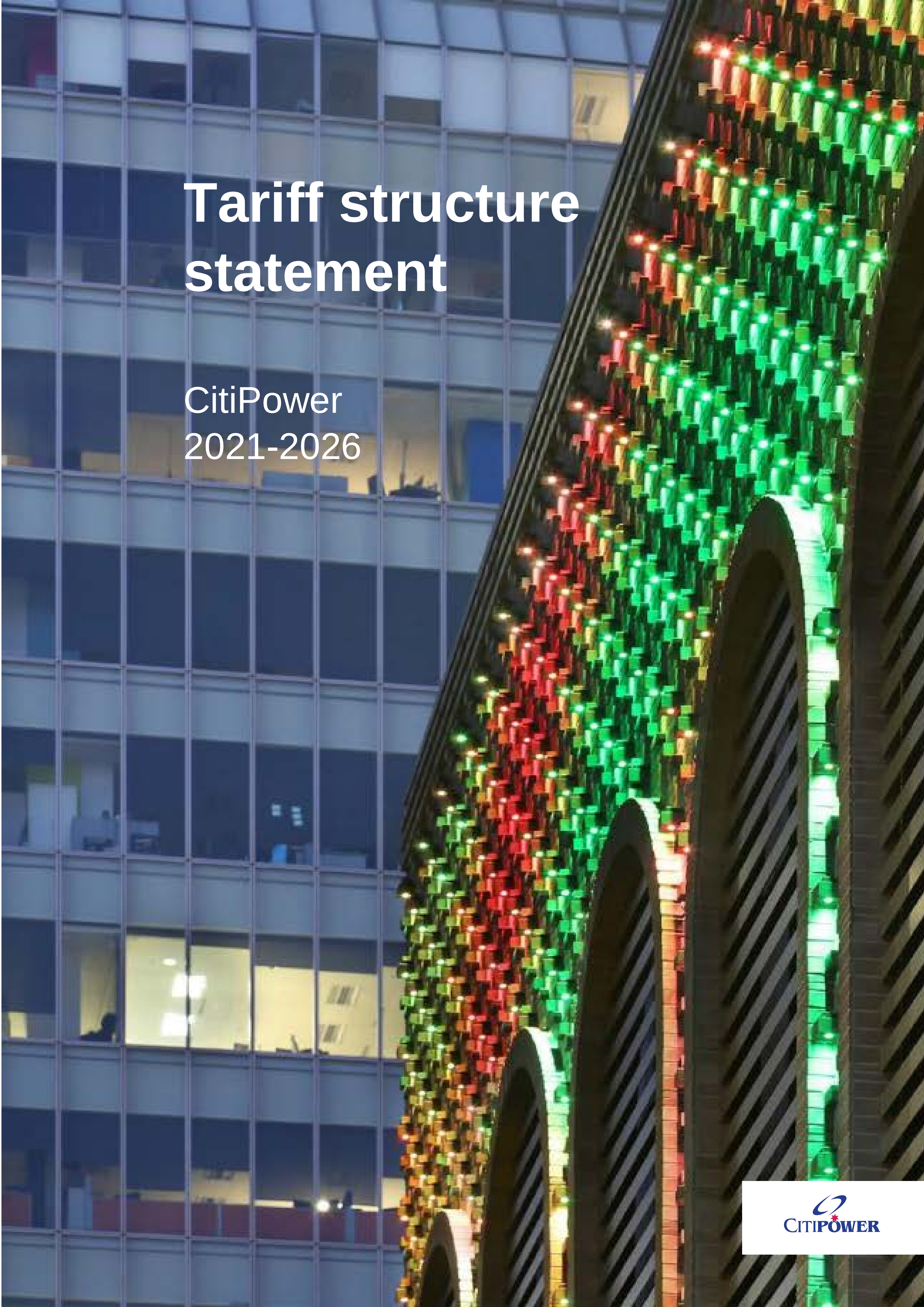
Tariff structure statement

CitiPower
2021-2026



Contents

1 About this tariff structure statement

1.1 Introduction

CitiPower is submitting this Tariff Structure Statement (TSS) to the Australian Energy Regulator (AER) in accordance with the requirements of the National Electricity Rules (the Rules).

1.2 Structure of this TSS

CitiPower's TSS structure is presented in the table below:

Chapter	Title	Purpose
2	Tariff classes and assignment policies	Description of the structure and purpose of the document
3	Structure and charging parameters	The structure and charging parameters for our tariffs are set out in this section in addition to the policies and procedures for assigning retail customers to tariffs
4	Approach to setting tariffs	This section describes our approach to setting tariffs, charging parameters and windows as well as calculation of avoided and stand alone cost and estimation of LRMC
A1	Glossary	This section provides definition for some key terms used in TSS
A2	Long run marginal cost	A description of how long run marginal cost was calculated and the results
A3	Indicative pricing schedule	This section sets out indicative prices for the regulatory control period
A4	Alternative control services	A description of alternative control services and how we will charge for them
A5	Compliance checklist	This section sets out a checklist that identifying where each of the TSS Rule Requirements are met in this submission

2 Tariff classes and assignment policies

2.1 Tariff classes

Standard control services are categorised into five tariff classes.

