PUBLIC

# Energex

## Annual Pricing Proposal

### 1 July 2014 to 30 June 2015

energex

positive energy

**Version control**

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| | | |
| | | |

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 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 2014/15. It has been prepared for the final year of Energex's 2010–15 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*) and additional requirements as specified by the AER in Energex's Final Determination 2010–2015 (the Final Determination).

This document is submitted in accordance, and complies, with the requirements of:

- The National Electricity Law (NEL)[1]
- the *Rules*, Version 62 (17 April 2014)[2]
- Final Determination, Queensland, 2010-11 to 2014/15 (AER, May 2010)[3]
- Australian Competition Tribunal order (19 May 2011)[4]
- Final decision, Framework and Approach Paper, Classification of services and control mechanisms, Energex and Ergon Energy 2010–15 (AER, August 2008).[5]

Specifically, this 2014/15 Pricing Proposal describes the methodology and principles Energex has followed during tariff development to recover its allowed revenue. It outlines the tariff classes, proposed network tariffs and charging parameters for Standard Control Services (SCS) and Alternative Control Services (ACS), and expected revenue for the year commencing 1 July 2014 and ending 30 June 2015.

[1] The NEL is established by the *National Electricity (South Australia) Act 1996*. The current version came into force on 19 December 2013.
[2] http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html (Date accessed: 17 April 2014).
[3] AER, 2010. Energex - Distribution determination 2010/11 to 2014/15, 4 May 2010. http://www.aer.gov.au/sites/default/files/Queensland%20determination%20-%20Energex.pdf (Date accessed: 20 February 2014).
[4] Australian Competition Tribunal, 2011. Review of a Distribution Determination by Energex Limited, 19 May 2011. http://www.aer.gov.au/sites/default/files/Australian%20Competition%20Tribunal%20order%20Energex%20-%2019%20May%202011.pdf (Date accessed: 20 February 2014).
[5] AER, 2008. Final decision, Framework and approach paper, Classification of services and control mechanisms, Energex and Ergon Energy 2010-2015, August 2008. http://www.aer.gov.au/sites/default/files/AER%20-%20Final%20Decision%20-%20Framework%20and%20approach%20paper%20-%20classification%20of%20service%20and%20control%20mechanisms%20-%20August%202008.pdf (Date accessed: 20 February 2014).

Energex is currently working on its Regulatory Proposal for the 2015-20 regulatory control period which will be submitted to the AER in October 2014. The proposal sets out the detail of our proposed capital and operating programs necessary to deliver our service obligations. More information is available on Energex website.[6]

## 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. It provides details of the modelling inputs and outputs used to develop the network tariffs to recover allowed revenue. |
| 3 | Standard control services: Tariff classes | Sets out the tariff classes for SCS, the basis for the proposed tariff classes and the procedures for the assignment and reassignment of customers to tariff classes. |
| 4 | Standard control services: Proposed tariffs | For each SCS tariff class, sets out the proposed tariffs and charging parameters. |
| 5 | Weighted average revenue | Sets out the weighted average revenue for SCS tariff classes. |
| 6 | Side constraints for SCS tariff classes | Sets out the formula for calculating side constraints and, by tariff class, demonstrates adherence to the formula. |
| 7 | Application of pricing principles | Provides information about how Energex applies the pricing principles stipulated in the *Rules*. |
| 8 | Transmission cost recovery | Outlines how adjustments to charges are calculated for Designated Pricing Proposal Charge (DPPC) resulting from over or under recovery. |
| 9 | Changes from previous regulatory year | Sets out annual adjustments to revenue cap components, and changes to tariffs and Energex's approach to price setting between 2013/14 and 2014/15. |
| 10 | Pricing strategy and tariff trials | Provides a brief overview of Energex's pricing strategy and tariff trials. |
| 11 | Alternative control services: Tariff classes | Sets out the tariff classes for ACS and the basis for the proposed tariff classes. |
| 12 | Alternative control services: Proposed tariffs | For each ACS tariff class, sets out the framework, proposed tariffs and charging parameters. |
| 13 | Customer impacts | Discusses the customer impacts from the tariffs that will be implemented in 2014/15. |
| 14 | Publication of information about tariffs and tariff classes | Sets out the documents relating to tariffs and pricing that will be published on the Energex website. |
| 15 | Appendices | Provides additional supporting information. |

[6] https://www.energex.com.au/about-us/network-regulation-and-pricing/energex-regulatory-proposal

## 1.3 Confidential information

Energex claims confidentiality over the following sections of this document:

- Appendix 1 – Site-specific tariffs
- Appendix 2.1 – Price development for ACS (selected tables)

Energex has provided information to support this requirement in accordance with the confidentiality guideline released by the AER in November 2013.[7]

## 1.4 Further information

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

[7] http://www.aer.gov.au/sites/default/files/AER%20Confidentiality%20guideline%20-%20November%202013.pdf (Date accessed: 20 February 2014)

# 2 Pricing framework

## 2.1 Pricing principles and objectives

When setting SCS tariffs, Energex's objective is to ensure its allowed revenue, 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*. Detailed information about Energex's application of and compliance with the pricing principles is set out in Chapter 7.

For ACS (subject to a price cap), the objective is to ensure that the price charged is cost-reflective and is consistent with the pricing principles. More information about ACS is included in Chapter 11 and Chapter 12.

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 tariffs. For individually calculated customers, Energex's network tariffs preserve the economic signals present in the structure of DPPC.

**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, or between SCS and ACS tariffs. |
| **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 users' 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. |

## 2.2 Setting the 2014/15 tariffs

This section provides a high level overview of how the allowed revenue is recovered through tariffs for SCS. More information about tariff classes, tariffs and charging parameters is available in Chapters 3 and 4, respectively.

### 2.2.1 Maximum allowed revenue and revenue cap

In May 2011, the Australian Competition Tribunal made a revised Determination based on its decision that the value of gamma is 0.25. The annual revenue requirement is set out in the Tribunal's Order dated 19 May 2011.[8]

Table 2.2 details the revenue cap calculation for 2014/15. The revenue cap is based on a building block approach, which includes each of the regulated cost components: regulatory depreciation, return on capital expenditure (capex), operating expenditure (opex) and tax allowance.

Chapter 9 provides a summary of the annual adjustments to the maximum allowed revenue and revenue cap.

[8] Refer to Footnote 4 (p1) for full citation.

**Table 2.2 - 2014/15 revenue cap calculations**

| Component | Amount ($m) | Comments/reference |
|---|---|---|
| **Annual Revenue Requirement 2013/14** | **1,671.9** | As approved by the AER in 2013/14 Pricing Proposal |
| • Consumer Price Index (CPI)[1] | 2.93% | CPI factors as published on the Australian Bureau of Statistics (ABS) website |
| • X Factor | -1.42% | |
| Impact on revenue | 73.4 | |
| **Annual Revenue Requirement 2014/15[2]** | **1,745.3** | Calculated in accordance with Final Determination Section 4.5.1 |
| **Other adjustments:** | | |
| • Capital contributions | 29.4 | Adjustment for under recovery in 2012/13 |
| • Service Target Performance Incentive Scheme (STPIS) Factor | 34.6 | Adjustment consistent with the 2011-12 S-banking approval from AER received 22 April 2013 |
| | 0.0 | Adjustment consistent with the proposed 2012/13 s-banking mechanism |
| • Solar Photovoltaic (PV) FiT pass-through[3] | 185.6 | Approved pass-through for Solar PV FiT based on under recovery in 2012/13 |
| **Maximum Allowed Revenue (MAR)** | **1,994.8** | |
| Revenue reduction | -69.5 | Adjustment to capex due to the 2011 Electricity Network Capital Program (ENCAP) Review[4]. |
| **Adjusted MAR** | **1,925.4** | |
| **Overs/Unders adjustments:** | | |
| DUOS[5] | 0.0 | No under recovery is included as the under recovery balance is to be carried forward into the next regulatory period. |
| **Revenue cap[6]** | **1,925.4** | **MAR plus DUOS over/under adjustment** |

**Notes:**
1. The CPI is the annual percentage change from March 2013 to March 2014.
2. Refer to Footnote 3 (p1) for full citation.
3. AER, 2013. Determination 2012/13 Queensland solar bonus scheme pass-through for Energex, December 2013 http://www.aer.gov.au/node/23154 (Date accessed: 17/01/2014)
4. Adjustment as detailed in Energex's 2014/15 SCI. For more information, refer to section 9.1.2.
5. Refer to Section 2.2.3. No under/over recovery balance has been included for 2014/15. Energex's DUOS overs and unders account is included in Table 2.4.
6. Due to rounding, individual components may not sum to the total.

### 2.2.2 Modelling outputs

The total revenue cap for 2014/15 is detailed in Table 2.2 and Table 2.3. The allowances for each of the regulatory cost components are adjusted to account for the smoothed revenue and the annual adjustments as per Table 2.3.

**Table 2.3 - Redistribution of smoothed revenue cap to cost components**

| Component | Sub-total ($m) | Total ($m) |
|---|---|---|
| **Regulatory depreciation** | | |
| Original building block revenue requirement | 111.6 | **127.8** |
| Smoothing/CPI allowance | 2.5 | |
| Tax allowance | 7.4 | |
| Solar PV FiT pass-through | 12.2 | |
| Revenue reduction (ENCAP)[1] | -5.8 | |
| **Return on capital** | | |
| Original building block revenue requirement | 1,213.9 | **1,343.6** |
| Smoothing/CPI allowance | -1.7 | |
| Tax allowance | 80.9 | |
| Solar PV FiT pass-through | 132.3 | |
| Revenue reduction (ENCAP)[1] | -63.6 | |
| Capital contributions | -76.4 | |
| Revenue from shared assets | -5.7 | |
| Overs/Unders adjustments: | | |
| • DUOS | 0.0 | |
| • Capital contributions | 29.4 | |
| • STPIS | 34.6 | |
| **Operating expenditure** | | |
| Original building block revenue requirement | 377.5 | **453.9** |
| Smoothing/CPI allowance | 10.1 | |
| Tax allowance | 25.2 | |
| Solar PV FiT pass-through | 41.2 | |
| Revenue reduction (ENCAP)[1] | 0.0 | |
| **Revenue cap[2]** | **1,925.4** | **1,925.4** |

**Notes:**

1. Adjustment as detailed in Energex's 2014/15 SCI. For more information, refer to Section 9.
2. Due to rounding, individual components may not sum to the total.

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)
- Embedded Generators (EG)
- Standard Asset Customer (SAC) Demand
- Standard Asset Customer (SAC) Non-Demand.

A description of these tariff classes, including customer eligibility, is included in Section 3.1.

Energex allocates costs to its tariff classes using a Distribution Cost of Supply (DCOS) model. This modelling process is explained in Appendix 3. The allocation of costs to recover the revenue cap is illustrated in Figure 2.1.

## Figure 2.1 - 2014/15 Cost allocation flowchart

| Maximum Allowable Revenue (MAR) | |
|---|---|
| $1,994.8 M | |
| *plus* DUOS under/over | $0.0 m |
| *plus Qld Govt. Direction* | ($69.5) m |
| *plus adjustment to STPIS* | $0.0 m |
| **Revenue Cap** | |
| $1,925.4 m | |

| Regulatory Depreciation | | Return on Capital[1] | | Operating and Maintenance Costs | |
|---|---|---|---|---|---|
| $120.4 m | | $1,262.8 m | | $428.8 m | |
| *plus* Tax | $7.4 m | *plus* Tax | $80.9 m | *plus* Tax | $25.2 m |
| $127.8 m | | $1,343.6 m | | $453.9 m | |
| 6.6% | | 69.8% | | 23.6% | |

**Distribution Cost of Supply Cost Categories**

| System | Common Services | Non-system | DPPC |
|---|---|---|---|
| $1,802.8 m | $16.4 m | $106.2 m | $402.2 m |

**Allocated Costs**

| Individually Calculated Customer (ICC) | Connection Asset Customer (CAC) - 33kV | Connection Asset Customer (CAC) - 11kV Bus | Connection Asset Customer (CAC) - 11kV Line | Embedded Generators (EG) | Standard Asset Customers (SAC) Demand | Standard Asset Customers (SAC) Non-Demand |
|---|---|---|---|---|---|---|
| DUOS $44.54 m | DUOS $4.99 m | DUOS $23.07 m | DUOS $113.77 m | DUOS $0.93 m | DUOS $470.68 m | DUOS $1,267.41 m |
| DPPC $35.8 m | DPPC $2.1 m | DPPC $10.1 m | DPPC $39.9 m | DPPC $0.0 m | DPPC $113.5 m | DPPC $200.7 m |

**Expected Revenue[2,3]**

| ICC | CAC - 33kV | CAC - 11kV Bus | CAC - 11kV Line | Embedded Generators (EG) | SAC Demand | SAC Non-Demand |
|---|---|---|---|---|---|---|
| DUOS $44.54 m | DUOS $4.99 m | DUOS $23.07 m | DUOS $113.77 m | DUOS $0.93 m | DUOS $470.68 m | DUOS $1,267.41 m |
| DPPC $35.8 m | DPPC $2.1 m | DPPC $10.1 m | DPPC $39.9 m | DPPC $0.0 m | DPPC $113.5 m | DPPC $200.7 m |

**Allocated Costs vs. Expected Revenue (including impact of Side Constraint)**

| | | | | | | |
|---|---|---|---|---|---|---|
| DUOS $0.00 m | DUOS $0.00 m | DUOS $0.00 m | DUOS $0.00 m | DUOS $0.00 m | DUOS $0.00 m | DUOS $0.00 m |
| DPPC $0.0 m | DPPC $0.0 m | DPPC $0.0 m | DPPC $0.0 m | DPPC $0.0 m | DPPC $0.0 m | DPPC $0.0 m |

**Total impact of side constraint**
DUOS $0.00 m

**Notes:**

1. Includes adjustments for DUOS unders and overs, revenue from shared assets and capital contributions from SACs.
2. Expected Revenue is shown as a result of the side constraint only (ie. the impact of rounding is not included)
3. Due to rounding, individual components may not sum to the total

### 2.2.3 DUOS overs and unders account

**FINAL DETERMINATION REQUIREMENT**

**Energex is to keep and provide information on a distribution use of system (DUOS) overs and unders account, in accordance with Clause 6.18.2(b)(7) of the *Rules.***

As part of the requirements of the Final Determination, 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 2014/15 Pricing Proposal, year t-2 is 2012/13 and year t is 2014/15.

The overs and unders account is detailed in Table 2.4. In 2012/13 the closing balance on the account is greater than five percent of the MAR. In accordance with Section 4 of the Final Determination, where Energex has an over or under recovery balance of greater than five percent of the MAR, the adjustment to revenue may be subject to a plan. Energex submitted a plan to the AER on 21 November 2013.

To moderate price increases for customers and provide a smooth transition into the 2015-20 regulatory control period, the plan submitted by Energex proposed not to recover any of the closing balance of the under recovery in 2014/15. Instead, Energex proposed to utilise the provisions of clauses 6.4.3(a)(6) and 6.4.3(b)(6) of the Rules which allow for the carry forward of balances of a control mechanism from one regulatory control period to the next and for these to be smoothed across the next 5 years of the Regulatory Determination.

This timing would allow the closing balance of the DUOS unders and overs account as at 30 June 2015 to be carried over into the building block revenue for the next regulatory period, therefore allowing Energex to commence the next regulatory control period with a zero account balance. Including the closing balance in the building block revenue for the first year would also allow this value to be included in any calculation of revenue smoothing. More information about this is included in Section 9.1.

Energex also recently consulted with customers and advocacy groups who favoured us recovering the closing balance over a longer period of time to enable price stability given the extent of the under recovery.

The AER requires the amounts used in Table 2.4 for the most recently completed regulatory year (t-2) (i.e. 2012/13) to be audited. Energex believes this requirement has been met as the amounts are either:

a. Audited as part of the statutory or regulatory account audits certified by Queensland Audit Office (QAO)

b. Provided by the AER in the Final Determination or Tribunal Order

c. Calculated based on underlying figures which are included under points (a) and/or (b) above.

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

**Table 2.4 - DUOS overs and unders account**

| Over/under account element | 2012/13 actual ($'000) | 2014/15 forecast ($'000) |
|---|---|---|
| Revenue from DUOS charges | 1,318,719 | 1,925,394 |
| Plus revenue from Community Service Obligation (CSO) | 35,841 | 0 |
| Less over/under adjustment approved for year t-2 (from t-4) | 20,457 | 0 |
| Less foregone revenues | -45,511 | -69,453 |
| Less MAR for the relevant year | 1,516,239 | 1,994,846 |
| • Allowed revenues ($AR_t$) | 1,468,944 | 1,745,316 |
| • STPIS reward/penalty ($S_t$) | 29,379 | 34,557 |
| • Capital contribution overs/unders adjustment ($C_t$) | 824 | 29,359 |
| • Transitional adjustments ($Transitional_t$) | 0 | 0 |
| • Approved pass-throughs ($Pass\text{-}through_t$) | 17,093 | 185,614 |
| **Over/under recovery for regulatory year** | **-136,627** | **-0** |
| **DUOS overs and unders account** | | |
| Nominal WACC 2012/13 | 9.72% | n/a |
| Opening balance from year t-2 (2012/13) | -74,169 | -253,766 |
| Interest on opening balance | -15,119 | n/a |
| Over/under recovery for regulatory year | -136,627 | 0 |
| Interest on over/under recovery for regulatory year | -27,851 | n/a |
| **Closing balance**[1] | **-253,766** | **-253,766** |

**Notes:**

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

### 2.2.4 Demand, energy and customer numbers forecasts

As part of the Regulatory Information Notice (RIN) for the Final Determination, Energex provided the AER with details of the demand and energy forecasts, and expected numbers of customers throughout the 2010-15 regulatory control period. A set of forecasts was approved in the Final Determination; these approved forecast figures have now been revised and are listed in Table 2.5. The revised energy forecast for 2014/15 follows conservative energy purchases during the current year (i.e. 2013/14), primarily resulting from reduced energy sales following mild temperatures, slowed economic resurgence, increased energy conservation and the impact of the growth in residential solar PV.

Energy sales for 2013/14 are forecast to reach 20,718 gigawatt hours (GWh). Reflecting the current conservative usage of electricity and the growth of solar PV, the energy sales for 2014/15 are forecast to vary between[9] 20,414 GWh and 21,076 GWh as per Energex's 2014/15 long term energy forecasts. Energy sales used for the development of 2014/15 prices are outlined in Table 2.5.

The forecast customer numbers are based on actual customer numbers at 30 November 2013 obtained from network billing systems, with a small allowance for population growth. Forecasts of demand, energy and numbers of customers are used to allocate different costs to tariff classes, as outlined in Appendix 3.

**Table 2.5 - 2014/15 demand, energy and customer number forecasts by SCS tariff class**

| Tariff class | Maximum demand (MW) | Forecast customer numbers | Forecast energy consumption (GWh) |
|---|---|---|---|
| **2014/15 original forecast[1]** | 5,733 | 1,480,294 | 25,845 |
| **2014/15 revised forecast** | 4,842 | 1,377,484 | 20,745 |
| **Split of revised forecast into tariff classes:** | | | |
| ICC | 313 | 38 | 2,027 |
| CAC | 555 | 464 | 3,810 |
| EG | 4 | 18 | 3 |
| SAC Demand | 1,142 | 11,459 | 5,451 |
| SAC Non-Demand | 2,828 | 1,365,505 | 9,454 |
| **Total** | **4,842** | **1,377,484** | **20,745** |

**Notes:**

1. Approved in the Final Determination, p64.

## 2.2.5 Jurisdictional schemes

In 2014/15, Energex is not subject to any jurisdictional schemes that are to be passed onto customers.

[9] Based on a 95% confidence interval

# 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.**

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'.

## 3.1 Tariff classes

**RULE REQUIREMENT**

**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.**

All customers who take supply from Energex for direct control services are a member of at least one tariff class. Direct control services comprise SCS and ACS. For the 2010–15 regulatory control period, the AER has classified network services, connection services and metering services as SCS; fee-based services, quoted services and street lighting[10] are classified as ACS. Where a customer has both SCS and ACS supplied, they may be a member of two or more tariff classes. More information about tariff class membership is included in Section 3.1.1.

In line with the *Rules* and to ensure economic efficiency, SCS tariff classes have been designed to group similar customers together according to voltage level, customer size and usage profiles, and connection characteristics. The underpinning characteristics of the existing tariff classes broadly reflect the costs associated with provision of service to those customers within the tariff class.

Tariff classes for SCS are outlined in Table 3.1, and detailed descriptions of each tariff class are included in Table 4.1. More information about ACS tariff classes, charging parameters and customer assignment to tariffs is available in Chapter 11 and Chapter 12.

[10] 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.

Each tariff class consists of a grouping of individual tariffs that are established on the same basis as the tariff classes. This ensures there are not an excessive number of tariffs and that available tariffs are clear and easily understood. Ultimately, this minimises transaction costs that may be incurred by customers from switching between tariffs and by Energex in managing the provision of an excessive number of tariffs.

**Table 3.1 - 2014/15 SCS tariff classes**

| Tariff class | Eligible customers |
|---|---|
| Individually Calculated Customers (ICC) | • electricity consumption **greater than 40 GWh** per year at a single connection point; and/or<br>• where demand is greater than or equal to 10 megavolt amperes (MVA); or<br>• where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted. |
| Connection Asset Customers (CAC) | • electricity consumption **greater than 4 GWh, but less than 40 GWh** per year at a single connection point; and/or<br>• where demand is greater than or equal to 1 MVA at a single connection point, but less than 10MVA; and/or<br>• where a customer has a dedicated supply system with connection assets; or<br>• where the customer has contributed to their dedicated connection assets; or<br>• where the uniqueness of the connection assets would result in distortion of the SAC pricing. |
| Embedded Generator (EG) | • predominantly generators, with an **installed capacity greater than 1 MVA** in accordance with the Energy Networks Association definition as follows:<br>- Medium: 1 – 5 MVA (Low Voltage - LV or High Voltage - HV) or less than 1 MVA (HV); and<br>- Large: greater than 5 MVA. |
| SAC Demand | • consumption typically **less than 4 GWh per year, but greater than 100 megawatt hours (MWh)** or **1 MVA** per year; and<br>• where a customer has a meter installed that is capable (and programmed) to measure both energy consumption (kilowatt hours - kWh) and demand (kilowatts - kW), and is capable (and programmed) to measure demand over 30 minute periods. |
| SAC Non-Demand | • consumption typically **below 100 MWh per year**; or<br>• where the customer's connection point has a meter installed that is capable (and programmed) of measuring energy consumption (kWh) only. |

### 3.1.1 Tariff class membership

To comply with the *Rules,* Energex's process for tariff assignment, as illustrated in Figure 3.1, ensures no direct control services customer can take supply without being a member of at least one tariff class.

Prior to supply being provided to a customer, they must be assigned to a relevant network tariff. As explained in Table 3.2, where a new customer connection request is received and no tariff is nominated, using the tariff assignment process (as shown in Figure 3.1), the customer will be allocated first to a tariff class and then to a tariff. In these instances, Energex will assign the customer to the relevant default tariff for the tariff class. The relevant default tariff is determined considering the guidelines outlined in Section 3.2.

