	6.015
	NTC9100 Economy	Usage flat	c/kWh	6.427	0.942	1.165	8.534
	NTC7300 Smart control	Usage flat	c/kWh	2.602	0.947	0.312	3.861
	NTC9600 Unmetered	Usage flat	c/kWh	7.046	0.804	1.293	9.143

A1.2 Prices for Alternative Control Services

Table A. 2 2017-18 Connection prices

Service Description	2017-18[1,2] ($/service)
Pre-connection services (connection application services)	
Negotiation services involved in negotiating a connection agreement – simple	
Standard jobs for small customer connections and real estate developments (sub-divisions). If service is non-standard, a quoted price may apply.	1,581.06
Protection and power quality assessment prior to connection - simple	
Solar PV 30-150 kW.	3,952.66
Application assessment, design review and audit real estate (sub-division) connection services - resubmission	
Design assessment and preparation of offer – Resubmission.	169.34
Pre - connection services (consultation services)	
Site inspection in order to determine nature of connection	
Small or large customer connection.	338.69
Provision of site-specific connection information and advice for small or large customer connections.	
Protection devices and settings, fault level, network information.	677.38
Connection services	
Customer request a temporary connection for short term supply (includes metered and unmetered) – simple	
Customer requested temporary connection (short term) and recovery of the temporary builders supply (business hours) - no CT.[3]	1,632.96
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - no CT.	2,293.90
Customer requested temporary connection (short term) and recovery of the temporary builders supply (anytime) - no CT.	2,293.90
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - no CT. Work requires traffic control due to imposed rules from external authorities.	3,397.77
Customer requested temporary connection (short term) and recovery of the temporary builders supply (anytime) - no CT. Work requires traffic control due to imposed rules from external authorities.	3,397.77
Customer requested temporary connection (short term) and recovery of the temporary builders supply (business hours) - CT. Includes additional crew.[3]	2,782.25
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - CT metering. Includes additional crew.	3,933.98
Customer requested temporary connection (short term) and recovery of the temporary builders supply (any time) - CT. Includes additional crew.	3,933.98
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - CT. Work requires traffic control due to imposed rules from external authorities and additional crew.	5,037.85
Customer requested temporary connection (short term) and recovery of the temporary builders supply (any time) - CT metering. Work requires traffic control due to imposed rules from external authorities and additional crew.	5,037.85
Temporary connection of unmetered equipment to an existing LV supply.[3]	270.07
Post - connection services	
Supply abolishment - simple	
Request to de-energise an unmetered supply point.	414.68
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community/unit one of multi-unit residential complexes (business	664.22

Service Description	2017-18[1,2] ($/service)
hours).	
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community/unit one of multi-unit residential complexes (after hours).	820.04
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community/unit one of multi-unit residential complexes (any time).	820.04
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community/unit one of multi-unit residential complexes (business hours). Work requires traffic control due to imposed rules from external authorities.	1,768.09
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community/unit one of multi-unit residential complexes (after hours). Work requires traffic control due to imposed rules from external authorities.	1,923.91
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community/unit one of multi-unit residential complexes (any time). Work requires traffic control due to imposed rules from external authorities.	1,923.91
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community/unit one (business hours).	125.14
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community/unit one (after hours).	178.64
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community/unit one (anytime).	178.64
Rearrange connection assets at customer's request - simple (upgrade from overhead to underground where main connection point is in existence)	
Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (business hours).	252.84
Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (after hours).	360.82
Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (any time).	360.82
Overhead service line replacement at customer's request (no material change to load)	
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (business hours).	641.83
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (after hours).	832.61
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (any time).	832.61
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (business hours). Work requires traffic control due to imposed rules from external authorities.	1,745.70
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (after hours). Work requires traffic control due to imposed rules from external authorities.	1,936.48
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (any time). Work requires traffic control due to imposed rules from external authorities.	1,936.48
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (business hours).	901.31
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (after hours).	1,142.17
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (any time).	1,142.17

Service Description	2017-18[1,2] ($/service)
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (business hours). Work requires traffic control due to imposed rules from external authorities.	2,005.18
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (after hours). Work requires traffic control due to imposed rules from external authorities.	2,246.05
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (any time). Work requires traffic control due to imposed rules from external authorities.	2,246.05
Auditing services – auditing/re-inspection of connection assets after energisation to network - simple	
Auditing/re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 0-6.	464.34
Auditing/re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 7-30.	742.94
Auditing/re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 31-60.	888.87
Auditing/re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 61+.	990.59
Temporary disconnections and reconnections (which may involve a line drop) - low voltage	
Temporary LV service disconnection/reconnection - no dismantling (business hours).	362.67
Temporary LV service disconnection/reconnection - no dismantling (after hours).	517.54
Temporary LV service disconnection/reconnection - no dismantling (anytime).	517.54
Temporary LV service disconnection/reconnection - physical dismantling (business hours).	592.52
Temporary LV service disconnection/reconnection - physical dismantling (after hours).	845.55
Temporary LV service disconnection/reconnection - physical dismantling (anytime).	845.55
Customer initiated supply enhancement	
Overhead service single phase upgrade (business hours).	1,059.52
Overhead service single phase upgrade – replace fuse only (business hours).	183.88
Overhead service single phase upgrade (after hours).	1,377.99
Overhead service single phase upgrade – replace fuse only (after hours).	262.41
Overhead service single phase upgrade (business hours). Work requires traffic control due to imposed rules from external authorities.	2,163.40
Overhead service single phase upgrade (after hours). Work requires traffic control due to imposed rules from external authorities.	2,481.86
Overhead service upgrade to multi-phase (business hours).	1,194.07
Overhead service upgrade to multi-phase (after hours).	1,603.06
Overhead service upgrade to multi-phase (business hours). Work requires traffic control due to imposed rules from external authorities.	2,297.94
Overhead service upgrade to multi-phase (after hours). Work requires traffic control due to imposed rules from external authorities.	2,706.93
Underground service - upgrade single phase (business hours).	130.25
Underground service - upgrade single phase (after hours).	185.87
Underground service - upgrade to multi-phase (business hours).	63.85

Service Description	2017-18[1,2] ($/service)
Underground service - upgrade to multi-phase (after hours).	91.11
Underground service - upgrade to multi-phase (business hours) - CT.	459.71
Underground service - upgrade to multi-phase (after hours) - CT.	656.03
Customer consultation or appointment	
A visit to the customer's premises to advise on electrical supply matters (complex).	229.86
A visit to the customer's premises to advise on electrical supply matters (simple).	104.71
De-energisation[3]	
Retailer requests de-energisation of the customer's premises where the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - no CT.	64.01
Retailer requests de-energisation of the customer's premises where the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - CT metering.	314.45
Retailer requests de-energisation of the customer's premises where the customer has not paid their electricity account and the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - no CT.	64.01
Retailer requests de-energisation of the customer's premises where the customer has not paid their electricity account and the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) – CT.	318.86
Retailer requests de-energisation of the customer's premises carried out by way of main switch seal (non-payment).	20.97
Retailer requests a de-energisation of the customer's premises and it is carried out by way of main switch seal.	20.97
Re-energisation[3]	
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (business hours).	48.90
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT (business hours).	48.90
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (after hours).	69.34
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT (after hours).	69.34
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (any time).	69.34
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT (any time).	69.34
Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required) (business hours).	11.80
Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required) (after hours).	78.89
Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required) (any time).	71.48
Retailer requests re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (business hours).	48.38
Retailer requests re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (after hours).	78.89
Retailer requests re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (any time).	71.48
Retailer requests a visual examination upon re-energisation of the customer's premises - no CT (business hours).	112.33