- residential
- small and medium business
- large low voltage
- high voltage
- sub-transmission

Figure 1 Tariff classes

	Tariff class	Supply voltage	Maximum demand
	Residential	< 1 kV	N/A
	Small and medium business	< 1 kV	< 120 kVA
	Large low voltage	< 1 kV	> 120 kVA
	High voltage	1 kV – 22kV	N/A
	Sub-transmission	≥ 22 kV	N/A

All alternative control services are a separate asset class.

2.2 Allocation of customers to tariff classes

Assignment of existing customers to tariff classes

- Each customer immediately prior to 1 July 2021 will be taken to be "assigned" to that tariff class from 1 July 2021.

Assignment of new or modified connections to a tariff class

- The process under which new customers are assigned to network tariff classes occurs following the receipt of a connection application by the customer or their retailer. A customer that lodges an application to modify or upgrade an existing network connection from single to three-phase or upgrades their connection to a bi-directional flow is treated identically to a new customer.
- If CitiPower becomes aware of new or modified connection, then CitiPower will determine the tariff class to which the customer of that connection will be assigned in accordance with the eligibility criteria in this tariff structure statement.

Reassignment of existing customers to tariff classes

- Checks that existing customers meet the eligibility criteria for their tariff class will be periodically conducted.
- If a customer clearly does not meet the eligibility criteria, they will be transferred to the appropriate tariff class following the notification process below.

Notification of proposed reassignments

- The customer's retailer will be notified in writing of an intended reassignment of a customer to another tariff class.
- If a request for further information is received from a customer's retailer, then it will be provided within a reasonable timeframe.
- If an objection is received from the customer's retailer, the reassignment will be reconsidered taking into account the relevant facts, and the customer's retailer will be notified in writing of the reconsidered decision and the reasons for that decision.

2.3 Tariff assignment policies

2.3.1 Residential

We will assign the following customers onto a new two-rate time-of-use (ToU) tariff, with a peak period occurring between 3pm to 9pm local time all days and off peak applying at all other times (default ToU):

- New connections (i.e. new homes connecting to the network for the first time, not re-energisations)
- Customers who choose to upgrade from single-phase to three-phase supply
- Customers who choose to install or upgrade PV solar or batteries
- Customers on existing legacy[1] or flexible time of use tariffs
- Electric vehicles and/or electric vehicle chargers in accordance with any Victorian Government Order.

[1] Customers on basic meters will be reassigned to single rate tariff as at 1 July 2021

Any customer with an AMI meter can opt into the new TOU tariff. Customers can opt out of the new TOU tariff to a single rate tariff or a demand tariff.

A secondary dedicated circuit tariff is available for eligible load.

The following table summarises all the residential tariffs.

Figure 2 Residential tariff summary

Proposed tariffs	Proposed assignment	Tariff options
Default ToU	New connections Supply upgrades to three-phase Households installing or upgrading PV solar or battery Existing legacy and flexible ToU customers	Single-rate or demand
Single-rate	All existing customers remain	Default ToU or demand
Demand	All existing customers remain	Single-rate or default ToU
Dedicated circuit	All existing customers remain	Any new eligible load

2.3.2 Small and medium business

This tariff class comprises:

- small businesses consuming less than 40 MWh per year
- medium businesses consuming more than 40 MWh per year with a maximum demand of less than 120 kVA
- unmetered supplies.

Small business

We will assign the following small business customers onto a default two-rate ToU pricing structure, with a peak period occurring between 9am to 9pm workdays local time and off peak applying at all other times (default ToU):

- New connections (i.e. new small businesses connecting to the network for the first time, not re-energisations)
- Customers who choose to upgrade from single-phase to three-phase supply
- Customers who choose to install or upgrade PV solar or batteries
- Small business customers on any non-demand ToU tariff as at 1 July 2021[2].

The following table summarises all the small business tariffs.

[2] Customers on basic meters will be reassigned to single rate tariff as at 1 July 2021

Figure 3 Small business tariff summary

Proposed tariffs	Proposed assignment	Tariff options
Default ToU	New connections Supply upgrades to three-phase Businesses installing or upgrading PV solar or battery Existing ToU customers	Single-rate or demand
Single-rate	All existing customers remain	Default ToU or demand
Demand	All existing customers remain	Single-rate or default ToU
Dedicated circuit	All existing customers remain	Any new eligible load

Medium business

Any new medium business customer will be assigned to the demand tariff which comprises a seasonal demand charge and a flat usage charge.

Customers consuming less than 160 MWh pa will have the option of opting out to the medium business opt-out tariff.

Figure 4 Medium business tariff summary

Proposed tariffs	Proposed assignment	Tariff options
Demand	All existing customers remain New connections	Medium Business opt-out
Medium Business Opt-out	All existing customers remain	Demand
Dedicated circuit	All existing customers remain	Any new eligible load

Unmetered supplies

We will continue to charge a two-rate ToU tariff with a 7am to 11pm weekdays peak period.

