2016 to 2020 Electricity Distribution Price Review

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United Energy's Response -

AER's 2016 to 2020 Preliminary Positions Framework and Approach

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Approval and Document Control

VERSION	DATE	AUTHOR
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Glossary

Abbreviations	
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AMI	Advanced metering infrastructure (smart meters)
CESS	Capital expenditure sharing scheme
COAG	Council of Australian Government's
CPI	Consumer Price Index
CAM	Cost allocation method
CROIC	Cost Recovery Order in Council
F&A	Framework and Approach Paper
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIS	Demand Management Incentive Scheme
DMIA	Demand Management Incentive Allowance
DSM	Demand side management
DUOS	Distribution use of system
EBSS	Efficiency benefit sharing scheme
GSL	Guaranteed service level
LRMC	Long-run marginal costs
MC	Metering coordinator
MAIFI	Momentary average interruption frequency index
NEL	National Electricity Law
Rules	National Electricity Rules
NECF	National Energy Customer Framework
OMR	Operation, maintenance, repair and replacement
PTRM	Post-tax revenue model
RAB	Regulatory asset base
STPIS	Service Target Performance Incentive Scheme
SSIS	Small Scale Incentive Scheme
SCER	Standing Council on Energy and Resources
VCR	Value of customer reliability
WAPC	Weighted average price cap

1. Introduction

United Energy welcomes the opportunity to comment on the AER's preliminary positions on its replacement Framework and Approach (**Preliminary F&A**) for the 2016 to 2020 regulatory control period. The AER will publish the Final F&A by October 2014.

United Energy generally supports and agrees with the AER's preliminary views, however there are some areas where further refinement and change is required. This response sets out where United Energy considers modifications need to be made or new issues considered.

United Energy has incorporated stakeholder feedback in its proposed views where possible and welcomes further input from stakeholders on this submission via http://uemg.com.au/home.aspx

2. Classification of distribution services

The AER proposes to group the distribution services provided by United Energy and other the Victorian distributors as follows:

- Network services;
- Connection services;
- Metering services;
- Ancillary network services; and
- Public lighting services.

United Energy agrees with the AER's proposed grouping and provides the following detailed comments on each of the service groupings below.

2.1. Network services

The AER's preliminary view is to continue to classify Network Services as standard control services. Network Services are those services that relate to the shared "distribution network" (i.e. poles, wires, substations, transformers[1]) including construction and maintenance, required to provide all distribution customers with a safe and reliable electricity supply.

United Energy supports the AER's preliminary view on these services.

United Energy would, however, welcome the AER's views on the treatment of non-traditional network investments that relate to the provision of a safe and reliable electricity supply for all customers.

The National electricity Rules (**Rules**) require United Energy to:

- Submit a building block proposal in its Regulatory Proposal which includes opex and capex forecasts that it considers it requires to meet the opex and capex expenditure objectives[2]; and
- Consider and make provision for efficient and prudent non network alternatives in developing its opex and capex forecasts for standard control services[3].

[1] The distribution system is defined as the distribution network together with the connection assets. The distribution network is defined as "the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a Network Service Provider, a network owned, operated or controlled by that Network Service Provider.

[2] Refer cl 6.5.6(a) (1)-(4) and cl 6.5.7(a) (1)-(4)

[3] Refer opex and capex factors at cl 6.5.6(e)(10) and 6.5.7(e)(10) that relates to the building block for standard control services

Therefore, clarity on the regulatory treatment of non-traditional network investments (for the purpose of cost recovery) is important for United Energy to be able to dynamically and flexibly deal with the challenges presented by the current and emerging environment while continuing to meet the Rules' requirements (set out above) and minimise costs. These challenges include the increased development and uptake of new technologies, such as solar panels.

The investments in question include, amongst other things, battery storage on feeders experiencing voltage issues or requiring capacity augmentation, load control devices and distributed generation. These investments could provide a more cost effective alternative to traditional network investments (i.e. poles and wires) for providing a safe and reliable electricity supply by assisting to avoid or defer costly network investment otherwise required to relieve network congestion, meet peak demand or improve system reliability (and thereby satisfy the "expenditure objectives"). These investments would therefore deliver benefits to customers and other end users through lower prices.

There are, however, some key differences between traditional network investment and non-traditional network investments including that:

- Non-traditional investments may in some cases be competitively provided and owned by third parties; and
- Non-traditional investments may not form part of or meet the full definition of the "distribution system" as currently provided under the Rules. For instance, they could be located on the customer's premises.

Notwithstanding these differences, the investments would be "operated <u>and</u> controlled" by United Energy for the provision of a safe and reliable electricity supply <u>for all</u> customers at relatively lower costs.

To this end, United Energy considers that these investments should be treated in a similar way to traditional network investments undertaken by United Energy that deliver network services. In particular, the cost of these investments should be shared by all customers through distribution use of system (**DUOS**) charges. Given that these investments <u>may</u> be owned by others (and therefore not included in United Energy's regulatory asset base (**RAB**)) funding for these services could be through:

- An operating expenditure allowance to fund the cost of these investments; or
- A revenue adjustment.

This would allow United Energy to agree terms and conditions of payment with the proponent of the investment. A revenue adjustment would be required to deal with all investments that United Energy has not identified in its Regulatory Proposal and for which it has therefore not been provided an opex allowance in the AER's Final Decision.

This would ensure United Energy is provided with a "*reasonable opportunity to recover at least the efficient costs it incurs in providing network services and in complying with a regulatory obligation or requirement or making a regulatory payment"* as required under Section 7A(2) of the National Electricity Law (**NEL**).

Importantly, where benefits of any such investment can be attributed to individual customers, then the costs would be allocated between the individual customers and all customers. The basis for any cost allocation would be set out in United Energy's Cost Allocation Method (**CAM**).

2.2. Connection services

The AER's preliminary view is to maintain its current classification for connection services, other than for Supply enhancement at the customer request, as set out in the table below:

Table 1: AER's preliminary views on the classification of connection services

Service	Classification
Routine connections (not requiring augmentation)	Alternative control
New connections requiring augmentation	Standard control
Temporary connections and disconnections	Alternative control
Inspection of PV installation site	Alternative control
Energisation and de-energisation	Alternative control
Supply enhancement at customer request	Unclassified[4]
Operate and maintain connection assets (captured as network services)	Standard control

A connection service is the service to connect a person's home, business or other premises to the distribution network, alter an existing connection or extend the network in order to facilitate a connection to be undertaken.

United Energy is required to make a connection offer to all customers seeking to connect to its network in accordance with its License conditions.

United Energy generally supports the AER's preliminary view, however seeks to clarify the following matters:

2.2.1. The AER's National Electricity Connection Guidelines

Currently, the connection charging provisions for new connections requiring augmentation, classified as standard control, are set out in the Victorian Electricity Industry Guidelines 14 and 15.

United Energy supports the introduction of a nationally consistent approach to regulation, and therefore supports the introduction of the National Energy Customer Framework (**NECF**). The introduction of Chapter 5A into the Rules, which would occur if NECF is adopted, or alternatively through enabling legislation, would mean that the AER's National Electricity Connection Guideline would likely replace Victorian Electricity Industry Guideline 14 and 15.

United Energy supports this change and strongly encourages the AER to liaise with the Victorian Government to ensure the timely introduction of the NECF or the development of enabling legislation to adopt Chapter 5A directly.

If this does not occur, then United Energy seeks amendment to the X-factor in Guideline 14. In particular, United Energy proposes that this is set to zero, as per the AER's National Electricity Connection Guideline. The X-factor is important for calculating the upfront capital contribution paid by the customer connecting to the network.

Guideline 14 states that the X-factor is "*the same as the X-factor that applies in the last calendar year in respect of which that Price Determination applies*". Accordingly, the higher (and negative) the X-factor, then the lower the up-front capital contribution[5]. This means that a greater proportion of the cost of connecting an individual customer is borne by all customers rather than the customer requesting the service. This is therefore not consistent with encouraging cost reflective pricing signals.

United Energy has separately written to the Victorian Government outlining its concerns as set out above.

[4] The AER's preliminary view is to reclassify this from Alternative Control to Unregulated on the basis there is no need to regulate this service as it is covered by other services in Guideline 14.

[5] This is because the higher x-factor the higher the incremental revenue and the

2.2.2. Elective under-grounding and rearrangement of network assets at customers request

Currently, elective undergrounding and rearrangement of network assets at a customer's request are classified as Alternative Control - Quoted Services. United Energy does not agree with this classification because it is not consistent with the following requirements:

(i) Clause 7 of its licence conditions - this requires United Energy to make an offer to underground or relocate its assets on the basis of health, safety or appearance; and

(ii) Clause 2.2 of the Electricity Industry Guideline 14 - this require United Energy to contribute to the cost of undergrounding an amount equal to its avoided costs.

This means that these services are provided in accordance with Guideline 14 in the same manner as any other new connection service requiring augmentation. Accordingly, these services should be classified in the same way as a new connection requiring augmentation, which is standard control, for the same reasons.

This would allow United Energy to include the "avoided cost" component of these services in its regulatory asset base and recover this from all its customers and the recover the remaining costs from the customer requesting the service.

2.3. Metering services

The AER's preliminary view is to classify metering services as follows:

Table 2: AER's preliminary views on the classification of metering services

Service	Classification
Type 1 to 4 metering services	Unclassified
Type 5 and 6 metering – before AMI expiry	Unclassified
Type 5 and 6 metering services – after AMI expiry	Alternative control
Metering provision, maintenance, reading and data services	Alternative control
Type 7 metering services	Standard control
Auxillary metering services, including exit fee	Alternative control

United Energy generally supports the AER's preliminary views subject to its comments set out below:

2.3.1. General matters for clarification

United Energy would like to clarify the following three matters:

(i) Table 5 of the AER's Preliminary F&A (replicated above) refers to "metering services" rather than metering installation services;

(ii) The AER proposes that "type 5 to 6 metering services – before AMI expiry" should be treated as unclassified. United Energy assumes that this wording reflects the fact that these services are regulated under the Cost Recovery Order in Council (**CROIC**) until 31 December 2015; and

(iii) The AER states that "Metering services for type 5 and 6 are currently excluded from classification by a derogation from the NER by Victoria which expires on 31 December 2016. The AER is to regulate these metering services under the derogation until 31 December 2016 and from 1 January 2017 under the NER". It appears that the AER has confused the expiry of the CROIC, which is the current regulatory instrument, with the end of the derogation. The CROIC in fact expires on 31 December 2015 (not on 31 December 2016

– this marks the end of the derogation unless national arrangements[6] are developed and adopted in Victoria before then) after which time the Rules become the relevant regulatory framework for these services (from 1 January 2016).

