

United Energy 2016 Pricing Proposal



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Executive summary

This Pricing Proposal addresses the obligations specified in the Electricity Distribution Price Review (EDPR) where United Energy (UE) is required to make an annual submission to the AER outlining;

- Electricity distribution (DUoS), transmission use of system (TUoS) and jurisdictional/pass through charges
- Rates for standard control and alternative control services
- Tariff eligibility criteria
- Customer impact of new tariffs versus prior year
- Pricing principles and tariff strategy
- Customer/stakeholder engagement process

In developing this Annual Tariff Report, UE has aligned with the strategies and obligations tabled in our Tariff Structure Statement (TSS) submitted to the AER in September this year. A key feature of the TSS was the articulation of a targeted consultation program with key stakeholder groups, the results of which have informed our future tariff strategies.

UE has responded to stakeholder feedback and has refined the residential demand tariff introduced last year and has also created a new tariff (LVMKWTOU), which will be available to eligible small business customers from 1st July 2016. Being demand based this tariff provides better alignment between consumer usage profiles and network system cost drivers. Details of the tariff are described in section 4.3.2.

Under the price control formula the average DUoS movement is calculated to be a decrease of 5.53% on the 2015 rates. United Energy acts as an agent for the recovery of grid fees levied by transmission operators. Recovery of grid fees is levied in the form of TUoS. Increases in grid fees for the 2014/15 financial year have driven an average TUoS tariff increase of 8.52% compared to 2015. The combined effect of these changes delivers an overall NUoS decrease for 2016 of 2.44%.

A summary of the annual movement in DUoS and TUoS appears below. When combined with price movements in jurisdictional and pass through charges (PFIT/TFIT recovery, AMI meter charges), the average residential customer on a single rate tariff will see an annual network use of system (NUoS) decrease of \$71.58 over the 2015 charges. Eligible residential customers have the potential to participate in further savings by transitioning to the residential demand tariff (RESKW1R) during 2016.

Unless otherwise stated, the tariffs proposed in this submission are intended to apply for the period 1st January 2016 to 31st December 2016 and are subject to endorsement by the AER. A response from the AER is anticipated in early December 2015.

UED Indicative 2016 Tariff Price Movements

Description	Tariff Code	DUOS % price movement	TUOS % price movement	NUOS % price movement
Class - Low Voltage Small				
Low voltage small 1 rate	LVS1R	-6.8%	6.4%	-4.0%
Dedicated circuit	LVDed	10.0%		10.0%
Residential KW time of use	RESKWTOU	-2.2%	14.9%	1.5%
Class - Low Voltage Medium				
Low voltage medium 1 rate	LVM1R	-17.2%	6.4%	-12.6%
Low voltage medium 2 rate 5 day	LVM2R5D	3.0%	6.4%	3.5%
Low voltage KW time of use	LVkWTOU	-8.0%	6.5%	-5.6%
Time Of Use	TOU	5.0%	6.4%	5.2%
Class - Low Voltage Large				
Low voltage large 2 rate	LVL2R	-8.0%	6.4%	-5.8%
Low voltage large 1 rate	LVL1R	-8.0%	6.5%	-3.7%
Low voltage large KVA time of use	LVkVATOU	-8.0%	6.5%	-4.3%
Class - High Voltage Large				
High voltage KVA time of use	HVkvATOU	-8.0%	6.5%	-3.2%
Class - Subtransmission Large				
Subtransmission KVA time of use	SubTkVATOU	-8.0%	6.4%	1.2%

1. Introduction and structure

United Energy (UE) is one of five electricity distribution businesses operating under licence within the State of Victoria. UE manages and operates an extensive urban and semi-rural electricity distribution network with a replacement value of over \$4 billion, comprising 47 zone substations, approximately 214,500 poles, 13,350 distribution substations, 10,100 km of overhead power lines and 2,740 km of underground cables. UE's electricity distribution network provides services to some 660,000 end-use customers, located in an area of 1,472 km² in south-east Melbourne and the Mornington Peninsula. UE's distribution area is shown below:

Figure 1-1: UE Distribution Territory



This document is UE's 2016 Pricing Proposal to the Australian Energy Regulator (AER). In accordance with the requirements of the National Electricity Rules (Rules), clause 6.18.2(b) requires that a Pricing Proposal must:

- (a) set out the proposed tariffs for each *tariff class*
- (b) set out, for each proposed tariff, the *charging parameters* and the elements of service to which each *charging parameter* relates;
- (c) 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*;
- (d) set out the nature of any variation or adjustment to the tariff that could occur during the course of the *regulatory year* and the basis on which it could occur;

- (e) 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*;
- (f) set out how *jurisdictional scheme amounts* for each *approved jurisdictional scheme* are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts;
- (g) describe how each *approved jurisdictional scheme* that has been amended since the *last jurisdictional scheme approval date* meets the *jurisdictional scheme eligibility criteria*;
- (h) demonstrate compliance with the *Rules* and any applicable distribution determination, including the *Distribution Network Service Provider's tariff structure statement* for the relevant *regulatory control period*;
- (i) demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant *regulatory year* as set out in the relevant *indicative pricing schedule*, or explain any material differences between them; and
- (j) 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.

In addition to the above provisions:

- clause 6.18.3 sets out requirements in relation to the definition of tariff classes;
- clause 6.18.4 sets out principles for the reassignment of customers to tariff classes;
- clause 6.18.5 describes the pricing principles that must apply to tariff classes;
- clause 6.18.6 provides for a side constraint on tariffs for standard control services;
- clause 6.18.7 defines the arrangements for the recovery of charges for transmission use of system;
- clause 6.18.8 sets out the arrangements for approving the Pricing Proposal; and
- clause 6.18.9 sets out provisions regarding the website publication of pricing information prior to the commencement of the regulatory year.

This Pricing Proposal takes account of the AER's preliminary decision¹ on United Energy's distribution determination for the period 2016-2020. The remainder of this Pricing Proposal is structured as follows;

- Section 2 identifies the pricing issues arising from the AER's preliminary decision¹;
- Section 3 sets out UE's proposed tariff classes and charging parameters;
- Section 4 describes UE's tariff strategy and the application of the pricing principles in the Rules;
- Section 5 sets out UE's proposed standard control tariffs for 2016 and the average charges to customers;
- Section 6 demonstrates that UE's proposed tariffs for 2016 complies with the Rules and the AER's final determination;
- Section 7 provides information in relation to the transmission component in the network tariffs;

¹ Issued by AER 29 October 2015.

- Section 8 provides details of UE's approach to tariff assignment and reassignment;
- Section 9 sets out information in relation to UE's alternative control services;
- Section 10 sets out information in relation to UE's alternative control services – metering services;
- Section 11 sets out information in relation to UE's public lighting charges; and
- The appendices provide details of UE's proposed tariffs for 2016.

In summary, this Pricing Proposal demonstrates compliance with the Rules and also provides information to assist stakeholders regarding the issues, principles and rationale that have shaped UE's approach to setting its network tariffs for 2016. UE welcomes comments from interested parties as UE continually evolves its approach to tariff and price setting.

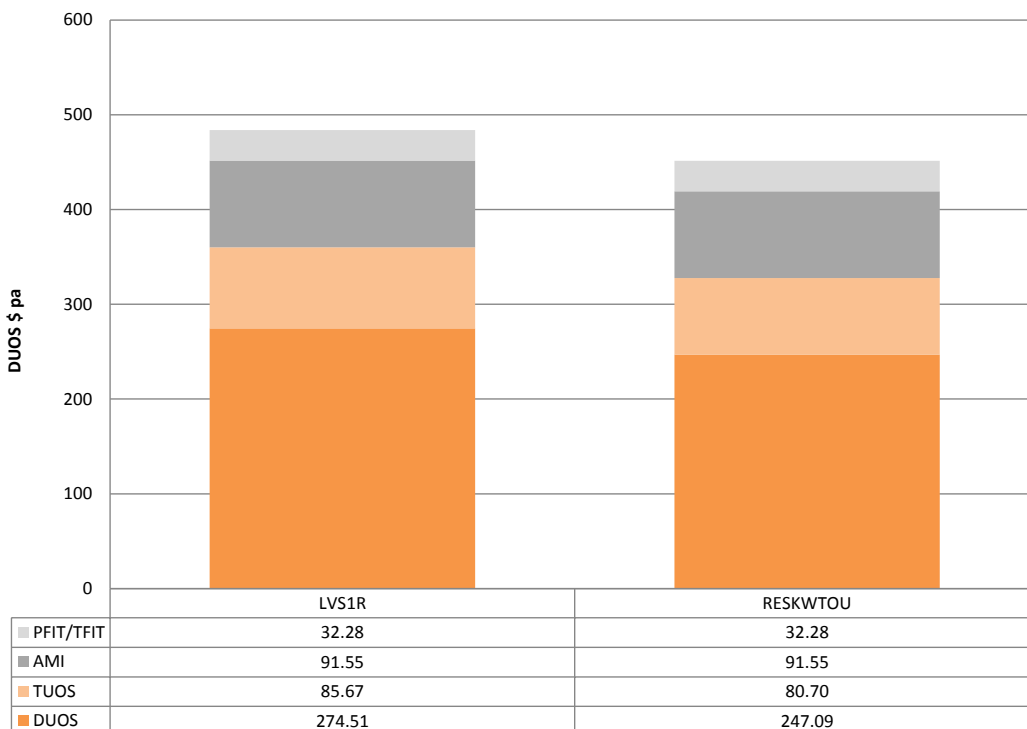
1.1. UE's average charge for small residential customers

For 2016 the average UE network tariff bill for residential customers will be comprised of four components; Distribution Use of System (DUoS), Transmission Use of System (TUoS), Advanced Interval Metering (AMI) and Solar Feed in Tariff schemes (PFIT/TFIT). The F (fire mitigation) factor being incorporated into DUoS from 2016.

The average residential customer without electric hot water consumes approximately 4.2MWh per annum. The composition of the network charge is approximately 57% DUoS, 18% TUoS, 19% AMI and 7% PFIT/TFIT.

Figure 1-2 below displays the 2016 average network charge for the common residential tariff (LVS1R) compared to the UE residential demand tariff alternative.

Figure 1-2: 2016 Indicative network charge for a residential customer (4200kWh pa)



Further details relating to residential/small customers average charges can be found in section 5.3.1.

2. Pricing impacts arising from the AER's preliminary decision on United Energy's distribution determination

2.1. UE's expected revenues for standard control services and X factors

As per the AER's preliminary decision², UE's revenue requirements and X factors are set out below.

Table 2-1: AER re-determination—revenues and X factors

	2016	2017	2018	2019	2020
Expected Revenues (\$'m, nominal)	375.1	350.9	359.7	368.7	377.9
AER's CPI estimate	2.50%	2.50%	2.50%	2.50%	2.50%
X factor*	8.72%	8.72%	0.00%	0.00%	0.00%

*Positive values for X indicate real price decreases

2.2. Revenue cap formula

As part of the Pricing Proposal, UE must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the total annual revenue formulae and side constraint equations.

The Revenue Cap formulae to apply to the Victorian DNSPs for the forthcoming regulatory control period is:

$$(1) \quad TAR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij} \quad i=1,\dots,n \text{ and } j=1,\dots,m \text{ and } t=1,\dots,5$$

$$(2) \quad TAR_t = AAR_t + I_t + T_t + B_t \quad t = 1, 2, \dots, 5$$

$$(3) \quad AAR_t = AR_t (1 + S_t) \quad t = 1$$

$$(4) \quad AAR_t = AAR_{t-1} (1 + \Delta CPI_t) (1 - X_t) (1 + S_t) \quad t = 2, \dots, 5$$

where;

TAR_t is the total annual revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

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

² As published by the AER on 29 October 2015.

AAR_t is the adjusted annual smoothed revenue requirement for year t.

I_t is the annual adjustment f-factor scheme amount in year t. This amount will be calculated as per the method set out in the relevant f-factor scheme.

T_t is the final carryover amount from the application of the DMIS from the 2011–15 regulatory control period. This amount will be calculated using the method set out in the DMIS and will be deducted from/added to allowed revenue in the 2017 pricing proposal.

B_t is the sum of:

- the recovery of license fee charges by the Victorian Essential Services Commission indexed by one and a half years of interest, calculated using the following method:

$$L_{t-1}(1+WACC_{t-1})(1+WACC_{t-2})^{1/2}$$

where:

L_{t-1} are the licence fees paid by United Energy to the Victorian Essential Services Commission in the financial year ending in June of regulatory year t–1,

$WACC$ is the approved nominal weighted average cost of capital (WACC) for the relevant regulatory year,

- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 as calculated using the method outlined in AER’s preliminary decision 29th October 2015 (Appendix A of Attachment 14).
- the AER approved pass through amounts (positive or negative) with respect to regulatory year t.

AR_t is the annual smoothed revenue requirement as stated in the Post Tax Revenue Model (PTRM) for year t (when year t is the first year of the 2016–20 regulatory control period).³

S_t is the s-factor determined in accordance with the service target performance incentive scheme (STPIS) for regulatory year t.⁴

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities⁵ from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

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

For example, for the 2017 regulatory year, t–2 is June quarter 2015 and t–1 is June quarter 2016 and for the 2018 regulatory year, t–2 is June quarter 2016 and t–1 is June quarter 2017 and so on.

³ AER states that if necessary an adjustment for inflation may be required to the annual smoothed revenue requirement for year t. However, as the annual smoothed revenue requirement for year t as stated in our preliminary decision PTRM is in nominal dollars there is no need to adjust it for inflation. This approach is consistent with past regulatory practice.

⁴ For the first two years of the 2016–20 regulatory control period, the value of S_t is to be adjusted to account for the change in revenue requirements between the regulatory control periods, as explained in attachment 11. In the formulas in the STPIS, the $AR_{(t+1)}$ is equivalent to AR_t in this formula. Calculations of the S factor adjustment are to be made accordingly.

⁵ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best estimate available of the index alternative index.

2.3. Side constraint formula

The side constraints formula to apply to the Victorian DNSPs for the 2016-20 regulatory control period is set out below. Noting that for each year after the first year of a regulatory control period, side constraints will apply to the weighted average revenue to be raised from each tariff class. Accordingly, 2016 revenue by tariff class is not subject to side constraints

Where for each tariff class a DNSP has n distribution tariffs, which each have up to m distribution tariff components:

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

- d_t^{ij} is the proposed price for component 'j' of tariff 'i' for year t.
- d_{t-1}^{ij} is the price charged for component 'j' of tariff 'i' in year t-1.
- q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.
- ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities⁶ from the June quarter in year t-2 to the June quarter in year t-1, calculated using the following method :

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

For example, for the 2017 regulatory year, t-2 is June quarter 2015 and t-1 is June quarter 2016 and for the 2018 regulatory year, t-2 is June quarter 2016 and t-1 is June quarter 2017 and so on.

- X_t is the X factor for each year of the 2016-20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in attachment 3—rate of return—calculated for the relevant year. If $X > 0$, then X will be set equal to zero for the purposes of the side constraint formula.
- S_t is the annual percentage change from the STPIS factor as determined in accordance with the STPIS in regulatory year t.⁷

⁶ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best estimate available of the index alternative index.