2.3.3 Large businesses

Large business cover the large low voltage, high voltage and sub-transmission tariff classes all of which have the same tariff structures as follows:

- 12-month rolling demand charge based on the maximum 15-minute kVA demand over a 12-month rolling period measured from 7am to 7pm on work days with minimum chargeable demand of 120 kVA for low voltage, 1 MVA for high voltage and 10 MVA for sub-transmission.
- Incentive demand charge based on a monthly maximum 15-minute kVA demand with chargeable months and daily measurement period assigned based on location of the customer
- Peak usage charge for usage between 7am and 7pm on work days
- Off-peak usage charge for usage that is not during peak times.

All large business customers will be assigned to a transition tariff with the incentive demand charge set to 0% in 2021/22, 33% in 2022/23, 67% in 2023/24 and 100% in 2024/25 of the full incentive demand charge. The 12-month rolling demand charge will correspondingly reduce each year of the transition period. Minimum chargeable demand will be adjusted during the transition to manage bill impacts.

Any large business customer can opt in to the full tariff but then cannot opt out of the full tariff.

Customers on existing large low voltage bulk tariff will be consolidated into the default transitional large low voltage tariff as at 1 July 2021.

3 Structure and charging parameters

The structure, charging parameters and eligibility criteria for the tariffs offered for customers in each of our tariff classes is set out below.[3]

[3] During the TSS period, CitiPower may need to introduce new tariff codes for billing purposes. Any new tariff codes introduced will comply with the tariff structures outlined in this document for each tariff class and the price level for NUOS services will equate to the tariff type under which the new tariff code has been created.

Figure 5 Residential tariff class[4]

Tariff type	Tariff Code	Supply voltage	Demand threshold	Status	Standing c/day	Anytime energy c/kWh	Peak energy c/kWh	Off-peak energy c/kWh	Summer demand[5] c/kW/day	Non-summer demand c/kW/day
Default ToU	CRTOU	< 1 kV	N/A	Default	✓		all days 3pm-9pm	all days 9pm-3pm		
Single rate	C1R			Opt-in	✓	✓				
Demand	CR			Opt-in	✓	✓			workdays 3pm-9pm	Workdays 3pm-9pm
Dedicated circuit	CDS			Opt-in				✓		

4 All times are local time

5 Summer period covers December to March, non-summer is April to November

Figure 6 Small and medium business tariff class[6]

Tariff type	Tariff Code	Supply voltage	Demand threshold	Status	Standing	Anytime energy	Peak energy	Off-peak energy	Summer demand[7]	Non-summer demand
					c/day	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day
Non-Residential ToU	CGTOU	< 1 kV	<40 MWh pa	Default	✓		workdays 9am-9pm	workdays 9pm-9am & weekends		
Single rate	C1G			Opt-in	✓	✓				
Demand	CG			Opt-in	✓	✓			workdays 10am-6pm	workdays 10am-6pm
Medium Business Demand	CMG		>40 MWh pa & <120 kVA	Default	✓	✓			workdays 10am-6pm	workdays 10am-6pm
Medium Business Opt-out	CMGO		<160 MWh pa	Opt-out	✓		workdays 10am-6pm	workdays 6pm-10am & weekends		
Unmetered	C2U		Unmetered supply	Default			weekdays 7am-11pm	weekdays 11pm-7am & weekends		

[6] All times are local time

[7] Summer period covers December to March, non-summer is April to November

Figure 7 Large low voltage, high voltage and sub-transmission tariff classes[8]

Tariff type	Tariff Code	Supply voltage	Demand threshold	Status	Standing	Anytime energy	Peak energy	Off-peak energy	12-month rolling demand	Incentive demand
					c/day	c/kWh	c/kWh	c/kWh	c/kVA/day	c/kVA/day
Large Low Voltage	CLLVT	< 1 kV	>120 kVA	Default			workdays 7am-7pm	Non peak times	workdays 7am-7pm	Location dependent
High Voltage	CHVT	1kV-66kV	N/A	Default			workdays 7pm-7pm	Non peak times	workdays 7am-7pm	Location dependent
Sub-transmission	CSTT	>=66kV	N/A	Default			workdays 7am-7pm	Non peak times	workdays 7am-7pm	Location dependent
Large Low Voltage	CLLV	< 1 kV	>120 kVA	opt-in			workdays 7am-7pm	Non peak times	workdays 7am-7pm	Location dependent
High Voltage	CHV	1kV-66kV	N/A	opt-in			workdays 7pm-7pm	Non peak times	workdays 7am-7pm	Location dependent
Sub-transmission	CST	>=66kV	N/A	opt-in			workdays 7am-7pm	Non peak times	workdays 7am-7pm	Location dependent

[8] All times are local time

3.1 Residential

Dedicated circuit tariff rules

- open to single phase customers with a resistive controlled load of less than 30 amps for an approved storage hot water service and/or space heating
- approved storage hot water service includes twin and single element storage, electric boosted solar hot water storage, but not heat pump hot water storage or instantaneous hot water storage
- customer must arrange for an electrician at their cost to separately wire the load to the meter board
- customer must have a single phase two element AMI meter, with load contactor installed to support a primary tariff and the dedicated circuit tariff
- if a meter change is required, the customer must pay for the labour cost of installing a new meter
- access by new customers is limited to single phase connections
- available only with relevant primary tariffs
- typically the dedicated load will be switched on for 7 hours a day during times that depend on localised demand management activities
- dedicated controlled load tariffs are charged at off-peak rates regardless of the specific switching times applied by the network
- dedicated circuits have a boost switch on the meter which if pressed allows electricity to be supplied to the dedicated circuit at the prevailing primary tariff rates
- existing dedicated circuit customers may have existing multiple meters and multiphase connections and will retain those arrangements despite being outside these current requirements
- existing slab heating customers have access to an off-peak switching between 1pm and 4pm in winter, but this is not available to new customers.