United Energy requests the AER to clarify these matters in its Final Framework and Approach Paper.

2.3.2. Smart metering before the end of the derogation

United Energy notes the following key contextual issues relating to the smart metering roll-out:

- Since 2009, United Energy has rolled out smart meters in accordance with the Victorian Government's mandated smart meter rollout;
- United Energy is currently the monopoly provider of type 5 and 6 meters and smart meters where they are used to replace a type 5 or 6 meter;
- Metering services for meter types 5 and 6 are currently excluded from classification by the Victorian derogation that expires on 31 December 2016, or earlier if the national arrangements are developed and adopted in Victoria;
- These assets have been regulated in accordance with the Victorian CROIC;
- The CROIC is due to expire on 31 December 2015, after which time these assets will be regulated under the Rules; and
- The CROIC provides for an exit fee to compensate United Energy for any unrecovered costs of the mandate.

United Energy supports the AER's preliminary view that all smart metering installation services before the end of the derogation should be regulated as ACS. United Energy clarifies that any replacement of these meters post the end of the derogation due to age or a non-compliant meter family or meter fault should also be treated as alternative control services as there has not been any change in the service provider and the meter was originally part of the mandated rollout.

United Energy welcomes the AER's support for an exit fee, as provided under the CROIC, to apply in the 2016 to 2020 regulatory control period in order to ensure that United Energy is financially compensated for the investments that it was required to make under the mandated roll-out.

The AER has invited submissions on the form and scope of an exit fee. United Energy strongly supports the exit fee and refers the AER to the AEMC's description of the rationale for an exit fee in its recent consultation paper[7]:

> *"SCER proposes that a transparent exit fee be determined by the AER and applied where a consumer, retailer or other party on behalf of the consumer chooses to upgrade an accumulation or manually read interval meter that is owned and managed by the local distribution network business. In many cases these meters will not be near the end of their useful lives. This represents a stranding risk to the distribution network businesses as they may not have recovered the full cost of those metering installations.*
>
> *The objective of an exit fee is to help the local distribution network business to recover the stranded (sunk) costs of its existing meters. An appropriate, clearly defined and transparent exit fee for accumulation or manually read interval meters would be expected to encourage competition and more efficient investment in advanced metering."*

United Energy strongly agrees with the AEMC's observation that an exit fee is intended to support efficient investment in smart meters by addressing the distributors' stranded asset risk. The scope and extent of the

[6] National metering competition for small customers and an orderly transition

[7] AEMC, National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2014, 17 April 2014, pages 64 and 65 page 51.

stranded asset risk faced by United Energy and other Victorian distributors is substantially different to other jurisdictions due to the mandated AMI rollout program which means that the stranded asset risk predominantly relates to smart meters, rather than accumulation meters as described by the AEMC. In addition, the magnitude and duration of the stranded asset risk in Victoria is substantially greater than other jurisdictions.

United Energy considers that the exit fees must be applicable where the provision of metering services has been mandated by a regulatory or jurisdictional obligation. In these circumstances, the metering service provider should be able to recover its sunk costs. An exit fee should therefore apply where a change in the service provider would otherwise preclude the recovery of these sunk costs.

In relation to the calculation of the fee, clause 7.2 of the CROIC states that:

> "*The Commission must determine an exit fee payable to each distributor as referred to in clause 7.1 in such a way that the exit fee enables the distributor to recover in a lump sum which is payable upon the change in responsible person referred to in clause 7.1:*
>
> *(a) the reasonable and efficient costs of removing the metering installation for which the distributor was the responsible person; and*
>
> *(b) the unavoidable costs (fixed and variable) that a prudent distributor has incurred or would incur as a result of the metering installation for which it was the responsible person being removed prior to the expiry of the life of that metering installation (which must be assumed to be as set out in clause 4.1(g)), including:*
>
> *(i) the written down value of the meter (assuming that depreciation is calculated on a straight line basis);*
>
> *(ii) the proportion referable to that metering installation of the written down value of commissioned telecommunications and information technology systems; and*
>
> *(iii) a reasonable rate of return on the written down values determined under paragraphs (i) and (ii), calculated using the applicable WACC*."

Given the above principles, it is surprising that the AER's preliminary position paper comments that[8]:

> "Our expectation is that a fee would be based on the unrecovered cost of existing regulated monopoly provided metering costs and IT systems that would be stranded if a customer elects to obtain a new, competitively supplied meter."

In addition to clarifying the role of the CROIC in setting exit fees, United Energy has also identified the following exit fee issues that require resolution:

- United Energy will continue to incur costs as a result of the extension of the Victorian derogation to 31 December 2016 and United Energy's likely role as 'default MC' or 'MC of last resort' in its distribution area. As presently drafted, however, the exit fee provisions in the CROIC do not provide protection against asset stranding for investments beyond 31 December 2015. This issue will need to be resolved so that the exit fee provisions match United Energy's regulatory and jurisdictional obligations.
- The rationale for an exit fee is not linked to the classification of smart metering services. In particular, even if smart metering services were subject to effective competition and categorised as 'unregulated' in a subsequent regulatory period, an exit fee could still apply depending on the terms of the commercial contract agreed with the customer.
- While it is appropriate for exit fees not to vary according to the age of the metering asset, it is appropriate for different exit fees to be set for different types of meters. In particular, three phase meters are more expensive than single phase, and therefore should attract a higher exit fee. A single average exit fee across

8 Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016, May 2014, page 32

meter types is unlikely to produce efficient outcomes because it will 'under-protect' more expensive services and 'over-protect' the less expensive.

United Energy would welcome the AER's confirmation in its final F&A that the AER supports the above exit fee principles and will adopted them to the extent allowed by the Rules.

2.3.3. After the end of the derogation

As noted in Table 2 above, the AER's preliminary view is to classify smart metering services post the end of the derogation as Alternative Control Services for the following reasons:

(i) In Victoria, installation of type 5 and 6 and smart metering is not currently contestable.

(ii) There is currently a regulatory barrier to any party other than the Victorian distributors providing type 5 and 6 and smart metering provision, maintenance, reading and data services.

(iii) Type 5 and 6 metering services are subject to a direct form of regulation in other NEM jurisdictions.

(iv) There is competition available for type 4 meters, but not smart meters.

United Energy does not agree with the AER's preliminary view on the classification of this service. This is because the above observations will not apply post the end of the derogation – rather there will be competition in the provision of type 5 and 6 (smart meters). To facilitate this, the Australian Energy Market Commission (**AEMC**) is currently developing a rule change to introduce national competition in the provision of metering. The AEMC proposes to publish a draft rule by December 2014 and the final rule by April 2015.

To this end, United Energy considers that these services, for new sites, should be unregulated to allow United Energy and other third party providers to offer these services on negotiated (commercial) terms and conditions. This will maximise customer flexibility and choice and should drive efficiency and innovation in product offerings.

United Energy recognises that the role of the "default Metering Coordinator" (**MC**) will be critical in the transition period to full workable competition. This is because there is no guarantee that the market will be sufficiently developed at the commencement of competition to ensure that all residential and small business customers will be able to access smart metering services at reasonably efficient prices. To this end, United Energy supports being the MC for all new customers in its distribution area that cannot secure a competitive market offer.

United Energy emphasises that all metering service offered by it as the MC should be classified and treated the same as those services it has provided under the derogation (i.e. as an alternative control service with an exit fee).

2.4. Public lighting services

The AER's preliminary view is to maintain the current service definition and classification of public lighting services being:

Service	Classification
(i) Operation, maintenance, repair and replacement of United Energy's existing public lighting assets (OMR)	Alternative Control
(ii) Alteration and relocation of United Energy's existing public lighting assets	Negotiated Service
(iii) Provision of new public lighting (greenfield sites)	Negotiated Service

However, the AER states that there may be customer benefits from re-classifying public lighting as a negotiated service and seeks comments on this. In particular, the AER states "*We note the dissatisfaction expressed in* *submissions with the current approach to public lighting. While our preliminary position is to continue the current classification approach, we think there may be a case to move to a negotiated service classification for public lighting services as a whole*”[9].

United Energy has consulted with its stakeholders, including local Councils, on this issue and agrees with the AER that its current approach to public lighting should be reviewed. United Energy’s proposed changes are set out below.

2.4.2. Operation, maintenance, repair and replacement of United Energy’s existing public lighting assets

United Energy provides an OMR service for two types of public lighting assets:

(a) Those assets that are dedicated to a particular customer (i.e. the pole and luminaire); and

(b) Those luminaires that are connected to the shared distribution network.

United Energy proposes that in relation to (a), the OMR services should be split into two separate services, both classified as Negotiated as shown in Table 3 below.

Table 3: Operation, maintenance, repair and replacement services for dedicated public lighting assets

Service	Classification
Operation, maintenance, repair	Negotiated
Replacement of existing public lighting assets	Negotiated

Splitting the OMR services into two separate “negotiated” services would allow United Energy, as well as other registered and / or qualified third parties, to competitively provide one or both of these services on negotiated (commercial) terms and prices that reflect the nature and cost of the service. This will therefore increase flexibility, choice, efficiency and innovation. Customers would be able to choose who maintains and repairs their assets and who replaces their existing assets when they are no longer operating at a satisfactory level and on what terms and conditions. Importantly, United Energy considers this service classification is consistent with the requirements of the Victorian Public Lighting Code, which does not require United Energy to own and or replace existing public lights (other than where there are safety issues). Under these proposed arrangements, any new public lighting assets would not need to be gifted to United Energy. Rather these assets could be owned, operated, maintained and replaced by others where it is more efficient to do so.

United Energy notes that there is already a relatively well defined market for this service.

