Energex

Annual Pricing Proposal

1 July 2016 to 30 June 2017

energex

positive energy

Version control

Version	Date	Description
V.1	29/04/16	Pricing Proposal submitted to the AER for approval
V.2	9/05/16	Minor amendments to Table 2.2, Table 8.1 and Table A1. Revised Table 11.11 to account for detailed AH meter installation charges.

Energex Limited (Energex) is a Queensland Government Owned Corporation 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.

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1 Introduction

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposal

(a) A Distribution Network Service Provider must:

(2) submit to the AER, at least 2 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.

1.1 Introduction

This document is Energex's Annual Pricing Proposal for 2016-17. It has been prepared for the second year of Energex's 2015-20 regulatory control period and is submitted for review and approval by the Australian Energy Regulator (AER), in accordance with clause 6.18.2(a)(2) of the National Electricity Rules (the Rules).

This document has been developed in accordance with, and complies with, the requirements of:

- The National Electricity Law (NEL).[1]
- The National Electricity Rules, Version 65.[2] Transitional arrangements in Section 11.73.1(b) of the Rules stipulate that the requirements set out in chapter 6 of version 65 of the Rules apply to Energex in the first and second regulatory years of the 2015-20 regulatory control period.
- Final Decision Energex Determination 2015-16 to 2019-20 (AER, October 2015).[3]
- Final Framework and Approach (F&A) for Energex and Ergon Energy Regulatory control period commencing 1 July 2015.[4]

Specifically, this Pricing Proposal describes the methodology and pricing principles Energex has followed to develop the tariff classes, network tariffs and charging parameters to recover its allowed revenue for the year commencing 1 July 2016 and ending 30 June 2017.

This 2016-17 Pricing Proposal represents the final pricing proposal prepared under the transitional arrangements outlined in clause 11.73.1(b) of the Rules. Under the new arrangements taking effect on 1 July 2017, Energex's 2017-18 Pricing Proposal will be required to comply with the 2017-20 Tariff Structure Statement (TSS) approved by the AER.

In October 2015, the AER released its Final Decision on Energex's Determination for the 2015-20 regulatory control period which substituted the April 2015 Preliminary Decision. The revised annual revenue to be recovered by Energex from customers is lower than initially anticipated, 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 Queensland Solar Bonus Scheme. The revenue approved in the Final Decision forms the basis of Energex's prices provided in Appendix 1 of this 2016-17 Pricing Proposal.

[1] The National Electricity Law is established by the National Electricity (South Australia) Act 1996, 30 January 2015.
[2] AEMC, National Electricity Rules V65, 1 October 2014.
[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.

1.2 Structure of this document

Table 1-1 – Pricing proposal structure

Chapter	Title	Overview
2	Pricing framework	Outlines the framework and methodology for setting tariffs. The pricing framework details the modelling inputs and outputs used to develop network tariffs to recover allowed revenue.
3	Standard control services: Tariff classes	Sets out the tariff classes for SCS and the basis for the tariff classes.
4	Standard control services: Network tariffs	For each SCS tariff class, sets out the tariffs and charging parameters for the 2016-17 regulatory year.
5	Recovery of distribution costs	Outlines Energex's approach to recovering DUoS charges. Includes details on the weighted average revenue for SCS tariff classes, and the formula for calculating side constraints for 2016-17.
6	Application of pricing principles	Demonstrates how Energex applies the pricing principles stipulated in the Rules.
7	Transmission cost recovery	Outlines how adjustments to tariffs are calculated to recover Designated Pricing Proposal Charges including adjustments for DPPC over or under recovery.
8	Jurisdictional schemes	Outlines Energex's approach to meeting the requirements of jurisdictional schemes.
9	Assignment and reassignment of customers to tariff classes and tariffs	Outlines the process and procedures governing the assignment and re-assignment of customers to or between tariff classes and tariffs.
10	Alternative control services: Tariff classes	Profiles the tariff classes for ACS and the basis for the tariff classes.
11	Alternative control services: Tariffs	For each ACS tariff class, outlines the framework, tariffs and charging parameters.
12	Changes from previous regulatory year	Outlines annual adjustments to total allowed revenue components, changes to tariff classes and tariffs, and Energex's approach to price setting between 2015-16 and 2016-17.
13	Customer impacts	Examines the impact on customers from the tariffs that will be implemented in 2016-17.
14	Publication of information about tariffs and tariff classes	Specifies the documents relating to tariffs and pricing that will be published on the Energex website.
	Appendices	Provides additional supporting information.

1.3 Confidential information

As provided for in clause 6.19.2 of the Rules, Energex claims confidentiality over the Energex Tariff Analysis Template 2016-17 which accompanies this 2016-17 Annual Pricing

Proposal. The Tariff Analysis Template contains the site specific tariffs for the Individually Calculated Customers (ICC) and Connection Asset Customers (CAC) which are not published in this Pricing Proposal due to confidentiality requirements. Publication of these network tariffs would be in breach of clause 6.19.2 of the Rules and the connection agreements between Energex and its customers.

Energex has provided information in Appendix 9 to support this requirement in accordance with the Better Regulation Confidentiality Guideline released by the AER in November 2013.[5]

1.4 Further information

Requests and enquiries concerning this document should be sent by email to networkpricing@energex.com.au.

[5] AER, Better Regulation Confidentiality Guideline, November 2013.

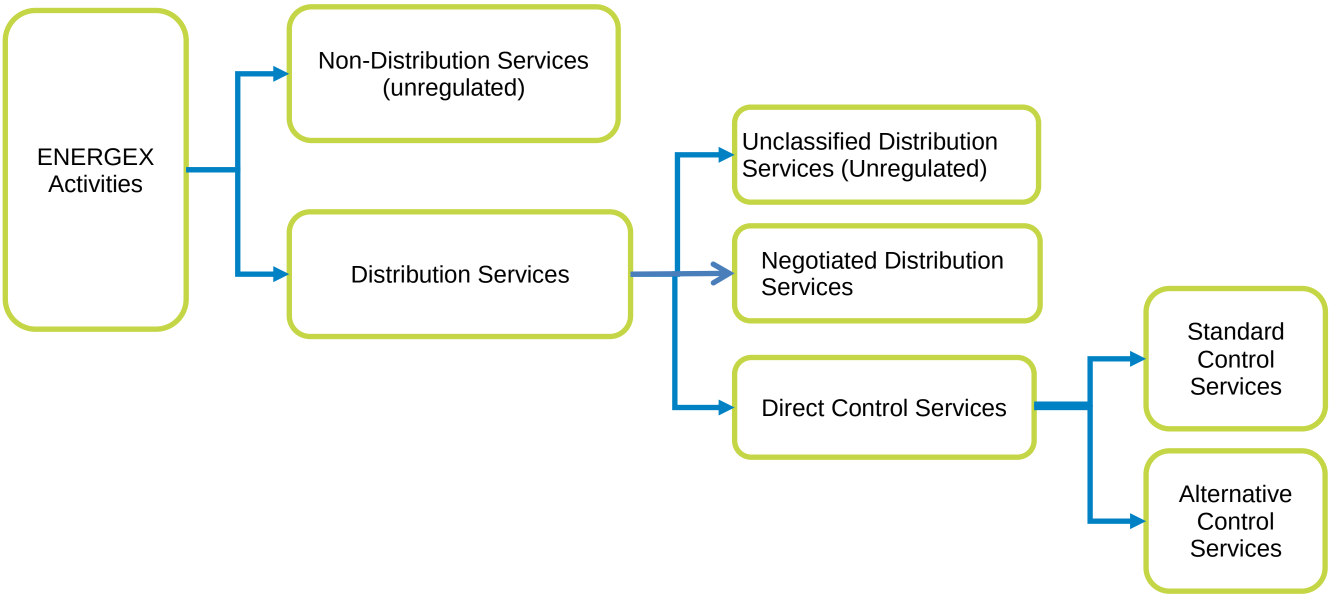
2 Pricing framework

2.1 Classification of distribution 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.

This Pricing Proposal refers to the tariff classes and tariffs for those distribution services classified as direct control services as shown in Figure 2-1.

Figure 2-1 – Classification of Energex's distribution services



In the final F&A issued in April 2014 and confirmed in the Final Decision, the AER classified distribution 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 poles and wires (distribution system) to customers. 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. Energex charges for ACS as a limited building block price cap, price cap or quoted price, depending on the services. ACS include services such as Type 6 metering services, public lighting services[6], an increasing number of connection services, and ancillary services. More information about ACS is included in Chapter 10 and Chapter 11.

2.2 Pricing principles and objectives

When setting SCS tariffs for 2016-17, Energex's objective is to ensure its total annual revenue (TAR), as set by the AER, is recovered from customers in a manner consistent with the pricing principles as outlined in clause 6.18.5 of the Rules. The pricing principles require Energex to demonstrate that:

[6] The conveyance of electricity to street lights remains a SCS, while services relating to the provision, construction and maintenance of street lighting assets have been classified by the AER as ACS.

- The revenue expected to be recovered from a tariff class lies between the stand alone and avoidable cost (clause 6.18.5(a)(1) and (2)).

- Tariffs and charging parameters take into account the long-run marginal cost (clause 6.18.5(b)(1)).

- Tariff and charging parameters have regard to the transaction costs to customers (clause 6.18.5(b)(2)(i)).

- Tariffs and tariff components are set with regard to whether customers are able or likely to respond to price signals (clause 6.18.5(b)(2)(ii)).

Detailed information about Energex's application of and compliance with the pricing principles is set out in Chapter 6.

For ACS, the objective is to ensure that the prices charged are cost-reflective and consistent with the pricing principles.

In addition to the pricing principles established under the Rules, Energex applies a number of pricing objectives in the formulation of tariffs which are described in Table 2-1. These pricing objectives are intended to complement the pricing principles and provide clarity when formulating network tariffs.

Table 2-1 – Energex's pricing objectives

Pricing objective	Description
No cross-subsidisation	To the maximum extent possible, for a network user, or group of users, there should be no cross-subsidies between each SCS tariff class.
Network efficiency	To the maximum extent possible, tariffs should incorporate appropriate signals to inform network users of their impact on existing and future network capacity and costs, and to encourage demand management.
Equity	To the maximum extent possible, tariffs should be equitable for customers and should reflect the user's utilisation of the existing network and the use of specific dedicated assets.
Price stability	Tariffs should not widely fluctuate over time to permit customers to make informed investment decisions.
Cost-reflectivity	As far as possible, tariffs should reflect the actual cost of service provision to customers.
Simplicity	Tariffs should be simple and straightforward to apply, based on a well-defined and clearly explained methodology and be readily understood by customers.

The pricing objectives in Table 2-1 are consistent with the Australian Energy Market Commission (AEMC) rule change introducing new pricing principles under which network tariffs must be developed from 1 July 2017.[7] Energex is of the view that implementing the pricing objectives in 2016-17 will ensure a smooth transition to Energex's tariff reform outlined in its 2017-20 TSS proposal.[8]

[7] AEMC, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No.9, 1 December 2014.
[8] Energex, Tariff Structure Statement 1 July 2017 to 30 June 2020, November 2015.

2.3 Setting the 2016-17 tariffs

This section provides an overview of how Energex's TAR is recovered through tariffs for SCS. More information about tariff classes, tariffs and charging parameters is available in Chapters 3 and 4, respectively.

2.3.1 Total annual revenue

Energex's SCS are regulated under a revenue cap form of price control determined by the AER in the Final Decision.[9] When calculating the TAR for 2016-17, Energex has applied the following 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 2016-17.

AR_{t-1} is the annual smoothed expected revenue for 2015-16.

ΔCPI_t is the annual percentage change in the ABS CPI All groups, Weighted Average of Eight Capital Cities, from the December quarter in 2014 to the December quarter in 2015.

X_t is the X-factor for 2016-17 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 2016-17.

TAR_t is the total annual revenue in 2016-17.

p_t^{ij} is the price of component j of tariff i in 2016-17.

q_t^{ij} is the forecast quantity of component j of tariff i in 2016-17.

I_t is final carryover from the application of the DMIS from the 2010-15 distribution determination. This amount is deducted from the allowed revenue in the 2016-17 Pricing Proposal.

B_t is the sum of under-recoveries relating to the capital contributions in 2014-15 and 2015-16, and the under-recoveries in DUoS charges in 2014-15.

C_t is the sum of the feed-in tariff (FiT) pass-through amounts relating to the 2014-15 regulatory year.

Table 2-2 below details the TAR calculation for 2016-17. 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. Section 12.1 provides a summary of the annual adjustments used to calculate the TAR.

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

In addition to the TAR, Designated Pricing Proposal Charges (DPPC)[10] and jurisdictional scheme amounts, including FiT payments made under the Solar Bonus Scheme (SBS) and the AEMC levy, are then allocated to customers.

In 2016-17, the total revenue that Energex will need to recover from network users is approximately $2,167.48 million.

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

Table 2-2 – 2016-17 Total Revenue calculations

Component	Amount ($m)	Comments/reference
Annual Revenue (AR_{t-1})	**1,139.80**	2015-16 annual smoothed expected revenue as per the AER's Final Decision and the PTRM.
• Consumer Price Index (CPI_t)	1.69%	Annual percentage change in the CPI All Groups, Average of Eight Capital Cities from the December quarter in 2014 to the December quarter in 2015 as published on the Australian Bureau of Statistics (ABS) website.
• X Factor (X_t)	-2.09%	X factor for 2016-17 updated as a result of the annual return on debt update, as determined by the AER.
• STPIS (S_t)	5.49%	S-factor determined in accordance with the STPIS requirements. Includes 2013-14 and 2014-15 STPIS.[1,2]
Impact on Revenue	***108.43***	
Annual Smoothed Expected Revenue 2016-17 (AR_t)	**1,248.22**	
Adjustments:		
• DMIS carryover amount (I_t)	(5.24)	Final figure as per the AER's decision.[3]
• DUoS 2014-15 under recoveries (B_t)	22.36	Under recovery for 2014-15
• Capital contributions under recoveries (B_t)	17.40	Under recovery for 2014-15
• Solar Bonus Scheme (SBS) FiT payment pass-through (C_t)[4]	219.55	Pass-through amount for SBS FiT payments based on under recovery in 2014-15 as approved by the AER.
Total Annual Revenue (TAR)[5]	**1,502.30**	
Further adjustments:		
• Jurisdictional Schemes	180.78	Queensland SBS Jurisdictional Scheme for 2016-17 and AEMC levy amounts for 2015-16 and 2016-17
• DPPC	484.80	Transmission cost to be recovered in 2016-17.
Total Revenue Requirement[6]	**2,167.88**	Total revenue that Energex will need to recover in 2016-17

Component	Amount ($m)	Comments/reference

Notes:

1. 2013-14 STPIS, designed for collection in 2015-16, is collected in 2016-17 to maintain price stability.
2. Energex's annual performance for 2013-14 and 2014-15 against STPIS resulted in S-factors of 2% and 1.5% respectively. The 2013-14 S-factor was previously banked and the 2014-15 performance reward will not be banked. The S-factors were further adjusted for the step change in revenues between regulatory periods.
3. AER, Decision Applications by DNPs for Demand Management Innovation Allowance for: Victorian DNSPs, TasNetworks, Other DNSPs, April 2016.
4. Refer to the AER's Determination 2014-15 Queensland Solar Bonus Scheme pass-through for Energex, December 2015.
5. DUoS under recoveries over the 2010-15 regulatory control period have been carried over into the building blocks for the 2015-20 regulatory control period.
6. Due to rounding, individual components may not sum to the total.

2.3.2 Revenue allocation

The first stage of the tariff setting process is to allocate or assign network costs to the tariff classes in the most cost-reflective way. Energex's tariff classes for SCS are:

- Individually Calculated Customers (ICC).
- Connection Asset Customers (CAC) – including customers formally classified as Embedded Generators.
- Standard Asset Customer (SAC) – including customers formally classified as SAC Demand and SAC Non-Demand.

A description of these tariff classes, including customer eligibility, is included in Chapter 3.

Energex allocates costs to its tariff classes using a Distribution Cost of Supply (DCOS) model. This modelling process is explained in Appendix 2. The allocation of costs to recover the TAR is illustrated in Figure 2-2.

Figure 2-2 – 2016-17 Revenue allocation flowchart

Annual revenue after tax (unsmoothed)	
$1,199.7 m	
Adjustment	
CPI and X factor smoothing	-16.4 m
STPIS	$65.0 m
Annual Smoothed Expected Revenue (AR)	
$1,248.2 m	
Further adjustments	
DUoS 2014-15 under recovery	$22.4 m
DMIS carryover	-$5.2 m
Capital contributions	$17.4 m
SBS FiT pass through	$219.6 m
Total Annual Revenue (TAR)[1]	
$1,502.3 m	

Regulatory Depreciation		Return on Capital		Operating & Maintenance Costs	
$107.0 m		$892.1 m		$451.0 m	
plus Tax	$3.9 m	plus Tax	$32.1 m	plus Tax	$16.2 m
$110.9 m		**$924.2 m**		**$467.2 m**	
7.4%		61.5%		31.1%	

Distribution Cost of Supply Categories[1]		
System	**Common Services**	**Non-system**
$1,414.3 m	$16.2 m	$71.8 m

Other	
Jurisdictional schemes	**DPPC**
$180.8 m	$484.8 m

Allocated Costs[1]		
Individually Calculated Customers (ICC)	**Connection Asset Customer (CAC)**	**Standard Asset Customer (SAC)**
DUoS $40.9 m	DUOS $122.8 m	DUOS $1,338.6 m
DPPC $46.9 m	DPPC $68.5 m	DPPC $369.5 m
Jurisdictional schemes $3.7 m	Jurisdictional schemes $13.9 m	Jurisdictional schemes $163.2 m

Expected Revenue[1]		
Individually Calculated Customers (ICC)	**Connection Asset Customer (CAC)**	**Standard Asset Customer (SAC)**
DUoS $40.9 m	DUoS $122.8 m	DUoS $1,338.6 m
DPPC $46.9 m	DPPC $68.5 m	DPPC $369.5 m
Jurisdictional schemes $3.7 m	Jurisdictional schemes $13.9 m	Jurisdictional schemes $163.2 m

Allocated Costs minus Expected Revenue[1]		
DUoS $0.0 m	DUoS $0.0 m	DUoS $0.0 m
DPPC $0.0 m	DPPC $0.0 m	DPPC $0.0 m
Jurisdictional schemes $0.0 m	Jurisdictional schemes $0.0 m	Jurisdictional schemes $0.0 m

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

2.3.4 DUoS overers and unders account

FINAL DECISION REQUIREMENT

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.

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 overs and unders account for the most recently completed regulatory year (t-2) and the next regulatory year (t). For this 2016-17 Pricing Proposal, year t-2 is 2014-15 and year t is 2016-17.

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 2014-15 DUoS under recovery to be passed through in the 2016-17 TAR

The AER's Final Decision treats the 2014-15 DUoS under recovery as an adjustment which has been passed through in the 2016-17 TAR. Further, the AER's Final Decision utilises clauses 6.4.3(a)(6) and 6.4.3(b)(6) of the Rules which allow the carry forward of balances of a control mechanism from one regulatory control period to the next. Consequently the under recovery balance for regulatory years 2010-11, 2011-12 and 2012-13 have been incorporated into the building block for the 2015-20 regulatory control period and therefore removed from the DUoS overs and unders account.

The AER requires the amounts used in Table 2-3 for the most recently completed regulatory year (t-2) (i.e. 2014-15) to be audited.[11] 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 overs and unders account is detailed in Table 2-3.

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

Table 2-3 – DUoS overs and unders account

Overs/unders account element	2014-15 actual ($'000)	2016-17 forecast ($'000)
(A) Actual Revenue from DUoS charges	1,906,174	1,502,296
Foregone revenue	69,453	0
(B) Revenue from DUoS charges (inclusive of foregone revenue)	**1,975,627**	**1,502,296**
(C) Less Total Annual Revenue for the relevant year	1,994,846	1,502,296
Plus Annual revenues (AR)	1,745,316	1,183,229
Plus Service Performance Incentive Scheme (STPIS)	34,557	64,995
Plus Demand Management Incentive Scheme carryover amount		-5,238
Plus DUoS under/over adjustment approved by the regulator for year t-2[1]		22,355
Plus Transitional under/over adjustments (capital contributions 2014-15)[1]	29,359	17,403
Plus Approved pass throughs and other adjustments	185,614	219,552
(B minus C) Actual under/over recovery year t-2 (proposed under/over adjustment in year t)	**-19,219**	**0**
DUoS Unders and Overs Account		
Nominal WACC for year t-2	9.72%	N/A
Nominal WACC for year t-1	6.01%	N/A
Opening balance	$0	-22,355
Interest on opening balance for 1 regulatory year	$0	N/A
Actual under/over recovery in year t-2 (proposed under/over adjustment in year t)	-19,219	22,355
Interest on under/over recovery for 2 regulatory years	-3,135	N/A
Closing balance[2]	**-22,355**	**0**

Notes:

1. As per the Final Decision, DUoS and Capital Contributions under-recoveries from the 2010-11, 2011-12 and 2012-13 regulatory years have been incorporated in the building block for the 2015-20 regulatory control period. 2014-15 DUoS and capital contribution under recoveries will be recovered in 2016-17 as adjustments.
2. Due to rounding, individual components may not sum to total.

2.3.5 Demand, energy and customer numbers forecasts

As part of the Regulatory Information Notice (RIN) prepared for the regulatory proposal, Energex provided the AER with details of the demand and energy forecasts, and expected numbers of customers throughout the 2015-20 regulatory control period.

When submitting its revised regulatory proposal, Energex revised its system maximum demand to account for a 6.9 per cent increase following higher than expected peak demand over the 2014-15 summer period. While not explicitly approved by the AER in the Final Decision, Energex's forecast was considered to be reasonable.

In its Final Decision, the AER accepted the customer number and energy consumption forecasts.

Using the most up to date assumptions, Energex has further refined its forecast to ensure greater accuracy in the development of the 2016-17 network prices. The revised forecast demand, volume and customer number are outlined in Table 2-4. It should be noted that undiversified Average Maximum Demand (MW) is used to allocate costs to tariffs while Average Demand (MVA) is used for billing purposes.

Table 2-4 – 2016-17 demand, energy and customer number forecasts by SCS tariff class

Tariff Class	ICC	CAC	SAC	Total
Average Demand (MVA)	419	826	1,583	**2,827**
Undiversified Average Maximum Demand (MW)[1,2]	366	755	8,243[3]	**9,364**
Volume (GWh)	2,097	3,771	15,201	**21,068**
Customer numbers	57	539	1,421,754	**1,422,350**

Note:

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.

The energy forecast for 2016-17 incorporates increasing energy conservation and ongoing growth in both residential customer numbers and solar PV.

The forecast customer numbers are based on actual customer numbers with a small allowance for population growth.

3 Standard control services: Tariff classes

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(1) set out the tariff classes that are to apply for the relevant regulatory year.

Clause 6.18.3 Tariff classes

(a) A pricing proposal must define the tariff classes into which retail customers for direct control services are divided.

(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 to whom alternative control services are supplied (but a customer for both standard control services and alternative control services may be a member of 2 or more tariff classes).

(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.

Under Chapter 10 of the Rules, tariff classes are defined as representing 'a class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs'.

Energex's tariff classes group retail customers on the basis of voltage level, usage profile and nature of connection in accordance with the principles set out in clause 6.18.4(a)(1) and 6.18.4(a)(2) of the Rules. This approach is considered to be efficient by ensuring a minimum number of tariff classes and lower transaction costs as per clause 6.18.3(d) of the Rules.

The underpinning characteristics of the tariff classes broadly reflect the costs associated with provision of service to those customers within the tariff class.

