ellipson
Consulting Services
Energy & Utilities

21 March 2014

Mr Ben Davis
Advisor
Australian Energy Market Commission
201 Elizabeth Street
Sydney NSW 2000

Dear Mr Davis

Submission to the Distribution Network Pricing Arrangements Rule Change (reference ERC0161)

Please find attached a submission to the Distribution Network Pricing Arrangements Rule Change. This submission is the recently completed research paper "Implications for small customers of more cost reflective tariffs". This project was funded by the Consumer Advocacy Panel and is supported by the Total Environment Centre in its capacity as consumer advocate.

This research paper investigates a range of consumer outcome scenarios using the cost reflective tariff examples provided in the Power of Choice (POC) Final Report. It also reviews the proposed amendments to the Distribution Pricing Principles in both the POC Final Report and SCER rule change. This research is particularly relevant to any changes to these principles that will make distribution tariffs more cost reflective, and should be a useful contribution to the current rule-making process.

Yours sincerely,

WRNixey

Bill Nixey
Director
Ellipson Pty Ltd

Implications for small customers of more cost reflective tariffs

20 March 2014

This project was funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

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1 MAIN FINDINGS OF THE RESEARCH

1. Several cost reflective[1] price structures were tested for their impacts on small electricity customers. Time of use based energy structures (such as seasonal time of use) were found to provide a compromise between minimising consumer network cost impacts and moving towards cost reflectivity. Demand and fixed charge structures were found to impact small customer costs to a greater extent.
2. Using Long Run Marginal Cost (LRMC) as a basis for price setting is likely to create significant revenue residuals and these recoveries may disadvantage small customers. The calculation of LRMC is open to interpretation and may not necessarily provide an effective cost structure for the allocation of network revenue in locations where demand is flat or in decline. Pricing based a locational basis will create a proliferation of tariffs and will reduce consumers' understanding of their charges.
3. The current Standing Council on Energy and Resources (SCER) rule change did not include some of the main findings of the POC Final Report. This includes an optional participation for small customers in flexible pricing and an allocation of revenue residuals using a postage stamp methodology. Other important recommendations from the POC Final Report, while not clearly within the scope of the SCER rule change, include a customer awareness campaign, a governmental review of concession schemes, and an extension of NECF hardship indicators. These initiatives should not be forgotten during the move to cost reflective network prices.
4. The existing side constraint formula in the Distribution Pricing Rules doesn't prevent sudden network revenue rebalancing across tariffs or charging parameters. Side constraints are an effective price control mechanism only in cases where a distributor has several tariff classes. The National Electricity Rules uses a broad definition of a tariff class and this creates too much flexibility in the distribution price setting process.
5. A Retail Rule mandated hardship tariff that has simple price structures is one way of protecting customers from any adverse impacts of a move to cost reflectivity. It is acknowledged that this tariff will not address the needs of all vulnerable customers, particularly those with above average levels of consumption. State based concession programs could allow for these differences. The introduction of a network set hardship tariff would require Rule amendments so that the discount is passed through in full by retailers.

[1] Cost reflective structures as proposed in the AEMC Power of Choice Final Report, 30 November 2012, p147

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2 INTRODUCTION

The primary purpose of this research project is to investigate the implications for small customers of a move to cost reflective network tariffs and component structures. A particular focus will be on what different consumer classes could expect as network prices become more efficient and flexible during future regulatory periods. The Australian Energy Market Commission (AEMC) Power of Choice (POC) Final Report in December 2012 recommended a move to cost reflective network tariffs. This research paper will investigate a range of consumer outcome scenarios using the cost reflective tariff examples provided in the POC.

The timing of this research coincides with the AEMC's recent expansion of an IPART rule change request on network price changes to include an overlapping SCER rule change request. The SCER rule change request proposes some of the most significant changes to regulated electricity tariffs since the National Electricity Rules (NER) were introduced. For example it proposes to use Long Run Marginal Cost (LRMC) as the primary means of setting network tariffs and individual charging components. This research project reviews these changes and considers the implications for consumers of more efficient, flexible and cost reflective network pricing.

This research involves a desktop analysis showing how current tariff structures are likely to be composed in a move to cost reflectivity and what the equity implications are for small customers of these changes. Most network tariffs (comprising up to half of the retail tariff) are not structured in ways that reflect underlying network costs. A move to cost reflectivity may require substantial changes to the network costs incurred by small customers. Such a transition is also likely to require greater engagement in or understanding of electricity prices by the consumer. Some consumers may be disadvantaged by this move, particularly where there is a rebalancing of tariff charging parameters (for example such as greater recovery on fixed charges).

Ellipson Pty Ltd has prepared this this report and has undertaken all of the analysis and commentary. Ellipson is a consulting company in the energy and utilities industry, providing services in pricing and procurement. It has significant experience in addressing customer issues that relate to the supply of electricity, particularly in the regulation of electricity network prices. Total Environment Centre is supporting this research project in its capacity as consumer advocate, and will be providing a contribution post-project in this area. TEC and Ellipson have provided a joint submission to the AEMC on the IPART/SCER combined rule change request using material from this research project. This paper will also be submitted to the AEMC as a "late submission" for this rule change process.

This research project aims to provide tangible evidence as to whether small customers are better or worse off when given a greater ability to manage their electricity consumption via cost reflective price signals. The research results discusses the impacts on small residential customers who use less than 5 MWh per annum in NSW and 3.5 MWh in Victoria (where residential electricity consumption is less due to a higher gas use). Note that the customers below this threshold will include both vulnerable and other types of customers, for example, dual income households. In addition some vulnerable customers will use more than these usage thresholds. The analysis also shows impacts for customers with consumption above the thresholds.

3 NETWORK PRICE STRUCTURES

The majority of network tariff pricing structures that are currently available for small customers can be grouped into four main categories. These are anytime energy, inclining block energy, time of use, and seasonal price structures.

Anytime volume tariffs. This is one of the simplest and most common ways to price electricity and has a two part tariff featuring a fixed and variable cents per kWh component. If this tariff was purely cost reflective the fixed charge would represent the fixed costs of supply while the variable charge would represent the additional cost for every kilowatt-hour (kWh) used by the customer. The fixed component is typically set below the cost reflective level of fixed network costs, with residuals recovered via the variable charge.

Inclining block tariffs. This is similar to a single variable rate but an inclining block tariff will have additional consumption threshold rates above which any consumption receives a higher rate. These tariffs are known as inclining blocks, where once consumption in a period exceeds a threshold the customer is charged a higher rate. The block tariffs could feature two, three, or even four block structures (as in the case of Powercor and SA Power Networks). Inclining block structures were introduced as a way of encouraging energy efficiency.

Time of use. Electricity can be charged at different energy rates depending on the time of day. Peak periods represent the times when demand on the network is at its greatest. Shoulder and off-peak times are usually levied overnight or on weekends. The time of use times can vary significantly across regions given different customer demand profiles in the NEM. For example peak time for time of use structures could commence at 7am, 1pm, 2pm, 3pm, 4pm or 5pm depending on the distribution area.

Seasonal time of use. These structures are similar to time of use but the peak period only applies during summer or winter months (or both). This structure is designed to take into account seasonal variations of customer demand profiles. Northern states have demand peaks in summer, southern states have demand peaks both in summer and winter.

The following table shows the main residential pricing structures offered by the 13 electricity distributers in the National Electricity Market (NEM). Note that any closed or obsolete residential tariffs are excluded.

Distributor	State	Anytime volume tariff	Inclining block tariff*	Time of use tariff	Seasonal time of use
Energex	QLD	•		•	
Ergon	QLD	•			
Ausgrid	NSW		•	•	
Endeavour	NSW		•	•	
Essential	NSW	•		•	
ActewAGL	ACT	•		•	
CitiPower	VIC		•	•	
Powercor	VIC		•	•	
Jemena	VIC	•		•	
United Energy	VIC	•			•
SP Ausnet	VIC	•	•		•
SA Power Networks	SA		•		
Aurora	TAS	•			

*Note that some distributors combine block tariffs with time of use or seasonality requirements.

Pricing electricity on a variable energy basis may be effective for the retail component of electricity charges given that the bulk of these costs originate from the NEM or forwards contracts. However variable energy pricing is less effective for representing marginal network costs. This is because the bulk of a network's costs are fixed in the short run, and if an additional kilowatt-hour (kWh) of electricity is supplied by the network to a customer it makes very little difference to its costs. As the POC Final Report states "the costs of a network business are dominated by large fixed and sunk cost; that is, costs which have already been incurred or do not vary greatly with consumption in the short term."[2] However as shown in the table above, all distributors have tariffs that include a variable energy component and most offer a single variable energy rate. This is because most small customers have simple metering installations that can only measure energy as an accumulated value and not the time the energy was used, or its peak demand. A move to cost reflective pricing means that the most likely change for small customers with basic metering will be higher recovery through a fixed charge and a reduction in anytime energy or inclining block charging components. Network costs are not marginal in the short term and the existing small customer energy charges are not reflective of these costs.

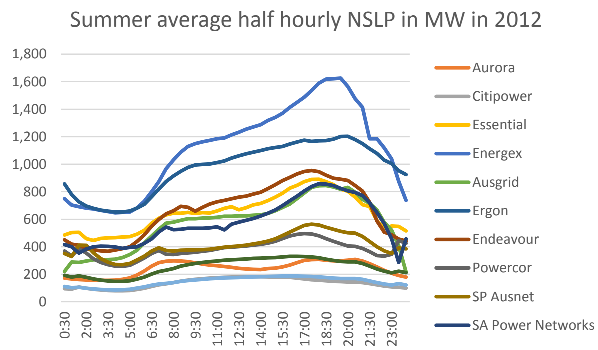
The metering installations for many small customers have already been upgraded. A recent estimate is that at least 1.5 million interval (ie. mainly half-hourly read) meters have been installed throughout Australia[3]. The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers in 2014[4]. These devices are known as smart meters. In addition the POC Final Report recommended that all new meters installed for small customers be smart meters, and that the roll out for small business customers be accelerated. It is important to note that when a customer has an interval read or smart meter installed it doesn't necessary receive time based electricity prices. For example, in Victoria customers have the option of switching to time varying prices and of reverting back to standard pricing (until March 2015).