Currently, the OMR charge is an ongoing average charge for the bundled OMR services paid to United Energy. That is, it is a ‘smeared’ average charge across all Councils. To this end, it is not cost reflective and does not promote competition, pricing efficiency or technological innovation. Under the current arrangements Councils and other customers are not able to negotiate the cost and other terms (such as lighting technology) with the provider of their choice. Due to the current smeared charging arrangement a renegotiation of the “replacement” (**R**) component may be a difficult issue to resolve for the existing asset base value as each council has a different stock of assets with different ages. Un-smearing the “R” component for these assets may create unintended consequences with winners and losers.

United Energy proposes that in relation to (b) - luminaires that are connected to the shared distribution network - no change is made to the OMR services (i.e. it remains a bundled service and the charge is based on an ongoing average price) and that it continues to be regulated as an Alternative Control Service. United Energy proposes to retain the current service definition and classification for safety related reasons for those working on and around its

[9] AER, Preliminary Framework and Approach, p. 57

network. In this case, Councils can still choose the lighting technology however the technology must comply with UE standards.

United Energy's preferred position for OMR is summarised in Table 4 below.

Table 4: Public lighting assets

Service		Classification
Dedicated public lighting assets	Operation, maintenance, repair	Negotiated
	Replacement	Negotiated
Shared public lighting assets	Operation, maintenance, repair, replacement.	Alternative Control Services

2.4.3. Alteration and relocation of United Energy's existing public lighting assets

United Energy is not proposing any changes to the definition or scope of this service or service classification.

2.4.4. Provision of new public lighting (greenfield sites)

United Energy is not proposing any changes to the definition or scope of this service or service classification however, clarifies that consistent with discussion above once the new public light has been built:

- United Energy and other third parties should be able to compete to: operate, maintain and repair; and replace the assets (where not part of United Energy's shared network) based on negotiated commercial terms and conditions (refer discussion in section 2.4.2 above); and
- New public lighting assets (where not part of United Energy's shared network) do not need to be gifted to United Energy. Rather, they could be owned, operated, maintained and replaced by others where it is more efficient to do so (refer discussion in section 2.4.2 above).

Where a customer chooses to own these assets, United Energy's current obligations under various standards would no longer apply to it and would fall to the new owner. In these cases United Energy would provide a standard connection service (i.e. a point of supply) as it currently does and would not be responsible for the public lighting assets beyond the point of supply.

3. Control mechanisms

3.1. Control method for direct control services

The form of control mechanism is an essential element of incentive-based regulation. The AER will determine the form of control mechanism to apply to United Energy for the 2016 to 2020 period in its Final Framework and Approach Paper to be published in October 2014. The AER's decision on the form of control mechanism is the only binding aspect of the Final Framework and Approach paper.

The AER's preliminary F&A sets out the AER's position on the benefits and costs of applying different control mechanisms for standard control services[10]. Based on this analysis, the AER's preliminary view is to apply the following form of control mechanisms to direct control services for the 2016 to 2020 period:

- A revenue cap for standard control services; and
- Caps on the prices of individual services for alternative control services.

[10] AER (2014), *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy, for the regulatory control period commencing 1 January 2016*, May 2014; chapter 2.

This is a significant change from the current arrangements for standard control services as determined by the AER in its 2011 to 2015 Final Framework and Approach Paper published in May 2009 being:

- A weighted average price cap (**WAPC**) for standard control services; and
- Caps on the prices of individual services for alternative control services.

United Energy does not support the AER's preliminary position to apply a revenue cap to standard control services and has set out its reasons and supporting analysis in the following sections of this chapter.

3.1.1. Summary of the analysis

- A well-known result is that, in general, marginal cost pricing is socially optimal. If the cost of producing an additional unit of some good is less than the price that consumers are willing to pay for the additional unit, then both consumers and producers can be made better off if one more unit is produced. If the reduction in costs brought about by producing one less unit of some good exceeds the price that consumers are willing to pay for the unit, then both consumers and producers can be made better off if one less unit is produced. If a firm faces large fixed costs, however, marginal cost pricing may entail the firm making a loss. If a firm is to cover its costs, then it may have to set price above marginal cost for at least one of the goods or services that it produces.
- A second well-known result is that, under the constraint that a firm not make a loss, it will be socially optimal for the firm to use Ramsey prices. If a firm uses Ramsey prices, then the firm will mark prices up, above marginal cost, for goods for which demand is inelastic, by more than the prices of goods for which demand is elastic. Thus, if the demand for access to a network is relatively inelastic while the demand for usage is relatively elastic, then it will be socially optimal for a network service provider to mark up the price of access by more than the price of usage.
- A weighted average price cap can encourage a profit maximising firm to employ Ramsey prices if the weights that the cap uses are chosen appropriately. Thus, if the demand for access to a network is relatively inelastic while the demand for usage is relatively elastic, and the weights that a weighted average price cap uses are chosen appropriately, then a network service operator operating under the cap will choose to mark up the price of access by more than the price of usage.
- In contrast, a revenue cap can encourage a profit maximising firm to employ prices that deviate from Ramsey prices. A firm operating under a revenue cap will mark up the prices above marginal cost of goods for which demand is elastic by more than the prices of goods for which demand is inelastic. Thus, if the demand for access to a network is relatively inelastic while the demand for usage is relatively elastic, a network service operator operating under a revenue cap will choose to mark up the price of access by less than the price of usage. Thus, a revenue cap has the potential to lower social welfare.

3.2. WAPC versus Revenue cap

WAPCs and revenue caps place restrictions on a weighted sum of the prices that a regulated firm can charge and are designed to provide incentives for a firm to engage in cost reduction[11]. Under a WAPC, the weights to be attached to the prices that a firm will charge in the current period for goods and services are the quantities of the goods and services sold in a prior period. Under a revenue cap the weights are the quantities of the goods and services sold in the current period. Therefore, revenue caps fix maximum revenue but not prices while WAPCs cap prices but not revenue.

[11] See:
Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

Since revenue is fixed under a revenue cap, a revenue cap provides an incentive for a firm to cut costs, not just through greater productive efficiency, but also via reductions in the quantities of goods and services sold. A firm can cut the quantities of goods and services sold through the use of demand management and by raising prices. In contrast, since a weighted average of prices is fixed under a WAPC, a WAPC can provide an incentive for a firm to expand sales.

WAPCs and revenue caps can also have impacts on the structure of prices. If the demand function (or, the demand for goods and services by consumers as a function of prices) does not change over time, then the use of a WAPC can provide an incentive for a regulated firm to set prices that will maximise social welfare subject to the constraint that the firm will not make a loss[12]. In particular, a WAPC will encourage the firm to set Ramsey prices, that is, to mark up the prices of products with high demand elasticities by less than the prices of products with low demand elasticities. Marking up the prices of products with high demand elasticities by less than the prices of products with low demand elasticities will minimise the loss in welfare originating from prices deviating from marginal cost.

The use of a revenue cap, on the other hand, can provide an incentive for a firm to set prices that deviate from those that will maximise social welfare. In particular, a revenue cap will encourage a firm to mark up the prices of products with high demand elasticities by more than the prices of products with low demand elasticities. The firm will do so because a revenue cap provides an incentive for the firm to focus solely on minimising costs. Marking up the prices of products with high demand elasticities by more than the prices of products with low demand elasticities will help the firm lower costs while maintaining revenue. However, to mark up prices in this way will not minimise the loss in welfare originating from prices deviating from marginal cost.

If the demand for goods and services by consumers as a function of prices changes over time, the use of a WAPC can also provide an incentive for a regulated firm to set prices that deviate from those that will maximise social welfare. If the demand changes over time, a firm under a WAPC will face an incentive to lower the prices – below where they would otherwise sit – of goods and services whose sales are expected to decline and raise the prices – above where they would otherwise sit – of goods and services whose sales are expected to rise.

3.3. Addressing the AER's key arguments for Revenue cap

The key reasons that the AER has given for its decision to transition United Energy from a WAPC to a revenue cap are that a revenue cap will result in:

- Efficient prices.
- Better incentives for demand side management; and
- Less reliance on forecasts.

United Energy has addressed each of these matters in turn below

3.3.1. Efficient prices

The AER states that[13]:

> *'efficient prices [will be determined by] the underlying cost of supply [and] the willingness of customers to pay.'*

The AER further states that[14]:

> *'Firstly, because for the majority of distributors, the costs of supply are fixed or relate to peak demand, efficient prices will be structured around fixed or peak prices. Secondly, because customers' willingness to pay for connection to the*

[12] Here social welfare is defined to be the sum of profits and consumer surplus. See:
Vogelsang, I., *Price cap regulation of telecommunications services: A long-run approach, in Price-cap Regulation and incentive regulation*, in telecommunications, edited by M.A. Crew, Kluwer, Amsterdam, 1989.

[13] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 65.

[14] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 66.

network is generally higher than for electricity consumption, where the price must be set above the cost of supply the largest margin is likely to be applied to fixed (connection) prices.'

United Energy agrees with the AER and notes that if there are no cross-price effects, Ramsey prices will generate a mark-up in the price of good *i* of: [15]

$$\frac{p_i - \partial C / \partial q_i}{p_i} = \frac{\theta}{\varepsilon_i}, \qquad (1)$$

where p_i is the price of good *i*, *C* denotes the DNSPs[16] total costs, q_i is the DNSP's production of good *i*, $\partial C/\partial q_i$ is the marginal cost of producing the good, θ is the so-called Ramsey number with, in general, $0 \leq \theta \leq 1$ and ε_i is the elasticity of demand for good *i* with respect to its price[17]. If there are cross-price effects – and there are likely to be – then a similar, but more complicated, analysis will follow[18].

Equation (1) states that marking up the prices of products with high demand elasticities by less than the prices of products with low demand elasticities will minimise the loss in welfare that will occur when prices deviate from marginal cost.

The AER points out that:

- DNSPs typically face large fixed costs, while variable costs of satisfying peak demand are higher than variable costs of satisfying off-peak demand; and
- The demand for access or connection is highly inelastic relative to both peak and off-peak demand.

It follows from (1) that a low price should be set for off-peak usage, a higher price should be set for peak usage and a price for access should be set high enough to ensure full cost recovery.