Service Description	2017-18[1,2] ($/service)
Retailer requests a visual examination upon re-energisation of the customer's premises - no CT (after hours).	160.08
Retailer requests a visual examination upon re-energisation of the customer's premises - no CT (anytime).	159.70
Retailer requests a visual examination upon re-energisation of the customer's premises – CT (business hours).	288.08
Retailer requests a visual examination upon re-energisation of the customer's premises - CT (after hours).	398.12
Retailer requests a visual examination upon re-energisation of the customer's premises - CT (anytime).	435.20
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - no CT (business hours).	112.33
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - no CT (after hours).	160.08
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - no CT (anytime).	159.70
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - CT (business hours).	288.08
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - CT (after hours).	398.12
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - CT (anytime).	435.20
Reading provided for an active site	
Retailer requests that fieldwork be undertaken to obtain a new reading rather than using a deemed meter reading. May also be used for retrospective move-in requests.	9.98
Retrospective move in read required.	9.98
Attending loss of supply (customer at fault)	
Energex attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) business hours.	229.86
Energex attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) after hours.	328.01
Energex attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) anytime.	328.01
Accreditation / certification	
Accreditation of design consultants	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation).	10,695.56
New applicant has ISO9001 accreditation with no other Energex accreditations in place.	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation).	12,464.46
New applicant is not ISO9001 accredited with no other Energex accreditations in place.	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation).	7,308.67
Applicant currently holds accreditation to undertake design services for rate 2 public lighting (design accreditation). Applicant requesting additional Energex accreditations with or without ISO9001 accreditation (priced per additional accreditation).	
Onsite management system evaluation (irrespective of prior accreditations).	707.57

Service Description	2017-18[1,2] ($/service)
Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation).	
Capability evaluation (irrespective of prior accreditations).	677.38
Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design Accreditation).	
Accreditation of alternative service providers (construction accreditation)	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	5,216.17
New applicant has ISO9001/AS4801/ISO14001 accreditation with no other Energex accreditations in place.	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	9,785.14
New applicant is not ISO9001/AS4801/ISO14001 accredited with no other Energex accreditations in place.	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	5,216.17
Applicant requesting additional Energex accreditations with or without ISO9001/AS4801/ISO14001 accreditation (price per additional accreditation).	
Onsite management system evaluation (irrespective of prior accreditations).	1,415.12
Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	
Capability evaluation irrespective of prior accreditations).	1,384.94
Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	
Management system re-evaluation	
Quality assessment (QA) process: This is conducted on request from existing service providers and design consultants with the intent to improve their management system score.	7,075.64
Shared assets authority	
High Level quality assessment (QA) and capability process: This is conducted to ensure the applicant has adequate safety and QA documentation to meet legislative and Energex Work Category Specification (WCS) requirements. Also involves a capability assessment of the applicant's ability to conduct the work.	5,306.73
Notes: 1. Prices are GST exclusive. 2. Prices are inclusive of overheads and on-costs. 3. Prices for these services are subject to Schedule 8 of the Queensland Electricity Regulation 2006. However, the prices provided in the table above have been developed in accordance with the AER's Final Decision.	

Table A. 3 2017-18 prices for ancillary services

Service Description	2017-18[1,2] ($/service)
Other recoverable works	
Customer requested consultations or appointments	
Customer requested consultation or appointment – Complex.	229.86
Customer requested consultation or appointment – Simple.	104.71
Attendance at customers premises to perform a statutory right where access is prevented[3]	
Energex attends a site at the customer's request and is unable to perform job due to customer's fault (business hours).	91.94
Energex attends a site at the customer's request and is unable to perform job due to customer's fault (business hours) 2 crew.	183.88
Energex attends a site at the customer's request and is unable to perform job due to customer's fault (after hours).	131.21
Energex attends a site at the customer's request and is unable to perform job due to customer's fault (after hours) 2 crew.	262.41
Energex attends a site at the customer's request and is unable to perform job due to customer's fault (anytime).	131.21
Energex (non-technical) attends a site at the customer's request and is unable to perform job due to customer's fault (business hours).	10.97
Energex (non-technical) attends a site at the customer's request and is unable to perform job due to customer's fault (after hours).	78.59
Energex (non-technical) attends a site at the customer's request and is unable to perform job due to customer's fault (anytime).	78.59

Notes:
1. Prices are GST exclusive.
2. Prices are inclusive of overheads and on-costs.
3. Includes faults caused by customer's electrical contractor.

Table A. 4 2017-18 prices for Type 6 metering services charges

Tariff Class	Cost	2017-18 (Cents/day)[1,2]
Primary	Non-capital	2.226
	Capital	6.963
Load Control	Non-Capital	0.668
	Capital	2.089
Solar PV	Non-Capital	1.558
	Capital	4.874

Notes:
1. Prices are GST exclusive.
2. Prices are inclusive of overheads and on-costs.

Table A. 5 2017-18 prices for auxiliary metering services

Service Description	2017-18[1,2] ($/service)
Meter installation (upfront capital charge)	
New Permanent Connections (meter installations)	
Upfront capital charge for new permanent meter installation. Single phase single element (Overhead Fox) (business hours).	333.61
Upfront capital charge for new permanent meter installation. Single phase single element (Overhead) (business hours).	333.61

Service Description	2017-18[1,2] ($/service)
Upfront capital charge for new permanent meter installation. Single phase single element (Underground) (business hours).	333.61
Upfront capital charge for new permanent meter installation. Single phase single element (Overhead Fox) (after hours).	470.55
Upfront capital charge for new permanent meter installation. Single phase single element (Overhead) (after hours).	436.74
Upfront capital charge for new permanent meter installation. Single phase single element (Underground) (after hours).	411.99
Upfront capital charge for new permanent meter installation. Single phase dual element (business hours).	416.94
Upfront capital charge for new permanent meter installation. Single phase dual element (after hours).	495.32
Upfront capital charge for new permanent meter installation. Multi-phase (Overhead Fox) (business hours).	613.75
Upfront capital charge for new permanent meter installation. Multi-phase (Overhead) (business hours).	613.75
Upfront capital charge for new permanent meter installation. Multi-phase (Underground) (business hours).	613.75
Upfront capital charge for new permanent meter installation. Multi-phase (Overhead Fox) (after hours).	787.02
Upfront capital charge for new permanent meter installation. Multi-phase (Overhead) (after hours).	744.15
Upfront capital charge for new permanent meter installation. Multi-phase (Underground) (after hours).	715.46
Upfront capital charge for new permanent meter installation. Multi-phase (Overhead with CT) (business hours).[4]	1,643.98
Upfront capital charge for new permanent meter installation. Multi-phase (Overhead with CT) (after hours).[4]	1,988.19
Upfront capital charge for new permanent meter installation. Multi-phase (Underground with CT) (business hours).[4]	1,643.98
Upfront capital charge for new permanent meter installation. Multi-phase (Underground with CT) (after hours).[4]	1,975.04
Install Controlled Load (meter installations)	
Upfront capital charge for meter installation resulting from the installation of controlled load. Single phase single element (business hours).	333.61
Upfront capital charge for meter installation resulting from the installation of controlled load. Single phase dual element (business hours).	416.94
Upfront capital charge for meter installation resulting from the installation of controlled load. Multi-phase (business hours).	613.75
Upfront capital charge for meter installation resulting from the installation of controlled load. Multi-phase CT (business hours).[4]	1,643.98
Install Hot Water (meter installations)	
Upfront capital charge for meter installation resulting from the installation of hot water. Single phase single element (business hours).	333.61
Upfront capital charge for meter installation resulting from the installation of hot water. Single phase dual element (business hours).	416.94
Upfront capital charge for meter installation resulting from the installation of hot water. Multi-phase (business hours).	613.75
Upfront capital charge for meter installation resulting from the installation of hot water. Multi-phase CT (business hours).[4]	1,643.98