All customers who take supply from Energex for direct control services are a member of at least one tariff class. Where a customer has both SCS and ACS supplied, they may be a member of two or more tariff classes.

Tariff classes and detailed descriptions for SCS are outlined in Table 3-1.

Table 3-1 – 2016-17 SCS tariff classes

Tariff class	Eligible customers
Individually Calculated Customers (ICC)	Customers are allocated to the ICC tariff class if they are coupled to the network at 110 kV or 33 kV.[1] Customers with a network coupling point at 11 kV may also be allocated to the ICC tariff class only if they meet one or more of the following criteria: • the customer's electricity consumption is greater than 40 GWh per year at a single connection; and/or • the customer's annual maximum demand is greater than or equal to 10 MVA; and/or • the customer's circumstances mean that their average shared network charge becomes meaningless or distorted. Where there is a network on private property and there are site-specific

Tariff class	Eligible customers
	Energex costs associated with operating, maintaining and accessing the network, these costs should be applied directly to the users of those assets when it is economically efficient to do so.
Connection Asset Customers (CAC)	Customers with a network coupling point at 11 kV who are not allocated to the ICC tariff class (e.g. 11kV generators) are allocated to the CAC tariff class. CAC tariff charges are based on: • the actual dedicated connection assets utilised by the customers; plus • average charges for use of the shared distribution network including common and non-system assets by the relevant tariff class. Where there is a network on private property and there are site-specific Energex costs associated with operating, maintaining and accessing the network, these costs should be applied directly to the users of those assets when it is economically efficient to do so.
Standard Asset Customers (SAC)	All customers connected at LV are classified as SACs. SAC tariff charges 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. The tariff class also applies to 110 kV and 33 kV connected generators with an installed capacity greater than 30 kVA.

To comply with the Rules, Energex's process for tariff class and tariff assignment and reassignment ensures no direct control services customer can take supply without being a member of at least one tariff class. This is further discussed in Chapter 9 and illustrated in Table 9-1.

Information about ACS tariff classes, charging parameters and customer assignment to tariffs is available in Chapter 10 and Chapter 11.

4 Standard control services: Tariffs

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(2) set out the proposed tariffs for each tariff class.

Each tariff class consists of a number of individual tariffs that are established on the same basis as the tariff classes. 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. Furthermore, in developing its network tariffs, Energex has ensured that they are clear and easily understood by customers.

4.1 Description of tariffs

Typically, customers are restricted to accessing tariffs allocated to the tariff class to which they are assigned. However, in some circumstances, and at Energex's discretion, customers may be able to access tariffs from another tariff class.

It can be noted that, in anticipation of the introduction of new cost reflective network pricing principles to be implemented from 1 July 2017, Energex is proposing to introduce two new voluntary network tariffs from 1 July 2016: a demand tariff for residential customers (NTC7000 – Residential Demand) and a secondary load control tariff (NTC7300 – Smart Control) available to residential customers only. This new secondary load control tariff will provide a targeted tool to manage demand that will complement the broad brush approach achieved in using primary demand based tariffs.

The tariffs for SCS for 2016-17 are described in Table 4-1.

Table 4-1 – Descriptions of SCS tariffs for 2016-17

<table>
<tr><th>Tariff class</th><th>Tariff code</th><th>Tariff description</th></tr>
<tr><td>ICC</td><td>NTC1000 – ICC</td><td>The charges for ICCs are individually calculated on a site-specific basis and are confidential. Energex provides site-specific charges directly to the customer and their electricity retailer.
The charges for connection and access services for generators with a network coupling point at 33 kV or 110 kV will be developed on a similar basis to site-specific customers. This is due to the nature of connections, which are typically non-standard and may require additional embedded generator (EG) protection system upgrades.
In accordance with the Rules, all generators will receive a charge for connection services regardless of whether they are a net importer or exporter of electricity. However, DUoS charges will not be incurred on the export of electricity generated by the user into the distribution network. Generators who are net importers of electricity will receive appropriate network charges.</td></tr>
<tr><td rowspan="5">CAC</td><td colspan="2">Customers are allocated to one of the CAC tariffs based on the nature of their connection to the network.
Tariffs for CACs include a mix of site-specific charging parameters (daily supply charge) and general tariff class charging parameters (demand and usage charges).
Tariffs for the site-specific charging parameter (daily supply charge) are provided as a separate Attachment. CAC site-specific tariffs are confidential and Energex provides these site-specific charges directly to the customer and their electricity retailer.</td></tr>
<tr><td>NTC3000 – EG 11kV[1]</td><td>This tariff is no longer offered to new customers since 1 July 2015.
Previously, this tariff was allocated to customers who were predominantly generation customers with a generation capacity greater than 30 kVA. New customers with these characteristics are allocated to NTC4000 – 11kV Bus or NTC4500 – 11kV Line.</td></tr>
<tr><td>NTC4000 – 11kV Bus</td><td>Customers with a network coupling point at an 11kV substation bus via a dedicated 11kV feeder that is not shared with any customer.</td></tr>
<tr><td>NTC4500 – 11kV Line</td><td>Customers with a network coupling point at an 11kV feeder shared with other customers.</td></tr>
<tr><td>NTC8000 – HV Demand[1]</td><td>This tariff is no longer offered to new customers since 1 July 2015.
Previously, this tariff was allocated to 11kV customers with energy less than 4 GWh per year and demand less than 1MVA.
New customers with these characteristics are allocated to NTC4000 – 11kV Bus or NTC4500 – 11kV Line.</td></tr>
</table>

Tariff class	Tariff code	Tariff description
SAC	The tariffs are based on an average shared network charge and average connection charge. The charges for SAC tariffs are provided in Table A. 1 – 2016-17 SCS tariff charges in Appendix 1. Capital contributions may apply to newly connecting SACs and are sought as prepayment for a revenue shortfall in the case of an uneconomic connection. Energex's Connection Policy is available on the Energex website.[2]	
	NTC8100 – Demand Large	This tariff is available to large low voltage customers with consumption greater than 100 MWh per year. Small customers may voluntarily access this tariff. Customers must have appropriate Type 1-4 metering to access this tariff.
	NTC8300 – Demand Small	This tariff is the default tariff for low voltage customers with consumption greater than 100 MWh per year. Small customers with consumption less than 100MWh may voluntarily access this tariff. Customers must have appropriate Type 1-4 metering to access this tariff.
	NTC8500 – Business Flat	This tariff is the default tariff for low voltage business customers with consumption less than 100 MWh per year.
	NTC8800 – Business ToU	This tariff is available to business customers with consumption less than 100 MWh per year. This ToU tariff accounts for when, as well as how much, electricity is used by each customer. With ToU, electricity is priced differently depending on the time of day electricity is consumed during off-peak hours, peak hours and shoulder times. Customers must have ToU-capable metering installed to access this tariff. ToU charging timeframes are outlined in Table 4-2.
	NTC8400 – Residential Flat	This tariff is the default tariff for residential customers regardless of their size and cannot be used in conjunction with Residential ToU (NTC8900 – Residential ToU).
	NTC8900 – Residential ToU	This tariff is available to residential customers regardless of their size and cannot be used in conjunction with Residential flat (NTC8400 – Residential Flat). Customers must have a ToU-capable meter to access this tariff. ToU charging timeframes are outlined in Table 4-2.
	NTC7000 – Residential Demand[3,4]	This new demand tariff is available to residential customers regardless of their size and cannot be used in conjunction with tariff NTC8400 – Residential Flat or NTC8900 – Residential ToU. Customers must have a Type 1-4 meter to access this tariff.
	NTC9900 – Solar FiT[5]	This tariff is part of the SBS, and is available to eligible customers participating in the Scheme. The Queensland Government sets the FiT rate (cents per kWh – c/kWh) to be paid for the excess energy generated and fed back into the electricity grid: A 44 c/kWh FiT rate will be paid to customers who became part of the scheme before 9 July 2012

Tariff class	Tariff code	Tariff description
		up until 2028 where they continue to meet eligibility requirements.
	NTC9000 – Super Economy	Details provided in secondary tariffs' terms and conditions in Appendix 3.
	NTC9100 - Economy	Details provided in secondary tariffs' terms and conditions in Appendix 3.
	NTC7300 – Smart Control[3]	Details provided in secondary tariffs' terms and conditions in Appendix 3.
	NTC9600 – Unmetered	This tariff is applicable to unmetered supplies. This includes facilities such as street lighting, public telephones, traffic signals, public barbecues and watchman lights. Energex only provides connection to the network for these services. The unmetered supply tariff therefore seeks to only recover a contribution towards the shared network (use of system charge). For the provision of street lighting services, additional levies may be incurred; these will be recovered as an ACS.

Note:

1. These tariffs are no longer offered to new customers since 1 July 2015.
2. Energex, Connection Policy, 1 July 2015, available on the Energex website (https://www.energex.com.au/__data/assets/pdf_file/0011/269363/2015-20-Energex-Connection-Policy_FINAL-APPROVED-BY-AER.pdf).
3. New tariff available from 1 July 2016.
4. Financial Risk Reduction Mechanism (FRRM) applies to this tariff as per the terms and conditions set out in Appendix 4.
5. Additional information on eligibility under the scheme can be accessed from the Department of Energy and Water Supply (http://www.dews.qld.gov.au/energy-water-home/electricity/solar-bonus-scheme).

4.2 Charging parameters

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposal

(b) A pricing proposal must:

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

Consistent with the Rules, the tariffs proposed by Energex comprise a number of charging parameters to recover revenue associated with the elements of service, either DUoS, DPPC or jurisdictional schemes. Charging parameters are structured to provide signals to customers about the efficient use of the network capacity and costs. The tariff structure and the proportioning of charging parameters have been developed to achieve the pricing principles in the Rules and Energex's pricing objectives in Table 2-1. The charging parameters used in this Pricing Proposal are discussed below.

Daily Supply Charge

For large customers, where network usage signals are provided by other charging parameters, daily supply charges reflect the incremental costs that arise from the connection and management of the customer. For small customers, the daily supply charge recovers a proportion of the average capacity set aside on the shared network for a typical customer using the network.

Demand and capacity charges

Demand charges are reflective of augmentation costs associated with customer demand activity. There are two demand charge parameter types: monthly maximum demand charge and capacity charge.

Monthly maximum demand charge:

This charge is levied on the basis that network users who place greater pressure on the network should incur higher charges. Network expansion becomes necessary where there is a likelihood of demand exceeding available capacity. It is based on the half hour interval during the month where demand is at its highest. Demand charges signal to customers that they can reduce their electricity costs by reducing their demand during peak periods, and thus potentially reduce required future augmentation.

The application of demand charges is limited by the type of metering installed. Demand charges are not appropriate for customers with metering equipment only capable of measuring and recording delivered electricity volume (accumulation meters).

Capacity charge:

This charge is similar to a monthly maximum demand charge, but more effectively assigns an adequate share of costs associated with system augmentations to network users. The capacity charge reflects the amount of network which is set aside for the customer which could be used by the customer at any time. Capacity charge is only incorporated in the network tariff of large ICC business customers. The price signal provided by the capacity charge is discussed in Section 6.4.

Flat usage charge

The flat usage charge (also known as energy or consumption charge) parameter provides a mechanism to recover those costs that are not recovered through the demand charge or the daily supply charge parameters, and allocated to the energy level a customer consumes during a billing period.

ToU usage charges

ToU tariffs offer lower charges during off-peak and shoulder periods and higher charges during peak periods, and can be used instead of, or in conjunction with, a demand charge. The objective of a ToU usage charge is to reduce capacity constraints on the network during peak times by encouraging customers to switch non-essential electricity use to off-peak and/or shoulder periods. This can reduce the infrastructure expenditure required to meet increasing peak demand and ensure resources are used more efficiently to potentially benefit all customers through reduced network costs over the long term.

The charging timeframes for Energex's ToU usage tariffs are included in Table 4-2.

Table 4-2 – ToU usage charging timeframes

Tariff	Network Tariff Code	Charging timeframes	Weekdays	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	Off-Peak	11pm – 7am	Anytime
	NTC4000 NTC4500 NTC8000 NTC3000	Peak	7am – 11pm	No peak

4.3 Proposed tariff charges

In accordance with the AER's Final Decision, the recovery of the Total Revenue Requirement elements from each individual tariff and charging parameters is separately disclosed in the following sections of this Pricing Proposal:[12]

- DUoS (TAR) – refer to Section 5.1
- DPPC – refer to Section 7.2.1
- Jurisdictional schemes – refer to Section 8.2.

[12] AER, Final Decision Energex Determination 2015-16 to 2019-20, Attachment 14 – Control Mechanisms, Section 14.4.5, October 2015.

The proposed tariff levels for SCS in 2016-17, including DUoS, DPPC, jurisdictional scheme payments and total Network Use of System (NUoS), are provided in Appendix 1.

Site-specific tariffs for ICC and CAC are confidential and are provided directly to the customer and their retailer.

The tariffs for SCS are set at the beginning of the regulatory year; however, within a regulatory year there may sometimes be a requirement to include either a tariff for a new ICC or CAC customer or revise the site-specific tariff for an existing customer.

Revision of a site-specific tariff charge may result from the requirements of a signed connection agreement with the customer, a change in connection assets, or for an ICC, a change in their specific usage of the upstream shared network. If new or revised charges are required, they will be calculated in accordance with the current approved Pricing Proposal and the customer (and/or the customer's retailer) will be notified in accordance with the process outlined in Chapter 9 and Appendix 5.

5 Recovery of DUoS

Distribution network tariffs and charging parameters are designed to recover Energex's TAR calculated as per the requirements set out in Chapter 2, in accordance with the side constraint requirements for SCS tariff classes as demonstrated in Section 5.3 and the pricing principles detailed in Chapter 6.

5.1 Recovery of DUoS from tariffs and charging parameters

The network charging parameters adopted by Energex for the recovery of DUoS for SCS tariffs are detailed in Table 5-1 below.

The selection of charging parameters for the recovery of DUoS is made to provide signals to customers about their efficient use of the network and their impact on future network capacity and costs. The tariff structure and the proportioning of charging parameters have been developed to achieve the pricing principles in the Rules and Energex's pricing objectives, as discussed in Section 2.1. Energex has sought to select charging parameters for each tariff that signal the impact customers will have on the network while managing demand and volume variance risk, minimising boundary issues within and between tariff classes, and avoiding any signals that may result in perverse outcomes.

Energex does not recover DUoS on electricity generated by customers that is exported by them into the distribution network, as required by clause 6.1.4(a) of the Rules.

Table 5-1 – Tariff charging parameters for DUoS charges

<table>
<tr><th rowspan="2">Tariff class</th><th rowspan="2">Tariff</th><th rowspan="2">Network tariff code</th><th colspan="6">Tariff charging parameters</th></tr>
<tr><th>Daily Supply Charge ($/day)</th><th>Capacity charge[1] ($/kVA/ month)</th><th>Monthly maximum demand charge ($/kVA/ month)</th><th>Monthly maximum demand charge ($/kW/ month)</th><th>Usage charge flat (c/kWh)</th><th>Usage charge ToU (c/kWh)</th></tr>
<tr><td>ICC</td><td>ICC</td><td>NTC1000[2]</td><td>✓</td><td>✓</td><td>✓</td><td></td><td></td><td>✓</td></tr>
<tr><td rowspan="4">CAC</td><td>EG - 11 kV</td><td>NTC3000[2,3]</td><td rowspan="4">✓</td><td rowspan="4"></td><td rowspan="4">✓</td><td rowspan="4"></td><td rowspan="4"></td><td rowspan="4">✓</td></tr>
<tr><td>11 kV Bus</td><td>NTC4000</td></tr>
<tr><td>11 kV Line</td><td>NTC4500</td></tr>
<tr><td>HV Demand</td><td>NTC8000[3]</td></tr>
<tr><td rowspan="8">SAC</td><td>Demand Large</td><td>NTC8100</td><td rowspan="2">✓</td><td rowspan="2"></td><td rowspan="2">✓</td><td rowspan="2"></td><td rowspan="2">✓</td><td rowspan="2"></td></tr>
<tr><td>Demand Small</td><td>NTC8300</td></tr>
<tr><td>Business Flat</td><td>NTC8500</td><td>✓</td><td></td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Business ToU</td><td>NTC8800</td><td>✓</td><td></td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>Residential Flat</td><td>NTC8400</td><td>✓</td><td></td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Residential ToU</td><td>NTC8900</td><td>✓</td><td></td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>Residential Demand</td><td>NTC7000[4]</td><td>✓</td><td></td><td></td><td>✓</td><td>✓</td><td></td></tr>
</table>

Tariff class	Tariff	Network tariff	Tariff charging parameters					
	Solar FiT	NTC9900[2]	Not Applicable					
	Super Economy	NTC9000					✓	
	Economy	NTC9100					✓	
	Smart Control	NTC7300[4]					✓	
	Unmetered	NTC9600					✓	

Notes:

1. The capacity charge is levied on the basis of either contracted capacity as specified in the customer connection agreement or maximum capacity based on forecasted information as determined by Energex.
2. Electricity exported to the distribution network does not attract DUoS charges.
3. These tariffs are no longer offered to new customers since 1 July 2015.
4. Tariffs offered from 1 July 2016.

5.2 Weighted average DUoS 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 2015-16 and 2016-17 is outlined in Table 5-2.

Table 5-2 – Expected weighted average DUoS revenue by tariff class

Tariff class	Current regulatory year 2015-16[1] ($m)	Relevant regulatory year 2016-17[1] ($m)	Change in weighted average revenue
ICC	41.9	40.9	-2.44%
CAC	123.6	122.8	-0.68%
SAC	1,361.8	1,338.6	-1.71%
Total[2]	**1,527.4**	**1,502.3**	**-1.64%**

Notes:

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

Energex notes that the WAR percentage change for each tariff class and all tariff classes between 2015-16 and 2016-17 remains below CPI.

5.3 Side constraints for SCS tariff classes

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).

(e) This clause does not, however, limit the extent a tariff for retail customers with remotely-read interval metering or other similar metering technology may vary according to the time or other circumstances of a customer's usage.

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 5-1 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 DPPC.
- The recovery of revenue relating to jurisdictional schemes.

Equation 5-1 – Side constraint formula

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

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.

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 - 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.

$C_t^{'}$ 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).

Table 5-3 below demonstrates Energex's compliance with the side constraint formula for each tariff class in 2016-17 and outlines the permissible percentage change, in accordance with clause 6.18.6(d) of the Rules, and as per the side constraint formula above.

Table 5-3 – Compliance with side constraint formula

Tariff class	Calculated percentage change between 2015-16 and 2016-17	Permissible percentage change
ICC	-2.44%	1.32%
CAC	-0.68%	1.32%
SAC	-1.71%	1.32%

6 Application of pricing principles

RULE REQUIREMENT

Clause 6.18.5 Pricing Principles

1. 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.
2. A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:
   (1) must take into account the long run marginal cost for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates; and
   (2) must be determined having regard to:
      (i) transaction costs associated with the tariff or each charging parameter;
      (ii) whether retail customers of the relevant tariff class are able or likely to respond to price signals.
3. If, however, as a result of the operation of paragraph (b), the Distribution Network Service Provider may not recover the expected revenue, the provider must adjust its tariffs so as to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption.

6.1 Estimating avoidable and stand alone costs

In accordance with clause 6.18.5(a) 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. By requiring revenue from a tariff class to be below stand alone costs and above avoidable costs, and by collecting no more than the TAR for the year, Energex ensures that it recovers the efficient costs for its services and cross-subsidisation between tariff classes does not occur.

This section describes how this requirement is met to ensure that the revenue recovered from each tariff class reflects costs and is free from cross subsidies.

Table 6-1 provides estimates which indicate that the expected revenue to be recovered from tariff classes for 2016-17 is between the two bounds created by avoidable and stand alone costs. These costs are described as:

- Avoidable costs – this hypothetical lower bound represents the costs that would be avoided if all customers in a tariff class were no longer connected to the network, assuming that all other customers remain connected. Should the network costs be below the lower bound, Energex would benefit by not providing network services to the customers in this customer class.

- Stand alone costs – this hypothetical upper bound represents the costs that would be incurred to replicate the network in order to service all customers in a tariff class on an individual (i.e. stand alone) basis. Should the network costs to be charged to the customers in this tariff class be above the upper bound, the customer group would benefit from bypassing Energex's network.

The Rules do not prescribe the approach DNSPs should adopt when determining the avoidable and stand alone costs. Energex's approach outlined in Section 6.1.2 and Section 6.1.3 remains unchanged from previous Pricing Proposals.

6.1.1 Boundary calculations in DCOS

The DCOS model that Energex uses to calculate tariffs generates DUoS charges based on the full distribution of the building block costs plus adjustments (TAR) approved by the AER. Appendix 2 outlines the tariff revenue allocation process used by Energex.

The DCOS model has also been applied to estimate the stand alone and avoidable costs for each tariff class. Table 6-1 outlines which of the DCOS cost categories are included in the calculation of the two price boundaries and converts the DCOS cost categories into tariff charging parameters.

Table 6-1 – DCOS categories used in price boundary calculations and the conversion of DCOS categories into tariffs

DCOS cost category		Price boundaries		Tariff charging parameter		
		Avoidable cost	Stand alone cost	Daily supply charge ($/day)	Usage charge[1] (c/kWh)	Capacity / demand charge ($/kVA or KW)
Operating and maintenance (O&M)[2]	Non-contributed connection assets	✓	✓	✓		
	Contributed connection assets	✓	✓	✓		
	Network assets		✓	✓[4]	✓[5]	✓
Regulatory depreciation	Non-contributed connection assets	✓	✓	✓		
	Contributed connection assets[3]					
	Network assets		✓	✓[4]	✓[5]	✓
Return on capital	Non-contributed connection assets	✓	✓	✓		
	Contributed connection assets[3]					
	Network assets		✓	✓[4]	✓[5]	✓
Common services			✓		✓	
Non-System			✓	✓	✓	✓

Notes:

1. Volume charges can be structured as a flat rate or a ToU rate.
2. O&M represents the application of the AER's building block 'Operating Expenditure'.
3. There is no regulatory depreciation or return on capital for contributed connection assets.
4. For SAC customers on volumetric tariffs the daily supply charge comprises a small component of the shared network costs.
5. Applicable to customers on volume (energy) based network tariffs.

6.1.2 Lower bound test (avoidable cost)

As shown in Table 6-1, the avoidable costs for a tariff class include the cost of non-contributed connection assets and the costs of operation and maintenance (O&M) for that connection. The daily supply (fixed) charge for the customer includes these costs, making it the floor price.

Any use of the shared network will incur additional charges (in the form of the usage and/or capacity / demand charge parameters), taking the charge paid by any customer above the avoidable cost of supply (the economic cost floor).

6.1.3 Upper bound test (stand alone cost)

In the DCOS model, the infrastructure and O&M costs for upstream assets are shared across multiple customers and tariff classes. For this reason, the allocated cost of supply for each tariff class will be equal to or below the stand alone costs of supply.

In the case of smaller network customers connected at the distribution level (11 kV and below), the allocated cost will be well below stand alone costs as the costs for high voltage assets are shared with larger customers. For larger network customers connected at the sub-transmission level (33 kV and above), the allocated cost model includes a site-specific parameter for supply network costs.

The cost based tariffs for CACs take into account the specific connection costs as well as an allocation of the upstream shared network costs. ICC cost based tariffs are determined by mapping the actual supply network and allocating the relevant proportion of costs to the customers on the basis of their use of that network. Therefore, as there is an allocation of costs and/or the full network costs are allocated in the case of a single user asset, the revenue recovered from tariffs must be equal to or below the stand alone cost of supply (economic cost ceiling).