United Energy agrees with the AER that[19]:

'by itself the revenue cap provides limited incentive for distributors to set efficient prices. That is, under a revenue cap, distributors' revenues are fixed over the regulatory control period. Distributors therefore maximise profits by decreasing costs. To maximise profits, distributors face an incentive to increase prices above marginal costs on price sensitive services, thereby reducing demand for those services.'

If there are no cross-price effects, under a revenue cap a DNSP will set a mark-up for good *i* of[20]:

$$\frac{p_i - \partial C / \partial q_i}{p_i} = \frac{1-\lambda}{\varepsilon_i} + \lambda \qquad (2)$$

where λ is a Lagrange multiplier that can be interpreted as the rate of change of maximum profits as the constraint on revenue imposed by a cap is relaxed. If the demand for each good is inelastic, that is, $\varepsilon_i < 1$ for each *i*, as is likely in the short run, then $\lambda > 1$.

Equation (2) states that under a revenue cap a DNSP will mark up the prices of products with high demand elasticities by more than the prices of products with low demand elasticities. Equation (1) implies that marking up prices in this way will not minimise the loss in welfare that will occur when prices deviate from marginal cost.

The AER, however, argues that a revenue cap[21]:

15 Further details are provided in Appendix A. See also:
Armstrong, C. Mark, Simon Cowan and John Vickers, *Regulatory reform - Economic analysis and UK experience,* MIT Press, 1994, page 52.

16 *All references to DNSPs in this section refer to a benchmark, profit maximizing utility.*

17 If θ were to equal zero, then the prices of all goods that the firm produces would be set equal to marginal cost, that is, the firm would set prices as if it faced perfect competition. If θ were to equal one, then the firm would charge the unregulated monopoly price for each good.

18 Armstrong, C. Mark, Simon Cowan and John Vickers, *Regulatory reform - Economic analysis and UK experience,* MIT Press, 1994, page 51.

19 AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 66.

20 Further details are provided in Appendix A. See also:
Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

> *'is unlikely to give rise to inefficient pricing for Victorian distributors. We consider that the majority of distributors' variable costs are caused by augmentations and connections (where demand for connections is likely price insensitive) to the network. The incentive for distributors to decrease costs through pricing is therefore likely to result in higher prices for peak demand. This would require a shift towards peak energy/capacity. In the current environment where tariffs largely consist of flat energy/capacity tariffs we consider that a shift towards peak energy/capacity prices will result in increases in pricing efficiency.'*

Based on the above analysis, United Energy queries the underpinnings of the AER's argument that a revenue cap will not lead to the setting of inefficient prices.

United Energy agrees that if the price elasticity of demand for a product is held constant, then under a revenue cap a DNSP will charge higher prices for peak compared to for off-peak demand. However, applying the same theory, also suggests that a under a revenue cap a DNSP may charge prices for both off-peak and peak demand that are higher than those that would be levied under a WAPC. The DNSP may also charge access or connection fees that are lower than those under a WAPC – therefore, prices overall would be inefficient.

An intuitive interpretation of the revenue cap result in equation (2) is that:

- If the elasticity of demand for a service is held constant a DNSP will charge higher prices for services that are at the margin more costly to produce those that are less costly to produce; however
- If the marginal cost of producing a service is held constant, then a DNSP will charge higher prices for services with (relatively) high demand elasticities by comparison with the prices charged for services with (relatively) low demand elasticities.

While the demand for off-peak and peak usage may be inelastic, the demand for access is likely to be even less elastic. Therefore,

- Under a WAPC, a DNSP should be encouraged to set a high access fee and low fees for usage, whereas
- Under a revenue cap a DNSP will be encouraged to set a low access fee and high fees for usage.

Stoft (1995) suggests that the impact of a revenue cap on profits and on the structure of prices can be more dramatic than the impact of a WAPC[22].

Although the Rules impose side constraints on the revenue that can be raised from each tariff class, these constraints will not prevent a DNSP from responding to the perverse incentives that may arise from a revenue cap[23]. This is because the constraints place only moderate restrictions on the DNSPs ability to change the components of each tariff. If, however, a DNSP believes that, in the long run, expanding its regulated asset base will maximise returns, then the incentives generated by a revenue cap may be offset by a desire to expand usage. Whether the incentives that may exist to expand the asset base will offset the incentives created by a revenue cap is an empirical question.

3.3.2. AEMC review of distribution network pricing arrangements

As noted in section 3.3.1, the AER suggests that a revenue cap might not lead to inefficient pricing. The AER has also asserted that a revenue cap might deliver benefits to consumers as a result of a "better alignment with the introduction of efficient prices". The AER has stated that "efficient prices" incorporate two key characteristics[24]:

- The underlying cost of supply, and
- The willingness of customers to pay.

However, the AER does not appear to have considered the criteria by which an efficient price might be assessed.

[21] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 66.

[22] Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

[23] Australian Energy Market Commission, *National Electricity Rules Version 63*, 1 July 2014..

[24] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 65.

It is useful to note the AEMC views on the objectives of network pricing, as discussed in its consultation paper on a network pricing arrangement Rule change[25]. The AEMC states:

> First, prices should signal to consumers the future (or avoidable) costs of providing network services, as it is these costs that consumers can influence by making informed choices about their consumption. A price signal based on future costs provides opportunities for consumers to respond by adjusting their consumption in ways that can reduce their own cost of using the network as well as contribute to reducing future network costs more broadly.
>
> Second, efficient prices should also allow DNSPs to recover the sunk costs of providing network services. If DNSPs are not assured of recovering efficient costs that they have already incurred, then this may diminish their incentives to undertake future investment in the network in a timely and efficient manner. Such an outcome would be inconsistent with achieving dynamic efficiency under the NEO.

The Standing Council on Energy and Resources (**SCER**) has reported that when network tariffs are set to recover long-run marginal costs (**LRMC**) there could be an under-recovery of total network costs, because LRMC only provides pricing signals for efficient forward-looking costs. SCER has suggested that while forward-looking efficient prices provide the appropriate price signal, the costs of historical investment decisions by DNSPs also need to be recovered from consumers. The historically incurred costs should be recouped from network tariffs in an economically efficient and non-distortionary manner[26].

The AEMC suggests that a Ramsey pricing approach might be one method for recovering residual costs[27]:

> 'Under Ramsey pricing, sunk costs are most efficiently allocated to consumer charges with the lowest price responsiveness, therefore causing the least distortion to demand. In the case of DNSPs, this results in recovery through fixed charges as most consumers require connection to the grid and are therefore very price insensitive to changes in fixed charges'.

The AEMC suggests that an advantage of Ramsey pricing is its flexibility. A method of LRMC pricing (with price varying according to time and location) could be allowed to operate in conjunction with the use of fixed charges to recover residual costs. The potential impacts on particular classes of consumers could be minimised by decreasing fixed charges for consumers who have received a relatively high usage or demand charge as a result of projected network expenditure in their particular location on the network[28].

The AEMC states the following in relation to revenue caps[29]:

> 'Under a revenue cap, DNSPs do not have an incentive to set efficient network tariffs that reflect the underlying costs of supply, given that they receive the same, fixed amount of revenue over the regulatory control period irrespective of the network prices they set'.

Accordingly, the AEMC appears to disagree with the AER's contention that a revenue cap will deliver benefits to consumers by enabling a better alignment with the introduction of efficient prices (see opening paragraph of this section).

Therefore, if the AER decides to apply a revenue cap to United Energy for the 2016 to 2020 regulatory period, this may create a conflict with the policy objectives of the SCER. As set out above, United Energy considers that a revenue cap may prevent socially optimal pricing methods such as Ramsey pricing from being introduced.

3.3.3. Incentives for demand side management

The AER recognises in its May 2014 paper that a revenue cap can influence the incentives that a regulated energy utility faces to influence the demand of consumers for its product. In particular, the AER states that[30]:

> 'Under a revenue cap we fix distributors' revenue over the regulatory control period. Distributors can therefore increase profits by reducing costs. This creates an incentive for distributors to undertake demand side management

[25] AEMC 2013, Distribution Network Pricing Arrangements (Reference ERC0161), Consultation Paper, 14 November 2013; section 5.1.
[26] AEMC 2013, Distribution Network Pricing Arrangements (Reference ERC0161), Consultation Paper, 14 November 2013; section 3.4.1.
[27] AEMC 2013, Distribution Network Pricing Arrangements (Reference ERC0161), Consultation Paper, 14 November 2013; section 9.3.4.
[28] AEMC 2013, ibid; section 9.3.4.
[29] AEMC 2013, ibid; footnote 25, page 14.
[30] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 73.

> projects that reduce total costs. That is, any demand side management project where the reduction in network expenditure is greater than the cost of implementing the demand side management. We consider this provides an efficient incentive to distributors to undertake demand side management within a regulatory control period.'

Stoft (1995) defines demand side management (**DSM**) to represent a shift of a demand curve rather than merely a move along a demand curve[31]. He states that:

> 'When DSM shifts demand; this does not mean simply moving along the demand curve, a process that involves only changing price and waiting for the response. Instead, DSM shifts the demand curve itself, so that less is demanded at any price, whatever that price may be.'

Hence, demand side management does not simply mean moving along a demand curve, which would amount to changing the price and waiting for a response. Demand side management shifts the demand curve itself, so that less is demanded at any price, whatever that price may be. When a DNSPs demand curve shifts down, then the revenue curve also shifts downwards.

The imposition, of a revenue cap will generally promote the uptake of demand side management by firms, but can also encourage a DNSP to undertake more demand side management than is socially optimal. This matter is addressed by Stoft (1995)[32], and a summary of the key results set out below.

As noted, a revenue cap encourages a DNSP to cut costs. Crew and Kleindorfer (1996) point out that a revenue cap provides an incentive to cut costs that is so large that a revenue cap can encourage a DNSP to set a price for its product above the level that an unregulated monopolist would choose[33]. Their argument is as follows: Assume that a DNSP faces demand that is inelastic at low prices and elastic at high prices. This assumption will hold if revenue approaches zero at very low prices and at very high prices. If the revenue cap binds, a monopolist will be forced to either lower or raise the price that it charges to satisfy the cap. To minimise costs and so maximise profits, a DNSP will choose to raise the price that it sets – above the level that it would choose as an unregulated monopolist. In other words, the firm will choose to set price where demand is inelastic.