3.2 Small and medium business tariffs

Demand

Demand is measured as the maximum half-hour kW demand between 10am and 6pm, local time, work days, resetting every month.

3.3 Large business tariffs

Large business cover the large low voltage, high voltage and sub-transmission tariff classes all of which have the same tariff structures.

The following table sets out how the tariff components are calculated.

Figure 8 Large business monthly tariff calculation

Tariff components	Calculation
12-month rolling demand charge	cents per kVA per day x 12-month rolling maximum kVA x days / 100
Incentive demand charge	cents per kVA per day x incentive kVA x days / 100
Peak usage charge	cents per peak kWh x peak kWh in month / 100
Off peak usage charge	cents per off-peak kWh x off-peak kWh in month / 100

12-month rolling maximum kVA

kVA 15-minute demand is calculated as:

$$kVA = \sqrt{kW^2 + kVAr^2}$$

Where

kW = *kWh* in a 15-minute period x 4

kVAr = *kVArh* in a 5-minute period x 4

Maximum 15-minute kVA demand measured between 7am and 7pm local time on workdays over the prior 12 months.

Minimum chargeable demand of 120kVA for low voltage large customers, 1 MVA for high voltage customers and 10 MVA for sub-transmission customers.

If there is a full 12-month history of the customer's consumption data, the rolling 12-month maximum kVA demand will take effect immediately looking back 12 months.

Demand for greenfield sites will be measured from energisation date to the end date of the bill, until 12 months of history is available when it will revert to a 12-month rolling demand.

Incentive kVA

Incentive KVA is the maximum monthly 15-minute kVA for four months of the year. There is no charge for the other eight months of the year. Maximum monthly kVA is based on a fixed three-hour measurement period on each workday of the applicable months. Each customer will be assigned to a fixed measurement period for the duration of this TSS. As an example, a customer could be assigned to 4-7pm local time workdays for the months of December to March.

Peak and off-peak usage

Peak usage is kWh usage between 7am and 7pm local time on workdays.

Off-peak usage is kWh usage at all other times.

Demand exclusions

The exclusion of temporary increases in demand from the 12-month rolling maximum demand charged to the customer at a supply point will be considered at our discretion. For example if there is a specific, short term need, such as commissioning a new plant. The customer must apply via their retailer in advance for a temporary increase in demand to be excluded from the supply point's 12-month rolling maximum demand charge.

Demand reset criteria

A 12-month rolling demand reset may be granted under the following circumstances:

- Install power factor correction (PFC) equipment and supply a copy of the Certificate of Electrical Safety (CES) to confirm the installation[9]. If granted, demand will be measured from the date of commissioning of the PFC equipment.
- If PFC has not been installed, provide evidence of what the customer has changed on site to permanently alter the load/usage, for instance, removal of equipment. Evidence may be in the form of a CES detailing the works performed, technical information and/or photographic evidence to demonstrate the site changes.
- Customers that have moved into a premise will automatically continue to have their maximum demand charge based on the 12-month rolling maximum demand. A customer will need to lodge an application for their demand to be measured from the date they occupied the premises.

Criteria to move away from large business tariff

We will require confirmation that the load for the connection point is/has been limited to 200 amps per phase to ensure the site cannot exceed a demand greater than 120 kVA. The load can be limited by a supply capacity control device (SCCD) or other types of load limiting devices. If an SCCD exists, an electrician may be required to attend to limit the amps. We will require a copy of the CES as evidence of the works completed on site.

3.4 Exemptions from a network tariff

Customers with generation facilities or batteries will be exempt from a network tariff if the customer has a signed contract with CitiPower which exempts the customer from a network tariff. CitiPower would only enter into such a contract if:

- there is no other load at the site other than load associated with the generation facility or battery
- the contract provides CitiPower with assurance that the generator or battery will be operated to the net benefit of CitiPower's customers
- the customer waives their right to receive avoided TUOS payments if they are eligible for such payments.

Any generation facilities or batteries owned by CitiPower and installed to manage the distribution network will be exempt from a network tariff and will not receive avoided TUOS payments.

3.5 Tariff trials in the first year of the regulatory period

We expect to commence a dynamic domestic EV tariff trial in the first year of this regulatory period. We are currently in discussions with retailers about commencing such a trial where the half-hour pricing profile for each day is nominated a day in advance.

[9] Customers installing power factor correction equipment will need to be cognisant of their obligations under the Victorian Electricity Distribution Code to keep harmonic distortion and power factor within prescribed levels. Power factor correction equipment has the potential to exacerbate harmonic distortion and can cause a leading power factor during times of low demand if the equipment is not designed properly.

4 Approach to setting tariffs

4.1 Setting tariffs

Our residential and small business tariffs rates will be set to create an incentive for customers to select the more cost-reflective tariffs.