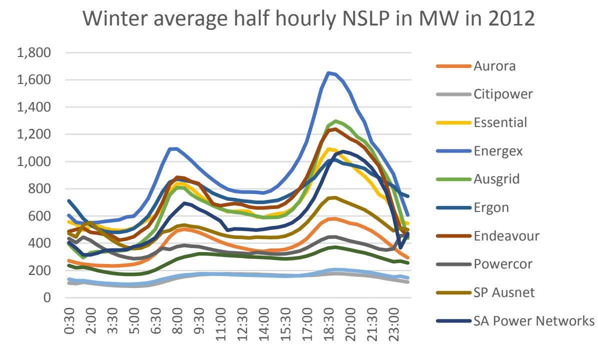
Seasonality and temperature variations across the jurisdictions contribute to variations in customer demand profiles and explain why there is very little consistency among the time of use structures. The following graphs show the net system load profiles (NSLP) in summer and winter of 2012. The NSLP is a reasonable representation of small customer demand in each network region. One of the most notable aspects of these graphs is that the load profiles for Queensland (Energex and Ergon) have high demands in the middle of the day in summer, but much less so in winter. This can be explained by the use of air conditioning in summer.

[2] AEMC Power of Choice Final Report 30 November 2012 p182

[3] Department Of Resources Energy and Tourism, National Smart Meter Infrastructure Report, 4 February 2013

[4] Australian Energy Regulator, State of the Energy Market 2013, p75





However, distribution augmentation costs are driven by a combination of factors at local and regional levels, rather than overall peak demand. For example the total peak demand for all customers located under the same zone substation is a good indicator of the need for investment in that substation. Peak demand as measured for an entire network does not necessarily indicate the need for network augmentation because it represents the aggregated trends across many substations, where each has different underlying demand trends.

The time of day of peak demand is also important if used as an indicator of network costs. A customer may have a relatively high maximum use, but if this does not coincide with the peak demand at that location in the network, then that customer isn't contributing significantly to any local increases in network augmentation costs. Therefore demand charging should also take into account when the network peak occurred. Some distributors have price structures that attempt to reflect this. For example, Endeavour Energy's demand charges are applied during the hours of 1pm and 8pm on working weekdays. This is when the total peak demand is most likely to occur throughout this network. The distributor Energex takes into account differences in network demand peaks for residential and business customers by having peak times defined differently for each of these groups of customers.

4 Annual Price Setting

The overall annual increase in prices for a distribution company is determined every five years during the regulatory determination process. In this process a distributor provides its forecast of capital and operating costs to the Australian Energy Regulator (AER), which makes an assessment as to whether these costs are efficient, prudent and comply with Chapter 6 of the NER. Once these costs are finalised the annual revenue entitlement for the distributor can be calculated. This revenue entitlement is also known as the building block revenue and is the aggregate of the operating costs, economic asset depreciation, a rate of return (or Weighted Average Cost of Capital, WACC) and tax liability. A distributor's approved revenue determination will be subject to a control mechanism, generally a weighted average price cap (WAPC) or a revenue cap.

A particular set of network tariffs are applied to a group of customers with similar load profiles or connection characteristics in the local distribution network. Examples of connection characteristics are the type of meter the customer has installed or the voltage at which it is supplied. Each distributor is responsible for its price list, tariffs and the type of pricing components that are offered. In a move to cost reflective network prices it is not possible for every customer to have their own unique network price, where the rates levied reflect the costs for distributing electricity to one site. The administrative burden on the distributor in such a situation would be too great. A network tariff will always be a compromise between: sending efficient price signals to a consumer, ensuring customers can understand and respond to price signals, and minimising the transactions costs of managing the tariff. The current rules provide for this in clause 6.18.3 (d) and require that in the price setting “unnecessary transaction costs must be avoided”. Individual network prices are currently only used for the largest customers, typically with annual consumption in excess of 40,000 MWh.

The POC Final Report recommended that network prices move towards greater cost reflectivity. It should be acknowledged that the prices introduced as a result of this in a move will generally not reflect actual costs. During the annual price setting process distributors allocate building block revenue to tariffs and pricing components (these are described in the NER as charging parameters, and are defined as “the constituent elements of a tariff”[5]). Network tariffs and their components can be considered as place markers for the recovery of the building block revenue. Network costs can be taken into account in the price setting, but they are used to determine how much revenue is allocated to each tariff and charging component. It is the relative proportions of revenue recovery across tariffs and charging parameters and how they change over time that are relevant in any discussion on cost reflectivity. As the POC Final Report states: “we do not mean prices that are perfectly cost reflective from a theoretical standpoint; rather we mean prices that will provide a more efficient signal to consumers for valuing consumption and energy services than those which exist currently.” [6]

The rules for allocating costs across tariffs and charging parameters will be discussed in more detail later in this paper.

5 SCENARIO ANALYSIS OF COST REFLECTIVE PRICE STRUCTURES

Cost reflective price structures for the network are defined in the POC Final Report as “A variable component that varies by both time and location to recover transmission and distribution network costs in a manner that signals the cost of future augmentations to meet peak demand in different parts of the network.”[7] The POC Final Report was optimistic about the likely outcomes of a move to these price structures. It states that “Sharper, more cost reflective prices will positively affect most users of electricity, but some will be impacted negatively.”[8] However no supporting analysis was provided to quantify the impact of these structures on consumers. This chapter summarises a desktop analysis of each of these pricing structures and evaluates the implications for small customers if network prices were transitioned to these structures. The analysis will use actual customer consumption data and compare the alternative structures to the prices that are already in place.

In the POC Final Report a number of examples of cost reflective pricing structures were provided which could be used by distributors in a move to cost reflectivity. This includes time of use, demand charging, and critical peak pricing. A summary of the structures considered in this research is presented in the

[5] National Electricity Rules p1099
[6] AEMC Power of Choice Final Report 30 November 2012 p150
[7] AEMC Power of Choice Final Report 30 November 2012 p149
[8] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 September 2013 p3

table below. Note that the POC report did not recommend any particular structure over others or provide guidance on the weighting of each component within each structure.

Charging parameter / pricing structure	**Charging units**	**Comments**	**Role in analysis**
Any time energy rate	Cents per kWh	Considered the least cost reflective charging parameter. If small customers do not move to cost reflective tariffs, they are likely to remain on a structure with a variable energy rate.	Used as base case
Standing/fixed charge	Cents per day	Can be considered a cost reflective charging component given many network costs are fixed and do not vary with customer energy usage.	To be tested
Maximum demand charge	Cents per kW	Increasing demand is a driver of network augmentation costs.	To be tested
Time of use TOU (peak, shoulder, off-peak) energy rates	Cents per kWh	The peak energy rate is levied during times of peak system demand.	To be tested
Critical peak pricing (CPP)	Cents per kWh	Customers are charged a very high rate during brief network events of maximum demand.	To be tested
Seasonal time of use	Cents per kWh	The peak energy rate only applies in specified months.	To be tested
Inclining block	Cents per kWh	Not considered a cost reflective price structure as network costs do not vary with energy consumption.	Excluded from analysis (see appendix)
Customer Base Line load	Cents per kWh	Rewards customers for reducing consumption. The demand response can only be tested with a live customer study.	Excluded from analysis

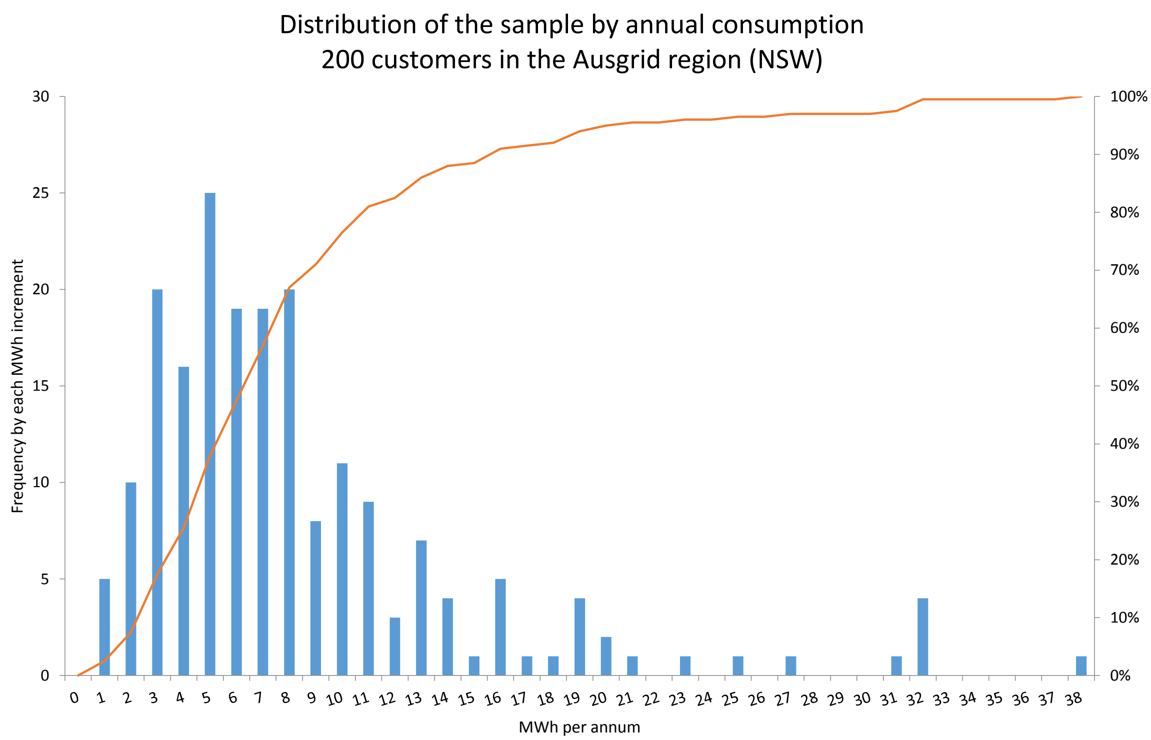
Note that the inclining block and customer baseline load structures weren't reviewed as part of this research[9]. The inclining block structures are based on variable energy rates and changes in customer energy consumption don't directly reflect network costs. Furthermore inclining blocks weren't flagged as cost reflective price structures in the POC Final Report. As the SCER rule change states, "Consumers are generally provided with flat or inclining block pricing structures which do not necessarily signal the time varying costs associated with their consumption on network and electricity supply costs." [10] Customer Baseline Load structures weren't included in this research given that a customer trial would

[9] In response to peer review feedback some graphs of an inclining block scenario were included in the appendix of this paper.
[10] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 September 2013 p5

need to be carried out to test the potential of demand reductions in response to an incentive. This is beyond the scope of this project.