The Crew-Kleindorfer outcome will fail to materialise if short-run demand for the DNSP's product is sufficiently inelastic. If short-run demand is inelastic, then by raising the price which it sets, a regulated firm will raise revenue and thereby violate its revenue cap. Stoft (1995) points out, however, that demand side management (DSM) can allow a firm to escape this short-run elasticity trap[34]. He argues that:

> 'if a regulator relies on a revenue cap, and no other controls, to motivate DSM, the utility will find it advantageous to run a number of programs that reduce demand, but that are not socially beneficial. This may widen the scope of "successful" DSM considerably.'

Hence:

> 'a revenue cap, while producing an incentive to reduce sales, does not target that incentive towards economically justified energy efficiency improvements. The incentive is too encompassing, and so encourages non-socially beneficial as well as beneficial reductions in sales'.

Stoft (1995) suggests a hybrid price-revenue cap as the safest way to avoid the Crew-Kleindorfer effect and related price effects, but concludes that: [35]

> 'The most important remaining question is what changes in relative prices will be induced by a hybrid cap. Until this is answered, utilities using the hybrid cap may have to maintain the tradition of implicitly regulating relative prices.'

[31] Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

[32] Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

[33] Crew, M.A. and P.R. Kleindorfer, *Price caps and revenue caps: Incentives and disincentives for efficiency*, in M.A. Crew (Ed.), Pricing and Regulatory Innovations Under Increasing Competition, 1996, Kluwer Academic Publishers.

[34] Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

[35] Stoft, S., *Revenue caps vs. price caps: Implications for DSM*, in G. A. Comnes, S. Stoft, N. Greene and L. J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues - Volume I, Energy & Environment Division University of California, Berkeley, November 1995, Chapter 4-2.

The AER does not plan to use a hybrid cap and, again, the side constraints on the revenue that can be raised from each tariff class, imposed by the Rules, place limited restrictions on the DNSP from changing the components of each tariff.

3.3.4. Reliance on forecasts

The AER states that: [36]

> 'a revenue cap will result in ... less reliance on energy forecasts.'

There does not appear to be any analysis that the development of energy sales projections is a lower priority task under a revenue cap than under a price cap. In order for DNSPs to be able to earn a fair rate of return on their assets – projections of prices and quantities must be established in advance of the commencement of a new regulatory period. Both WAPCs and revenue caps place restrictions on a weighted sum of the prices that a DNSP can charge. Under a WAPC, the weights to be attached to the prices that a DNSP may charge for its services in the current period are based on the prior period quantities. Under a revenue cap, the weights are the quantities of the services sold in the current period.

Explicit forecasts of energy sales over a regulatory period are needed in order to make a revenue cap operational. Under a WAPC, the forecasts are needed to assist in the determination of X-factors when applying the AER's post-tax revenue model (**PTRM**). However, once a regulatory period has commenced, the original set of sales forecasts is progressively replaced with actual energy sales to-date, and new, updated forecasts. Therefore, the original set of sales projections will not have a role in the ongoing process of setting annual tariffs. The AER's contention that a revenue cap will result in less reliance on forecasts is unsubstantiated.

The AER states that: [37]

> 'the risks to consumers of incurring higher costs are exacerbated under a WAPC in a situation where an unanticipated negative trend in the rate of energy use may continue. Consequently, we consider this risk is better managed under a revenue cap.'

Under a WAPC, falling usage will typically be accompanied by falling revenue and falling profits. If, as is likely, short-run demand is inelastic, then under a revenue cap falling usage will be accompanied by constant revenue, rising prices and rising profits. Under neither a WAPC nor a revenue cap will consumers face rising costs with falling usage, but under a revenue cap, consumers will face rising per unit costs.

The AER, further states that: [38]

> 'a WAPC does not provide a high or even reasonable likelihood of efficient cost recovery. We consider the WAPC provides an opportunity for distributors to recover revenue systematically above forecast. That is, under a WAPC distributors have the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast quantities, and to recover revenue close to forecast when actual quantities are below forecast quantities.'

Under a WAPC, the AER must set a cap such that the DNSP will, on average, earn a fair rate of return on its assets. If the regulator sets the cap correctly, then it is difficult to see how a DNSP will be able to recover revenue systematically above forecast.

3.3.5. Other issues

Under a revenue cap, if usage falls, because, for example, of poor economic conditions, then prices must rise to maintain a constant level of revenue. A combination of falling usage, poor economic conditions, and rising prices can be unpopular with consumers and may expose a regulated firm to political risk. The AER in its preliminary

[36] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 65.
[37] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 68.
[38] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, page 68.

positions paper compares the behaviour of Queensland distributors operating under a revenue cap with New South Wales distributors operating under a WAPC[39]. Both sets of distributors are state owned and so it is unclear that one should expect privately operated firms to behave in the same way. There is ample evidence to suggest that the profits earned by government owned enterprises are lower than the profits earned by their privately owned counterparts[40].

The AER argues in a March 2014 paper that[41]:

> 'block tariff structures will send a blunt signal of higher use costing more (inclining block tariff) or less (declining block tariff). We consider these signals are not efficient, as they do not reflect the cost of providing the service.'

Armstrong, Cowan and Vickers (1994) emphasise that welfare maximising tariffs may be nonlinear and may take the form of a declining block tariff[42]. Essentially a declining block tariff can be a way in which a regulated firm can charge a low access fee to low usage consumers who might otherwise be discouraged from gaining access by a high access fee.

When times are bad (good) the profits of a firm that faces a WAPC will typically fall (rise). In contrast, when times are bad (good) the profits of a firm that faces a revenue cap will typically rise (fall) as its revenue remains constant but its costs fall (rise). This analysis suggests that the cost of equity for a firm that faces a revenue cap may sit below the cost of equity for a firm that faces a WAPC. The Brattle Group (2014) in a recent report, however, find no evidence to support this suggestion[43].

3.3.6. Revenue caps and the cost of capital

The Brattle Group (2014) examined symmetric revenue true-up mechanisms (revenue caps) and compared outcomes for the cost of capital under these arrangements with those recorded under rate of return regulation. The Brattle Group described revenue caps, or revenue decoupling as follows[44]:

> An overall base revenue target is established for a future period, and a periodic adjustment of volumetric rates is then instituted to true up actual revenues to target revenues, whether actual revenues are above or below target.

The Brattle Group performed empirical work by considering a sample of regulated utilities that had experienced a change in decoupling policy over the period from 2005 to 2012. The composition of the sample can be explained as follows[45]:

- 14 electric holding companies.
- 21 state-regulated electric subsidiaries of the holding companies. The subsidiaries operated in 11 states and were subject to a decoupling regime during some quarters in the study period.
- Observations were available for 32 quarters from 2005 to 2012, a period over which there was rapid growth in the policy of decoupling across regulated US utilities.
- The total number of observations used in the econometric analysis was 291, with each panel data reading pertaining to a holding company and consisting of the cost of capital in that quarter, the value of the decoupling index in the quarter, and a set of explanatory variables and dummy variables.

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39 AER (2014), *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy, for the regulatory control period commencing 1 January 2016*, May 2014; section 2.3.1

40 See, for example:
Dewenter, K and P. Malatesta, *State-owned and privately owned firms: An empirical analysis of profitability, leverage,and labor intensity*, American Economic Review 91, 2001, pages 320-334.

41 AER, *Stage 1 Framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy, Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, page 91.

42 Armstrong, C. Mark, Simon Cowan and John Vickers*, Regulatory reform - Economic analysis and UK experience,* MIT Press, 1994, pages 20-24.

43 The Brattle Group, *The impact of revenue decoupling on the cost of capital for electric utilities: An Empirical Investigation prepared for The Energy Foundation*, March 2014.

44 The Brattle Group, *The impact of revenue decoupling on the cost of capital for electric utilities: An Empirical Investigation prepared for The Energy Foundation*, March 2014; page 1.

45 The Brattle Group, *The impact of revenue decoupling on the cost of capital for electric utilities: An Empirical Investigation prepared for The Energy Foundation*, March 2014; page 10.

Brattle (2014) reported that holding companies, rather than their subsidiaries, had publicly traded stock which provided the financial information necessary to estimate the cost of capital. However, the individual subsidiaries of these companies were subject to state-based regulation, and would thus potentially meet the eligibility criteria for a decoupling form of revenue regulation. A decoupling metric was calculated for each holding company by examining the regulatory context for each subsidiary, (which was a function of the state in which the subsidiary operated), and applying weights that were a function of the subsidiary's share of the holding company's assets.

A simple, one-stage dividend discount model was used to estimate the cost of equity for a holding company, with the value of the long-term rate of growth of dividends per share having been inferred from the medium term forecasts of analysts. Brattle (2014) reported that they used dividend and earnings projections from analysts for a five-year period, with the variable measured over 15 trading days. Current stock prices were also recorded.

The cost of equity was incorporated into a measure of the after-tax weighted average cost of capital, which also took into account the gearing for each firm, and the market cost of debt. The latter variable was formed using the yield on utility debt obtained from Bloomberg's bond index for companies of comparable S&P credit ratings. Brattle (2014) also included the return on preferred equity in its calculations, for those companies with preferred stock[46].

Brattle (2014) postulated that the occurrence of decoupling could be providing a signal that a company was about to enter a period of high risk. Decoupling reduces both the upside and downside for a regulated company. If a company believed that policies or economic conditions might impose additional risk, then the company could seek decoupling so as to mitigate increasing risk. Alternatively, state policy makers and commissions could seek to impose decoupling so as to ensure the success of energy efficiency programmes. Conceivably, decoupling could reduce risk, but not by enough to offset the elevated risk due to other associated policies or circumstances.

A regression was run using the after-tax WACC as the dependent variable, and with explanatory variables as follows: The value of the decoupling index, a dummy variable for each quarter (time period), and a dummy variable to control for each company. In the equation specifications that were trialled by Brattle (2014), the parameter estimate on the decoupling index was found to be negative, small in magnitude, and statistically insignificant at the 5 per cent level of significance. Hence, Brattle (2014) concluded that there was no evidence to support the claim that a policy of decoupling might have the effect of bringing down the cost of capital for a company[47]:

> If decoupling policy decreases the cost of capital, these [empirical] tests strongly suggest that the effect must be relatively small because we are not able to detect it statistically.