Residential

We will gradually reduce the default ToU rates relative to the single-rate tariff to provide an incentive for most customers to move to the more cost-reflective tariff. We will aim to have 80% of residential customers better off on the default ToU tariff relative to the single-rate tariff by 2026.

The following table illustrates that only one per cent per year relative reduction in the default ToU rates would result in about 80% of customers being better off by 2026.

Table 1 Proportion of residential customers better off on the default ToU tariff

TOU reduction relative to revenue neutral	Proportion of customers better off on ToU
0%	46%
1%	53%
2%	60%
3%	66%
4%	72%
5%	76%

CitiPower proposes to keep residential network standing charges constant within next regulatory period.

Small and medium business

We will follow a similar approach for the default ToU tariff and the existing demand tariff. Customers will on average be better off on the default ToU and demand tariffs relative to the single rate tariff.

4.2 Compliance with pricing principles

Our tariffs must comply with the following pricing principles:

1. for each tariff class, the revenue expected to be recovered must lie on or between stand-alone and avoidable cost
2. each tariff must take into account the long run marginal cost of providing the service
3. the revenue expected to be recovered from each tariff must reflect the total efficient costs of serving customers and the total revenue should be in accordance with the relevant distribution determination
4. we must consider the impact on retail customers of changes in tariffs from the previous regulatory year
5. our tariffs must be reasonably capable of being understood by customers
6. our tariffs must comply with the Rules and all applicable regulatory instruments.

Each principle is covered below.

Revenue lies between stand-alone and avoidable costs

We must ensure that the revenue recovered for each tariff class lies between:

- an upper bound, representing the stand-alone cost of serving customers who belong to that class
- a lower bound, representing the avoidable cost of not serving those customers.

The stand-alone and avoidable cost methodologies are used to calculate the revenues for each standard control service tariff class associated with each cost methodology. These costs are compared with the weighted average revenue derived from our proposed tariffs.

These two categories of cost may be defined as follows:

- the stand-alone cost comprises of both the capital and operating costs of service provision. The stand-alone network capital cost for each tariff class was derived from an estimate of the proportions of the cost of providing network infrastructure that would need to remain in place to service the load in each tariff class if the other tariff classes were no longer required to be supplied. The stand-alone operating cost for a tariff class has been estimated as the total of all operating cost less the avoidable operating costs of serving all the other tariff classes; and
- the avoidable cost for a tariff class is defined as the cost that would be avoided should the distribution business no longer serve that specific tariff class (whilst all other tariff classes remain supplied). If a tariff class were to be charged below the avoidable cost, it would be economically efficient for the business to stop supplying that tariff class as the associated costs would exceed the revenue obtained from the customer. Further, where avoidable costs are higher than revenue recovered, the associated tariff levels may also result in inefficient levels of consumption, which therefore provides a rationale for having avoidable costs as a lower bound.

The following table demonstrates that revenue falls between avoidable and stand-alone costs.

Table 2 2021/22 revenue compared with avoidable and stand-alone costs ($000 June-21)

Tariff class	Avoidable cost	2021/22 revenue	Stand-alone cost
Residential	29,324	81,474	164,512
Small and medium business	18,768	99,781	131,609
Large low voltage	17,595	102,926	197,414
High voltage	3,519	14,676	98,707
Sub-transmission	324	1,006	90,811

Long run marginal cost has been taken into account

Appendix 2 describes how LRMC was calculated and provides the calculated values.

LRMC has been taken into account in our tariff structures by setting our peak usage and demand periods at the times when network peaks, at the various voltage levels, are expected to occur in the long run.

We have chosen not to deterministically calculate peak energy or demand prices from LRMC because:

- LRMC cannot be calculated with any degree of precision due to the lack of accurate long term forecasts of demand and investment at all levels in the network
- the calculated LRMC is sensitive to methodology and input assumptions. See Table 3 and Table 4 in Appendix 2 which present LRMC calculated using the marginal increment cost and long run incremental cost methods. The average LRMC across the network differs by a factor of 1.4 (low voltage feeder) to 7.5 (zone substation) between the two methodologies
- LRMC is high in 3 zone substation supply areas, and low in the remaining 34 zone substation supply areas. Since there is strong community and political resistance to differentiated network pricing by location, it is not practical to reflect the local LRMC deterministically in network tariffs
- we have set the peak time of use price signal for residential and small business customers based on historical ratios to minimise bill impacts for customers that are re-assigned to the new time of use tariffs.

Efficient costs of providing the services

The AER final determination sets out the efficient revenue that CitiPower can recover, based on efficient costs, and price controls which ensure that total revenue is in accordance with the relevant distribution determination.

Impact on retail customers

The customer impact principle has driven much of the work and outcomes described in the TSS reasons document.

In particular, the simple new residential and small business ToU tariff design and assignment approach (including ability to choose tariffs alternative tariffs) are a result of the significant customer and stakeholder engagement we have undertaken and is targeted at ensuring we make progress on tariff reform in a way that is acceptable to stakeholders.

Tariffs reasonably capable of being understood by customers

Our selection of the new residential and small business ToU tariff design was strongly motivated by the desire of customers and stakeholders for a simple easily understood tariff.