6.1.4 Cost estimates

The avoidable cost estimate for each tariff class has been developed based on:

- Avoidable capital – the return on capital and depreciation allocations for the non-contributed connection assets.
- Avoidable O&M – those costs allocated to all (contributed and non-contributed) connection assets for the tariff class in the DCOS model (i.e. annual O&M). Avoidable O&M does not include common and non-system assets as they are incurred irrespective of whether one particular tariff class is no longer connected.

The stand alone cost estimate for each tariff class has been developed based on:

- Stand alone capital – avoidable capital plus all network (shared) assets required to service the tariff class.
- Stand alone O&M – all annual O&M costs allocated for each tariff class in the DCOS model, including costs for connection and network assets, common services and non-system assets.

Total avoidable and stand alone costs are represented as annual charges in Table 6-2.

Table 6-2 – 2015-16 Stand alone and avoidable cost boundaries

Tariff class	Avoidable cost ($m)	Expected revenue ($m)	Stand alone cost ($m)
ICC	14.6	40.9	69.7
CAC	17.2	122.8	221.4
SAC	65.0	1,338.6	1,449.0
Total[1]	**96.8**	**1,502.3**	**1,740.1**

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

6.2 Long-run marginal cost

Clause 6.18.5(b)(1) of the Rules stipulates that, in determining the charging parameters for a tariff class, Energex must take into account the long run marginal cost (LRMC) for the element of the service or the element of the service to which the charging parameter relates.

Marginal costs can be calculated as either short run marginal costs (SRMC) or LRMC. Marginal cost is the change in total cost that arises when the quantity produced changes by one unit. In the case of an electricity network, the marginal cost could be the cost incurred from one additional customer connecting to the network or an additional megawatt of demand or electricity consumed. In the short run, investment in capacity is fixed; therefore, the SRMC refers to the cost of a customer connecting to the network but using only the existing network capacity. In the long run, investment in capacity is variable, hence LRMC indicates an estimate of the cost of connecting the customer when an augmentation to the capacity of the network is necessary.

Pricing on the basis of LRMC assumes that prices should be based on the cost of meeting an increase in demand over an extended period of time. As demand on the electricity network increases, network capacity needs to be expanded to accommodate the additional demand. By basing prices on LRMC, Energex can better signal to customers how their behaviour impacts the forward augmentation costs of the network and this, in turn, will be better reflected in the prices that consumers pay for electricity.

Energex has estimated LRMC values at the voltage level using the Average Incremental Cost (AIC) method, described in Equation 6-1.

The LRMC values are used as a test to ensure capacity, demand and energy charges incorporated into each tariff are reasonable.

Equation 6-1 – LRMC: average incremental cost method

$$\text{LRMC (AIC)} = \frac{\text{PV(Capex)} + \text{PV(Opex)}}{\text{PV(Incremental Demand)}}$$

where:

'PV (Capex)' and *'PV (Opex)'* represent the Present Value (PV) capital and operating costs associated with meeting future additional demand.

This calculation method provides an estimate that allows irregular 'lumpy' capital expenditure to be smoothed over time, while providing an indication of the capital and operating costs associated with the increased demand. Thus, the LRMC indicates the level at which future increments of output must be priced to ensure total revenue recovery given a certain forecast demand.

The incremental capital and operating costs associated with increased demand are included in Energex's forecast capex and opex programs. Energex receives a return on these (and other) costs in the form of a return on and a return of the forecast incremental assets at each major voltage level of its network. These costs are then allocated to each tariff class in the DCOS model.

LRMC values are expressed as $/kVA/month, $/kW/month, c/kWh peak energy and c/kWh energy and are shown in Table 6-3.

Energex applies diversity factors to the LRMC values. In doing so, Energex recognises that not all customers contribute to network peaks at the same time. The approach used by Energex to calculate diversity factors is provided in Equation 6-2.

Equation 6-2 – Diversity factor formula

$$\text{Diversity Factor} = \frac{\text{After Diversity Maximum Demand (ADMD)}}{\text{Average Monthly Maximum Demand (AMMD)}}$$

Table 6-3 – Diversified LRMC by voltage level

Voltage Level	$/kVA/month	$/kW/month[2]	c/kWh peak energy[3,4]	c/kWh energy
110/33 kV[1]	$4.89	N/A	N/A	N/A
11 kV[1]	$10.03	N/A	N/A	N/A
LV business	$10.53	N/A	2.61	1.24
LV residential	N/A	$9.08	10.44	1.24

Notes:

1. LRMC is expressed in terms of monthly demand charges because the associated tariffs reflect LRMC through demand charges only.
2. Residential Demand Time of Use hours 4pm to 8pm workdays.
3. Residential Usage Time of Use hours 4pm to 8pm weekdays.
4. Business Usage Time of Use hours 7am to 9pm weekdays.

In accordance with clause 6.18.5(b)(1) of the Rules, Energex designs tariffs to include a combination of charging parameters to which it has applied LRMC.

LRMC is allocated first to the charging parameters that will most strongly signal the network costs of meeting future demand, that is: 1) peak demand, 2) peak usage and 3) flat usage.

Since 2015-16, Energex has begun to transition charging elements of legacy network tariffs closer to their LRMC value and will continue to engage on transitioning towards full LRMC cost reflectivity. In contrast the newly introduced demand tariff for residential customers, NTC7000 – Residential Demand, will be reflective of the full diversified LRMC from the start.

Table 6-4 below shows the allocation of LRMC to the charging parameter for each tariff that will ultimately provide the most efficient price signal.

Table 6-4 – Allocation of diversified LRMC to tariff charging parameters

Tariff class	Tariff(s)	LRMC Charging Parameters
ICC	• NTC 1000	N/A[1]
CAC	• NTC3000 EG 11 kV[2] • NTC4000 11 kV Bus • NTC4500 11kV Line • NTC8000 HV Demand[2]	Demand ($/kVA/month)
SAC	• NTC8100 Demand Large • NTC8300 Demand Small	Demand ($/kVA/month)
	• NTC8400 Residential Flat • NTC8500 Business Flat	Flat energy (c/kWh)
	• NTC8800 Business ToU • NTC8900 Residential ToU	Peak energy (c/kWh)
	• NTC7000 Residential Demand	Demand (c/kW/month)
	• NTC9600 Unmetered	Flat energy (c/kWh)
	• NTC9000 Super Economy	N/A[3]
	• NTC9100 Economy	N/A[3]
	• NTC7300 Smart Control	N/A[3]

Notes:
1. ICC's are individually priced.
2. These tariffs are no longer offered to new customers.
3. No LRMC (load is switched off during localised peak demand period).

6.3 Transaction costs

For each tariff, Energex has selected a number of charging parameters, identified in Chapter 4 for SCS and Chapter 11 for ACS. Each combination of tariff charging parameters has been selected to reflect the need for both fixed and variable components.

A combination of various parameters is required to achieve economic functionality and to ensure that appropriate pricing signals are provided to customers. However, as required by clause 6.18.5(b)(2)(i) of the Rules, the number and design of these parameters have been selected with regard to minimising the associated transaction and pricing administration costs.

As explained in Chapter 3 and Chapter 4, Energex has developed individual tariffs and tariff classes to ensure that customers are grouped on an economically efficient basis and there are not an excessive number of tariffs available. Ultimately, this minimises transaction costs that may be incurred by the customers through switching between tariffs and by Energex in managing the provision of an excessive number of tariffs.

Additionally, for customers with demand levels that fluctuate frequently, Energex may, at its own discretion, apply a reasonable tolerance limit on tariff thresholds to mitigate frequent tariff reassignment and reduce transaction costs for customers and Energex. Further details on customer assignment and reassignment to tariff classes and tariffs are provided in Chapter 9 and Appendix 5.

6.4 Response to price signals

Consistent with clause 6.18.5(b)(2)(ii) of the Rules, the tariffs proposed by Energex provide signals to customers about the efficient use of the network and are based on the impact of future network capacity and costs. The charging parameters used to signal customers include capacity, demand and volume charges, which have been priced to allow customers to respond to the signal provided. These parameters, discussed in Section 4.2, include:

- Capacity charges – for customers with an authorised capacity, customers can respond by setting up an efficient network connection. For those who do not have an authorised capacity, capacity is forecasted using prior year maximum annual demand. Customers with an authorised capacity can seek an in-period review based upon changed circumstances (at Energex's discretion). Customers with no authorised capacity can reduce network charges by reducing their annual maximum demand.

- Demand charges - customers can reduce network charges by reducing their maximum consumption over their peak half hour period in the month. This can be achieved by staggering the start time of appliances with significant load, purchasing load management or energy efficient technologies, or turning off other appliances when an appliance is switched on. For demand charges based on kVA, customers can reduce network charges by improving their power factor through the use of power factor correction technology.

- Volume charges – customers can reduce network charges by reducing their energy consumption over the billing period. This can be achieved by purchasing energy-efficient appliances or conserving energy.

- ToU volume charges – customers can reduce network charges by shifting load out of more expensive peak periods and into lower cost off-peak periods. This can be done through electricity timers that automatically turn appliances on in the off-peak period. This can also be achieved through pre-cooling and pre-heating.

Commercial and industrial customers with capacity and/or demand charges can stagger the starting time of equipment such as motors, air-conditioning (A/C) units and large lighting installations, thereby reducing their maximum demand on the network as all the start-up loads are not simultaneous. The short term benefit to the customer is a lower monthly demand charge and, if they effectively manage their longer term maximum demand, they will benefit from reduced capacity charges.

Energy usage costs are affected by the overall electrical efficiency of installations. If customers improve the efficiency of their usage they will reduce their energy-related charges. For example, this can be achieved by installing more efficient lighting and air conditioning, and improving thermal insulation of cold rooms.

6.5 Tariff adjustment to address revenue shortfalls

When setting network tariffs, Energex uses a combination of charging parameters. These are developed taking into account LRMC, transaction costs and customer response to pricing signals, as required under clause 6.18.5(b) of the Rules. However, the expected revenue is not fully recovered by LRMC based charging parameters alone. For example, building block revenue is greater than LRMC since it allows for recovery of sunk costs (i.e. it allows for the recovery of long-run average costs).

Accordingly, the charging parameters outlined in Table 5-1 are applied to allow for the collection of residual revenue allowed under Energex's total efficient costs of servicing customers in each tariff. These parameters are selected in a manner which complements the chosen pricing signals and minimises distortion to efficient patterns of consumption, as required by clause 6.18.5(c) of the Rules.

7 Transmission cost recovery

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(6) 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.

Clause 6.18.7 Recovery of designated pricing proposal charges

(a) A pricing proposal must provide for tariffs designed to pass on to retail customers the designated pricing proposal charges to be incurred by the Distribution Network Service Provider.

(b) The amount to be passed on to retail customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal charges adjusted for over or under recovery in accordance with paragraph (c).

(d) Notwithstanding anything else in this clause 6.18.7, a Distribution Network Service Provider may not recover charges under this clause to the extent these are:

(1) recovered through the Distribution Network Service Provider's annual revenue requirement;

(2) recovered under clause 6.18.7A; or

(3) recovered from another Distribution Network Service Provider.

Most electricity is delivered from generators to Energex's network via Powerlink's transmission network. Energex pays DPPC to Powerlink on behalf of its customers and recovers these costs through network tariffs. Energex's transmission cost recovery tariffs are based on a forecast of DPPC for each year, adjusted for over or under recoveries.

DPPC includes avoided Transmission Use of System (TUoS) and network support costs.

In accordance with clauses 6.18.2(b)(6) and 6.18.7 of the Rules, tariffs outlined in this Pricing Proposal will allow for the pass-through of DPPC, including any adjustments for over or under recovery.

To comply with the Rules and the AER's Final Decision requirements, information reported as part of this Pricing Proposal includes:

- Expenses:
  - regulated DPPC paid to Transmission Network Service Providers (TNSPs)
  - avoided charges for the locational component of prescribed TUoS Services (to be referred to as avoided TUoS)
  - payments made to other DNSPs for use of their network.
- Revenue:
  - payments received from distribution network users
  - payments received from other DNSPs.
- Adjustments for over or under recovery:
  - difference between revenue and expenses.

7.1 Expenses

7.1.1 DPPC paid to TNSPs

Energex connects to the Powerlink network at multiple transmission network connection points (TNCPs). Powerlink, as a regulated TNSP, recovers its revenue from directly connected customers and DNSPs connected to its network.

In accordance with the connection agreement with Powerlink, Energex is required to pay DPPC to Powerlink on a monthly basis. For 2016-17, Powerlink's transmission related costs are expected to increase by 8.7 per cent.

Energex is 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. Clause 6.18.7(c)(2) provides that a DPPC can be recovered through the unders and overs recovery account as set out in Section 7.3.

7.1.2 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).

In accordance with the Rules, for EGs where prices for the locational component of prescribed DPPC services were applicable at the relevant TNCP during the relevant financial year, 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 2016-17, avoided TUoS payments will generally be remitted in the form of a lump sum payment after 30 June 2017, similar to previous years.

Payments associated with avoided TUoS to EGs by Energex reflect the avoided costs of upstream transmission network reinforcement. 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 2016-17 is included in Table 7-2.

7.1.3 Payments 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 2016-17 is included in Table 7-2.

7.2 Revenue

7.2.1 Recovery of DPPC through tariffs and charging parameters

Energex's transmission costs are based on a forecast of DPPC charges for each year, adjusted for over and under recoveries to be applied that year. In accordance with Clause 6.18.7(d) of the Rules, Energex does not recover DPPC charges through its revenue requirement or jurisdictional scheme.

The DPPC from Powerlink comprises both daily supply and variable charges. 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. DPPC charges for ICC tariffs are based on the relevant transmission connection point, plus charges associated with the customer's shared distribution network, plus connection charges based on the customer's connection assets. 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, plus average shared network charges, plus site-specific connection charges based on the customer's connection capacity. This provides a significant degree of cost-reflectivity for this group of customers while recognising the practical difficulties of calculating individual shared network charges for each customer connected at the 11 kV network.

DPPC cost amounts are allocated to SAC tariffs proportionally based on average monthly maximum demands. The charges are recovered from the DUoS tariff structure (fixed charge, maximum demand and/or volume charge). However, for the newly introduced residential demand tariff (NTC7000 – Residential Demand), Energex will not recover DPPC from the fixed charge parameter to strengthen the network LRMC signal.

A forecast of the DPPC is provided to Energex by Powerlink in April 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 7-1.

Table 7-1 – Tariff charging parameters for DPPC

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameter				
			Daily supply charge ($/day)	Monthly maximum demand charge ($/kVA/ month)	Monthly maximum demand charge ($/kW/ 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]	✓	✓		✓	
SAC	Demand Large	8100	✓	✓		✓	
	Demand Small	8300	✓	✓		✓	
	Business Flat	8500	✓			✓	
	Business ToU	8800	✓				✓
	Residential Flat	8400	✓			✓	
	Residential ToU	8900	✓				✓
	Residential Demand	7000[4]			✓	✓	
	Solar FiT	9900	N/A				
	Super Economy	9000				✓	
	Economy	9100				✓	
	Smart Control	7300[4]				✓	
	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. 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. Tariffs offered from 1 July 2016.

The total DPPC revenue received is indicated in Table 7-2 below.

7.3 DPPC overs and unders accounts

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(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 in the relevant distribution determination for the Distribution Network Service Provider;

(2) ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges 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.

(3) recovered from another Distribution Network Service Provider.

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 overs and unders account for the most recently completed regulatory year (t-2) and the next regulatory year (t). For this 2016-17 Pricing Proposal, year t-2 is 2014-15 and year t is 2016-17.

The overs and unders account is detailed in Table 7-2 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 overs and unders 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. 2014-15) to be audited.[13] Energex believes this requirement has been met as part of the statutory or regulatory account audits certified by Queensland Audit Office (QAO).

Amounts for the next regulatory year (t) are forecast amounts.

Table 7-2 – DPPC overs and unders account

Over/under account element	2014-15 actual ($'000)	2016-17 forecast ($'000)
(A) Revenue from DPPC charges	405,911	484,802
(B) Less DPPC related payments for regulatory year =	404,492	484,802
DPPC charges to be paid to TNSP	386,996	484,313
Avoided TUoS payments	385	560
Inter-distributor payments[1]	344	1,580
DPPC revenue under/over recovery approved	16,767	-1,651
(A minus B)Under/over recovery for regulatory year	**1,419**	**0**

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

Over/under account element	2014-15 actual ($'000)	2016-17 forecast ($'000)
Unders and Overs Account		
Nominal WACC t-2 (per cent)	9.72%	N/A
Nominal WACC t-1 (per cent)	6.01%	N/A
Opening balance	0	1,651
Under/over recovery of revenue for regulatory year	1,419	-1,651
Interest on under/over recovery for 2 regulatory years	232	N/A
Closing balance[2]	**1,651**	**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.

8 Jurisdictional schemes

RULE REQUIREMENT

Clause 6.18.2 Pricing proposals

(b) 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; and**
>
> **(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

Pricing Proposal

(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.

On 22 March 2016, Energex's distribution authority (DA) was amended to require Energex to pay a new industry levy covering the Queensland's funding commitment to the AEMC for the work it performs under National Energy Retail Law. The Electricity Act 1994 requires Energex to comply with the conditions set out in its DA.

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. As such, the amounts for 2015-16 and 2016-17 have been included in this Pricing Proposal.

8.1 Forecast of jurisdictional scheme amounts

8.1.1 SBS FiT payments to customers

Energex has established the forecast value of SBS FiT payments to be recovered in 2016-17 based on historical trends using actual SBS payments and information to 31 March 2016 and by applying the following formula:

Figure 8-1 – 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 8-1 includes the values of the inputs used to estimate the 2016-17 SBS FiT payments.

Table 8-1 – Forecast for 2016-17 SBS FiT payments

	2016-17
Average export per system (GWh)	410.2
Export rate (c/kWh)	0.44
Solar FiT Payment ($M)	**$180.48**

The allocation of the SBS FiT payments among the tariff classes and tariffs is presented in Table 8-3.

8.1.2 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 will be done in accordance with the relative customer numbers reported to the Queensland Government each October for the preceding financial year.

The estimated jurisdictional scheme amount to be recovered in 2016-17 is $302,123 which includes the levy amounts for 2015-16 and 2016-17.

Table 8-2 – Forecast of AEMC levy payments to be recovered in 2016-17

Financial year	Estimate
2015-16	$144,409
2016-17	$157,714
Total	**$302,123**

The allocation of the AEMC levy payments among the tariff classes and tariffs is presented in Table 8-3.

8.2 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.[14]

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

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:

[14] As discussed in Chapter 7, DPPC is also added to TAR as a revenue adjustment.

1) Jurisdictional scheme payments are allocated to all SCS tariffs proportional to the allocation of shared network revenues for each tariff.
2) Jurisdictional scheme payments 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 (either usage or demand depending on the tariff type) on a c/kWh or $/kW 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 8-3.

Table 8-3 – Tariff charging parameters for jurisdictional schemes

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameter				
			Daily supply charge ($/day)	**Monthly maximum demand charge** ($/kVA/ month)	**Monthly maximum demand charge** ($/kW/ 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]	✓	✓			
SAC	Demand Large	8100	✓	✓			
	Demand Small	8300	✓	✓			
	Business Flat	8500	✓			✓	
	Business ToU	8800	✓				✓
	Residential Flat	8400	✓			✓	
	Residential ToU	8900	✓				✓
	Residential Demand	7000[2]	✓		✓		
	Solar FiT	9900	N/A				
	Super Economy	9000				✓	
	Economy	9100				✓	

	Smart Control	7300[2]				✓	
	Unmetered	9600				✓	

Notes:
1. These tariffs will no longer be offered to new customers from 1 July 2015.
2. Tariffs offered from 1 July 2016.

8.3 Jurisdictional scheme payments overs and unders 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[15], Energex is required to provide amounts for the overs and unders relating to jurisdictional schemes for the most recently completed regulatory year t-2, being 2014-15, and the next regulatory year t, being 2016-17. This requirement is therefore not relevant to the 2016-17 Pricing Proposal as the SBS FiT and the AEMC Levy payments were not treated as jurisdictional schemes until 1 July 2015 and April 2016 respectively. As a result, the unders and overs account has a balance of zero.

8.4 Disclosure of SBS FiT jurisdictional scheme

As part of the requirements of the Final Decision, the AER requires Energex to separately disclose for each tariff and individual charging parameter, the jurisdictional scheme amounts.[16] This additional level of disclosure is a new feature of the 2016-17 Pricing Proposal and has been added to Table A. 1 – 2016-17 SCS tariff charges in Appendix 1.

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

8.5 Amendments to the jurisdictional scheme

RULE REQUIREMENT

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

(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 6.18.2 (b)(6B) does not apply to the SBS as it was not approved by the AER. The SBS was established under Section 44A of the Electricity Act and therefore classified as a jurisdictional scheme in accordance with clause 6.18.7A (e)(1)(iii) of the Rules.

With respect to the AEMC levy, there has been no amendment to the scheme since it was approved by the AER.

9 Assignment and re-assignment of customers to SCS tariff class and tariffs

RULE REQUIREMENT

Clause 6.18.4 Principles governing assignment or reassignment of retail customers to tariff classes and assessment and review of basis of charging

(a) In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the reassignment of retail customers from one tariff class to another, the AER must have regard to the following principles:

(1) retail customers should be assigned to tariff classes on the basis of one or more of the following factors:

(i) the nature and extent of their usage;

(ii) the nature of their connection to the network;

(iii) whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;

(2) retail customers with a similar connection and usage profile should be treated on an equal basis;

(3) however, retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile;

(4) a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

(b) 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, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.

FINAL DECISION REQUIREMENT

Energex must demonstrate compliance with the procedures stipulated by the AER in Appendix D of Attachment 14 which relates to the assigning of retail customers to tariff classes or reassigning of retail customers from one tariff class to another.

The principles and provisions governing the assignment and re-assignment of customers to or between tariff classes and tariffs are outlined in clause 6.18.4 of the Rules and the AER's Final Decision.

The Final Decision introduced amendments to a number of principles initially outlined in the Preliminary Decision. These amendments include:[17]

- Notifications – Energex should notify the customer's retailer (rather than the customer) when a tariff class and tariff assignment and reassignment is proposed.
- Dispute resolution – Energy and Water Ombudsman Queensland is the entity to resolve tariff assignment and reassignment dispute resolution for small customers.
- Tariff adjustments – Adjustments to a customer's tariff should occur at the next network bill if an objection to a tariff assignment or reassignment is upheld.

[17] AER, Final Decision – Energex determination 2015-16 to 2019-20, Attachment 14 – Control mechanisms, Appendix D, October 2015.

- ACS – Specific principles for assigning or reassigning customers to ACS need not be developed as this would not be practical. In fact, customers or customers' retailers assign themselves to the tariff class when requesting the ACS they require.

The process guiding Energex in assigning and re-assigning customers to tariff classes and tariffs is summarised in this Chapter 9 and Appendix 5.

9.1 Tariff class and tariff assignment process

To comply with the Rules and provisions outlined in the Final Decision, Energex's process for tariff class and tariff assignment, as detailed in Table 9-1, ensures no direct control services customer can take supply without being a member of at least one tariff class.

Where a new customer connection request is received and no tariff is nominated, using the tariff assignment process (as shown in Table 9-1), the customer will be allocated first to a tariff class and then to the most appropriate default tariff. In these instances, Energex will take into account the following connection characteristics:

- The nature and extent of the customer's usage.
- The nature of the customer's connection to the network (i.e. significant amount and/or capacity of connection assets).
- Whether remotely-read interval or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

In addition to the above, the following procedures apply:

- Customers with similar connection and usage profiles are treated equally.
- Allocation of a customer with micro-generation facilities to a tariff will be made on the same basis as other connections in so far as they have similar usage profile. Energex's policy is detailed in Section 9.2.
- Where a new tariff is applied to a customer, Energex's standard practice is to apply the tariff from the next billing period.
- For new connections with no previous load history, they will be assigned to the appropriate default tariff based on their network agreement specifications, expected energy usage, supply voltage and meter type.
- Instead of the default tariff, a customer will be assigned to a specific tariff for which they are eligible if requested by their electricity retailer or electrical contractor.
- In accordance with clauses 6.18.4(a)(4) and 6.18.4(b), assignment of customers to tariff classes and tariffs is reviewed periodically to assess if the tariff assignment is still applicable, given potential changes in usage. A change in connection voltage means that the connection is treated as if it is a new connection and the process in Table 9-1 will be followed to assign the customer to a suitable tariff class. Customers who have chosen to participate in a tariff trial will not be subject to this review process.