Service Description	2017-18[1,2] ($/service)
Installation of a new meter at an existing premises (not controlled load)	
Upfront capital charge for additional meter installation. Single phase single element (business hours).	333.61
Upfront capital charge for additional meter installation. Single phase single element (after hours).	408.92
Upfront capital charge for additional meter installation. Single phase single element (anytime).	408.92
Upfront capital charge for additional meter installation. Single phase single element (after hours) – Solar PV.	397.60
Upfront capital charge for additional meter installation. Single phase single element (anytime).	408.92
Upfront capital charge for additional meter installation. Single phase dual element (business hours).	416.94
Upfront capital charge for additional meter installation. Single phase dual element (after hours).	492.25
Upfront capital charge for additional meter installation. Multi-phase (business hours).	613.75
Upfront capital charge for additional meter installation. Multi-phase (after hours) – Solar PV.	693.14
Upfront capital charge for additional meter installation. Multi-phase (after hours).	735.71
Upfront capital charge for additional meter installation. Multi-phase CT (business hours).[4]	1,643.98
Upfront capital charge for additional meter installation. Multi-phase CT (after hours) – Solar PV.[4]	1,834.58
Upfront capital charge for additional meter installation. Multi-phase CT (after hours).[4]	2,002.28
Upfront capital charge for additional meter installation. Multi-phase CT (anytime).[4]	2,002.28
Customer requested meter exchange (eg for alternative metering configuration/consolidation of multiple meters for one meter)	
Upfront capital charge for meter exchange. Single phase single element (business hours).	333.61
Upfront capital charge for meter exchange. Single phase single element (after hours).	386.96
Upfront capital charge for meter exchange. Single phase single element (anytime).	386.96
Upfront capital charge for meter exchange. Single phase dual element (business hours).	416.94
Upfront capital charge for meter exchange. Single phase dual element (after hours).	470.28
Upfront capital charge for meter exchange. Multi-phase (business hours).	613.75
Upfront capital charge for meter exchange. Multi-phase (after hours).	689.06
Upfront capital charge for meter exchange. Multi-phase CT (business hours).[4]	1,643.98
Upfront capital charge for meter exchange. Multi-phase CT (after hours).[4]	2,002.28
Upfront capital charge for meter exchange. Multi-phase CT (anytime).[4]	2,002.28
Meter maintenance	
After hours removal of meter/s from customer's premises	
After hours removal of meter - no CT (after hours - incremental costs only - base cost included in the Metering Services Charge – see Table A. 4).).	54.27
After hours removal of meter - CT (after hours - incremental costs only - base cost included in the Metering Services Charge – see Table A. 4).	173.05
Customer requested meter accuracy test (physically test meter)[4]	
Testing for type 5 & 6 meters - customer requested meter accuracy testing - no CT.	380.93
Testing for type 5 & 6 meters - customer requested meter accuracy testing – CT.	794.28
Customer requested meter inspection & investigation (no physical testing of meter)	
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - no CT (business hours).	93.55
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - no CT (after hours).	168.79
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - no CT (anytime).	168.79

Service Description	2017-18[1,2] ($/service)
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT (business hours).	347.75
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT (after hours).	496.25
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT (anytime).	496.25
Customer requested reconfiguration of meters[3]	
A request to make a change from one tariff to another tariff (controlled load) - no CT.	95.41
A request to make a change from one tariff to another tariff (controlled load) – CT.	439.28
A request to make a change from residential flat (NTC 8400) to residential ToU (NTC 8900) - no CT.	145.57
A request to make a change from residential flat (NTC 8400) to residential ToU (NTC 8900) – CT.	485.26
A request to make a change from one tariff to another tariff - no CT (business hours).	95.41
A request to make a change from one tariff to another tariff - CT (business hours).	439.28
A request to make a change from one tariff to another tariff - no CT (after hours).	112.78
A request to make a change from one tariff to another tariff - CT metering (after hours).	626.88
A request to make a change from one tariff to another tariff - no CT (anytime).	112.78
A request to make a change from one tariff to another tariff - CT metering (anytime).	626.88
A request to make a change from residential ToU (NTC 8900) to residential flat (NTC 8400).	95.41
Change timeswitch - no CT.	127.70
Change timeswitch - CT.	403.53
Meter alteration – meter integrity verification	
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (business hours).	133.43
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (after hours).	190.82
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (anytime).	190.82
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT (business hours).	826.86
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT (after hours).	1,179.96
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT (anytime).	1,179.96
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (business hours) – Additional meter.	110.38
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (after hours) – Additional meter.	157.51
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (anytime) – Additional meter.	157.51
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT (business hours) – Additional meter.	694.05
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT (after hours) – Additional meter.	990.44
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT (anytime) – Additional meter.	990.44
Meter reading	
Check read[4]	
Customer requests a check read on the meter due to reported error in the meter reading. This is only used to check the accuracy of the meter reading.	7.96

Service Description	2017-18[1,2] ($/service)
Final read[4]	
Retailer requires a reading for preparing a final bill for customer.	7.96
Transfer read[4]	
Customer requests a transfer read, as a result of transferring to a different retailer during a billing period.	7.96
Estimated read	
Estimated read.	8.05
Meter data services	
Type 5-7 non-standard metering services	
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (business hours). First unit.	133.33
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (business hours). Additional units.	66.93
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (after hours). First unit.	380.53
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (after hours). Additional units.	191.02
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (anytime). First unit.	380.53
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (anytime). Additional units.	191.02
Other metering services	
Instrument transformers	
Provision, installation, testing and maintenance of instrument transformers for metering purposes.	990.01
Testing and maintenance of instrument transformers for metering purposes.	181.33

Notes:
1. Prices are GST Exclusive.
2. Prices are inclusive of overheads and on-costs.
3. If a new meter installation is required, a meter installation charge will apply.
4. Prices for these services are subject to Schedule 8 of the Queensland Electricity Regulation 2006. The prices provided in the table above have been developed in accordance with the AER's Final Decision.

Table A. 6 2017-18 prices for street lighting services

Street light services[1]	Price ($/luminaire/day)[2]
Major non-contributed (EOO)	0.819
Major contributed (GOO)	0.285
Minor non-contributed (EOO)	0.376
Minor contributed (GOO)	0.138

Notes:
1. Definitions for street light major and street light minor are included in the glossary in Appendix 6 of this Pricing Proposal.
2. All prices exclude GST.

Table A. 7 2017-18 prices for price cap public lighting services

Service description	2017-18[1,2] ($/service)
Provision of glare shields, vandal guards, luminaire replacement with aero screens	
Customer requests the supply and installation of adhesive luminaire glare screen(s).	195.46
Customer requests the supply and installation of standard luminaire glare screen(s) – internal.	159.76
Replacement of existing streetlight luminaires with aero screen low glare luminaires.	537.71
Application assessment, design review and audit	
Rate 3 public lighting services.	84.67
Design assessment and preparation of offer.	
Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits).	
0-6 sites.	
Rate 3 public lighting services.	127.01
Design assessment and preparation of offer.	
Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits).	
7-30 sites.	
Rate 3 public lighting services.	254.01
Design assessment and preparation of offer.	
Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits).	
31+ sites.	
Rate 2 public lighting services.	169.34
Design assessment and preparation of offer.	
Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits).	
Resubmission.	

Notes:
1. Prices are GST Exclusive.
2. Prices are inclusive of overheads and on-costs.

Appendix 2: Terms and conditions for secondary tariffs

1. Secondary tariffs terms and conditions

1.1 Overview

Energex provides customers with the opportunity to obtain supply through circuits which are connected to Energex's load control mechanisms and charged through Energex's load control tariffs. These load control tariffs are secondary tariffs as they can only be accessed as adjuncts to a primary tariff.

Energex provides a load control option to customers because the ability to manage load at Energex's discretion provides network advantages. The customer benefits from being charged a usage rate for the supply of electricity that recognises the network benefits which Energex gains from this ability to control load.

The ongoing provision of load controlled supply metered via load control tariffs to a customer's premise is at Energex's discretion. This discretion will be exercised in accordance with the fair use policy and the rules related to those particular tariffs set out below.

In addition to the conditions listed below, in extreme or emergency conditions Energex as an alternative to removing all supply, reserves the right to control the load for periods in excess of the times stated in the tariff conditions.

1.2 Fair Use policy

All secondary tariffs must be accessed as an adjunct to a primary tariff at the customer's premises. Secondary tariffs are not priced, or intended, to be the tariff which supplies the main light and power load for premises.

Customers who utilise a mix of wiring, appliances and technologies, or any other means, in such a manner as to generally supply the energy needs of their light and power for their premises through secondary tariffs, to the detriment of their use of their primary tariff, will be excluded from access to secondary tariffs.

This fair use policy will not exclude access to secondary tariffs for customers with solar PV or other micro generation who register very low consumption on the primary tariff because they consume large amounts of self-generated power, or for customers who naturally have very low consumption of light and power.

1.3 NTC9000 Super Economy

(a) <u>Availability</u>

The tariff is available as a secondary tariff provided it is used in conjunction with a primary tariff at the same NMI. However this tariff cannot be used in conjunction with NTC7000 – Residential Demand. Supply to the controlled load circuit will be available for a minimum of 8 hours per day. Load will be managed to maintain customer comfort, maximise utilisation and minimise peak demand on the Energex network. The time when supply is available is subject to variation at Energex's absolute discretion.

(b) Technical Requirements

(i) All loads supplied by the tariff must be supplied by a dedicated circuit and controlled by an Energex approved Network Load Control Device.

(ii) The premises must have been wired in accordance with the requirements of the QECMM at the time of requesting access to the tariff.

(iii) General light and power cannot be supplied directly or indirectly from electricity supplied under NTC9000 – Super Economy and must be supplied from a primary tariff or self-generation.