Tariffs must comply with the Rules and all applicable regulatory instruments

Legislation made by the Victorian Government—by way of an 'order in council'—sets out certain requirements for network tariffs that expire on 31 December 2020. We understand that the Victorian Government will be reviewing the order in council in 2021 and if necessary we will update our TSS to comply with those requirements.

Appendix 1: Glossary

Term	Definition
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time is 10 hours ahead of UTC
AMI	Advanced Metering Infrastructure
Business customer	Customer whose usage is predominately for business purposes
CES	Certificate of Electrical Safety
Controlled load	The DNSP controls the hours in which the supply is made available
Flexible Pricing	Flexible pricing means different rates for electricity at different times of the day as defined by the Victorian Governments policy on ToU pricing
kVA	Kilovolt amperes, units of instantaneous total electrical power demand
kVAr	kilovolt amperes (reactive), unit of instantaneous reactive electrical power demand
kVArh	kilovolt amperes hour (reactive), unit of reactive electrical power usage
kW	kilowatt, unit of instantaneous real electrical power demand
kWh	kilowatt hour, units of real electrical energy consumption
Local time	daylight saving time in accordance with the Victorian Government’s requirements
LV	Low voltage which is 230 V single phase or 415 V three phase
LRMC	long run marginal cost
MIC	marginal incremental cost
NUoS	Network use of system
PFC	Power factor correction
REC	Registered Electrical Contractor
Residential customer	Customer whose usage is predominately for residential purposes
Rules	National Electricity Rules
SCCD	supply capacity control device
ToU	time of use
TSS	tariff structure statement
Unmetered supply	A connection to the distribution system which is not equipped with a meter and has estimated consumption. Public lights, phone boxes, and traffic lights are not normally metered

Appendix 2: Long Run Marginal Cost

Approach

Long run marginal cost (LRMC) is a measure of the change in the forward looking costs as output increases when all factors of production including plant and equipment are variable. The LRMC for electricity distribution will usually relate to the annualised cost of augmenting capacity (at a particular voltage, location, and time) per unit of additional capacity provided. LRMC can also be the annualised avoided replacement cost per unit of capacity reduction.

We calculated LRMC at a granular level in our network to observe how LRMC cost differs across our network, and to see if LRMC could be used as a basis for the rebate we would be prepared to pay for non-network solutions to relieve localised network constraints.

We engaged a consultant, ENEA, to undertake LRMC calculations for our network. ENEA was instructed to:

- calculate LRMC for each zone substation supply area
- calculate LRMC for each level of the network
- include augmentation and replacement cost in LRMC
- use our available planning information
- apply our planning criteria to identify when augmentation is triggered.

ENEA selected the marginal incremental cost (MIC) approach to calculating long run marginal cost because it can cater for network areas with decreasing/flat demand and can be adapted to accommodate replacement costs.

Since the low voltage network is planned in the short term only, there was no planning data for the low voltage network. As a consequence, the average historic marginal cost of reinforcement of the low voltage network was used as a proxy for the low voltage LRMC in all zone substation supply areas. ENEA have pointed out that marginal cost of reinforcement is representative of new connections only, and not of existing low voltage customers who have a stable or decreasing maximum demand.

A number of other 'average' assumptions were made such as incremental O&M costs and diversity factors at each voltage level.

During the engagement, ENEA was engaged by another distributor to calculate LRMC using the long run incremental cost (LRIC) approach.

ENEA gave us two sets of results: one using the MIC approach and one using the LRIC approach.

Due to the number and complexity of calculations, they were performed in Python (as opposed to Excel).

Results

The following table summarises the calculated LRMC.

Table 3 LRMC summary ($ per kVA per year)

	Low voltage feeder	Low voltage transformer	High voltage feeder	Zone substation	Sub-transmission feeder
MIC					
Average	58	28	12	5	0
Low	53	22	8	0	0
High	112	91	57	50	0
LRIC					
Average	84	67	41	35	0
Low	42	17	6	0	0
High	530	587	413	407	0

The following tables present calculated LRMC for each zone substation and network level for MIC and LRIC.

Table 4 MIC LRMC ($ per kVA per year)

Zone substation	Low voltage feeder ($/kVA/year)	Low voltage transformer ($/kVA/year)	High voltage feeder ($/kVA/year)	Zone substation ($/kVA/year)	Subtransmission feeder ($/kVA/year)
AP	60	30	14	6	0
AR	53	22	8	0	0
B	98	75	46	38	0
BC	53	22	8	0	0
BK	53	22	8	0	0
BQ	53	22	8	0	0
C	53	22	8	0	0
CL	53	22	8	0	0
CW	53	22	8	0	0
DA	53	22	8	0	0
DLF	53	22	8	0	0
E	55	24	9	2	0
F	53	22	8	0	0
FB	53	22	8	0	0
FR	53	22	8	0	0
J	53	22	8	0	0
JA	53	22	8	0	0
L	53	22	8	0	0
LQ	53	22	8	0	0
LS	53	22	8	0	0
MG	53	22	8	0	0
MP	53	22	8	0	0
NC	53	22	8	0	0
NR	112	91	57	50	0
PM	55	24	9	2	0
Q	53	22	8	0	0
R	110	88	55	48	0
RD	53	22	8	0	0
RP	53	22	8	0	0
SB	60	30	14	6	0
SK	53	22	8	0	0
SO	53	22	8	0	0
TK	53	22	8	0	0
VM	58	28	12	4	0
WA	64	34	17	9	0
WB	53	22	8	0	0
WG	55	24	9	2	0
Average	**58**	**28**	**12**	**5**	**0**