The process for assigning a customer to a tariff class (and applicable network tariff codes) for SCS is outlined in Table 9-1 below. As depicted, within each tariff class, there are a number of tariffs available. Typically, each tariff class has a default tariff that is applied to customers unless a specific tariff is requested by their electricity retailer or electrical contractor.

Table 9-1 – Assignment and re-assignment process of customers to SCS tariff classes in 2016-17

Voltage	LV												11 kV		110 kV or 33 kV
Tariff Class (SAC, CAC or ICC)	**SAC**												**CAC[2]**		**ICC[2]**
Classification (Small or Large)	**Small (consumption < 100 MWh/year)**									**Large (consumption > 100 MWh/year)**			**Large**		**Large**
Customer type (Residential, Bus or Line)	**Residential**				**Non-residential**					**Residential**		**Non-residential**	**Bus**	**Line**	**N/A**
Metering (Type 4, Type 6, Unmetered)	**Type 1-4**		**Type 6**		**Type 1-4**		**Type 6**		**Unmetered**	**Type 1-4**			**Type 1-4**		**Type 1-4**
Tariff type (Primary or Secondary)	**Primary**	**Secondary (optional)**	**Primary**	**Secondary (optional)**	**Primary**	**Secondary (optional)**	**Primary**	**Secondary (optional)**	**Primary**	**Primary**	**Secondary (optional)**	**Primary**	**Primary**	**Primary**	**Primary**
Permitted tariffs	At most one from the following list: NTC7000, NTC8100, NTC8300, NTC8400 or NTC8900	May access one or more of the following: NTC7300[1], NTC9000[3], NTC9100[3] or NTC9900	Must access at least one of the following: NTC8400 (default) or NTC8900. May access one or more from the following list: NTC8500, NTC8800	May access one or more of the following: NTC9000, NTC9100 or NTC9900	At most one from the following list: NTC8300, NTC8500 or NTC8800	May access one or more of the following: NTC9900	Must access at least one of the following: NTC8500 or NTC8800	May access one or more of the following: NTC9000, NTC9100 or NTC9900	Must access NTC9600	At most one from the following list: NTC7000, NTC8100, NTC8300, NTC8400, or NTC8900	May access one or more of the following: NTC7300[1], NTC9000[3], NTC9100[3] or NTC9900	At most one from the following list: NTC8100 or NTC8300	Must access: NTC4000 (until 30 June 2017)	Must access: NTC4500 (until 30 June 2017)	Must access NTC1000 (default)
Default Tariff	NTC8400	N/A	NTC8400	N/A	NTC8500	N/A	NTC8500	N/A	NTC9600	NTC8400	N/A	NTC8300	NTC4000	NTC4500	NTC1000

Notes:

1. NTC7300 is only available for residential customers with primary tariffs NTC7000, NTC8100 or NTC8300. NTC7300 is not available for residential customers with primary tariffs NTC8400, NTC8500, NTC8800 or NTC8900.
2. 11kV customers whose connection and usage characteristics mean that average shared network charges are inappropriate, or who consume more than 40 GWh per annum, or with an annual maximum demand greater than 10 MW, are allocated to the ICC tariff class.
3. This tariff cannot be used in conjunction with NTC7000.

9.2 Customers with micro-generation facilities

In accordance with clause 6.18.4(a)(3) of the Rules, it is Energex's policy to treat customers with micro-generation facilities no less favourably than customers without these facilities but with a similar consumption profile. Allocation of a micro-generation customer to a tariff class will be made on the same basis as other customers; this being the extent and nature of usage and the nature of the connection to the network. The network tariff will include fixed and variable components, and if the customer's demand is met entirely by the micro-generator, then the levied charge will only be the fixed connection component.

Energex's compliance with clause 6.18.4(a)(3) of the Rules is demonstrated by the fact that customers participating in the SBS are treated no less favourably than other customers as the billed consumption of these customers will be unaffected by their participation in the SBS. The tariff class assignment is also unaffected by participation in the SBS.

9.3 Tariff class and tariff re-assignment process

Energex may review the assignment of customers to tariff classes and tariffs to ensure customers are assigned to the correct 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 process for tariff class and tariff re-assignment is similar to that used for the assignment of customers to tariff classes and tariffs as outlined in Section 9.1 above and the connection characteristics outlined in Section 9.1. Consistent with clause 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.

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.

Energex's detailed procedures for the re-assignment of tariff classes and tariffs for SAC customers have been included in Appendix 5.

For customer requested tariff re-assignments, customers are only allowed one tariff change per 12 month period to limit transaction costs and ensure pricing signals are not distorted by constant changes.

9.4 Customer notification process for tariff class and tariff assignment and re-assignment

The Final Decision requires Energex to notify the customer's electricity retailer of the tariff class to which the customer has been assigned or re-assigned. It can be noted, however, that in some instances, Energex has elected to continue the practice of notifying both the customer's retailer and the customer. The process for notifying a customer's retailer of a tariff class and/or tariff change is outlined in Table 9-2.

Table 9-2 – Customer notification process for tariff class changes

Input to tariff class assignment process	Notification process
Energex-driven re-assignment based on a change in usage or connection	Based on NMI classification, Energex identifies customers who are assigned to an incorrect tariff class and/or tariff code. The correct tariff class and/or tariff code is determined based on the process outlined in Table 9-1 and Appendix 5. The customer's retailer is notified in writing of the intended tariff class and/or tariff code re-assignment, and the customer is given the opportunity to object to the proposed re-assignment and request a review[1] of the decision be undertaken prior to the change being initiated.
Retailer-driven re-assignment (through Energex Form 1634 - QESI)	Energex receives a completed Form 1634 – QESI from the retailer for tariff re-assignment. A customer is able to submit the QESI request to Energex; however Energex will seek the endorsement from the customer's retailer prior to proceeding with the tariff change. If the request is approved, the customer's retailer is notified in writing of the tariff re-assignment and subsequent tariff class re-assignment. If the request is not approved, the customer's retailer is notified in writing that the tariff re-assignment and subsequent tariff class re-assignment have not been approved. The customer is given the opportunity to object to the decision and request that a review[1] be undertaken.
New connection	Energex receives notification of a new customer connection. For CAC and ICC customers: • The correct tariff class and tariff code are determined by undertaking a network and connection investigation and following the process outlined in Section 9.1 and in Table 9-1. • The customer's retailer and customer are notified of the tariff classification as part of the Connection Agreement, and are given the opportunity to object to the classification and request a review[1] of the decision. For SAC customers: • Where a tariff code is nominated on the connection request thus informing tariff class assignment, Energex will confirm if this is appropriate. • If a tariff code is not nominated on the connection request, the correct tariff class and tariff code are determined based on the process outlined in Section 9.1 and Table 9-1. The customer will thereafter be assigned to the default tariff. • Notification to the retailer will occur electronically by way of a Change Request notice through Market Settlement and Transfer Solution (MSATS) and the customer is given an opportunity to request a review[1] of the decision.

Input to tariff class assignment process	Notification process
Tariff re-assignment	Energex notifies the affected customer and/or customer's retailer to inform them about: • The customer's current network tariff class and tariff and what these are changed to. • The reasons for the change. • How the customer can dispute the decision. • The date the change will take effect.

Notes:

1. The process for tariff class and tariff code assignment or re-assignment objection review is outlined in Section 9.5.

9.5 Tariff class and tariff assignment objections review process

The notification of a tariff class or tariff code assignment or re-assignment will include advice that the customer may request further information from Energex and that they may object to the proposed assignment or re-assignment and request that Energex undertake a review.

This notification will include:

- Advice that if a customer is not satisfied with their tariff class or tariff code assignment or re-assignment they may request a review of the tariff allocation made by Energex.
- A copy of Energex's internal assignment/re-assignment review procedures or the link to where such information is available on the Energex website.
- Advice that if the customer is not satisfied with the review and their objection has not been addressed adequately by Energex's internal review procedures, the next steps include:
  - for small customers – to the extent that resolution of the dispute is within the jurisdiction of the Energy and Water Ombudsman Queensland, the customer is entitled to escalate the matter to such a body.
  - for large customers – the customer is entitled to escalate the matter to the Department of Energy and Water Supply for resolution.
- Advice that if the dispute is still not resolved to the customer's satisfaction, the customer is entitled to seek resolution via the dispute resolution process available under Part 10 of the NEL and enforced by the AER.

If a customer objects to the proposed assignment or re-assignment and requests a review be undertaken, Energex will follow the process set out in Appendix 6. In reviewing a customer's request, Energex will take into account clauses 6.18.4(a)(1)–(3) of the Rules, and the tariff class and tariff assignment process detailed in Table 9-1 of this Pricing Proposal. Energex will notify the customer and/or their electricity retailer in writing of its decision and the reasons for that decision.

In accordance with the AER's Final Decision, if a customer's objection to an assignment or re-assignment is upheld by an external dispute resolution body, the tariff adjustments deriving from this decision will be made by Energex as part of the next network bill.[18]

[18] AER, Final Decision Energex Determination 2015-20 to 2019-20, Attachment 14 – Control Mechanisms, Appendix D, October 2015, p.24.

10 Alternative control services: Tariff classes

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.

10.1 ACS Classification of Services

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(1) set out the tariff classes that are to apply for the relevant regulatory year.

For the 2015–20 regulatory control period, the AER has classified the following as ACS:[19]

- Connection services, including:
  - pre-connection services
    - connection application services
    - pre-connection consultation services
  - connection services (excluding small customer connections)
  - post connection services (excluding operating and maintaining connection assets)
  - accreditation services.
- Ancillary network services
- Metering services, including:
  - Type 6 metering services, and auxiliary metering services
- Public lighting services.

These services form the basis of tariff classes for ACS which are described in Table 10-1.

[19] AER, Final Framework and Approach for Energex and Ergon Energy Regulatory control period commencing 1 July 2015, April 2014.

Table 10-1 – 2016-17 ACS tariff classes

Tariff Class	Activity
Connection services	**Pre-connection services** Pre-connection services are those services that relate to assessing a connection application, making a connection offer and negotiating offer acceptance and additional support services provided by the DNSP (on request) during connection enquiry and connection application other than general connection enquiry services and connection application services. Generally relates to services which require a customised or site-specific response and/or are available contestably. Unless otherwise specified, services or activities undertaken under this service group relate to both small and large customers and real estate development connections.
	Connection services Connection services include the design, construction, commissioning and energisation of connection assets for large customers and for real estate developments. Also includes the augmentation of the network to remove a constraint faced by an EG. This does not include customers with micro-generation facilities that connect under a SAC tariff class. Energex considers that generators larger than 30 kVA but smaller than 1 MW should be treated as EGs for the purpose of removing network constraints. Include temporary connections for short term supply (e.g. blood bank vans, school fetes).
	Post-connection services Post-connection services are those services initiated by a customer which are specific to an existing connection point.
	Accreditation services Accreditation of alternative service providers and approval of their designs, works and materials.
Ancillary network services	Ancillary network services include services provided in relation to a Retailer of Last Resort (ROLR) event and works initiated by a customer, which are not covered by another service and are not required for the efficient management of the network, or to satisfy DNSP purposes or obligations.
Metering services	**Type 6 Metering** Metering services encompass the metering installation, provision, maintenance, reading and data services of Type 6 metering. **Auxiliary Metering Services** Includes work initiated by a customer which is specific to a metering point.
Public lighting	Public lighting services relate to the provision, construction and maintenance of public lighting assets owned by Energex (conveyance of electricity to street lights remains an SCS). Includes energy efficient retrofits and new public lighting technologies, including trials.

10.2 Assignment or re-assignment of ACS customers to tariff class

RULE REQUIREMENT

Clause 6.18.4 Principles governing assignment or reassignment of retail customers to tariff classes and assessment and review of basis of charging

(c) In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the reassignment of retail customers from one tariff class to another, the AER must have regard to the following principles:

(1) retail customers should be assigned to tariff classes on the basis of one or more of the following factors:

(i) the nature and extent of their usage;

(ii) the nature of their connection to the network;

(iii) whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;

(2) retail customers with a similar connection and usage profile should be treated on an equal basis;

(3) however, retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile;

(4) a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

(d) 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, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.

FINAL DECISION REQUIREMENT

AER's decision in Appendix D.2.4 of Attachment 14 about notification of a customer's retailer for each tariff class assignment or re-assignment for alternative control services.

AER's decision in Appendix D.3 of Attachment 14 about notification of a customer's retailer of right of objection for alternative control services.

Prior to the provision of an ACS, a customer will be assigned to the relevant tariff class based on the type of ACS required. Similar to tariff class membership requirement for SCS, described in Chapter 9, an ACS customer will not receive the service prior to being allocated to the appropriate tariff class. The process for assigning customers to the appropriate ACS tariff class is illustrated in Table 10-2.

It can be noted that in the Final Decision the AER considered that it was not practical for Energex to provide written notification to a customer's retailer for each tariff class assignment or reassignment in relation to ACS. The AER was of the view that customers or customers' retailers essentially assign themselves to tariff class when requesting the ACS they require.

If a customer makes an objection about the proposed assignment or re-assignment to an ACS tariff class, Energex will follow the procedures set out in Attachment 14 (Appendix D) of the AER's Final Decision and the process used for objection of SCS tariff class assignment as outlined in Section 9.5.

Table 10-2 – Assignment of customers to ACS tariff classes

ACS Tariff Class	Description	ACS Service	ACS Tariff
Connection services	Services performed in relation to: • A connection of premises to the electricity distribution network • Getting more electricity from the distribution network than is possible at the moment • Extending the network to reach a person's premises.	**Pre-connection**	Connection application services
			Pre-connection consultation services
		Connection	Large customer connections (design and construction)
			Commissioning and energisation of large customer connections
			Real estate development connections (design, construction, commissioning and energisation)
			Removal of network constraints for EGs
			Review, inspection and auditing of design and works carried out by an alternative service provider prior to energisation
			Temporary connection (short term supply)
		Post connection (Connection Management Services)	Supply abolishment
			Rearrangement (including upgrade from overhead to underground service)
			Overhead service line replacement
			Auditing services
			Protection and power quality assessment
			Customer requested works to allow contractor to work close
			Temporary disconnection and reconnection
			Supply enhancement
			Provision of connection services above minimum requirements
			Customer consultation or appointments
			Rectification of illegal connections or damage
			De-energisation
			Re-energisation
			Reading provided for an active site
			Attending loss of supply (customer at fault)
		Accreditation	Accreditation of service providers that meet competency criteria

ACS Tariff Class	Description	ACS Service	ACS Tariff
			Approval of third party design, works and materials
Ancillary network services	Non-routine services provided to individual customers on an 'as needs' basis. Ancillary network services involve work on, or in relation to, parts of the distribution network.	**Ancillary network services**	Services provided in relation to a retailer of last resort (ROLR) event
			Customer requested provision of electricity network data requiring customised investigation, analysis and technical input
			Bundling (conversion) of cables
			Provision of services to extend/augment the network
			Customer requested appointments
			Attendance at customer's premises to perform a statutory right where access is prevented
			Rearrangement of non-connection network assets
			Assessment of parallel generator applications
			Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer / contractor to work close to non-connection network assets
Metering services	Provision, installation and maintenance of Type 6 metering as well as non-routine auxiliary metering services provided on an 'as needs' basis	**Type 6 metering**	Provision, installation, maintenance, reading and data services
		Auxiliary metering services	New and upgraded meter installation
			Off-cycle meter reads
			Customer requested meter accuracy testing
			Customer requested meter inspection and investigation
			Meter reconfiguration
			Meter alteration – meter integrity verification
			Meter removal where not covered by the metering service charge
			Meter data services (non-standard)
			Provision, testing and maintenance of instrument transformers for metering purposes

ACS Tariff Class	Description	ACS Service	ACS Tariff
Public lighting	Activities of provision, construction and maintenance of public lighting assets, including emerging public lighting technology.	**Provision, construction and maintenance of public lighting**	Non-contributed (Energex installed and maintained): • Major (high watt) • Minor (low watt). Contributed (Energex maintained): • Major (high watt) • Minor (low watt).
		Other public lighting	Construction of new street light services (contributed)
			Provision of glare shield, vandal guards, luminaire replacement with aero screens
			Application assessment, design review and audit
			Alteration, repair, relocation, rearrangement or removal of existing street light assets
			Residual asset fee
		Emerging public lighting	New public lighting technologies including trials
			Energy efficient retrofit

11 Alternative control services: Proposed tariffs

11.1 ACS pricing framework and requirements

RULE REQUIREMENT

Clause 6.2.6 Basis of control mechanisms for direct control services

(b) For alternative control services, the control mechanism must have a basis stated in the distribution determination.

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(2) set out the proposed tariffs for each tariff class ; and.

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

Clause 6.18.5 Pricing Principles

(b) A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:

(1) must take into account the long run marginal cost for the service, or in the case of a charging parameter, for the element of the service to which the charging parameter relates.

FINAL DECISION REQUIREMENT

In accordance with clause 6.12.1(12) of the Rules, the form of control mechanism for alternative control services is the application of price caps.

Services under the ACS framework are provided on an individual fee-for-service basis to retailers and end-use customers. Energex provides ACS as a limited building block price cap, price cap or quoted price, depending on the service.

Price cap (or fee based) and quoted services are usually provided at the explicit request of third parties. These are defined as:

- Price cap services – Services relating to activities undertaken by Energex at the request of customers or their agents (e.g. retailers or contractors). The costs for these activities can be directly attributed to customers and service-specific prices can be charged.
- Quoted services – Services for which the nature and scope cannot be known in advance irrespective of whether it is requested by the customer or triggered by an external event.

11.2 Control mechanisms

11.2.1 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 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 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 2016-17, Energex has applied the approved control mechanism formula in Equation 11-1.

Equation 11-1 – 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 2016-17 price cap services, Energex used the CPI value of 1.69 per cent as per Table 12-1. Energex also applied the relevant X factors in accordance with the Final Decision.[20] These are summarised in Table 11-1 below.

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

Table 11-1 -2016-17 X factors and Escalations for price capped services

Service Description	X factor %	Escalation %
Limited Building Block:		
Public Lighting	(0.98)	2.7
Metering Services Charge		
Non Capital Component	28.57	(27.4)
Capital Component	0.40	1.3
Price Cap (fee based services)	(0.41)	2.1
Upfront Meter Capital Charge		
Single phase one element	(5.22)	7.0
Single phase two elements	(0.88)	2.6
Multi-phase	0.81	0.9
Multi-phase with Current transformer	5.79	(4.2)

It can be noted that unlike SCS, the WACC will not be updated annually to reflect changes in the cost of debt. Furthermore, prior to the application of the escalation formula some services have been updated to reflect the outcome of the Final Decision, which was not available at the time of submitting the 2015-16 Pricing Proposal.

11.2.2 Control mechanism for quoted services

Prices for quoted services are determined at the time the customer makes an enquiry and reflect the individual nature of the service requested.

To develop the prices for quoted services in 2016-17, Energex applies the AER approved formula to calculate the price for price capped outlined in Equation 11-2. This formula includes cost parameters for different services which are representative of the efficient costs of providing and delivering the services.

Equation 11-2 - 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 11-1. From 2016-17 onwards the base labour rates for 2015-16 will be escalated annually by $(1+\Delta CPI_t)(1-X_t)$ (see equation 12-2 for definitions). For 2016-17 the CPI value is 1.69 per cent as per Table 12-1 and the X-factor is as per Table 11-2. Other costs are determined at the time when the quote request is made.

Table 11-2 2016-17 X factor and Escalation for Quoted services

Service Description	X factor %	Escalation %
Labour component of quoted services	(0.41)	2.1

11.3 Compliance with Pricing Principles

11.3.1 Long run marginal costs

Customers requesting ACS are exposed to the future efficient costs of the services they seek and have the ability to respond by modifying their request. As these services are priced on a price path basis, an LRMC based pricing approach is not 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.

11.3.2 Estimating avoidable and stand alone costs

The price build up for ACS has been designed to ensure prices will represent the efficient costs of providing and delivering the service, and signal the economic costs of service provision by being subsidy-free.

Prices are cost-reflective, representing costs derived through the same allocation method as that used to determine costs for SCS, in accordance with the AER's approved Cost Allocation Method (CAM). The prices for each tariff class within ACS will be between the bounds of avoidable and stand alone costs due to the economies of scale in providing each service.

The avoidable cost for a particular service is equivalent to the direct labour, contractor cost and materials cost. Overhead costs and capital allowance will be incurred regardless of whether the service is provided.

The stand alone cost is equal to the costs of serving each tariff class within ACS on a stand alone basis. For example, the stand alone cost would require the use of dedicated resources and assets. As these costs can be shared among tariff classes within SCS and ACS, the cost calculated for each individual service will be less than the stand alone cost.

11.4 Connection services

11.4.1 Overview

This section discusses connection services that have been classified as ACS. All connection services, excluding small customer connections, operating and maintaining connection assets and general enquiry services for pre-connection are classified as ACS. These services can be broken down into pre-connection, connection, post-connection services and accreditation. Table 11-3 outlines Energex's connection service categories and classifications.

Table 11-3 - Classification for connection services

Connection Service Group	Connection Service Sub Group	AER Proposed Classification
Pre-connection Services	General connection enquiry services	Standard Control
	Connection application services	Alternative Control
	Pre-connection consultation services	Alternative Control
Connection Services	Small customer connections - design, construction, commissioning and energisation	Standard Control
	Large customer connections - design and construction	Alternative Control
	Commissioning and energisation of large customer connections*	Alternative Control
	Real estate development (sub-division) connections – design, construction, commissioning and energisation*	Alternative Control
	Removal of network constraints for EGs*	Alternative Control
	Review, inspection and auditing of design and works carried out by an alternative service provider prior to energisation	Alternative Control
	Temporary connections for short term supply	Alternative Control
Post Connection Services	Operate and maintain connection assets	Standard Control
	Connection management services (post connection)	Alternative Control
Accreditation/Certification	Accreditation of design consultants and alternative service providers and approval of materials.[1]	Alternative Control
Notes: 1. Connection services reclassified from standard control to alternative control in the 2015-20 regulatory control period.		

11.4.2 Connection service charges

Price capped connection services

The 2016-17 prices for price capped connection services are provided in Table 11-4 below. The pricing signals differentiate between time of day of the service request to be more cost reflective. To minimise costs, customers are able to choose to have the services delivered during business hours and within standard timeframes.