(iv) The customer can only connect items on the Approved List set out at item 1.5 below to NTC9000.

(v) Electricity supply must be permanently connected to the items on the Approved List, except for electric vehicle supply equipment / EV Chargers or pool filtration systems which can be supplied through a dedicated socket-outlet.

(c) Restrictions

This tariff will not be available, and will be removed from any premises, where the customer has the ability to supply the appliance or asset via another means (changeover switch to a primary tariff) of supplying such appliance or asset in the periods during which supply is not available under this tariff.

1.4 NTC9100 Economy

(a) Availability

The tariff is available as a secondary tariff provided it is used in conjunction with a primary tariff at the same NMI. However this tariff cannot be used in conjunction with NTC7000 – Residential Demand. Supply to the controlled load circuit will be available for a minimum of 18 hours per day. Load will be managed to maintain customer comfort, maximise utilisation and minimise peak demand on the Energex network. The time when supply is available is subject to variation at Energex's absolute discretion.

(b) Technical Requirements

(i) All loads supplied by the tariff must be supplied by a dedicated circuit and controlled by an Energex approved Network Load Control Device.

(ii) The premises must have been wired in accordance with the requirements of the QECMM at the time of requesting access to the tariff.

(iii) General light and power cannot be supplied directly or indirectly from electricity supplied under NTC9100 – Economy and must be supplied from a primary tariff or self-generation.

(iv) The customer can only connect items on the Approved List set out at item 1.5 below to NTC9100.

(v) Electricity supply must be permanently connected to the items on the Approved List, except for electric vehicle supply equipment / EV chargers or pool filtration systems which can be supplied through a dedicated socket-outlet.

(c) Restrictions

This tariff will not be available, and will be removed from any premises, where the customer has the ability to supply the appliance or asset via another means (changeover switch to a primary tariff) to supply such appliance or asset in the periods during which supply is not available under this tariff.

1.5 Approved List

Only the following appliances or machines can be connected to NTC9000 – Super Economy or NTC9100 – Economy:

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units.

(ii) Boost elements of solar-heated water heaters.

(iii) Electric Vehicle Supply Equipment (EV Chargers).

(iv) Pool filtration systems.

(v) Heat pump water heaters.

(vi) Other domestic appliances (e.g. air conditioners, washing machines and dishwashers) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

1.6 NTC7300 – Smart Control

(a) Availability

NTC7300 – Smart Control is available for the supply of controllable residential loads, as a secondary tariff for residential customers on NTC7000 – Residential demand, or other primary demand tariffs including NTC8100 or NTC8300.

For appliances connected to audio frequency load control relays, supply will be available for typically 12 hours per day. For customers transferring from NTC9000 or NTC9100 their existing switching times will be maintained until the audio frequency load control relay is reprogramed in accordance with Energex’s requirements.

For PeakSmart air-conditioners the device may be limited to 75% or 50% of rated capacity for periods of up to four hours up to twelve times per year.

Demand will be managed to maintain customer comfort, maximise utilisation and minimise peak demand on the Energex network. The time when demand is managed is subject to variation at Energex’s absolute discretion.

(b) Technical Requirements

(i) The customer must have appropriate advanced metering for both the primary and secondary tariffs.

(ii) The metering must be capable of measuring import and export energy and providing Energex with power quality data on request.

(iii) All appliances supplied by NTC7300 must be supplied by a dedicated circuit and controlled by an Energex approved Network Load Control Device.

(iv) Electricity supply must be permanently connected to the items on the Approved List, except for electric vehicle supply chargers / EV chargers or pool filtration systems which can be supplied through a dedicated socket-outlet.

(v) The premises and load control devices must have been wired in accordance with the requirements of the QECMM at the time of requesting access to the tariff.

(vi) The customer can only have items on the Approved List set out at item 1.7 below supplied by NTC7300.

(vii) General light and power cannot be supplied directly or indirectly from electricity supplied under NTC7300 and must be supplied from a primary tariff or self-generation.

(c) Restrictions

NTC7300 will not be available, and may be removed from any premises, where:

(i) The customer has the ability to supply the appliance or asset via another means (changeover switch to a primary tariff) to supply such appliance or asset in the periods during which supply is not available under this tariff; or

(ii) The load control device or DRED is tampered with or removed.

(d) Enforcement

Energex will run automated queries on the energy consumption data for all customers connected to NTC7300 – Smart Control to identify inoperable load control devices. When a load control device is found to not be responding to demand response signals Energex will:

(i) Notify the customer that load control devices are not operating and advise the customer to contact their service provider and have the load control device repaired or replaced.

(ii) If the failure is caused by a problem with the Energex communications or control system Energex will reimburse the customer the cost of the service call.

(iii) Whilst the load control device is inoperable, from the start of the next billing month the energy consumption data from NTC7300 – Smart Control circuit will be added to the applicable primary demand tariff NTC7000, NTC8100 or NTC8300 for the purposes of network billing.

(iv) Once the customer has had the load control rectified they must reapply to Energex to be moved back to NTC7300 – Smart Control.

1.7 Approved List

Only the following appliances or machines can be connected to NTC7300 – Smart Control:

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units.

(ii) Boost elements of solar-heated water heaters.

(iii) Air conditioners compliant with AS/NZS4755 and fitted with a DRED.

(iv) Pool filtration systems.

(v) Electric Vehicle Supply Equipment (EV Chargers).

(vi) Battery Energy Storage Systems compliant with AS/NZS4755 and fitted with a DRED with export limited to a 5kW inverter (export in excess of this limit will require an assessment by Energex).

(vii) Other appliances compliant with AS/NZS4755 and fitted with a DRED.

(viii) Heat pump water heaters.

(ix) Other domestic appliances (e.g. air conditioners, washing machines and dishwashers) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

1.8 Energex approved Load Control Devices

The following devices are required to control all appliances on economy tariffs:

(i) Audio frequency load control relays which disconnect supply from the circuit when signalled by Energex.

(ii) AS4755 appliances must be fitted with an Energex Approved DRED.

(iii) The prices for providing and installing load control equipment will be as set out in Energex's tariff schedule available at www.energex.com.au.

1.9 Safety issues

Clothes dryers are not recommended for connection to economy tariffs.

1.10 Battery Energy Storage Systems

Customers wanting to supply their light and power via a hard wired battery to gain the advantages of drawing electricity at cheaper usage rates should do so through the appropriate primary tariff.

Appendix 3: Financial Risk Reduction Mechanism terms and conditions

1.1 Overview

Energex is proposing to introduce from 1 July 2016 a demand tariff available to residential customers on a voluntary basis. This new initiative forms part of Energex's objective to gradually transition residential and small business network tariffs to full cost reflectivity. Further information on Energex's tariff reform is provided in Energex's 2017-20 TSS proposal.

To ensure demand tariffs are understood and customers have sufficient time to adapt and respond to the tariff signals, Energex is proposing the introduction of a Financial Risk Reduction Mechanism (FRRM) will we be made available to residential and small business customers for a fixed period of time. This mechanism is intended to provide a degree of bill protection to eligible customers while they are familiarising themselves with the new demand concept.

The terms and conditions detailing the criteria determining the eligibility of customers are provided below.

1.2 Terms and conditions

1) The FRRM applies to customers with the specified demand primary network tariffs NTC7000 – Residential Demand (Specified Demand Tariff).

2) Access to the FRRM is limited to customers with a Maximum Annual Consumption of 10 MWh at the time of adopting the Specified Demand Tariff.

3) The FRRM will be made available on a voluntary basis to the eligible customers on the day the Specified Demand Tariff applies.

4) The FRRM applies for a maximum of 12 months from the day an eligible customer has adopted a Specified Demand Tariff.
5) If the FRRM does not commence on the first day of the month, the demand cap will be applied on a pro rata basis for the first month. The mechanism will apply as if it had started on the first day of the month – to avoid confusion, if a customer starts on the residential demand tariff on 18 August 2016, the FRRM will end on 31 July 2017.
6) The FRRM applies for one continuous period only. Once the 12 month period begins, it continues until it is completed or until one of the events listed in (7) occurs, whichever comes earlier.

7) The FRRM is no longer available where an eligible customer or their retailer declines the initial offer of a FRRM when adopting a Specified Demand Tariff.