The distributors Ausgrid, Endeavour, CitiPower and Powercor provided this research project with half hourly meter data of a sample of residential customers for the 2012 and 2013 years. Half hourly meter data is important for the analysis as it allows several time based price structures (such as TOU, CPP, demand, and seasonal tariffs) to be examined. The sample sizes ranged from 138 to 200 customers each and their locations enabled the analysis to include both NSW and Victoria in the study. This is useful given the different load profiles in each region. The customers in the samples have an interval meter installed, and receive a residential time of use tariff or inclining block tariff for the applicable region. Any consumption for electric heating of water on a secondary meter (and tariff) wasn't included in the datasets. All customer details were withheld by the distributors given the need for privacy.

The average annual electricity consumption of the customers in the sample is 7.9 MWh pa for the Ausgrid sample and 6.4 MWh pa for the Endeavour sample. This corresponds reasonably well with an IPART survey from 2010 which states that the average residential electricity consumption in the Sydney metropolitan region was 7.3 MWh pa[11] (note though that this study included controlled load volumes). NSW small customers were defined in this study as using less than 5 MWh per annum. The average annual consumption in the CitiPower and Powercor samples was 5.1 and 5.6 MWh pa respectively, slightly above the established average in Victoria of approximately 4 MWh pa[12] excluding electric water heating. Victorian small customers were defined in this study as using less than 3.5 MWh per annum. Residential electricity consumption is lower in Victoria than in NSW.

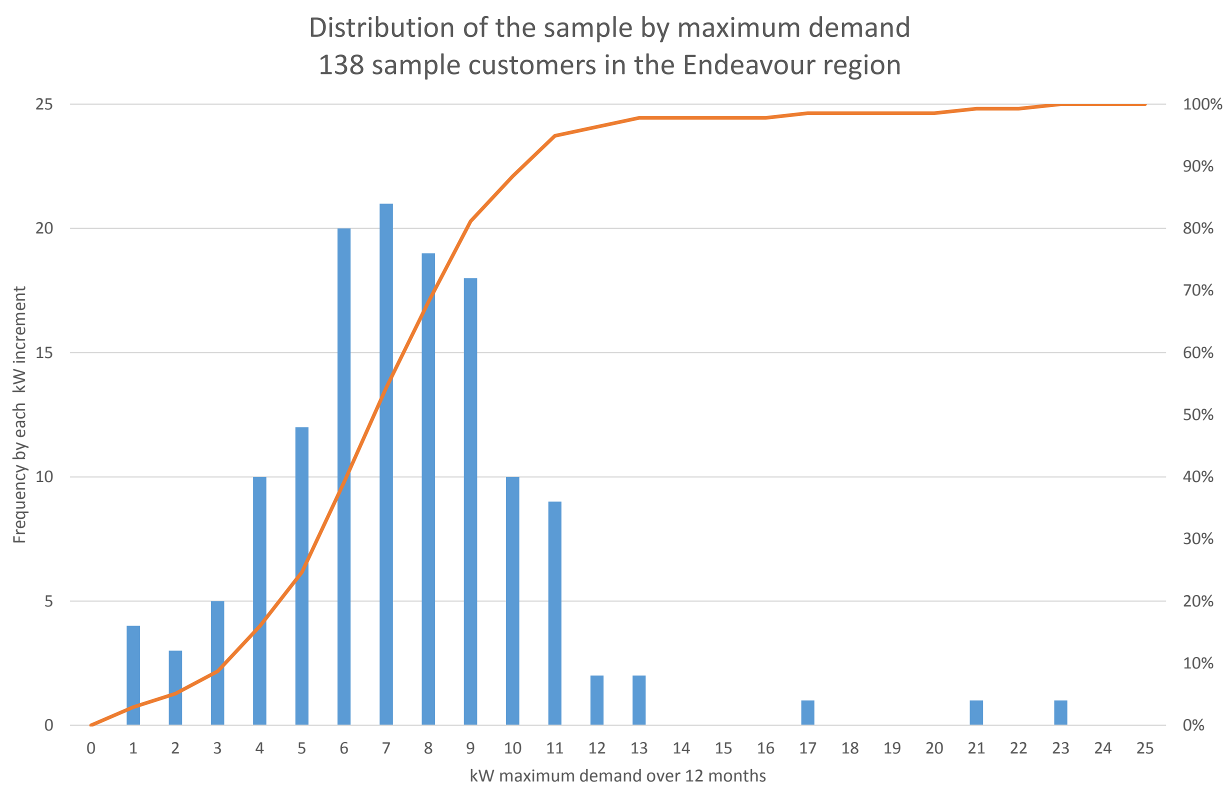


[11] IPART Residential energy and water use in Sydney, the Blue Mountains and Illawarra p41

[12] Causes of Residential Electricity Bill Increases in Victoria, Oakley Greenwood, 15 March 2013, p2

The graph above shows the frequency distributions of annual consumption for the Ausgrid sample. The graphs for the Endeavour, Powercor and CitiPower samples are in the appendix. The left axis of the graph represents the frequency of a customer falling into each 1 MWh increment. The right axis shows the percentage of the customers included at that amount of annual consumption. In the graph for the Ausgrid sample, 38% of the sample (or 76 customers) use less than 5 MWh per annum and a further 38.5% of the sample (or 77 customers) use between 5 and 10 MWh per annum. The samples provide a good mixture of small and large residential customers, which will be useful during the tests of each price structure.

A second way to represent the consumption data is to summarise the maximum half hourly metered demand for each customer. A peak demand figure from a sample represents the moment of a customer's maximum rate of electricity use during the 2012/13 year. The graph below shows the frequency distribution of these demands across kilowatt (kW) increments for the Endeavour sample. The graphs for the Ausgrid, CitiPower and Powercor samples are in the appendix. Most of the NSW sample customers (about 65%) have a peak demands between 5 and 10 kW. 53% of the Victorian customers have peak demands between 5 and 10 kW.



Establishing a Base Case

When comparing the impacts of cost reflective price structures on small customers it is necessary to have a base case as a reference point. The base case is used as a comparison to the annual network charge costs that are incurred by the sample customers if they were moved to a cost reflective structure. To understand the impacts of the transition to cost reflectivity the initial structure represented in the base case should be the simplest and least cost reflective structure commonly used by distributors. One of the most basic electricity price structures is a single variable energy rate with a standing charge. Many of the 686 customers from the four sample groups were on a time of use or inclining block tariff in 2012 and 2013 (the full details of these prices is in the appendix). The time of use structure is not suitable as a base case as it is an existing cost reflective price structure and will be tested as part of a scenario during this research. The inclining block structures are not a cost reflective price structure as identified by the POC Final Report. However the block structures among Ausgrid, Endeavour, CitiPower and Powercor vary greatly. For example Powercor has a four block structure, Ausgrid has three blocks, while Endeavour and CitiPower both have two blocks. To ensure that these structures do not affect the analysis results, the base case tariff was not set as inclining block but instead set as a single variable energy with standing charge.

The base case tariff (with a single energy rate and standing charge) was constructed using the total annual network charges actually incurred by each of the four sample groups (see appendix). The standing charge was set as the rate that the customers received from their existing network tariff in their local network area. The residual revenue was then allocated to a single variable energy rate. For example the Ausgrid sample customers paid a combined total of $169,494 in time of use (TOU) network charges in 2012/13. The standing charges for the actual residential TOU tariff make up $36,500 of this amount. The remaining network revenue was used to determine the variable energy rate by allocating it using the total energy consumption in 2012/13 for the sample (a volume of 1,585 MWh). This gives a variable energy rate of 8.4 cents per kWh. This derived “anytime” energy rate with standing charge is the base case structure for the Ausgrid sample and all of the subsequent scenarios in this paper are referenced to it when comparing cost impacts. A similar approach was taken for the Endeavour, CitiPower and Powercor samples. The existing standing charges were used and the remaining revenue was allocated using the total annual electricity consumption. Note that the Victorian customer data, base case and all subsequent scenarios were established using assumptions from the 2012 year instead of 2012/13 financial year, given that network tariffs are set on a calendar year basis in that state.

Sample group	Base case standing charge c/day	Base case anytime energy rate c/kWh
Ausgrid	50.0	8.4
Endeavour	35.0	11.6
CitiPower*	10.5	5.3
Powercor*	12.3	6.2

*These base case standing charges for the Victorian samples were averages given that the sample customers were on different residential tariffs within each network region