⁷ For the first two years of the 2016-20 regulatory control period, the value of S_t is to be adjusted to account for the change in revenue requirements between the regulatory control periods, as explained in attachment 11. In the formulas in the STPIS, the $AR_{(t+1)}$ is equivalent to AR_t in this formula. Calculations of the S factor adjustment are to be made accordingly.

- I_t' is the annual percentage change from the f-factor scheme amount in year t. This amount will be calculated as per the method set out in the relevant f-factor scheme.
- T_t' is the annual percentage change from the final carryover amount from the application of the DMIS from the 2011–15 regulatory control period. This amount will be calculated using the method set out in the DMIS and will be deducted from/added to allowed revenue in the 2017 pricing proposal.
- B_t' is annual percentage change from the sum of:
 - the recovery of license fee charges by the Victorian Essential Services Commission indexed by one and a half years of interest, calculated using the following method:

$$L_{t-1}(1+WACC_{t-1})(1+WACC_{t-2})^{1/2}$$

where:

L_{t-1} are the licence fees paid by United Energy to the Victorian Essential Services Commission in the financial year ending in June of regulatory year t–1,

$WACC$ is the approved nominal weighted average cost of capital (WACC) for the relevant regulatory year,

- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 as calculated using the B factor described in section 2.2.
- the AER approved pass through amounts (positive or negative) with respect to regulatory year t.

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

2.4. Tariff class assignment and reassignment procedures

The AER determines the principles governing assignment or reassignment of retail customers (customers) to or between tariff classes.⁸ The principles that United Energy is to adhere to in assigning and reassigning customers to tariff classes is outlined below.⁹

UE must take into account one or more of the following factors:

- the nature and extent of the customer's usage;
- the nature of the customer's connection to the network; and
- whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

In addition to these requirements, when assigning or reassigning a customer to a tariff class, UE must ensure the following:

⁸ NER, cl. 6.12.1(17).

⁹ NER, cl. 6.18.4.

- that customers with similar connection and usage profiles are treated equally
- that customers who have micro-generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

In addition to these guiding principles, the AER's procedures for tariff assignment and reassignment:

- describe the arrangements that DNSPs must adopt to notify their customers of a tariff assignment or reassignment, and to address a customer's objections;
- require the DNSP's Pricing Proposal to describe its system for assessing and reviewing the basis on which a customer is charged; and
- confirms that if a DNSP installs an interval meter for an existing distribution customer, the DNSP may reassign that distribution customer to a time of use distribution tariff subject to clause 9.1.14 of the Victorian Electricity Distribution Code.

In this Pricing Proposal, UE confirms that it will comply fully with the AER's procedures for assigning and reassigning customers to tariff classes as set out in Attachment 14 - Control Mechanism Appendix D of the AER's preliminary decision. Further details of UE's approach to tariff assignment and reassignment are provided in section 8 of this Pricing Proposal.

2.5. Recovering the cost of Transmission/Grid fees

As shown by table 2-2 and Figure 2-1 below, grid fees vary from year to year.

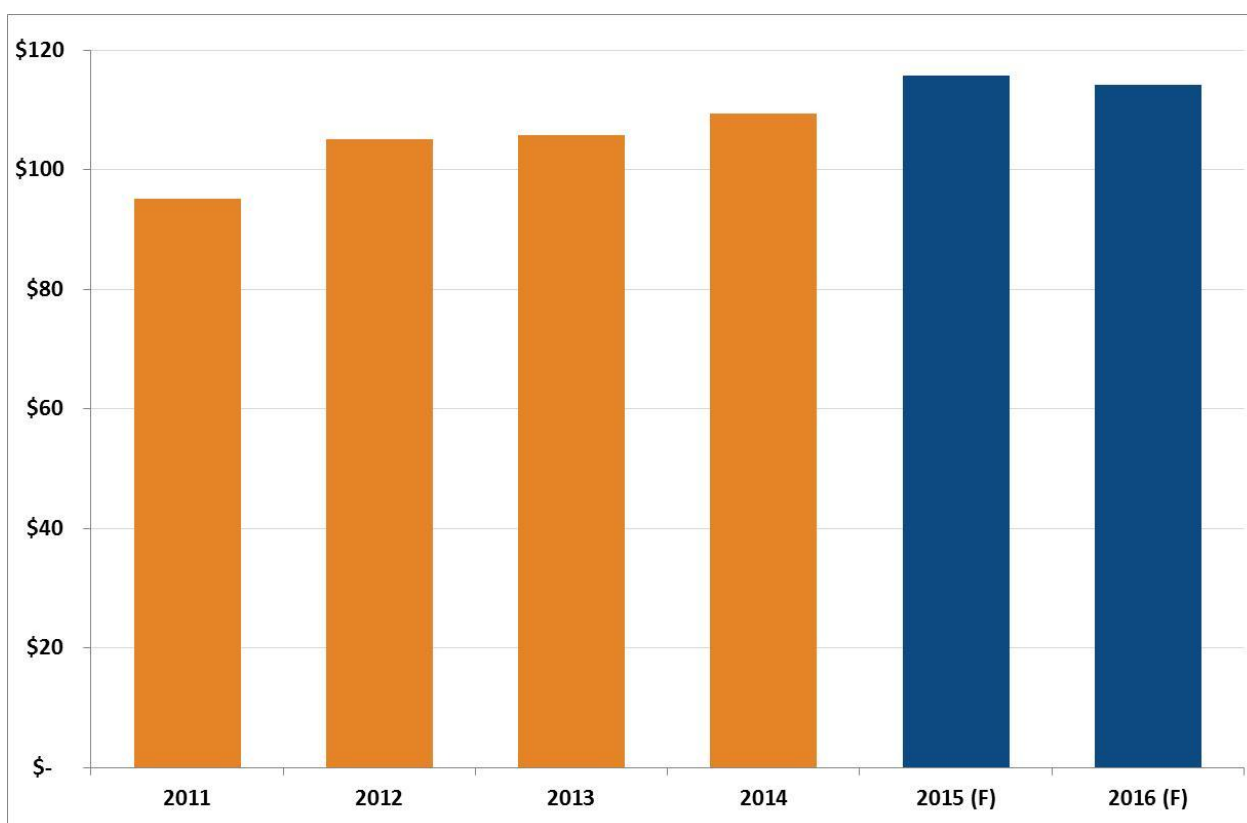
The expected TUOS revenue increase from 2015 to 2016 is 6%. This increase is primarily driven by the following factors:

- Under-recovery from prior years
- AEMO Opex budget increase

Table 2-2: Estimated TUOS Revenue Increase (\$'m)

	2015	2016	Var(%)
Grid Fee Forecast	\$113	\$114	
Over(under) recovery from previous year	\$2	-\$4	
Actual/Allowed Revenue current year (grid fees less over recovery)	\$112	\$118	
Estimated Revenue collected	\$112	\$118	6%

Figure 2-1: Grid Fees 2011-2016 (\$'m)



3. Tariff classes and charging parameters

3.1. Regulatory requirements

This section addresses the Rules requirements in relation to tariff classes. In particular, it provides the following information:

- the tariff classes that are to apply for 2016, in accordance with clause 6.18.2(b)(1);
- the proposed tariffs for each tariff class, in accordance with clause 6.18.2(b)(2); and
- for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates, in accordance with clause 6.18.2(b)(3); and
- the tariff classes into which customers for direct control services are divided, in accordance with clause 6.18.3, noting that:
 - *Separate tariff classes* must be constituted for customers to whom *standard control services* are supplied and 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*).
 - *A tariff class* must be constituted with regard to:
 1. the need to group customers together on an economically efficient basis; and
 2. the need to avoid unnecessary transaction costs.

3.2. Service classification

Before addressing the provisions outlined in section 3.1 above, to assist stakeholders' understanding of the Rules requirements it is useful to summarise the AER's final determination for UE's classification of services into Standard Control Services, Alternative Control Services; Negotiated Services; and Unregulated Services.

3.2.1. Standard control services - Network services

The following services are provided within this classification.

- Constructing the distribution network
- Maintaining the distribution network and connection assets
- Operating the distribution network and connection assets (for DNSP purposes)
- Designing the distribution network
- Planning the distribution network
- Emergency response
- Administrative support (for example, call centre, network billing)
- Location of underground cables

3.2.2. Standard control services - Connection services

The following services are provided within this classification.

- New connections requiring augmentations

3.2.3. Alternative control services - Fee based services

The following services are provided within this classification.

- Fault response (not DNSP fault)
- De-energisation of existing connections
- Re-energisation of existing connections
- Meter investigation
- Special meter reading
- Remote AMI services
- Temporary disconnect / reconnect services
- Wasted attendance (not DNSP fault)
- Service truck visits
- Fault level compliance service
- Photovoltaic installation
- Routine connections (customers below 100 amps)
- Temporary supply services

3.2.4. Alternative control services - Quoted services

The following services are provided within this classification.

- Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets
- Supply enhancement at customer request
- Emergency recoverable works (that is, emergency works where customer is at fault and immediate action needs to be taken by the DNSP)
- Auditing of design and construction
- Specification and design enquiry fees
- Elective underground service where an existing overhead service exists
- Covering of low voltage mains for safety reasons
- Damage to overhead service cables caused by high load vehicles
- High load escorts (lifting overhead lines)

- Routine connections (customers above 100 amps)
- Supply abolishment
- Reserve feeder
- After hours truck by appointment.

3.2.5. Alternative control services - Public lighting services – fee based

The following services are provided within this classification.

- Operation, repair, replacement and maintenance of DNSP public lighting assets

3.2.6. Alternative control services - Metering services – fee based

The following services are provided within this classification.

- Metering charges (AMI)
- Metering charges public lighting
- Exit fees for transition to competitively sourced meter

3.2.7. Negotiated services

The following services are provided within this classification.

- Alteration and relocation of DNSP public lighting assets
- New public lighting assets (that is, new lighting types not subject to a regulated charge and new public lighting at green field sites)

3.2.8. Unregulated services

The following services are provided within this classification.

- The installation, maintenance and provision and repair of watchman (security) lights
- Provision of possum guards.
- Pole rental

It should be noted that Section 9 of this Pricing Proposal outlines the arrangements for UE's alternative control metering service tariffs, which in accordance with clause 6.18.3(c) of the Rules has been constituted as a separate tariff class with separate charging parameters. The remainder of this section 3 addresses the Rules tariff class requirements in relation to the standard control services.

3.3. Standard control service tariff classes

UE has established five tariff classes for standard control services as follows:

	Tariff Class	Typical Customer	Tariff Name	Criteria	Voltage
	Low Voltage Small	Residential	Low Voltage Small One Rate (LVS1R)	<20 MWh annual energy usage	230 Volts
		The typical customer may also have a dedicated circuit tariff (for hot water/slab heating), which has an average usage of 2.8 MWh per annum.			
	Low Voltage Medium	Small Commercial	Low Voltage Medium One Rate (LVM1R)	20 to 400 MWh annual energy usage	<1,000 Volts
		Large residential customers may be included in this category.			
	Low Voltage Large	Large Commercial	Low Voltage Large kVA Time of Use (LVkVATOU)	>400 MWh annual energy usage and/or >150 kVA Maximum Demand	<11,000 Volts
	High Voltage Large	Industrial	High Voltage kVA Time of Use (HVkVATOU)	High voltage supply	11,000 to 22,000 Volts
	Sub-transmission Large	Large Industrial	Sub-transmission kVA Time of Use (SubTkVATOU)	Sub-transmission supply	> 66,000 Volts

UE's proposed allocation of individual tariffs into tariff classes is shown below.

Table 3-1: Proposed Tariff Class Allocation

Tariff Code	Tariff Open New Connection	Tariff Description	Tariff Class
Unmet	Yes	Unmetered supplies	Low voltage small
LVS1R	Yes	Low voltage small 1 rate	
LVS2R	No	Low voltage small 2 rate	
LVDed ¹	Yes	Dedicated circuit	
WET2Step	No	Winter economy tariff	
TOD	Yes	Time of Day	
TOD9	Yes	Time of Day 9pm off peak	
RESKW1R ^{4,5}	Yes	Seasonal demand anytime energy rate	
RESKWTOU ^{2, 4}	Yes	Seasonal demand TOU energy rate	
TODFLEX	Yes	Time of Day Flexible	
LVM1R	Yes	Low voltage medium 1 rate	Low voltage medium
LVM2R5D	No	Low voltage medium 2 rate 5 day	
LVM2R7D	No	Low voltage medium 2 rate 7 day	
LVkWTOU	No	Low voltage KW time of use	
LVkWTOUH	No	Low voltage KW time of use – HOT	
TOU	Yes	Time of use	
LVMKWTOU ^{3,4}	Yes	Seasonal Demand anytime energy rate	
LVL2R	No	Low voltage large 2 rate	Low voltage large
LVL1R	No	Low voltage large 1 rate	
LVkVATOU	Yes	Low voltage large KVA time of use	
LVkVATOUH	No	Low voltage large KVA time of use-HOT	
HVkVATOU	Yes	High voltage KVA time of use	High voltage large
SubTkVATOU	No	Subtransmission KVA time of use	Subtransmission large

1. LVDed not available to customers with solar PV installed.

2. RESKWTOU will be replaced by RESKW1R from 1st April 2016. It has been updated with an anytime energy rate and max monthly demand measured on work days only.

3. LVMKWTOU available on an opt-in basis from July 1st 2016.

4. Not available to customers with dedicated hot water meters

5. RESKWTOU to be superseded by RESKW1R with existing RESKWTOU customers migrated to the new tariff effective 1st April 2016

NB: Where the tariff also includes P/TFIT, a prefix of "F" or "T" for each applicable tariff will apply eg.FLVS1R or TLVS1R

UE's 2016 Network Use of System tariffs (NUoS) for standard control services reflect the underlying structure of both the TUoS and DUoS charges. That is, the structures of the Transmission Use of System (TUoS) and Distribution Use of System (DUoS) tariffs are identical and the NUoS rates are the simple addition of the two.

The following sections set out the charging parameters for each proposed tariff, in accordance with clause 6.18.2(b)(3) of the Rules.