## 3.2 Assignment and reassignment of customers to tariff classes

**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.**

### 3.2.1 Tariff class assignment process

The following customer characteristics are taken into account by Energex when determining the applicable tariff class for a potential customer:

- voltage level
- customer size and usage profiles
- connection characteristics.

In addition to the above, the following guidelines apply:

- Allocation of a customer with micro-generation facilities to a tariff will be made on the same basis as other connections. Energex's policy is detailed in Section 3.2.2
- Where a new tariff is applied to a customer, it is standard practice to apply the tariff from the next billing period

- For new connections with no previous load history, the default tariff is based on their 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 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 Figure 3.1 will be followed to assign the customer to a suitable tariff class.

The procedure for assigning and reassigning customers to tariff classes relates specifically to the application of mandated tariffs. Customers who have chosen to participate in a tariff trial will not normally 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 Figure 3.1 and Figure 3.2. As depicted, within each tariff class there are a number of tariffs available; typically, a specific tariff will be applied to customers within the same tariff class.

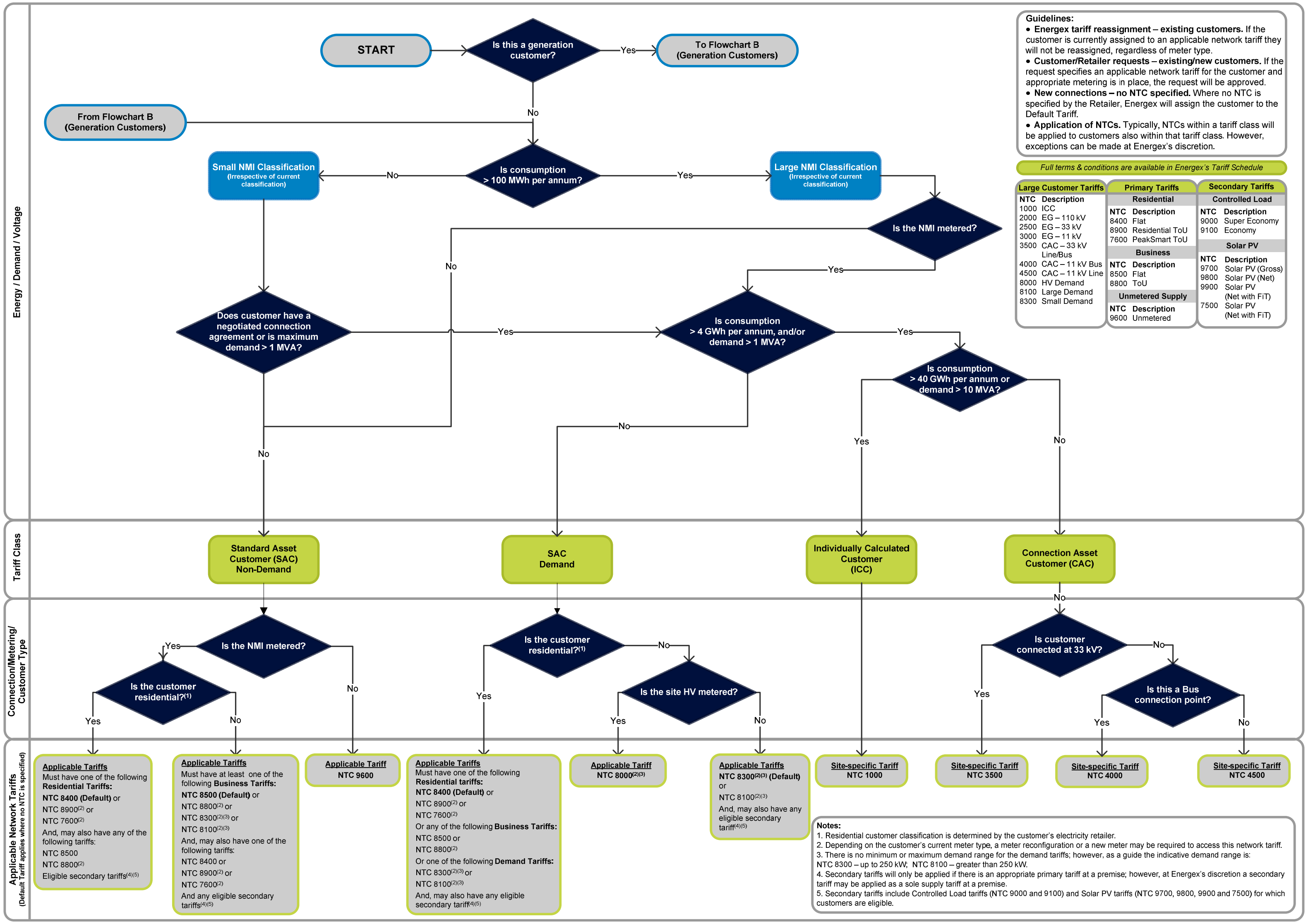
To limit transaction costs and ensure pricing signals are not distorted by constant changes in customer tariff assignment, customers are generally only allowed one requested tariff change per 12 month period. For customers with demand levels that fluctuate frequently, Energex may apply a reasonable tolerance limit up to 20 percent on tariff thresholds to mitigate frequent tariff reassignment, and subsequently limit customer impact.

### 3.2.2 Customers with micro-generation facilities

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 proposed network pricing arrangements for customers participating in the Queensland Solar Bonus Scheme (the Scheme), which ensure that these customers are treated no less favourably than other customers as the billed consumption of these customers will be unaffected by their participation in the Scheme.

## Figure 3.1 - Assignment of customers to SCS tariff classes (flowchart A)




**Guidelines:**

- **Energex tariff reassignment – existing customers.** If the customer is currently assigned to an applicable network tariff they will not be reassigned, regardless of meter type.
- **Customer/Retailer requests – existing/new customers.** If the request specifies an applicable network tariff for the customer and appropriate metering is in place, the request will be approved.
- **New connections – no NTC specified.** Where no NTC is specified by the Retailer, Energex will assign the customer to the Default Tariff.
- **Application of NTCs.** Typically, NTCs within a tariff class will be applied to customers also within that tariff class. However, exceptions can be made at Energex's discretion.

*Full terms & conditions are available in Energex's Tariff Schedule*

**Large Customer Tariffs**

| NTC | Description |
|---|---|
| 1000 | ICC |
| 2000 | EG – 110 kV |
| 2500 | EG – 33 kV |
| 3000 | EG – 11 kV |
| 3500 | CAC – 33 kV Line/Bus |
| 4000 | CAC – 11 kV Bus |
| 4500 | CAC – 11 kV Line |
| 8000 | HV Demand |
| 8100 | Large Demand |
| 8300 | Small Demand |

**Primary Tariffs**

Residential

| NTC | Description |
|---|---|
| 8400 | Flat |
| 8900 | Residential ToU |
| 7600 | PeakSmart ToU |

Business

| NTC | Description |
|---|---|
| 8500 | Flat |
| 8800 | ToU |

Unmetered Supply

| NTC | Description |
|---|---|
| 9600 | Unmetered |

**Secondary Tariffs**

Controlled Load

| NTC | Description |
|---|---|
| 9000 | Super Economy |
| 9100 | Economy |

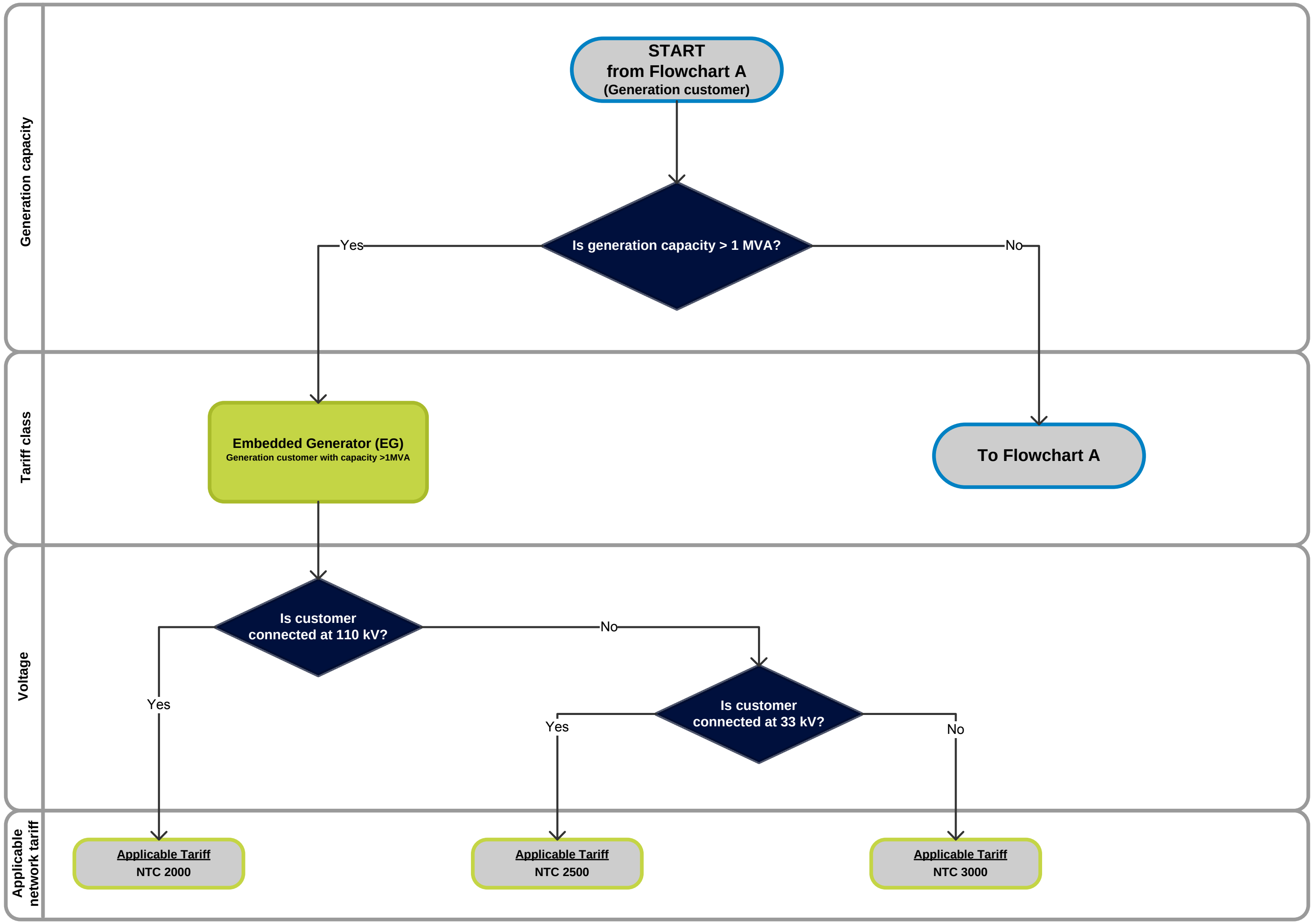
Solar PV

| NTC | Description |
|---|---|
| 9700 | Solar PV (Gross) |
| 9800 | Solar PV (Net) |
| 9900 | Solar PV (Net with FiT) |
| 7500 | Solar PV (Net with FiT) |

**Notes:**

1. Residential customer classification is determined by the customer's electricity retailer.
2. Depending on the customer's current meter type, a meter reconfiguration or a new meter may be required to access this network tariff.
3. There is no minimum or maximum demand range for the demand tariffs; however, as a guide the indicative demand range is: NTC 8300 – up to 250 kW; NTC 8100 – greater than 250 kW.
4. Secondary tariffs will only be applied if there is an appropriate primary tariff at a premise; however, at Energex's discretion a secondary tariff may be applied as a sole supply tariff at a premise.
5. Secondary tariffs include Controlled Load tariffs (NTC 9000 and 9100) and Solar PV tariffs (NTC 9700, 9800, 9900 and 7500) for which customers are eligible.

## Figure 3.2 - Assignment of customers to SCS tariff classes (flowchart B)



### 3.2.3 Customer notification process for tariff class changes

In accordance with Appendix B of the Final Determination, customers and their electricity retailer will be notified of the tariff class to which they have been assigned or reassigned. The process for notifying customers of tariff class changes is outlined in Table 3.2.

**Table 3.2 - Customer notification process for tariff class changes**

| Input to tariff class assignment process | Notification process |
|---|---|
| Energex-driven reassignment based on a change in usage or connection | Based on NMI classification, Energex identifies customers who are assigned to an incorrect tariff class. The correct tariff class is determined based on the process outlined in Figure 3.1. The customer is notified in writing of the intended tariff class reassignment, and is given the opportunity to object to the proposed reassignment and request a review[1] of the decision be undertaken prior to the change being initiated. |
| Customer-driven reassignment (through Energex Form 1634 - QESI) | Energex receives a completed Form 1634 – QESI from the retailer for tariff reassignment.<br>If the request is approved, the customer and their retailer are notified in writing of the tariff reassignment and subsequent tariff class reassignment.<br>If the request is not approved, the customer and their retailer are notified in writing that the tariff reassignment and subsequent tariff class reassignment have not been approved.<br>The customer is given the opportunity to object to the decision and request a review[1] be undertaken. |
| New connection | Energex receives notification of a new customer connection.<br>For CAC, EG and ICC customers:<br>• The correct tariff class is determined based on the process outlined in Figure 3.1.<br>• The customer is notified of the tariff classification as part of the Connection Agreement, and is given the opportunity to object to the classification and request a review[1] of the decision.<br>For SAC Demand and SAC Non-Demand customers:<br>• Where a tariff code is nominated on the connection request thus informing tariff class assignment, Energex will confirm if this is appropriate.<br>• 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 Figure 3.1, and the customer is assigned to the default tariff.<br>• 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. |

**Notes:**

1. The process for tariff class review is outlined in Section 3.2.4.

Under market rules, it is the responsibility of a customer's electricity retailer to provide Energex with the correct customer details. Where the customer contact details are known, the customer will be notified directly; their retailer will also be notified. If the customer details are unknown or if the letter is returned to Energex, Energex will notify the customer's retailer.

### 3.2.4 Tariff class assignment objections review process

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

This notice will include:

- a copy of Energex's internal review procedures or the link to where such information is available on the Energex website
- advice that if the review of the objection is not resolved to the customer's satisfaction under Energex's internal review system then:
    - for small customers – to the extent that resolution of such disputes is within the jurisdiction of a state-based energy ombudsman scheme 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 review of the objection is not resolved to the customer's satisfaction under Energex's internal review system, then the customer is entitled to seek resolution via the dispute resolution process available under Part 10 of the NEL.

If a customer objects to the proposed assignment or reassignment and requests a review be undertaken, Energex will consider this request taking into account clauses 6.18.4(a)(1)–(3) of the *Rules*, and the process detailed in Figure 3.1 and Figure 3.2 of this pricing proposal. Energex will notify the customer and their electricity retailer in writing of its decision and the reasons for that decision.

# 4 Standard control services: Proposed tariffs

## 4.1 Description of tariffs

The tariffs for SCS are described in Table 4.1. 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.

**Table 4.1 - Descriptions of SCS tariffs**

| Tariff class | NTCs | Tariff class/tariff description | Tariff details |
|---|---|---|---|
| **ICC** | 1000 | Tariff class typically applies to customers with electricity **consumption greater than 40 GWh per year** at a single connection point; and/or where the customer's demand is greater than or equal to 10 MVA; or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted.<br>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. | The tariffs for ICCs are calculated on a site-specific basis and are confidential – they are provided in Appendix 1.1 (confidential).<br>Energex will provide site-specific tariffs directly to the customer and their electricity retailer. |
| **CAC** | 3500<br>4000<br>4500 | Tariff class typically applies to customers with electricity consumption **greater than 4 GWh, but less than 40 GWh per year** at a single connection point; and/or where demand is greater than or equal to 1 MVA at a single connection point; and/or where a customer has a dedicated supply system with connection assets; or where the customer has contributed to their dedicated connection assets; or where the uniqueness of the connection assets would result in distortion of the SAC pricing.<br>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.<br>CAC tariffs are:<br>• 33 kV Line/Bus (3500)<br>• 11 kV Bus (4000)<br>• 11 kV Line (4500)<br>Customers are allocated to only one of the above tariffs based on the nature of their connection to the network. | Tariffs for CACs include a mix of site-specific charging parameters (fixed charge) and general tariff class charging parameters (capacity, demand and volume charges).<br>Tariffs for the site-specific charging parameter (fixed charge) are provided in Appendix 1.2 (confidential). Energex will provide these site-specific charges directly to the customer and their electricity retailer.<br>The other charging parameters for CACs are outlined in Table 4.6. |

| Tariff class | NTCs | Tariff class/tariff description | Tariff details |
|---|---|---|---|
| **EG** | 2000<br>2500<br>3000 | Tariff class typically applies to generators with an **installed capacity greater than 1 MVA** in accordance with the Energy Networks Association definition:<br>Medium: 1 – 5 MVA (Low Voltage – LV or High Voltage – HV) or less than 1 MVA (HV); and<br>Large: greater than 5 MVA.<br>Tariffs for connection and access services for medium and large EGs 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 protection system upgrades.<br>In accordance with the *Rules*, all EGs 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 for the export of electricity generated by the user into the distribution network. EGs who are net importers of electricity will receive appropriate network charges.<br>Micro and small generators with an installed capacity less than or equal to (≤) 1 MVA (LV) will be connected under an applicable SAC tariff based on the consumption level and metering type of the customer. However, a small generator may be treated as a CAC if there is a supply arrangement which is different to that which would be provided for a load customer of similar size or as per CAC requirements.<br>EG tariffs are:<br>• 110 kV (NTC 2000)<br>• 33 kV (NTC 2500)<br>• 11 kV (NTC 3000)<br>Customers are allocated to only one of the above tariffs based on the nature of their connection to the network. | Tariffs for EGs include a mix of site-specific charging parameters (fixed charge) and general tariff class charging parameters (capacity, demand and volume charges).<br>Tariffs for the site-specific charging parameter (fixed charge) are provided in Appendix 1.2 (confidential). Energex will provide these site-specific charges directly to the customer and their electricity retailer.<br>The other charging parameters for EGs are outlined in Table 4.6. |

<table>
<tr><th>Tariff class</th><th>NTCs</th><th colspan="3">Tariff class/tariff description</th><th>Tariff details</th></tr>
<tr><td rowspan="4">SAC Demand</td><td rowspan="4">8000<br>8100<br>8300</td><td colspan="3">Tariff class typically applies to customers with consumption less than 4 GWh per year, but greater than 100 MWh or 1 MVA per year. Customers must have a meter installed that is capable (and programmed) to measure energy consumption (kWh) and demand (kW), and records total energy consumption and demand over 30 minute periods.<br>Each tariff includes a demand parameter as well as a fixed and volume charge.<br>SAC Demand tariffs are:</td><td rowspan="4">Tariffs are based on an average shared network price and average connection price.<br>The tariff charges for SACs are outlined in Table 4.6.<br>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 capital contributions policy is available on the Energex website.</td></tr>
<tr><td>HV Demand</td><td>8000</td><td>This tariff is available to customers connected at HV with demand up to 1,000 kVA.</td></tr>
<tr><td>Large Demand</td><td>8100</td><td>This tariff generally applies to customers with maximum demand between 250 and 1,000 kVA.</td></tr>
<tr><td>Small Demand</td><td>8300</td><td>This is the default tariff for customers with consumption between 100 MWh and 4 GWh per year where no previous demand history exists. Generally, the small demand tariff applies for customers with maximum demand up to 250 kVA. Customers with consumption less than 100 MWh can choose to access this tariff on a voluntary basis.</td></tr>
<tr><td rowspan="2">SAC Non-Demand</td><td rowspan="2">7500<br>7600<br>8400<br>8500<br>8800<br>8900</td><td colspan="3">Tariff class typically applies to customers with consumption below 100 MWh per year. A Non-Demand tariff may also apply when the customer's connection point has a meter installed that is capable (and programmed) to measure total energy consumption (kWh) only (applicable in limited circumstances).<br>SAC Non-Demand tariffs are:</td><td rowspan="2">Tariffs are based on an average shared network price and average connection price.<br>The tariffs for SACs are outlined in Table 4.6.<br>Capital contributions may apply to newly connecting SACs and are sought as</td></tr>
<tr><td>Business Flat</td><td>8500</td><td>This tariff is the default tariff for business customers with consumption less than 100 MWh per year.</td></tr>
</table>

| Tariff class | NTCs | Tariff class/tariff description | | | Tariff details |
|---|---|---|---|---|---|
| | 9000<br>9100<br>9600<br>9700<br>9800<br>9900 | Business ToU | 8800 | 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 at multiple levels, depending on the time of day. Volume charges are lower during off-peak hours and higher during peak hours. | prepayment for a revenue shortfall in the case of an uneconomic connection. Energex's capital contributions policy is available on the Energex website.<br>For Super Economy (NTC 9000) and Economy (NTC 9100) tariffs, specified connected appliances are detailed in Energex's Tariff Schedule.[11] |
| | | Residential Flat | 8400 | This tariff is the default tariff for residential customers regardless of their size and cannot be used in conjunction with Residential ToU (NTC 8900) or PeakSmart ToU (NTC 7600). | |
| | | Residential ToU | 8900 | This tariff is available to residential customers regardless of their size and cannot be used in conjunction with Residential flat (NTC 8400) or PeakSmart ToU (NTC 7600). Depending on the time of day, the tariff is priced differently with highest rates during peak hours and lower rates the rest of the day. Customers must have a ToU-capable meter to access this tariff. | |
| | | PeakSmart ToU | 7600 | This tariff is available to residential customers regardless of their size and cannot be used in conjunction with Residential flat (NTC 8400) or Residential ToU (NTC 8900). Depending on the time of day, the tariff is priced differently with highest rates during peak hours and lower rates the rest of the day. Customers must have a ToU-capable meter to access this tariff, and additional eligibility requirements must be met. | |

[11] Energex's tariff schedule can be found on the Energex website https://www.energex.com.au/about-us/network-regulation-and-pricing/network-prices

| Tariff class | NTCs | Tariff class/tariff description | | | Tariff details |
|---|---|---|---|---|---|
| | | Solar PV (net with FiT) | 9900 | This tariff is part of the Queensland Solar Bonus Scheme, 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:<br>A 44 c/kWh FiT rate is available to existing customers until 2028 where they continue to meet eligibility requirements.[12] | |
| | | Solar PV (net with FiT) | 7500 | From 1 July 2014, no FiT is payable by Energex under this tariff.<br>For customers in South East Queensland, there will be no regulated FiT. The rate that is paid is negotiated between the customer and the electricity retailer or other third party.<br>For customers in regional Queensland, the FiT will be set by the QCA based on the market value of electricity being exported. | |
| | | Solar PV (net) | 9800 | These tariffs are not part of the Queensland Solar Bonus Scheme. Under a net arrangement, energy generated is used in the premises first and any excess energy exported to the grid is metered. Under a gross agreement, all energy produced is exported to the grid and metered. No FiT is payable by Energex for either of these tariffs. For NTC 9800 and NTC9700 any energy exported back to the grid is purchased by the electricity retailer. The rate that is paid is negotiated between the customer and the electricity retailer or other third party. | |
| | | Solar PV (gross) | 9700 | | |

[12] 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

| Tariff class | NTCs | Tariff class/tariff description | | | Tariff details |
|---|---|---|---|---|---|
| | | Super Economy | 9000 | Specified connected appliances are controlled by network equipment so supply will be permanently available for a minimum period of 8 hours per day during time periods set at the absolute discretion of Energex, but usually between the hours of 10:00 pm and 7:00 am. | |
| | | Economy | 9100 | Specified connected appliances are controlled by network equipment so supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Energex. | |
| | | Unmetered | 9600 | This tariff is applicable to unmetered supplies. This includes facilities such as street lighting, public telephones, traffic signals, and 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. | |
| Detailed terms and conditions relating to each tariff are included in Energex's Tariff Schedule. Energex's Tariff Schedule can be found on the Energex website https://www.energex.com.au/about-us/network-regulation-and-pricing/network-prices. | | | | | |

## 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 or DPPC. The charging parameters relating to each element of service are included in Table 4.2.