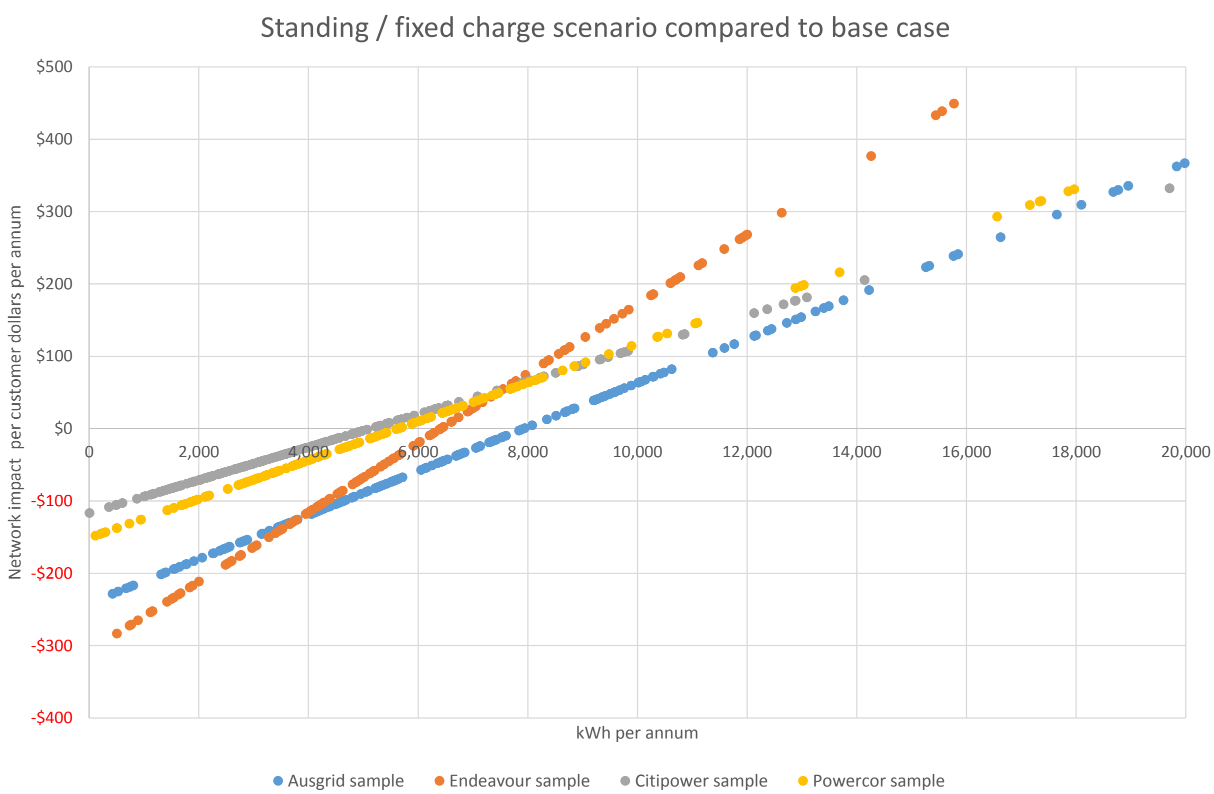
Other studies have taken a similar approach in constructing base case tariffs in order to compare proposed electricity pricing structures. For example a 2011 Deloitte study[13] on smart meters constructed “representative tariffs” for Victoria to gauge the impacts of retail TOU pricing on small and vulnerable customers.

Scenario 1 – Fixed charge

[13] Deloitte, Advanced metering infrastructure customer impacts study (for DPI Victoria), 18 October 2011

This scenario compared the base case to a basic fixed charge structure, also known as a standing charge. Most network tariffs include a standing charge in small customer tariffs, but usually include other charging parameters with the tariff (such as energy charges or a demand charge). This scenario created a residential tariff with a standing charge recovering 50% of the revenue, and the remainder recovered on a variable energy rate. The consumer impacts were then compared to the base case. Constructing this "50% fixed" charge involved taking half of the total network charges that were levied on each sample group in the 2012/13 (or 2012 calendar) year and allocating them equally to each sampled customer. For example in the Ausgrid sample, the sample customers spent a total of $169.5k on network costs in the 2012/13 year. $84.7k of this network revenue was divided equally among the 200 sample customers. This gave a total annual fixed charge of $424 for each customer. To make up the full $169.5k, the remaining $84.7k was allocated to the sample customers on the basis of their total annual energy volume.

The difference between the base case network charges and the scenario tariff is shown for each customer (with its annual consumption) in the following graph. Note that a positive number indicates that a sample customer would be better off with the scenario structure.



The sample customers using less than 8 MWh per year in the Ausgrid sample and 6.3 MWh pa for Endeavour are worse off under a standalone fixed charge structure. The CitiPower and Powercor customers using less than 5.5 MWh per year were worse off under the fixed structure. The graph demonstrates that a move to greater network revenue recovery on a fixed charge could create adverse impacts for small customers. Under this structure larger customers are not being penalised for using more network capacity compared to smaller customers. A fixed charge creates a network revenue cross subsidy between small and large customers.

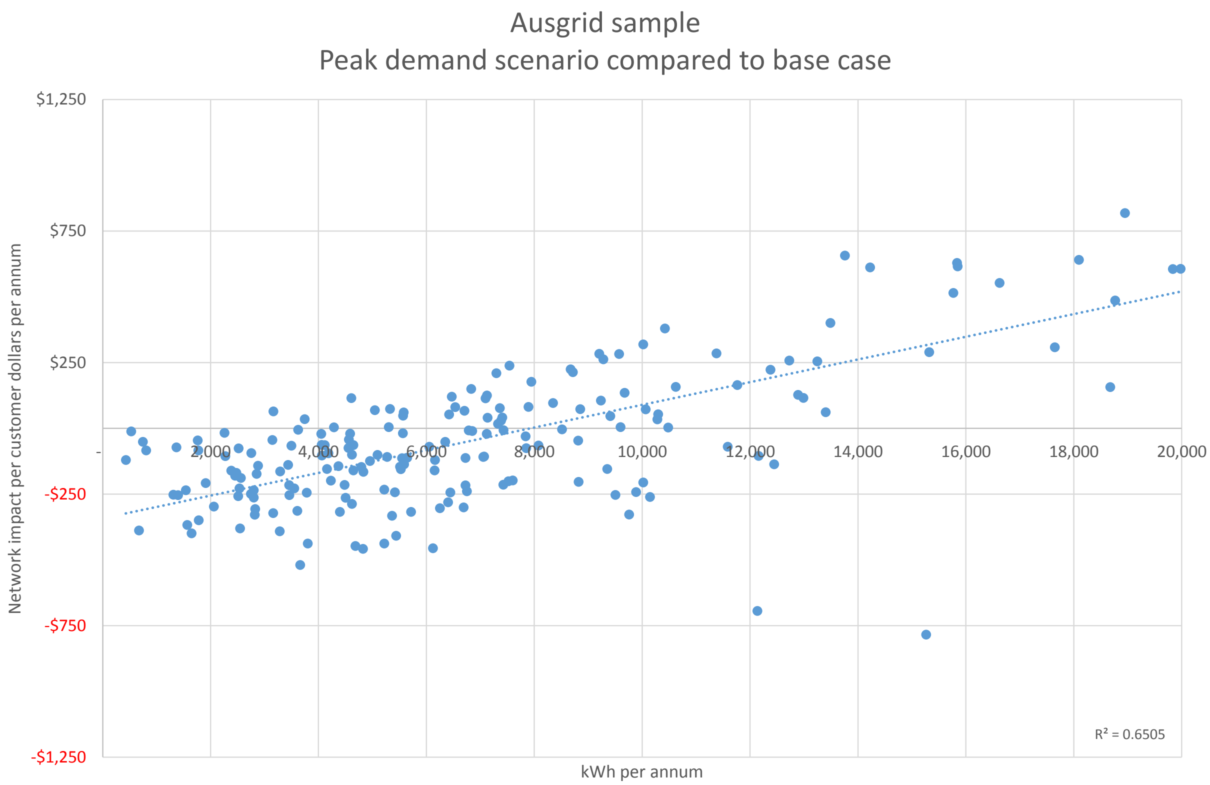
Scenario 2 – Demand charge

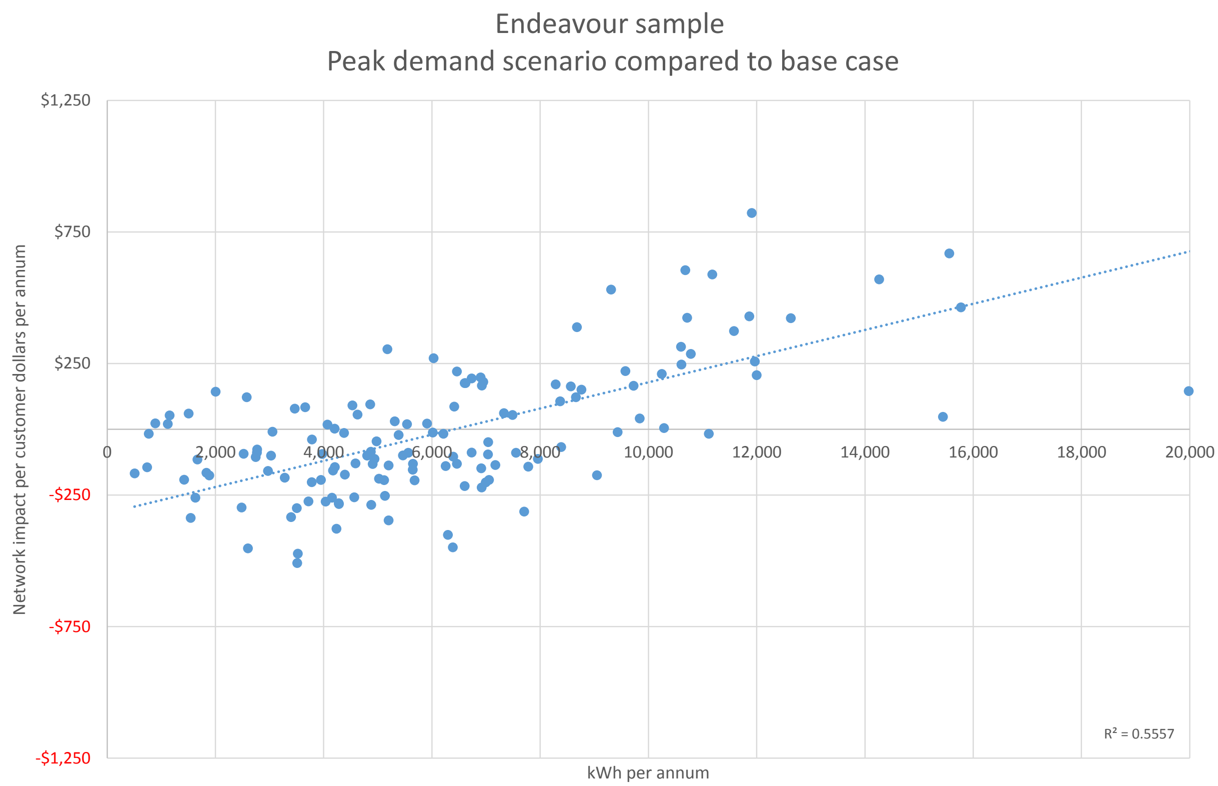
The second price structure tested was a demand charge structure with a small standing charge. This scenario shows whether a trend towards moving toward a demand charge makes the sampled customers better or worse off, as compared to the anytime energy rate and standing charge in the base case.