8) Access to the FRRM is removed if an eligible customer :
    a. Changes primary tariff
    b. Moves location
    c. Disconnects for reasons other than non-payment

d. Changes account holder

e. Reverts from the Specified Demand Tariff to any other tariff, and then adopts a Specified Demand Tariff again.

9) Access to the FRRM is not removed if:

a. A customer transfers from one retailer to another, with the same tariffs

b. If a customer's consumption increases during the 12 month period the bill protection applies to.

10) The FRRM allows eligible customers to experience demand tariffs up to a Maximum Demand Cap of 5 kW.

11) The Maximum Demand Cap is updated on an annual basis at the sole discretion of Energex but in a manner that is consistent with the pricing principles set out in the National Electricity Rules.

12) All eligible customers are exposed to the same Maximum Demand Cap.

13) An eligible customer's monthly maximum demand used for the FRRM is determined in accordance with the approach detailed in the relevant Energex TSS for the relevant Specified Demand Tariffs.

14) The FRRM can be manually end-dated immediately if a customer or their retailer does not wish to partake in it.

Appendix 4 – List of ACS to be adjusted on 1 December 2017

Table A. 8 ACS to be adjusted on 1 December 2017

Category	Service	Proposed changes
Connection services		
Customer request a temporary connection for short term supply (includes metered and unmetered) – simple.	Customer requested temporary connection (short term) and recovery of the temporary builders supply. Applies to connections <12 months for SAC's (including temporary builders supply), typically up to 10 kVA where minimum technical standards are required.	Metering provision component to be removed from 1 December 2017.
Post connection services		
Supply abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes.	Restructure charge components to allow for flexibility for cost reflectivity from 1 December 2017 as not all supply abolishment's will involve the requirement for Energex to remove the meter (non Energex owned meters).
	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community / unit one.	
Customer initiated supply enhancement	Underground service upgrade from Single to Multiphase	Following Power of Choice on 1 December 2017, the service will be undertaken without the meter installation.
Customer requested works to allow customer or contractor to work close	Appointment negotiation and power isolation to allow third party to install contestable metering – single premises dwelling	Following Power of Choice on 1 December 2017, the installation of the meter by a contestable metering provider may require a separate charge to charge the

Category	Service	Proposed changes
	Appointment negotiation and power isolation to allow third party to install contestable metering – multi premises dwelling or non-standard single dwelling.	retailer, customer or metering provider to negotiate an appointment time for power isolation.
Attending Loss of Supply (customer at fault)	Energex attending LV customers fault call and found fault in LV customer's installation (includes tripped safety switch, internal fault, customers overload).	Duplication of the fee if the meter (or its installation) is faulty: 1. If the meter belongs to Energex, Energex will cover the cost 2. If the meter belongs to a metering provider, the charge will be allocated to the meter provider. If the customer's installation is found to be faulty, the charge will be allocated to the customer. (This will allow for the retailer to identify the relevant party to on-charge).
Meter installation (new and upgraded)	New permanent connection (meter installation) – Temporary to permanent; connection to the Energex network for the first time.	Will be discontinued on 1 December 2017.
	Install controlled load	Will be discontinued on 1 December 2017.
	Install Hot Water	Will be discontinued on 1 December 2017.
	Installation of a new meter (not controlled load) – Existing premises; additions and alterations.	Will be discontinued on 1 December 2107.
	Customer requested meter exchange (eg for alternative metering configuration /consolidation of multiple meters for one meter).	Will be discontinued on 1 December 2107.
Meter maintenance	Customer requested meter inspection and investigation (no physical testing of meter) – no fault in meter found.	Will only be performed on Energex owned regulated meters from the 1 December 2107.
	Customer requested meter reconfiguration.	Will only be performed on Energex owned regulated meters from the 1 December 2107.

Appendix 5 – Summary of compliance

Table A. 9 – Compliance with the National Electricity Rules

Clause	Requirement	Reference
5.5(h) and (i)	Energex must pass through to a connection applicant the amount (calculated in accordance with paragraph (i)) for the locational component of prescribed TUoS services that would have been payable by Energex to Powerlink had the connection applicant not been connected to its distribution network ('avoided charges for the locational component of prescribed TUoS services').	Section 3.4.1.2 and Table 3-9.
6.1.4(a)	Energex must demonstrate that it does not charge a Distribution Network User DUoS charges for the export of electricity generated by the user into the distribution network.	Section 3.3.1.
6.1.4(b)	Energex must demonstrate that it charges for the provision of connection services as allowed in the Rules.	Chapter 3 and Chapter 4.
6.18.2(a)(2)	Energex must submit to the AER, at least 3 months before the commencement of the second and each subsequent regulatory year of the regulatory control period, a further pricing proposal (an annual pricing proposal) for the relevant regulatory year.	Submission of this Pricing Proposal on 31 March 2017.
6.18.2(b)(2)	Energex's Pricing Proposal must set out each tariff class (including the classes of alternative control services) for the relevant regulatory control period.	Section 2.1 (SCS). Section 4.1 (ACS).
6.18.2(b)(3)	Energex's Pricing Proposal must set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates.	Section 2.2 (SCS). Section 4.3 (ACS).
6.18.2(b)(4)	Energex's Pricing Proposal must set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year.	Section 3.3.3.
6.18.2(b)(5)	Energex's Pricing Proposal must 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.	Section 0.
6.18.2(b)(6)	Energex's Pricing Proposal must set out how DPPCs are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year.	Section 3.4.1 and Section 3.4.3.
6.18.2(b)(6A)	Energex's Pricing Proposal must set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts.	Section 3.5.2 and Section 3.5.3.

Clause	Requirement	Reference
6.18.2(b)(6B)	Energex's Pricing Proposal must describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.	Not applicable.
6.18.2(b)(7)	Energex's Pricing Proposal must demonstrate compliance with the Rules and any applicable distribution determination, including Energex's TSS for the relevant regulatory control period.	Appendix 5
6.18.2(b)(7A)	Energex's pricing proposal must demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the indicative pricing schedule, or explain any material differences between them.	Section 5.4.
6.18.2(b)(8)	Energex's Pricing Proposal must describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the Rules and any applicable distribution determination.	Section 5.2.
6.18.2(d)	At the same time as Energex submits its pricing proposal, Energex must submit to the AER a revised indicative pricing schedule which sets out, for each tariff and for each of the remaining regulatory years of the regulatory control period, the indicative price levels determined in accordance with Energex's TSS for that regulatory control period and updated so as to take into account that pricing proposal.	Attachment 1
6.18.2(e)	Where Energex submits an annual pricing proposal, the revised indicative pricing schedule referred to in clause 6.18.2(d) must also set out, for each relevant tariff under clause 6.18.1C, the indicative price levels for that relevant tariff for each of the remaining regulatory years of the regulatory control period, updated so as to take into account that pricing proposal.	Not Applicable
6.18.3(b)	Energex must demonstrate that for each customer for direct control services is a member of one or more tariff class.	Section 2.1 (SCS) and Section 4.1 (ACS) of this Pricing Proposal. Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.3(c)	Energex must demonstrate that separate tariff classes have been constituted for standard control and alternative control customers. A customer for both standard control services and alternative control services may be a member of 2 or more tariff classes.	Section 2.1 and Section 4.1 of this Pricing Proposal. Section 3.1 and Section 6.1 of the TSS
6.18.3(d)(1)	Energex must demonstrate that tariff classes have been formed based on groupings of customers on an economically efficient basis.	Section 3.1 and Section 6.1 of the TSS Section 2.1 and Section 4.1 of the Pricing Proposal.