3.4. Charging parameters

3.4.1. Charging Parameters for DUoS Tariffs

The following table provides the charging parameters for each open Distribution tariff:

Table 3-2: Charging parameters – DUoS

DUoS Tariffs											
Charging Parameters	Units	Unmet	LVS1R	RESKWTOU RESKW1R	LVDed	TOD/TOD9/ TODFLEX	LVM1R	LVMKWTOU	TOU	LVkVA TOU	HVkVA TOU
Standing Charge	c/day		✓			✓	✓				
Anytime energy	c/kWh			✓				✓			
Summer peak energy	c/kWh	✓	✓			✓	✓		✓	✓	✓
Non summer peak energy	c/kWh	✓	✓			✓	✓		✓	✓	✓
Summer shoulder energy	c/kWh					✓					
Non summer shoulder energy	c/kWh					✓					
Off peak energy	c/kWh	✓			✓	✓			✓	✓	✓
Rolling Peak Demand	c/kVA/day									✓	✓
Summer demand incentive charge	c/kVA/day								✓	✓	✓
Summer demand charge	c/kW/day			✓				✓			
Non summer demand charge	c/kW/day			✓				✓			

3.4.2. Charging Parameters for TUoS Tariffs

The following table provides the charging parameters for each open Transmission tariff:

Table 3-3: Charging parameters–TUOS

TUoS Tariffs												
Charging Parameters	Units	Unmet	LVS1R	RESKWTOU	RESKW1R	LVDeD	TOD/TOD9/ TODFLEX	LVM1R	LVMKWTOU	TOU	LVkVA TOU	HVkVA TOU
Standing Charge	c/day											
Anytime energy	c/kWh				✓				✓			
Summer peak energy	c/kWh	✓	✓	✓			✓	✓		✓	✓	✓
Non summer peak energy	c/kWh	✓	✓	✓			✓	✓		✓	✓	✓
Summer shoulder energy	c/kWh			✓			✓					
Non summer shoulder energy	c/kWh			✓			✓					
Off peak energy	c/kWh			✓								
Rolling Peak Demand	c/kVA/day										✓	✓
Summer demand incentive charge	c/kVA/day									✓	✓	✓
Summer demand charge	c/kW/day			✓	✓				✓			
Non summer demand charge	c/kW/day			✓	✓				✓			

3.5. Tariff Availability per tariff class

The following section outlines which type of customer the UE network tariff is available to:

3.5.1. Low Voltage Small

- **Unmet** Available to unmetered supplies.
- **LVS1R** The Low Voltage Small Single Rate tariff is available to customers consuming less than 20 MWh per annum.
- **LVDed** The low voltage dedicated circuit tariff is available on request to eligible new connections on the LVS1R tariff with hot water and or slab heating consuming less than 20MWh per annum. Not available to customers with solar PV systems.
- **TOD** The Time of Day tariff is available to customers consuming less than 20MWh per annum with an interval meter.
- **TOD9** The Time of Day 9pm off peak tariff is available to customers consuming less than 20MWh per annum with an interval meter.
- **TODFLEX** The Time of Day Flexible Tariff is available to residential customers with an AMI enabled interval meter.
- **RESKWTOU** Seasonal demand with TOU energy available to customers with an AMI enabled interval meter consuming less than 20MWh per annum. Not available to customers with dedicated off peak meter. Will be superseded by RESKW1R from 1st April 2016.
- **RESKW1R** Seasonal workday demand with anytime energy available to customers with an AMI enabled interval meter consuming less than 20MWh per annum. Not available to customers with dedicated off peak meter. Available from 1st April 2016

3.5.2. Low Voltage Medium

- **LVM1R** The low voltage medium single rate tariff is available to customers consuming between 20MWh and 400 MWh per annum.
- **TOU** The Time of Use tariff is available to customers consuming between 20 MWh and 400 MWh per annum, and demand of less than 150kVA pa with an interval meter.
- **LVMKWTOU** The Time of Use tariff is available to customers consuming between 20 MWh and 400 MWh per annum. Available from 1st July 2016.

3.5.3. Low Voltage Large

- **LVkVATOU** The Low Voltage Large kVA Time of Use tariff is available to large customers consuming 400 MWh or above, and/or a demand of 150 kVA or above. A minimum chargeable rolling demand of 150 KVA applies.

3.5.4. High Voltage Large

- **HVkVATOU** The High Voltage kVA Time of Use tariff is available to large customers consuming 400 MWh or above, and/or a demand of 150 kVA or above. A minimum chargeable rolling demand of 1,150 KVA applies.

3.5.5. Subtransmission Large

- **SubTkVATOU:** The Subtransmission KVA Time of Use tariff is closed to new connections. It has a similar makeup (different rates) to the High Voltage kVA Time of Use Tariff; however a minimum chargeable rolling demand of 11,100 kVA applies.

3.6. Operating periods, time of day and season definitions

The tables below provide a reference showing the time of day for peak, off peak and shoulder periods together with providing details of UE seasonal charging parameters.

Table 3-4: Tariff - HVkVATOU, LVkVATOU, SUBTkVATOU

Business Days	N/A						Rolling Demand														N/A									
Business Days	Off Peak						Peak														Off Peak									
Business Days Summer Only	N/A												Summer Demand						N/A											
Weekends & Public Holidays	Off Peak																													
1/2 hr interval	1	2			13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		46	47	48
Local Time	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		to		11:00 PM	

Table 3-5: Tariff – TOU

Business Days	Off Peak						Peak																								Off Peak	
Business Days Summer Only	N/A												Summer Demand										N/A									
Weekends & Public Holidays	Off Peak																															
1/2 hr interval	1	2			13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		46	47	48		
Local Time*	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		to		11:00 PM			

Table 3-6: Tariff – TOD

Business Days	Off Peak						Shoulder						Peak														Off Peak			
Weekends & Public Holidays	Off Peak																													
1/2 hr interval	1	2			13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		46	47	48
Local Time*	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		to		11:00 PM	

Table 3-7: Tariff – TOD9

Business Days	Off Peak						Shoulder						Peak												Off Peak					
Weekends & Public Holidays	Off Peak																													
1/2 hr interval	1	2			13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	48
Local Time*	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		9:00 PM		10-12 PM	

Table 3-8: Tariff – TODFLEX

Weekdays	Off Peak						Shoulder						Peak												Shoulder		Off Peak			
Weekends	Off Peak						Shoulder																		Off Peak					
1/2 hr interval	1	2			13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	48
Local Time*	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		9:00 PM		10-12 PM	

Table 3-9: Tariff – RESKW1R (Seasonal Demand anytime energy Residential)

Demand																Peak																																
Energy	Anytime rate																																															
1/2 hr interval	1	2				13	14	15	16				27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48														
Local Time*	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		9- 10 PM		10- 12 PM																			

NOTE: Monthly maximum demand is based on WORK DAYS (i.e. excluding weekends and public holidays).

Table 3-10: Tariff – RESKWTOU (Seasonal Demand anytime energy Residential)

Demand															Peak																																	
Energy	Anytime rate																																															
1/2 hr interval	1	2				13	14	15	16				27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48														
Local Time*	12:00 AM		to		6:00 AM		7:00 AM		to		1:00 PM		2:00 PM		3:00 PM		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		9- 10 PM		10- 12 PM																			

NOTE: Monthly maximum demand is based on ANY DAY (i.e. including weekends and public holidays).

Table 3-11: Tariff - LVDED (Dedicated Load)

Any Day	Off Peak						N/A																								Off Peak	
1/2 hr interval	1	2	3	4	13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		46	47	48		
Local Time*	12:00 AM		1:00am 6:00 AM				7:00 AM to 1:00 PM 2:00 PM 3:00 PM 4:00 PM 5:00 PM 6:00 PM 7:00 PM 8:00 PM to 11:00 PM																									

NOTE: Off peak for LVDED is for up to 8 hours between 11pm and 7am local time controlled at United Energy's discretion. Note that if any controlled load boosts occur outside the off-peak periods, these will be charged at the premise's corresponding peak tariff rate.

Table 3-12: Tariff - LVS1R, LVM1R

All times	Peak																													
1/2 hr interval	1	2	3	4	13	14	15	16			27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42			47	48
EST	12:00 AM		1:00am 6:00 AM				7:00 AM to 1:00 PM 2:00 PM 3:00 PM 4:00 PM 5:00 PM 6:00 PM 7:00 PM 8:00 PM to 11:00 PM																							

NOTE: In order to maintain the same time limits during Eastern Standard Time (EST) and Daylight Saving Time (DST), billing data is adjusted by shifting the data forward an hour to accommodate for the time shift during DST.

Demand											Peak																																					
Energy	Anytime rate																																															
1/2 hr interval	1	2			17	18	19	20	21	22	23	24	29	30			33	34	35	36	37	38	39	40	41	42	43	44	45	48																		
Local Time*	12:00 AM		to		8:00 AM		9:00 AM		10:00AM		11:00AM		12:00PM		to		4:00 PM		5:00 PM		6:00 PM		7:00 PM		8:00 PM		9-10 PM		10-12 PM																			

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Table 3-14: Seasonal Periods (all tariffs except TODFLEX & RESKWTOU & RESKW1R & LVMKWTOU)

Months	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Period	Non Summer				Summer					Non Summer		

Table 3-15: Seasonal Periods (TODFLEX)

(Summer commences 1st day Daylight savings and finishes last day of Daylight savings)

Months	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Period	Non Summer			Summer						Non Summer		

Table 3-16: Seasonal Periods (RESKWTOU & RESKW1R & LVMKWTOU)

Months	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Period	Non Summer					Summer				Non Summer		

4. Pricing principles and UE's tariff strategy

4.1. Regulatory requirements

In November 2014 the Australian Energy Market Commission (AEMC) made a new National Electricity Rule¹ that requires distribution network businesses to develop prices that better reflect the costs of providing services to customers. The Rules establishes a new pricing objective and pricing principles to guide tariff setting. The key change is the requirement that each tariff be based on the Long Run Marginal Cost (LRMC) of providing network services. Under the new Rule, network pricing will be more cost-reflective, thereby providing more efficient signals for investment and usage decisions. Clause 6.18.5 of the Rules requires UE to comply with the following pricing principles.

- (a) For each tariff class, the revenue expected to be recovered should lie on or between:
 - (i) an upper bound representing the stand alone cost of serving the customers who belong to that class; and
 - (ii) a lower bound representing the avoidable cost of not serving those customers.
- (b) 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:
 - (i) the costs and benefits associated with calculating, implementing and applying that method as proposed;
 - (ii) 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
 - (ii) 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*.
- (c) The revenue expected to be recovered from each tariff must:
 - (i) reflect the *Distribution Network Service Provider's* total efficient costs of serving the *retail customers* that are assigned to that tariff;
 - (ii) 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
 - (iii) minimise distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (b).
- (d) 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 (a) to (c) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to:
 - (i) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (b) and (c), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*);

- (ii) the extent to which *retail customers* can choose the tariff to which they are assigned; and
- (iii) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.
- (e) The structure of each tariff must be reasonably capable of being understood by *retail customers* that are assigned to that tariff, having regard to:
 - (i) the type and nature of those *retail customers*; and
 - (ii) the information provided to, and the consultation undertaken with, those *retail customers*.
- (f) A tariff must comply with the *Rules* and all *applicable regulatory instruments*.

This section provides an overview of UE's approach to tariff-setting, including its application of the pricing principles described above. Section 6 of this Pricing Proposal demonstrates that UE's tariff proposals for 2016 comply with the Rules requirements and the AER's final determination.

4.2. UE's Network Tariff Objectives

UE's objectives have been developed through the consultation process with customers and retailers. The objectives describe the characteristics that our network tariffs should exhibit in order to:

- Give practical effect to the network pricing objective and the pricing principles set out in the Rules.
- To realise the potential benefits associated with technological change and more efficient network usage.

These objectives have provided a practical way for stakeholders to engage directly in the design of our new tariffs and provided a useful framework for testing our tariffs against the Rules principles.

The development and adjustment of UE tariffs broadly incorporates the following policy principles:

- **Simple:** Ability for customers to react and understand.
- **Attractive:** Desire of retailer to pass the tariff through to customers. While our preference is for our tariffs to be passed through to customers by the retailer we recognise that exposure of retailers to an input price signal should lead to competition and actions to manage the associated cost risk.
- **Forward Looking:** Ability to deal with changing market conditions while being technology and policy agnostic.
- **Manage Volatility:** Desire for low year-on-year volatility.
- **Predictable:** Ability for customers to forecast and understand impacts - no bill shock.
- **Cost-reflective:** Reduce inefficiencies and cross-subsidies and adapt to different types of customer load profiles and technologies.
- **Compliant:** Compliance within the various regulatory and legislative criteria.

UE's tariff proposals may reflect a compromise between these competing pricing objectives. UE's overall approach is to satisfy the above principles to the greatest extent possible, subject to ensuring that UE's regulatory obligations are fully satisfied.

4.3. Stakeholder consultation & tariff initiatives

United Energy (UE) is committed to customer and key stakeholders to better inform public policy positions and on major elements of our business that impact customers, including tariffs.

While distributors do not traditionally deal directly with end use customers, we understand that customers ultimately bear the cost of our services. In this regard, UE plays a significant role in distributing electricity to many Victorian business and domestic customers. Together with our core objectives of delivering energy in a safe and reliable manner, UE strives to provide an efficient and cost effective service for our customers.

Our stakeholder engagement initiatives addressed a broad range of issues including: the case for tariff reform; tariff reform objectives; proposed tariff strategy; different options and structures; transition arrangements; the scope and purpose of the Tariff Structure Statement; customer impact analysis, the evolving benefits of cost reflective network tariffs; and the specification and pricing of our optional residential demand tariff, introduced in July 2015.

Our approach to stakeholder engagement on the development of our TSS was based on the strategic approach we established in February 2014, in preparation for our Electricity Distribution Pricing Review. We recognised that in order to meet changing community expectations reflected changes to Chapter 6 of the National Electricity Rules (NER) and the AER Better Regulation Guidelines, we needed fresh thinking about the way we communicate. We developed our Customer and Stakeholder Engagement Strategy to outline our commitment and approach.

Our stakeholder engagement objectives are illustrated in Figure 4.1. Our engagement on the TSS has been diverse in nature, commencing in mid-2014. Our final submission has benefited significantly from the sustained and constructive input of a broad range of stakeholders.