Charging parameters are structured to provide signals to customers about the efficient use of the network and their impact on future network capacity and costs. The tariff structure and the proportioning of charge parameters have been developed to achieve the pricing principles in the *Rules* and Energex's pricing objectives, as discussed in Chapter 2. Energex has sought to select charging parameters for each tariff that signal the impact end users 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.

**Table 4.2 - Charging parameters relating to each element of service**

| Element of service | Fixed charges | Capacity charges | Demand charges | Volume charges |
|---|---|---|---|---|
| **DUOS** | ✓ | ✓ | ✓ | ✓ |
| **DPPC** | ✓ | | ✓[1] | ✓ |

**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.

### 4.2.1 Recovery of DUOS

Network tariffs and charging parameters are designed to recover Energex's allowed revenue, consistent with the calculation of the MAR as outlined in Chapter 2. The network charging parameters adopted by Energex for the recovery of DUOS for SCS tariffs are detailed in Table 4.3.

As demonstrated in Table 4.3, 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 4.3 - 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 (NTC)</th><th colspan="5">Tariff charging parameter</th></tr>
<tr><th>Fixed charge ($/day)</th><th>Capacity charge[1] ($/kVA/ month)</th><th>Monthly maximum demand charge ($/kVA month or $/kW/ month)</th><th>Volume charge flat (c/kWh)</th><th>Volume charge ToU (c/kWh)</th></tr>
<tr><td>ICC</td><td>ICC</td><td>1000</td><td>✓</td><td>✓</td><td>✓</td><td></td><td>✓</td></tr>
<tr><td rowspan="3">CAC</td><td>CAC – 33 kV Line/Bus</td><td>3500</td><td rowspan="3">✓</td><td rowspan="3">✓</td><td rowspan="3">✓</td><td rowspan="3"></td><td rowspan="3">✓</td></tr>
<tr><td>CAC – 11 kV Line</td><td>4500</td></tr>
<tr><td>CAC – 11 kV Bus</td><td>4000</td></tr>
<tr><td>EG</td><td>EG</td><td>2000, 2500, 3000</td><td>✓</td><td>✓[2]</td><td>✓</td><td></td><td>✓</td></tr>
<tr><td rowspan="3">SAC Demand</td><td>HV Demand</td><td>8000</td><td rowspan="3">✓</td><td rowspan="3"></td><td rowspan="3">✓</td><td rowspan="3">✓</td><td rowspan="3"></td></tr>
<tr><td>Demand Large</td><td>8100</td></tr>
<tr><td>Demand Small</td><td>8300</td></tr>
<tr><td rowspan="9">SAC Non-Demand</td><td>Business Flat</td><td>8500</td><td>✓</td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Business ToU</td><td>8800</td><td>✓</td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>Residential Flat</td><td>8400</td><td>✓</td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Residential ToU</td><td>8900</td><td>✓</td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>PeakSmart ToU</td><td>7600</td><td>✓</td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>Solar PV</td><td>7500, 9700, 9800, 9900</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Super Economy</td><td>9000</td><td></td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Economy</td><td>9100</td><td></td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Unmetered</td><td>9600</td><td></td><td></td><td></td><td>✓</td><td></td></tr>
</table>

**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. Only applicable to EGs where the amount of demand and upstream augmentation costs warrant its application.

### Fixed charges

For large customers, where network usage signals are provided by other charging parameters, fixed charges reflect the incremental costs that arise from the connection and management of the customer. For small customers, due to metering limitations, the fixed charges can be used instead of capacity charges to reflect the average capacity set aside on the shared network for a typical customer using the tariff.

### 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:
  - This charge is levied on the basis that network users who place greater pressure on the system 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.
- 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.

Demand charges signal to customers that they can reduce their electricity costs by reducing their peak demand, and thus potentially reduce required future augmentation. Capacity charges account for augmentation costs at the customer connection level and all associated upstream augmentation costs already incurred to provide sufficient network capacity to accommodate peak demand.

The application of demand-based 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.

### Flat volume charges

Flat volume charge parameters provide a mechanism to recover those costs that are related to the volume of the customer's consumption but not specifically the demand the customer places on the network. For SAC Non-Demand customers, the volume charge parameter recovers costs that would have been recovered from a demand-based or capacity charge that are not recovered from the fixed charge.

### ToU volume charges

ToU tariffs offer lower charges during off-peak periods and/or shoulder periods and higher charges during peak periods and can be used instead of a demand charge. The objective of a ToU volume charge is to reduce the demand 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.

Due to metering limitations for small customers, ToU tariffs had not previously been offered prior to 1 July 2012. However, since 2007 all new meters installed in Energex's area are capable (once programmed) of recording energy consumption at different periods of the day resulting in numerous residential customers now having meters capable of supporting ToU pricing.

To provide an incentive for users to decrease consumption during periods of peak demand, the Residential ToU tariff (NTC 8900) was introduced in 2012/13, and the PeakSmart ToU tariff (NTC 7600) was introduced in 2013/14. These tariffs allow price signals to be sent to customers via the variable charging structure; they also bring Energex's pricing structure in line with other Distribution Network Service Providers (DNSPs) across Australia.

The charging timeframes for Energex's ToU energy tariffs are included in Table 4.4.

**Table 4.4 - ToU charging timeframes**

| Tariff | Network Tariff Code (NTC) | Charging timeframes | Weekdays | Weekends |
|---|---|---|---|---|
| Residential ToU<br>PeakSmart ToU | 8900<br>7600 | Off-Peak | 10pm – 7am | 10pm – 7am |
| | | Shoulder | 7am – 4pm,<br>8pm – 10pm | 7am – 10pm |
| | | Peak | 4pm – 8pm | No peak |
| Business ToU | 8800 | Off-Peak | 9pm – 7am | Anytime |
| | | Peak | 7am – 9pm | No peak |
| ICC, CAC, EG | All network tariffs | Off-Peak | 11pm – 7am | Anytime |
| | | Peak | 7am – 11pm | No peak |

### 4.2.2 Recovery of DPPC

DPPC includes charges from Powerlink, avoided TUOS and network support costs. For further information on the breakdown of DPPC, refer to Chapter 8.

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.

The DPPC from Powerlink comprises both fixed 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.

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 assets. 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.

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 DPPC services are detailed in Table 4.5.

**Table 4.5 - Tariff charging parameters for DPPC**

<table>
<tr><th rowspan="2">Tariff class</th><th rowspan="2">Tariff</th><th rowspan="2">Network Tariff Code (NTC)</th><th colspan="4">Tariff charging parameter</th></tr>
<tr><th>Fixed charge ($/day)</th><th>Monthly maximum demand charge ($/kW/ month or $/kVA /month)</th><th>Volume charge flat (c/kWh)</th><th>Volume charge ToU (c/kWh)</th></tr>
<tr><td>ICC</td><td>ICC</td><td>1000</td><td>✓</td><td>✓[1]</td><td>✓[2]</td><td></td></tr>
<tr><td rowspan="3">CAC</td><td>CAC – 33 kV Line/Bus</td><td>3500</td><td rowspan="3">✓</td><td rowspan="3">✓</td><td rowspan="3"></td><td rowspan="3">✓</td></tr>
<tr><td>CAC – 11 kV Line</td><td>4500</td></tr>
<tr><td>CAC – 11 kV Bus</td><td>4000</td></tr>
<tr><td>EG</td><td>EG</td><td>2000, 2500, 3000</td><td>✓</td><td>✓</td><td></td><td>✓</td></tr>
<tr><td rowspan="3">SAC Demand</td><td>HV Demand</td><td>8000</td><td rowspan="3">✓</td><td rowspan="3">✓</td><td rowspan="3">✓</td><td rowspan="3"></td></tr>
<tr><td>Demand Large</td><td>8100</td></tr>
<tr><td>Demand Small</td><td>8300</td></tr>
<tr><td rowspan="9">SAC Non-Demand</td><td>Business Flat</td><td>8500</td><td>✓</td><td></td><td>✓</td><td></td></tr>
<tr><td>Business ToU</td><td>8800</td><td>✓</td><td></td><td></td><td>✓</td></tr>
<tr><td>Residential Flat</td><td>8400</td><td>✓</td><td></td><td>✓</td><td></td></tr>
<tr><td>Residential ToU</td><td>8900</td><td>✓</td><td></td><td></td><td>✓</td></tr>
<tr><td>PeakSmart ToU</td><td>7600</td><td>✓</td><td></td><td></td><td>✓</td></tr>
<tr><td>Solar PV</td><td>7500, 9700, 9800, 9900</td><td colspan="4">Not Applicable</td></tr>
<tr><td>Super Economy</td><td>9000</td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Economy</td><td>9100</td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>Unmetered</td><td>9600</td><td></td><td></td><td>✓</td><td></td></tr>
</table>

**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.

## 4.3 Proposed tariffs

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(b) A pricing proposal must:**

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

The proposed tariffs for SCS, including DUOS, DPPC and total Network Use of System (NUOS), are provided in Table 4.6. Site-specific tariffs for ICC, CAC and EG customers are provided in Appendix 1.

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, CAC or EG customer or revise the site-specific tariff for an existing customer.

Revision of a site-specific tariff 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. This ensures that customers with similar characteristics are treated equitably and is consistent with clause 6.18.4 of the *Rules* by specifically taking into account the nature and extent of their usage and the nature of their connection to the network. If new or revised charges are required, they will be calculated in accordance with the approved pricing proposal and the customer will be notified in accordance with the process outlined in Table 3.2.

## Table 4.6 - 2014/15 SCS tariff charges (proposed DUOS, DPPC and NUOS charges)

| Tariff Class | Tariff Description | NTC | DUOS Charges[1] Fixed ($/day) | DUOS Capacity ($/kVA/ month) | DUOS Demand ($/kVA/ month) | DUOS Demand ($/kW/ month) | DUOS Volume Flat (c/kWh) | DUOS Off Peak Volume (c/kWh) | DUOS Shoulder Volume (c/kWh) | DUOS Peak Volume (c/kWh) | DPPC Charges[1] Fixed ($/day) | DPPC Demand ($/kVA/ month) | DPPC Demand ($/kW/ month) | DPPC Volume Flat (c/kWh) | DPPC Off Peak Volume (c/kWh) | DPPC Shoulder Volume (c/kWh) | DPPC Peak Volume (c/kWh) | NUOS Charges[1] Fixed ($/day) | NUOS Capacity ($/kVA/ month) | NUOS Demand ($/kVA/ month) | NUOS Demand ($/kW/ month) | NUOS Volume Flat (c/kWh) | NUOS Off Peak Volume (c/kWh) | NUOS Shoulder Volume (c/kWh) | NUOS Peak Volume (c/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ICC | ICC | 1000 | Tariffs for ICC customers are confidential (see Appendix 1.1) | | | | | | | | | | | | | | | | | | | | | | |
| CAC | CAC - 33 kV Line/Bus | 3500 | Site-specific (see Appendix 1.2) | 1.016 | 3.166 | | | 0.107 | | 0.163 | Site-specific (see Appendix 1.2) | 1.000 | | | 0.137 | | 0.137 | Site-specific (see Appendix 1.2) | 1.016 | 4.166 | | | 0.244 | | 0.300 |
| | CAC - 11 kV Bus | 4000 | | 2.313 | 5.025 | | | 0.107 | | 0.163 | | 1.000 | | | 0.137 | | 0.137 | | 2.313 | 6.025 | | | 0.244 | | 0.300 |
| | CAC - 11 kV Line | 4500 | | 3.481 | 8.046 | | | 0107 | | 0.163 | | 1.000 | | | 0.137 | | 0.137 | | 3.481 | 9.046 | | | 0.244 | | 0.300 |
| EG | EG – 110 kV | 2000 | | Site Specific (see Appendix 1.2) | | | | | | | | Site Specific (see Appendix 1.2) | | | | | | | | Site Specific (see Appendix 1.2) | | | | | | |
| | EG - 33 kV | 2500 | | 1.016 | 3.166 | | | 0.107 | | 0.163 | | 1.000 | | | 0.137 | | 0.137 | | 1.016 | 4.166 | | | 0.244 | | 0.300 |
| | EG - 11 kV | 3000 | | 3.481 | 8.046 | | | 0.107 | | 0.163 | | 1.000 | | | 0.137 | | 0.137 | | 3.481 | 9.046 | | | 0.244 | | 0.300 |
| SAC Demand | HV Demand | 8000 | 41.765 | | | 14.341 | 0.102 | | | | 9.827 | | 2.282 | 0.954 | | | | 51.592 | | | 16.623 | 1.056 | | | |
| | Demand Large | 8100 | 29.807 | | | 19.845 | 0.102 | | | | 9.827 | | 2.282 | 0.954 | | | | 39.634 | | | 22.127 | 1.056 | | | |
| | Demand Small | 8300 | 4.894 | | | 22.730 | 0.102 | | | | 1.878 | | 1.409 | 1.395 | | | | 6.772 | | | 24.139 | 1.497 | | | |
| SAC Non-Demand | Business Flat | 8500 | 0.550 | | | | 12.177 | | | | 0.255 | | | 1.255 | | | | 0.805 | | | | 13.432 | | | |
| | Business ToU | 8800 | 0.550 | | | | | 7.985 | | 13.985 | 0.255 | | | | 1.255 | | 1.255 | 0.805 | | | | | 9.240 | | 15.240 |
| | Residential Flat | 8400 | 0.500 | | | | 11.434 | | | | 0.091 | | | 1.693 | | | | 0.591 | | | | 13.127 | | | |
| | Residential ToU | 8900 | 0.500 | | | | | 6.994 | 10.434 | 20.266 | 0.091 | | | | 1.693 | 1.693 | 1.693 | 0.591 | | | | | 8.687 | 12.127 | 21.959 |
| | PeakSmart ToU | 7600 | 0.500 | | | | | 4.994 | 10.434 | 20.266 | 0.091 | | | | 1.693 | 1.693 | 1.693 | 0.591 | | | | | 6.687 | 12.127 | 21.959 |
| | Super Economy | 9000 | | | | | 3.994 | | | | | | | 1.550 | | | | | | | | 5.544 | | | |
| | Economy | 9100 | | | | | 8.511 | | | | | | | 1.550 | | | | | | | | 10.061 | | | |
| | Unmetered | 9600 | | | | | 8.511 | | | | | | | 1.550 | | | | | | | | 10.061 | | | |
| | Solar PV (net with FiT) | 7500 | FiT rate negotiated with third party (SEQ) or set by QCA (Regional Queensland) | | | | | | | | | | | | | | | | | | | | | | |
| | Solar PV (net with FiT) | 9900 | FiT rate legislated by State Government | | | | | | | | | | | | | | | | | | | | | | |
| | Solar PV (gross) | 9700 | FiT rate negotiated with third party | | | | | | | | | | | | | | | | | | | | | | |
| | Solar PV (net) | 9800 | FiT rate negotiated with third party | | | | | | | | | | | | | | | | | | | | | | |

**Notes:**
1. All prices exclude GST.

# 5 Weighted average revenue

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(b) A pricing proposal must:**

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

The Weighted Average Revenue (WAR) for SCS tariff classes for 2013/14 and 2014/15 is outlined in Table 5.1.

**Table 5.1 - Expected weighted average revenue by tariff class**

| Tariff class | Current regulatory year 2013/14[1] ($m) | Relevant regulatory year 2014/15[1] ($m) |
|---|---|---|
| ICC | 39.5 | 44.5 |
| CAC | 124.5 | 141.8 |
| EG | 0.8 | 0.9 |
| SAC Demand | 392.7 | 470.7 |
| SAC Non-Demand | 1,085.6 | 1,267.4 |
| **Total[2]** | **1,643.2** | **1,925.4** |

**Notes:**

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

# 6 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.

Under the *Rules*, Energex is required to demonstrate that the proposed DUOS tariffs for the next year (t) will, for each tariff class, meet the side constraint formula in Equation 6.1. This formula and requirement are set by the AER in Section 4.5.2 of the Final Determination.

**Equation 6.1 - Side constraint formula**

$$\frac{\sum_{j=1}^{m} d_t^j \times q_t^j}{\sum_{j=1}^{m} d_{t-1}^j \times q_t^j} \leq (1+\Delta CPI_t)\times(1-X_t)x(1+2\%) \pm S_t \pm C_t \pm transitional_t \pm passthrough_t \pm unders\ and\ overs_t$$

where each tariff class ‘j’ has up to ‘m’ components, and where:

$d_t^j$ is the proposed price for component *j* of the tariff class for year t

$d_{t-1}^j$ is the price charged by Energex for component *j* of the tariff class in year *t*-1

$q_t^j$ is the forecast quantity of component *j* of the tariff class in year *t*

$\Delta CPI_t$ is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year *t*-2 to March in regulatory year *t*-1

$X_t$ is the X Factor for each year of the regulatory control period*.* If $X > 0$, then *X* will be set equal to zero for the purposes of the side constraint formula

$S_t$ is the Service Target Performance Incentive Scheme (STPIS) factor to be applied in regulatory year *t*

$C_t$ is the annual adjustment factor for the difference between actual and forecast capital contributions in year *t*-2

$transitional_t$ is a transitional factor for matters such as over/under in tax paid during the current regulatory control period and over/under adjustments related to shared assets used for purposes other than *SCS*

$pass\text{-}through_t$ is an annual adjustment factor that reflects the pass-through amounts approved by the AER with respect to regulatory year *t*

$unders\ and\ overs_t$ is an annual adjustment factor related to the balance of the DUOS under and over account with respect to regulatory year *t*.

Table 6.1 demonstrates Energex’s compliance with the side constraint formula for each tariff class in 2014/15 and outlines the permissible percentage change. Specifically, in accordance with clause 6.18.6(b) of the *Rules,* the table illustrates that the expected WAR to be raised from each tariff class in 2014/15 does not exceed the WAR for each tariff class in 2013/14 by more than the permissible percentage.

In accordance with clause 6.18.6(d) of the *Rules*, and as per the side constraint formula, the permissible percentage change excludes all DPPC charges and an adjustment is made for any approved pass-throughs. Energex has applied the side constraint to all tariff classes in 2014/15. The side constraint results in the net impact on revenue shown in Figure 2.1.

**Table 6.1 - Compliance with side constraint formula**

| Tariff class | Weighted average revenue 2013/14[1] ($m) | Expected revenue 2014/15[2] ($m) | Calculated percentage change[4] | Permissible percentage change |
|---|---|---|---|---|
| ICC | 39.5 | 44.5 | 12.7% | 21.7% |
| CAC - 33 kV | 4.5 | 5.0 | 11.9% | 21.7% |
| CAC - 11 kV Bus | 20.5 | 23.1 | 12.8% | 21.7% |
| CAC - 11 kV Line | 99.6 | 113.8 | 14.2% | 21.7% |
| EG | 0.8 | 0.9 | 13.9% | 21.7% |
| SAC Demand | 392.7 | 470.7 | 19.9% | 21.7% |
| SAC Non-Demand | 1,085.6 | 1,267.4 | 16.7% | 21.7% |
| **Total[3]** | **1,643.2** | **1,925.4** | | |

**Notes:**

1. Regulatory year t-1.
2. Regulatory year t, including side constraint adjustment.
3. Due to rounding, individual components may not sum to the total.
4. In order to calculate the percentage change for each tariff class, the WAR for 2014/15 is based on 2013/14 rates and 2014/15 quantities, as stipulated in the side constraint formula.

# 7 Application of pricing principles

**RULE REQUIREMENT**

**Clause 6.18.5 Pricing Principles**

**(a) 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.**

**(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; 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.**

**(c) 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.**

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

Table 7.1 provides estimates which indicate that the expected revenue to be recovered from tariff classes for 2014/15 is between the two bounds created by avoidable and stand alone costs. These costs are described as:

- Avoidable costs – 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
- Stand alone costs – the costs that would be incurred to service all customers in a tariff class on an individual (i.e. stand alone) basis.

### 7.1.1 The DCOS model

The DCOS model that Energex uses to calculate tariffs (as described in Chapter 2) generates DUOS tariffs based on the full distribution of the building block costs (plus adjustments) approved by the AER. Appendix 3 outlines the tariff cost allocation process used by Energex.

The DCOS model has also been used to estimate the stand alone and avoidable costs for each tariff class. Table 7.1 outlines which of the DCOS cost categories are used in the calculation of the two price boundaries and converts the DCOS cost categories into tariff charging parameters.

**Table 7.1 - DCOS categories used in price boundary calculations and the conversion of DCOS categories into tariffs**

| DCOS cost category | | Pricing boundaries | | Tariff charging parameter | | |
|---|---|---|---|---|---|---|
| | | Avoidable cost | Stand alone cost | Fixed charge ($/period) | Volume charge[1] (c/kWh) | Capacity / demand charge ($/kW or $/kVA) |
| **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 Building Block 'Operating Expenditure.
3. There is no regulatory depreciation or return on capital for contributed connection assets.
4. For SAC Non-Demand customers the fixed charge comprises a small component of the shared network costs.
5. Applicable to customers on volume (energy) based network tariffs.

### 7.1.2 Lower bound test (avoidable cost)

As shown in Table 7.1, the avoidable costs for a tariff class include the cost of non-contributed connections and the costs of operation and maintenance (O&M) for that connection. The 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 volume and/or capacity / demand charge parameters), taking the charge paid by any customer above the avoidable cost of supply (the economic cost floor).

### 7.1.3 Upper bound test (stand alone cost)

In the DCOS model, the infrastructure and operation and maintenance (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).

### 7.1.4 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 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
- Total avoidable costs – the sum of avoidable capital and avoidable O&M is represented as an annual charge in Table 7.2.

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 stand alone costs – the sum of stand alone capital and stand alone O&M is represented as an annual charge in Table 7.2.