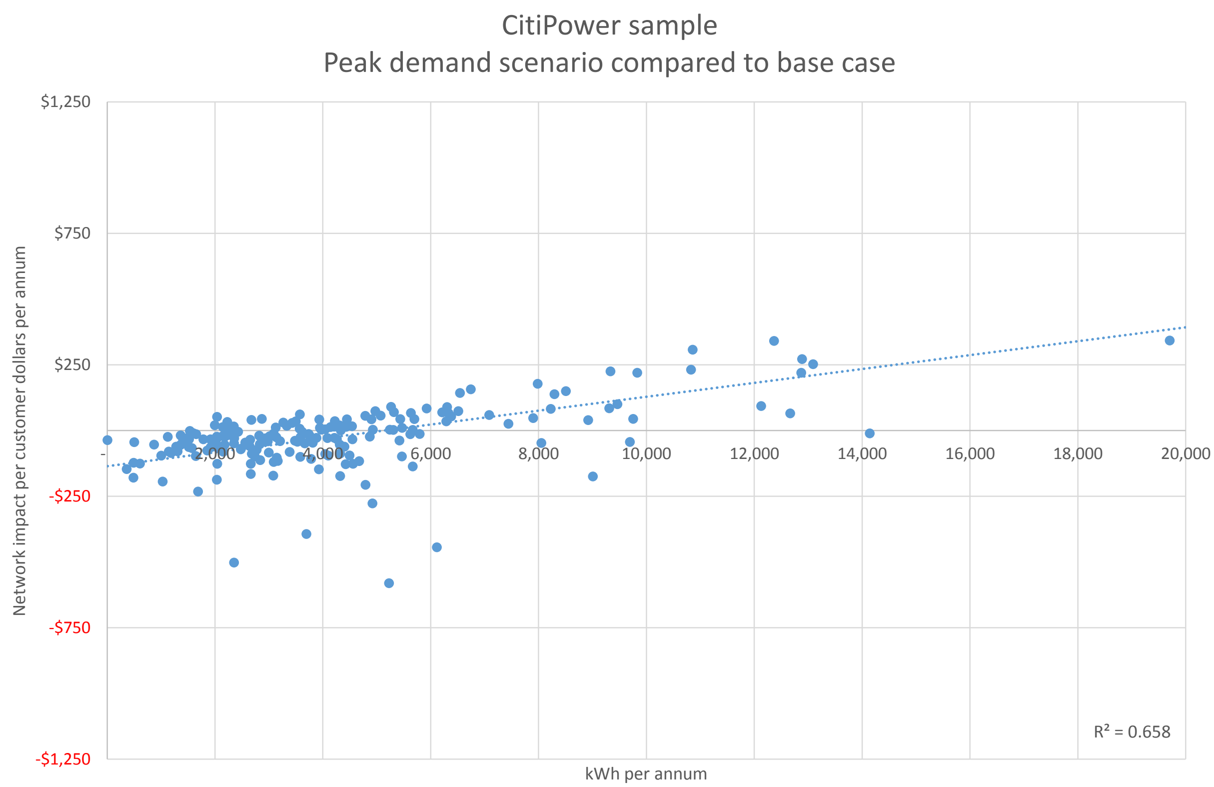
The maximum demand was retrieved from the meter data of all the 686 customers during the 2012/13 (or 2012 calendar) year. Note that this was the maximum across a year, and not the 12 month average of the maximums from each month. The 12 month maximum is a more accurate indicator of the amount of network capacity that a customer requires for its electricity needs. The total base case network revenue (less standing charge) from each of the four samples was allocated to each customer on the basis of its maximum yearly demand. This calculation produced the following charges for each sample group.

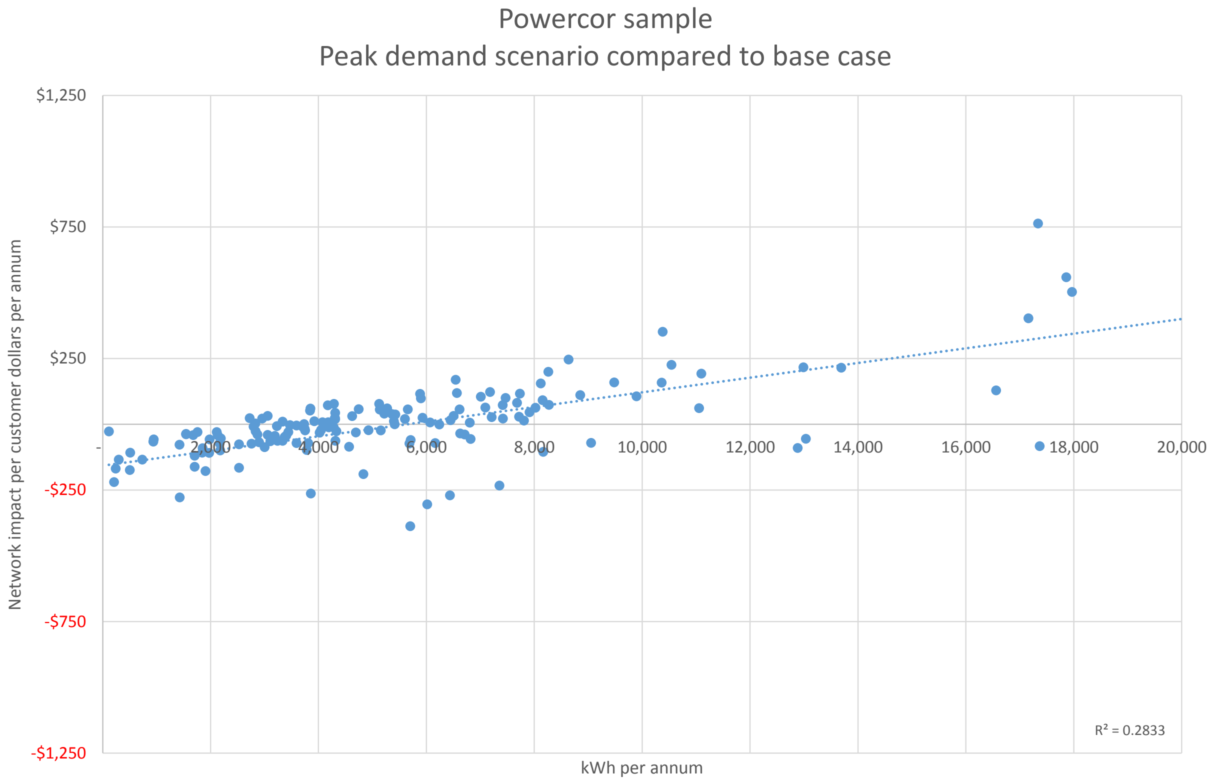
Sample group	Demand charge (derived) $/kW/year	Standing charge (same as base case) c/day
Ausgrid	$112.08	50.0
Endeavour	$126.72	35.0
CitiPower	$53.76	10.5
Powercor	$62.76	12.3

The annual network costs for each customer were compared to the base case, as shown in the following graphs. A positive number indicates that a sample customer would be better off with the demand structure, compared to the base case energy charge.




Endeavour sample
Peak demand scenario compared to base case
$1,250
$750
$250
-$250
-$750
-$1,250
Network impact per customer dollars per annum
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
R² = 0.5557
kWh per annum


CitiPower sample
Peak demand scenario compared to base case
$1,250
$750
$250
-$250
-$750
-$1,250
Network impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
R² = 0.658
kWh per annum



The graphs suggest that the impacts of the demand charge on the sampled customers varies by annual consumption and that smaller customers are more likely to be impacted by a move to a price structure with a demand component. To clarify the findings the following tables summarise the impacts for the samples across three bands of energy consumption. The results are presented separately for NSW and Victoria given the differences in average electricity consumption.

Customer impacts for a demand charge: NSW samples (Ausgrid and Endeavor)

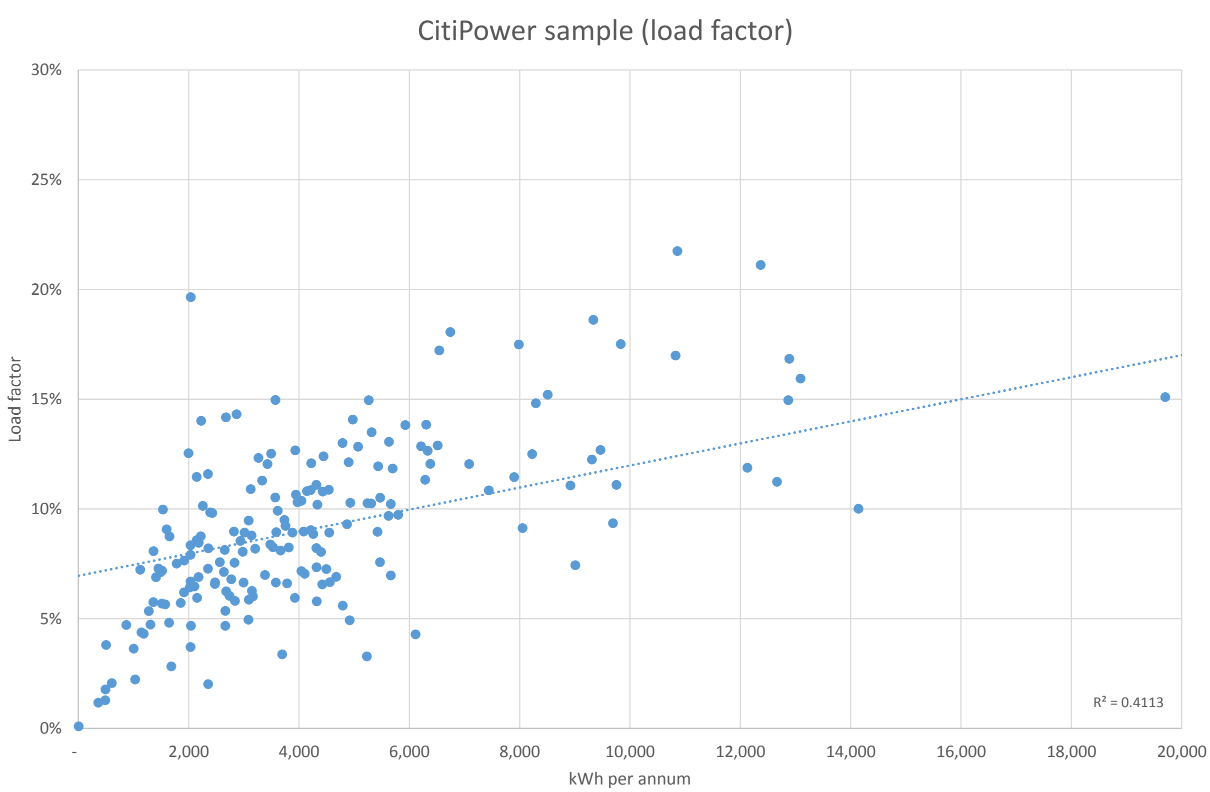
Annual consumption	Sample customers better off	Sample customers worse off	
Less than 5 MWh	17	117	
Between 5 and 10 MWh	57	79	
Greater than 10 MWh	60	8	
Total	134	204	Total 338

Customer impacts for a demand charge: Victorian samples (CitiPower and Powercor)

Annual consumption	Sample customers better off	Sample customers worse off	
Less than 3.5 MWh	17	120	
Between 3.5 and 8 MWh	88	67	
Greater than 8 MWh	47	9	
Total	152	196	Total 348

58% of all the sample customers would be worse off if they were moved to a pricing structure that featured only a demand charge component. Across the customers in the small customer category this becomes 87% in NSW and 88% in Victoria.