Table 11-4 – 2016-17 prices for connection price capped services

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
Pre – connection services (connection application services)				
Protection and power quality assessment prior to connection - simple	Solar PV 30-150 kW	N/A		$3,871.40
Negotiation services involved in negotiating a connection agreement – simple	Standard jobs for small customer connections and real estate developments (sub-divisions). Please note that if service is non-standard, a quoted price may apply.	N/A		$1,548.56
Application assessment, design review and audit real estate (sub-division) connection services - resubmission	Design assessment and preparation of offer - Resubmission	N/A		$165.86
Pre - connection services (consultation services)				
Site inspection in order to determine nature of connection	Small or large customer connection	N/A		$331.73
Provision of site-specific connection information and advice for small or large customer connections.	Protection devices and settings, fault level, network information	N/A		$663.45
Connection services				
Temporary Connection: 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.	120	No CT – Business Hours[2]	$1,599.39
		124/128	No CT – After Hours / Anytime	$2,246.74
		120	No CT – Traffic Control - Business Hours[2]	$1,599.39
		125/129	No CT – Traffic Control - After Hours / Anytime	$3,327.92
		122	CT – Business Hours[2]	$2,725.05

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		126/130	CT – After Hours / Anytime	$3,853.10
		122	CT – Traffic Control - Business Hours[2]	$2,725.05
		127/131	CT – Traffic Control - After Hours / Anytime	$4,934.28
	Temporary connection of unmetered equipment to an existing LV supply[2].	1400		$264.52
Post Connection Services				
Supply Abolishment (simple)	Request to de-energise an unmetered supply point.	328		$406.15
	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[3].	800	Business Hours	$650.56
		801/806	After Hours / Anytime	$803.18
		809	Traffic Control – Business Hours	$1,731.74
		805/807	Traffic Control – After Hours / Anytime	$1,884.36
	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.	803	Business Hours	$122.57
		804/808	After Hours / Anytime	$174.97
Rearrange connection assets at customers at customers request (simple)	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	1004	Business Hours	$247.64
		1019/1035	After Hours / Anytime	$353.40
Customer requested Overhead Service	Customer requests their existing overhead service	920	Single Phase – Business Hours	$628.63

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
Line Replacement (no material change to load)	to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load.	921/923	Single Phase – After Hours / Anytime	$815.49
		559	Single Phase – Traffic Control – Business Hours[3]	$1,709.81
		922/925	Single Phase – Traffic Control – After Hours / Anytime	$1,896.67
		924	Multi-Phase – Business Hours	$882.78
		927/931	Multi-Phase – After Hours / Anytime	$1,118.69
		560	Multi-Phase – Traffic Control – Business Hours[3]	$1,963.96
		929/933	Multi-Phase – Traffic Control – After Hours / Anytime	$2,199.87
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)	N/A	0-6 sites	$454.79
		N/A	7-30 sites	$727.67
		N/A	31-60 sites	$870.60
		N/A	60 + sites	$970.22
Temporary disconnections and reconnections (which may involve a line drop) - low voltage	Temporary LV service Disconnection/reconnection – Primary Fuse (no dismantling)	902	Business Hours	$355.21
		908/914	After Hours / Anytime	$506.90
	Temporary LV service Drop and re-erect (dismantling)	904	Business Hours	$580.34
		910/915	After Hours / Anytime	$828.17
Customer Initiated Supply Enhancement (Load Service Upgrade)	Overhead Service Upgrade to Single Phase	1008	Business Hours	$1,037.74
		1053	After Hours[3]	$1,349.66

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		1055	Traffic Control – Business Hours[3]	$2,118.92
		1054	Traffic Control – After Hours[3]	$2,430.84
	Overhead Service Upgrade to Multi-phase	1014	Business Hours	$1,169.52
		1000	After Hours[3]	$1,570.10
		1001	Traffic Control – Business Hours	$2,250.70
		1052	Traffic Control – After Hours[3]	$2,651.28
	Underground Service Upgrade to Single Phase[4]	1060	Business Hours[3]	$127.57
		1061	After Hours[3]	$182.05
	Underground Service Upgrade to Multi Phase[4]	1042	Business Hours	$62.54
		1062	After Hours[3]	$89.24
		1063	CT – Business Hours[3]	$450.26
		1064	CT – After Hours[3]	$642.54
Customer consultation or appointment	A visit to the customers premise to advise on electrical supply matters, could be for various reasons	952	Complex	$225.13
		TBA	Simple[4] (e.g. advice on location of POA)	$102.56
De-energisations[2]	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)	300	Reason Other than Non Payment - No CT	$62.69
		302	Reason Other than Non Payment - CT	$307.99
		304	Non Payment – No CT	$62.69

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		306	Non Payment – CT	$312.30
	Retailer Requested de-energisation (Main Switch Seal – MSS)	320	Non Payment	$20.54
		324	Reason Other than Non Payment	$20.54
Re-energisations[2]	Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required	200	No CT - Business Hours	$47.89
		204/208	No CT - After Hours / Anytime	$67.91
		202	CT – Business Hours	$47.89
		206/210	CT – After Hours / Anytime	$67.91
	Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required)	406	Reason Other than Non Payment - Business Hours	$11.56
		408	Reason Other than Non Payment - After Hours	$77.27
		410	Reason Other than Non Payment - Anytime	$70.01
		412	Non Payment – Business Hours	$47.39
		416	Non Payment – After Hours	$77.27
		414	Non Payment – Anytime	$70.01
	Retailer requests a visual examination upon re-energisation of the customer's premises	224	No CT – Business Hours	$110.02
		228	No CT – After Hours	$156.79
		232	No CT – Anytime	$156.42
		226	CT – Business Hours	$282.16

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		230	CT – After Hours	$389.94
		234	CT - Anytime	$426.25
	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	212	No CT – Business Hours	$110.02
		216	No CT – After Hours	$156.79
		220	No CT – Anytime	$156.42
		214	CT – Business Hours	$282.16
		218	CT – After Hours	$389.94
		222	CT - Anytime	$426.25
Readings provided for an active site	Readings provided for an active site	238	Retailer Requested Fieldwork to obtain new reading	$9.77
		240	Retrospective move in read required	$9.77
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)	1500	Business Hours	$225.13
		1602/1600	After Hours / Anytime	$321.27
Accreditation / certification				
Accreditation of Design Consultants Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), Rate 2 public lighting, LCC &	Desktop management system evaluation New applicant has ISO9001 accreditation with no other Energex accreditations in place.	N/A	New applicant has ISO9001 accreditation with no other Energex accreditations in place.	$10,475.67
		N/A	New applicant is not ISO9001 accredited with no other Energex accreditations in place.	$12,208.21

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
distribution works that are reticulated with Energex network (Design Accreditation)		N/A	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).	$7,158.41
	Onsite management system evaluation (irrespective of prior accreditations).	N/A		$693.02
	Capability evaluation (irrespective of prior accreditations).	N/A		$663.45
Accreditation of Alternative Service Providers 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)	Desktop management system evaluation New applicant has ISO9001 accreditation with no other Energex accreditations in place.	N/A	New applicant has ISO9001/AS4801/ISO14001 accreditation with no other Energex accreditations in place.	$5,108.93
		N/A	New applicant is not ISO9001/AS4801/ISO14001 accredited with no other Energex accreditations in place.	$9,583.97
		N/A	Applicant requesting additional Energex accreditations with or without ISO9001/AS4801/ISO14001 accreditation (price per additional accreditation).	$5,108.93
	Onsite management system evaluation (irrespective of prior accreditations).	N/A		$1,386.03
	Capability evaluation (irrespective of prior accreditations).	N/A		$1,356.47

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
Management System Re-Evaluation	QA process: This is conducted on request from existing service providers and design consultants with the intent to improve their management system score.	N/A		$6,930.17
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 WCS requirements. Also involves a capability assessment of the applicant's ability to conduct the work.	N/A		$5,197.63

Notes:

1. Prices are GST exclusive. Prices are inclusive of overheads and on-costs.
2. Prices for these services are subject to Schedule 8 of the Queensland Electricity Regulation 2006. As Schedule 8 prices for 2016-17 are yet to be published, the rates in this table represent the proposed Energex costs using the ACS formula. Schedule 8 prices will be included in Energex's 2016-17 Tariff Schedule which will be published on the Energex website as soon as practicable.
3. The service assumptions and prices for these services were modified or added and subsequently approved as part of the AER's Final Decision. As this process occurred after the publication of the 2015-16 Pricing Proposal, the change between 2015-16 and 2016-17 pricing proposals does not conform to the relevant escalation formula.
4. Subsequent to the Final Decision a review of the service assumptions associated with these services has been undertaken and a lower price has been determined and applied.

11.5 Large customer connections

11.5.1 Overview

Energex defines large customer connections (LCC) as those connections that fall within the tariff classes of ICC or CAC including embedded generators with installed capacity greater than or equal to 30kVA.[21]

Customers may choose either Energex or an accredited service provider to undertake the design and construction of the connection assets (to Energex's technical standards). The operation and maintenance of all connection assets, including large connections, is an SCS.

11.5.2 Framework

The framework for new and existing LCC is provided in Figure 11-1 and Table 11-5.

The design and construction of LCC will be classified as one of the following:

- ACS – All new connections or upgrades to existing connections, which are paid for by the customer and gifted to Energex. This may include an upfront payment for the design and construction of the connection assets. These assets will form part of the Contributed Asset Base (CAB). Items in the CAB will have no return on capital or regulatory depreciation cost allocated to them. However, there will be an allocation for O&M costs recovered through DUoS as per the tariff revenue allocation process detailed in Appendix 2 - Revenue allocation process.

- SCS – LCC assets, existing prior to 1 July 2010, which are owned and maintained by Energex, or were built as part of an Energex driven asset replacement. These services will continue to form part of the Regulatory Asset Base (RAB). These connection assets have costs allocated to them for return on capital, regulatory depreciation and O&M as per the tariff revenue allocation process detailed in Appendix 2 - Revenue allocation process.

- Unregulated services – Connection assets that are funded, owned and operated by the customer. These services will attract no specific connection asset charges.

[21] It should be noted that LCC, for the 2015-20 regulatory control period, have been redefined to lower the threshold for EGs from 1 MVA to 30 kVA.

Figure 11-1 – Service classification for LCC

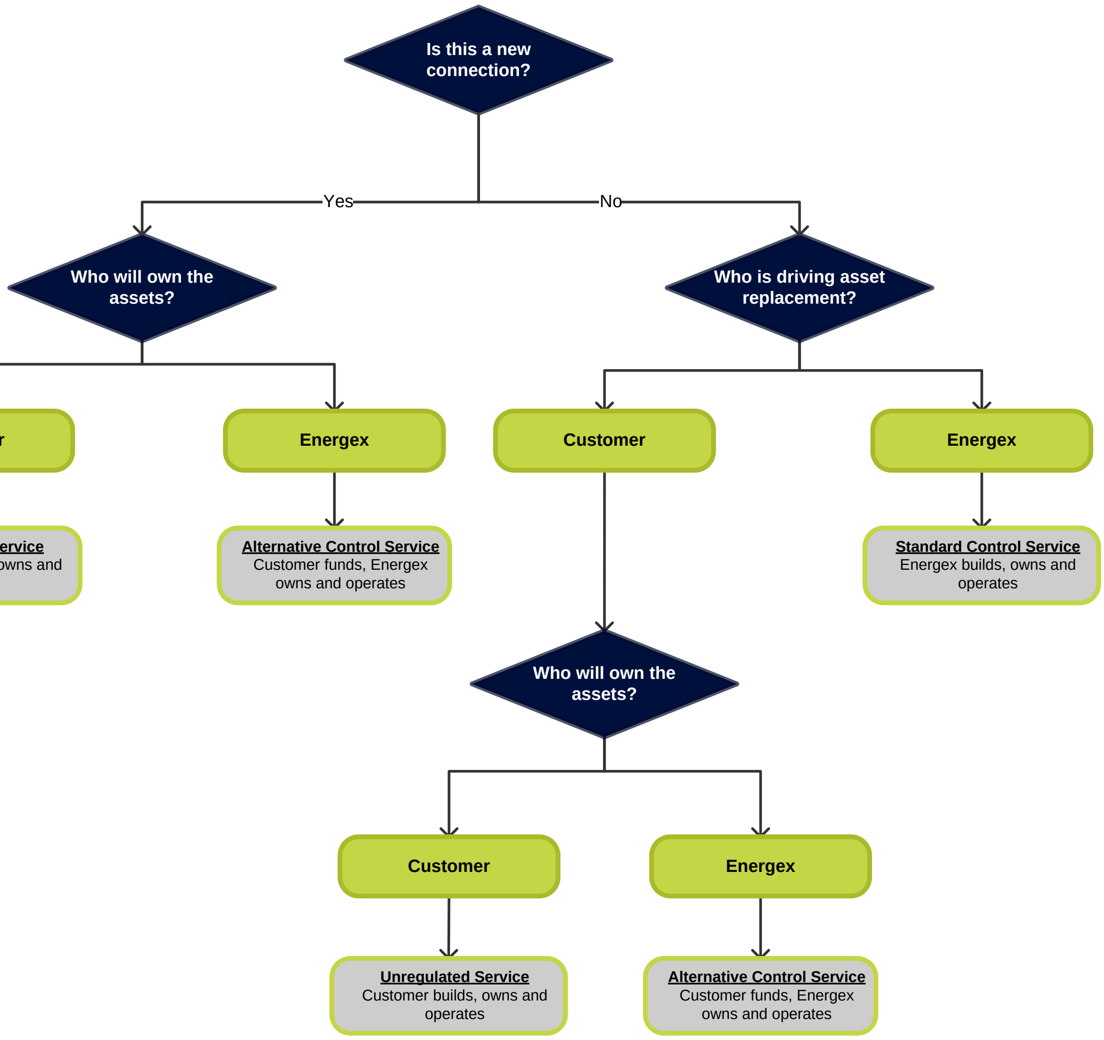


Table 11-5 – LCC pricing framework

Initial connection date	Description	Ownership[1]	Asset classification	Service classification	Asset base	Upfront customer payment (quoted price, relating to design and construction costs)	Tariff charging parameter (site-specific fixed charge): Recovery of depreciation and return on capital (through DUoS)	Tariff charging parameter (site-specific fixed charge): Recovery of operating expenditure (through DUoS)
Before 1 July 2010 (or part of transitional arrangement) Asset constructed under previous framework	Existing connection	Energex	Non-contributed	SCS	RAB	N/A	✓	✓
	Upgrade to existing asset - Energex driven[2]	Energex	Non-contributed	SCS	RAB	N/A	✓	✓
	Upgrade to existing asset - customer request	Energex (gifted)	Contributed	ACS	CAB	✓	N/A	✓
After 1 July 2010 Asset constructed under new framework	New connection	Energex (gifted)	Contributed	ACS	CAB	✓	N/A	✓
	Upgrade to existing asset - customer request	Energex (gifted)	Contributed	ACS	CAB	✓	N/A	✓
	Upgrade to existing asset - Energex driven[2]	Energex	Non-contributed	SCS	RAB	N/A	✓	✓
Asset constructed under either framework	Replacement - during warranty period for gifted assets	Energex (gifted)	Contributed	N/A	N/A	N/A (covered under warranty)	N/A	✓
	Replacement - outside manufacturer's warranty period	Energex (gifted)	Contributed	ACS	CAB	✓	N/A	✓
		Energex	Non-contributed	SCS	RAB	N/A	✓	✓
	Any service	Customer	N/A	Unregulated	N/A	No specific connection asset charges		

Notes:

1. If the customer chooses to retain ownership of the asset, the service is unregulated and there are no specific connection asset charges.
2. An Energex driven upgrade to a customer's connection assets could occur, when for network reasons, the connection arrangement needs to be altered.

11.5.3 Charging parameters and proposed charges

Specific prices for LCC quoted services cannot be provided due to the variability in the scope, design and construction of LCC assets. Quotations can be provided to the customer for their selected service upon request using the formula in Equation 11-2.

11.6 Ancillary network services

11.6.1 Overview

Table 11-6 sets out Energex's classification of ancillary network services. Consistent with the approach adopted for other ACS, services have been determined to be price cap or quoted depending on whether the scope of work is pre-defined or subject to variability.

Table 11-6 – Classification of ancillary network services

Service Group	Price Cap/ Quoted Service
Services provided in relation to the retailer of last resort	Quoted
Other recoverable works:	
Customer requests provision of electricity network data requiring customised investigation, analysis or technical input	Quoted
Bundling (conversion) of cables carried out at the request of another party	Quoted
Provision of services to extend /augment the network, to make supply available for the connection of approved unmetered equipment	Quoted
Customer requested appointments	Price cap
Rearrangement of network assets (other than connection assets)	Quoted
Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customers/contractors to work close	Quoted
Assessment of parallel generator applications	Quoted
Attendance at customer's premises to perform a statutory right where access is prevented	Price cap

11.6.2 Charging parameters

Price capped ancillary network services

Energex has developed prices which reflect efficient and prudent costs in providing connection services based on existing and prospective service obligations. The price schedule for price capped services in 2016-17 is provided in Table 11-7.

Table 11-7 – Price caps for ancillary network services

Category	Service Description	Code	Permutations	2016-17[2] ($/service)
Other Recoverable Works				
Customer Requested Appointments	Customer requested appointments	N/A		$225.13
Attendance at customers premises to perform a statutory right where access is prevented[1]	Energex attends a site at the customer's request and is unable to perform job due to customer's fault	1044	Technical – Business Hours	$90.05
		1050	Technical – Business Hours (2 crew)[3]	$180.10
		1045/1047	Technical – After Hours / Anytime	$128.51
		1051	Technical - After Hours (2 crew) [3]	$257.02
		1046	Non-Technical – Business Hours	$10.74
		1048/1049	Non-Technical – After Hours / Anytime	$76.97

Notes:

1. Includes faults caused by customer's electrical contractor.
2. Prices are GST exclusive. Prices are inclusive of overheads and on-costs.
3. Subsequent to the Final Decision a review of the service assumptions associated with these services has been undertaken and a lower price has been determined and applied.

11.7 Type 6 metering services

11.7.1 Overview

For the 2015-20 regulatory control period, Type 6 metering installations and auxiliary metering services have been classified as ACS.[22] Type 6 metering installations incorporate the provision, installation, ongoing maintenance, meter reading and meter data services for Type 6 metering.

Auxiliary metering services are customer requested metering services provided to individual customers on a non-routine basis. The scope of auxiliary metering services currently involves a number of services including meter alterations, Type 6 non-standard metering services, off-cycle meter reads, meter tests (customer initiated), meter inspections and meter reconfigurations.

Table 11-8 summarises the classification of metering services for the 2015-20 regulatory control period. This section addresses metering services that are classified as ACS only.

Table 11-8 – Classification of Energex metering services

Metering Type	Description	Classification
Metering Types 1-4	Provision, installation, maintenance, meter reading and meter data services for Type 1-4 meters	Unregulated
Metering Type 6	Provision, installation, maintenance, meter reading and meter data services for Type 6 meters.	Alternative Control Service
Metering Type 7	Unmetered connections where usage is estimated (includes public lighting and traffic lights).	Standard Control Service
Auxiliary Metering Services	Range of customer requested metering services which are provided to individual customers on a non-routine basis.	Alternative Control Service
Note: Type 5 meters are not permitted in Queensland.		

11.7.2 Type 6 meters and auxiliary metering services

Table 11-9 summarises the control mechanism and charging arrangements for Type 6 and auxiliary metering services as per the AER's Final Decision.

Table 11-9 – Alternative control metering services for 2015-20 regulatory control period

Metering service	Description	Type 6/ Auxiliary Service	Basis of Control	Charging Arrangements
Meter provision	Meter selection, meter procurement, meter programming, meter testing on delivery.	Type 6	Building block	Metering services charge
Meter installation	Initial installation of meter at customer's premises.	Auxiliary	Cost build up approach	Price cap
	Install additional metering.	Auxiliary	Cost build up approach	Price cap

[22] Type 5 meters are not permitted in Queensland.

Metering service	Description	Type 6/ Auxiliary Service	Basis of Control	Charging Arrangements
	Replacement of meter at customer's premises - Energex initiated.	Type 6	Building block	Metering services charge
	Customer requested meter exchange.	Auxiliary	Cost build up approach	Price cap
Meter maintenance	Customer requested meter test.	Auxiliary	Cost build up approach	Price cap
	Customer requested meter inspection and investigation.	Auxiliary	Cost build up approach	Price cap
	Customer requested reconfiguration of meters (e.g. tariff change).	Auxiliary	Cost build up approach	Price cap
	Meter alteration-Meter integrity verification i.e. as a result of a meter alteration (includes meter reseal).	Auxiliary	Cost build up approach	Price cap
	Replacement or removal of a Type 6 meter instigated by a customer switching to a non-Type 6 meter that is not covered by any other fee.	Auxiliary	Cost build up approach	Quoted
	Removal of meter/s from customer's premises.	Type 6	Building block	Metering services charge
	Meter maintenance (includes network initiated meter inspection and meter tamper).	Type 6	Building block	Metering services charge
	Meter sample testing and replacing per Metering Asset Management Plan.	Type 6	Building block	Metering services charge
	Monthly and quarterly cycle meter reading. Includes Energex audit of third party provider.	Type 6	Building block	Metering services charge
Meter reading	Final read.	Auxiliary	Cost build up approach	Price cap
	Check read.	Auxiliary	Cost build up approach	Price cap
	Transfer read.	Auxiliary	Cost build up approach	Price cap
	Estimated read.	Auxiliary	Cost build up approach	Price cap
	Processing data (validations, substitutions, forward estimates).	Type 6	Building block	Metering services charge
Meter data services	Storing data.	Type 6	Building block	Metering services charge
	Delivering data.	Type 6	Building block	Metering services charge
	Non-standard data services (Type 6-7).	Auxiliary	Cost build up approach	Quoted

Metering service	Description	Type 6/ Auxiliary Service	Basis of Control	Charging Arrangements
Other metering services	Stranded asset value of metering asset.	Type 6	Cost build up approach	Metering services charge
	Instrument transformers.	Auxiliary	Cost build up approach	Price cap

Note:

Services included in the building block approach are assumed to be performed during business hours, any request for after-hours service may incur an additional fee payable by the customer.

11.7.3 Type 6 metering services charge

Energex's revenue requirement for Type 6 metering services charge has been determined based on limited building block components consistent with the approach set out by the AER in the Final Decision.

The recovery of revenue requirement from existing and new Type 6 metering customers is dependent on:

- The number of applicable tariffs which approximates the number of meters/complexity of the metering installation.
- The extent to which the customer contributed to the MAB.
- Whether the customer's metering connection existed before 1 July 2015.
- Whether the customer has churned to an alternative meter service provider.

The AER's Final Decision provides that existing Type 6 metering services (before 1 July 2015) will attract an annual charge comprising of the following components:

- Capital component – MAB recovery including the recovery of the tax liability component of the building block.
- Non-capital component – Operating expenditure.

The capital component applies to all existing Type 6 meter connections before 1 July 2015 regardless of whether customers elect to churn to an alternative meter provider or upgrades. Churning customers will continue to pay the capital component on an on-going basis to recover the residual value of the stranded assets.

Non-capital charge comprises of ongoing Energex initiated meter maintenance, cyclic meter reading and data storage and provision. The non-capital component applies to both existing and new/additional Type 6 meter connections. To clarify, the non-capital component will not apply to churning metering customers.

The metering service charge is applied to each SAC non-demand tariff with tariffs being developed with reference to primary and secondary meter services. Secondary services may include services such as off-peak hot water or solar PV metering. Those customers with multiple tariffs will face relatively higher metering services charges reflecting the number of meters and/or complexity of metering installation. This approach ensures that customers who have more than one metering service will pay more to reflect the additional services being provided.

The price per tariff is based on the revenue proportion assigned to and the forecast volume of Type 6 meters for each tariff group. These prices reflect efficient and prudent costs in providing Type 6 metering services based on existing and prospective service obligations. Charges have been developed to promote the objectives of administrative simplicity and cost reflectivity. Table 11-10 displays the daily metering services charge by metering tariff class for 2016-17.

Table 11-10 – 2016-17 prices for Type 6 metering service charge

Tariff Class	Cost	2016-17 (Cents/day)[1,2]
Primary	Non-capital	2.1504
	Capital	6.7933
Load Control	Non-Capital	0.6451
	Capital	2.0380
Solar PV	Non-Capital	1.5053
	Capital	4.7553

Notes:

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

Price capped auxiliary metering services

In addition to the ongoing metering service charge, Energex will continue to perform one off metering services at the request of customers, including meter installations, metering alterations, special meter reads, meter tests and instrument transformer tests. Energex utilises a cost build-up approach, based on a number of service assumptions, to determine the price cap to apply to the majority of auxiliary metering services.