Figure 4.1: Stakeholder engagement objectives and outcomes

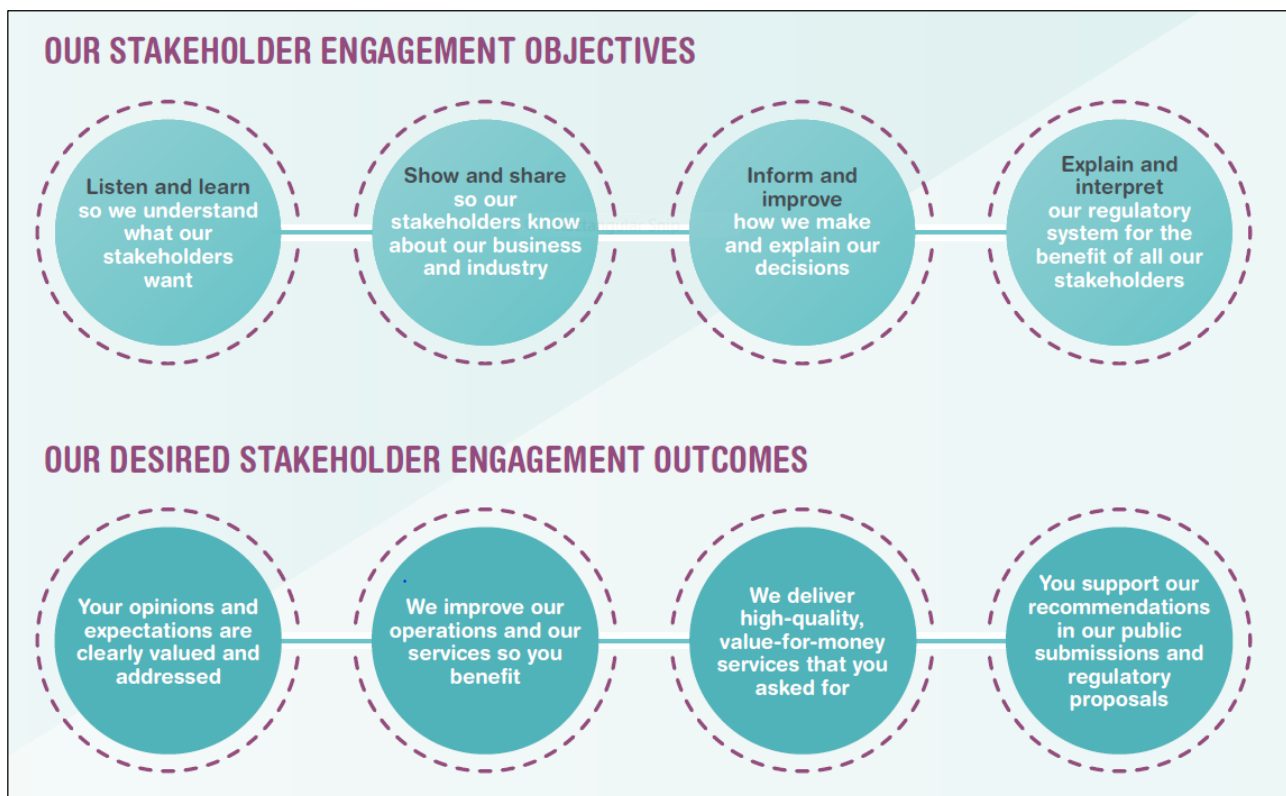


Figure 4.2 provides a summary of the key drivers that stakeholders emphasised as part of the consultation processes that UE has engaged in since mid-2014.

Figure 4.2: Stakeholder key drivers



4.3.1. Seasonal demand tariff options for Residential low voltage customers (RESKWTOU / RESKW1R)

In November 2014 the Australian Energy Market Commission (AEMC) made a new National Electricity Rule (NER, cl. 6.18.4.) that requires distribution network businesses to develop prices that better reflect the costs of providing services to customers. Whilst we are aware of our obligations under the NER, UE is committed to achieving greater alignment between individual customer usage profiles and their resultant cost on the UE network. We believe that that customers will benefit through;

- Improved equity and fairness due to reduction in cross subsidies between different types of network users. For example, air conditioning, solar PV and seasonal consumption.
- Reduced cost of network investment as customers respond to price signals by shifting discretionary load to off peak periods and reducing load in peak demand periods.
- Benefit realisation of the AMI (smart meter) program where greater insight about customer consumption profiles will lead to overall reduction in cost to network users.
- Appropriate price signals regarding investment in new technology to drive the most efficient network solutions for our customers in the future.

UE considers that fundamental to transitioning to a more cost reflective tariff structure is the requirement to reduce the emphasis on fixed and usage based charges and introduce demand tariff components (aligned to network peak

constraints). Having introduced a residential demand tariff on an opt-in basis for 2015, UE has had the opportunity to evaluate the feedback received from stakeholders on elements of tariff design and application. Consequently, UE has made some enhancements to the design of the residential demand tariff which will be available from 1st of April 2016. From this date, UE will be seeking to transition customers from RESKWTOU to RESKW1R.

They key changes are;

- Availability of RESKWTOU to 31st March 2016 converts to RESKW1R from 1st April 2016.
- Maximum monthly demand charge window excludes weekends and public holidays.
- Commitment to anytime energy rate rather than potential TOU rate structure.
- TUoS tariff components that are aligned to DUoS structure.

The table below provides a summary of charge parameters and an indication of how the DUoS is allocated between demand/energy components and summer/non-summer periods for 2016.

Table 4-1: Seasonal Demand Anytime Energy Residential Tariff Specification (Indicative DUoS)

Tariff Name	Component	Description	Charging Parameter	Rate Summer (Dec-Mar)	Rate Non Summer (Apr-Nov)	Criteria	Average DUoS Bill (4,200KWh pa)	DUoS Charge Split	Billing
Seasonal demand / single rate (RESKW1R)	Energy	Anytime energy rate on any day type.	c/kWh	2.44	2.44	Monthly energy kWh. Summer = Dec-Mar	\$103	40%	Monthly
	Demand	<ul style="list-style-type: none"> - Seasonal demand elements. - Premium for Summer reflects network constraint. 	\$/kW/month	22.82	9.01	<ul style="list-style-type: none"> - Highest half hourly peak average between 3-9PM local time on business days for the month. - Summer = Dec-Mar. - Maximum demand is reset monthly. - Monthly minimum demand of 1.5KW 	\$144	60%	
	Seasonal Split		\$/Month	\$30.35	\$15.71	Total	\$247	100%	

4.3.2. Seasonal demand tariff options for Small Business low voltage customers (LVMKWTOU)

During 2016, UE's commitment to achieving greater alignment between individual customer usage profiles and their resultant cost on the UE network will also extend to low voltage (small business) customers via the introduction of a demand/anytime energy tariff that bears the same features as the residential customer tariff. This tariff will be available for eligible customers on an optional basis from 1st July 2016.

Table 4.2 provides a summary of charge parameters and an indication of how the DUoS is allocated between demand/energy components and summer/non-summer periods for 2016.

Table 4-2: Seasonal Demand Anytime Energy Small Business Tariff Specification (Indicative DUoS)

Tariff Name	Component	Description	Charging Parameter	Rate Summer (Dec-Mar)	Rate Non Summer (Apr-Nov)	Criteria	Indicative DUoS Bill (100MWh pa)	DUoS Charge Split	Billing
Small business demand / Time of Use (LVMKWTOU)	Energy	Anytime energy rate on any day type.	c/kWh	3.60	3.60	Monthly energy kWh. Summer = Dec-Mar	\$3,595	50%	Monthly
	Demand	<ul style="list-style-type: none"> - Seasonal demand elements. - Premium for Summer reflects network constraint. 	\$/kW/month	37.47	24.98	<ul style="list-style-type: none"> - Highest half hourly peak average between 10-6PM local time on business days for the month. - Summer = Dec-Mar. - Maximum demand is reset monthly. - Monthly minimum demand of 1.5KW 	\$3,592	50%	
	Seasonal Split		\$/Month	\$673.23	\$561.82	Total	\$7,187	100%	

4.4. Future tariff developments

Clause 6.18.2 (b)(5) requires UE set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur. For the forthcoming regulatory year, UE does not anticipate any variation to the tariffs set out in this Pricing Proposal other than those indicated in section 4.3.1.

UE is committed to tariff reform as set out in our Tariff Structure Statement 2017-2020 (TSS) submitted to the AER on the 25th of September 2015. UE also supports tariff reform as part of a wider industry transformation that will;

- Incentivise demand management solutions
- Encourage competition
- Facilitate storage technologies
- Reduce the long term costs to consumers if we are able to reduce demand at peak times

Our TSS is an important evolutionary step on the path to the network of the future and includes;

- The introduction of demand components for residential customer measured between 3pm-9pm on work days.
- The introduction of demand components for small business customers measured between 10am-6pm on work days.

In addition to the tariff initiatives described in section 4.3.1 and 4.3.2, and as set out in our TSS, from 2017 UE proposes commencing the transition of all customers to demand based tariffs to deliver real benefits to our customers. UE will continue to provide updated information on future price changes in accordance with the requirements of Clause 6.18.9 of the Rules.

4.5. Publication of information regarding tariffs and tariff classes

Clause 6.18.9 of the Rules requires that a DNSP 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 DNSP expects prices to change over the regulatory control period and the reasons for the expected changes.

The Rules also require that the information for a particular regulatory year must, if practicable, be posted on the website 20 business days before the commencement of the relevant regulatory year and, if that is not practicable, as soon as practicable thereafter. In accordance with the Rules requirements and subject to AER approval, UE will make this information available on its website within the specified timeframe.

4.6. Expected DUoS price trends

The following table summarises UE's indicative movement in tariff charging parameters. The actual price movements in each year will remain subject to review at the time, following consideration of the objectives set out in section 4.4.

Table 4-3: Indicative charging component movement in the 2016-2020 Regulatory Control Period

Indicative relative charging component movement in the 2016-20 Regulatory Control Period										
Distribution Tariff Class and Tariff	Standing Charge	Summer Peak Energy	Non Summer Peak Energy	Summer Shoulder Energy	Non Summer Shoulder Energy	Off Peak Energy	Summer Capacity Max KW	Non-summer Capacity Max KW	Rolling Peak Demand	Summer Demand Incentive Charge
Low Voltage Small										
Unmetered supplies		-	-			-				
Low voltage small 1 rate	↓	↑	↑							
Dedicated circuit						↑				
Time of Day (TOD, TOD9 & TODFLEX)	-	↑	↑	-	↓	↓				
Seasonal Demand TOU Residential		↓	↓	↓	↓	↓	↑	↑		
Low Voltage Medium										
Low voltage medium 1 rate	↓	↑	↑							
Time of Use		↑	↑	-	↓	↓				↑
Seasonal Demand TOU Small bus.		↓	↓	↓	↓	↓	↑	↑		
Low Voltage Large										
Low voltage large KVA time of use		↑	↑	-	↓	↓			↓	↓
High Voltage Large										
High voltage KVA time of use		↑	↑	-	↓	↓			-	-
Subtransmission Large										
Subtransmission KVA time of use		-	-	-	-	-			-	-

↑ Increase relative to the average price movement per tariff.

↓ Decrease relative to the average price movement per tariff.

- In line with average price movement per tariff.

A grey cell indicates that the corresponding charging parameter is not applicable for a particular tariff.

5. Standard control services - Tariffs and average charges

5.1. Regulatory Requirements

This section of the Pricing Proposal addresses clause 6.18.2(b)(4) of the Rules, which requires UE to provide details of the expected weighted average revenue for each tariff class for standard control services for the relevant regulatory year, 2016, and also for the current regulatory year, 2015. This section also provides useful information regarding the proposed average price change for each standard control tariff.

5.2. Proposed average increases and weighted average revenue

The following table indicates movement of DUoS, TUoS and NUoS revenue for each tariff between 2015 and 2016:

Table 5-1: UE 2016 Tariff Price Movements

UED 2016 Tariff Price Movements

Description	Tariff Code	DUoS % price movement	TUoS % price movement	NUoS % price movement
Class - Low Voltage Small				
Unmetered supplies	UnMet	-8.0%	6.4%	-4.9%
Low voltage small 1 rate	LVS1R	-6.8%	6.4%	-4.0%
Low voltage small 2 rate	LVS2R*	-8.0%	6.5%	-5.2%
Dedicated circuit	LVDed	10.0%		10.0%
Winter economy tariff	WET2Step*	-8.0%	6.4%	-3.5%
Time Of Day	TOD	-8.0%	45.7%	-1.2%
Time of Day 9pm Off Peak	TOD9	-8.0%	0.0%	-8.0%
Time of Day Flexible	TODFLEX	-0.9%	6.4%	-0.3%
Residential KW time of use	RESKWTOU	-2.2%	14.9%	1.5%
Class - Low Voltage Medium				
Low voltage medium 1 rate	LVM1R	-17.2%	6.4%	-12.6%
Low voltage medium 2 rate 5 day	LVM2R5D*	3.0%	6.4%	3.5%
Low voltage medium 2 rate 7 day	LVM2R7D*	5.0%	6.4%	5.3%
Low voltage KW time of use	LVkWTOU*	-8.0%	6.5%	-5.6%
Low voltage KW time of use - HOT	LVkWTOUH*	-8.0%	6.5%	-6.3%
Reverse cycle airconditioning time of use	RCACKWTOU*	0.0%	0.0%	0.0%
Time Of Use	TOU	5.0%	6.4%	5.2%
Low voltage medium KW time of use	LVMKWTOU			
Class - Low Voltage Large				
Low voltage large 2 rate	LVL2R*	-8.0%	6.4%	-5.8%
Low voltage large 1 rate	LVL1R*	-8.0%	6.5%	-3.7%
Low voltage large KVA time of use	LVkVATOU	-8.0%	6.5%	-4.3%
Low voltage large KVA time of use - HOT	LVkVATOUH*	-8.0%	6.5%	-5.5%
Class - High Voltage Large				
High voltage KVA time of use	HVkVATOU	-8.0%	6.5%	-3.2%
High voltage KVA time of use - HOT	HVkVATOUH*	0.0%	0.0%	0.0%
Class - Subtransmission Large				
Subtransmission KVA time of use	SubTkVATOU*	-8.0%	6.4%	1.2%

*Tariff closed to premises not already taking supply under this tariff and new connections.

The average price movement for the 2016 DUOS tariffs is a reduction of 5.53%. This reduction is predominantly attributable to the X factor of 8.72% which manifests as a reduction in DUoS revenue of 8.72% stemming from the AER's preliminary decision in determining UE's efficient costs.

The average price movement for the 2016 TUOS tariffs is an increase of 8.52%. This is determined by the maximum transmission revenue allowed for 2016 versus the estimated transmission revenue recovered in 2015. The previous table shows this price movement has been applied to the all TUOS tariffs, except TOD and RESKWTOU.

The table below indicates the expected weighted average DUoS revenue for each tariff class for standard control services for the relevant regulatory year, 2016, and also for the current regulatory year, 2015.

Table 5-2: UE DUOS Revenue by Tariff Class

UED DUOS Revenue by Tariff Class

Class	2015 Revenue \$M	2016 Revenue \$M	% Movement
Low Voltage Small	\$ 181.4	\$ 169.3	-6.7%
Low Voltage Medium	\$ 91.6	\$ 91.4	-0.3%
Low Voltage Large	\$ 93.9	\$ 86.4	-8.0%
High Voltage Large	\$ 17.2	\$ 15.8	-8.0%
Subtransmission Large	\$ 0.2	\$ 0.2	-8.0%
Total	\$ 384.3	\$ 363.1	-5.5%

The underlying drivers of DUOS prices are cost recovery to meet expanding network at peak times and replacement of infrastructure. The AER determines allowed revenue for distributors over a 5 year period with rates of increase subject to annual variation (see table 2.1).