Brattle (2014) argued further that if decoupling were associated with the implementation of enhanced energy efficiency programmes, then if a regulator were to preside over a reduction in the allowed return on equity, the utility would, in effect, be punished for pursuing those programmes.

3.3.7. Formulae for standard control services

Formulae to be used with a continuation of the price cap

United Energy considers that the AER should retain a weighted average price cap for standard control services to apply for the duration of the 2016 to 2020 regulatory control period. The AER should maintain consistency in its approach to the regulation of standard control services over time. To that end, United Energy believes that the AER should continue to apply the price cap formulae and mechanisms that were described in the final decision for the EDPR, 2011 to 2015[48]. Chapter 4 of the final decision presents the AER's perspectives on the form of the control mechanism under a weighted average price cap, and on related issues such as the recovery of transmission tariffs. The distribution determination for United Energy also contains details of the weighted average price cap formula for the 2011 to 2015 regulatory period[49].

[46] The Brattle Group, *The impact of revenue decoupling on the cost of capital for electric utilities: An Empirical Investigation prepared for The Energy Foundation*, March 2014; page 15.

[47] The Brattle Group, *The impact of revenue decoupling on the cost of capital for electric utilities: An Empirical Investigation prepared for The Energy Foundation*, March 2014; page 18.

[48] AER (2010a), Final decision, *Victorian electricity distribution network service providers, Distribution determination 2011-2015,* Australian Energy Regulator, October 2010, chapter 4.

[49] AER (2010b), United Energy Distribution*, Distribution determination 2011-2015,* Australian Energy Regulator, October 2010, section 2.

United Energy perspective on the revenue cap formulae proposed by the AER

Although United Energy is not in favour of a revenue cap, United Energy would like to remain engaged in the discussion about appropriate forms of the revenue cap control mechanism. Accordingly, United Energy has considered the control mechanism formulae that the AER has put forward in section 2.3.10 of the preliminary positions paper, and would like to present its response in this section.

The AER has stated in its preliminary positions paper that it considers that the following formulae give effect to the revenue cap:[50]

(1) $MAR_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t*}$ $\qquad$ i = 1,...,n and j = 1,...,m and t = 1,...,5

(2) $MAR_t = AR_t + I_t + T_t + B_t$

(3) $AR_t = AR_{t-1}(1+CPI_t)(1-X_t)$

Where:

MAR_t is the maximum allowable revenue in year t.

p_{ij}^{t} is the price of component i of tariff j in year t.

q_{ij}^{*t} is the forecast quantity of component i of tariff j in year t.

AR_t is the allowed smoothed revenue requirement in the Post Tax Revenue Model for year t.

I_t is the sum of incentive scheme adjustments in year t. To be decided upon in the final decision.

T_t is the sum of end-of-period adjustments in year t. Likely to incorporate but not limited to adjustments from the transitional regulatory control period. To be decided upon in the final decision.

B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the overs and unders account. To be decided upon in the final decision.

CPI_t is the percentage increase in the consumer price index. To be decided upon in the final decision.

X_t is the X-factor in year t. To be decided upon in the final decision.'

There are a number of points to be made about these formulae.

First, prior to a five-year regulatory period, a regulator, under a revenue cap, must decide what cap placed on revenue in each year will ensure that a firm will on average earn a fair rate of return. To make this decision, the regulator will use the PTRM and forecasts of costs, prices and quantities. The outcome of this process will be, after adjustments have been made, maximum allowable revenue for each year.

[50] AER, *Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016*, May 2014, pages 74-75.

Prior to the start of each regulatory year the firm must propose a set of prices for the services that it will provide. To determine whether the firm's proposal will be likely to satisfy the revenue cap, the regulator will compare a forecast of the revenue that the firm will earn using the set of prices proposed and the maximum allowable revenue for the year. The regulator will approve the proposal if forecast revenue, the right-hand side of the AER's equation (1) does not exceed maximum allowable revenue for the year, the left-hand side of the AER's equation (1).[51] The forecasts that the regulator will use in this process will not be the forecasts that it used in using the PTRM prior to the start of the regulatory period but will be an updated set of forecasts.

After each year, the regulator will assess whether a firm has satisfied the revenue cap. To do so, the regulator will compare actual, not forecast, revenue to the maximum allowable revenue for the year. If actual revenue falls short of maximum allowable revenue because demand is less than expected or exceeds maximum allowable revenue because demand is greater than expected, then an 'unders-and-overs' mechanism will be used to raise or lower maximum allowable revenue for the following year.[52]

This discussion indicates that the AER's equation (1) does not fully describe the role that maximum allowable revenue plays in each year. In particular, the equation does not reveal that the restriction that the regulator ultimately places is on the firm's actual, rather than forecast, revenue. Equation (1) provides the impression that the restriction that the regulator ultimately places is on the firm's forecast, rather than actual, revenue.

Second, the evolution of the maximum allowable revenue through the regulatory period will depend on actual inflation rather than inflation as forecast in the PTRM and the impact of incentive scheme adjustments can be multiplicative rather than additive. As an example, the s-factor adjustments made to allowed revenue are multiplicative.[53]

We therefore suggest that the AER's equations (2) and (3) be replaced by the three equations (4), (5) and (10) below. Define AAR_t to be allowed revenue adjusted for multiplicative incentive scheme adjustments and let AR_t continue to be the annual smoothed unadjusted revenue requirement taken from the PTRM. Then, in the first year of the regulatory period 2016-2020, that is, 2016, allowed revenue adjusted for multiplicative incentive scheme adjustments should be:

$$AAR_1 = AR_1(1 + S_1''') \tag{4}$$

while in the second through fifth years of the regulatory period, that is, 2017 through 2020, allowed revenue adjusted for multiplicative incentive scheme adjustments should be:

$$AAR_t = AAR_{t-1}(1 + CPI_t)(1 - X_t)(1 + S_t), \qquad t = 2,3,\ldots,5. \tag{5}$$

Here, using the AER's notation, S_1''' is the sum of the s-factors for all parameters, after application of the s-bank, adjusted for the change in the annual revenue requirement between the last year of the 2011-2015 regulatory period, that is, 2015, and the first year of the 2016-2020 regulatory period, that is, 2015.[54] CPI_t is the actual rate of inflation and not the forecast rate of inflation from the PTRM, X_t is the x-factor contained in the PTRM for year t of the 2016-2020 regulatory period and not for year t-1 of the period and S_t is the s-factor expressed as a percentage of revenue.[55]

Note that the s-factor S_t undoes the incentive adjustment made in period t-1 whereas the variable S_1''' does not. Using the definitions provided by the AER in its *Electricity distribution network service providers: Service target performance incentive scheme* of 2009:

[51] Australian *Energy Market Commission, Advice to SCER: Consideration of differences in actual compared to forecast demand in network regulation*, 26 April 2013, page 84.
[52] Australian *Energy Market Commission, Advice to SCER: Consideration of differences in actual compared to forecast demand in network regulation*, 26 April 2013, pages 84-85.
[53] AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009.
[54] AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009, pages 33-34.
[55] AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009, pages 28-29 and 33-34.

$$S_2 = (1+S_2''')/(1+S_1''') - 1, \quad (6)$$

$$S_3 = (1+S_3')/(1+S_2''') - 1, \quad (7)$$

$$S_4 = (1+S_4')/(1+S_3') - 1, \quad (8)$$

$$S_5 = (1+S_5')/(1+S_4') - 1, \quad (9)$$

The difference between S_t''' and S_t' is that S_t''' makes an adjustment for the change in the annual revenue requirement between the last year of the 2011-2015 regulatory period, that is, 2015, and the first year of the 2016-2020 regulatory period, that is, 2016, whereas S_t' does not.[56] S_t''' is used for the first two years of the new regulatory period because of the two-year lag between performance and the reward or penalty provided by the incentive scheme.

The equation describing the evolution of maximum allowable revenue through time should be replaced by:

$$MAR_t = AAR_t + I_t + T_t + B_t, \qquad t = 1, 2, \ldots, 5. \quad (10)$$

Third, for clarity, it would be useful to make clear that I_t measures the sum of the additive (rather than multiplicative) incentive scheme adjustments.

Finally, we note that section 6.6 of the NER lists the following adjustments that should be made where necessary after making a building block determination: Adjustments for cost pass through, a reopening on a jurisdictional scheme, demand management and embedded generation connection incentive schemes, the small-scale incentive scheme, a reopening of a distribution determination for capital expenditure, an acceptance of a contingent project in a distribution determination and an amendment of a distribution determination for a contingent project[57]. Besides these adjustments listed in the NER, additional adjustments must be made for state initiatives such as the F-factor scheme.[58] All additive adjustments should be incorporated into either I_t, T_t or B_t. Any multiplicative adjustment should be made in the same way as the adjustment made for the service target performance scheme.

United Energy reserves the right to make further submissions to the AER on the control mechanism in the context of its regulatory proposal, which is due to be lodged with the AER in 2015.

3.4. Control method for alternative control services

For alternative control services, United Energy is in broad agreement with the AER that an appropriate control mechanism is likely to take the form of caps on the prices of individual services. In its forthcoming regulatory proposal, United Energy will set out the manner in which it believes the caps should be calculated.

In its distribution determination for the 2011 to 2015 regulatory period, the AER published caps which would apply to the prices of different public lighting services[59]. Caps were also imposed on the prices of individual, fee-based alternative control services, although the caps were to apply only to the first year, 2011. For 2012 to 2015, escalation using the annual change in the consumer price index (CPI) would be permitted. The AER also invoked price caps for quoted alternative control services, although the caps, and subsequent price paths, applied to hourly labour rates. The AER described the hourly labour rates as quoted, alternative control service charge-out rates.

United Energy will explain in its regulatory proposal whether it believes that a departure from the 2011 to 2015 precedents is warranted.

[56] AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009, pages 33-34.
[57] Australian Energy Market Commission, *National Electricity Rules Version 63*, 1 July 2014, pages 654-674.
[58] AER, *Final determinations and explanatory statement: F-factor scheme determinations 2012–15 for Victorian electricity distribution network service providers*, 22 December 2011.
[59] AER (2010b), United Energy Distribution, *Distribution determination 2011-2015,* Australian Energy Regulator, October 2010, section 2.2.