The likely reason for small customers being worse off under a demand charge structure is load factor. Load factor is a useful indicator of how often a customer uses electricity and also the extent that a customer uses its local network assets. Small customers, by definition, use less electricity than larger customers but they don't necessarily use proportionally less demand. The electricity use for small customers compared to their peak demand is lower than other customers. For example a holiday house may only be used one month a year but could have the same peak demand as a suburban home occupied for 12 months of the year. However the energy use of the holiday house will be substantial less than the suburban house. A load factor can capture these differences by showing the ratio of energy use to peak demand as a percentage. If small customers use less energy but have their peak demand at levels similar to larger customers, then they will have low load factors. The following graph (for the CitiPower sample) shows that the low energy consumption customers sampled generally have lower load factors compared to the average. The horizontal axes represent kWh per annum consumption and the vertical axes load factor. The graphs for the Ausgrid, Endeavour and Powercor samples can be found in the appendix and show similar results.



Moving from a simple variable energy rate to demand charging impacts small customers more given that small customers would no longer benefit from being low users of electricity (compared to the average). While small customers on a demand charge would be receiving more cost reflective prices they would on average pay more for their total network costs and it may present a challenge if the needs of vulnerable customers are to be met. Note that further research needs to be carried out into the load factors of vulnerable customers, in comparison to the average load factor of other categories of small customers (such as households with two full time workers). The data used in this analysis does not enable any distinction to be made based on incomes or demography.

Scenario 3 – Time of Use (TOU)

A third scenario was to determine whether small customers would be better or worse off as a result of moving from the simple base case structure to a TOU energy structure. One way to make this comparison would be to compare the base case tariff to the actual Ausgrid, Endeavour, CitiPower and Powercor residential TOU tariffs. However this comparison could only be made if the total network revenue for the base case were the same for this scenario. This was possible for the Ausgrid sample because these sample customers were charged a residential TOU tariff in 2012/13. Therefore the TOU scenario tariff in the table below is the same as the actual Ausgrid TOU tariff as it maintains the revenue neutrality requirement.

For the other three distributor samples it was necessary to construct the TOU tariffs used in the scenarios so that revenue neutrality was achieved. The Endeavour sample customers were charged a residential inclining block tariff in 2012/13. Therefore the total revenue from this base case would not be equal to that of the TOU scenario case if the Endeavour 2012/13 year TOU rates were used in the comparison. The Powercor and CitiPower samples were on different residential tariffs within each region in the 2012 year and revenue neutrality could also not be maintained if the actual Powercor and CitiPower TOU rates featured in the scenario. To construct the TOU tariffs the standing charge was set as the same as the base case and the residual revenue was then allocated to the peak, shoulder and off-peak rates. The original ratios between peak, shoulder and off-peak prices were preserved. For example the Endeavour sample customers paid a total of $120,154 in 2012/13. With a standing charge of 35 cents per day from the base case, the residual revenue to be allocated to the peak, shoulder and off-peak rates was $102,525. A similar approach was carried out for the CitiPower and Powercor samples noting that the base year used for the sample data was 2012 and the peak and off-peak times differ in these distribution regions (and there are no shoulder periods).

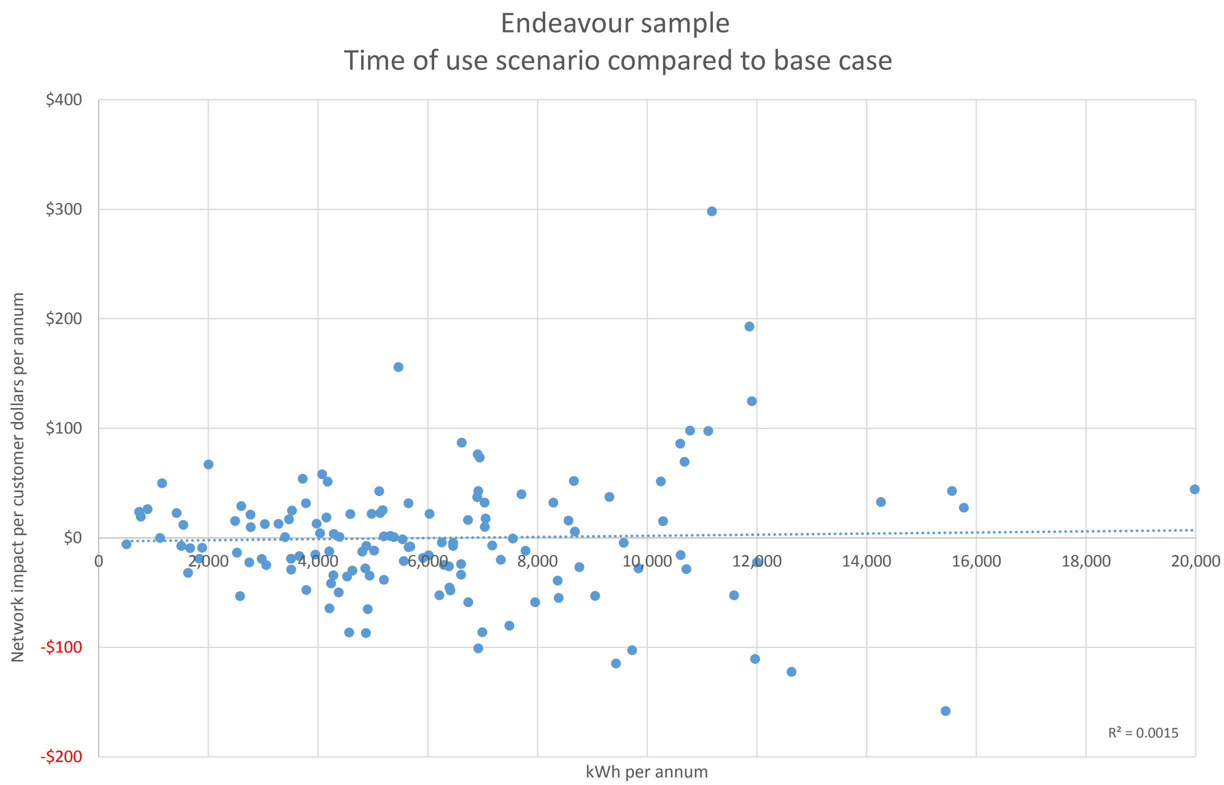
Table: Comparison of the TOU tariffs used in the analysis and the actual residential TOU tariff (NSW)

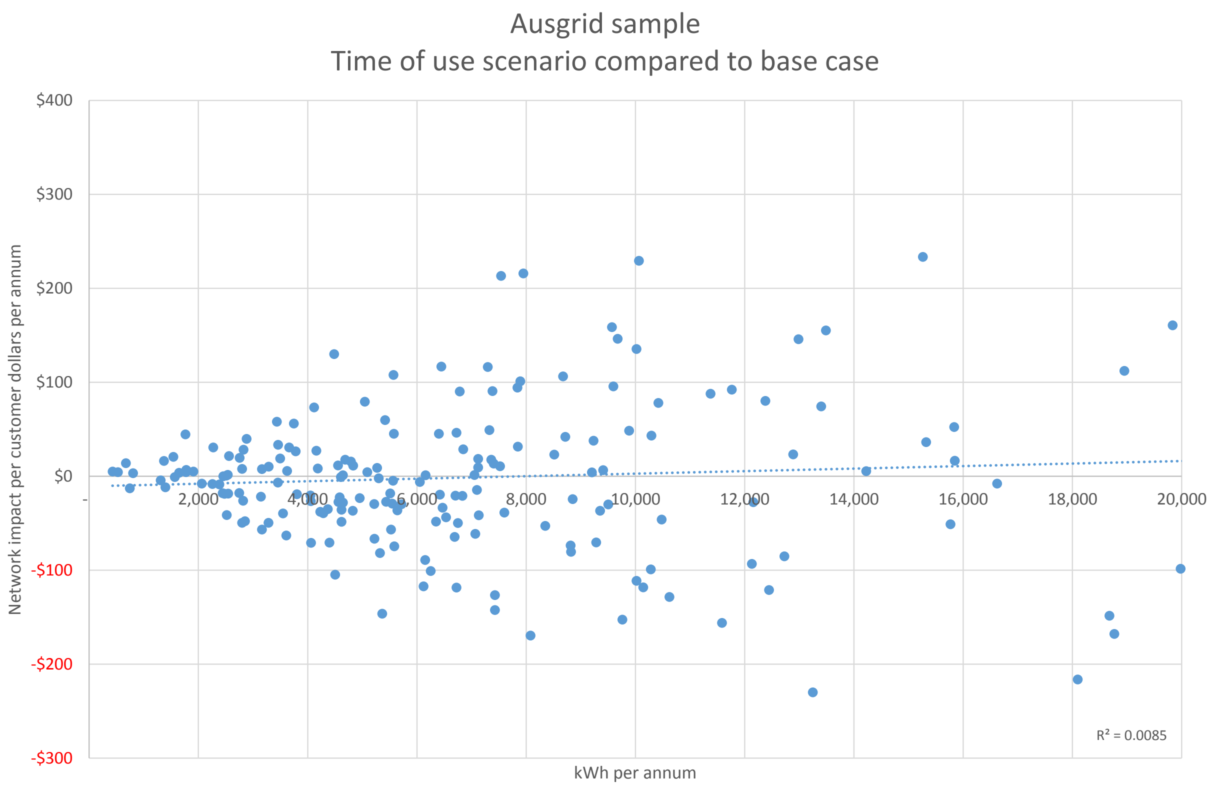
Charging parameter	**Ausgrid domestic TOU tariff 2012/13**	**TOU tariff tested for Ausgrid sample**	**Endeavour domestic TOU tariff 2012/13**	**TOU tariff tested for Endeavour sample**
Standing/fixed charge c/day	50.0	50.0	95	35.0
Peak energy c/kWh	25.5	25.5	19.4	20.1
Shoulder energy c/kWh	5.0	5.0	11.2	11.6
Off-peak energy c/kWh	2.6	2.6	4.7	4.9