The pricing signals differentiate between time of day of the service request to be more cost reflective. To minimise costs, customers are able to choose to have them delivered during business hours and within standard timeframes.

The price schedule for price capped services in 2016-17 is provided in Table 11-11. These prices reflect efficient and prudent costs in providing these auxiliary metering services based on existing and prospective service obligations.

Table 11-11 – Price caps for auxiliary metering Services

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
Meter Installations				
Upfront Capital Charge	New Permanent Connection (Temp to Perm, connecting to the Energex Network for the first time)	460	Single Phase Single Element Overhead Fox – Business Hours	$327.53
		461	Single Phase Single Element Overhead – Business Hours	$327.53
		462	Single Phase Single Element Underground– Business Hours	$327.53
		452	Single Phase Single Element Overhead Fox – After Hours[2]	$461.97
		453	Single Phase Single Element Overhead – After Hours[2]	$428.78
		454	Single Phase Single Element Underground – After Hours[2]	$404.48
		466	Single Phase Dual Element – Business Hours	$409.34
		467	Single Phase Dual Element – After Hours[2]	$486.29
		463	Multi-Phase Overhead Fox – Business Hours	$602.57
		464	Multi-Phase Overhead – Business Hours	$602.57
		465	Multi-Phase Underground– Business Hours	$602.57
		455	Multi-Phase Overhead Fox – After Hours[2]	$772.69

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		456	Multi-Phase Overhead – After Hours[2]	$730.60
		457	Multi-Phase Underground– After Hours[2]	$702.43
		458	Multi-Phase Overhead CT – Business Hours	$1,614.03
		450	Multi-Phase Overhead CT – After Hours[2]	$1,951.97
		459	Multi-Phase Underground CT – Business Hours	$1,614.03
		451	Multi-Phase Underground CT– After Hours[2]	$1,939.06
	Install Control Load / Hot Water	516 / 518	Single Phase Single Element - Business Hours	$327.53
		546 / 553	Single Phase Dual Element – Business Hours	$409.34
		548 / 555	Multi-phase DC – Business Hours	$602.57
		550 / 557	Multi-phase CT – Business Hours	$1,614.03
	Installation of a new meter (not controlled load / hot water) existing premises – Additions and Alternations	520	Single Phase Single Element (incl. solar pv) – Business Hours	$327.53
		469	Single Phase Dual Element – Business Hours	$409.34
		532 / 504 / 508	Single Phase Single Element – After Hours / Anytime[2]	$401.47
		534	Single Phase Single Element (solar pv) –After Hours[2]	$390.35

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		468	Single Phase Dual Element – After Hours[2]	$483.28
		521	Multi-phase DC (incl. solar pv) – Business Hours	$602.57
		533	Multi-phase DC – After Hours[2]	$722.31
		535	Multi-phase DC (solar pv) – After Hours[2]	$680.52
		522	Multi-phase CT (incl. solar pv) – Business Hours	$1,614.03
		506 / 510	Multi-phase CT – After Hours / Anytime[2]	$1,965.80
		531	Multi-phase CT (solar pv) – After Hours[2]	$1,801.16
	Customer requested meter exchange (eg alternative metering configuration / consolidation of multiple meters for one meter	500	Single Phase Single Element – Business Hours	$327.53
		541	Single Phase Dual Element – Business Hours	$409.34
		501 / 505	Single Phase Single Element – After Hours / Anytime[2]	$379.90
		542	Single Phase Dual Element – After Hours[2]	$461.71
		543	Multi-phase DC – Business Hours	$602.57
		544	Multi-phase DC – After Hours	$676.51
		502	Multi-phase CT – Business Hours	$1,614.03

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
		503 / 507	Multi-phase CT – After Hours / Anytime[2]	$1,965.80
Meter Maintenance				
After hours removal of meter/s from customer's premises	After hours removal of meter/s from customer's premises	536	No CT – After Hours	$53.15
		537	CT Metering – After Hours	$169.49
Customer requested meter test (physically test meter	Testing for type 5 & 6 meters – customer requested meter accuracy testing	704	No CT	$373.10
		706	CT Metering	$777.95
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)	957	No CT – Business Hours	$91.63
		965/967	No CT – After Hours / Anytime	$165.32
		959	CT Metering – Business Hours	$340.60
		969/971	CT Metering – After Hours / Anytime	$486.05
Customer requested reconfiguration of meters[3]	Controlled Load	1200	No CT – Business Hours	$93.45
		1202	CT Metering – Business Hours	$430.25
	A request to make a change from one tariff to another	1204	No CT – Business Hours	$93.45
		1212/1220	No CT – After Hours / Anytime	$110.46
		1206	CT Metering – Business Hours	$430.25
		1214/1222	CT Metering – After Hours / Anytime	$613.99
	A request to make a change involving a residential	1201	To TOU - No CT	$142.58

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
	TOU tariff	1203	To TOU - CT Metering	$475.28
		1205	TOU reversion	$93.45
Change Time-switch	Change Time-switch	1208	No CT – Business Hours	$125.07
		1210	CT Metering – Business Hours	$395.23
Meter Alteration – meter integrity verification (e.g. after move meter)	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment	512	No CT – Business Hours	$130.69
		513/517	No CT – After Hours / Anytime	$186.90
		514	CT Metering – Business Hours	$809.86
		515/519	CT Metering – After Hours / Anytime	$1,155.70
Meter Reading	**Check Read** - 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.	400		$7.08
	Final Read - Retailer requires a reading for preparing a final bill for customer.	402		$7.08
	Transfer Read - Customer requests a transfer read, as a result of transferring to a different retailer during a billing period.	404		$7.08
	Estimated Read			$7.88
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	955	First Unit – Business Hours	$130.59
		TBA	Additional Unit – Business Hours	$65.55
		961/963	First Unit – After Hours / Anytime	$372.71

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
	reported or suspected fault. Does not include provision of any hardware	TBA	Additional Unit – After Hours / Anytime	$187.09
CT Metering	Provision, installation, testing and maintenance of instrument transformers for metering purposes	539		$969.66
	Testing and maintenance of instrument transformers for metering purposes	540		$177.60

Notes:

1. Prices are GST exclusive. Prices are inclusive of overheads and on-costs.
2. The Final Decision set out the after-hours incremental charge for meter installations as an add-on to the business hours upfront capital charge. This was in keeping with Energex's initial approach of incorporating the business hours meter installation fee within the Metering Service Charge. As the installation fee now is a stand-alone fee the after-hours fee have then been incorporated with the base charge to form a complete after hours charge.
3. If a new meter installation is required, a meter installation charge will apply.

11.8 Public lighting

11.8.1 Overview

The provision, construction and maintenance of public lighting assets, as well as emerging public lighting technology and other public lighting services, are classified as a direct control service and further as an ACS under a price cap form of control. The conveyance of electricity to public lights will continue to be classified as a SCS. The ACS element of public lighting services is addressed in this section.

Table 11-12 – Energex's control mechanisms for public lighting

Public lighting service	Description	Basis of control	Charging arrangements
Provision, construction and maintenance of public lighting	Non-contributed (EOO): • Major (high watt) • Minor (low watt) Contributed (GOO): • Major (high watt) • Minor (low watt)	Building Block	Street light daily fixed fee
Other public lighting	Construction of new street light services (contributed)	Cost build up approach	Quoted
	Provision of glare shield, vandal guards, luminaire replacement with aero screens	Cost build up approach	Price cap / Quoted
	Application assessment, design review and audit	Cost build up approach	Price cap / Quoted
	Alteration, repair, relocation, rearrangement or removal of existing street light assets	Cost build up approach	Quoted
	Residual asset fee	Cost build up approach	Quoted
Emerging public lighting	New public lighting technologies including trials	Cost build up approach	Quoted
	Energy efficient retrofit	Cost build up approach	Quoted

In the 2015–20 regulatory control period, Energex will continue to provide for non-contributed and contributed street lighting services.

Energex classified public lighting services as follows:

- Non-Contributed (luminaires owned and operated by Energex (EEO))[23] - Since 1 July 2010, this service applies where Energex has constructed standard public lighting

[23] Terminology used by the AER in its Final Decision.

assets and owns and maintains the asset. In this situation, the customer pays an ongoing charge for the provision (capital), installation and standard level of maintenance.

- Contributed (luminaires gifted by councils and operated by Energex (GOO))[24] - This service applies where a customer installs the public lighting assets and gifts the assets to Energex to own and maintain the asset. The customer is charged for the maintenance of the asset only. Where maintaining standard public lighting is uneconomical (e.g. due to location) an incremental cost will be charged as an ACS.

- Pre-2010 Contributed - This current distribution determination provides that contributed public lighting assets should continue to be recovered as SCS. Aligning with the historical capital contribution treatment in Queensland, contributed public lighting assets were incorporated in Energex's RAB with a corresponding one-off (negative) revenue adjustment to offset the revenue Energex will earn from these assets until they are fully depreciated..

- Other - This service applies to the provision, installation and maintenance of public lighting not owned or maintained by Energex.

11.8.2 Framework

The approach for the treatment of public lighting assets, contributed and non-contributed, other and emerging public lighting services satisfies the requirements of the Rules and delivers network charges which directly correlate with the level of service provided.

Energex proposes that the basis of the control mechanism for:

- Standard non-contributed and contributed public lighting services is a limited building block approach to determine the efficient costs of providing both non-contributed and contributed public lighting services under the price cap control mechanism for the regulatory control period.

- Other (non-standard) and emerging public lighting services are a cost build up approach (for both price cap and quoted service).

Emerging public lighting technology and other public lighting services, which have a predefined scope of work, will be subject to a price cap. Where the scope of work varies considerably, the work will be subject to a cost build-up price.

Where the provision of a standard street light becomes uneconomical (i.e. due to its location) then the incremental cost will be charged as a quoted service. Non-standard street lights will be available as a fully contributed service. Charges associated with these services will need to be paid upfront by the customer.

In the instances where work is required outside of business hours due to maintenance access restrictions or customer requirements, these incremental services will be provided as quoted services.

[24] Terminology used by the AER in its Final Decision

11.8.3 Charging parameters

Street light contributed and non-contributed public lighting services

Energex's revenue requirements for street lighting services have been determined based on the revenue building block components consistent with the approach used for SCS. Street lights are allocated into two categories, street light major and street light minor, according to luminaire type and size (as defined in the glossary), and to non-contributed and contributed based on the funding arrangement.

Table 11-13 below provides the price schedule for the provision, construction and maintenance of street lights for 2016-17. The prices are based on the methodology approved in the Final Decision and charges are tailored to enable the customer to be charged according to the level of service requested. The prices reflect standardised lights and no restriction on access for operation, maintenance and repair. In the case of restricted access, an additional charge may apply.

Table 11-13 – 2016-17 prices for street lighting services

Street light service[1]	Price[2] ($/luminaire/day)
Major non-contributed (EOO)	0.80
Major contributed (GOO)	0.28
Minor non-contributed (EOO)	0.37
Minor contributed (GOO)	0.13

Notes

1. Definitions for street light major and street light minor are included in the glossary.
2. All prices exclude GST.

Price capped and other emerging public lighting services

Energex will continue to perform one off public lighting services at the request of customers, including provision of glare shield, vandal guards, luminaire replacement with aero screens and application assessment, design review and audit. Energex utilises a cost build-up approach, based on a number of service assumptions, to determine the price cap to apply to the majority of public lighting services.

The price schedule for price capped public lighting services in 2016-17 is provided in Table 11-14. These prices reflect efficient and prudent costs in providing these public lighting services based on existing and prospective service obligations.

Table 11-14 – Indicative price caps for public lighting services

Category	Service Description	Code	Permutations	2016-17[1] ($/service)
Provision of glare shields, vandal guards, luminaire replacement with aero screens	Customer requests the supply and installation of adhesive luminaire glare screen (s)	602		$191.44
	Customer requests the supply and installation of standard internal luminaire glare screen (s)	604		$156.48
	Replacement of existing streetlight luminaires with aero screen low glare luminaires	600		$526.66
Application assessment, design review and audit	Rate 3 Public Lighting services. Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits)	N/A	0 – 6 sites	$82.93
		N/A	7 – 30 sites	$124.40
		N/A	31 + sites	$248.79
	Rate 2 Public Lighting services. Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits)	N/A	Resubmission	$165.85

Notes:

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

11.8.4 ACS Quoted services

Quoted services are utilised for all ACS connections, ancillary network services, auxiliary metering services and public lighting services.

For all quoted services, Energex has retained its current policy of not establishing a fixed price where variations in the precise nature of the services being sought mean that averaging would result in significant inequity for customers. The prices for quoted services will be calculated to reflect the actual cost of service provision based on the specific requirements of the customer.

In relation to auxiliary metering services and public lighting services, Energex has applied a number of service level assumptions, which account for regulatory obligations with regard to the provision of the listed price cap services prescribed under the Electricity Distribution Network Code[25] and the Queensland Electricity Connection and Metering Manual.[26] Any changes to the standard terms and conditions will be charged at a quoted cost where the price reflects the specific requirements of the customer.

[25] Queensland Competition Authority, Electricity Distribution Network Code made under the Electricity Act 1994, July 2015
[26] Energex/Ergon, Queensland Electricity Connection and Metering Manual, 2014

12 Changes from previous regulatory year

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 2015-16 and 2016-17, including:

- Adjustments to TAR components.
- Changes to tariffs.
- Changes to the approach to price setting.
- Changes resulting from the 2016-17 Pricing Proposal being based on the AER's Final Decision while the 2015-16 Pricing Proposal was based on the Preliminary Decision.

An analysis of the customer impacts of the various changes is included in Chapter 13.

12.1 Summary of annual adjustments

As shown in Table 2-2, various adjustments are made to the annual smoothed expected revenue for the relevant regulatory year to calculate the TAR. These adjustments are specified in the Final Decision, including:

- CPI (Attachment 14 – Control mechanisms) – Energex is to use a CPI factor based on the year to December t-1. This CPI factor is the annual percentage change in the ABS CPI for All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1.
- STPIS (Attachment 11 – Service target performance incentive scheme) – Annual adjustment to reflect the STPIS reward/penalty from year t-2 (2014-15), as approved by the AER.
- SBS FiT payments (Attachment 1 – Annual Revenue Requirement) – Forecast SBS FiT payments to be paid in the 2016-17 financial year.
- DUoS over or under recovery (Attachment 1 – Annual Revenue Requirement) – Significant under recoveries for the 2010-15 regulatory control period have been incorporated in the building blocks for SCS pricing via a carry-over mechanism between regulatory control period and smoothed over the 5 year period. In addition,

DUoS under recoveries from 2014-15 are to be recovered in 2016-17 as a pass through.[27]

- The X Factor for 2016-17 (Attachment 1 – Annual Revenue Requirement) – The X-factor for 2016-17 was updated in the PTRM by the AER, as a result of the annual return on debt update.

These adjustments ensure that the TAR accounts for changes in the value of various revenue components between regulatory years within the 2015-20 regulatory control period.

A summary of the annual adjustments is included in Table 12-1.

Table 12-1 – Summary of annual adjustments

Component / adjustment	2015-16 values	2016-17 values	Reason for change
CPI	2.55%	1.69%	Annual adjustment for 2015-16 as per the Preliminary Decision and for 2016-17 as per information published by the ABS. See Section 12.1 for further information.
X Factor	40.05%	-2.09%	X Factor for 2015-16 as per the Preliminary Decision and for 2016-17 as per the Final Decision, updated for the return on debt annual update.
Capital contributions	$47.3 m	$17.4 m	The value in 2015-16 relates to under recovery in 2013-14. The value in 2016-17 relates to under recovery in 2014-15.
STPIS	$13.5 m	$65.0 m	The value in 2015-16 relates to a portion of the 2012-13 STPIS reward. The adjustment is consistent with the S-banking approval from AER received on 21 February and 19 December 2014. Energex proposes to recover the 2013-14 STPIS in 2016-17.
DMIS Carry-over		$-5.2 m	Adjusted value of the DMIS from the 2010-15 regulatory control period returned to customers.
SBS FiT payments pass-through	$254.6 m	$219.6 m	The value in 2015-16 relates to approved FiT pass through for 2013-14. The value in 2016-17 relates to the approved FiT pass-through for 2014-15.

[27] AER, Final Decision, Energex Cost pass through Qld Solar Bonus Scheme 2014-15, December 2015.

Component / adjustment	2015-16 values	2016-17 values	Reason for change
Jurisdictional schemes	$202.2 m	$180.8 m	The value in 2016-17 relates to the forecast expected payments to be made in that year for the SBS and the AEMC levy as jurisdictional schemes. The value in 2015-16 only included SBS FiT payments.
DUoS under recovery	$110.9 m	$22.4 m	DUoS under recovery for 2014-15 recovered in 2016-17.

12.2 Changes to SCS tariffs

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.

Energex's proposed changes to its network tariffs in 2016-17 have been designed with a view to transition customers to cost reflective tariffs in anticipation of the new pricing principles taking effect from 1 July 2017. Energex's tariff strategy is outlined in its 2017-20 TSS proposal.

12.2.1 Introduction of a demand tariff for residential customers

From 1 July 2016, Energex is proposing a new demand tariff for residential customers, NTC7000 – Residential Demand, offered on a voluntary basis. Residential customers must have an appropriate Type 1 - 4 metering to access this tariff.

The structure of the new demand tariff is summarised in Table 12-2 below.

Table 12-2 – Tariff structure for NTC7000

Tariff	Tariff structure	Charging parameter
Residential Demand (NTC7000)	Supply daily charge	Unit: $/day Quantity: days in billing period
	Usage charge	Unit: c/kWh Quantity: kWh in billing period
	Demand charge	Unit: $/kW/month Maximum kilowatt demand measured as a single peak over a 30 minute period between 4pm and 8pm on workdays during the billing period.[1] Workdays are weekdays but exclude government public holidays.
Note: 1. The billing period is set to be monthly.		

The demand charging parameter will be based on 100 per cent diversified LRMC from the day the tariff is offered and it will not reflect expected locational capacity constraints.

To enable time for customers and stakeholders to understand and adapt to the tariff reform journey, Energex proposes to introduce a financial risk reduction mechanism (FRRM). Under this mechanism, for the first 12 months on this tariff, customers with an annual consumption less than 10 MWh will have their demand capped at 5 kW. If a customer's metered monthly maximum demand is less than the cap, their network bill is calculated without any adjustments.

As demonstrated in Table 12-3, Energex considers the new residential demand tariff aligns with Energex's pricing principles and objectives.

Table 12-3 – Alignment with pricing principles and objectives

Pricing Principles	Alignment
Cost reflectivity	The new demand tariff has been designed to address cross subsidies by reflecting the true cost of network services. It also encourages more efficient use of the network.
Efficient price signal	This principle is met by incorporating 100 per cent LRMC in the demand charging parameter of the tariff.
Consumer impact	Having considered the impact on residential customers, availability of smart meters in Qld and pace of tariff reform, the new tariff will be offered initially on a voluntary basis. Furthermore, to avoid bill shocks in the first 12 months of adopting the new demand tariff, Energex will offer FRRM to eligible customers.
Compliance with the Rules and all applicable regulatory instruments	The proposed tariff complies with the Rules and all applicable regulatory instruments (including jurisdictional schemes). Qld currently has a Uniform Tariff Policy on retail prices for small customers. Energex complies with the jurisdictional requirement by not differentiating LRMC or prices on a locational basis.

More information on this matter is provided in Energex's 2017-20 TSS proposal.

12.2.2 Introduction of a new load control tariff

As of 1 July 2016, Energex will introduce a new load control tariff NTC7300 – Smart Control. This new secondary tariff has been developed with a particular focus on emerging technologies such as batteries and electric vehicles, with a view to benefit the network. It is anticipated to offer a more targeted approach to reducing localised peaks.

NTC7300 will only be available to residential customers on NTC7000 – Residential Demand, NTC8100 – Large Demand and NTC8300 – Small Demand.

The terms and conditions for the secondary load control tariffs are provided in Appendix 3.

The structure of the new load control tariff is provided in Table 12-4 below.

Table 12-4 – Tariff structure for NTC7300

Tariff	Tariff structure	Charging parameter
Smart Control (NTC7300)	Usage charge	Unit: c/kWh Quantity: kWh in billing period

Energex considers the new secondary load control tariff will enable it to implement cost reflective demand tariffs for residential customers and to reduce network peaks while minimising the impact on residential customers.

Finally it can be noted that Energex intends to retain over the 2017-20 period the suite of existing load control tariffs NTC9000 – Super Economy and NTC9100 – Economy as they can be used in conjunction with the existing primary usage tariffs but not the new proposed residential demand tariff NTC7000 – Residential Demand.

12.2.3 Implementation of a Real Time Tariff Study (RTTS)

In 2016 Energex intends to monitor customer behaviour for a representative sample of residential customers who have taken up the voluntary demand tariff NTC7000 – Residential Demand. This initiative is conducted in partnership with retailers and consumer advocacy stakeholders and aims to:

- Learn about customer response to the demand signals.
- Test customer education materials.
- Address retailer concerns.
- Collect indicative representative data.
- Provide an opportunity for stakeholders to share learnings.
- Build social licence for faster tariff reform.
- Inform stakeholders of estimated customer impact.

More details on this initiative are contained in Energex's 2017-20 TSS proposal.

12.2.4 New jurisdictional scheme: AEMC Levy

Energex's distribution authority (DA) was amended on 22 March 2016 to enable it to recover the parts of the Queensland Government's share of an energy levy to fund the costs of the Australian Energy Market Commission (AEMC). The amount payable by Energex will be determined by the Department of Energy and Water Supply (DEWS) each financial year. DEWS proposes to apportion the levy between DA holders according to the relative customer numbers reported to the Queensland Government each October for the preceding financial year.

12.3 Changes to ACS tariffs

This Pricing Proposal includes a number of changes to the ACS as a result of the AER's Final Decision, namely:

- Re-scoped supply abolishment services which are part of the price-cap connection services include additional resource for meter removal (Attachment 16, Section 16.2.2).
- Additional services which are a permutation of services previously approved in the Preliminary Decision, including different metering types, additional labour, after hours services and inclusion of traffic control (Attachment 16, Section 16.2.2).
- Recovery of tax liability moved from the non-capital component of the annual metering charge to the capital component (Attachment 16, Section 16.3.3.1).
- Adjusted the approach that determines the X factor for metering services charges (Attachment 16, Section 13.3.5.3).

The impact of the changes to Type 6 metering services charges are further detailed in Section 11.7 of this Pricing Proposal.

13 Customer impacts

13.1 Standard control services

Energex is aware of the changing expectations of customers and the concern with the upward pressure being exerted on energy prices and has considered this when developing its network tariffs. Energex is committed to achieving a balanced commercial outcome while meeting its obligations to customers and managing sustainability and risk. Energex remains committed to delivering real price reductions for customers.

13.1.1 The relationship between consumption and revenue in 2016-17

Reflective of the assets required to service customers, the ratio of assets per kWh of consumption is lower for ICC and CAC tariff classes than for SAC tariff class, as it is a function of the network voltage level they are connected to. Whilst customers assigned to ICC and CAC tariff classes use large volumes of electricity, they are connected higher up in the distribution network and are only allocated the costs of the HV network. In contrast, the customers assigned to the SAC tariff class consume smaller volumes but are connected at LV network, which is the lowest part of the network, and therefore are allocated the costs of both the LV and HV networks. As such, the cost-reflective price is higher for customers assigned to the SAC tariff class than for the ICC and CAC tariff class.