4. Other Matters

4.1. Indexation of the regulatory asset base for inflation

4.1.1. Implications of United Energy final decision, 2011 to 2015 regulatory period

The opening value of the regulatory asset base for United Energy for 1st January 2006 is written down in the National Electricity Rules, in clause S6.2.1(c)(1) of Schedule 6.2, with the dollar value expressed in July 2004 prices. The opening regulatory asset base (RAB) value was used for the purpose of the 2011 to 2015 distribution determination. The value of the RAB for United Energy is shown to be $1,220.3 million (as at 1st January 2006 in July 2004 dollars).

The AER made a distribution determination for United Energy for the 2011 to 2015 regulatory period, in October 2010. The opening RAB value for 2011 was obtained by escalating the opening RAB value as at 1st January 2006, which was expressed in July 2004 prices, using inflation data for six years. The AER also made other adjustments to the 2006 opening RAB value expressed in 1st July 2010 dollar terms, with the result that the overall opening RAB value for 2011 was stated in July 2010 terms. The opening RAB value for 2011 should, of course, have been expressed in January 2011 prices.

The post-tax revenue model, (**PTRM**), published by the AER is expressed in nominal terms, and this is a consequence of the way in which the components of the PTRM are described in clauses 6.4.1, 6.4.2, and 6.4.3. The opening value of the RAB should be entered into the PTRM in nominal terms. The implication, therefore, is that the PTRM which will be developed for the 2016 to 2020 regulatory period, will require an opening RAB value that has been expressed in the price level of 1st January 2016.

A consequence of the specification for 2016 is that the opening RAB value for 2011, which was used for the purpose of the 2011 to 2015 distribution determination, will need to be escalated using an approach that delivers five and a half years' worth of inflation. An inflation adjustment of this type will ensure that the opening RAB value for 2016 is stated in the dollar terms of 1st January 2016. The opening RAB value at the commencement of the next regulatory period must be expressed in current prices before being inputted into the PTRM.

4.1.2. Decision of the ACT in Application by United Energy Distribution Pty Limited [2012] ACompT 1

The Australian Competition Tribunal found that the AER had erred in its approach to the indexation of the RAB values for Jemena Electricity Networks (**JEN**)[60]. The AER had escalated the RAB values, relying on a presumption that the values in clause S6.5.1(c) (1) were stated in the price level of September 2003[61]. The Tribunal confirmed that the opening RAB values, for 1st January 2006, in clause S6.2.1(c) of the NER, were written in July 2004 prices, and that looking behind the table was an impermissible exercise.

Regarding the interpretation of clause 6.5.1(e) (3), the Tribunal concluded that applying 'actual' inflation in the RAB roll-forward model would necessitate the use of observed inflation for the relevant indexation period (rather than a measure of inflation based on observed inflation in an earlier period). The Tribunal therefore deduced that:

- 'Actual inflation' in clause 6.5.1(e) (3) involves a retrospective determination of inflation because actual inflation can only be determined retrospectively[62].
- Therefore, since the regulatory determination has to be made prior to the commencement of the subsequent regulatory period, the implication is that clause 6.5.1(e) (3) does not require the values to be indexed for the whole of the expiring regulatory period. Instead, the end point of the indexation period will be a point in time which is before the commencement of the subsequent regulatory period[63].

[60] The Tribunal only made orders in respect of JEN, concluding that the other Victorian DNSPs were precluded from raising the matter before the Tribunal because they had not broached the matter with the AER.
[61] Application by United Energy Distribution Pty Limited [2012] ACompT 1, at paragraph [378].
[62] Application by United Energy Distribution Pty Limited [2012] ACompT 1, at paragraph [371].
[63] Application by United Energy Distribution Pty Limited [2012] ACompT 1, at paragraph [372].

The Tribunal also ruled that the weighted average consumer price index, (CPI), for the eight capital cities of Australia would need to be used to make an inflation adjustment which was consistent with the method used for indexation of the control mechanism from 2006 to 2010[64]. However, the Tribunal also stated that the AER would not be confined to using the change in the CPI for the September to September period, but could, in fact, nominate another four quarterly period, or 12-month interval, if the AER considered that there would be merit in pursuing such an approach.

Finally, the Tribunal indicated that the end point of the indexation period should be a matter that is left to the AER's discretion. In its deliberations, the Tribunal opined that provided the end point of the period of escalation is reasonable, in all the circumstances, and is as close as possible to the date upon which the new regulatory control period is to commence, then the choice of end point should be a matter that is left to the AER[65]. The Tribunal believed that DNSPs would not suffer so long as the adjustments for inflation in the next period commenced at the point in time to which the values had been escalated in the previous period.

4.1.3. Method for escalation for the 2016 to 2020 regulatory control period

As has been mentioned in section 4.1.1, the opening RAB value for 2011 that was reported in United Energy's distribution determination for the 2011 to 2015 period will need to be escalated using the cumulative inflation over a five and a half year time interval, in order for the RAB values to be transformed into January 2016 prices. The practical consequence is that before United Energy's RAB can be rolled forward to determine the opening RAB on 1st January 2016, an adjustment of six months of inflation would need to be built in so as to transform the RAB from July 2010 prices into the price level of January 2011.

The AER has, in the past, used the four-quarterly change in the CPI from September to September when applying indexation to the RAB. A lagged measure of inflation, recorded over the period from March 2009 to September 2009, could be used to amend United Energy's 2011 opening RAB, ensuring that the values are converted from July 2010 prices to January 2011 prices. The lagged measure of inflation thus employed would be described as having a 15-month lag because of the time span from September 2009 to January 2011.

The aforementioned approach would result in an overlap in the way in which the CPI measure of inflation is applied to RAB values. This is because the change in the CPI from March 2009 to September 2009 would have been brought in twice, once for the purposes of the 2011 to 2015 distribution determinations, and once for the purposes of the 2016 to 2020 distribution determinations. However, the doubling up of price indexation would be a one-off measure, designed to facilitate the move from a mid-year cash flow timing assumption to an end of year cash flow timing assumption, as occurred in the 2011 to 2015 regulatory period.

A relevant consideration is that the AER applied a set of results for the CPI twice when implementing an inflation adjustment to the RAB for JEN upon remittal. The AER made use of the squared result for the change in the CPI from July 2004 to December 2004, in order to apply a further six months of inflation.

[64] Application by United Energy Distribution Pty Limited [2012] ACompT 1, at paragraph [380].
[65] Application by United Energy Distribution Pty Limited [2012] ACompT 1, at paragraph [383].

5. Incentive schemes

5.1. Service Target Performance Incentive Scheme (STPIS)

The AER's preliminary position is to continue to apply the STPIS outlined in the AER's Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme, 1 November 2009 (**STPIS Guideline**).

United Energy notes that the AER did not review the STPIS Guideline as part of its Better Regulation Program and has deferred undertaking any review until other national reviews are complete – these reviews include:

- The AEMC review of distribution reliability outcomes and standards; and
- The AEMO review of the estimating the value of customer reliability (**VCR**).

United Energy generally supports the AER's decision to continue to apply the national STPIS in the 2016 to 2020 regulatory control period however has proposed changes to certain parameters and/or components of the Guideline, as permitted under the STPIS Guideline, on the basis that these changes better:

- Support the Role[66] of the Scheme which is to "provide incentive for DNSPs to <u>maintain</u> and <u>improve</u> service performance"; and
- Satisfy the AER's objectives of the Scheme which are that the Scheme:
  - *(a) is consistent with the national electricity objective in section 7 of National Electricity Law (NEL)*
  - *(b) is consistent with clause 6.6.2(b)(3) of the NER which requires that in developing and implementing a service target performance incentive scheme, the AER must take into account:*
    - *(1) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs*
    - *(2) any regulatory obligation or requirement to which the DNSP is subject*
    - *(3) the past performance of the distribution network*
    - *(4) any other incentives available to the DNSP under the Rules or a relevant distribution determination*
    - *(5) the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels*
    - *(6) the willingness of the customer or end user to pay for improved performance in the delivery of services*
    - *(7) the possible effects of the scheme on incentives for the implementation of non-network alternatives*

United Energy proposes the following changes in the context of:

- Its current period performance under the STPIS which has involved significant financial penalties despite it investing in line with the AER's approved capital expenditure allowance. United Energy emphasises that the Rules require the AER to consider a DNSPs past performance in implementing the STPIS; and
- The AER's preliminary view to apply the capital expenditure sharing scheme (**CESS**) to United Energy in the 2016 to 2020 period. United Energy emphasises that the application of the CESS will impose new additional financial incentives on DNSPs to ensure that they do not reduce costs at the expense of service levels.

United Energy would support a future review of the STPIS Guideline once the national reviews are complete.

[66] Set out in clause.1.4

5.1.1. Revenue at risk

United Energy proposes reducing the lower limit cap from -5 % to -3% cap and retaining +5% cap on upside. The key reasons underpinning these proposed changes are:

- The introduction of the CESS imposes new additional incentives for DNSPs to not underspend their allowance at the expense of service reliability therefore the lower limit cap should be reduce to ensure United Energy is not unduly penalised where targets are not met (particularly due to random events – refer point below);
- Reducing the lower limit to -3% would protect United Energy against the financial effect of large random events that only occur on the downside. Over the current period, United Energy has incurred significant financial penalties due to large random events on the downside under the STPIS. These events cannot be addressed through investment levels that would be consistent with customers' willingness to pay; and
- Preliminary outcomes from United Energy's research on the willingness of customers to pay for improved performance indicates that the majority of customers are satisfied with existing reliability and are not willing to pay more for improved reliability. Reducing lower limit to -3% would limit exposure of customers to price increases due to investment required to improve reliability.

5.1.2. Momentary Average Interruption Frequency Index (MAIFI)

United Energy supports increasing MAIFI from 1 to 3-5 minutes. This change is currently being considered by the AEMC as part of its Review of Distribution Reliability Measures. In particular, the AEMC is considering the benefits of alignment to the *IEEE 1366 - 2012* standard of less than 5 minutes or the United Kingdom/European standard of less than 3 minutes in order to provide an economic incentive to DNSPs to invest in feeder automation solutions.