Clause	Requirement	Reference
6.18.3(d)(2)	Energex must demonstrate that customers are grouped into tariff classes with regard to the need to avoid unnecessary transaction costs.	Section 3.1 and Section 6.1 of the TSS. Section 5.1 of the Explanatory Notes accompanying the TSS. Section 2.1 and Section 4.1 of the Pricing Proposal.
6.18.4(a)(1)(i), (ii) and (iii)	Energex must demonstrate that customers are assigned (or reassigned) to tariff classes on the basis of the nature and extent of their usage, the nature of their connection to the network, and the metering installed at the customer's premises.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.4(a)(2)	Energex must demonstrate that customers with a similar profile are treated on an equal basis.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.4(a)(3)	Energex must demonstrate that customers with micro-generation facilities are treated no less favourably than customers without such facilities but with a similar load profile.	Section 5.2 of the TSS
6.18.4(a)(4)	Energex must demonstrate that customer assignment (or reassignment) to a particular tariff class does not occur in the absence of an effective system of assessment and review.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.4(b)	Energex must demonstrate that if the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, an effective system of assessment and review should be provided of the basis on which a customer is charged.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.5(a)	The network pricing objective is that the tariffs that Energex charges in respect of its provision of direct control services to a retail customer should reflect Energex's efficient costs of providing those services to the retail customer.	Chapter 3 and Chapter 4
6.18.5(b)	Subject to clause 6.18.5(c), Energex's tariffs must comply with the pricing principles.	Sections 3.3.5, 3.3.6, 3.3.7 and 3.3.8 (SCS). Section 4.4 (ACS).
6.18.5(c)	Energex's tariff may vary from tariffs which would result from complying with the pricing principles only: (1) to the extent permitted under clause 6.18.5(h) which requires Energex to consider the impact of annual changes in tariffs on customers (2) to the extend necessary to give effect to the pricing principles.	Chapter 6, Section 6.3 of the Explanatory Notes accompanying the TSS.
6.18.5(e)(1) and (2)	Energex must demonstrate that the revenue expected to be recovered from a tariff class lies between the stand alone and avoidable cost.	Section 3.3.5(SCS). Section 4.4.1 (ACS). Section 2.2 of the TSS.

Clause	Requirement	Reference
6.18.5(f)	Energex must demonstrate that its tariffs are based on the long-run marginal cost.	Section 3.3.6(SCS) Section 4.4.2 (ACS)
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect Energex's total efficient of serving the retail customers that are assigned to that tariff (2) when summed with the revenue expected to be received from all other tariffs, permit Energex to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for Energex; and (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in clause 6.18.5(f) which requires Energex's tariffs to be based on LRMC.	Section 3.3.7 (SCS) Section 4.4.3 (ACS)
6.18.5(h)	Energex must consider the impact on customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with clauses 6.18.5(e) to 6.18.5(g) to the extent Energex considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in clauses 6.18.5(f) and 6.18.5(g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) the extent to which customers can choose the tariff to which they are assigned; and (3) the extent to which customers are able to mitigate the impact of changes in tariffs through their usage decisions.	Section 5.1
6.18.5(i)	The structure of each tariff must be reasonably capable of being understood by customers that are assigned to that tariff, having regard to: (1) the type and nature of those retail customers; and (2) the information provided to, and the consultation undertaken with, those customers.	Section 3.3.8. Section 2.6 of the TSS
6.18.5(j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Appendix 5.
6.18.6(b)	Energex must demonstrate that the weighted average to be raised from a tariff class for a particular regulatory control year of a regulatory control period does not exceed the corresponding expected weighted average revenue for the preceding regulatory year in that regulatory year by more than the "permissible percentage" defined in clause 6.18.6(c).	Section 3.3.4.
6.18.7(a)	Energex's Pricing Proposal must demonstrate that tariffs passed on to customers include the charges to be incurred by Energex for DPPC.	Section 3.4.2.

Clause	Requirement	Reference
6.18.7(b)	Energex must demonstrate that the DPPC charges passed on to customers do not exceed the estimated DPPC charges adjusted for over or under recovery in the previous regulatory year.	Section 3.4.3.
6.18.7(c))	Energex must demonstrate that any DPPC over or under recovery is calculated in a way that: (1) is consistent with the method determined by the AER in the relevant distribution determination for Energex; (2) ensures that Energex is able to recover from retail customers no more and no less than the DPPC it incurs; and (3) adjusts for an appropriate cost of capital consistent with the allowed rate of return used in the relevant determination for the relevant regulatory year.	Section 3.4.3.
6.18.7(d)	Energex must demonstrate that is does not recover DPPC to the extent these are: (1) recovered through Energex's annual revenue requirement; (2) recovered through tariffs designed to pass on jurisdictional scheme amounts under clause 6.18.7A; or (3) recovered from another DNSP.	Section 3.4.2.
6.18.7A(a)	Energex's Pricing Proposal must provide for tariffs designed to pass on to customers Energex's jurisdictional scheme amounts for approved jurisdictional schemes.	Section 3.5.1.
6.18.7A(b)	Energex's Pricing Proposal must demonstrate that the amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for Energex's approved jurisdictional schemes adjusted for over or under recovery calculated in accordance with clause 6.18.7A(c).	Section 3.5.2.
6.18.7A(c)	Energex must demonstrate that the over and under recovery has been calculated in a way that: (1) is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination; (2) ensures Energex is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; (3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	Section 3.5.2.
6.18.9(a)(3)	Energex must maintain on its website a statement of Energex's tariff classes and the tariffs applicable to each tariff class.	Tariff classes and tariffs to be updated on Energex's website upon AER's approval of the 2017-18 pricing proposal.

Clause	Requirement	Reference
6.18.9(b)	Energex must publish all information set out in clause 6.18.9(a)(3) is published on its website 5 business days from the date the AER publishes Energex's approved Pricing Proposal.	Energex's website.
6.19.2(a)	Subject to the Law and the Rules, all information about a service applicant or distribution network user used by Energex for the purposes of distribution service pricing is confidential information.	Appendix 8.
6.19.2(b)	No requirement in this Chapter 6 to publish information about a tariff class is to be construed as requiring publication of information about an individual retail customer.	Appendix 8.

Table A. 10 – Compliance with the Final Decision – Energex Determination 2015-2020

Section	Requirement	Reference
Attachment 14, Section 14.1, Figure 14.2.	Energex must demonstrate that the side constraints applied to the price movements of each tariff class are consistent with the side constraint formulae.	Section 3.3.4.
Attachment 14, Section 14.4.5	To the extent possible, Energex's pricing proposal should publicly disclose the separate charging parameters relating to DUoS, designated pricing proposal charges and jurisdictional scheme amount.	Appendix 1.
Attachment 14, Section 14.1, Figure 14.1 and Appendix A.	Energex must demonstrate compliance with the control mechanism for standard control services in accordance with the set revenue cap formulae – including adjustments for DUoS revenue under or over recovery in accordance with Appendix A of Attachment 14.	Section 3.3.2.
Attachment 14, Section 14.1, Appendix B.	Energex must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from DPPC and associated payments in accordance with Appendix B of Attachment 14.	Section 3.4.3.
Attachment 14, Section 14.1, Appendix C.	Energex must report to the AER as part of its annual pricing proposal its jurisdictional scheme recovery amounts in accordance with Appendix C of Attachment 14.	Section 3.5.3.
Attachment 14, Section 14.1, Appendix D.	Energex must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.	Section 2.5 and Section 4.5.
Attachment 16, Section 16.2, Section 16.3.	Energex must demonstrate the application of a price cap as the form of control for ancillary network services. The AER's control mechanism formulae must be applied to fee based services, quoted services and individual Type 5 and 6 meters.	Section 4.2.2.

Appendix 6: Glossaries

Table A. 11 – Acronyms and abbreviations

Abbreviation	Description
ACS	Alternative Control Service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AR	Annual Smoothed Revenue
ARR	Annual Revenue Requirement
CAC	Connection Asset Customers
Capex	Capital Expenditure
CPI	Consumer Price Index
CT	Current transformer
DCOS	Distribution Cost of Supply
DNSP	Distribution Network Service Provider
DPPC	Designated Pricing Proposal Charges (previously known as TUoS)
DUoS	Distribution Use of System
EG	Embedded Generators
ENA	Energy Network Australia
EOO	Luminaires owned and operated by Energex
FiT	Feed-in Tariff (Solar FiT) under the Queensland Solar Bonus Scheme
GOO	Luminaires gifted to Energex by a council and operated by Energex
HV	High Voltage
ICC	Individually Calculated Customers
LCC	Large Customer Connection
LRMC	Long Run Marginal Cost
LV	Low Voltage
MAR	Maximum Allowable Revenue
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules (or Rules)
NMI	National Meter Identifier
NTC	Network Tariff Code
NUoS	Network Use of System
O&M	Operating and Maintenance Allowance (Opex)
Opex	Operating and Maintenance Expenditure

Abbreviation	Description
PV	Photovoltaic (Solar PV)
PV	Present Value
QAO	Queensland Audit Office
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
Rules	National Electricity Rules (or NER)
SAC	Standard Asset Customers
SCS	Standard Control Service
STPIS	Service Target Performance Incentive Scheme
TAR	Total Annual Revenue
TNCP	Transmission Network Connection Point
TNSP	Transmission Network Service Provider
ToU	Time of Use
TSS	Tariff Structure Statement
TUoS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WAR	Weighted Average Revenue