Figure 5-1: 2016 Expected Revenue % by Customer Class

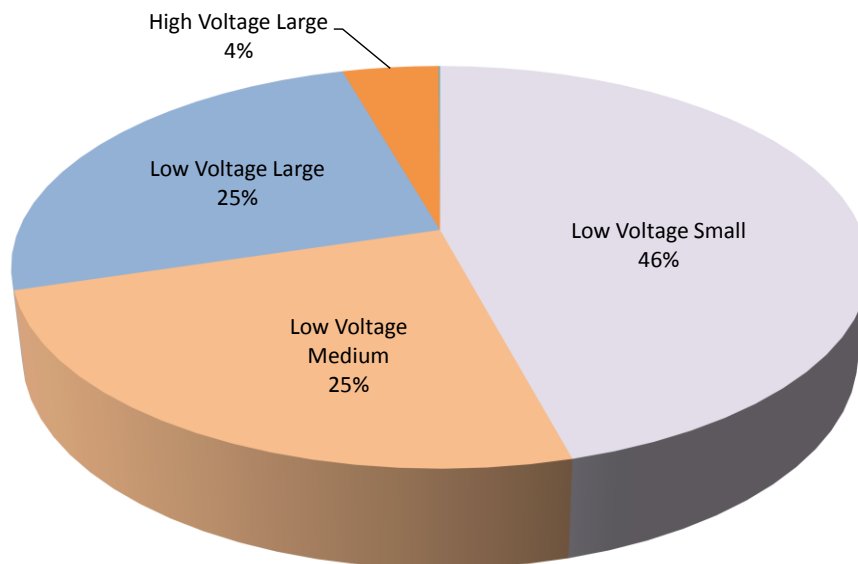
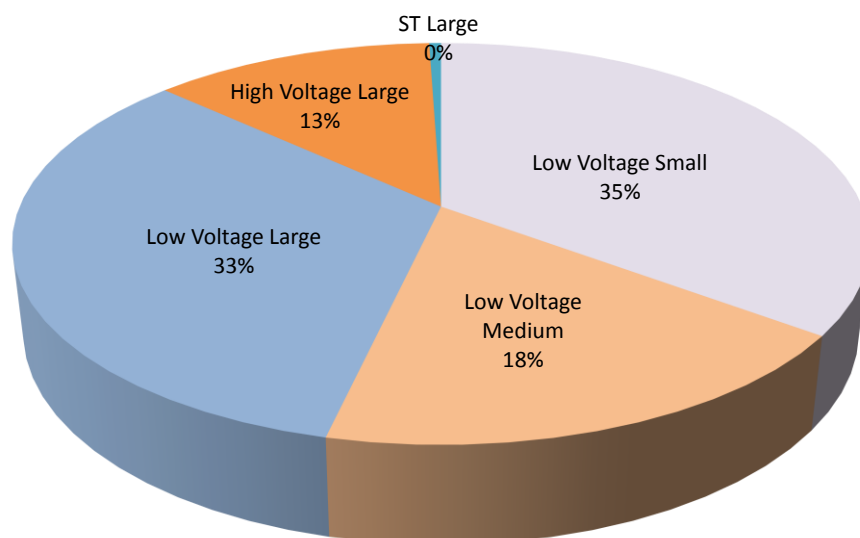


Figure 5-2: 2016 Expected Energy Consumption % by Customer Class

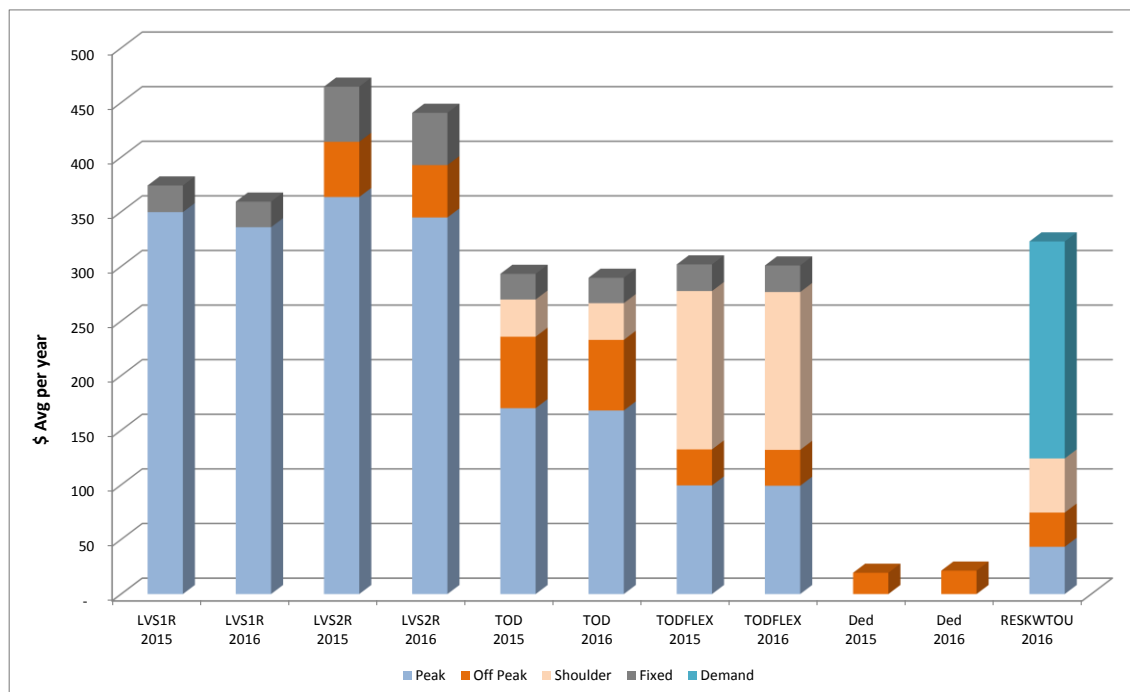
As shown by figure 1 and 2, UE's larger customers represent greater energy volumes, but contribute less revenue, and conversely the smaller customers represent lesser energy in comparison to revenue. This reflects the aggregate of assets required to service the customers. Smaller customers utilise more of the electricity network, therefore are priced comparatively higher than larger customers who use comparatively less of the electricity network.

5.3. Average tariff charges per customer for 2015 and 2016

This section presents the average yearly charges for UE's customers in 2015 and 2016. The following graphs are presented for each tariff class for standard control services.

5.3.1. Low Voltage Small Class

Figure 5-3: Average Distribution and Transmission charge per customer – LV Small



Each customer's bill is comprised of two components in addition to DUOS and TUOS. These components are Advanced Interval Meter (AMI) and PFIT/TFIT charges which respectively recover revenue for AMI meters and solar rebates.

Table 5.2 indicates the average network charge and percentage increases for a residential customer with no hot water split by the 4 components for the residential tariffs. The average residential customer with no hot water uses approximately 4.2MWh per annum.

Table 5-2: Residential Customer Impact based on 4.2MWh per annum

Indicative Tariff	Component	2014	2015	2016	% Change	Delta \$
LVS1R	DUOS	\$ 264.19	\$ 294.53	\$ 274.51	-6.8%	-\$ 20.02
	TUOS	\$ 70.72	\$ 80.49	\$ 85.67	6.4%	\$ 5.18
	Metering	\$ 141.33	\$ 154.51	\$ 91.55	-40.7%	-\$ 62.96
	Pass through	\$ 46.77	\$ 26.18	\$ 32.28	23.3%	\$ 6.09
	Total	\$ 523.01	\$ 555.71	\$ 484.01	-12.9%	-\$ 71.70
RESKWTOU	DUOS		\$ 252.73	\$ 247.09	-2.2%	-\$ 5.64
	TUOS		\$ 70.24	\$ 80.70	14.9%	\$ 10.46
	Metering		\$ 154.51	\$ 91.55	-40.7%	-\$ 62.96
	Pass through		\$ 26.18	\$ 32.28	23.3%	\$ 6.09
	Total		\$ 503.67	\$ 451.62	-10.3%	-\$ 52.05

Figure 5-4: Residential Customer Impact (LVS1R) 4.2MWh per annum

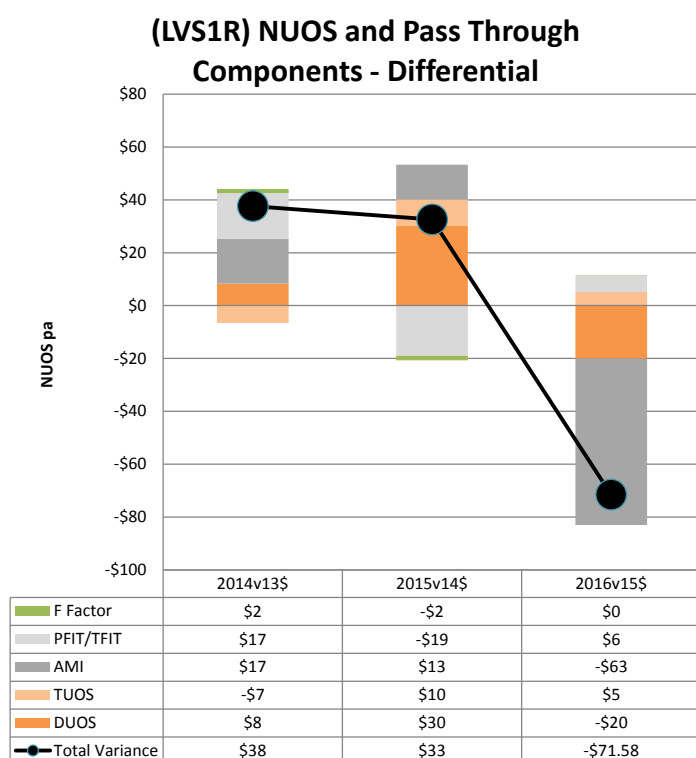
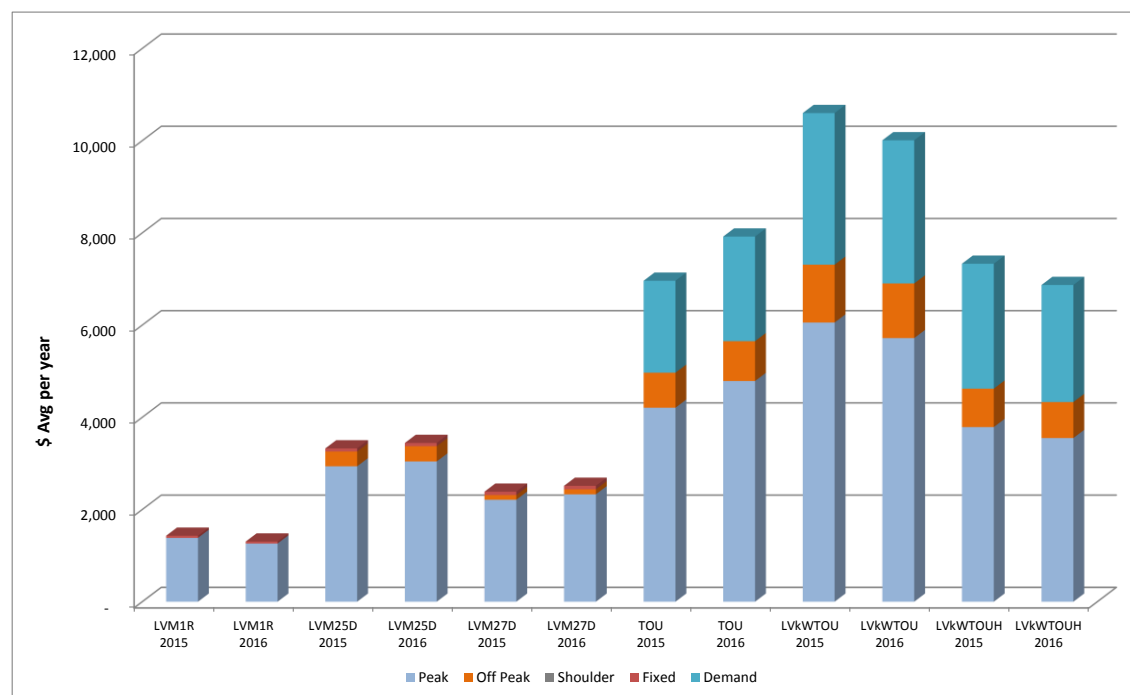


Figure 5-4 indicates that the annual increase in NUOS & pass throughs from 2015 to 2016, for the most common residential tariff, is a decline of \$71.58.