Table 5 LRIC LRMC ($ per kVA per year)

Zone substation	Low voltage feeder ($/kVA/year)	Low voltage transformer ($/kVA/year)	High voltage feeder ($/kVA/year)	Zone substation ($/kVA/year)	Subtransmission feeder ($/kVA/year)
AP	105	91	59	52	0
AR	42	17	6	0	0
B	506	558	393	387	0
BC	42	17	6	0	0
BK	42	17	6	0	0
BQ	42	17	6	0	0
C	42	17	6	0	0
CL	42	17	6	0	0
CW	42	17	6	0	0
DA	42	17	6	0	0
DLF	42	17	6	0	0
E	45	21	9	2	0
F	42	17	6	0	0
FB	42	17	6	0	0
FR	42	17	6	0	0
J	42	17	6	0	0
JA	42	17	6	0	0
L	42	17	6	0	0
LQ	42	17	6	0	0
LS	42	17	6	0	0
MG	42	17	6	0	0
MP	42	17	6	0	0
NC	42	17	6	0	0
NR	530	587	413	407	0
PM	45	21	9	2	0
Q	42	17	6	0	0
R	437	478	335	329	0
RD	42	17	6	0	0
RP	42	17	6	0	0
SB	111	98	64	58	0
SK	42	17	6	0	0
SO	42	17	6	0	0
TK	42	17	6	0	0
VM	47	24	11	5	0
WA	56	34	18	12	0
WB	42	17	6	0	0
WG	45	21	9	2	0
Average	**84**	**67**	**41**	**35**	**0**

Appendix 3: Indicative prices

Indicative prices for 2021-2026 regulatory control period for the following components of network charges are provided in the attachment, CP RRP APP07 - Indicative Pricing Schedule - Dec2020 – Public:

- Distribution use of system charges
- Transmission use of system charges
- Jurisdictional scheme charges
- Network use of system charges (the sum of the above three charges)

They will be updated annually to reflect the latest forecasts, but will remain indicative only because the actual prices that will be charged will depend on:

- The indicative X factors that the AER will determine for us for the 2021-2026 regulatory control period, and that are updated annually for rate of return and any contingent projects
- actual energy consumption
  - if energy consumption falls below our forecast, prices would need to increase more than indicated or
  - if energy consumption rises above our forecast, prices would decline below the estimates indicated
- the impact of incentive schemes
- the impact of 'unders and overs' amounts adjusted for the time value of money due to variances between actual and forecast volumes
- the impact of any pass-through amounts
- amount of transmission, avoided transmission, and inter-distributor charges which are outside our control
- jurisdictional scheme costs which are beyond our control.

Appendix 4: Alternative control services

Alternative control services are customer specific or customer requested services, and so the full cost of the service is attributed to that particular customer.

The following table summarises categories of alternative control services.

Table 6 **Categories of alternative control services**

Service category	Form of price control	Examples of services
Network ancillary services – fee based	Price cap	Manual re-energisation, service truck visit (servicing), access to meter data, etc.
Network ancillary services – quoted	Price cap	Audit design and construction, reserve feeder maintenance, after hour truck appointment, etc.
Basic connection services	Price cap	Basic connection services as defined in CitiPower's connection policy
Public lighting services	Price cap	Operation of public lighting assets, maintenance, repair and replacement of public lighting assets, etc.
Metering services	Revenue cap	Meter provision, meter maintenance, meter reading and data services, meter exit fees, etc.

These services will be charged in accordance with the AER final determination.

Appendix 5: Compliance checklist

This section sets out the Rule requirements relevant to this TSS and the section in which those requirements have been met.