**Table 7.2 - 2014/15 stand alone and avoidable cost boundaries**

| Tariff class | Avoidable cost ($m) | Expected revenue[1] ($m) | Stand alone cost ($m) |
|---|---|---|---|
| ICC | 12.0 | 44.5 | 46.3 |
| CAC - 33 kV | 2.7 | 5.0 | 5.3 |
| CAC - 11 kV Bus | 6.3 | 23.1 | 33.2 |
| CAC - 11 kV Line | 13.7 | 113.8 | 121.9 |
| EG | 0.6 | 0.9 | 0.9 |
| SAC Demand | 29.8 | 470.7 | 473.0 |
| SAC Non-Demand | 120.8 | 1,267.4 | 1,291.8 |
| **Total[2]** | **185.9** | **1,925.4** | **1,972.5** |

**Notes:**

1. Excluding any side constraint adjustment.
2. Due to rounding, individual components may not sum to the total.

## 7.2 Long-run marginal cost

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.

Marginal costs can be calculated as either Short-Run Marginal Costs (SRMC) or Long-Run Marginal Costs (LRMC). 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. In order to provide correct signals for customers, prices must account for LRMC as it can provide appropriate signalling to customers and will assist in achieving a stable tariff structure over the forecast period.

Energex has estimated LRMC values at the voltage level using the Average Incremental Cost (AIC) method, described in Equation 7.1. The LRMC values are used as a test to ensure capacity / demand charges and energy charges incorporated into each tariff are reasonable.

**Equation 7.1 - 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) costs associated with meeting the additional demand over the regulatory control period.

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

The incremental capital and operating costs associated with increased demand are included in the Energex forecast capex and opex programs for the 2010–15 regulatory control period. Energex receives a return on these (and other) costs in the form of a return on capital and depreciation charges, as approved by the AER. These costs are then allocated to each tariff class in the DCOS model.

In accordance with clause 6.18.5(b)(1) of the *Rules,* Energex designs tariffs to include a combination of charging parameters to reflect LRMC and recover the total allowable revenue. The charging parameters include:

- Capacity charges – where appropriate take into account the long term demand peak and can provide effective pricing signals to customers of the next increment of load
- Demand charges – used to take into account short term peaks in demand
- Volume charges – used, where appropriate, due to limitations with current metering
- Fixed charges – used to ensure any remaining costs, including costs associated with connection assets, are recovered.

## 7.3 Transaction costs

For each tariff, Energex has selected a number of charging parameters, identified in Chapter 4 for SCS and Chapter 12 for ACS. Each combination of tariff charging parameters has been selected to reflect the need for both fixed and variable components, as required by clause 6.18.5(b)(2)(i).

A combination of various parameters is required to achieve economic functionality and to ensure that appropriate pricing signals are provided to customers. However, the number and design of these parameters have been selected with regard to minimising the associated transaction and pricing administration costs.

As explained in Section 3.1, Energex groups individual tariffs in the same way as tariff classes. This approach ensures 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 apply a reasonable tolerance limit up to 20 percent on tariff thresholds to mitigate frequent tariff reassignment and reduce transaction costs for customers and Energex.

## 7.4 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 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 are discussed in Section 4.2.1.

- 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 information.

  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 save money by reducing their maximum consumption over time.

- Demand charges - customers can reduce network charges by reducing their maximum consumption over any half hour period throughout the month. This can be achieved by staggering the start time of appliances with significant load, purchasing load management technology, or turning off other appliances when an appliance is switched on.

- Volume charges – customers can save money by reducing their energy consumption over the billing period. This can be achieved by the purchase of energy-efficient appliances.

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

Energex is aware of customers putting systems in place to manage their network charges in response to price signals. For example, commercial and industrial customers (who have these elements as part of the network tariff) may 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 A/C, and improving thermal insulation of cold rooms. Some outcomes of Energex's current demand management programs are highlighted in Section 10.

## 7.5 Tariff adjustment to address revenue shortfalls

When setting network tariffs, Energex uses a combination of charging parameters. These are developed taking into account the LRMC, transaction costs and customer response to pricing signals, as required under Clause 6.18.5(b) of the *Rules.* However, the expected revenue will not be recovered if charging parameters consider only those items identified. For example, building block revenue is greater than LRMC since it allows for recovery of sunk costs (i.e. it allows for recovery of long-run average cost).

Accordingly, the charging parameters outlined in Table 4.3 are applied to allow for any shortfall in expected revenue. These parameters are selected in a manner which complements the chosen pricing signals and minimises price distortion, as required by clause 6.18.5(c) of the *Rules*.

# 8 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).**

**(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.**

**(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.**

**DETERMINATION REQUIREMENT**

**Energex, in accordance with clause 6.12.1(19) of the Rules, is to maintain a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with Appendix E of the Final Determination.**

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*, 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 network users
  - payments received from other DNSPs

- Adjustments for over or under recovery – difference between revenue and expenses.

## 8.1 Expenses

### 8.1.1 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.

### 8.1.2 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’).**

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) exceed 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 2014/15, avoided TUOS payments will generally be remitted in the form of a lump sum payment after 30 June 2015, similar to previous years.

Avoided TUOS to EGs by Energex reflects the avoided costs of upstream transmission network reinforcement to SEQ – that is, avoided TUOS does not solely impact on the TNCP to which the EG is connected. Consequently, the benefits of avoided TUOS relate to all customers and have been assigned to all tariff classes.

### 8.1.3 Payments to other DNSPs

In contingency circumstances, Essential Energy (the DNSP in northern NSW) 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.

## 8.2 Revenue

### 8.2.1 Recovery of DPPC through tariffs

A description of how DPPC is recovered through standard control tariffs is given in Section 4.2.2. The total revenue received is indicated in Table 8.1 .

### 8.2.2 Payments received from other DNSPs

Energex does not currently receive any transmission-related payments from other DNSPs.

## 8.3 DPPC overs and unders accounts

As part of the requirements of the Final Determination, 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 2014/15 Pricing Proposal, year t-2 is 2012/13 and year t is 2014/15.

The overs and unders account is detailed in Table 8.1.

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. 2012/13) to be audited. Energex believes this requirement has been met as the amounts are either:

a. Audited as part of the statutory or regulatory account audits certified by Queensland Audit Office (QAO)
b. Provided by the AER in the Final Determination or Tribunal Order
c. Calculated based on underlying figures which are included under points (a) and/or (b) above.

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

**Table 8.1 - DPPC overs and unders account**

| Over/under account element | 2012/13 actual ($'000) | 2014/15 forecast ($'000) |
|---|---|---|
| Revenue from DPPC charges | 390,712 | 402,229 |
| Less over/under adjustment approved for year t-2 | 10,357 | n/a |
| Less total transmission related payments | 394,283 | 385,462 |
| • Transmission charges to be paid to TNSPs | 392,569 | 383,835 |
| • Avoided customer TUOS payments | 490 | 509 |
| • Inter-DNSP payments | 1,223 | 1,118 |
| **Over/Under recovery for regulatory year** | **-13,928** | **16,767** |
| **DPPC overs and unders account** | | |
| Nominal WACC 2012/13 | 9.72% | n/a |
| Opening balance | - | -16,767 |
| Over/under recovery for regulatory year | -13,928 | 16,767 |
| Interest on over/under recovery for regulatory year | -2,839 | n/a |
| **Closing balance[1]** | **-16,767** | **-** |

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

# 9 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 2013/14 and 2014/15, including adjustments to revenue cap components, and changes to tariffs and the approach to price setting. It also details potential changes within the regulatory year. An analysis of the customer impacts of the various changes is included in Chapter 13.

## 9.1 Summary of annual adjustments

As shown in Table 2.2, various adjustments are made to the annual revenue requirement for the relevant regulatory year to calculate the MAR. A summary of the annual adjustments is included in Table 9.1.

These adjustments ensure the MAR accounts for changes in the value of various revenue cap components between regulatory years. These adjustments also impact the calculation of the annual applicable side constraint, as outlined in Chapter 6.

**Table 9.1 - Summary of annual adjustments**

| Component / adjustment | 2013/14 value ($m) | 2014/15 value ($m) | Reason for change |
|---|---|---|---|
| CPI | 2.50% | 2.93% | Annual adjustment as per ABS |
| X Factor | -11.04% | -1.42% | As specified in Tribunal Order |
| Capital contributions | 9.3 | 29.4 | The value in 2013/14 relates to under recovery in 2011/12<br>The value in 2014/15 relates to under recovery in 2012/13 |
| STPIS | 0.3 | 34.6 | The value in 2013/14 relates to the 1% portion of 2011/12 STPIS reward. Adjustment consistent with S-banking approval from AER received on 22 April 2013<br>The value in 2014/15 relates to the remaining 99% portion of 2011/12 STPIS reward. Adjustment consistent with S-banking approval from AER received on 22 April 2013 |
| | n/a | 0.0 | Adjustment consistent with the proposed 2012/13 s-banking mechanism |
| Solar PV FiT pass-through | 78.6 | 185.6 | The value in 2012/13 relates to approved FiT pass through for 2011/12<br>The value in 2014/15 relates to approved FiT pass-through for 2012/13 |
| Revenue reduction (ENCAP) | -59.9 | -69.5 | Reduction in capex in both years due to ENCAP review, subject to 2014/15 SCI/CP[1] |
| DUOS under recovery | 0.2 | 0.0 | The value in 2013/14 relates to portion of under recovery balance approved for inclusion in the 2013/14 Pricing Proposal<br>No under recovery is included in 2014/15 as the under recovery balance is to be carried forward into next regulatory period |

### 9.1.1 Adjustments required by the Final Determination and Tribunal order

The Final Determination sets out a number of adjustments to be made annually for calculating the MAR, including:

- CPI (Final Determination Section 4) – Energex is to use a CPI factor based on the year to March t-1. This CPI factor is the annual percentage change in the ABS CPI for All Groups, Weighted Average of Eight Capital Cities from March in year t-2 to March in year t-1. For 2014/15, that is March 2013 to March 2014.

- Capital contributions (Final Determination Section 4) – An annual adjustment to the MAR is to be made for over or under recovery of capital contributions in year t-2 (2012/13).

- STPIS (Final Determination Section 12) – Annual adjustment to reflect the STPIS reward/penalty from year t-2 (2012/13). In addition, as per Energex's 2013/14 Pricing Proposal, Energex is entitled to recover the remaining 99% of its 2011/12 STPIS reward.

- Solar PV FiT pass-through (Final Determination Section 15) – Annually adjusted figure to account for FiT pass-through in year t-2 (2012/13), as approved by the AER on 17 December 2013.[13]

- DUOS over or under recovery (Final Determination Section 4) – An annually adjusted amount to reflect the actual overs or unders in year t-2 (2012/13).

The X Factor is pre-determined[14] and based on the Australian Competition Tribunal's order and revised Determination.[15] Under this revised Determination, the X Factor for 2014/15 is -1.42%.

### 9.1.2 Other adjustments

The revenue reduction (ENCAP) is the result of a Queensland Government direction. On 11 February 2012, Energex received a direction notice from the Queensland Government under Section 115 of the *Government Owned Corporations Act 1993* (Queensland). This direction requires Energex to exclude revenue related to the expected reduction in its capital expenditure (capex) program, arising from the 2011 Electricity Network Capital Program (ENCAP) review for the remaining years of the regulatory control period. As such, the 2014/15 MAR includes an adjustment for this direction and is detailed in Energex's 2014/15 SCI.

When compared to 2013/14, the impact of the increased annual revenue requirement, the diminishing volume of electricity sales, increasing revenue under recoveries and the pass-through of significant Solar PV FiT payments will result in a significant increase in 2014/15 network prices.

Based on the anticipated easing of pricing pressures in the next regulatory period, Energex is employing the following initiatives to mitigate the impact of the significant 2014/15 electricity price increase on customers and to smooth volatility in prices over the longer term:

- Including the closing balance of the DUOS under recovery in the first year of the next regulatory control period.

- Energex has proposed to defer 100 percent of its STPIS reward to 2015/16. Energex does not intend to recover the full revenue increment associated with the

[13] AER, 2013. Determination 2012/13 Queensland solar bonus scheme pass-through for Energex, December 2013. http://www.aer.gov.au/node/23154 (Date accessed: 17/01/2014)
[14] The X Factor was set at -11.04% for first four years of the Regulatory control period; the final year (2014/15) is set at -1.42%.
[15] Refer to Footnote 4 (p1) for full citation.

approved 2012/13 s-factor, but will only seek to recover the incremental costs of responding to Ex Tropical Cyclone Oswald.

- Reducing revenue by $69.5m, as per the Queensland Government direction resulting from the ENCAP review.

Energex expects that price increases will moderate over the next regulatory period; incorporating these adjustment mechanisms will reduce the potential volatility of the current and longer term price impacts on customers.

## 9.2 Changes to tariffs

Energex has an ongoing program for reviewing network tariffs for its customers. The changes proposed for 2014/15 are designed to improve cost-reflectivity in tariffs.

### 9.2.1 Continuation of kVA pricing for large customers

From 1 July 2014, DPPC demand will be charged in kVA for CAC and EG customers, replacing the current kW charge. This is a continuation of the straight kVA pricing that was rolled out to ICC, CAC and EG customers in 2013/14. Tariffs based on kVA are a more accurate measure of a customer's impact on the network, relative to tariffs based on kW, as they better reflect costs imposed on the network by the customer.

### 9.2.2 SAC Non-Demand customers

For SAC Non-Demand customers, DPPC volume charges will be passed on as flat volume charges, regardless of the DUOS structure. The ToU structure will be retained with all ToU tariff charge elements set equal to mirror a flat rate. This differs from 2013/14 where a ToU signal was included for both DUOS and DPPC charges for ToU tariffs.

## 9.3 Changes to pricing approach

### 9.3.1 Smoothing transition between tariff classes

Energex considers the price differential experienced by customers as they transition between tariffs. As much as possible, Energex minimises the price differential for customers who sit on the boundary between two tariffs. This is especially relevant for customers transitioning between SAC Non-Demand business tariffs (NTC8500 and NTC8800) and SAC Demand tariff NTC8300. In order to achieve this smooth transition, it is necessary to rebalance the NTC8300 DUOS fixed and volume charges.

### 9.3.2 Review of cost allocation methodology

Energex has undertaken an extensive review of the DCOS cost allocation methodology. Opportunities to simplify and improve the shared network cost allocation methodology have been identified. During the 2014/15 year, Energex will continue to engage with customers and stakeholders in the development of an alternative approach to shared network cost allocation. The alternative approach should result in greater price stability and position

Energex to respond to upcoming challenges highlighted by the SCER and AEMC proposed rule changes.

### 9.3.3 Volume charges for site-specific customers

In prior years, a portion of the DUOS common and non-system charges were collected through demand and capacity charges. In 2014/15 and in future years, the entire collection of common and non-system charges will be collected through volume charges. This has caused a large increase in the DUOS peak and off-peak volume charges, which comprise approximately 5% of the DUOS revenue allocated to site-specific customers. The NUOS peak and off-peak volume charges are moderated by a small decline in the TUOS peak and off-peak volume charges.

### 9.3.4 Use of capacity and demand to calculate prices

Previously, Energex has used either the authorised capacity or prior year maximum demand (full calendar year) to calculate the quantity. We are now using either authorised capacity or a forecasted capacity using prior year information.

## 9.4 Proposed removal of tariffs

Energex does not anticipate the removal of any tariffs during 2014/15.

## 9.5 Changes to tariffs within the 2014/15 regulatory year

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(b) A pricing proposal must:**

**(5) set out the variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.**

SAC customer tariffs typically remain unchanged within the regulatory year; however, some SAC customers may participate in voluntary tariff trials. These tariffs will be specifically designed to determine customer behaviour and may have special tariff elements for this purpose. More details on these tariffs are contained in Chapter 10.

The tariffs for larger customers are most likely to change where there are changes specific to an individual customer's connection arrangements and/or there is a material change in use of the site. There is also the possibility of Government-mandated tariff changes. An example of such a change is the setting of prices for some ACS via Schedule 8 of the *Queensland Electricity Regulation 2006*.[16]

Any tariff changes for either SCS or ACS during the 2014/15 regulatory year would be developed taking into account the principles and objectives outlined in Chapter 2.

[16] Details of the services which are included under Schedule 8 can be found at https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricR06.pdf page 162

# 10 Pricing strategy and tariff trials

Energex's Network Pricing Strategy is currently being revised with a focus on developing tariff and pricing strategies that will be implemented in the 2015–2020 Regulatory Determination Period, with a scan of contemporary tariffs that will continue to be investigated beyond this period. Pricing strategy is dominated by the need to maintain a commercially sustainable business, and the facilitation of greater customer engagement.

Energex's commercial sustainability depends on our ability to navigate the challenge of emerging technologies amidst falling energy consumption and system peak demand, but with localised pockets of increasing peak demand. The need to achieve significant customer engagement is underpinned by a need to have simple tariffs with clear pricing signals that customers can understand and respond to. This is driving tariff reform and innovation in the way we deliver tariffs to our customers.

Energex's Network Pricing department is working closely with the Customer Engagement department to undertake customer engagement in accordance with the International Association of Public Participation best-practice engagement approach (the IAP2 Spectrum). Initial findings suggest that we need to further develop communication plans with our customers, and provide more targeted information about how to choose appropriate tariffs and respond to pricing signals using the customer's own meter data.

## 10.1 Tariff class strategy

Energex is reviewing the existing tariff classes with a view to restructuring them for the 2015–2020 Determination. In future, when demand-based tariffs are introduced for LV customers, it will become necessary to merge the existing SAC Demand and SAC Non-Demand tariff classes into an LV tariff class. Energex is also examining the alignment of all 110 kV and 33 kV customers into a sub-transmission tariff class, as all of these customers require individualised pricing. Energex may consider merging the EG tariff class into the sub-transmission or CAC tariff classes where appropriate. Energex will engage, as required on these proposals.

## 10.2 Time of use signalling for large customers

Energex's billing system does not currently have the capability to implement a ToU demand charge, to strengthen the ToU signal for larger customers. Energex will consider the impact of strengthening the ToU volume signal while this constraint remains.

## 10.3 CAC tariff strategy

### 10.3.1 Removal of capacity charges

The CAC capacity charge was originally intended as a signal to discourage customers from requesting excessive network be built to supply their requirements. Under Energex's Large Customer Connections framework, customers are now required to contribute to their assets upfront, thereby removing the need for a capacity charge. Energex will be removing the DUOS capacity charge from 2015/16 onwards as part of a broader move towards user-pays pricing.

### 10.3.2 Common fixed charges

Energex is cognisant of the fact that individually calculated fixed daily charges for CACs increase volatility for customers and increase the difficulty customers have in budgeting for network usage. Energex is also aware of customers' preferences for more streamlined, stable prices.

Energex is reviewing the current fixed charge pricing structure for CACs and whether or not a common fixed charge may be suitable, with cost-reflectivity achieved through demand and volume charges rather than through fixed charges. Customers will be engaged throughout the development of this strategy and requested to indicate their preferences on the proposal, and the manner in which it is implemented.

## 10.4 DPPC fixed charges for EG customers

Currently EGs do not receive a DPPC fixed charge. In 2015/16, Energex will move towards more cost reflective prices and align EGs with the current charging structures for other site-specific customers.

## 10.5 kVA-based charging for SAC Demand customers

Tariffs in the SAC Demand tariff class will have their demand charges denominated in kVA rather than in kW as part of a broad move towards kVA-based charging for all large customers. Engagement was undertaken with organisations representative of impacted customers and electricity retailers in December 2013 and January 2014 to determine their preference in how this change is implemented. Overwhelmingly, they indicated a strong preference for a one-step change. The implementation of kVA-based charging will commence from 2015/16, with communication to impacted customers beginning in early 2014. More information is available on the Energex website at http://www.energex.com.au/tariffchanges.

## 10.6 SAC Non-Demand strategy

In the short term, Energex will continue to incentivise ToU tariffs and off-peak tariffs for residential and small business customers. This includes the PeakSmart ToU tariff which rewards customers for placing appliances under control.

In the short and medium term, Energex remains committed to moving towards demand-based charging for residential and small business customers. A number of feasibility studies have been held or are planned to be held to determine feasible paths to implement such a change. Energex is currently engaging with retailers and customers to determine their preferences, constraints and concerns associated with each path.

Current metering abilities, customer understanding and awareness, and the limited availability of representative meter data present challenges for the development of demand-based tariffs for small customers.

## 10.7 Tariff trials and demand management programs

Energex has completed a number of tariff trials and is undertaking residential programs as part of a strategy to encourage more efficient network use. These programs and associated customer research provide Energex with information on potential customer behaviour with respect to new tariffs.

### 10.7.1 Controlled load tariffs

Controlled load is load that can be managed at Energex's discretion within specific periods as agreed with the customer. Controlled load provides a means to manage peak demand during times of maximum network utilisation, reducing network capacity requirements. Load may be interrupted without loss of utility benefits to customers or, where customers volunteer, some utility benefit may be forgone for a financial and/or environmental reward.

**Air-conditioning demand management**

Domestic and commercial A/C load continues to be a significant contributor to peak demand. During the 2010–15 regulatory control period Energex is continuing to build on the early success of its 'time for a cool change' (Cool Change) trials, by rolling out PeakSmart A/C across Energex's distribution area. This work supports the new demand management technology being applied by most A/C manufacturers. As part of this program, a signal receiver is supplied for customers who purchase and activate a new PeakSmart capable A/C unit and a cash 'reward' is provided for signing up to the program. To date, approximately 12,000 customers have applied for the PeakSmart program. The PeakSmart program is supported by the PeakSmart ToU tariff.

**Pool pump direct load control**

The Cool Change and Energy Conservation Communities programs also included work focused on improving load control solutions for pool pumps. Pool pumps contribute significantly to peak demand and analysis indicates that benefits exist in shifting pool pump usage from peak use times. Accordingly, in addition to offering and promoting a better rate for electricity used by pool pumps at non-peak times through a controlled load tariff, Energex will continue to offer alternative customer choice in relation to pool pump load control where tariff conversion may not be practical or feasible.

Energex continues to run a broad based pool program (with significant pool industry and electrician support) rebating customers who either connect their pool pump to a controlled load tariff (such as NTC 9100)) or convert a fixed speed pool pump to a minimum five star rated energy efficient pool pump.

### 10.7.2 Hot water load control

Energex is currently conducting a campaign across SEQ offering incentives to convert water heating from a continuous supply tariff (NTC 8400 or NTC 8900) to a controlled load tariff that provides supply for a minimum of eight hours (NTC 9000) or 18 hours (NTC 9100) per day. Energex reviews switch times on an ongoing basis to optimise load managed during peak times. A rewards campaign is scheduled to run through the 2014/15 winter period to incentivise customers to take advantage of tariff conversions.

# 11 Alternative control services: Tariff classes

## 11.1 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.**

For the 2010–15 regulatory control period, the AER has classified fee-based services, quoted services and street lighting as ACS. These three services form the basis of tariff classes for ACS which are described in Table 11.1.