While the AER's STPIS currently specifies MAIFI, United Energy and other Victorian distributors have traditionally reported and been rewarded and penalised against MAIFIe - Momentary Average Interruption Frequency Index event. The use of MAIFIe would encourage distributors to optimise reclose operations to improve network reliability. Customers are therefore likely to benefit from improved restoration outcomes, although they may be more aware of multiple restoration attempts.

United Energy strongly supports increasing MAIFI to 3-5 minutes to allow it to use automated supply restore functionality and adopting MAIFIe rather than MAIFI.

5.1.3. Urban rural feeders

United Energy considers that in order to ensure that the feeder classification reflects changes in load density on feeders during the regulatory control period United Energy should be able to submit forecasts of urban and rural customers (and the impact on the classification of feeders for each year of the regulatory control period) at the start of the regulatory control period. These forecasts would be incorporated into the calculation of the reliability benchmarks for 2016 to 2020 period.

5.1.4. Guaranteed Service Level (GSL) payments

The AER proposes to continue to apply the GSL payments determined by the Victorian Government and set out in the Victorian Electricity Distribution Code (**Code**). United Energy notes that the nature and scope of these payments have not been reviewed for many years.

United Energy reminds the AER of the Council of Australian Government's (**COAG**) best practice regulatory principles, which emphasise the importance of ensuring that regulation is subject to periodic review.

United Energy, therefore intends to consult with its customers and other stakeholder to ensure that these GSL payments reflect what they want and are willing to pay for. Depending on the outcome of this consultation, United Energy may propose changes to the GSL payments in its Regulatory Proposal.

5.1.5. Other components / elements of the Scheme

United Energy is also currently considering other potential changes and will outline these in its Regulatory Proposal.

5.2. Efficiency Benefit Sharing Scheme (EBSS)

The AER proposes to apply the Efficiency Benefit Sharing Scheme (**EBSS**) outlined in *Electricity Distribution Network Service Providers Efficiency Benefits Sharing Scheme* (**EBSS Guideline**), 29 November 2013.

United Energy accepts the EBSS however notes that the EBSS of 29 November 2013 introduces changes to limit adjustments and exclusions from the scheme as currently applied. United Energy will work with the AER to reach agreement on appropriate exclusions from the EBSS at the determination stage.

5.3. Capital Expenditure Sharing Scheme (CESS)

The AER propose to apply the CESS, as set out in its Expenditure Forecast Assessment Guideline, November 2013. United Energy accepts the AER’s proposed CESS for the upcoming regulatory control period.

5.4. Demand Management Incentive Scheme (DMIS)

The AER proposes to continue to apply the Demand Management Incentive Allowance (**DMIA**) (Part A of the DMIS) in the 2016 to 2020 period, albeit that it has not proposed an allowance cap. The AER is not proposing to apply the forgone revenue component (Part B of the DMIS) on the basis that it has proposed a revenue cap for the upcoming regulatory control period.

United Energy is committed to developing a smarter and more flexible network that delivers benefits to customers through lower prices achieved though less costly non-network investments. To this end, United Energy strongly supports an allowance for demand management initiatives that enables it to achieve this objective. United Energy notes that the total current period allowance of $2 million (or an annual capped amount of $400,000) is not sufficient to achieve this objective. United Energy considers that for the 2016 to 2020 period, the AER should allow investment under the DMIA to be un-capped given the requirements for pre-approval of expenditure. In this case all expenditure would be reviewed on a case by case ex-ante basis within period to ensure the expenditure is prudent and efficient.

United Energy also supports a review of the DMIS in light of:

- 2011 Rule change which introduced provisions for the development of Demand Management and Embedded Generation connection incentive Scheme (**DMEGCIS**); and
- The Standing Council on Energy and Resources Power of Choice review once finalised.

5.5. Small scale incentive scheme

United Energy notes that the AER has not developed any new small scale incentive scheme (**SSIS**). United Energy is still developing its position on whether a SSIS should be introduced and will seek views from its stakeholders and other customers on this matter to inform its position. United Energy will therefore set out its position on this in its Regulatory Proposal to be lodged in April 2015.

5.6. Application of the Expenditure Forecast Assessment Guideline

The AER propose to continue to apply its Expenditure forecast Assessment Guideline to United Energy in the 2016 to 2020 period. United Energy notes that the AER is intending to apply all the assessment tools in its guideline to assess the efficiency and prudency of United Energy’s expenditure forecasts.

United Energy would welcome further clarification of how the AER will use the broad range of tools and approaches set out in its Guideline.

6. Depreciation

United Energy notes the AER's position to use forecast depreciation to establish the 2021 opening regulatory asset base.

7. Dual Function assets

As defined in the Rules, dual function assets are owned, operated or controlled by a DNSP which operate at voltages between 66kV and 220KV, to support the higher voltage transmission network.

United Energy confirms that it does not own or operate any such assets.

Appendix A: Relative Prices under price and revenue caps

This appendix presents the derivations of the main results (1) and (2) shown in section 3.3.1.

A.1. Ramsey prices

In general, it will be socially optimal for prices to be set equal to marginal cost. Marginal cost pricing, however, may not allow a firm to cover its costs. If a regulator will not permit a utility to practise perfect price discrimination, then the most efficient way for the firm to cover its costs will be for the firm to set Ramsey prices.

Ramsey prices are the prices that will maximise consumer surplus subject to the constraint that the regulated firm must break even[67]. In other words, Ramsey prices will maximise consumer surplus.

$V(p_1,\ p_2,\ \ldots,\ p_N),$ (A.1)

Where:

$$\frac{\delta V}{\delta p_1} = -q_1 \qquad \text{(A.2)}$$

Subject to the breakeven constraint:

$$\boldsymbol{\pi = \sum_{i=1}^{N} p_i q_i - C = 0} \qquad \text{(A.3)}$$

Here, p_i is the price of good i, q_i is the quantity of good i consumed and produced, there are N goods, π is the firm's profits, and C is the total cost of production. The Lagrangian for the problem will be:

$$\boldsymbol{L = V(p_1,\ p_2,\ \ldots,\ p_N) + \lambda\left(\sum_{i=1}^{N} p_i q_i - C\right)} \qquad \text{(A.4)}$$

Where $\boldsymbol{\lambda}$ is a Lagrangian multiplier. The multiplier $\boldsymbol{\lambda}$ can be interpreted as the rate of change in consumer surplus as the constraint that the firm breaks even is relaxed.

For expositional ease, we assume in this submission that there are no cross price effects. In other words, we assume that an increase in the price of good i has no impact on the demand for good k, where $i \neq k$. With this assumption, the first order conditions for the problem will be:

$$\boldsymbol{\frac{\delta L}{\delta p_i} = -q_i + \lambda\left(q_i + p_i\frac{\delta q_i}{\delta p_i} - \frac{\delta C}{\delta q_i}\frac{\delta q_i}{\delta p_i}\right) = 0} \qquad \text{(A.5)}$$

$$\boldsymbol{\frac{\delta L}{\delta \lambda} = \sum_{i=1}^{N} p_i q_i - C = 0} \qquad \text{(A.6)}$$

From (A.5):

[67] See for example:

Armstrong, M., S. Cowan and J. Vickers, *Regulatory reform: Economic analysis and British experience*, MIT Press, 1994, pages 51-57.

$$\boldsymbol{\lambda} = \frac{q_i}{\left(q_i + \left(p_i - \frac{\delta C}{\delta q_i}\right)\frac{\delta q_i}{\delta p_i}\right)} \tag{A.7}$$

The presumption that price must exceed marginal cost for the firm to break even implies that the multiplier $\boldsymbol{\lambda} > \mathbf{1}$. Equation A.7 can be rewritten as:

$$\frac{\left(p_i - \delta C/\delta q_i\right)}{p_i} = \frac{\theta}{\epsilon_i} \quad , \tag{A.8}$$

Where:

$$\theta = \lambda^{-1}(\lambda - 1) > 0 \text{ and } \epsilon_i = -\frac{\delta q_i}{\delta p_i}\frac{p_i}{q_i} \tag{A.9}$$

The quantity $\boldsymbol{\theta}$ is the so-called Ramsey number and (A.8) is equation (1) in the main body of the text of United Energy's submission.

A.2. Revenue caps

We assume that the firm will wish to maximise profits:

$$\pi = \sum_{i=1}^{N} p_i q_i - C = 0 \tag{A.10}$$

Subject to the constraint on revenue given by:

$$\sum_{i=1}^{N} p_i q_i = K \tag{A.11}$$

Here, K is the cap on revenue, which we assume is binding. The Lagrangian for the problem will be[68]:

$$L = \sum_{i=1}^{N} p_i q_i - C + \lambda\left(K - \sum_{i=1}^{N} p_i q_i\right) \tag{A.12}$$

The multiplier $\boldsymbol{\lambda}$ can be interpreted as the rate of change in the firm's profits brought about as the constraint on revenue is relaxed. The first order conditions for the firm's problem will be:

$$\frac{\delta L}{\delta p_i} = q_i + p_i\frac{\delta q_i}{\delta p_i} - \frac{\delta C}{\delta q_i}\frac{\delta q_i}{\delta p_i} - \lambda\left(q_i + p_i\frac{\delta q_i}{\delta p_i}\right) = 0 \tag{A.13}$$

$$\frac{\delta L}{\delta \lambda} = K - \sum_{i=1}^{N} p_i q_i = 0 \tag{A.14}$$

From (A.13)

$$\lambda = \frac{1 + \epsilon_i - \frac{1}{q_i}\frac{\delta C}{\delta q_i}\frac{\delta q_i}{\delta p_i}}{1 + \epsilon_i} \tag{A.15}$$

If the demand elasticity $\epsilon_i < 1,$ as is likely in the short run, then the multiplier $\lambda > 1.$ Equation (A.15) can be rewritten as:

$$\frac{\left(p_i - \delta C_t/\delta q_i\right)}{p_i} = \frac{1 - \lambda}{\epsilon_i} + \lambda \tag{A.16}$$

68 See:
Comnes, G.A., S. Stoft, N. Greene and L.J. Hill, Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource-planning issues. Volume II: Appendices, 1995, pages 91-92.

(A.16) is equation (2) in the main body of this submission.