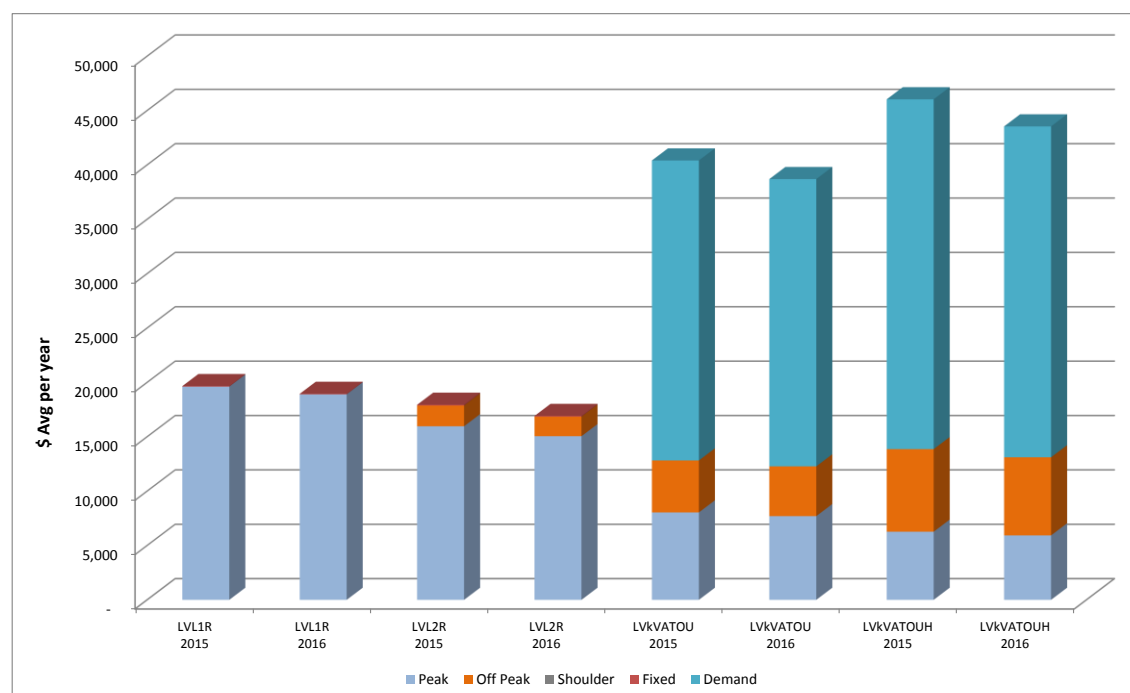
5.3.2. Low Voltage Medium Class

Figure 5-5: Average network charge per customer – LV Medium



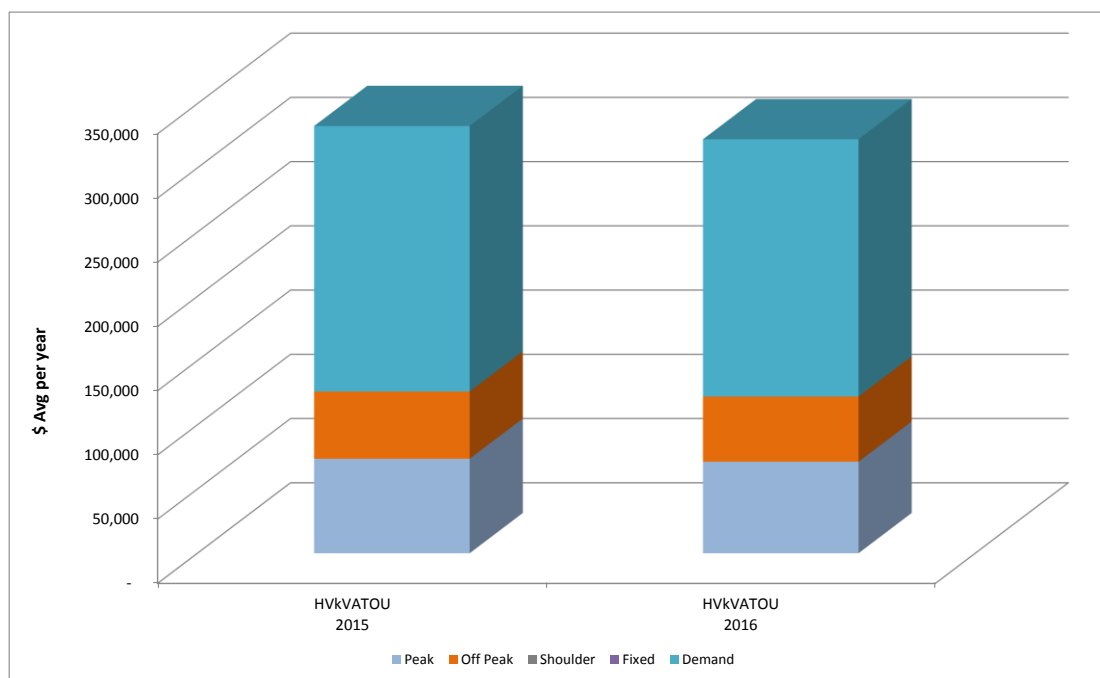
5.3.3 Low Voltage Large Class

Figure 5-6: Average network charge per customer – LV Large



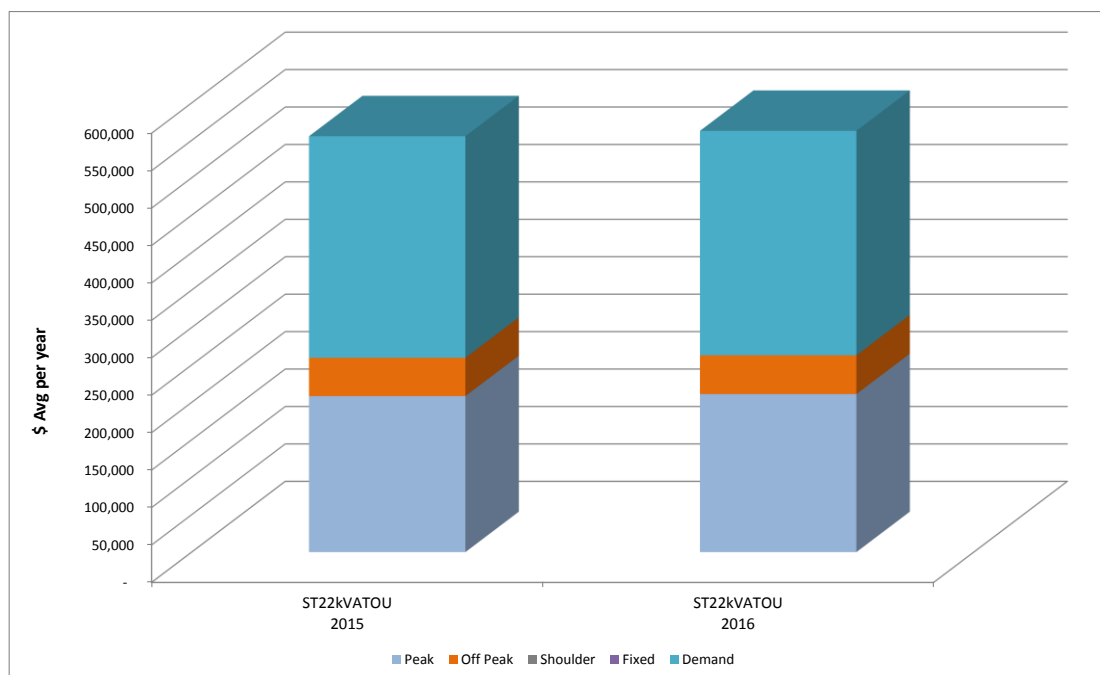
5.3.4. High Voltage Large Class

Figure 5-7: Average network charge per customer – HV Large



5.3.5. Sub-transmission Large Class

Figure 5-8: Average network charge per customer – Subtransmission Large



6. Demonstrating compliance with the Rules

6.1. Regulatory Requirements

Clause 6.18.2(b)(7) requires UE to demonstrate compliance with the Rules and any applicable distribution determination. Section 2 of this Pricing Proposal provided information in relation to the compliance issues arising from the AER's final determination, and the steps that UE has taken to ensure compliance. Furthermore, Section 3 described UE's approach to tariff-setting, including its compliance with the pricing principles in the Rules.

Notwithstanding the information already provided, this section provides further detailed information regarding UE's compliance with the Rules.

6.2. Compliance with the Revenue Cap formulae

Section 2.2 of this Pricing Proposal sets out the AER's revenue cap formulae that applies to UE for the 2016-2020 period. In its preliminary decision the AER has determined UE's annual expected smoothed 2016 revenue to be \$375.1 million (refer table 2.1). For 2016, the AER has indicated (PTRM model preliminary decision) that UE shall apply an X factor of 8.72 and a CPI of 2.5%.

In order to determine the Total Annual Revenue target applicable to UE in 2016, application of further pricing components indicated in Table 6.1 below needs to be taken into account. More detailed descriptions of these elements and their application under the formulae are provided in section 2.2.

After the application of the formulae, UE's Annual Expected Smoothed Revenue for 2016 of \$375.1 million is converted to a Total Annual Revenue of \$363.05million. The table below indicates the components of the formula and their impact.

Table 6.1 – 2016 Total Annual Revenue Control Mechanism Formulae Components

Component	% Increase/Decrease
CPI	2.5%
B	0.02%
X	-8.72%
S ^{**}	-2.66%
I [*]	-0.6%
T	N/A for 2016
Total Annual Revenue (\$ mil.)	\$363.05

* For 2016 the AER has approved an 'I' factor of -\$2,245,000 relating to United Energy's fire prevention performance in 2014 as assessed by the AER. In 2016 this will be passed through to customers as part of the DUOS rates.

** For 2016 the AER has approved an 'S' factor of -2.66% relating to United Energy's performance under the Service Target Performance Incentive Scheme (STIPIS) in 2014 as assessed by the AER. In 2016 this will be passed through to customers as part of the DUOS rates.

6.3. Compliance with the side constraints

Section 2.3 provides details of the side constraint that applies to average price changes for tariff classes, and section 5.2 shows the DUOS movement by tariff. UE's Pricing Proposal is compliant given side constraints do not apply to the first year of a new regulatory period.

6.4. Standalone and Avoidable Costs

6.4.1. Definition

Standalone Costs:

The Standalone cost for a tariff class is the cost of supplying only the tariff class concerned, with all other tariff classes not being supplied. If customers were to pay above the standalone cost then it would be economically beneficial for customers to switch to an alternate provider, and economically feasible for an alternate provider to operate. This creates the possibility of inefficient bypass of the existing infrastructure.

Avoidable Costs:

The Avoidable cost for a tariff class is the reduction in network cost that would take place if the tariff class were not supplied (whilst all other tariffs remained supplied). If customers were to be charged below the avoidable cost, it would be economically beneficial for the business to stop supplying the customers as the associated costs would exceed the revenue obtained from the customer.

6.4.2. Compliance

As noted in Section 4 of this Pricing Proposal, the Rules require that distribution tariffs should lie between the following upper and lower bounds:

- tariffs for each customer should generate revenue in excess of the avoidable cost to service the customer; and
- tariffs for each customer should generate revenue less than the cost of providing the service on a stand-alone basis to the customer.

To demonstrate that distribution tariffs fall between the avoidable cost "floor" and standalone cost "ceiling", UE must first apply a "cost of supply" methodology to assist in setting tariff rates. Broadly speaking, tariff rates are set to recover the allocated distribution revenue from that customer group. It is noted, however, that UE's approach to setting tariff rates is to consider all the pricing principles outlined in Section 4 of this Pricing Proposal.

The critical issue from a cost of supply modelling perspective is the method by which distribution revenue is allocated across the tariff groups. As network businesses are characterised by relatively high fixed costs and significant asset-sharing between customer groups, there is no unambiguously "correct" method for allocating costs. UE's method of allocation is based on each tariff's relative usage of UE's network assets.

In the model, customers are assigned into tariff groups based on voltage and demand characteristics. The consumption and demand characteristics for each tariff group are calculated as follows:

- For asset based costs, the quantity of assets and supporting infrastructure are assigned to the tariff groups according to the combined consumption and demand characteristics of all customers using the asset, e.g. HV assets are assigned to LV and HV customers, but not to sub-transmission customers. The cost of providing the assigned assets is then calculated for each customer class.
- For operational and maintenance costs, costs are directly attributed to particular asset classes, where possible, and the remaining costs are assigned to overheads

- Attributable costs use a weighted averaging to apply to the customers in each class
- Overheads are averaged over all customers
- Combining the overhead, maintenance and infrastructure costs, the overall cost of supply for each customer is calculated.
- UE has extended its “cost of supply” methodology to assess the avoidable and standalone costs. The avoidable cost model recognises that only a proportion of total costs are avoidable. In particular, the majority of asset-related costs cannot be avoided even if a particular customer group is no longer served. Inevitably, the assessment of which costs are avoidable is a matter of judgement. It should be noted, however, that as the avoidable costs are less than the total costs, UE’s cost of supply methodology will always set tariffs at a level that exceeds avoidable costs.

UE’s modelling of standalone costs is similarly based on the cost of supply model. The principal differences between the “basic” cost of supply estimates and standalone costs are:

- Standalone networks to serve a particular tariff class will not enjoy the benefit of diversity in peak demand between tariff classes;
- Economies of scale may be lost in supplying a subset of existing customers or tariffs;
- Greater urban congestion may result in the optimised replacement cost exceeding UE’s regulated asset value; and
- It is likely that a notional “standalone” competitor to UE may seek a rate of return that exceeds the regulated cost of capital.

These factors indicate that the standalone costs will exceed the cost of supply estimates on which UE bases its tariff design. It is important to recognise that it is difficult to determine the standalone costs with precision – inevitably a judgement must be made. The results of UE’s modelling is summarised in Table 6.2:

Table 6-2: Comparison of 2016 Tariff Rates with Existing Estimated “Cost Window”

Tariff Code	Tariff Class	Lower Bound "Avoidable Cost" (c/kWh)	2016 Avg DUOS (Exc GST) (c/kWh)	Upper Bound "Standalone Cost" (c/kWh)
Unmet	Low Voltage Small	0.37	2.91	14.53
LVS1R			6.51	
LVS2R*			4.90	
LVDed			1.75	
WET2Step*			2.84	
TOD			5.89	
TOD9			4.60	
TODFLEX			6.51	
LVSKWTOU			6.51	
LVM1R	Low Voltage Medium	0.44	8.05	19.65
LVM2R5D*			5.73	
LVM2R7D*			6.81	
LVkWTOU*			5.79	
LVkWTOUH*			6.20	
TOU			7.65	
LVMKWTOU			7.65	
LVL2R*	Low Voltage Large	0.15	5.23	6.54
LVL1R*			4.82	
LVKVATOU			5.79	
LVKVATOUH			6.20	
HVKVATOU	High Voltage Large	0.08	1.66	3.32
SubTkVATOU*	Subtransmission Large	0.08	0.47	3.32

* Tariff closed to new connections and customers not already taking supply under this tariff

6.5. Long Run Marginal Costs

Sections 6.18.5 (f) to (j) of the NER establish the requirement for UE to demonstrate that each tariff is based on the Long Run Marginal Cost (LRMC) of providing network services. UE's TSS document submitted to the AER on the 25th of September 2015 details how UE has addressed the new pricing objective and pricing principles in relation to LRMC calculation methodology and recovery of efficient costs. Given that the TSS is currently subject to an AER regulatory approval process, UE considers that the original TSS document is the best source of information regarding LRMC and indicative pricing levels for tariffs.

United Energy approach to LRMC signalling for TSS period

UE will apply an approach to transition customers to tariffs which better reflect the estimated LRMC cost of demand within each customer segment. As part of this transition UE has also taken into account potential customer impacts. In signalling LRMC UE will seek to reflect a balance between the pure LRMC demand signal, recovered via tariff demand component revenue and the desire to minimise year on year customer NUOS impacts and the objectives described in section 6.18.5 (f) to (j) of the NER.

The proposed approach to transition for each tariff class is described briefly as follows;

Low voltage small residential customers – Whilst UE already has a residential tariff with demand components in operation, it is proposed that all customers transition to a tariff with a demand component by 1st January 2017. This initial step will target 30% of a customer's DUOS charge to be recovered from demand tariff components with a subsequent step up to 60% (of DUOS from demand) from 2019. At this level approximately 75% of the

calculated LRM of demand is being recovered from demand tariff components, with the residual revenue being recovered through an anytime energy tariff. Demand tariff components will be recovered on a \$/kW basis.

Low voltage small business customers – United Energy will introduce an optional small business tariff with demand components in 2016. Additionally, it is proposed in the TSS that all customers transition to a new tariff with a demand component by 1st January 2017. This initial step will target 25% of a customer's DUOS charge to be recovered from demand tariff components with a subsequent step up to 50% (of DUOS from demand) from 2019. This level approximates the calculated LRM of demand with the residual revenue being recovered through an anytime energy tariff. Demand tariff components will be recovered on a \$/kW basis.

Large business customers – As our large customer tariffs already have well established monthly and seasonal demand components our approach will be to use the estimated scaled LRM demand values to guide tariffs levied on demand components on a \$/kVA basis. Residual revenue will be recovered on a TOU energy basis. For this customer class United Energy will be seeking to minimise tariff driven customer impacts for the current TSS period.

6.6. Description of price changes

Consistent with the AER 2016-2020 Price Determination, rebalancing has been undertaken of tariffs at the tariff class level.

This rebalancing takes into consideration and is consistent with the Price Determination and tariff policies, balancing the need to:

- recover maximum allowable revenue to recover the efficient costs of operating the network business;
- reduce risk in recovering revenue;
- give pricing signals to customers to provide an incentive for efficient utilisation of the network;
- be consistent with Pricing Principles and Cost of Supply Model where each tariff is;
 - above the avoidable cost of serving distribution customers;
 - below the cost of providing the service on a standalone basis;
- signal the impact of additional usage on future investment costs;
- recover NUoS from customers in proportion to the services provided - classified by voltage, demand, and consumption patterns;
- be consistent with UE's tariff strategies;
- be consistent with the UE tariff policy framework.

Given the above considerations, it has been decided not to implement the average price movement across all tariffs as this would be inconsistent with the pricing principles which require signalling of the impact of additional usage on future investment costs. Accordingly some rebalancing has been undertaken at the tariff class level.