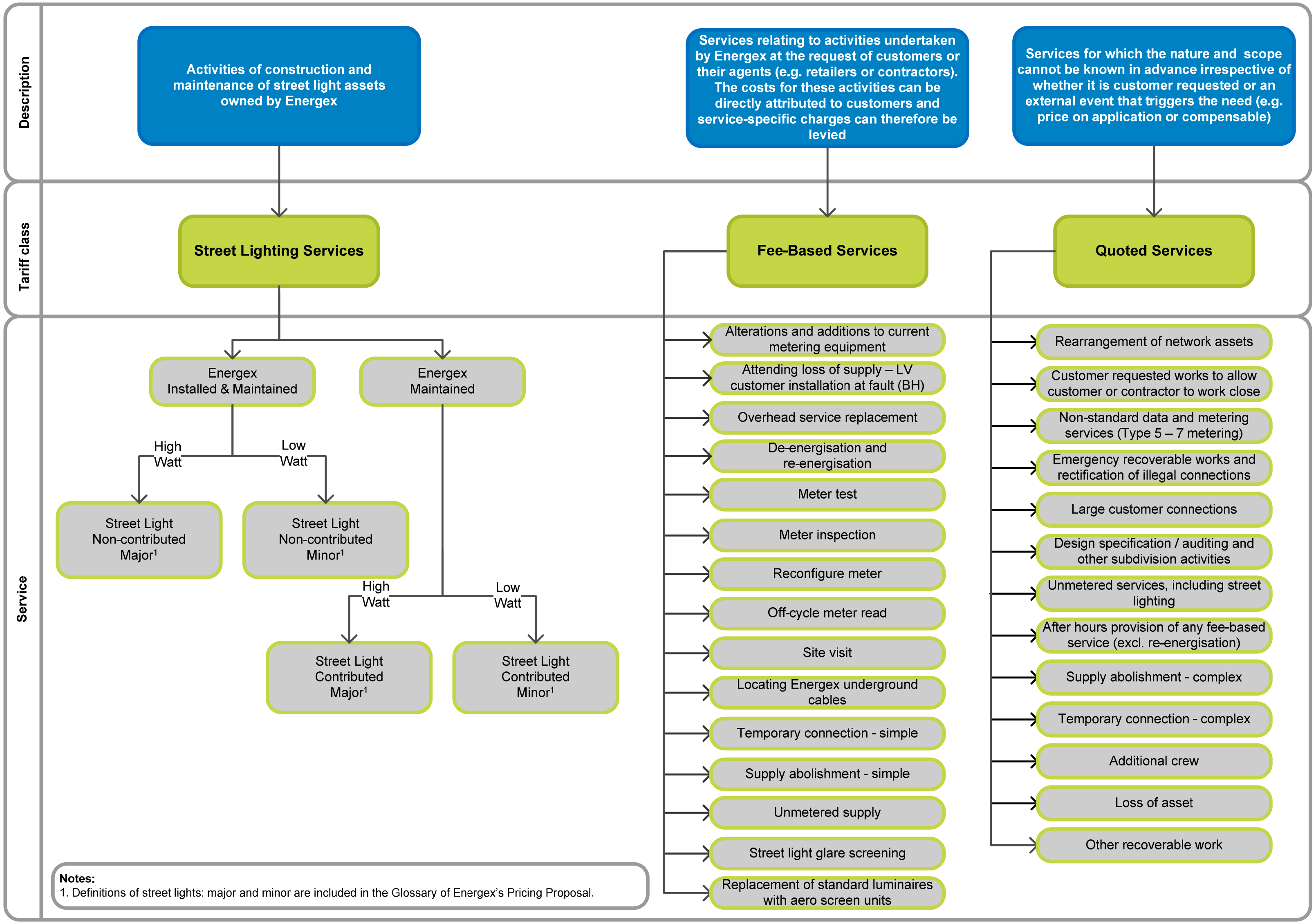
**Table 11.1 - 2014/15 ACS tariff classes**

| Tariff Class | Activity |
|---|---|
| **Street lighting** | Street lighting services relate to activities of provision, construction and maintenance of street light assets owned by Energex (conveyance of electricity to street lights remains an SCS). |
| **Fee-based** | 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 charges can therefore be levied. |
| **Quoted services** | The nature and scope of services cannot be known in advance, irrespective of whether it is customer requested or an external event that triggers the need (e.g. price on application). |

## 11.2 Assignment of customers to tariff classes

Prior to receiving supply for 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 Section 3.1.1, 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 Figure 11.1.

Figure 11.1 - Assignment of customers to ACS tariff classes



# 12 Alternative control services: Proposed tariffs

## 12.1 Street lighting

### 12.1.1 Overview

Since 1 July 2010, the bundled prices that customers are charged for street lighting consist of an SCS and an ACS. 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 ACS element of street lighting services is addressed in this chapter.

In the 2010–15 regulatory control period, Energex will continue to provide for non-contributed and contributed street lighting services.

Since 1 July 2010, the non-contributed service only applies where Energex has constructed standard street lights. In these situations customers will still receive an ongoing charge for the provision, construction and standard level of maintenance of these non-contributed lights. Customers also have the option of contributing fully (upfront) to the provision and construction of standard street lights. In this instance the customer will receive an ongoing charge for the standard level of maintenance over these street lights.

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 a quoted service.

The AER approved a price cap form of control for street lighting services over the 2010–15 regulatory control period, comprising:

- a schedule of fixed prices for street lighting services for 2010/11
- a price path for the remaining years of the 2010–15 regulatory control period.

### 12.1.2 Framework

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

**Street lighting services where Energex constructs the asset**

In the 2010–15 regulatory control period, where a non-standard street light is requested by the customer, a separate charge for the incremental cost difference will be levied as a quoted service. The customer will still receive an ongoing charge for the non-contributed service.

**Street lighting services where customer or agent constructs the asset**

In the 2010–15 regulatory control period, Energex will recognise gifted assets as contributed assets and will not seek to recover any asset-related costs from the customer. The customer will receive an ongoing charge for the maintenance of the street light under the contributed service.

**Existing contributed street lighting services**

Contributed street lights existing prior to 1 July 2010 will be recognised within SCS. This aligns with the historical capital contributions treatment where benefits from the street light asset contributions were accrued by all SACs. This reflected a view that all SACs are the end beneficiary of the contributed street lighting service.

### 12.1.3 Charging parameters

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(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.**

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, major and minor, according to luminaire type and size (as defined in the Glossary), and to non-contributed and contributed based on the funding arrangement.

Energex developed prices for the first year of the regulatory control period using a methodology that applies a revenue allocation based on the relative installation costs for major and minor street lights and the applicable asset funding arrangement (non-contributed and contributed).

### 12.1.4 Proposed charges

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(b) A pricing proposal must:**

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

**DETERMINATION REQUIREMENT**

**Energex to provide for street lighting, the proposed price for each service in the regulatory year and the revenues collected from the provision of each service in the preceding regulatory year.**

Table 12.1 below provides the price schedule for the provision, construction and maintenance of street lights for 2014/15. The prices are based on the methodology approved in the AER Final Determination 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 12.1 – 2014/15 prices for street lighting services**

| Street light service | Price[1] ($/light/day) |
|---|---|
| Major non-contributed | 1.20 |
| Major contributed | 0.33 |
| Minor non-contributed | 0.48 |
| Minor contributed | 0.13 |

**Notes**

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

In line with AER requirements, the revenues collected from the provision of each service in the preceding regulatory year are provided in Appendix 2. The applicable terms and conditions for each street light service are outlined in Energex's published Tariff Schedule.

## 12.2 Fee-based and quoted services

### 12.2.1 Overview

Energex's fee-based and quoted services are usually provided at the explicit request of third parties. These services are defined as:

- Fee-based 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.

For the 2010–15 regulatory control period, the prices for fee-based and quoted services will be subject to an annual escalation process which will take into account a weighted average price increase for each of the components of the price formula.

### 12.2.2 Framework

Services under the ACS framework are provided on an individual fee-for-service basis to retailers and end-use customers. Energex will provide a fixed-fee or quoted price, depending on the service.

The AER has approved a formula-based price cap form of control mechanism for fee-based services and quoted services over the 2010–15 regulatory control period. This consists of:

- a schedule of fixed prices for fee-based services and a schedule of rates for quoted services (illustrative configuration) for the first year of the 2010–15 regulatory control period
- an annual escalation process for the remaining years of the 2010–15 regulatory control period.

This formula outlined in Equation 12.1 below has been designed to ensure prices will be representative of the efficient costs of providing and delivering the service.

From 1 July 2010, large customer connections have been classified as a quoted service under ACS. Additional detail on the framework and approach for large customer connections is provided in Section 12.3.

### 12.2.3 Charging parameters

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(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.**

Energex uses the formula in Equation 12.1 to calculate the price for fee-based and quoted services. This formula includes cost parameters for different services to determine the price.

**Equation 12.1 - Formula for pricing fee-based and 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.

## 12.2.4 Proposed charges

RULE REQUIREMENT

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

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

DETERMINATION REQUIREMENT

Energex to provide for fee-based and quotes services, the proposed price for each service in the regulatory year, in addition to the volume of services provided and revenues collected from the provision of each service in the preceding regulatory year.

### Fee-based services

Prices for fee-based services have been calculated using the formula in Equation 12.1 and forecast costs for labour and fleet on-costs, overheads and capital allowance. The pricing signals now differentiate between services performed during business hours, those performed after hours and those requested on a priority basis. Customers are able to minimise the costs incurred for these services by choosing to have them delivered during business hours and within standard timeframes, where possible.

The proposed price schedule for fee-based services in 2014/15 is provided in Table 12.2. The prices were determined using the AER's approved formula-based price cap control mechanisms. Revised cost escalators and on-cost and overhead rates were calculated in accordance with the Final Determination. Additional information on the calculations and rates used is included in Appendix 2 (Confidential).

**Table 12.2 – 2014/15 prices for fee-based services**

| Fee-based service | Price[1] ($/service) |
|---|---|
| Alterations and additions to current metering equipment | 109.67 |
| Attending loss of supply – low voltage customer installation at fault (BH) | 122.50 |
| Overhead service replacement – single phase | 335.38 |
| Overhead service replacement – multiple phase | 395.08 |
| De-energisation[2] | 54.93 |
| Meter test | 126.92 |
| Meter inspection | 98.03 |
| Re-configure meter | 81.27 |
| Off-cycle meter read | 9.15 |
| Site visit | 70.39 |
| Locating Energex underground cables | n/a |

| Fee-based service | Price[1] ($/service) |
|---|---|
| Temporary connection | 975.17 |
| Re-energisation (BH)[2] | 47.86 |
| Re-energisation (AH)[2] | 136.58 |
| Re-energisation (visual) (BH)[2] | 81.37 |
| Re-energisation (visual) (AH)[2] | 178.43 |
| Re-energisation non–payment (visual) (BH)[2] | 81.37 |
| Re-energisation non–payment (visual) (AH)[2] | 178.43 |
| Supply abolishment | 379.84 |
| Unmetered supply | 167.64 |
| Street light glare screening | 162.01 |
| Replacement of standard luminaires with aero screen units (per street light) | 374.55 |

**Notes:**

1. All prices exclude GST.
2. Prices for these services are subject to Schedule 8 of the Queensland *Electricity Regulation 2006.* As Schedule 8 prices for 2014/15 are yet to be published, the rates in this table represent the proposed Energex costs using the ACS formula. The Schedule 8 prices will be included in Energex's 2014/15 Tariff Schedule which will be published on the Energex website prior to 1 July 2014.

### Quoted services

The proposed price schedule for quoted services (illustrative configuration) in 2014/15 is provided in Table 12.3. 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.

These indicative prices were determined using the AER's approved formula-based price cap control mechanisms for an illustrative configuration and do not represent a binding capped price for an individual quoted service.

**Table 12.3 – 2014/15 prices for quoted services**

| Quoted service[1] | Price[2] ($/service) |
|---|---|
| Rearrangement of network assets | 4,776.55 |
| Customer requested works to allow customer or contractor to work close | 7,149.00 |
| Non-standard data and metering services (Type 5 – 7 metering) | 127.79 |

| Quoted service[1] | Price[2] ($/service) |
|---|---|
| Emergency recoverable works and rectification of illegal connections | 10,576.47 |
| Large customer connections[3] | 397,811.17 |
| Design specification / auditing and other subdivision activities | 1,533.52 |
| Unmetered services, including street lighting | 2,069.52 |
| After hours provision of any fee-based service (excluding re-energisation) | 1,818.30 |
| Supply abolishment – complex | 508.60 |
| Additional crew | 134.78 |
| Temporary connection – complex | 52,463.81 |
| Loss of asset | 10,664.38 |
| Other recoverable work[4] | 0.00 |

**Notes:**

1. Illustrative configuration only.
2. All prices exclude GST.
3. Refer to Section 12.3 for additional information.
4. There is no common configuration of the 'other recoverable work' service. The service is applied only in those circumstances where the service requested is not covered by any of the other service categories or would not otherwise have been requested for the efficient management of the network.

In line with the AER requirements, the volume of services and the revenues collected from the provision of each fee-based and quoted service in the most recently completed regulatory year are provided in Appendix 2.

### 12.2.5 Long-run marginal costs

**RULE REQUIREMENT**

**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.**

The LRMC is taken into consideration when determining prices for ACS, as per clause 6.18.5(b)(1) of the *Rules*. Given that there is only a single charge parameter for each service, prices have been set at average cost ensuring total costs are recovered for these services, as allowed for under clause 6.18.5(c) of the *Rules.*

### 12.2.6 Estimating avoidable and stand alone costs

The formula used for calculating prices for fee-based services and quoted services 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 based on this formula will be cost-reflective, representing costs derived through the same allocation method as that used to determine costs for SCS, in accordance with the AER-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. Consequently, the price calculated using the formula in Equation 12.1 (which includes an allowance for overhead costs and capital allowance) will be greater than the avoidable cost.

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.

## 12.3 Large customer connections

### 12.3.1 Overview

From 1 July 2010, for new or upgraded connections (requested by a customer) of greater than 1 MVA or 4 GWh per year (that is a tariff class of EG, CAC or ICC), the design and construction of the connection assets is a quoted service and will be priced as detailed in Section 12.2. As part of the ACS service classification, customers may choose either Energex or an accredited service provider to undertake the design and construction of the connection assets (to Energex's technical standard/s).

The commissioning, operation and maintenance of all connection assets, including large connections, is an SCS.

### 12.3.2 Framework

The framework for new and existing large customer connections (LCC) is provided in Figure 12.1 and Table 12.4.

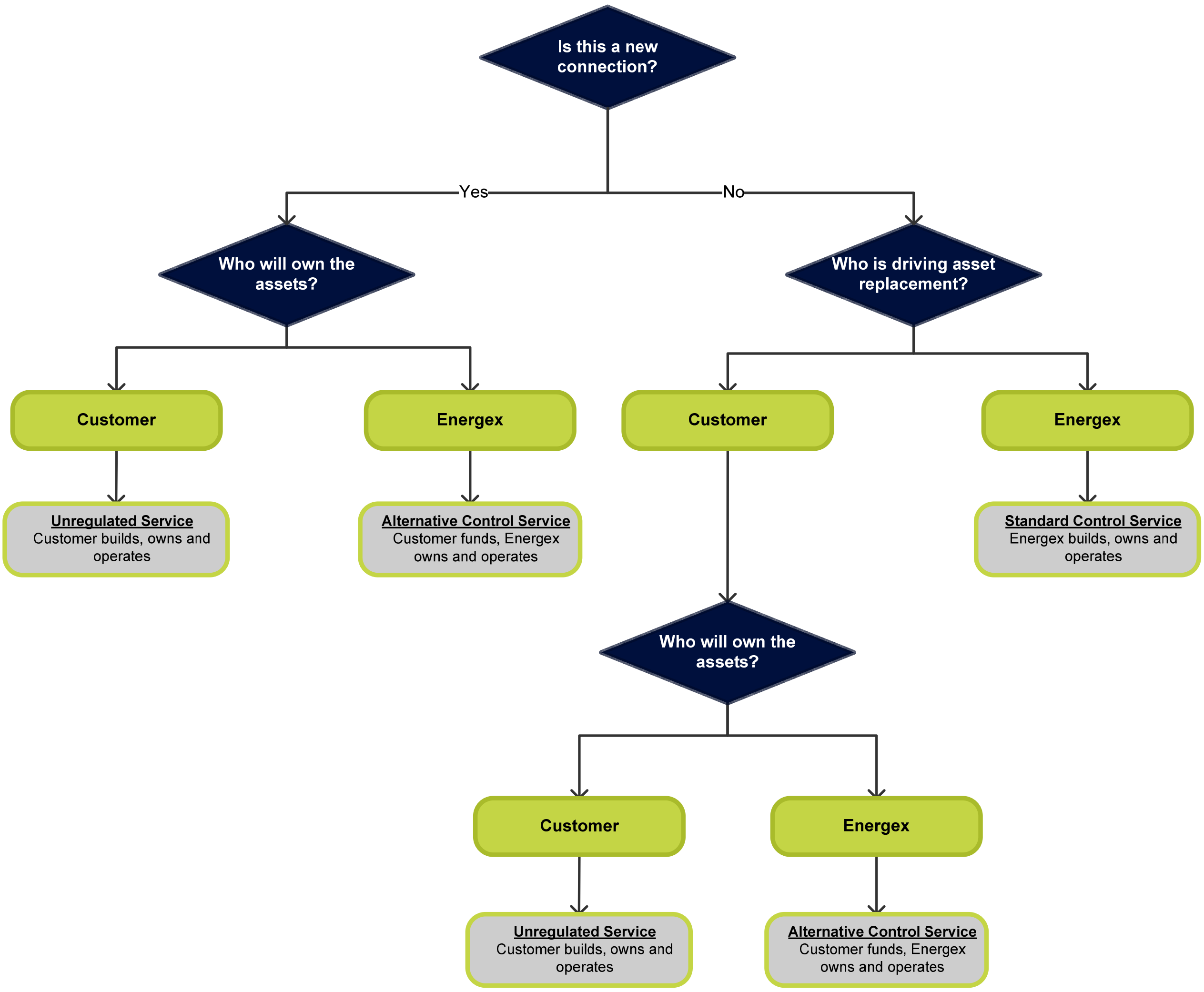
The design and construction of LCC will be classified as one of the following:

- 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, calculated in accordance with Equation 12.1 (Section 12.2.3). 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 cost allocation process detailed in Appendix 3.

- 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 cost allocation process detailed in Appendix 3.

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

**Figure 12.1 - Service classification for LCC**



## Table 12.4 - 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) | Recovery of operating expenditure (through DUOS) |
| Before 1 July 2010 (or part of transitional arrangement)<br>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<br>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.

### 12.3.3 Charging parameters

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(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.**

Energex will calculate the price for the design and construction of LCC assets in accordance with the formula in Equation 12.1.

### 12.3.4 Proposed charges

**RULE REQUIREMENT**

**Clause 6.18.2 Pricing Proposals**

**(b) A pricing proposal must:**

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

Due to the variability in the scope, the design and construction of LCC is a quoted service for which no specific prices are published. The price for the illustrative service configuration for large customer connections is shown in Table 12.4.

# 13 Customer impacts

## 13.1 Standard control services

Energex is aware of the changing expectations of customers and the current 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.

### 13.1.1 The relationship between consumption and revenue in 2014/15

Reflective of the assets required to service customers, the ratio of revenue consumption for ICC and CAC tariff classes is lower than the ratio for the SAC Non-Demand tariff class. The ICC and CAC customers, though they use large volumes, are connected high up in the distribution network, whereas the SAC Non-Demand customers have smaller volumes but are connected at LV, which is the lowest part of the network. As such, the cost-reflective price is higher for SAC Non-Demand customers connected at the LV level, compared to the cost-reflective price for the ICC and CAC customers who are connected at the HV or sub-transmission voltage level.

### 13.1.2 2014/15 price impacts

The ongoing average price increases across the regulatory control period are necessary for Energex to deliver the capital and operating expenditure programs which support development and growth in SEQ, as well as maintaining reliability and security of supply.

Table 13.1 provides an estimate of the charges in 2014/15 for the average consumption level in each tariff class. This table provides an estimate of the percentage change 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 2013/14 to 2014/15**

| Tariff Class | Approved DUOS charge 2013/14[2] (c/kWh) | Estimated DUOS charge 2014/15 (c/kWh) | Average percentage change (%) |
|---|---|---|---|
| ICC | 1.95 | 2.20 | 12.7% |
| CAC | 9.38 | 10.60 | 13.0% |
| EG | 27.25 | 31.02 | 13.9% |
| SAC Demand | 7.20 | 8.64 | 19.9% |
| SAC Non-Demand | 11.48 | 13.41 | 16.7% |

**Notes:**
1. All prices exclude GST
2. This quantity is the revenue Energex would recover using the 2013/14 approved DUOS charges, applied to the 2014/15 forecasted quantities, and divided by the 2014/15 forecasted energy.

Analysis undertaken by Energex on the network price increase that may be experienced by customers on tariffs within the SAC Demand and SAC Non-Demand tariff classes is included in Table 13.2. ICC, CAC and EG tariffs comprise various site-specific charges, and as such, have been excluded from this analysis.

The network prices used for the analysis comprise total annual NUOS excluding GST, and represent the typical ‘N’ (Network) component of a customer’s bill. These NUOS prices are the AER approved prices for 2013/14 and the proposed 2014/15 prices included in this document for AER approval.

For SAC Non-Demand business and controlled load tariffs, the typical annual energy consumption scenarios are drawn from the QCA Draft Determination. For SAC Non-Demand primary residential tariffs, three different annual energy consumption scenarios are drawn from the QCA Draft Determination. Due to its complexity, the unmetered supply tariff has been excluded.

For SAC Demand, an average load factor has been applied to the minimum recommended, typical (average forecasted) and maximum recommended demand for the purposes of analysis. Due to small customer numbers, NTC8000 has been excluded.