Table A. 12 – Units of measurement used throughout this document

Base Unit	Unit name	Multiples used in this document
h	hour	GWh, kWh, MWh
V	volt	kV, kVA, MVA
VA	volt ampere	kVA, MVA
var	var	kvar
W	watt	W, kW, kWh, MW

Table A. 13 – Multiples of prefixes (units) used throughout this document

Prefix symbol	Prefix name	Prefix multiples by unit	Prefixes used in this document
G	giga	10^9	GWh
M	mega	1 million or 10^6	MW, MWh, MVA
k	kilo	1 thousand or 10^3	kV, kVA, kvar, kW, kWh

Table A. 14 – Definitions of terminology used throughout this document

Term	Abbreviation / Acronym	Definition
Alternative Control Service	ACS	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local DNSP. This service class includes the provision, construction and maintenance of type 6 metering services, street lighting assets, and fee based and quoted services.
Australian Energy Market Commission	AEMC	A national, independent body that exists to make and amend the detailed rules for the NEM to ensure efficient, reliable and secure energy market frameworks which serve the long term interests of consumers.
AEMC Power of Choice Review		Conducted by the AEMC, the Power of choice review sets out a substantial reform package for the NEM to provide consumers with more opportunities to make informed choices about the way they use electricity and manage expenditure. The package of reforms proposed by the AEMC includes, among other things: • reform of distribution network pricing principles to improve consumer understanding of cost reflective prices and give customers more opportunity to be rewarded for changing their consumption patterns. • expand competition in metering services with a view to provide services that reflect consumer preferences at efficient prices.
Annual smoothed revenue	AR	Refer to AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanism, October 2015.
Australian Energy Regulator	AER	The economic regulator of the NEM established under section 44AE of the *Competition and Consumer Act 2010* (Commonwealth).
Business hours	BH	8 am to 5 pm, Monday to Friday.
Capacity charge		This part of the tariff seeks to reflect the costs associated with providing network capacity required by a customer on a long term basis. It is levied on the basis of either contracted demand or forecasted capacity using prior year information. The charge is applied as a fixed dollar amount per kVA per month.
Capital expenditure	Capex	Expenditure typically resulting in an asset (or the amount Energex has spent on assets).
Charging parameter		The charges comprising a tariff. Parameters include demand, capacity, fixed and volume (flat or ToU) charges.
Common service		A service that ensures the integrity of a distribution system, benefits all distribution customers and cannot reasonably be allocated on a locational basis.
Connection Asset Customers	CAC	Typically, those customers connected at 11 kV who are not allocated to the ICC tariff class.

Term	Abbreviation / Acronym	Definition
Connection asset (Contributed or non-contributed)		Related to building connection assets at a customer's premises as well as the connection of these assets to the distribution network. Connection assets can be contributed (customer funded, then gifted to Energex) or non-contributed (Energex funded).
Connection point		The agreed point of supply established between a Network Service Provider and another Registered Participant, Non-Registered Customer or franchise customer. The meter is installed as close as possible to this location.
Customer		Refer to chapter 10 of the Rules.
Daily supply charge (or Fixed charge)		For large customers, reflects the incremental costs that arise from the connection and management of the customer. For small customers, reflects the average capacity set aside on the shared network for a typical customer using the tariff.
Demand		The amount of electricity energy being consumed at a given time measured in either kilowatts (kW) or kilovolt amperes (kVA). The ratio between the two is the power factor.
Demand charge		This part of the tariff accounts for the actual demand a customer places on the electricity network. The actual demand levied for billing purposes is the metered monthly maximum demand. The charge is applied as: • a fixed dollar price per kW per month or kVA per month for DPPC charges, and • a fixed dollar price per kVA per month for DUoS charges (ICC, CAC and SAC demand based customers).
Demand tariff		The tariff has been structured to include a demand component so the customer's actual demand is reflected in the price they pay for their electricity.
Designated Pricing Proposal Charge	DPPC	Refers to the charges incurred for use of the transmission network; previously referred to as Transmission Use of System (TUoS).
Distribution Cost of Supply Model	DCOS	The Energex model used to allocate costs approved by the AER to the various tariff classes.
Distribution Use of System	DUoS	This refers to the network charges which recover the costs of providing Standard Control Services.
Economy		Secondary tariff whereby a customer's specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Energex.
Embedded Generator	EG	In line with the ENA classification, EGs are generally those generators with an installed capacity as follows: Medium: 1-5 MVA (LV or HV) or < 1 MVA (HV) Large: > 5 MVA

Term	Abbreviation / Acronym	Definition
Energy (or usage)		Refer to the definition of Usage below.
Feed-in Tariff	FiT	The rate that is to be paid for the excess energy generated by customers and fed back into the electricity grid under the Queensland Solar Bonus Scheme. The FiT rate is determined by the Queensland Government and is paid by the purchaser of the excess energy.
Final Determination		A distribution Determination document published by the AER in its role as Energex's economic regulator that provides for distribution charges to increase during Energex's Regulatory Control Period. In this proposal, reference to the Final Determination refers to the 2015-2020 AER Final Determination.
High Voltage	HV	Refers to the network at 11 kV or above.
Individually Calculated Customer	ICC	Typically those customers connected at 110 kV or 33 kV, or connected at 11 kV and with electricity consumption greater than 40 GWh per year at a single connection point or demand greater than or equal to 10 MVA, or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted.
Large customer classification		As per tariff class assignment process for customers with consumption greater than 100 MWh per year.
Large customer connection	LCC	Large customer connections are those connections that fall within the tariff classes of Individually Calculated Customer (ICC) and Connection Asset Customer (CAC) including embedded generators with installed capacity greater than or equal to 30 kVA.
Long Run Marginal Cost	LRMC	An estimate of the cost (long term variable investment) of augmenting the existing network to provide sufficient capacity for one additional customer to connect to the network or an additional MW of demand.
Low Voltage	LV	Refers to the sub-11 kV network
Maximum Allowable Revenue	MAR	The maximum revenue which can be recovered through tariffs for the regulatory year. This terminology is no longer in use as per the AER's F&A.
Maximum demand		The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network.
Micro Generator		AS4777-compliant generators with an installation size of less than 10 kW (single phase) or 30 kW (three phase) connected to the LV network.

Term	Abbreviation / Acronym	Definition
Market Settlement and Transfer Solution	MSATS	The central repository for Standing Data for all NMIs in contestable markets.
National Electricity Law	NEL	The legislation that establishes the role of the AER as the economic regulator of the NEM and the regulatory framework under which the AER operates.
National Electricity Market	NEM	The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.
National Electricity Rules	NER (the Rules)	The legal provisions (enforced by the AER) that regulate the operation of the NEM and the national electricity systems, the activities of market participants and the provision of connection services to retail customers.
National Metering Identifier	NMI	A unique number assigned to each metering installation.
Network Coupling Point	NCP	The point at which connection assets join a distribution network, used to identify the distribution service price payable by a customer.
Network Tariff Code	NTC	Energex's nominated code that represents the network tariff being charged to customers for network services.
Network Use of System	NUoS	The tariff for use of the distribution and transmission networks. It is the sum of both Distribution Use of System (DUoS) and Designated Pricing Proposal Charge (DPPC).
Non-demand tariff		The tariff is based around a fixed daily component and the actual usage (or energy), expressed in kWh, used by the customer.
Non-standard		Where specialist resources or extensive man-hours for a small customer connection are required to assess the applicants proposed changes to connection agreements or standard methods of connection to the DNSP's network.
Off-peak period		All hours which are outside Peak and Shoulder periods.
Operating expenditure	Opex	Opex is the combined total of maintenance and operating costs. Maintenance Costs are those that are directly and specifically attributable to the repair and maintenance of network assets, while Operating Costs are those that relate to the day to day operations of Energex which are not maintenance costs.
Peak period		Meter Type 1–4 (ICC, CAC & SAC demand based): The hours between 7 am and 11 pm, Monday to Friday. Meter Type 6 (SAC Non-demand Small Business): The hours between 7 am and 9 pm, Monday to Friday. Meter Type 6 (SAC Non-demand based Residential): The hours between 4 pm and 8 pm, Monday to Friday.