7. Transmission Cost Recovery Tariffs

7.1. Transmission Cost Recovery Tariff Methodology

TUoS tariffs are designed to recover the transmission costs (grid fees) incurred by the distribution business. The TUoS tariff structure is compatible with the DUoS tariff structure. This structure has been maintained in order to allow the NUoS tariff to be determined by simply adding the DUoS and TUoS rates. The application of TUoS rates are designed to best reflect the underlying cost of grid fees (i.e. Peak Energy and demand related charges such as the summer demand incentive and rolling demand charges).

7.2. Transmission Use of System Charges and Under/Over Recovery Previous Years

As shown by table 7-1 below, the expected TUOS revenue increase from 2015 to 2016 is 6%.

Table 7-1: Estimated TUOS Revenue Increase (\$'m)

	2015	2016	Var(%)
Grid Fee Forecast	\$113	\$114	
Over/under recovery from previous year	\$2	-\$4	
Actual/Allowed Revenue current year (grid fees less over recovery)	\$112	\$118	
Estimated Revenue collected	\$112	\$118	6%

8. Customer Tariff Class Assignment and Reassignment

8.1. Network Use of System Tariffs

Table 8.1 sets out tariff availability for newly connecting customers.

Table 8-1: Closed and Open Network Tariffs to new connections

Tariff Code	Tariff Open New Connection	Tariff Description	Tariff Class
Unmet	Yes	Unmetered supplies	Low voltage small
LVS1R	Yes	Low voltage small 1 rate	
LVS2R	No	Low voltage small 2 rate	
LVDed ¹	Yes	Dedicated circuit	
WET2Step	No	Winter economy tariff	
TOD	Yes	Time of Day	
TOD9	Yes	Time of Day 9pm off peak	
RESKW1R ^{4,5}	Yes	Seasonal demand anytime energy rate	
RESKWTOU ^{2, 4}	Yes	Seasonal demand TOU energy rate	
TODFLEX	Yes	Time of Day Flexible	
LVM1R	Yes	Low voltage medium 1 rate	Low voltage medium
LVM2R5D	No	Low voltage medium 2 rate 5 day	
LVM2R7D	No	Low voltage medium 2 rate 7 day	
LVkWTOU	No	Low voltage KW time of use	
LVkWTOUH	No	Low voltage KW time of use – HOT	
TOU	Yes	Time of use	
LVMKWTOU ^{3,4}	Yes	Seasonal Demand anytime energy rate	Low voltage large
LVL2R	No	Low voltage large 2 rate	
LVL1R	No	Low voltage large 1 rate	
LVkVATOU	Yes	Low voltage large KVA time of use	
LVkVATOUH	No	Low voltage large KVA time of use-HOT	High voltage large
HVkvATOU	Yes	High voltage KVA time of use	
SubTkVATOU	No	Subtransmission KVA time of use	Subtransmission large

1. LVDed not available to customers with solar PV installed.

2. RESKWTOU will be replaced by RESKW1R from 1st April 2016. It has been updated with an anytime energy rate and max monthly demand measured on work days only.

3. LVMKWTOU available on an opt-in basis from July 1st 2016.

4. Not available to customers with dedicated hot water meters

5. RESKWTOU to be superseded by RESKW1R with existing RESKWTOU customers migrated to the new tariff effective 1st April 2016

NB: Where the tariff also includes P/TFIT, a prefix of “F” or “T” for each applicable tariff will apply eg.FLVS1R or TLVS1R

8.2. Tariff assignment for New Connections

The AER's procedures for assigning and reassigning customers to tariff classes for the Victorian DNSPs are set out in appendix D of the AER's Preliminary Decision. These procedures require that in determining the tariff class to which a customer or potential customer will be assigned, or reassigned, UE must take into account one or more of the following factors:

- (a) the nature and extent of the customer's usage;
- (b) the nature of the customer's connection to the network; and
- (c) whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

8.2.1. Customers Usage

The table below outlines the customer categories based on energy consumption and maximum demand. The customer category determines the network tariff options.

Table 8-2: Customer Usage

Category	Maximum Demand (kVA)	Annual Energy Consumption (MWh)
Small	NA	<20
Medium	NA	20 to 400
Large	>150 and/or	>400

8.2.2. Metering and regulatory implications

UE has completed its roll out of advanced interval metering (AMI program) for customers consuming less than 160MWh per annum.

Where single phase customers have an off peak heating load and a LVS1R plus Dedicated tariff combination, a single phase two element AMI enabled meter with contactor will be installed to separately measure the off peak hot water load, which is the same as the current two meters plus time switch meter combination.

Where a customer wishes to receive a feed in tariff, a net interval metering configuration is required to provide a net export energy stream. In this circumstance, a single measurement element will not be able to provide a dedicated measurement for off peak heating load and a Time of Day or a Time of Use network tariff with an off peak component will be assigned as the default.

8.2.3. Tariff Re-assignment

UE's network tariffs contain summer and non-summer components. To avoid tariff arbitrage, a new connection must remain on the initial network tariff for a minimum of 12 consecutive months unless there is a load or connection characteristic change. It is important that customers contact retailers to ensure they are well informed about retail and network tariff offerings.

8.3 Network options for newly connecting small customers <20MWh pa

For customers who use less than 20MWh per annum, the default and optional tariff combinations for new connections are detailed below.

All new connections and replacement meters will use an AMI interval meter.

Table 8-3: Default and Tariff Options (Small Residential Customers)

	Default UE Network Tariff from 1 January 2016	Optional UE Network Tariff from 1 January 2016 if requested*
New connections (no solar)		
- Standard	LVS1R	TOD TOD9 TODFLEX RESKWTOU / RESKW1R
- Plus hot water and or slab	LVS1R + Ded	TOD TOD9 TODFLEX LVS1R
New Connections (Solar)		
- Standard	TOD9	TOD TODFLEX RESKWTOU / RESKW1R LVS1R
- Plus hot water and or slab	TOD9	TOD TODFLEX LVS1R

NB: Where a customer is not residential, a new connection must remain on the initial network tariff for a minimum of 12 consecutive months unless there is a load or connection characteristic change.

8.4 Network options for newly connecting medium customers >20MWh pa and <400MWh per annum

For customers who use between 20-400 MWh per annum, the default and optional tariff combinations for new connections are detailed below:

Table 8-4: Default Tariff Options (Medium Customers)

	Default UE Network Tariff from 1 January 2016	Optional UE Network Tariff from 1 January 2016 if requested
New connections (no Solar)		
- Standard	LVM1R	TOU LVMKWTOU (from 1 st July 2016)
New Connections (Solar)		
- Standard	TOU	LVM1R LVMKWTOU (from 1 st July 2016)

Further information on the above tariffs and tariff eligibility is provided in the following section.

The TODFLEX tariff is applicable to residential customers only with an AMI meter. On occasion, a residential customer may consume greater than 20MWh. In these cases, these customers are deemed “medium” but can remain eligible for either tariff class.

8.5 2016 Default Network Tariffs for New Connections

The following section provides information on the default tariffs for new connections and the applicable tariff eligibility:

LVS1R:

- This tariff is available to new connections.
- Customers must consume <20 MWh/pa.
- Includes a summer and non-summer peak energy charge.
- Customers can make savings by reducing their energy consumption during summer months. Usage during non-summer is cheaper.
- Summer is defined as 1 November to 31 March.
- Where the customer is residential with an AMI meter installed, tariff re-assignment rules apply as per section 8.2.3 and table 8.3.

LVM1R:

- This tariff is available to new connections.
- Customers must consume between 20 and 400 MWh/pa.
- Includes a summer and non-summer peak energy charge.

- Customers can make savings by reducing their energy consumption during summer months. Usage during non-summer is cheaper.
- Summer is defined as 1 November to 31 March.
- Once on this tariff, non-residential customers cannot move onto another tariff for a minimum period of 12 months.

Small Business Demand (LVMKWTOU):

- Customers must consume between 20 and 400 MWh/pa.
- Requires an AMI meter.
- Available from July 2016.
- No standing charge.
- Summer demand charge (1st December to 31st March) based on monthly maximum demand between 10am and 6pm local time on workdays.
- Non-summer demand charge (1st April to 30th November) based on monthly maximum demand occurring between 10am and 6pm local time on workdays.
- Minimum monthly chargeable demand of 1.5KW.
- Flat energy rate applies for all periods.
- Fully cost reflective demand based tariff available on opt in basis from July 2016.

LVDED:

- This tariff is only available in conjunction with the LVS1R tariff for new connections.
- Customer must have a dedicated circuit connected to a controlled electric hot water service and/or storage space heating.
- Requires a separately metered dedicated circuit controlled by UE by means of time switch or other means.
- Is a dedicated off-peak charge that applies for a maximum of 8 hours during the off-peak period.
- The Off-Peak period is 11pm to 7am local time.
- All controlled load is controlled by the meter. Note, if there are any controlled load boosts during peak periods, these will be charged the peak tariff rate.
- This tariff is not available to new customers with embedded generation or existing customers that install embedded generation.

TIME OF DAY (TOD):

- Customers to consume <20MWh/pa.
- Requires an interval meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (3pm-11pm local time workdays).
- Non-Summer Peak energy charge is lower than Summer Peak energy charge to encourage heating usage.
- Includes a seasonal shoulder energy charge. Customers can make savings by reducing their energy consumption during the shoulder periods (7am-3pm local time workdays).
- Non-Summer shoulder energy charge is lower than Summer Shoulder energy charge to encourage heating usage.
- Off-peak energy is all day weekends and public holidays and 11pm to 7am local time workdays. Usage during off-peak times is cheaper than peak times.
- Includes a daily Standing Charge
- Where the customer is residential with an AMI meter installed, tariff re-assignment rules apply as per section 8.2.3 and section 8.3.
- Summer is defined as 1 November to 31 March.

TIME OF DAY 9PM OFF PEAK (TOD9):

- Customers to consume <20MWh/pa.
- Requires an interval meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (3pm-9pm local time workdays).
- Non-Summer Peak energy charge is lower than Summer Peak energy charge to encourage heating usage.
- Includes a seasonal shoulder energy charge. Customers can make savings by reducing their energy consumption during the shoulder periods (7am-3pm local time workdays).
- Non-Summer shoulder energy charge is lower than Summer Shoulder energy charge to encourage heating usage.
- Off-peak energy is all day weekends and public holidays and 9pm to 7am local time workdays. Usage during off-peak times is cheaper than peak times.
- Includes a daily Standing Charge.
- Where the customer is residential with an AMI meter installed, tariff re-assignment rules apply as per section 8.2.3 and section 8.3.
- Summer is defined as 1 November to 31 March.

TIME OF DAY FLEXIBLE (TODFLEX):

- Customers must be Residential.
- Requires an AMI meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods. The peak energy period is between 3pm and 9pm local time workdays inclusive of public holidays on weekdays.
- Non-Summer Peak energy charge is lower than Summer Peak energy charge to encourage heating usage.
- Includes a seasonal shoulder energy charge. Customers can make savings by reducing their energy consumption during the shoulder periods. Shoulder energy is 7am-3pm and 9pm-10pm local time workdays including public holidays, and 7am-10pm local time on weekends.
- Non-Summer shoulder energy charge is lower than Summer Shoulder energy charge to encourage heating usage.
- Off-peak energy is 10pm to 7am local time workdays including public holidays and weekends . Usage during off-peak times is cheaper than peak times.
- Includes a daily Standing Charge.
- Tariff re-assignment rules apply as per section 8.2.3 and section 8.3.
- Summer is defined as the commencement of daylight savings (early October) to the finish of daylight savings (early April).

TIME OF USE (TOU):

- Customers must consume >20 and <400MWh/pa.
- Requires an interval meter.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (7am-11pm local time workdays).
- Off-peak energy is all day weekends and public holidays and 11pm to 7am local time workdays. Usage during off-peak times is cheaper than peak times.
- Includes a Summer Demand Incentive Charge measured at maximum kW per billing period between 2pm and 7pm local time workdays in summer. This empowers customers to make savings by altering the time of use of their consumption away from 2pm to 7pm local time workdays in summer.
- Once on this tariff, non-residential customers cannot move onto another tariff for a minimum period of 12 months.
- Summer is defined as 1 November to 31 March.

Seasonal Demand Time of Use Residential (RESKWTOU):

- Customers must be Residential.
- Requires an AMI meter.
- Available to customers without a dedicated circuit meter configuration.
- No standing charge.
- Summer demand charge (1st December to 31st March) based on monthly maximum demand between 3pm and 9pm local time. No distinction between workday and non-workday. Minimum chargeable demand of 1.5KW.
- Non-summer demand charge (1st April to 30th November) based on monthly maximum demand occurring between 3pm and 9pm local time. No distinction between workday and non-workday. Minimum chargeable demand of 1.5kW.
- Tariff specification makes provision for differential energy rates for peak, shoulder and off-peak periods (as per TODFLEX). However, initial rate will be a single rate common to all periods.
- United Energy will transition customers from RESKWTOU to RESKW1R from 1st April 2016.

Seasonal Demand Anytime Energy Residential (RESKW1R):

- Customers must consume < 20MWh/pa.
- Requires an AMI meter.
- Available from 1st April 2016
- No standing charge.
- Summer demand charge (1st December to 31st March) based on monthly maximum demand between 3pm and 9pm local time on work days.
- Non summer demand charge (1st April to 30th November) based on monthly maximum demand occurring between 3pm and 9pm local time on work days.
- Minimum monthly chargeable demand of 1.5KW.
- Flat energy rate applies for all periods.
- Fully cost reflective demand based tariff available on opt-in basis from 2016.
- Tariff re-assignment rules apply as per section 8.2.3 and section 8.3.

LVkVATOU:

- Customers must be in "large" category (>400MWh and/or >150KVA).
- Must have an Interval meter measuring kW and kVar.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (7am to 7pm local time workdays).
- Includes a Summer Demand Incentive Charge (measured as kVA at maximum kW per billing period). This empowers customers to make savings by altering the time of use of their consumption away from 3pm to 6pm local time workdays in summer.
- Off-peak energy is all day weekends and public holidays and 7pm to 7am local time workdays. Usage during off-peak times is cheaper than peak times.
- The peak rolling demand is 7am to 7pm local time workdays and is measured as kVA at maximum kW. The minimum rolling demand applicable is 150 kVA.
- Once on this tariff, customers cannot move onto another tariff for a minimum period of 12 months.
- Summer is defined as 1 November to 31 March.

HVKVATOU:

- Customers must be in "large" category (>400MWh and/or >150KVA).
- Must have an Interval meter measuring kW and kVar.
- Includes a seasonal peak energy charge. Customers can make savings by reducing their energy consumption during the peak periods (7am to 7pm local time workdays).
- Includes a Summer Demand Incentive Charge (measured as kVA at maximum kW per billing period). This empowers customers to make savings by altering the time of use of their consumption away from 3pm to 6pm local time workdays in summer.
- Off-peak energy is all day weekends and public holidays and 7pm to 7am local time workdays. Usage during off-peak times is cheaper than peak times.
- The peak rolling demand is 7am to 7pm local time workdays and is measured as kVA at maximum kW. The minimum rolling demand applicable is 1150 kVA.
- Once on this tariff, customers cannot move onto another tariff for a minimum period of 12 months. .
- Summer is defined as 1 November to 31 March.