Rule Provision	Requirement	Relevant section
Part E: Regulatory proposal and proposed tariff structure statement		
6.8.2	**Submission of tariff structure statement**	
6.8.2(a)	A *Distribution Network Service Provider* must, whenever required to do so under paragraph (b), submit to the *AER* a *regulatory proposal* and a proposed *tariff structure statement* related to the *distribution services* provided by means of, or in connection with, the *Distribution Network Service Provider's distribution system*.	Noted
6.8.2(b)	A regulatory proposal, a proposed tariff structure statement and, if required under paragraph (a1), an exemption application must be submitted: (1) at least 17 months before the expiry of a distribution determination that applies to the Distribution Network Service Provider; or (2) if no distribution determination applies to the Distribution Network Service Provider, within 3 months after being required to do so by the AER.	This document
6.8.2(c)	A proposed *tariff structure statement* must be accompanied by information that contains a description (with supporting materials) of how the proposed *tariff structure statement* complies with the *pricing principles for direct control services.*	4.2 Compliance with pricing principles
6.8.2(c1a)	The proposed *tariff structure statement* must be accompanied by an overview paper which includes a description of how the *Distribution Network Service Provider* has engaged with *retail customers* and *retailers* in developing the proposed *tariff structure statement* and has sought to address any relevant concerns identified as a result of that engagement	Explanatory document
6.8.2(d1)	The *tariff structure statement* must be accompanied by an *indicative pricing schedule*.	Indicative pricing schedule – Appendix 3
6.8.2(d2)	The *tariff structure statement* must comply with the *pricing principles for direct control services*.	4.2 Compliance with pricing principles
6.8.2(e)	If more than one *distribution system* is owned, controlled or operated by a *Distribution Network Service Provider*, then, unless the *AER* otherwise determines, a separate *tariff structure statement* are to be submitted for each *distribution system*.	Noted
6.8.2(f)	If, at the commencement of this Chapter, different parts of the same distribution *system* were separately regulated, then, unless the *AER* otherwise determines, a separate *tariff structure statement* are to be submitted for each part as if it were a separate *distribution system*.	Not applicable
6.18.1A	**Tariff Structure Statement**	
6.18.1A(a)(1)	The *tariff structure statement* must include the *tariff classes* into which *retail customers* for *direct control services* will be divided during the relevant *regulatory control period*.	2.1 Tariff classes
6.18.1A(a)(2)	The *tariff structure statement* must include the policies and procedures the *Distribution Network Service Provider* will apply for assigning *retail customers* to tariffs or reassigning	2.5 Allocation of customers to tariff classes

	retail customers from one tariff to another (including any applicable restrictions).	
6.18.1A(a)(3)	The *tariff structure statement* must include the structures for each proposed tariff.	3 Structure and charging parameters
6.18.1A(a)(4)	The *tariff structure statement* must include the *charging parameters* for each proposed tariff.	3 Structure and charging parameters
6.18.1A(a)(5)	The *tariff structure statement* must include a description of the approach that the *Distribution Network Service Provider* will take in setting each tariff in each *pricing proposal* during the relevant *regulatory control period* in accordance with clause 6.18.5 (pricing principles).	4 Approach to setting tariffs
6.18.1A(b)	The *tariff structure statement* must comply with the *pricing principles for direct control services*.	4.2 Compliance with pricing principles
6.18.1A(e)	A *tariff structure statement* must be accompanied by an *indicative pricing schedule* which sets out, for each tariff for each *regulatory year* of the *regulatory control period*, the indicative price levels determined in accordance with the *tariff structure statement.*	Appendix 3 Indicative pricing schedule
6.18.3	**Tariff Classes**	
6.18.3(b)	Each customer for *direct control services* must be a member of 1 or more *tariff classes*.	2.1 Tariff classes
6.18.3(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*).	2.1 Tariff classes
6.18.3(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.	2.1 Tariff classes
6.18.4	**Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging**	
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the AER must have regard to the following principles:	Noted
6.18.4(a)(1)	*retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors: the nature and extent of their usage; the nature of their connection to the network; 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;	2.1 Tariff classes
6.18.4(a)(2)	retail customers with a similar connection and usage profile should be treated on an equal basis;	2.1 Tariff classes
6.18.4(a)(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;	2.1 Tariff classes
6.18.4(a)(4)	a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer	2.1 Tariff classes and 2.5 Allocation of

	from one tariff class to another should be subject to an effective system of assessment and review. **Note:** If (for example) a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed maximum demand, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in maximum demand to a tariff class that is more appropriate to the customer's load profile.	customers to tariff classes
6.18.4(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 Structure and charging parameters
	Network Pricing Objective	
6.18.5(a)	The *network pricing objective* is that the tariffs that a *Distribution Network Service Provider* charges in respect of its provision of *direct control services* to a *retail customer* should reflect the *Distribution Network Service Provider's* efficient costs of providing those services to the *retail customer*.	4 Approach to setting tariffs
	Application of the Pricing Principles	
6.18.5(b)	Subject to paragraph (c), a *DNSP's* tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	4.2 Compliance with pricing principles
6.18.5(c)	A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: to the extent permitted under paragraph (h); and to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	4.2 Compliance with pricing principles
6.18.5(d)	A *Distribution Network Service Provider* must comply with paragraph (b) in a manner that will contribute to the achievement of the *network pricing objective*.	4.2 Compliance with pricing principles
	Pricing Principles	
6.18.5(e)	For each tariff class, the revenue expected to be recovered must 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.	4.2 Compliance with pricing principles and Appendix 2 Long Run Marginal Cost
6.18.5(f)	Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: 1. the costs and benefits associated with calculating, implementing and applying that method as proposed; 2. the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and	Appendix 2 Long Run Marginal Cost

	3. the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.	
6.18.5(g)	The revenue expected to be recovered from each tariff must: 1. reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; 2. when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and 3. comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	4.2 Compliance with pricing principles and Appendix 2 Long Run Marginal Cost
6.18.5(h)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: 1. the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); 2. the extent to which retail customers can choose the tariff to which they are assigned; and 3. the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.	2 Tariff classes and assignment policies and 4.2 Compliance with pricing principles
6.18.5(i)	The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to: 1. the type and nature of those retail customers; and 2. the information provided to, and the consultation undertaken with, those retail customers.	3 Structure and charging parameters
6.18.5(j)	A tariff must comply with the *Rules* and all *applicable regulatory instruments*.	Noted