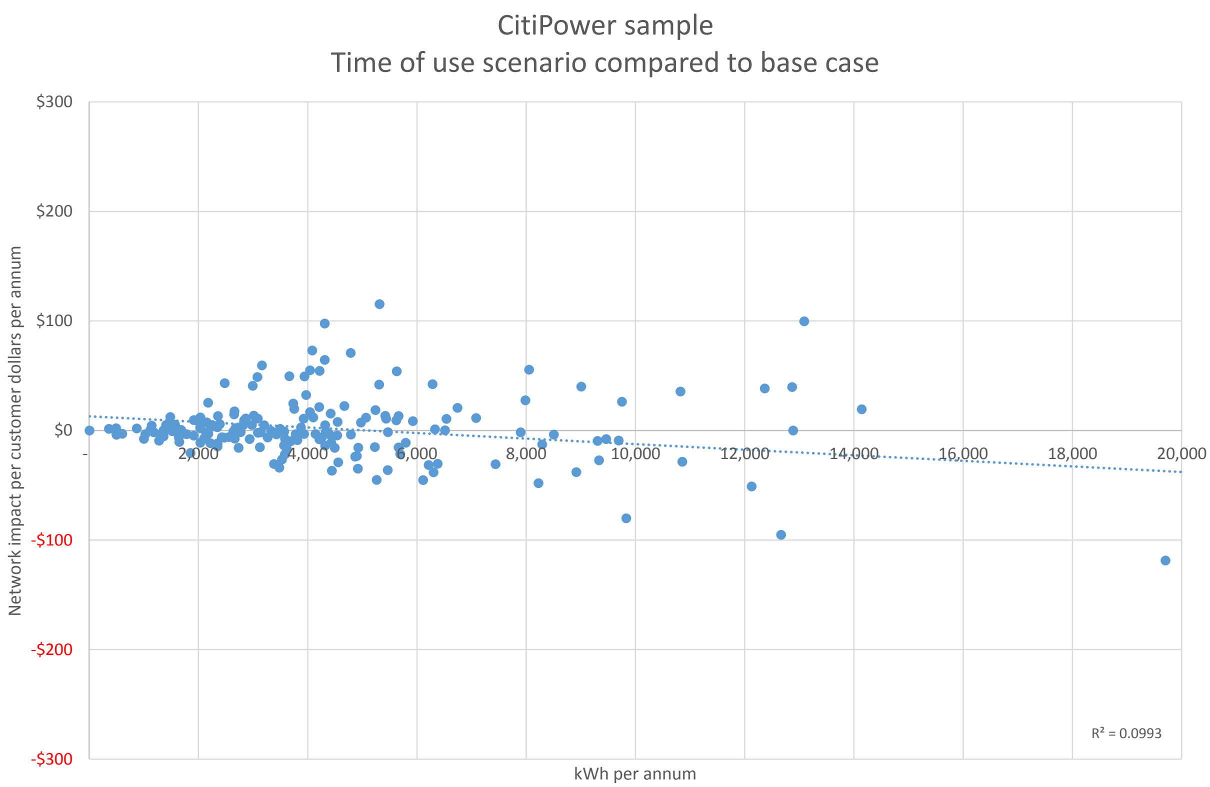
Table: Comparison of the TOU tariffs used in the analysis and the actual residential TOU tariff (VIC)

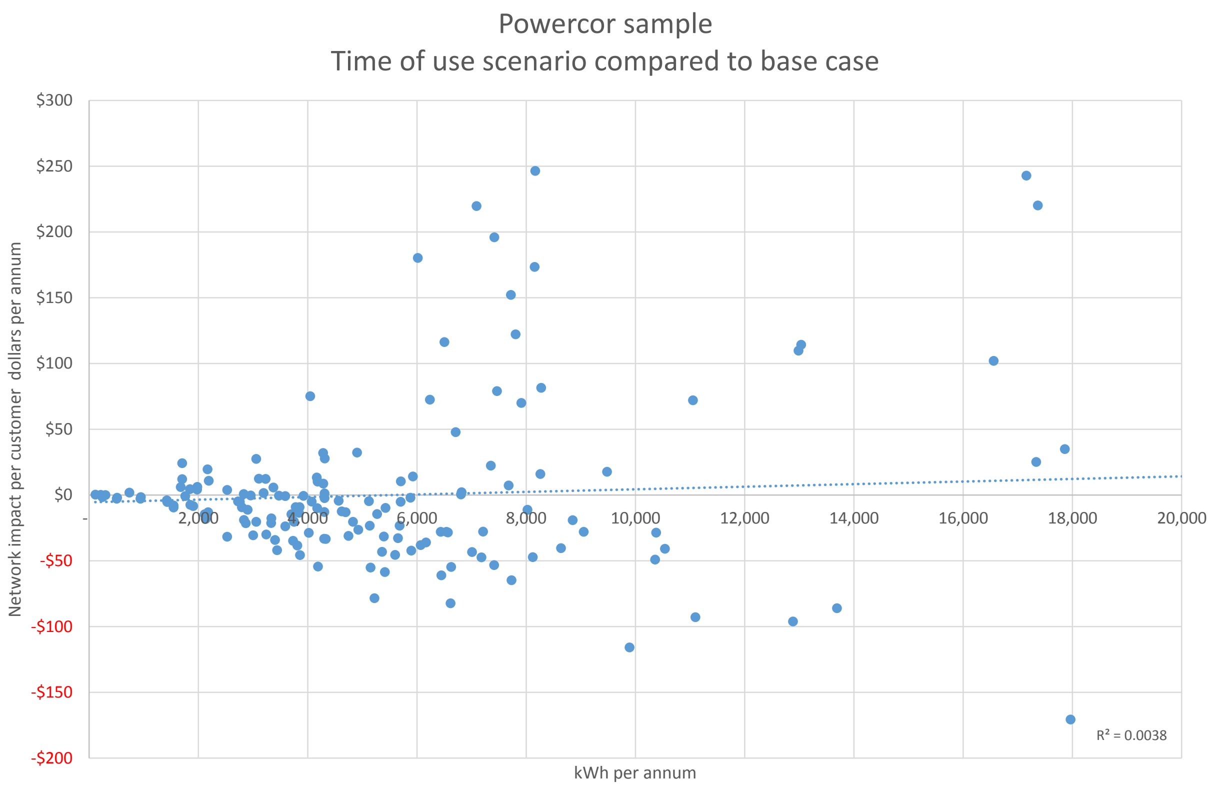
Charging parameter	CitiPower domestic TOU tariff 2012	TOU tariff tested for CitiPower sample	Powercor domestic TOU tariff 2012	TOU tariff tested for Powercor sample
Standing/fixed charge c/day	13.4	10.5	13.1	12.3
Peak energy c/kWh	9.3	8.9	12.0	10.7
Off-peak energy c/kWh	1.6	1.5	1.9	1.7

The following graphs show the annual network cost impacts to each customer in the sample with annual electricity consumption. A positive number indicates that the sample customer is better off.




Ausgrid sample
Time of use scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
Network impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R^2 = 0.0085


CitiPower sample
Time of use scenario compared to base case
$300
$200
$100
$0
-$100
-$200
-$300
Network impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R^2 = 0.0993



The graphs above don't show any obvious trends for the impacts of moving from a simple price structure to a TOU structure. The cost impacts across the sampled customers are fairly evenly spread, and as annual consumption increases so does the range of the dollar differences (which would be expected). However the following tables combine the samples for each state and show a clearer summary of the trends across the small, medium and large residential customer segments.

Customer impacts for TOU: NSW sample (Ausgrid and Endeavour)

Annual consumption	**Sample customers better off**	**Sample customers worse off**	
Less than 5 MWh	65	69	
Between 5 and 10 MWh	60	76	
Greater than 10 MWh	39	29	
Total	164	174	Total 338

Customer impacts for TOU: Victorian samples (CitiPower and Powercor)

Annual consumption	Sample customers better off	Sample customers worse off	
Less than 3.5 MWh	63	74	
Between 3.5 and 8 MWh	62	93	
Greater than 8 MWh	24	32	
Total	149	199	Total 348

The cost impacts for small customers appear to be almost evenly split for NSW but for Victoria they are more likely to impact these customers adversely.

Compared to the previous two scenarios, the total annual network cost impacts on the sample customers in this scenario are relatively small. For the time of use scenario 89% of the cost impacts were within $100 per year and 97% were within $200 per year (including both the favourable and unfavourable impacts). However for the demand structure in scenario 2, only 51% of the impacts were within $100 per year. With the fixed charge structure in scenario 1, 64% of the impacts were within $100. This would suggest that a transition to a network time of use structure provides more equitable outcomes for small customers compared to alternative pricing structures.