Term	Abbreviation / Acronym	Definition
Power factor		Power factor is the ratio of kW to kVA, and is a useful measure of the efficiency in the use of the network infrastructure. The closer the power factor is to one (1), the more efficiently the network assets are utilised. Power factor = kW / kVA
Preliminary Decision		A Preliminary Decision is produced by the AER in its role as Energex's economic regulator. A Preliminary Decision is an interim Determination for the forthcoming regulatory period provided to Energex by the AER, prior to the release of a Final Determination. In this proposal, reference to the Preliminary Decision refers to the Preliminary Decision Energex determination 2015-16 to 2019-20.
Price path		Outlines the escalation factors to be applied to the initial price over the *Regulatory Control Period.*
Pricing objectives		Objectives established by Energex to complement (and ensure compliance with) the pricing principles set out in the Rules, and to provide clarity when formulating tariffs.
Pricing principles		The pricing principles are established in clause 6.18.5 of the Rules and provide guidance to Energex for setting tariffs.
Pricing Proposal		This document. Prepared by Energex in accordance with clause 6.18.2 of the Rules. It is provided to the AER for approval and outlines how Energex will collect its revenue during the relevant regulatory year.
Queensland Government Solar Bonus Scheme	SBS FiT	A program that pays residential and other small energy customers for the surplus electricity generated from roof-top solar photovoltaic (PV) systems that is exported to the Queensland electricity grid.
Regulatory Control Period		A standard Regulatory Control Period for DNSPs is a period of not less than 5 regulatory years. Energex's current Regulatory Control Period is 2015-20, commencing 1 July 2015.
Regulatory depreciation		Also referred to as the return of capital – the sum of the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).
Regulatory year		A specific year within the regulatory control period.
Return on capital		The return necessary to achieve a fair and reasonable rate of return on the assets necessarily invested in the business.
S-banking		Mechanism allowing Energex to propose delaying a portion of the STPIS revenue increment or decrement to reduce price volatility to customers in accordance with clauses 6.4.3(a)(6) and 6.4.3(b)(6).
Service Target Performance Incentive Scheme	STPIS	A scheme developed and published by the AER in accordance with clause 6.6.2 of the Rules, that provides incentives (that may include targets) for DNSPs (including Energex) to maintain and improve network performance.

Term	Abbreviation / Acronym	Definition
Shoulder period		The hours between 7 am to 4 pm and 8 pm to 10 pm, Monday to Friday and 7 am to 10 pm weekends. For residential ToU tariff (NTC8900).
Side constraint		A side constraint is an upper limit on price increases applied at the tariff class level for SCS and is calculated in accordance with clause 6.18.6 of the Rules by taking into account volume forecasts, CPI, X Factor, STPIS and Capital Contributions. The purpose of a side constraint is to mitigate the impact of prices on customers from one year to the next within a regulatory control period.
Site-specific charge		This charge is calculated for a site and is specific to the individual connection point.
Small customer classification		As per tariff class assignment process for customers with consumption less than 100 MWh per year.
Smart control		Secondary tariff whereby a customer's specified permanently connected appliances are connected to audio frequency load control relays. The tariff is only available to residential customers with advanced metering for both the primary and secondary tariffs. This tariff has been developed to complement Energex's demand tariffs and to incentivise residential customers to invest in emerging technologies (such as batteries and electric vehicles) that will benefit the network by targeting localised peaks.
Solar Photovoltaic	Solar PV	A system that uses sunlight to generate electricity for residential use. The system provides power for the premises with any excess production feeding into the electricity grid.
Standard Asset Customer	SAC	Generally those customers connected to the LV network.
Standard Control Service	SCS	Distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. This service classification includes network services (e.g. construction, maintenance and repair of the network), some connection services (e.g. small customer connections) and Type 7 metering services (i.e. unmetered connections such as traffic lights).
Street lights (Major)		Lamps in common use for major road lighting including: a) High Pressure Sodium 100 watt (S100) and above; b) Metal Halide 150 watt (H150) and above; and c) Mercury Vapour 250 watt (M250) and above.
Street lights (Minor)		All lamps in common use for minor road lighting, including Mercury Vapour, High Pressure Sodium and Fluorescent.
Super economy		Secondary tariff whereby a customer's specified permanently connected appliances are controlled by network equipment so that supply will be permanently available for a minimum period of 8 hours at the absolute discretion of Energex but usually between the hours of 10:00 pm and 6:00 am.

Term	Abbreviation / Acronym	Definition
Tariff		The set of charges applied to a customer in the respective billing period. A tariff consists of one or more charging parameters that comprise the total tariff rate.
Tariff class		A class of customers for one or more *direct control services* who are subject to a particular tariff or particular tariffs (as per chapter 10 of the Rules).
Tariff Schedule		The Tariff Schedule is published by Energex annually at the beginning of the financial year and outlines its tariffs for SCS and ACS. It also provides information about how Energex assigns customers to tariff classes and the internal review process undertaken if a customer requests a review of a decision. The Tariff Schedule applies for the duration of the relevant financial year.
Tariff Structure Statement	TSS	Document prepared in accordance with Part I of chapter 6 of the Rules, setting out Energex's network price structures and indicative tariffs that will apply over each year of the regulatory control period. Energex submitted its 2017-20 TSS proposal to the AER in November 2015. Once approved, the TSS will take effect from 1 July 2017.
Time of use	ToU	Refers to tariffs that vary according to the time of day at which the electricity is consumed. The Time of Use (ToU) periods include Off-peak, Peak and Shoulder
Total annual revenue	TAR	Refer to AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanism, October 2015.
Transmission Use of System	TUoS	Superseded terminology for Designated Pricing Proposal Charges (DPPC) which are charges incurred for use of the transmission network.
Unmetered supply		A customer who takes supply where no meter is installed at the connection point.
Usage (or energy)		The amount of electricity consumed by a customer (or all customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Usage charge		This part of the tariff seeks to reflect costs not directly allocated to network drivers and costs that are proportional to the size of the customer. The energy consumption (kWh) for the period, as recorded by the customer's meter, is utilised to calculate this part of the tariff charge. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh), i.e. c/kWh.
Usage charge - Off-peak		This charge is applicable to those customers who are on a Residential and/or Business Time of Use (ToU) tariff. The energy consumption (kWh) during off-peak periods (refer to Off-peak Period for times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh), i.e. c/kWh.

Term	Abbreviation / Acronym	Definition
Usage charge - Peak		This charge is applicable to those customers who are on a Residential and/or Business Time of Use (ToU) tariff. The energy consumption (kWh) during peak periods (refer to Peak Period for times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh) i.e. c/kWh.
Usage charge - Shoulder		This charge is applicable to those customers who are on a Residential Time of Use (ToU) tariff. The energy consumption (kWh) during shoulder periods (refer to Shoulder Period for times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh), i.e. c/kWh.
Weighted Average Cost of Capital	WACC	The return a business must earn on an existing asset base. For Energex, the WACC is set by the AER in a Determination for a specific regulatory control period.
Weighted Average Revenue	WAR	This is the average revenue that is expected to be recovered by tariff class during the relevant regulatory control year.
X Factor		Under the CPI – X form, prices or allowed revenues are adjusted annually for inflation (CPI) less an adjustment factor 'X'. The X Factor represents the change in real prices or revenues each year, so the DNSP can recover the costs that it expects to incur over the regulatory control period.

Appendix 8 - Confidentiality template

Title, page and paragraph number of the document containing the confidential information	Description of the confidential information	Topic the confidential information relates to (e.g. capex, opex, the rate of return)	Provide a brief explanation of why the confidential information falls into the selected category	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers)
Tariff Analysis Template 2017-18 CONFIDENTIAL.xls; worksheet: ICC Summary	Individually Calculated Customers (ICC) Site Specific tariffs.	2017-18 proposed tariffs for the ICC tariff class.	Site specific prices are not published due to the confidentiality requirements of the customer. Energex will provide these site-specific tariffs directly to the customer and their retailer.	Personal Information	There is little or no public benefit to disclosing Individual Calculated Customers' prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.
Tariff Analysis Template 2017-18 CONFIDENTIAL.xls; worksheet: CAC Summary	Connection Asset Customers (CAC) Site Specific Tariffs	2017-18 proposed tariffs for the CAC tariff class.	Site specific prices are not published due to the confidentiality requirements of the customer. Energex will provide these site-specific tariffs directly to the customer and their retailer.	Personal Information	There is little or no public benefit to disclosing CAC site specific prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.