**Table 13.2 - Indicative NUOS price change from 2013/14 to 2014/15 for varying usage profiles for SAC Demand and SAC Non-Demand tariffs**

| SAC Demand tariffs | Usage type | Monthly demand[1] (kW) | 2013/14 NUOS ($) | 2014/15 NUOS[3] ($) | Typical annual NUOS increase[4] ($) | Typical annual NUOS increase[5] (%) |
|---|---|---|---|---|---|---|
| **HV Demand – 8000** | Not included due to insufficient customer numbers | | | | | |
| **Demand Large – 8100** | Lowest usage | 250 | $78,118.71 | $90,095.93 | $11,977.22 | 15.3% |
| | Typical usage | 446 | $130,096.31 | $149,496.81 | $19,400.50 | 14.9% |
| | Highest usage | 1000 | $276,652.78 | $316,984.03 | $40,331.25 | 14.6% |
| **Demand Small – 8300** | Lowest usage | 32 | $11,925.46 | $13,231.34 | $1,305.89 | 11.0% |
| | Typical usage | 97 | $31,019.04 | $34,962.05 | $3,943.01 | 12.7% |
| | Highest usage | 250 | $76,383.41 | $86,591.94 | $10,208.53 | 13.4% |
| **SAC Non-Demand tariffs** | **Usage type** | **Annual consumption[2] (kWh)** | **2013/14 NUOS ($)** | **2014/15 NUOS[3] ($)** | **Typical annual NUOS increase[4] ($)** | **Typical annual NUOS increase[5] (%)** |
| **Business Flat – 8500** | Typical usage | 5,375 | $919.32 | $1,015.75 | $96.42 | 10.5% |
| **Business ToU – 8800** | Typical usage | 15,250 | $1,985.27 | $2,178.64 | $193.36 | 9.7% |
| **Residential Flat – 8400** | Frugal, single person | 2,200 | $423.09 | $504.49 | $81.40 | 19.2% |
| | Single parent, one child | 4,091 | $649.19 | $752.71 | $103.52 | 15.9% |
| | Two parent, two child family | 6,133 | $893.34 | $1,020.75 | $127.41 | 14.3% |
| **Residential ToU – 8900** | Frugal, single person | 2,200 | $471.40 | $492.89 | $21.49 | 4.6% |
| | Single parent, one child | 4,091 | $695.09 | $731.13 | $36.04 | 5.2% |
| | Two parent, two child family | 6,133 | $936.64 | $988.39 | $51.75 | 5.5% |
| **Peak Smart – 7600** | Frugal, single person | 2,200 | $457.32 | $478.81 | $21.49 | 4.7% |
| | Single parent, one child | 4,091 | $668.91 | $704.95 | $36.04 | 5.4% |
| | Two parent, two child family | 6,133 | $897.39 | $949.14 | $51.75 | 5.8% |
| **Super Economy – 9000** | Typical usage | 2,000 | $96.75 | $110.88 | $14.13 | 14.6% |
| **Economy – 9100** | Typical usage | 2,000 | $175.58 | $201.22 | $25.64 | 14.6% |

**Notes:**

1. Typical demand is the average 2014/15 forecasted demand for each tariff. Lowest and highest demand are the lowest and highest demand recommended for each tariff, respectively.
2. Consumption values for each scenario are drawn from the QCA Draft Determination.
3. Total annual NUOS excluding GST represents the typical ‘N’ component of a customer’s bill.
4. Due to rounding, columns *2013/14 NUOS* and *Typical annual NUOS increase* may not sum to *2014/15 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.

## 13.2 Alternative control services

The price changes between 2013/14 and 2014/15 for ACS (street lighting and fee-based services) are provided in Table 13.3 and Table 13.4, respectively.

**Table 13.3 - Street light services percentage increase from 2013/14 to 2014/15**

| Street lighting service[1] | Percentage change (%) |
|---|---|
| Major non-contributed | 9.09% |
| Major contributed | 10.00% |
| Minor non-contributed | 9.09% |
| Minor contributed | 8.33% |

**Notes:**
1. Definitions for major and minor street lights are included in the glossary

**Table 13.4 - Fee-based services percentage increase from 2013/14 to 2014/15**

| Fee-based service | Percentage change (%) |
|---|---|
| All fee-based services[1] | 4.00% |

**Notes:**
1. Some fee based services are subject to Schedule 8 of the Queensland *Electricity Regulation 2006.* As Schedule 8 prices for 2014/15 are yet to be published, the rate in this table represent s the proposed increase using the ACS formula. The Schedule 8 prices will be included in Energex's 2014/15 Tariff Schedule which will be published on the Energex website prior to 1 July 2014.

# 14 Publication of information about tariffs and tariff classes

**RULE REQUIREMENT**

**Clause 6.18.9 Publication of information about tariffs and tariff classes**

**(f) 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; and**

**(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.**

**(g) 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.**

Once approved, Energex's 2014/15 Pricing Proposal (this document) and Energex's 2014/15 Tariff Schedule will be published on the Energex website. As required by clause 6.18.9(a)(1) and (2), these documents describe Energex's tariff classes, the tariffs applicable to each class, the charging parameters and the elements of the service to which each charging parameter relates.

The statement of expected price trends is also published annually on the Energex website. This document details that:

- for SCS, any change in prices will be subject to the approved X Factor from the Final Determination, the change in CPI and any applicable yearly adjustments
- in each regulatory year (as part of the requirements of a pricing proposal under the *Rules*), Energex will demonstrate that the proposed tariffs for DUOS will meet the side constraints formula for each tariff class
- for ACS including street lighting and fee-based services, the prices will be subject to an annual escalation process.

In accordance with clause 6.18.9(b) of the *Rules*, this document, the Tariff Schedule, and the statement of expected price trends will be published on the Energex website on 2 June 2014, or as soon as practicable thereafter.

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# APPENDIX 1 -

# Standard control services: 2014/15 site-specific tariffs

# Appendix 1.1 – ICC site-specific tariffs

This section contains the 2014/15 proposed tariffs for the ICC tariff class. This year, no ICC customers are side constrained.

The ICC tariffs, included in Table A-1.1, are site-specific and are not published due to the confidentiality requirements of the customer. Energex will provide these site-specific tariffs directly to the customer and their electricity retailer.

# Appendix 1.2 – CAC and EG site-specific tariffs

This section contains the 2014/15 proposed tariffs for the CAC and EG tariff classes. This year, no CAC or EG customers are side constrained.

These tariffs, included in Table A-1.2, are site-specific and are not published due to the confidentiality requirements of the customer. Energex will provide these site-specific tariffs directly to the customer and their electricity retailer.

# APPENDIX 2 -

# Alternative control services: Price development & reporting requirements

# Appendix 2.1 – Price development for ACS

**DETERMINATION REQUIREMENT**

**Energex is required to:**

**Section 18.3.3**

**Calculate the respective internal and external labour cost escalators for each regulatory year of the next Regulatory Control Period and provide both qualitative and quantitative supporting information to the AER as part of the annual pricing proposal.**

**Section 18.3.4**

**Calculate the on cost and overhead rates in each regulatory year of the next Regulatory Control Period in accordance with the methodologies set out in the CAM and submit both qualitative and quantitative supporting information to the AER as part of the annual pricing proposal.**

**Section 18.3.5**

**Demonstrate compliance with the price cap control mechanism in each year of the Regulatory Control Period through the pricing proposal which must:**

- **(a) Apply the AER approved price cap control mechanism formula, set out in Section 18.4 of the Final Determination, to calculate the price for each illustrative configuration of each individual quoted service and fee-based service to be offered in the relevant regulatory year.**
- **(b) Provide quantitative information to the AER what demonstrates the calculation of the price of each illustrative quoted service example and fee-based service.**
- **(c) Set out the nature and extent of any variation to an individual formula component, on cost or overhead rate from that applicable in the previous regulatory year that is above the indicative illustrative quoted service examples and fee-based services set out in Appendix I, J and K of the final decision.**
- **(d) Set out the nature and extent of any variation or adjustment to the methodology employed to derive a formula component escalator or on cost or overhead rate.**

## Cost escalators

In accordance with the Final Determination, Energex has the opportunity to calculate the cost escalators to be applied in 2014/15. These escalators are incorporated into the proposed rates for 2014/15. The proposed rates and supporting information are indicated in Table A-2.1.

**Table A-2.1 – 2014/15 Proposed cost escalators [CONFIDENTIAL]**

| Factor | Internal labour escalation rate (%) | External labour escalation rate (%) | Materials escalation rate (%) |
|---|---|---|---|
| AER Final Determination – May 2010[1] | [redacted] | [redacted] | [redacted] |
| Energex revised – April 2014 | [redacted] | [redacted] | [redacted] |

**Notes**

1. Rates are indicative only.

### Labour escalation rate

Energex's external labour rates are based on a competitive tendering process, resulting in a market-driven outcome. Energex internal and external labour, particularly specialist electrical labour, forms a labour market pool capable of working on Energex's projects. Generally, the labour resources have the same or similar qualifications and skills as internal employees. Given this, the resources can be substituted for each other and movements in the wages of employees and contractors should increase on a similar basis.

Energex proposes to use the same labour escalation rate for internal and external labour. As the external labour rates are part of a competitive tender process, the estimated escalation in these rates will be used.

### Materials escalation rate

The materials escalation rate for 2014/15 is based on the Energex SCI rate, which in turn is based on existing and future contracts for the supply of materials, which are sourced through competitive tender processes. These contracts factor in movements in material costs.

### On-cost and overhead rates

In line with the Final Determination, Energex has the opportunity to calculate the on-costs and overhead rates to be applied in 2014/15. These rates will be applied to the proposed 2014/15 labour rates and materials costs. The proposed rates and supporting information are provided in Table A-2.2.

**Table A-2.2 – 2014/15 Proposed on-cost and overhead rates [CONFIDENTIAL]**

| Factor | Labour on-costs[2] | Fleet on-costs[2] | Materials on-costs[2] | General overheads[2] | Capital allowance |
|---|---|---|---|---|---|
| AER Final Determination – May 2010[1] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Energex revised – April 2014 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

**Notes:**
1. Rates are indicative only.
2. All on cost and overhead rates are dollar per dollar of labour expenditure.

The AER approved Energex's CAM in February 2009. The CAM details the principles and policies for allocating costs, both direct and indirect, among the various categories of distribution services to comply with clause 2.2.5 of the AER's Cost Allocation Guidelines.

The CAM is applied consistently each year throughout the regulatory period. On-costs and overhead rates are established at the beginning of the year based on forecast data. Energex manages the variable nature of on-costs through an annual adjustment process that reconciles actual and estimated expenditure and reallocates any over or under recoveries.

### Labour on-costs

The labour on-cost reflects employee-related costs which are incurred in addition to wages and salaries, such as payroll tax and long service leave. The on-costs are allocated based on direct labour expenditure. The on-cost rate is calculated at the beginning of the year based on forecast expenditure.

### Fleet on-costs

The fleet on-cost reflects costs incurred to operate and maintain vehicles owned or leased that are used in the construction, operation or maintenance of the electricity network. The fleet on-cost is allocated based on direct labour expenditure (inclusive of labour on-costs).

### Materials on-costs

The materials on-cost reflects materials handling and storage costs associated with storing and co-ordinating materials or stock. The on-costs are allocated based on direct material expenditure. The on-cost rate is calculated at the beginning of the year based on forecast expenditure.

### General overheads

General overheads cover the other indirect costs which are incurred in the provision of services but are not directly attributed to specific services. The general overhead pool is determined on the basis of the total overhead pool after deducing on-cost pools, excluded items and deducting the unregulated activities allocation. The general overhead is allocated based on direct operating and capital expenditure of the regulated activities.

### Capital allowance

The capital allowance for 2014/15 was originally set and approved by the AER in the Final Determination. However, following the Australian Competition Tribunal's decision[17] that the value of gamma is 0.25, a new rate has been calculated. This has resulted in an increase to the capital allowance.

### Price calculation

The proposed prices for fee-based and quoted services are provided in Chapter 12.

Prices for fee-based and quoted services have been calculated using the AER-approved formula, based on price cap control mechanisms outlined in Chapter 12 and forecast costs for labour, on-costs, overheads and capital allowance. The 2014/15 service level assumptions used in the price calculation are as approved in the Final Determination and included in Table A-2.3.

For fee-based services, a forecast volume of services in 2014/15 has been used to determine an appropriate price increase across all services (the price path).The forecast

[17] Australian Competition Tribunal, 2011. Review of a Distribution Determination by Energex Limited, 19 May 2011. http://www.aer.gov.au/sites/default/files/Australian%20Competition%20Tribunal%20order%20Energex%20-%2019%20May%202011.pdf (Date accessed: 20 February 2014).

volume is based on a forecast of 2013/14 volumes (using actual services to date), with an allowance for additional services in 2014/15. For fee-based services the revised 2014/15 price path is 4.0%.

**Table A-2.3 - Service level assumptions and forecast volume used for 2014/15 price calculations**

| Service | 2014/15 Service level assumptions | | | | 2014/15 forecast volume |
|---|---|---|---|---|---|
| | No. of crew | Travel time (hr) | Time on site (hr) | Total time (hr) | |
| Alterations and additions to current metering equipment | 1 | 0.25 | 1 | 1.25 | 2,770 |
| Attending loss of supply – LV customer installation at fault (BH) | 1 | 1 | 0.5 | 1.5 | 962 |
| Overhead service replacement – single phase | 2 | 0.5 | 0.9 | 2.8 | 740 |
| Overhead service replacement – multiple phase | 2 | 0.5 | 1.2 | 3.4 | 282 |
| De-energisation | 1 | 0.4 | 0.12 | 0.52 | 105,382 |
| Meter test | 1 | 0.4 | 0.66 | 1.06 | 1,474 |
| Meter inspection | 1 | 0.25 | 1 | 1.25 | 708 |
| Reconfigure meter | 1 | 0.4 | 0.5 | 0.9 | 3,720 |
| Off-cycle meter read | 0 | 0 | 0 | 0 | 84,526 |
| Site visit | 1 | 0.5 | 0 | 0.5 | 22,882 |
| Locating Energex underground cables | 1 | 0.25 | 1 | 1.25 | - |
| Temporary connection | 3 | 1 | 1.8 | 8.4 | 2,330 |
| Re-energisation (BH)[1] | 1 | 0.33 | 0.15 | 0.48 | 188,628 |
| Re-energisation (AH)[1] | 1 | 0.5 | 0.15 | 0.65 | 1,360 |
| Re-energisation (visual) (BH)[2] | 1 | 0.33 | 0.33 | 0.66 | 53,400 |
| Re-energisation (visual) (AH) | 1 | 0.5 | 0.33 | 0.83 | 11,580 |
| Re-energisation non-payment (visual) (BH)[1] | 1 | 0.33 | 0.33 | 0.66 | 66 |
| Re-energisation non-payment (visual) (AH)[1] | 1 | 0.5 | 0.33 | 0.83 | 14 |
| Supply abolishment[3] | 1.85 | 0.5 | 0.7 | 2.22 | 1,478 |
| Unmetered supply | 1 | 0.4 | 1 | 1.4 | 22 |
| Streetlight glare screening | 0 | 0 | 0 | 0 | 183 |
| Replacement of standard luminaries with aero screen units (per street light) | 0 | 0 | 0 | 0 | 92 |

**Notes:**
1. Re-energisation following non-payment.
2. Volume for re-energisation read services are excluded.
3. Split based on a mixture of overhead and underground jobs.

# Appendix 2.2 – Additional reporting for ACS

In accordance with AER requirements, the revenues collected from the provision of each street lighting service in the preceding regulatory year are provided in Table A-2.4.

Additionally, the volume of services and revenues collected from the provision of each fee-based and quoted service in the preceding regulatory year are provided in Tables A.2.5 and A.2.6.

**Table A-2.4 – 2012/13 Revenue collected from street light services**

| Street light services[1] | Revenue collected ($m) |
|---|---|
| Major non-contributed | 14.7 |
| Major contributed | 4.4 |
| Minor non-contributed | 16.2 |
| Minor contributed | 4.3 |
| **Total** | **39.6** |

**Notes:**

1. Definitions of major & minor lamps are included in the glossary

**Table A-2.5 – 2012/13 Volume of fee-based services and collected revenue**

| Fee-based service | Volume of services | Revenue collected ($) |
|---|---|---|
| Alterations and additions to current metering equipment | 3,027 | 380,205 |
| Attending loss of supply - LV customer installation at fault (BH) | 319 | 34,860 |
| Overhead service replacement – single phase | 714 | 175,582 |
| Overhead Service replacement – multiple phase | 280 | 68,664 |
| De-energisation | 102,519 | 0 |
| Meter test | 1,537 | 61,940 |
| Meter inspection | 785 | 31,732 |
| Reconfigure meter | 3,126 | 232,338 |
| Off-cycle meter read | 86,906 | 731,108 |
| Site visit | 20,248 | 762,366 |
| Locating Energex underground cables | 0 | 0 |
| Temporary connection | 1,919 | 667,023 |
| Re-energisation (BH) (Read & MSS) | 191,921 | 446,253 |
| Re-energisation (AH) (Read & MSS) | 2,116 | 195,712 |
| Re-energisation (visual) (BH) | 50,403 | 0 |
| Re-energisation (visual) (AH) | 10,611 | 982,251 |
| Re-energisation (visual) non-payment (BH) | 13 | 501 |
| Re-energisation (visual) non-payment (AH) | 6 | 556 |
| Supply abolishment | 1,274 | 392,901 |
| Unmetered supply | 51 | 7,911 |
| Street light glare screening | 183 | 30,077 |
| Replacement of standard luminaries with aero screen units (per street light) | 92 | 30,812 |

**Table A-2.6 – Volume of quoted services completed in 2012/13 and associated life-to-date revenue**

| Quoted service | Volume of services | Revenue collected ($) |
|---|---|---|
| Rearrangement of network assets | 185 | 1,264,743 |
| Customer requested works to allow customer or contractor to work close | 311 | 788,520 |
| Non-standard data and metering services (Type 5 – 7 metering) | 0 | 0 |
| Emergency recoverable works and rectification of illegal connections | 265 | 2,254,488 |
| Large customer connections | 6 | 27,016 |
| Design specification / auditing and other subdivision activities | 687 | 954,596 |
| Unmetered services, including street lighting | 1 | 1,912 |
| AH provision of any fee-based service (excluding re-energisation) | 1,805 | 351,085 |
| Supply abolishment – complex | 0 | 0 |
| Additional crew | 163 | 24,362 |
| Temporary connection – complex | 6 | 45,194 |
| Loss of asset | 113 | 345,337 |
| Other recoverable work[1] | 62 | 1,022,308 |

**Notes**

1. There is no common configuration of the 'other recoverable work' service. The service is applied only in circumstance where the service requested is not covered by any of the other service categories or would not otherwise have been requested for the efficient management of the network.

# APPENDIX 3 -
# Tariff cost allocation approach

# Appendix 3 - Tariff cost allocation process

## Part 1. Tariff cost allocation process

Energex's revenue cap (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
- Capital contribution
- Revenue from shared assets.

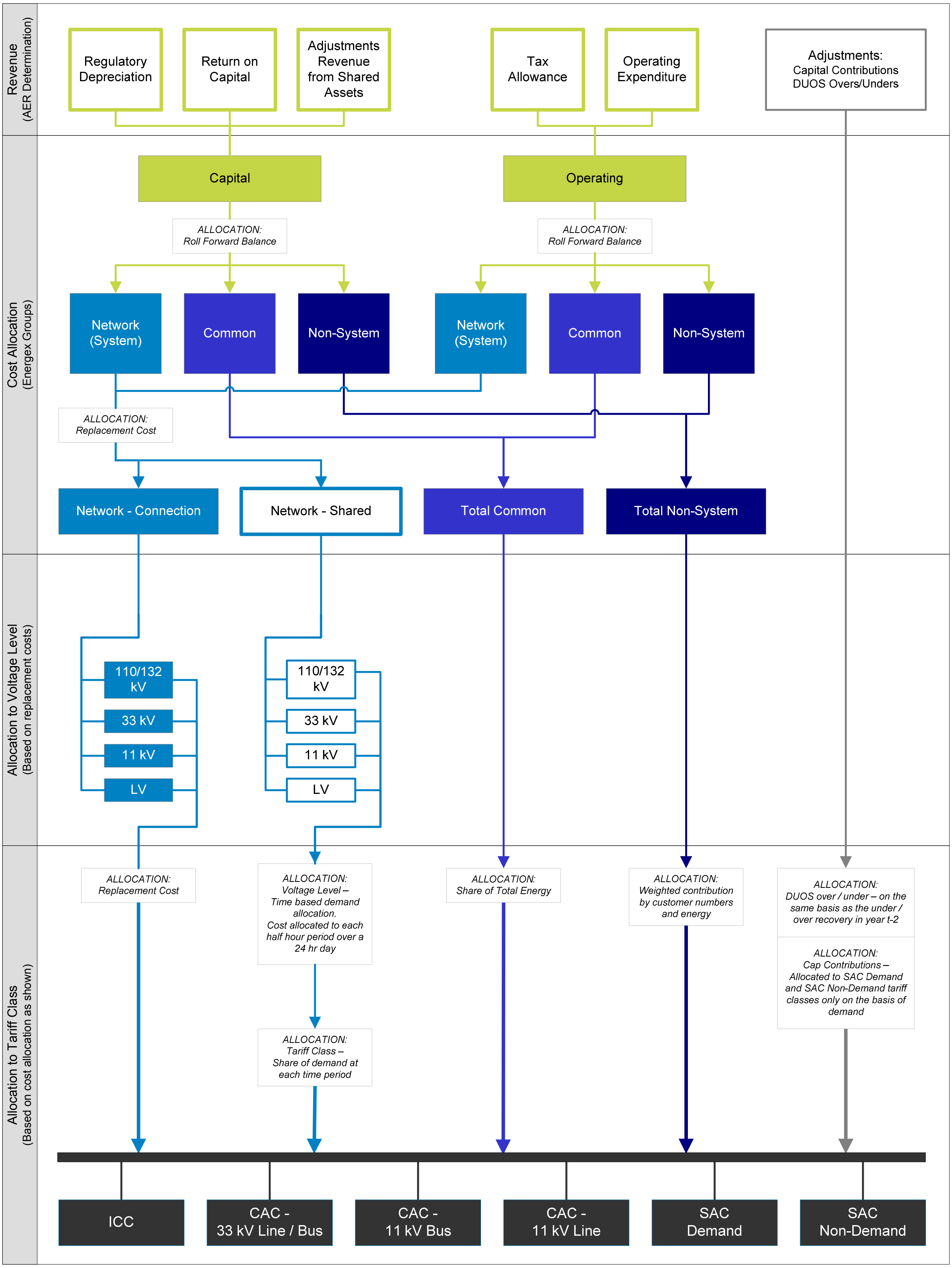
The amount attributed to each component is provided in Energex's 2014/15 Pricing Proposal. The purpose of the tariff cost allocation process is to allocate or assign the network costs to the tariff classes in the most economically efficient and cost-reflective way.

The major steps in the process are:

- Step 1 – Allocate AER building blocks to Energex DCOS cost groups
- 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-3.1 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-3.1 - Cost allocations to tariff classes



### 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 cost 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. Each ICC is then allocated a share of upstream shared network. This is based on the ratio of the customer's individual demand to the total demand of the respective supply (substation).

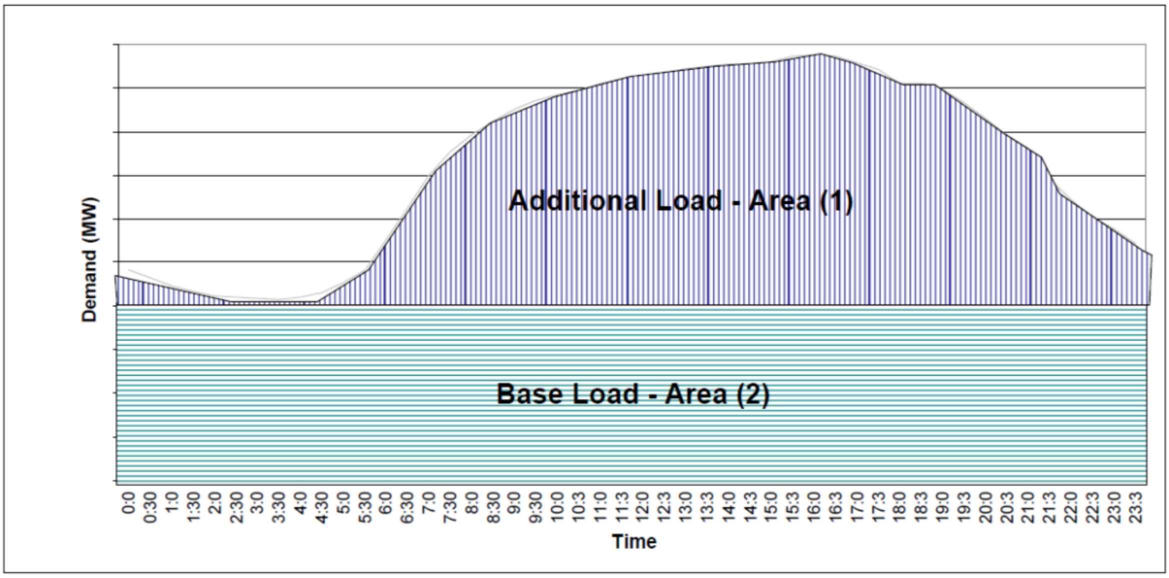
The ratio is then applied to the replacement cost of system assets within the supply network to which the individual customer is connected.