13.1.2 2016-17 price impacts

Table 13-1 provides an estimate of the charges in 2016-17 for the average consumption level in each tariff class. This table provides an estimate of the percentage change in DUoS charges for the average customer. The impact on each customer will be dependent on the individual customer's demand and consumption patterns.

Table 13-1 – Estimated average percentage price[1] change by tariff class from 2015-16 to 2016-17

Tariff Class	Approved DUoS charge 2015-16[1,2] (c/kWh)	Estimated DUoS charge 2016-17[1] (c/kWh)	Average percentage change (%)
ICC	2.00	1.95	-2.4%
CAC	3.28	3.26	-0.7%
SAC	8.96	8.81	-1.7%

Notes:

1. All prices exclude GST.
2. This quantity is the revenue Energex would recover using the 2015-16 approved DUoS charges (excluding metering services), applied to 2016-17 forecasted quantities, and divided by the 2016-17 forecasted energy.

Table 13.1 shows that all tariff classes will experience on average a decrease in average DUoS charges in 2016-17.

ICC and CAC tariffs comprise various site-specific charges, and consequently customer specific impact analysis is omitted. General trends in ICC and CAC customer impacts are included in Table 13-2.

Table 13-2 – Average customer impacts for the ICC and CAC tariff classes[1]

Tariff Class	Impact	DUoS annual impact (%)	Jurisdictional schemes annual impact (%)	DPPC annual impact (%)	NUoS annual impact (%)
ICC	Average Impact	-2.4%	-8.1%	9.6%	3.1%
CAC	Average Impact	-0.7%	-10.2%	9.9%	1.9%

Notes:

1. Impacts are calculated based on the revenue Energex would recover using the 2016-17 approved DUoS charges, divided by the revenue Energex would recover using the 2015-16 approved DUoS charges, using 2016-17 forecasted quantities, minus 1.

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 13-3.

The network prices used for the analysis comprise total annual NUoS excluding GST. These NUoS prices are the AER approved prices for 2015-16 and the proposed 2016-17 prices included in this document for AER approval.

For volume based SAC tariffs, the typical annual energy consumption scenarios are drawn from the Queensland Competition Authority (QCA) Final Determination 2015-16.[28]

For SAC customers with demand based tariffs, an average load factor has been applied to the minimum recommended, typical (average forecasted) and maximum recommended demand for the purposes of analysis.

[28] QCA Final Determination – Regulated Retail Electricity Prices 2015-16, June 2015.

Table 13-3 – Indicative NUoS price change from 2015-16 to 2016-17 for varying usage profiles for SAC tariffs

Demand based tariffs	Usage type	Monthly demand[1] (kVA)	2015-16 NUoS ($)	2016-17 NUoS[3] ($)	Typical annual NUoS increase[4] ($)	Typical annual NUoS increase[5] (%)
Demand Large – NTC8100	Lowest usage	250	$84,381	$85,837	$1,456	1.7%
	Typical usage	446	$140,052	$142,474	$2,421	1.7%
	Highest usage	1,000	$297,395	$302,541	$5,146	1.7%
Demand Small – NTC8300	Lowest usage	32	$12,111	$12,216	$105	0.9%
	Typical usage	97	$32,934	$33,085	$151	0.5%
	Highest usage	250	$81,950	$82,210	$259	0.3%
Volume based tariffs	**Usage type**	**Annual consumption[2] (kWh)**	**2015-16 NUoS[6] ($)**	**2016-17 NUoS[3] ($)**	**Typical annual NUoS increase[4] ($)**	**Typical annual NUoS increase[5] (%)**
Business Flat – NTC8500	Typical usage	5,375	$922	$934	$12	1.3%
Business ToU – NTC8800	Typical usage	15,250	$2,061	$2,103	$42	2.0%
Residential Flat – NTC8400	Frugal, single person	2,200	$447	$439	-$8	-1.8%
	Single parent, one child	4,091	$676	$659	-$18	-2.6%
	Two parent, two child family	6,133	$924	$896	-$28	-3.0%
Residential ToU – NTC8900	Frugal, single person	2,200	$419	$416	-$3	-0.8%
	Single parent, one child	4,091	$625	$616	-$9	-1.4%
	Two parent, two child family	6,133	$846	$831	-$15	-1.8%
Super Economy – NTC9000[7]	Typical usage	2,000	$126	$128	$3	2.3%
Economy – NTC9100[7]	Typical usage	2,000	$211	$194	-$17	-8.0%

Notes:

1. Typical demand is the average 2016-17 forecasted demand for each tariff. Lowest and highest demands are the lowest and highest demands recommended for each tariff, respectively.
2. Consumption values for each scenario are drawn from the QCA Final Determination 2015-16.
3. Total annual NUoS excluding GST represents the typical 'N" component of a customer's bill.
4. Due to rounding, columns *2015-16 NUoS* and *Typical annual NUoS increase* may not sum to *2016-17 NUoS*.
5. Price increases shown in this table are indicative only. Individual customers should consider their specific circumstances to determine their likely network tariff impact.
6. In 2016-17, Metering services were moved from SCS to ACS and are no longer recovered through NUoS charges. So that comparisons are on a like for like basis, 2015-16 NUoS charges are reduced by the appropriate value of metering services.
7. NTC9000 and NTC9001 are secondary tariffs, when combined with the primary tariff an overall net benefit to the customer may result.

13.2 Alternative control services

Price changes between 2015-16 and 2016-17 for ACS price cap services are limited to changes in CPI and the X factor approved in the Final Decision. These are explained in Section 11.2.1.

14 Publication of information about tariffs and tariff classes

RULE REQUIREMENT

Clause 6.18.9 Publication of information about tariffs and tariff classes

(a) A Distribution Network Service Provider must maintain on its website:

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

(2) for each tariff – the charging parameters and the elements of the service to which each charging parameter relates; and

(3) a statement of expected price trends (to be updated for each regulatory year) giving an indication of how the Distribution Network Service Provider expects prices to change over the Regulatory control period and the reasons for the expected price changes.

(b) The information for a particular regulatory year must, if practicable, be posted on the website 20 business days before the commencement of the relevant regulatory year and, if that is not practicable, as soon as practicable thereafter.

In accordance with clause 6.18.9(b), Energex's 2016-17 Pricing Proposal (this document) will be published on Energex's website by 3 June 2016, or as soon as practicable thereafter. Energex's 2016-17 Tariff Schedule will also be published as soon as practicable. As required by clause 6.18.9(a)(1) and (2) of the Rules, these documents outline Energex's tariff classes, the tariffs applicable to each class, and the charging parameters and elements of service to which each charging parameter relates.

In accordance with clause 6.18.9(a)(3), a statement of expected price trends will be published on the Energex website. The publication of this document will align to the publication of Energex's 2016-17 Tariff Schedule.

Appendix 1 - 2016-17 proposed charges

Table A. 1 – 2016-17 SCS tariff charges

Tariff class	Tariff	Tariff charge parameter	Unit	DUoS	Jurisdictional	DPPC	NUoS
CAC	**NTC4000** 11kV Bus	Supply	$/Day	*Site specific prices are confidential*			
		Demand	$/kVA/month	7.442	0.631	1.263	9.336
		Usage off-peak	c/kWh	0.132	0.000	0.238	0.370
		Usage peak	c/kWh	0.132	0.000	0.238	0.370
	NTC4500 11kV Line	Supply	$/Day	*Site specific prices are confidential*			
		Demand	$/kVA/month	11.117	1.373	1.263	13.753
		Usage off-peak	c/kWh	0.132	0.000	0.238	0.370
		Usage peak	c/kWh	0.132	0.000	0.238	0.370
	NTC3000 EG 11kV	Supply	$/Day	*Site specific prices are confidential*			
		Demand	$/kVA/month	9.691	0.524	1.227	11.442
		Usage off-peak	c/kWh	0.132	0.000	0.238	0.370
		Usage peak	c/kWh	0.132	0.000	0.238	0.370
	NTC8000 HV Demand	Supply	$/Day	26.977	0.721	30.305	58.003
		Demand	$/kVA/month	10.510	1.410	2.386	14.306
		Usage flat	c/kWh	0.132	0.000	0.638	0.770
SAC	**NTC8100** Demand Large	Supply	$/Day	27.417	2.005	7.851	37.273
		Demand	$/kVA/month	14.144	2.160	2.099	18.403
		Usage flat	c/kWh	0.654	0.000	1.120	1.774
	NTC8300 Demand Small	Supply	$/Day	3.098	0.313	1.910	5.321
		Demand	$/kVA/month	18.087	2.457	1.315	21.859
		Usage flat	c/kWh	0.221	0.000	1.836	2.057
	NTC8500 Business Flat	Supply	$/Day	0.451	0.009	0.259	0.719
		Usage flat	c/kWh	9.567	1.308	1.610	12.485
	NTC8800 Business TOU	Supply	$/Day	0.451	0.009	0.259	0.719
		Usage off-peak	c/kWh	7.242	0.927	1.513	9.682
		Usage peak	c/kWh	11.259	1.442	1.694	14.395
	NTC8400 Residential Flat	Supply	$/Day	0.400	0.009	0.093	0.502
		Usage flat	c/kWh	8.260	1.268	2.095	11.623

Tariff class	Tariff	Tariff charge parameter	Unit	DUoS	Jurisdictional	DPPC	NUoS
	NTC8900 Residential ToU	Supply	$/Day	0.400	0.009	0.093	0.502
		Usage off-peak	c/kWh	5.633	0.633	0.677	6.943
		Usage shoulder	c/kWh	7.668	0.861	2.095	10.624
		Usage peak	c/kWh	12.762	1.433	4.119	18.314
	NTC7000 Residential Demand	Supply	$/Day	0.393	0.009	0.000	0.402
		Peak demand	$/kW/month	4.373	1.529	1.939	7.841
		Usage flat	c/kWh	4.587	0.000	1.129	5.716
	NTC9000 Super Economy	Usage flat	c/kWh	4.069	0.530	1.822	6.421
	NTC9100 Economy	Usage flat	c/kWh	6.981	0.883	1.822	9.686
	NTC7300 Smart control	Usage flat	c/kWh	3.502	0.446	1.129	5.077
	NTC9600 Unmetered	Usage flat	c/kWh	7.390	0.916	1.992	10.298

Appendix 2 - Revenue allocation process

Part 1. Revenue allocation process

Energex's TAR (as determined by the AER) is based on a building block approach, which includes each of the following regulated cost components:

- Regulatory depreciation (the net of (negative) straight-line depreciation and the (positive) annual inflation adjustment of the asset base)
- Return on capital
- Operating expenditure
- Tax allowance.

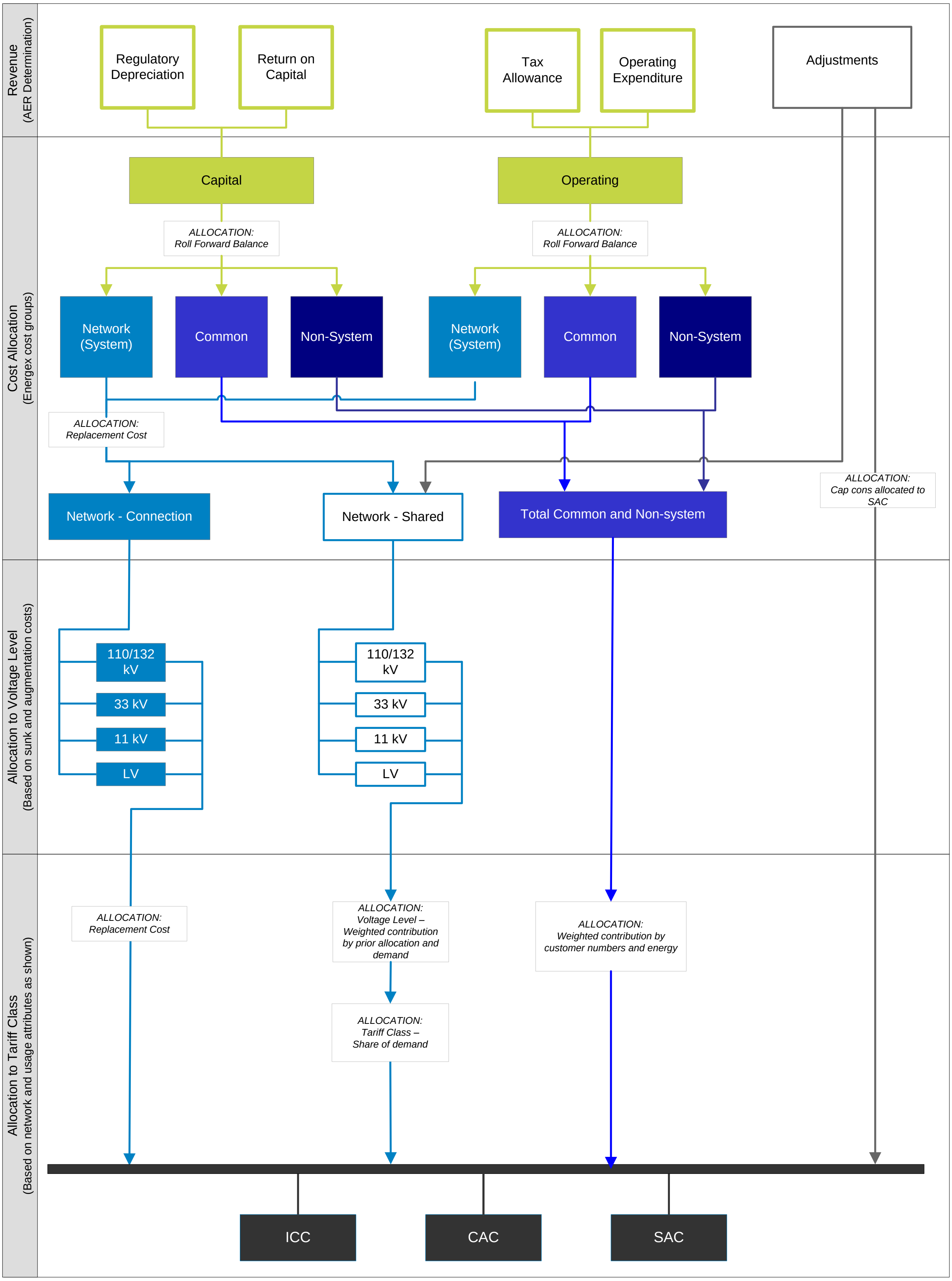
The purpose of the revenue allocation process is to allocate the network costs to the tariff classes in an economically efficient and cost reflective way.

The major steps in the process are:

- Step 1 – Allocate AER building blocks to Energex DCOS cost groups: Network (System); Common and Non-system costs.
- Step 2 – Allocate network (system) costs to voltage level.
- Step 3 – Allocate costs to tariff classes and tariffs.

These steps are illustrated in Figure A. 1 and explained throughout the remainder of Part 1 of this appendix. Part 2 of this appendix addresses the allocation of costs to specific tariffs.

Figure A. 1 – Revenue allocations to tariff class



Step 1 – Allocate AER building blocks to Energex DCOS cost groups

The regulated cost components specified by the AER are initially allocated into the Energex cost groups of:

- Network (system)
- Common services
- Non-system
- Adjustments.

Network (system)

Network (system) costs are the 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.

Network costs are further allocated to each of the following voltage cost groups based on the replacement costs of assets:

- 110/132 kV
- 33 kV
- 11 kV
- LV.

Common services

Common services costs are 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

Non-system costs include items such as corporate support (e.g. CEO, Finance, Human Resources and Legal), customer 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 are treated consistently as a group as the cost drivers for this set of costs are consistent and it is impractical to manage a cost allocation stream for each of the specific components.

Step 2 – Allocate network (system) costs to voltage level

Individually calculated customers

The revenue allocation to each ICC is performed on an individual basis. Connection assets are assigned to ICCs based on information obtained from Energex network panel diagrams and connection agreements. Each ICC is then allocated a share of upstream shared network based on the ratio of the customer's capacity to the total capacity of the respective supply (substation).

The ratio is then applied to the replacement cost of system assets within the supply network to which the individual customer is connected.

Remaining allocation

Following the allocation of costs to ICCs, the remaining network costs are allocated to each of the voltage levels (110/132 kV, 33 kV, 11 kV and LV) on the basis of the replacement value of sunk assets. Costs per voltage level are then shared among tariffs that utilise that voltage level of the network using a hybrid allocation. The contribution of each tariff to network peak demand over the period prior to the widespread adoption of solar PV, herein referred to as the "peak contribution", and forecast average monthly maximum demands (kVA) are used. These weightings reflect the importance of cost reflectivity and compliance with the side constraint formula (through the weighting on the peak contribution) as well as the importance of stability (through the weighting on the forecast average monthly maximum demands). The weights vary each financial year as required to meet side constraint obligations and in the consideration of the consumer impact principle.[29]

Step 3 – Allocated costs to tariff classes

There are several SCS tariff classes[30] to which network costs are allocated:

- ICC
- CAC
- SAC.

Network

Connection assets

Connection assets are allocated to each tariff class based on their share of the replacement cost for each voltage level. Contributed connection assets are not used in the allocation of capital costs as these assets have already been paid upfront by the customer.

[29] Energex is not required to comply with the side constraint formula in the first year of the regulatory control period, as such Energex will not be applying the methodology in 2015-16.
[30] For more information about Energex's tariff classes, refer to Table 3-1 Energex 2015-16 Pricing Proposal.

Shared network

With the exception of ICCs, the cost for each voltage level is allocated to each tariff class based on a weighted mixture of peak contribution (for cost reflectivity, reflecting the fact that peak demand is the primary driver of shared network costs) and forecast average monthly maximum demands (kVA) (for stability). This results in a revenue allocation for each tariff class as illustrated in Energex's 2015-16 Pricing Proposal.

Common services and non-system costs

Common services and non-system costs are allocated to each tariff class using a hybrid allocation. Customer numbers (75 per cent) and total forecast energy (25 per cent) are used. These weightings reflect that the number of customers is the primary driver of service and non-system costs.

Customer numbers and energy are used for the cost allocation approach as these costs are associated with the number of customers and their expectations/service requirements. Energex has a number of costs that are customer number based. A significant proportion of the overhead costs of the business are driven by the number of staff and systems required to serve the customer base.

Part 2. Revenue (charging parameter) allocation process

Following the revenue allocation to tariff classes, costs must be allocated to tariffs and ultimately to charging parameters (tariff elements), which may include any combination of the following:

- fixed charges
- capacity charges
- demand charges
- volume charges.

The purpose of the revenue (charging parameter) allocation process is to allocate or assign the costs to each parameter in the most efficient and cost-reflective way. Part 1 of this appendix sets out the process utilised by Energex for the allocation of revenue to charging parameters.

The process for revenue allocation involves two major steps:

- Step 1 – Allocate revenue to individual tariffs
- Step 2 – Allocate revenue to charging parameters.

These steps are undertaken for each tariff class and are illustrated in Figure A. 2 – Revenue allocation approach - ICC and CAC tariff classes, Figure A. 3 – Revenue allocation approach - SAC demand tariffs and Figure A. 4 – Revenue allocation approach – SAC Small non-demand tariffs.