8.6 Jurisdictional Scheme: Feed in Tariff schemes

The Victorian Government introduced a premium feed in tariff policy in November 2009. A premium feed in tariff (PFIT) was available to residential and commercial customers consuming less than 100 MWh/annum who installed up to 5 kW of solar panels and had net interval metering. However, upon reaching 100MW of installed solar capacity across Victoria in November 2011, the Minister declared the end of the scheme. As a replacement, the Government introduced the Transitional Feed in Tariff (TFIT). The TFIT scheme closed as at 31 December 2012, and there is no new Distributor administered scheme to replace PFIT/TFIT.

UE administers the rebates under the jurisdictional scheme and seeks to recover the cost of the PFIT/TFIT credits by recovering on a fixed rate per customer basis. For 2016 the annual recovery is \$32.27 per customer which represents an increase of \$5.98 from the prior year.

8.6.1 Jurisdictional Scheme Amounts

Table 8.5 outlines the jurisdictional charges and correction factors applicable to UE in 2016. The correction factor represents the accumulated under recovery of revenue versus rebates paid since the commencement of the scheme.

Table 8-5: Jurisdictional PFIT Scheme Amounts (Real \$'000)

Jurisdictional PFIT/TFIT Scheme Amounts (\$'000)						
	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast
Revenue from PFIT/TFIT charges	\$ 614	\$ 9,209,887	\$ 17,901,791	\$ 27,799,757	\$ 18,801,498	\$ 21,280,407
PFIT/TFIT rebates paid	\$ 5,477	\$ 14,226,909	\$ 19,136,566	\$ 17,703,479	\$ 17,707,466	\$ 18,594,236
Correction factor						-\$ 2,688,147

8.6.2 Calculation PFIT Rebate Costs applicable to Jurisdictional revenue forecast

The following table outlines the actual and estimated PFIT rebate costs from 2011 to 2016:

Table 8-6: PFIT Rebates

PFIT Rebate Cost	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast
PFIT Rebate \$/kWh exported	\$ 0.60	\$ 0.60	\$ 0.60	\$ 0.60	\$ 0.60	\$ 0.60
Customers on PFIT (31 Dec)	17,973	18,231	18,231	18,231	18,231	18,231
Customers on PFIT (average for year)	11,904	18,049	18,231	18,231	18,231	18,231
kWh exported	9,127,967	15,735,149	23,024,531	18,194,947	19,709,404	22,284,045
KWh per customer	767	872	1,263	998	1,081	1,222
PFIT rebate cost (\$'000)	\$ 5,477	\$ 9,441	\$ 13,815	\$ 10,917	\$ 11,826	\$ 13,370

8.6.3 Calculation TFIT Rebate Costs applicable to Jurisdictional revenue forecast

The following table outlines the actual TFIT rebate costs from 2012 to 2016:

Table 8-7: TFIT Rebates

TFIT Rebate Cost	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast
TFIT Rebate \$/kWh exported		\$ 0.25	\$ 0.25	\$ 0.25	\$ 0.25	\$ 0.25
Customers on TFIT (31 Dec)		11,844	13,667	13,667	13,667	13,667
Customers on TFIT (average for year)		5,922	13,667	13,667	13,667	13,667
kWh exported		5,162,810	21,261,865	26,932,730	23,527,295	20,895,236
KWh per customer		872	1,556	1,971	1,721	1,529
TFIT rebate cost (\$'000)		\$1,291	\$ 5,315	\$ 6,733	\$ 5,882	\$ 5,224

8.7 Tariff Reassignments for Existing Customers

Table 8-8: Tariff Reassignment for Existing Customers

Meter Type	<20MWh	>20MWh
Basic	LVS1R	LVM1R
Interval	LVS1R TOD TOD9	LVM1R TOU
AMI	LVS1R TOD TOD9 TODFLEX (residential only) RESKWTOU / RESKW1R	LVM1R TOU TODFLEX (residential only) LVMKWTOU (from 1 st July 2016)
Solar	LVS1R TOD TOD9 TODFLEX (residential only with AMI enabled meter) RESKWTOU / RESKW1R	LVM1R TOU TODFLEX (residential only with AMI enabled meter) LVMKWTOU (from 1 st July 2016)

NB: Where solar metering exists, customers may be on Feed in Schemes (TFIT or PFIT). In these cases, a prefix of 'T' or 'F' will precede the tariff eg. TOU becomes TTOU or FTOU.

UE's network tariffs contain summer and non-summer components. To avoid tariff arbitrage, an existing non-residential customer must remain on a re-assigned/assigned network tariff for a minimum of 12 consecutive months unless there is a load or connection characteristic change. It is important that customers speak to retailers to ensure they are well informed about retail and network tariff offerings.

Additional reassignment rules relating are indicated below;

- Change of network tariff will be prospective. Limited retrospectivity may be sought to align to a retail transfer.

8.8 UE's system of assessing and reviewing a customer's charges

As noted in Section 2.4 of this Pricing Proposal, the AER's preliminary decision requires UE to provide for an appropriate system of assessment and review of the basis on which a customer is charged. In accordance with the AER's requirements, UE's system of assessment and review involves the following three-step process:

- Step 1: UE critically examines its draft annual tariff changes to identify customers that are likely to experience price changes that are materially different to the tariff average. It is noted that such variations may occur if a customer's load profile contrasts sharply with typical tariff customer and where tariff changes differ across tariff components. UE will amend its draft tariff proposals where appropriate, having regard to the principles that guide tariff prices.
- Step 2: Following UE's annual tariff review, UE contacts customers where the current tariff is inappropriate for the customer's load profile or would likely to result in a substantial increase in network charges. UE would identify alternative network options for the customer's consideration or measures to assist the customer in reducing its network charges.
- Step 3: Where a customer or customer's retailer contacts UE regarding the basis on which a customer is charged, UE will identify alternative network options or measures to assist the customer in reducing network charges. However, UE notes that steps 1 and 2 properly executed should minimise, if not eliminate, the number of contacts from customers and retailers regarding inappropriately high network charges.

In addition to the above steps, UE will be guided by the Rules (NER s6.18.5) in determining the appropriate course of action to review and assess customers usage for tariff applicability. In this regard, UE has outlined a method to transition customers to meet the new pricing objective and pricing principles of cost reflectivity as outlined in our TSS document.

9 Alternative Control Services

9.4 Regulatory Requirements

A number of the Rule requirements in clause 6.18 relating to direct control services are applicable to both standard control services and alternative control services.

9.5 Pricing principles

Clause 6.18.5 of the Rules sets out the pricing principles that must be complied with in respect of each tariff class, including a tariff class within the classification of alternative control services.

9.6 Charging parameters for alternative control services – fee based

The price path for the regulatory period is $CPI - X$, where X equals zero. The table below contains the approved fee based alternative control services charges as per the AER Preliminary Decision (October 2015) updated with the September 2015 CPI.

Table 9-1: Fee based alternative control services prices for 2016

Fee based services	2016 Price (ex GST)
<i>Field Officer Visits – Existing Premises</i>	
Special read (basic meter)	\$21.12
Special read (interval meter)	\$21.12
Re-energise (fuse insert) - BH (unit rate)	\$44.98
De-energise (fuse removal) - BH (unit rate)	\$44.98
Express move in re-energise (fuse insert) – BH (unit rate)	\$67.82
Re-energise (fuse insert) – AH (unit rate)	\$79.82
Express move in re-energise (fuse insert) – AH (unit rate)	\$125.52
De-energise at point of attachment (pole/pit/premise) – BH (unit rate)	\$347.69
<i>Temporary Supplies (excl inspection) – Coincident Disconnection where UE is the Responsible Person</i>	
Standard single phase – BH (unit rate)	\$454.27
Multi phase to 100A – BH (unit rate)	\$454.08
Standard single phase – AH (unit rate)	\$693.76
Multi phase to 100A – AH (unit rate)	\$693.58
<i>Temporary Supplies (excl inspection) – where UE is Not the Responsible Person</i>	
Single Phase Servicing and Energisation only – BH (unit rate)	\$421.56
Multi Phase Servicing and Energisation only – BH (unit rate)	\$421.56

Fee based services	2016 Price (ex GST)
Single Phase Servicing and Energisation only – AH (unit rate)	\$693.76
Multi Phase Servicing and Energisation only – AH (unit rate)	\$693.76
<i>New Connection where UE is the Responsible Person</i>	
Single phase single element – BH (unit rate)	\$454.27
Single phase two element (off peak) – BH (unit rate)	\$454.27
Three phase direct connected – BH (unit rate)	\$454.08
Single phase single element – AH (unit rate)	\$693.76
Single phase two element (off peak) – AH (unit rate)	\$693.76
Three phase direct connected – AH (unit rate)	\$693.58
Routine new connections – three phase current transformer connected – BH	Quoted
Routine new connections – three phase current transformer connected – AH	Quoted
<i>New Connections – where UE is Not the Responsible Person</i>	
Single phase single element – BH (unit rate)	\$421.56
Single phase two element (off peak) – BH (unit rate)	\$421.56
Three phase direct connected – BH (unit rate)	\$421.56
Single phase single element – AH (unit rate)	\$693.76
Single phase two element (off peak) – AH (unit rate)	\$693.76
Three phase direct connected – AH (unit rate)	\$693.76
Routine new connections – three phase current transformer connected - BH	Quoted
Routine new connections – three phase current transformer connected - AH	Quoted
<i>Service Vehicle Visits (without inspection)</i>	
Service truck – first 30 minutes – BH (unit rate)	\$322.74
Each additional 15 minutes – BH (unit rate)	\$66.74
Wasted service truck visit - BH (unit rate)	\$279.94
Service truck – 2 hrs min – AH (unit rate)	\$714.28
Each additional 15 minutes – AH (unit rate)	\$92.55
Wasted service truck visit – AH (unit rate)	\$714.28
Truck Visit + 1x additional 15 mins BH (unit rate)	\$389.48
Truck Visit + 2x additional 15 mins BH (unit rate)	\$456.22

Fee based services	2016 Price (ex GST)
Truck Visit + 3x additional 15 mins BH (unit rate)	\$522.95
Truck Visit + 4x additional 15 mins BH (unit rate)	\$589.69
Truck Visit + 5x additional 15 mins BH (unit rate)	\$656.42
Truck Visit + 6x additional 15 mins BH (unit rate)	\$723.15
Truck Visit + 1x additional 15 mins AH (unit rate)	\$806.83
Truck Visit + 2x additional 15 mins AH (unit rate)	\$899.39
Truck Visit + 3x additional 15 mins AH (unit rate)	\$991.95
Truck Visit + 4x additional 15 mins AH (unit rate)	\$1,084.50
Truck Visit + 5x additional 15 mins AH (unit rate)	\$1,177.05
Truck Visit + 6x additional 15 mins AH (unit rate)	\$1,269.61
Meter Equipment Test	
Single phase	\$251.46
Single phase (each additional meter)	\$120.66
Multi phase	\$251.15
Multi phase (each additional meter)	\$120.66
Remote AMI Services	
Remote Meter Configuration	\$59.97
Remote Special Meter Reading	\$0.81
Remote Re-Energise	\$10.13
Remote de-Energise	\$10.13

Table 9-2: Charge out rates for quoted alternative control services 2016

Description	2016 Rate (ex GST)
Field worker - one person - BH	\$123.25
Field worker - one person - AH	\$175.03
Field worker - one person plus vehicle - BH	\$144.48
Field worker - one person plus vehicle - AH	\$196.27
Administration - BH	\$95.23
Senior engineer - BH	\$181.51
Project planner - BH	\$181.51

10 Charging parameters for alternative control services - Metering Services

There are only two charging parameters within the alternative control services metering services tariff class: customer numbers and exit fee transactions.

Meter provision services are charged to each alternative control services network customer on a \$/day basis, so the relevant charging parameter is the number of customer days. Meter services exit fee transactions will be charged on an as incurred basis, so the relevant charging parameter is the number of exit fee transactions. As per the AER Preliminary Decision (October 2015) the charging parameters for each tariff within the alternative control services - metering services tariff class are set out in the tables below.

10.1 Advanced Metering Infrastructure Charges (AMI) <160Mwh customers

The AER's framework and approach for standard metering services for small customers (those who consume less than 160 MWh per annum) is to regulate these as prescribed services, with the charges for these services set separately to distribution use of system charges.

Table 10.1 Charges for AMI metering charges of single and three phase meters.

AMI metering charges	2016 Price (ex GST)
Single phase non off peak meter	\$91.55
Single phase off peak meter*	\$91.55
Three phase direct connected meter	\$103.24
Three phase current transformer connected meter	\$109.38

Note: * A single phase off peak accumulation meter but has one logical meter for charging but has two physical single phase meters.

10.2 Prescribed Metering Service Charge

The metering data services for public lighting are services provided exclusively to public lighting customers, such as retailers, municipal councils and Vic Roads.

Table 10.2 Meter data services (Public lighting)

Meter data services	2016 Price (ex GST)
Unmetered supplies – Public lighting (per light)	\$1.322

10.3 Metering Exit Fees

An exit fee applies when a customer chooses to replace a regulated meter installed under the derogation with a competitively sourced meter.

Table 10.3 Metering exit fees

Metering exit fees	2016 Price (ex GST)
Single phase single element meter	\$372.37
Single phase single element meter with contactor	\$371.72
Three phase direct connected meter	\$426.28
Three phase current transformer connected meter	\$596.17

11 Public Lighting

The table below contains the approved public lighting charges as per the AER Preliminary decision (October 2015) Public Lighting updated with the September 2015 CPI.

Table 11-1: Alternative Control Services - Public Lighting Charges

Light Type	2016 Price (ex GST)
Mercury Vapour 80 watt	\$51.35
Sodium High Pressure 150 watt	\$66.01
Sodium High Pressure 250 watt	\$67.64
Fluorescent 2x20 watt	\$66.24
Fluorescent 3x20 watt	\$66.24
Mercury Vapour 50 watt	\$76.00
Mercury Vapour 125 watt	\$76.00
Mercury Vapour 250 watt	\$61.55
Mercury Vapour 400 watt	\$85.22
Mercury Vapour 700 watt	\$85.22
Sodium High Pressure 70 watt	\$112.46
Sodium High Pressure 100 watt	\$72.61
Sodium High Pressure 400 watt	\$85.22
Metal Halide 70 watt	\$89.11
Metal Halide 100 watt	\$89.11
Metal Halide 150 watt	\$89.11
Metal Halide 250 watt	\$91.31
Metal Halide 400 watt	\$91.31
T5 2X14W	\$36.57
Twin 24W Fluorescent	\$36.57
Compact Fluoro 32W	\$36.57
Compact Fluoro 42W	\$36.57

Appendix A: Tariff Model

Appendix B: Tariff Summary

Appendix C: Public Lighting Model

Appendix D: Alternative Control Services Model

Appendix E: Audit Report