### 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 a weighted average of replacement value of sunk assets, and LRMC-based augmentation.

Network costs (capital and operating) are allocated to time periods based on the level of demand for that period. The basic principle is that the cost of providing the network (for system costs) should be allocated to the time periods when it is being utilised. Accordingly there is a "base load" that uses a proportion of the network all the time (Area 2 on Figure A-3.2). The cost of this base load of network can be recouped across all time periods. On the other hand, the extra network constructed for other periods, including the peak, should be recouped across the time periods when this is used (Area 1 on Figure A-3.2).

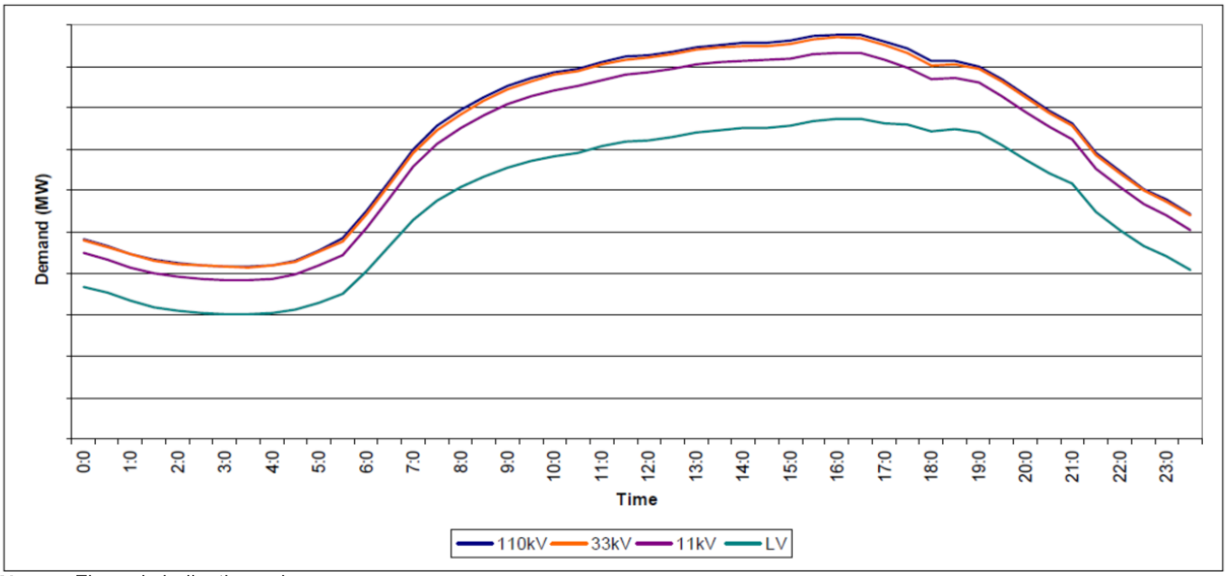
**Figure A-3.2 - Time based cost allocation approach**




**Note.** Figure is indicative only.

Meter data is obtained for all interval-metered customers (110/132 kV, 33 kV, 11 kV and LV Demand). From this meter data, an estimated peak daily load profile is obtained for each voltage level, as illustrated in Figure A-3.3.

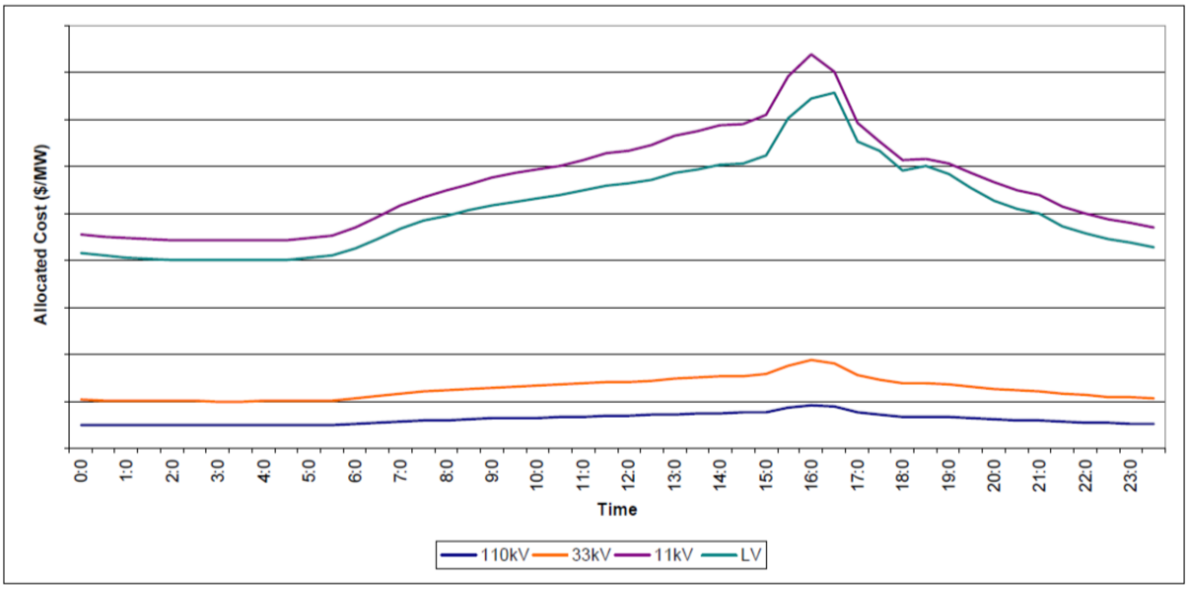
**Figure A-3.3 - Demand profiles by voltage level**




**Note.** Figure is indicative only.

Costs are allocated across daily half hour periods (48 periods) based on an estimate of the peak daily load profile for each voltage level. More costs are allocated to periods with a higher demand on the network, as shown in Figure A-3.4.

**Figure A-3.4 - Daily cost allocation by voltage level ($/MW)**




**Note.** Figure is indicative only.

### Step 3 – Allocated costs to tariff classes

There are several SCS tariff classes[18] to which network costs are allocated:

- ICC
- CAC – 33 kV
- CAC – 11 kV Bus
- CAC – 11 kV Line
- EG
- SAC Demand
- SAC Non-Demand.

**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.

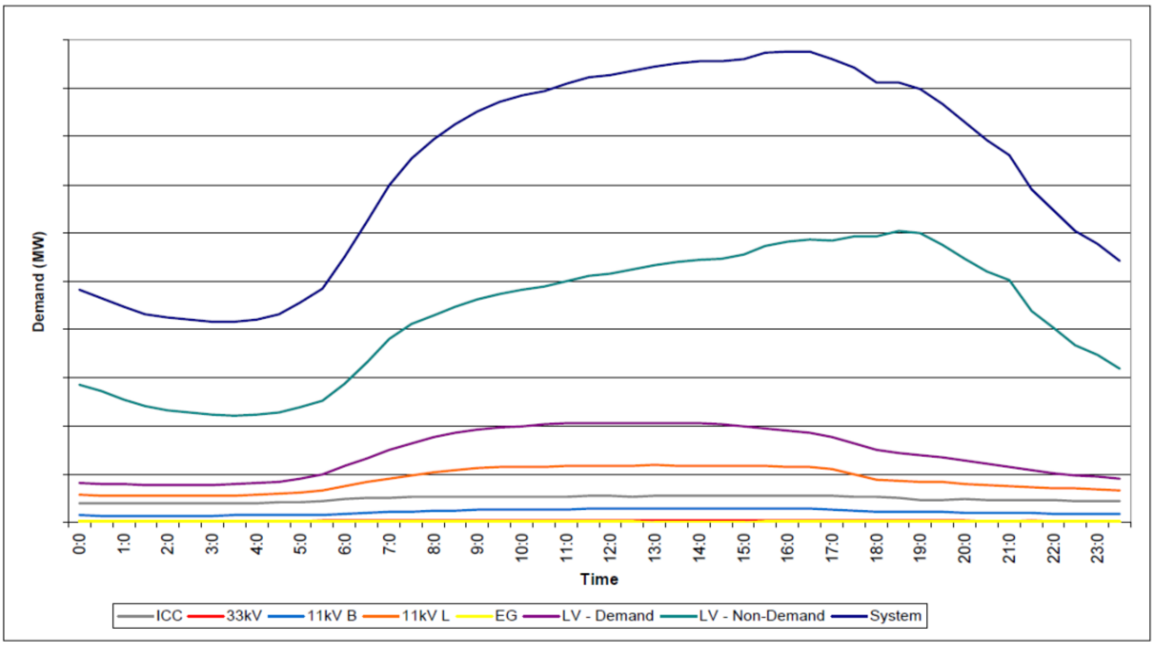
***Shared network***

With the exception of ICCs, the cost for each voltage level during each time period is allocated to each tariff class based on their share of demand at that time. This results in a daily cost allocation for each tariff class for each time period. The total across all periods is then aggregated as the cost allocated to each tariff class as illustrated in Energex's 2014/15 Pricing Proposal.

A period demand (ToU) allocation has been used for the shared system costs as it reflects the fact that demand is the primary driver of shared network costs. Using a period demand allocates costs of the network to the time periods when it is being utilised. This method reflects the impact that demand (particularly peak demand) has on increasing network investment. Demand profiles for each of the SCS tariff classes are shown in Figure A-3.5 and the daily cost allocation by tariff class is shown in Figure A-3.6.

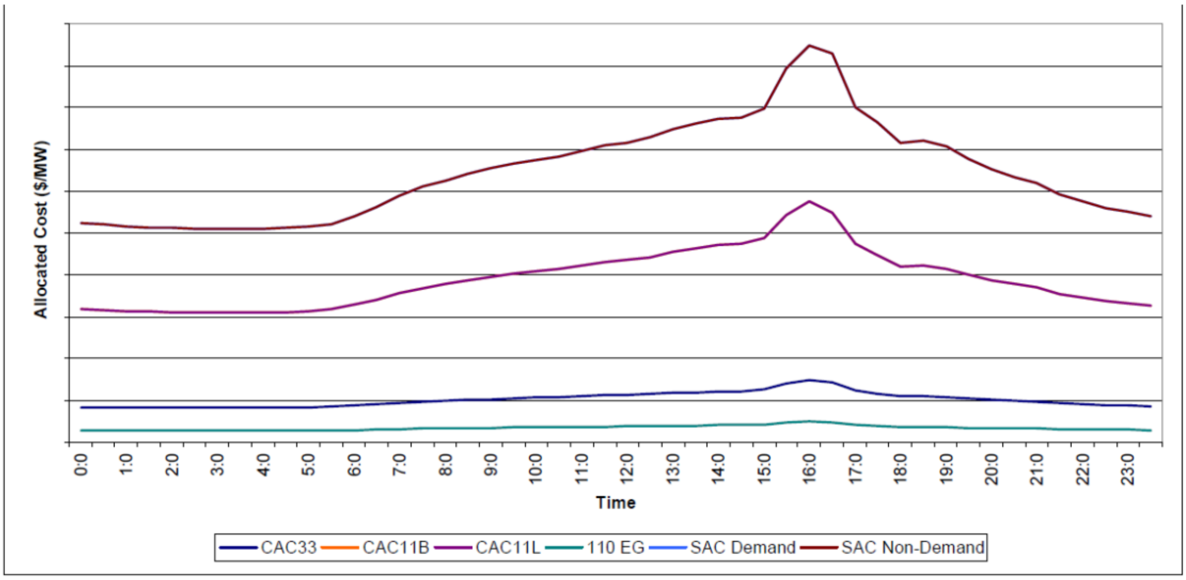
[18] For more information about Energex's tariff classes, refer to Table 3.1 in Energex's 2014/15 Pricing Proposal (Chapter 3, Section 3.1).

### Figure A-3.5 - Demand profiles by tariff class




**Note.** Figure is indicative only.

### Figure A-3.6 - Daily cost allocation by tariff class ($/MW)




**Note.** Figure is indicative only.

## *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%) and total energy (25%) 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. Tariff (charging parameter) cost allocation process

Following the cost 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 tariff (charging parameter) cost allocation process is to allocate or assign the costs to each parameter in the most efficient and cost-reflective way. Section 1 of this Appendix sets out the process utilised by Energex for the allocation of costs to charging parameters.

The process for cost allocation involves two major steps:

- Step 1 – Allocate tariff class costs to individual tariffs
- Step 2 – Allocate tariff costs to charging parameters.

These steps are undertaken for each tariff class and are illustrated in Figures A-3.7, A-3.8 and A-3.9.

**Figure A-3.7 - Cost allocation approach: ICC, CAC and EG tariff classes**

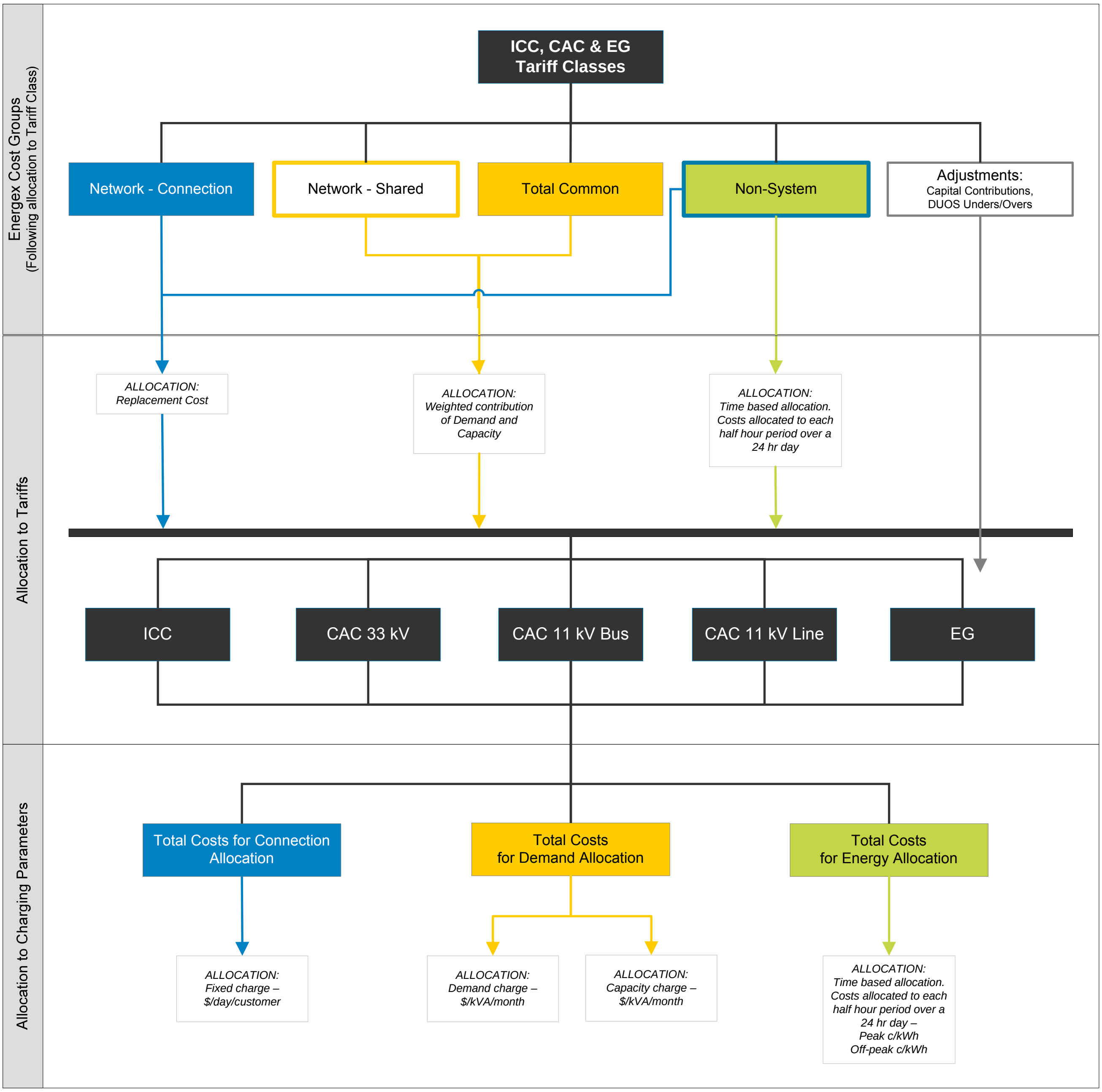
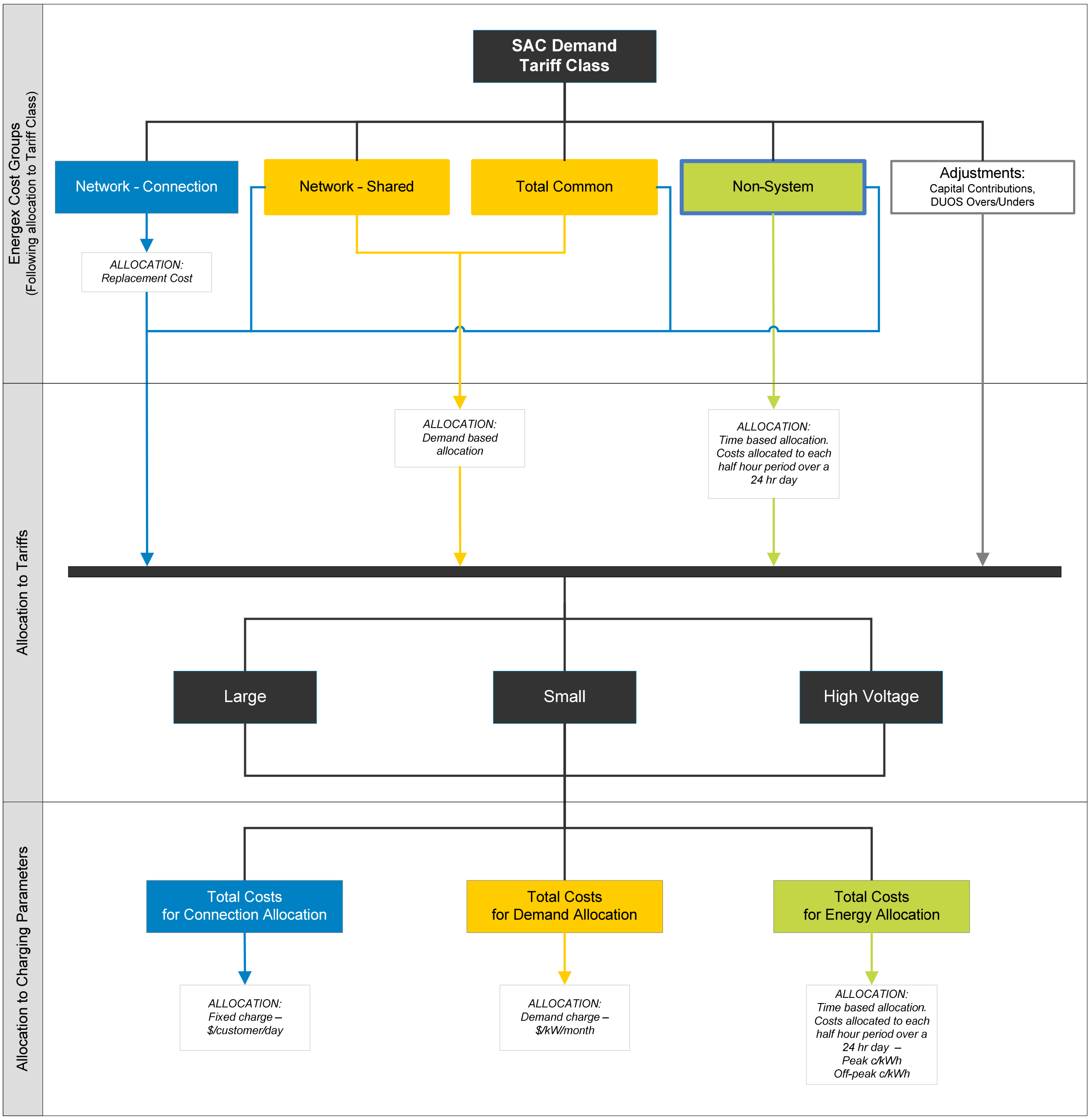
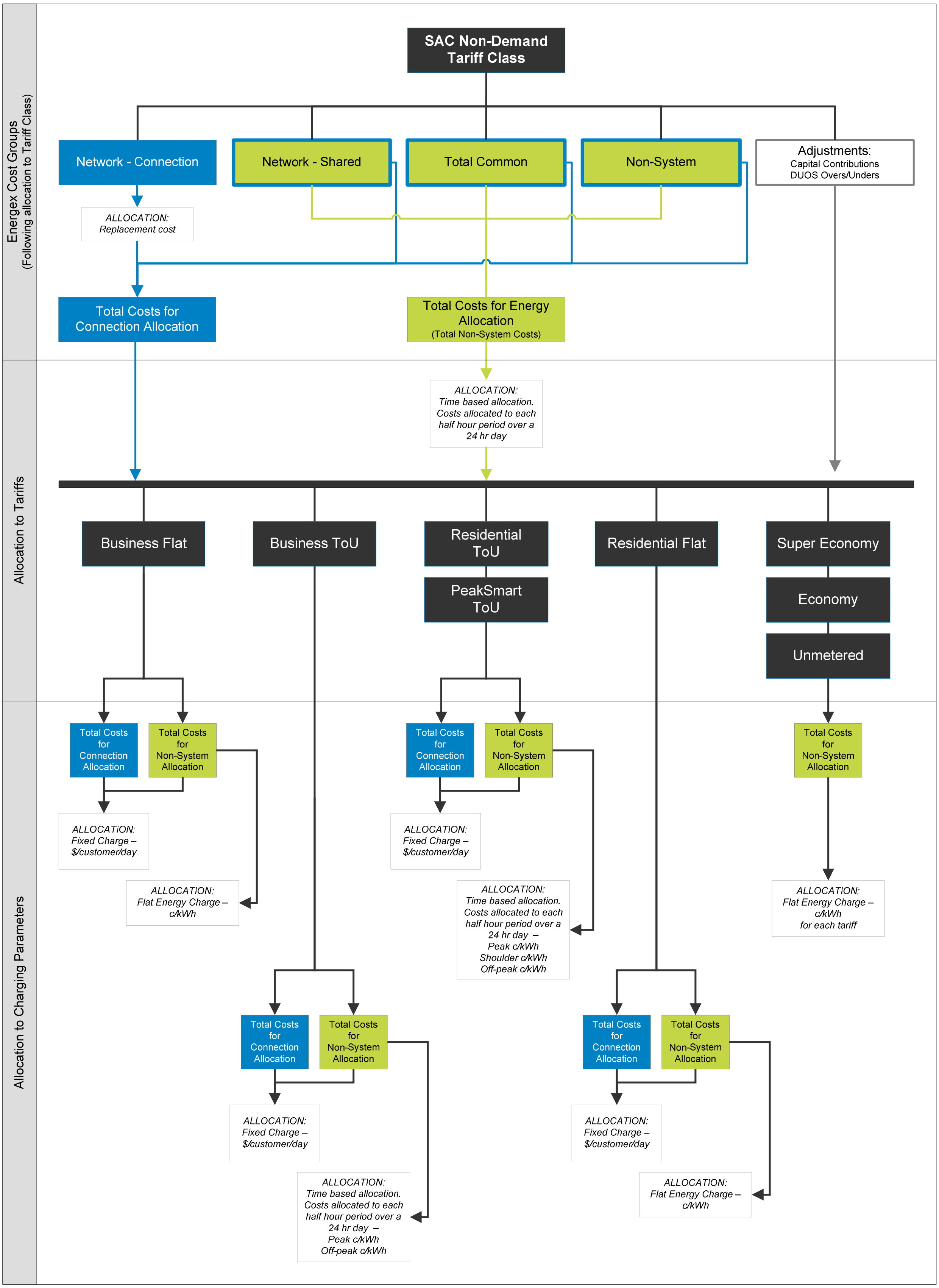