Figure A. 2 – Revenue allocation approach - ICC and CAC tariff classes

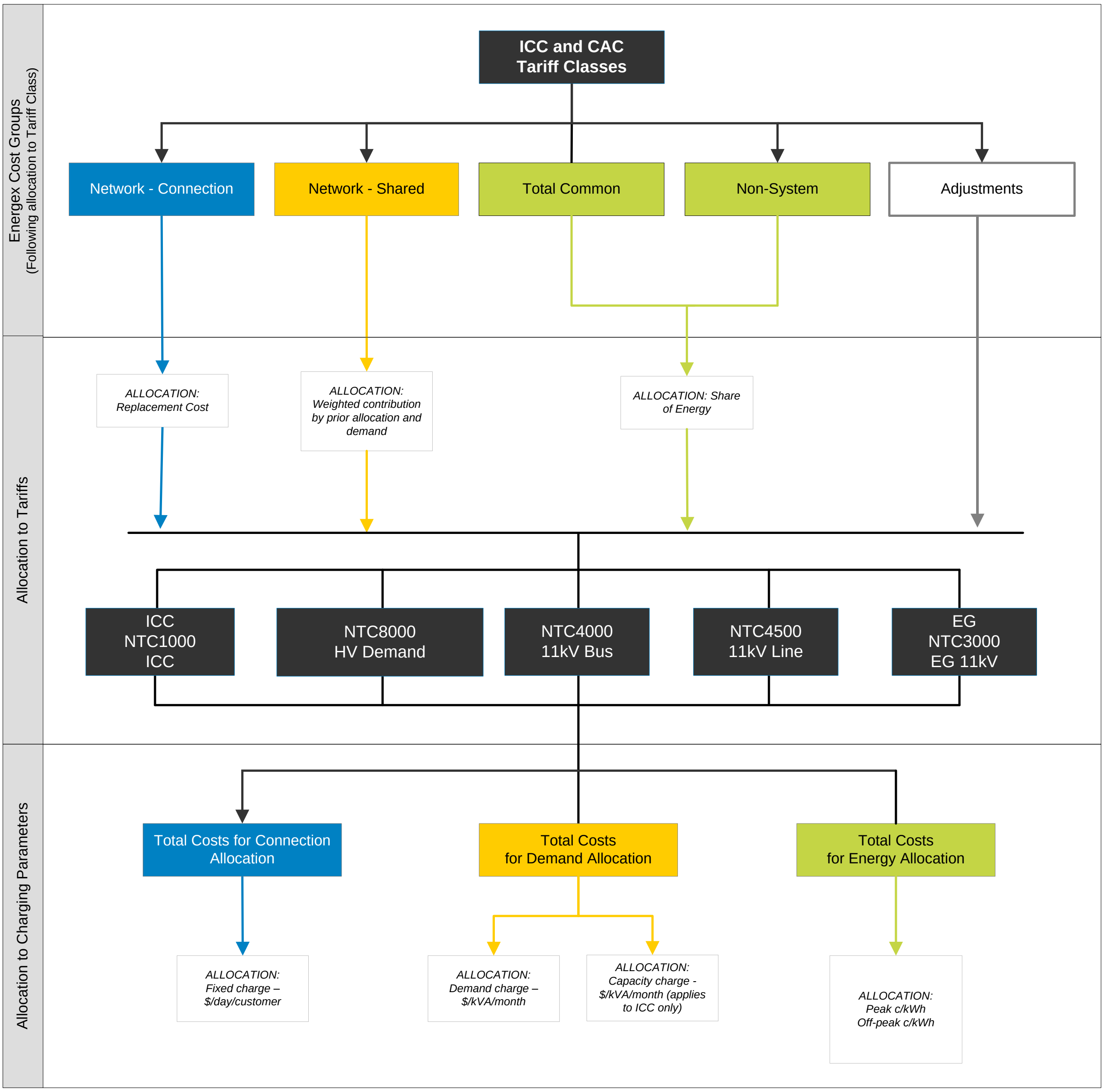


Figure A. 3 – Revenue allocation approach - SAC demand tariffs

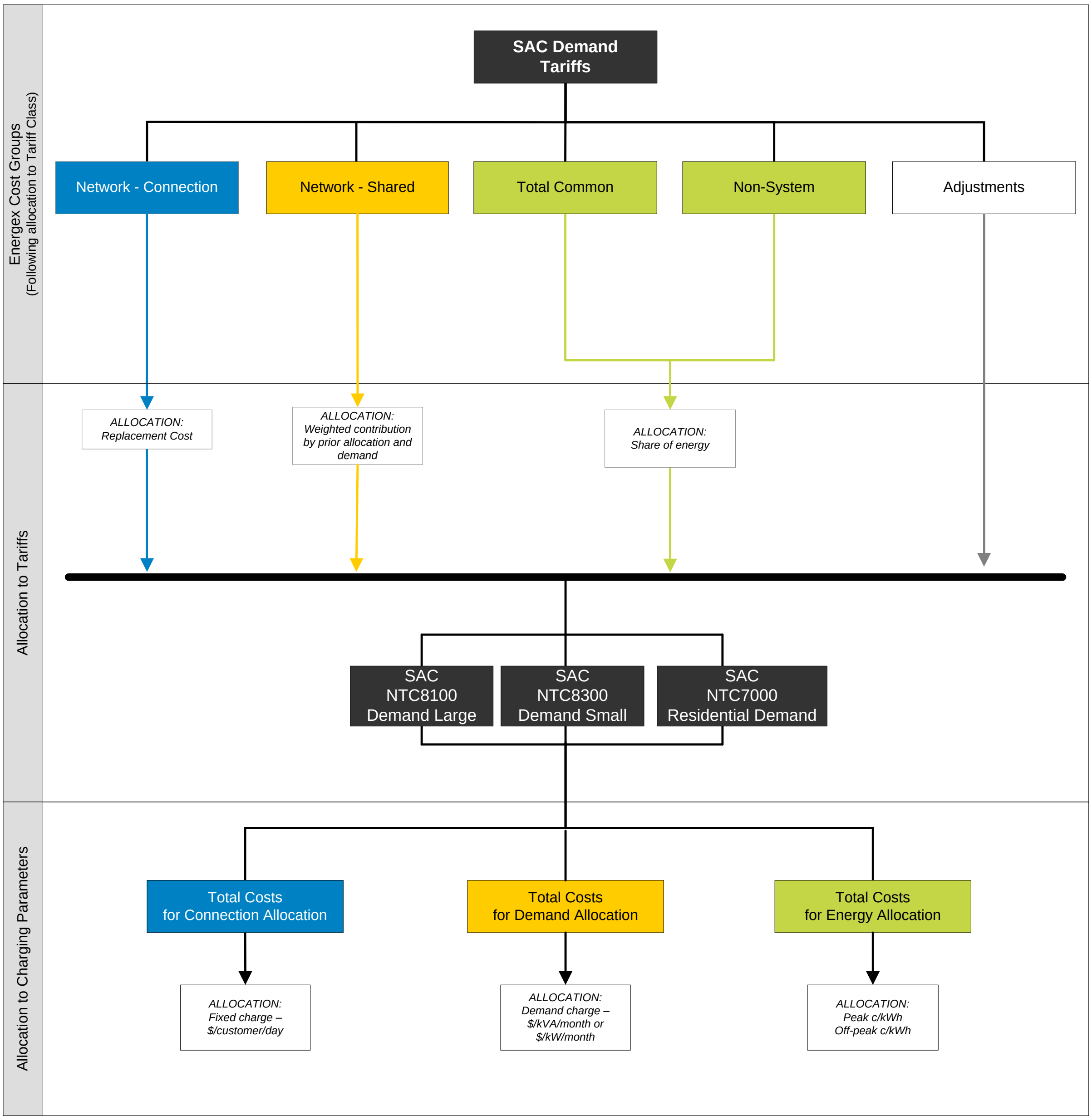
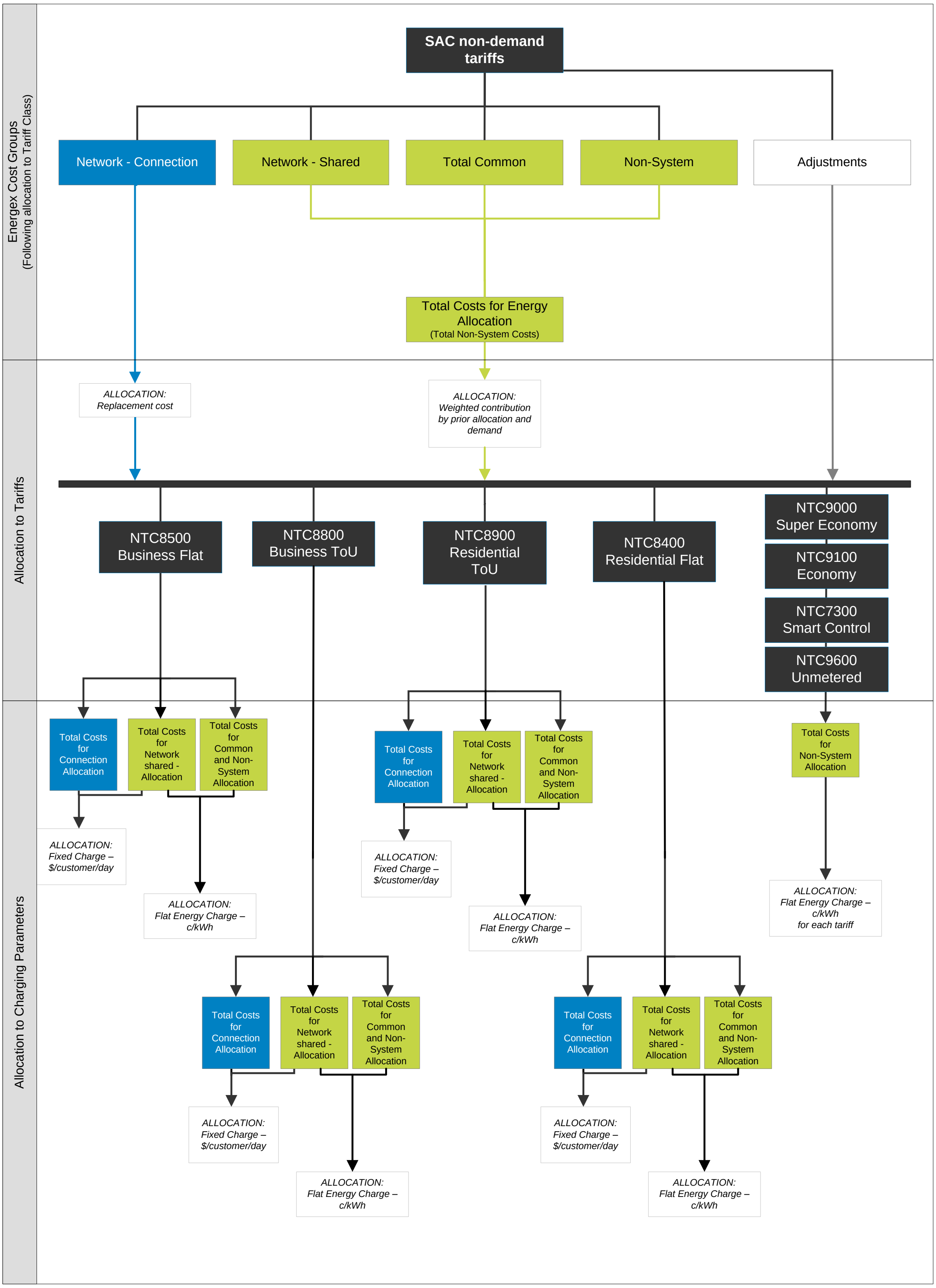


Figure A. 4 – Revenue allocation approach – SAC Small non-demand tariffs



Variances from allocated cost based tariffs

Energex develops and applies network tariffs based on the DCOS model. For each tariff class, the costs outlined above are recovered through a combination of fixed charges, capacity charges, demand charges and/or volume charges. The network pricing methodology applied to each of those groups has precluded any possible bypass challenge on the basis that the network tariff is efficient and an alternative electricity service cannot be sourced at a lower economic value.

Providing it is consistent with the Rules, Energex may negotiate a tariff other than the tariff calculated using the cost allocation approach, if it can be demonstrated that:

- the cost based network tariff is not efficient
- an economic bypass opportunity exists
- alternative electricity service could be utilised.

Appendix 3 – Secondary tariff terms and conditions

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 4 – 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 5 – Tariff class and tariff re-assignment procedures for SAC customers

Energex undertakes a review of the assignment of network tariffs and tariff classes to its SAC customers on a regular basis to ensure customers are assigned to the correct network tariff and have suitable metering in place.

SAC customers are assigned a classification of either Large or Small depending on their consumption. If a customer has an annual consumption greater than 100 MWh per annum, the customer is classified as Large and, in accordance with the National Metrology Procedures, is required to have communication-enabled metering (Type 1 – 4). Large business customers are required to be placed on a demand network tariff subject to having the appropriate metering.

Customers with an annual consumption of less than 100 MWh per annum are classified as Small and can either access an energy based tariff or, subject to having the appropriate metering, a demand network tariff.

1. Energex initiated tariff re-assignment

1.1 Small to Large business reclassification and network tariff re-assignment

Energex reviews SAC small business customers with Type 1 – 4 (Comms) metering on an annual basis to ensure they are classified correctly and assigned to the appropriate network tariff code. Upon identifying incorrectly classified customers, Energex will initiate a reclassification and network tariff code re-assignment, and will write to the customer's retailer making it aware of the impending changes.

The notification that is sent to the customer's retailer includes the following:

- The current NMI classification the customer is moving from and the new NMI classification they are moving to.
- The current network tariff class and network tariff code of the customer and what these are changing to.
- The reason for the change.
- A definition of what a Small or Large customer is.
- The specifications relating to the classification as a Large or Small customer (this includes metering, network tariff code, governing bodies they may refer to).
- How the customer can dispute the decision.
- The date the change will take effect (all Energex initiated changes are prospective).

Note: Where a NMI is reclassified from Small to Large and has the appropriate metering, Energex is able to assign the customer to a demand network tariff code as specified in the relevant Energex Annual Pricing Proposal.

1.2 SAC Large customers upgrading to a communication-enabled Type 1 – 4 metering

Where a Large business customer has upgraded their metering from Type 6 (accumulation or Basic) to Type 1 – 4 (Comms), Energex will initiate a network tariff change to a demand tariff. Energex will notify the customer and the customer's retailer in writing making them aware of the impending change.

2. Retailer initiated reclassification and network tariff code change

A customer's retailer is permitted to initiate an application or request for a reclassification and network tariff code re-assignment where Type 1 – 4 (Comms) metering is installed at the site. A customer is able to submit the QESI Application for Review (Form 1634) to Energex; however Energex will seek the endorsement from the customer's retailer prior to proceeding with the tariff change. Upon receipt of the application, Energex will carry out the following:

2.1 Retailer requesting a Large to Small / Small to Large reclassification and network tariff code re-assignment

Energex will assess the customer's consumption for the last 12 months. Where the request is approved, the customer's classification and network tariff code will be updated. Energex will notify the requesting retailer of the approval and the date in which the changes have taken place. Energex will write to the customer making it aware of the changes, outlining the following:

- Who initiated the classification and/or network tariff code change (Energex or customer's retailer).
- The current network tariff class and network tariff code of the customer and what these are changing to.
- A definition of what a Small or Large customer is.
- The specifications relating to the classification as a Large or Small customer (this includes metering, network tariff code, governing bodies they may refer to).
- How the customer can dispute the decision.
- The date the change will take effect (all retailer initiated changes take place at the first of the month the information is received unless specified otherwise).

2.2 Retailer initiated network tariff code re-assignment only

Where the network tariff change aligns to its tariff assignment policy (as per the Energex Annual Pricing Proposal), Energex will approve the request and notify the requesting retailer. The notification will include the following:

- Who initiated the network tariff change (Energex/retailer).
- The current network tariff class and network tariff of the customer and what these are moving to.
- How the customer can dispute the decision.
- The date the change will take effect (all retailer initiated changes take place at the first of the month the information is received unless specified otherwise).

Appendix 6 – Tariff class and tariff assignment review objection process

Table A. 2 - Tariff class assignment review of objections process

Process	Inputs	Outcome
Written request for review of objection received		Energex will notify customer within 1 business day acknowledging reception of request
Review energy / demand / voltage / nature of connection	Energy usage will be determined considering: • Any additional information the customer has provided • Estimated energy consumption for new customers • Historical consumption for existing customers. Nature of connection will be determined by: • Reviewing connection asset databases. Note: Depending on the nature of the connection, there may be exceptions to the application of criteria around energy use. Nature of connection will be determined considering: • Any additional information the customer provided • Network connection point / charge • Assets	Customer's energy use (i.e. consumption and/or demand) and nature of connection is known.
Determine tariff class	Using the data collected, the applicable tariff class will be determined according to the approved process for assigning customers to tariff classes.	**Key outcome 1 (KO 1)** Applicable tariff is identified
Determine metering and customer type	For SAC on demand tariffs, CAC and ICC: • Metering: is the site HV or LV? • Customer type: is the customer business or residential? For SAC customer on non-demand tariffs: • Metering: Is the NMI metered or unmetered? • Customer type: Is the customer business or residential?	Metering and customer type is known.
Determine network tariffs	Using the data collected, the applicable network tariff will be determined according to the approved process for assigning customers to tariff classes	**Key outcome 2 (KO 2)** Applicable network tariff is identified.
Managerial review of identified tariff class / network tariff	The review department's manager will review the tariff class (KO1) and network tariff (KO2) identified through this process and decide whether the proposed tariff class / tariff assignment / re-assignment.	**Key outcome 3 (KO 3)** Managerial approval to proceed with assignment / re-assignment
Notification of outcome	The review outcome and final decision for the appropriate tariff class / tariff assignment or re-assignment confirmed in KO3.	Energex will use best endeavours to notify in writing the customer's retailer of the outcome of the review within: • 10 business days for SAC customers • 20 business days for CAC and ICC customers

Appendix 7 – Summary of compliance

Table A. 3 – Compliance with the National Electricity Rules

Clause	Requirement	Reference
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.	Chapter 5, Section 5.1 and Table 5-1
6.1.4(b)	Energex must demonstrate that it charges for the provision of connection services as allowed in the Rules.	Chapter 5, Section 5.1 and Table 5-1, Section 5.2 and , Section 5.3 and Table 5-3. Chapter 6, Section 6.1 and Table 6-2, Section 6.2, Section 6.3, Section 6.4, Section 6.5.
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').	Chapter 7, Section 7.1.2 and Table 7-2.
6.18.2(a)(2)	Energex must submit to the AER, at least 2 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 2016-17 Pricing Proposal on 29 April 2016.
6.18.2(b)(1)	Energex's Pricing Proposal must set out each tariff class (including the classes of alternative control services) for the relevant regulatory year.	Chapter 3, Table 3-1. Chapter 10, Section 10.1 and Table 10-1
6.18.2(b)(2)	Energex's Pricing Proposal must set out the proposed tariffs for each tariff class.	Chapter 4, Section 4.1 and Table 4-1 Chapter 11, Section 11.4 and Table 11-3
6.18.2(b)(3)	Energex's Pricing Proposal must set out, for each proposed tariff, the charge parameters and the elements of service to which each charging parameter relates.	Chapter 4, Section 4.2. Chapter 5, Table 5-1 Chapter 7, Section 7.2.1, Chapter 8, Section 8.2, Table 8-3. Chapter 11, Section 11.2.1, Section 11.4.2 and Table 11-4

Clause	Requirement	Reference
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.	Chapter 5, Session 5.2.
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.	Chapter 12
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.	Chapter 7, Section 7.2.1 Section 7.3 and Table 7-2.
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.	Chapter 8 Section 8.2 and Table 8-3.
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.	Appendix 7
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.	Chapter 12 Appendix 7
6.18.3(a)	Energex's Pricing Proposal must define the tariff classes into which customers for direct control services are divided.	Chapter 3, Table 3-1 Chapter 10, Section 10.1 and Table 10-1
6.18.3(b)	Energex must demonstrate that for each customer for direct control services is a member of one or more tariff class.	Chapter 9. Appendix 5. Chapter 10, Section 10.2 and Table 10-2
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.	Chapter 3, Table 3-1. Chapter 10, Section 10.1.
6.18.3(d)(1)	Energex must demonstrate that tariff classes have been formed based on groupings of customers on an economically efficient basis.	Chapter 3, Table 3-1. Chapter 10, Section 10.1

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.	Chapter 3, Table 3-1. Chapter 6, section 6.3. Chapter 10, Section 10.1
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 9, Section 9.1
6.18.4(a)(2)	Energex must demonstrate that customers with a similar profile are treated on an equal basis.	Chapter 9, Section 9.1
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.	Chapter 9, Section 9.2
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 9, Section 9.1 and Table 9-1, Section 9.3, Section 9.4 and Table 9-2. Appendix 5. Chapter 10, Section 10.2 and Table 10-2.
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 9. Appendix 5.
6.18.5(a)(1) and (2)	Energex must demonstrate that revenue expected to be recovered from a tariff class lies between the stand alone and avoidable cost.	Chapter 6, Section 6.1, Table 6-2. Chapter 11, Section 11.3.2
6.18.5(b)(1)	Energex must demonstrate that tariffs and charging parameters have regard for long-run marginal cost.	Chapter 6, Section 6.2 and Table 6-3. Chapter 11, Section 11.3.1.
6.18.5(b)(2)(i)	Energex must demonstrate that tariffs and charging parameters have regard for the transaction costs to customers.	Chapter 6, Section 6.3.
6.18.5(b)(2)(ii)	Energex must demonstrate that tariffs and tariff components are set with regard to whether customers are able or likely to respond to price signals.	Chapter 6, Section 6.4.
6.18.5(c)	Energex must demonstrate that if tariffs do not recover the required revenue as a result of the operation of clause 6.18.5(b), the tariffs have been adjusted so as to recover the expected revenue with minimum distortion to efficient patterns of consumption.	Chapter 6, Section 6.5.

Clause	Requirement	Reference
6.18.6(b)	Energex must demonstrate that the weighted average revenue for a standard control tariff class does not exceed that for the previous regulatory year by more than the “permissible percentage” defined in clause 6.18.6(c) of the Rules.	Chapter 5, Section 5.3 and Table 5-3.
6.18.6(c)(1) and (2)	Energex must demonstrate the “permissible percentage” has been calculated in accordance with the definition set out in this clause of the Rules.	Chapter 5, Section 5.3.
6.18.6(d)(1,2,3 and 4)	In deciding whether the permissible percentage has been exceeded in a particular regulatory year, Energex must disregard the following: • the recovery of revenue to accommodate a variation to the distribution determination; • the recovery of revenue to accommodate pass through of designated Pricing Proposal charges to retail customers; • the recovery of revenue to accommodate pass through of jurisdictional scheme amounts for approved jurisdictional schemes; • the recovery of revenue to accommodate any increase in Energex’s annual revenue requirement by virtue of an application of a formula referred to in clause 6.5.2 (l).	Chapter 5, Section 5.3.
6.18.7(a)	Energex must demonstrate that tariffs passed on to customers include the charges to be incurred by Energex for DPPC.	Chapter 7, Session 7.2.1, Appendix 1
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.	Chapter 7, Section 7.3 and Table 7-2
6.18.7(c)(1), (2) and (3)	Energex must demonstrate that any DPPC over or under recovery is calculated in a way that: • is consistent with the method determined by the AER in the relevant distribution determination for Energex; • ensures that Energex is able to recover from retail customers no more and no less than the DPPC it incurs; and • adjusts for an appropriate cost of capital consistent with the allowed rate of return.	Chapter 7, Section 7.3 and Table 7-2 .
6.18.7(d)(1), (2) and (3)	Energex must demonstrate that is does not recover DPPC to the extent these are: • recovered through Energex’s annual revenue requirement; • recovered through tariffs designed to pass on jurisdictional scheme amounts under clause 6.18.7A; or • recovered from another DNSP.	Chapter 7, Section 7.2.

Clause	Requirement	Reference
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.	Chapter 8, Section 8.1. Appendix 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.	Chapter 8, Section 8.3.
6.18.7A(c)	Energex must demonstrate that the over and under recovery has been calculated in a way that: • is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination; • ensures Energex is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; • 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.	Chapter 8, Section 8.3.
6.18.9(a)(1)	Energex must maintain on its website a statement of Energex's tariff classes and the tariffs (or prices) applicable to each tariff class.	Chapter 14
6.18.9(a)(2)	Energex must maintain on its website for each tariff, the charging parameters within each tariff class (i.e. the fixed, demand and energy prices) and the elements of the service to which each charging parameter relates.	Chapter 14
6.18.9(a)(3)	Energex must maintain on its website, a statement of expected price trends providing an indication of how Energex expects prices to change over the regulatory control period and why.	Chapter 14
6.18.9(b)	Energex must publish all information set out in clause 6.18.9(a) is published on its website 20 business days prior to the start of the relevant regulatory year or as soon as practicable thereafter.	Chapter 14

Table A. 4 – 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.	Chapter 5, Section 5.3.
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, Table A. 1 – 2016-17 SCS tariff charges
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.	Chapter 2, Section 2.3 and Table 2-2, Section 2.3.4 and Table 2-3.
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.	Chapter 7, Section 7.3, Table 7-2 .
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.	Chapter 8, Section 8.5.
Attachment 14, Section 14.1, Appendix D.	Energex must demonstrate compliance with the procedures stipulated by the AER in Appendix D of Attachment 14 which relates to the assigning of retail customers to tariff classes or reassigning of retail customers from one tariff class to another.	Chapter 9, Appendix 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.	Chapter 11.
Attachment 16, Section 16.2.	Energex must demonstrate the application of a price cap form of control to ancillary network services. The AER's control mechanism formulae must be applied to fee based services.	Chapter 11.

Appendix 8 – Glossary

Table A. 5 – Acronyms and abbreviations

Abbreviation	Description
A/C	Air-conditioning
ACS	Alternative Control Service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AH	After Hours
AIC	Average Incremental Cost
AR	Annual Smoothed Revenue
ARR	Annual Revenue Requirement
BH	Business Hours
CAB	Contributed Asset Base
CAC	Connection Asset Customers
CAM	Cost Allocation Method
Capex	Capital Expenditure
CPI	Consumer Price Index
CT	Current transformer
DC	Direct Connected
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
IAP2	International Association for Public Participation
ICC	Individually Calculated Customers
LCC	Large Customer Connection
LRMC	Long Run Marginal Cost
LV	Low Voltage
MAR	Maximum Allowable Revenue

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

Table A. 6 – 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. 7 – 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. 8 – Definitions of terminology used throughout this document

Term	Abbreviation / Acronym	Definition
After Hours	AH	Any time outside business hours.
Air-conditioning	A/C	An air-conditioning appliance; commonly used in the context of a unit, i.e. A/C unit.
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.

Term	Abbreviation / Acronym	Definition
Connection Asset Customers	CAC	Typically, those customers connected at 11 kV who are not allocated to the ICC tariff class.
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 for the use of the distribution network.
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.

Term	Abbreviation / Acronym	Definition
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
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.
International Association for Public Participation Spectrum	IAP2 Spectrum	Approach used by Energex in its engagement activities with shareholders. The IAP2 Spectrum© clarifies with decision makers the level of public participation required for an engagement activity. The approach needs to consider the specific circumstances and how involved the customer needs to be for each engagement activity.
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

Term	Abbreviation / Acronym	Definition
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.
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.

Term	Abbreviation / Acronym	Definition
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.
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 Electricity Supply Industry	QESI	Queensland Electricity Supply Industry (QESI) – Application for Review. This review allows a customer's retailer to request a change to the customer's NTC or NMI classification utilising form 1634.
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.

Term	Abbreviation / Acronym	Definition
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.
Short-Run Marginal Cost	SRMC	The cost (short term, fixed investment) of a customer connecting to the network but using only the existing network capacity.
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.

Term	Abbreviation / Acronym	Definition
Standard Control Service	SCS	Services that are central to electricity supply and therefore relied on by most (if not all) customers. This service class includes network and connection services.
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.
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.

Term	Abbreviation / Acronym	Definition
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.
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 9 – 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 2016-17.xls; Worksheet: ICC Summary.	Individually Calculated Customers (ICC) Site Specific tariffs.	2016-17 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 2016-17.xls; Worksheet: CAC Summary.	Connection Asset Customers (CAC) Site Specific Tariffs	2016-17 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.