**Figure A-3.8 - Cost allocation approach: SAC Demand tariff class**



## Figure A-3.9 - Cost allocation approach: SAC Non-Demand tariff class



**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 4 -
# Summary of compliance

# Appendix 4 – Summary of compliance

**Table A-4.1 - Compliance with the National Electricity Rules**

| Clause | Requirement | Reference |
|---|---|---|
| 6.1.4(a) | Demonstrates that Energex does not charge a Distribution Network User DUOS charges for the export of electricity generated by the user into the distribution network. | Figure 3.1<br>Chapter 4<br>s 4.2.1 and s 4.3<br>Table 4.3 |
| 6.1.4(b) | Demonstrates that Energex charges for the provision of connection services as allowed in the *Rules.* | Chapter 4<br>s 4.2.1 and s 4.3 |
| 6.18.2(b)(1) | Sets out each tariff class (including the classes of alternative control services). | Chapter 3<br>s 3.1 and Table 3.1<br>Chapter 11<br>s 11.1 and Table 11.1 |
| 6.18.2(b)(2) | Sets out the proposed tariffs for each tariff class. | Chapter 3<br>s 3.1 and Table 3.1<br>Figure 3.1<br>Chapter 4<br>s 4.3<br>Chapter 11<br>s 11.1 and Table 11.1<br>Chapter 12<br>s 12.1, 12.2, 12.3<br>Appendix 1<br>A 1.1 and A 1.2 |
| 6.18.2(b)(3) | Sets out, for each proposed tariff, the charge parameters and the elements of service to which each charging parameter relates. | Chapter 4<br>s 4.2.1<br>Table 4.2, Table 4.3 and Table 4.5<br>Chapter 12<br>s12.1.3, s12.2.3, s12.3.3 and<br>Equation 12.1 |
| 6.18.2(b)(4) | Sets 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<br>Table 5.1 |
| 6.18.2(b)(5) | Sets 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 9<br>s 9.5 |

| Clause | Requirement | Reference |
|---|---|---|
| 6.18.2(b)(6) | Sets out how DPPC 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 4<br>s4.2.2 and Table 4.5<br>Chapter 8 |
| 6.18.2(b)(6A) | Sets 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 2<br>s 2.2.5 |
| 6.18.2(b)(6B) | Describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria. | Chapter 2<br>s 2.2.5 |
| 6.18.2(b)(7) | Demonstrates compliance with the *Rules* and any applicable distribution Determination. | Appendix 4<br>A 4.1 and A 4.2 |
| 6.18.2(b)(8) | Describes the nature and extent of change from the previous regulatory year and demonstrates that the changes comply with the *Rules* and any applicable distribution Determination. | Chapter 9 |
| 6.18.3(a) | Define the tariff classes into which customers for direct control services are divided. | Chapter 3<br>s 3.1 and Table 3.1<br>Chapter 4<br>s 4.1 and Table 4.1.<br>Chapter 11<br>s 11.1 and Table 11.1 |
| 6.18.3(b) | Demonstrates that each customer for direct control services is a member of at least one tariff class. | Chapter 3<br>s 3.1.1<br>Chapter 11<br>s 11.1 |
| 6.18.3(c) | Sets out separate tariff classes for standard control and alternative control customers. | Chapter 3<br>s 3.1 and Table 3.1<br>Chapter 11<br>s 11.1 and Table 11.1 |
| 6.18.3(d)(1) | Demonstrates that tariff classes are formed based on groupings of customers on an economically efficient basis. | Chapter 3<br>s 3.1<br>Chapter 11<br>s 11.1 |
| 6.18.3(d)(2) | Demonstrates that customers and tariffs are grouped into tariff classes with regard to the need to avoid unnecessary transaction costs. | Chapter 3<br>s 3.1<br>Chapter 7<br>s 7.3<br>Chapter 11<br>s 11.1 |

| Clause | Requirement | Reference |
|---|---|---|
| 6.18.4(a)(1)(i), (ii) and (iii) | Demonstrates 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 3<br>s 3.2.1 and Figure 3.1 |
| 6.18.4(a)(2) | Demonstrates that customers with a similar usage and connection profile are treated on an equal basis. | Chapter 3<br>s 3.2.1 |
| 6.18.4(a)(3) | Demonstrates that customers with micro-generation facilities are treated no less favourably than customers without such facilities. | Chapter 3<br>s 3.2.2 |
| 6.18.4(a)(4) and (b) | Demonstrates that customer assignment (or reassignment) to a tariff class does not occur in the absence of an effective system of assessment and review. | Chapter 3<br>s 3.2.4 |
| 6.18.4(b) | Demonstrates 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. | Chapter 3<br>s 3.2.4 |
| 6.18.5(a)(1) and (2) | Demonstrates that revenue from a tariff class lies between the stand alone and avoidable cost. | Chapter 7<br>s 7.1 and Table 7.2<br>Chapter 12<br>s 12.2.6 |
| 6.18.5(b)(1) | Demonstrates that tariffs and tariff components have regard for long-run marginal cost. | Chapter 7<br>s 7.2 and Equation 7.1<br>Chapter 12<br>s 12.2.5 |
| 6.18.5(b)(2)(i) | Demonstrates that tariffs and tariff components have regard for the transaction costs to customers. | Chapter 7<br>s 7.3 |
| 6.18.5(b)(2)(ii) | Demonstrates that tariffs and tariff components are set with regard to whether customers are able or likely to respond to price signals. | Chapter 7<br>s 7.4 |
| 6.18.5(c) | Demonstrates 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 with minimum distortion to efficient patterns of consumption. | Chapter 7<br>s 7.5 |
| 6.18.6(b) | Demonstrates that the weighted average revenue for a standard control tariff class does not exceed that for the previous year by more than the "permissible percentage" defined in clause 6.18.6(c) of the *Rules*. | Chapter 6<br>Table 6.1 |

| Clause | Requirement | Reference |
|---|---|---|
| 6.18.6(c)(1) and (2) | Demonstrates the “permissible percentage” has been calculated in accordance with the definition set out in this clause of the *Rules*. | Chapter 6<br>Equation 6.1 |
| 6.18.6(d)(1) and (2) | Demonstrates that Designated Pricing Proposal Charges and pass-throughs were removed from the calculation of the side constraint. | Chapter 6<br>Equation 6.1 |
| 6.18.7(a) | Demonstrates that tariffs passed on to customers include the charges to be incurred by Energex for transmission use of system services. | Chapter 4<br>s 4.2.2<br>Table 4.5<br>Chapter 8 |
| 6.18.7(b) | Demonstrates 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 8<br>s 8.3, Table 8.1 |
| 6.18.7(c)(1) , (2) and (3) | Demonstrates that any DPPC over or under recovery is the difference between what was paid to Powerlink and what was recovered from customers via DPPC charges and is adjusted for an appropriate cost of capital consistent with the allowed rate of return. | Chapter 8<br>s 8.3, Table 8.1 |
| 6.18.7A | The pricing proposal provides for tariffs designed to pass on jurisdictional scheme amounts to customers. | Chapter 2<br>s 2.2.5 |
| 6.18.9(a)(1) | The tariff classes and the applicable tariffs (or prices) are published on Energex’s website. | Chapter 14 |
| 6.18.9(a)(2) | 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 are published on Energex’s website. | Chapter 14 |
| 6.18.9(a)(3) | The manner in which tariffs are expected to change over the remainder of the Regulatory Control Period, and the reasons for the changes, are published on Energex’s website. | Chapter 14 |
| 6.18.9(b) | The information set out in clause 6.18.9(a) is published on Energex’s website 20 days prior to the start of the relevant regulatory year or as soon as practicable thereafter. | Chapter 14 |

**Table A-4.2 - Compliance with the Final Determination**

| Section | Requirement | Reference |
|---|---|---|
| Section 2.5.2 | Energex to follow the procedure for assigning customers to tariff classes or reassigning customers from one tariff class to another as specified in Appendix B of the Final Determination. | Chapter 3<br>s 3.2, Figure 3.1,<br>s 3.2.3 and s 3.2.4 |
| Section 4.5.2 | Demonstrates that the proposed DUOS prices for the next year (t) will meet the side constraints formula set out in Section 4.5.2 of the Final Determination. | Chapter 6<br>Equation 6.1, Table 6.1 |
| Section 4.6 | Include a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with Appendix E of the Final Determination. | Chapter 8 |
| Section 17.3.3 | Include the revenues collected from the provision of each street light service in the preceding regulatory year. | Appendix 2<br>A-2.2 |
| Section 18.3.3 | Calculate the respective internal and external labour cost escalators for each regulatory year of the next Regulatory Control Period and provide both qualitative and quantitative supporting information to the AER as part of the annual pricing proposals. | Appendix 2<br>A-2.1 |
| Section 18.3.4 | Calculate the on cost and overhead rates in each regulatory year of the next Regulatory Control Period in accordance with the methodologies set out in the CAM and submit both qualitative and quantitative supporting information to the AER as part of the annual pricing proposal. | Appendix 2<br>A-2.1 |
| Section 18.3.5 | Include the volume of fee-based and quoted services provided and the revenues recovered from the provision of fee-based and quoted services in the preceding regulatory year. | Appendix 2<br>A-2.2 |
| Section 18.3.5 | Sets out the nature and extent of any variation to an individual formula component, on cost or overhead rate from that applicable in the previous regulatory year that is above the indicative illustrative quoted service examples and fee-based services set out in Appendix I, J and K of the final decision. | Appendix 2<br>A-2.1 |
| Section 18.3.5 | Sets out in its pricing proposal the nature and extent of any variation or adjustment to the methodology employed to derive a formula component escalator or on cost or overhead rate. | Appendix 2<br>A-2.1 |
| Appendix D | Maintain a distribution use of system (DUOS) overs and unders account. Energex must provide information on this account to the AER as part of its annual pricing proposals. | Chapter 2<br>s 2.2.3, Table 2.4 |
| Appendix E | Maintain a transmission use of system (TUOS) overs and unders account. Energex must provide information on this account to the AER as part of its annual pricing proposals. | Chapter 8<br>s 8.3, Table 8.1 |

# APPENDIX 5 -
## Glossary

# Appendix 5 – Glossary

**Table A-5.1 – Acronyms and abbreviations**

| Abbreviation | Description |
|---|---|
| ABS | Australian Bureau of Statistics |
| A/C | Air-conditioning |
| ACS | Alternative Control Service |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| AH | After Hours |
| AIC | Average Incremental Cost |
| BH | Business Hours |
| CAB | Contributed Asset Base |
| CAC | Connection Asset Customers |
| CAM | Cost Allocation Method |
| Capex | Capital Expenditure |
| CPI | Consumer Price Index |
| CSO | Community Service Obligation |
| DCOS | Distribution Cost of Supply |
| DLF | Distribution Loss Factor |
| DNSP | Distribution Network Service Provider |
| DPP | Dynamic Peak Pricing |
| DPPC | Designated Pricing Proposal Charges (previously known as TUOS) |
| DRR | Demand Response Ready |
| DUOS | Distribution Use of System |
| EG | Embedded Generators |
| ENA | Energy Network Australia |
| ENCAP | Electricity Network Capital Program |
| FiT | Feed-in Tariff (Solar PV) |
| HV | High Voltage |
| IAP2 Spectrum | International Association for Public Participation |
| ICC | Individually Calculated Customers |
| LCC | Large Customer Connection |
| LRMC | Long-Run Marginal Cost |
| LV | Low Voltage |

| Abbreviation | Description |
|---|---|
| MAR | Maximum Allowable Revenue |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NER | National Electricity Rules (or *Rules)* |
| NMI | National Meter Identifier |
| NSW | New South Wales |
| NTC | Network Tariff Code |
| NUOS | Network Use of System |
| O&M | Operating and Maintenance Allowance (Opex) |
| Opex | Operational Expenditure |
| PFA | Power Factor Adjustment |
| PV | Photovoltaic (Solar PV) |
| PV | Present Value |
| QAO | Queensland Audit Office |
| QCA | Queensland Competition Authority |
| QESI | Queensland Electricity Supply Industry |
| RAB | Regulatory Asset Base |
| RBT | Reward-Based Tariff |
| *Rules* | National Electricity Rules (or NER) |
| SAC | Standard Asset Customers |
| SACD | Standard Asset Customers (demand) |
| SCI | Statement of Corporate Intent |
| SCS | Standard Control Service |
| SEQ | South East Queensland |
| SRMC | Short-Run Marginal Cost |
| STPIS | Service Target Performance Incentive Scheme |
| TNCP | Transmission Network Connection Point |
| TNSP | Transmission Network Service Provider |
| ToU | Time of Use |
| TUOS | Transmission Use of System |
| WACC | Weighted Average Cost of Capital |
| WAR | Weighted Average Revenue |

Table A-5.2 - 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-5.3 - 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-5.4 - 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, including in reference to the PeakSmart ToU tariff. |
| Alternative Control Service | ACS | This service class includes the provision, construction and maintenance of street lighting assets, and fee-based and quoted services. |
| Australian Bureau of Statistics | ABS | The ABS is Australia's national statistical agency that provides key statistics on a wide range of economic, environmental and social issues. |
| 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. |
| Australian Energy Regulator | AER | The economic regulator of the national electricity market 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. |
| Capacity - network | | The maximum demand (kW) that the distribution network can provide for at any one time. |
| Capital expenditure | | 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 and benefits all distribution customers and cannot reasonably be allocated on a locational basis. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| Connection Asset Customer | CAC | Typically, those customers with electricity consumption greater than 4 GWh, but less than 40 GWh, per year at a single connection point; or where demand is greater than or equal to 1 MVA; or where a customer has a dedicated supply system with significant connection assets or the customer has contributed to their dedicated connection assets. |
| CAC 11Line | | CAC customer where the point of connection to the electricity distribution network is on the 11 kV line shared between other customers. |
| CAC 11Bus | | CAC customer where the point of connection to the electricity distribution network is directly to the 11 kV Bus. The customer is supplied by a dedicated connection that is not shared with any other customer directly from the substation. |
| 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 point of electrical coupling between the electricity distribution network and a customer's electrical installation. The meter is installed as close as possible to this location. |
| Customer | | At Energex we define our customers through their mutual relationships with us. Through the diversity of our local and broader influences, they are the many who influence how we make decisions and provide services to our region. Energex has categorized customers into 4 broad categories: Community and Connected Customers (who we do work for) & Stakeholders and Partners (who we do work with). |
| 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:<br>• a fixed dollar price per kW per month or kVA per month for DPPC charges, and<br>• a fixed dollar price per kVA per month for DUOS charges (ICC, CAC and EG customers) or<br>• a fixed dollar price per kW per month for DUOS charges (SAC Demand customers) |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| Demand-metered SAC | | The customer’s connection point has a meter installed that is capable of measuring energy consumption (kWh) and demand (kW). This meter records total energy consumption (kWh) and demand over 30 minute periods. A customer’s demand is the average demand (kW) over the 30 minute period. |
| Demand-metered 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. The highest demand reading for that month is used to calculate the customer’s electricity bill. |
| Demand Response Ready | DRR | A DRR appliance, such as a PeakSmart A/C unit, is fitted with a signal receiver that allows demand management of these appliances by Energex. |
| Distribution Cost of Supply Model | DCOS | The Energex model used to allocate costs approved by the AER to the various tariff classes. |
| Distribution Loss Factor | DLFs | These represent the average electrical energy losses incurred when electricity is transmitted over a distribution network. |
| Distribution Use of System | DUOS | This refers to the network charges for the use of the distribution network. |
| 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). |
| Economy | | Specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Energex. |
| Embedded Generator | EG | In line with the ENA classification, EGs are generally those generators with an installed capacity as follows:<br>Medium: 1-5 MVA (LV or HV) or < 1 MVA (HV)<br>Large: > 5 MVA |
| Electricity Network Capital Program Review | ENCAP | The ENCAP Review was commissioned by the Queensland Government in late 2011. An independent panel was established to undertake a review of the capital infrastructure programs of Energex, Ergon Energy and Powerlink with the view to achieving efficiencies and cost savings while maintaining network security and reliability.<br>The panel identified significant potential capital expenditure savings and Energex’s program of capital work was reduced in line with these findings. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| 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). |
| 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. |
| 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. |
| Form 1634 – QESI | | An Energex form, "Queensland Electricity Supply Industry (QESI) – Application for Review" which allows a customer's retailer to request a change to the customer's NTC or NMI Classification. |
| High Voltage | HV | Refers to the 11 kV or above network. |
| Individually Calculated Customer | ICC | Typically those customers with electricity consumption greater than 40 GWh per year at a single connection point; or where the customers demand is 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 Associated for Public Participation Spectrum | IAP2 Spectrum | The approach used by Energex to incorporate customer engagement actives into our decision making processes has been designed using the IAP2 Spectrum© and the associated five step planning process.<br><br>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. A customer in this sense is any individual, organisation or political entity with an interest in the outcome of the decision.<br><br>© 2006, International Association for Public Participation www.iap2.org |
| Large customer classification | | As per tariff class assignment process for customers with consumption greater than 100 MWh per year. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| Large customer connection | | New or upgraded connections of greater than 1 MVA or 4 GWh per year, or where the uniqueness of the connection assets would result in distortion of the SAC pricing. |
| Long-Run Marginal Cost | LRMC | An estimate of the cost (long term variable investment) of augmenting the existing network to provide sufficient capacity for one additional customer to connect to the network or an additional MW of demand. |
| Low Voltage | LV | Refers to the sub-11 kV network |
| Maximum Allowable Revenue | MAR | The maximum revenue which can be recovered through tariffs for the regulatory year. |
| 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<br>(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 Tariff Code | NTC | Energex's nominated code that represents the network tariff being charged to customers for network services. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| 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 Charges (DPPC). |
| Non-Demand metered SAC | | The customer's connection point has a meter installed that is capable of measuring the total energy consumption (kWh). |
| Non-Demand metered tariff | | The tariff is based around a fixed daily component and the actual energy (kWh) used by the customer. |
| Off-peak period | | All hours which are outside Peak and Shoulder periods. |
| Operational 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): The hours between 7 am and 11 pm, Monday to Friday.<br>Meter type 6 (SAC Non-Demand - Business): The hours between 7 am and 9 pm, Monday to Friday.<br>Meter type 6 (SAC Non-Demand - Residential): The hours between 4 pm and 8 pm, Monday to Friday. |
| PeakSmart A/C | | A PeakSmart A/C unit is a DRR A/C unit that, when its signal receiver is activated, allows it to be demand managed by Energex. In addition to other criteria, eligibility for the PeakSmart ToU tariff includes a customer activating at least one PeakSmart A/C at their premise. |
| 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.<br>Power factor = kW / kVA |
| 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 and to provide clarity when formulating tariffs. |
| Pricing principles | | The pricing principles are established in Clause 6.18.5 of the NER and provide guidance to Energex for setting tariffs. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| Pricing Proposal | | This document. Prepared by Energex in accordance with Clause 6.18.2(a)(2) of the *Rules*, it is provided to the AER for approval and outlines how Energex will collect its revenue during the relevant regulatory year. |
| Queensland Government Solar Bonus Scheme | | 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 2010-2015, as per the Final Determination. |
| 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. |
| Reward Based Tariff | RBT | A reward-based tariff provides a strong price signal to customers to drive changes in customer behaviour. If changes are achieved, the customer is rewarded by way of a financial incentive. |
| Revenue cap | | The amount of revenue Energex is approved by the AER to recover during the Regulatory Control Period and specific regulatory years. |
| 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 | | Meter type 6 (SAC Non-Demand – Residential): The hours between 7 am to 4 pm and 8 pm to 10 pm, Monday to Friday and 7 am to 10 pm weekends. |
| Side constraint | | A side constraint is an upper limit on price increases applied at the tariff class level and is calculated 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. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| 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. |
| 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 with annual electricity consumption below 4 GWh per year, whose supply arrangements are consistent across the customer group; and where there is no contribution for their dedicated connection assets. SAC Non-Demand are customers within SAC with consumption less than 100 MWh per year and who are on consumption (kWh) tariffs. SAC Demand are customers within SAC with consumption greater than 100 MWh per year and less than 4 GWh per year and who are on demand (kW) tariffs. |
| Standard Control Service | SCS | This service class includes network, connection and metering services. |
| Statement of Corporate Intent | SCI | The SCI is published at least annually and represents the agreement between Energex's Board of Directors and the shareholding Minister's on Energex's Performance in the relevant financial year in support of the state reform agenda. It is prepared in accordance with Section 7(2) of the *Government Owned Corporates Act 1993* (Queensland). |
| Street lights (Major) | | Lamps in common use for major road lighting including:<br>a) High Pressure Sodium 100 watt (S100) and above;<br>b) Metal Halide 150 watt (H150) and above; and<br>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 | | 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 7:00 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. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| 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 the *Rules* definition). |
| 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. |
| Time of use | ToU | Refers to tariffs that vary according to the time of day at which the electricity is consumed. |
| 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. |
| Volume (energy) 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. |
| Volume (energy) charge (Off-peak) | | This charge is applicable to those customers who are on a Residential and/or Business Time of Use 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. |
| Volume (energy) charge (Peak) | | This charge is applicable to those customers who are on a Residential and/or Business Time of Use 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. |
| Volume (energy) charge (Shoulder) | | This charge is applicable to those customers who are on a Residential Time of Use 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. |

| Term | Abbreviation / Acronym | Definition |
|---|---|---|
| Weighted Average Cost of Capital | WACC | The minimum return a business must earn on an existing asset base. For Energex, the WACC is set by the AER in its Final 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. |