Scenario 4 – Seasonal Time of Use

Seasonal TOU structures were flagged in the POC Final Report as a cost reflective option and are currently in use in the Jemena and United Energy network areas. The method for conducting this scenario was similar to Scenario 3, except that the peak rate was applied only in the summer and winter months. When the peak rate didn’t apply the shoulder rates (for Ausgrid/Endeavour) or the off-peak rates (for CitiPower/Powercor) were applied. Seasonal TOU tariffs were constructed by keeping the standing charge, shoulder, and off-peak energy rates the same as from the previous TOU scenario. The peak rate however could not be kept constant because applying this rate only on summer and winter days would result in a lower total revenue compared to the base case. The peak energy rates for both samples were increased to ensure revenue neutrality in the comparison. The resulting seasonal TOU tariffs tested in this scenario are as follows:

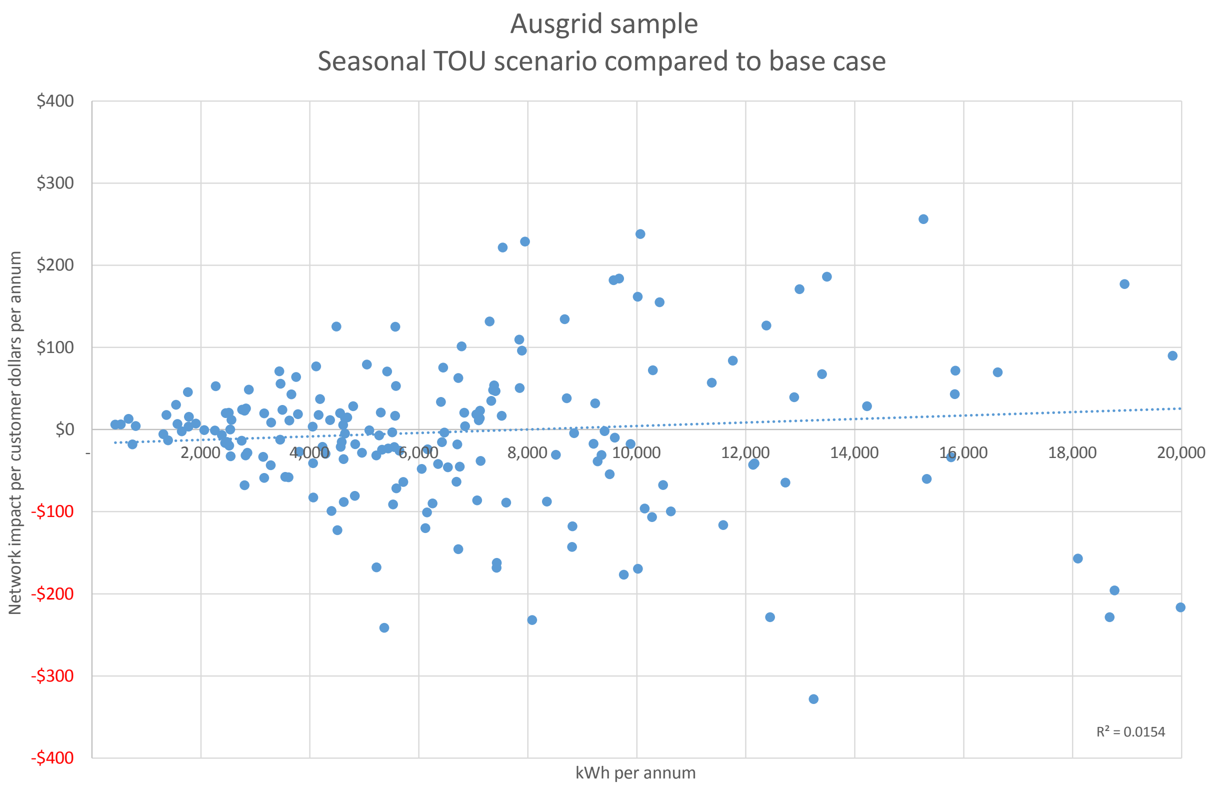
Table: Comparison of the seasonal TOU tariffs used in the analysis

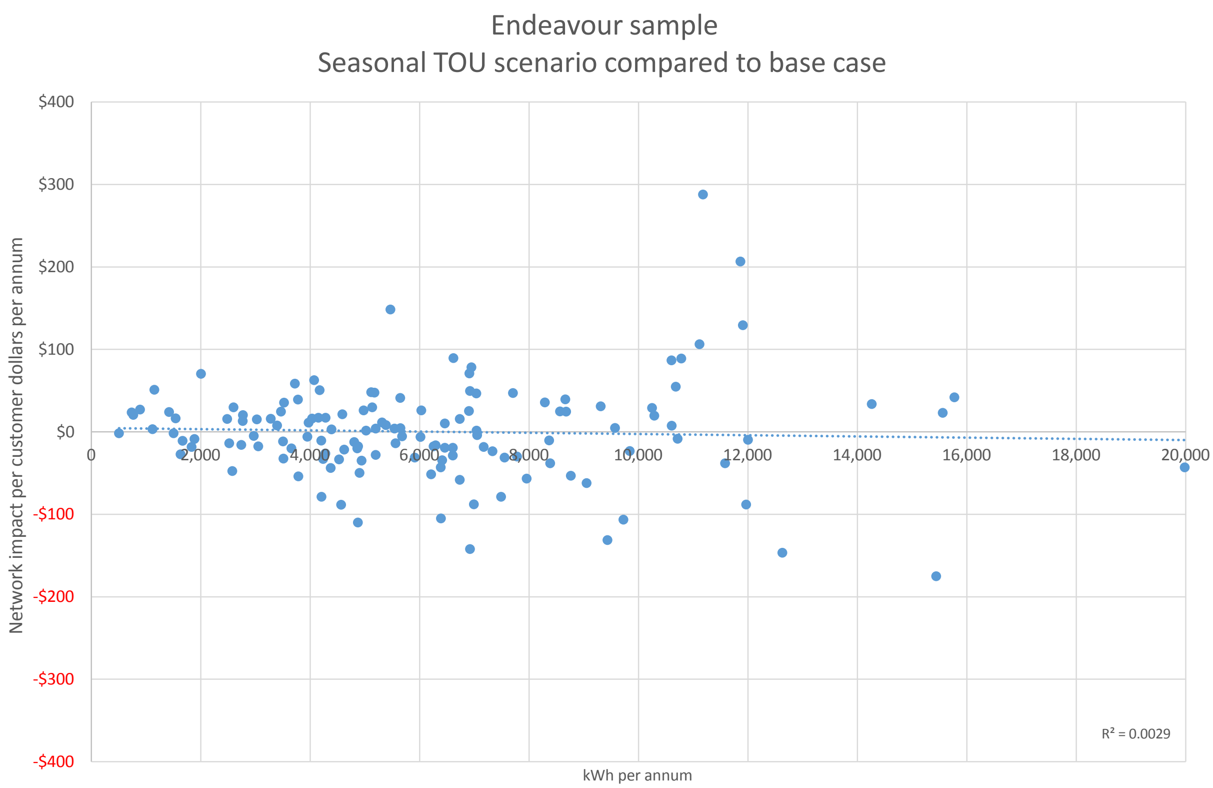
Charging parameter	**Seasonal TOU tariff tested for the Ausgrid sample**	**Seasonal TOU tariff tested for the Endeavour sample**	**Seasonal TOU tariff tested for the CitiPower sample**	**Seasonal TOU tariff tested for Powercor sample**
Standing/fixed charge c/day	50.0	35.0	10.5	12.3
Peak* energy c/kWh	42.0	26.6	14.9	18.2
Shoulder energy c/kWh	5.0	11.6	0	0
Off-peak energy c/kWh	2.6	4.9	1.5	1.7

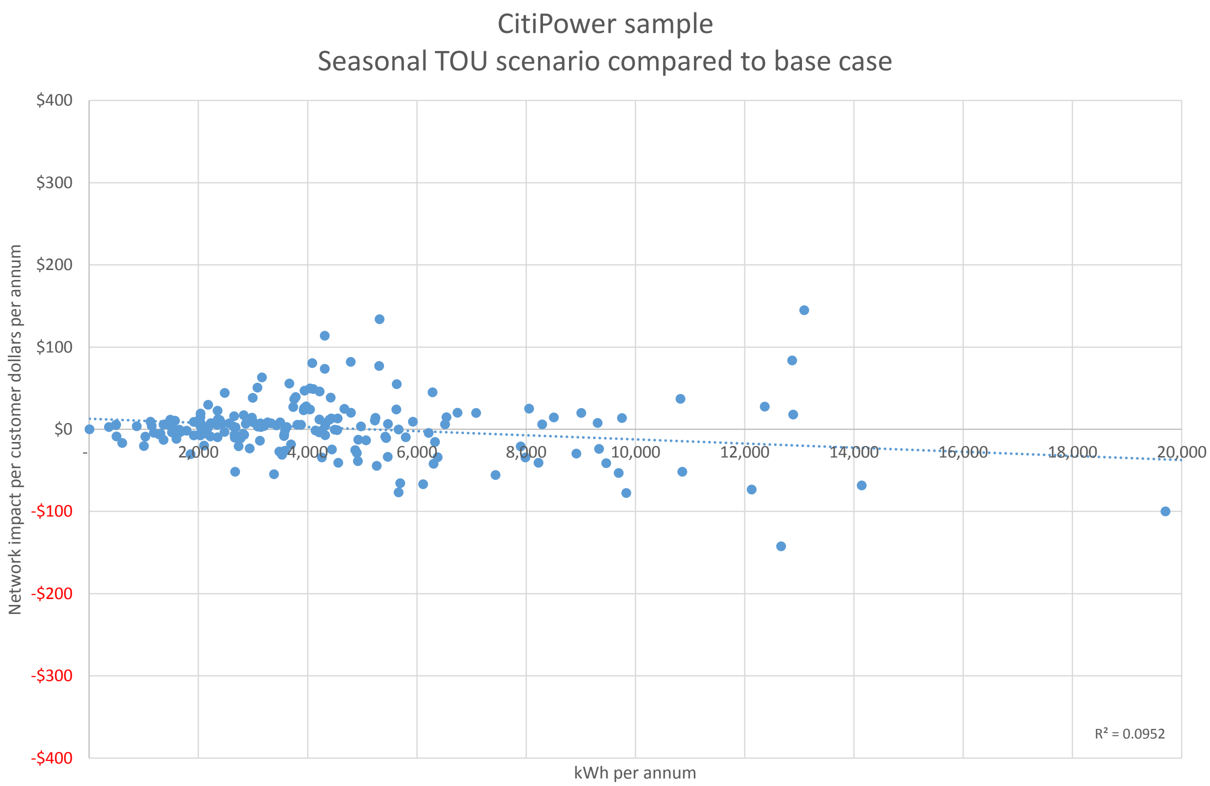
*Applies in peak times as defined by the local distributor, but in summer and winter months only

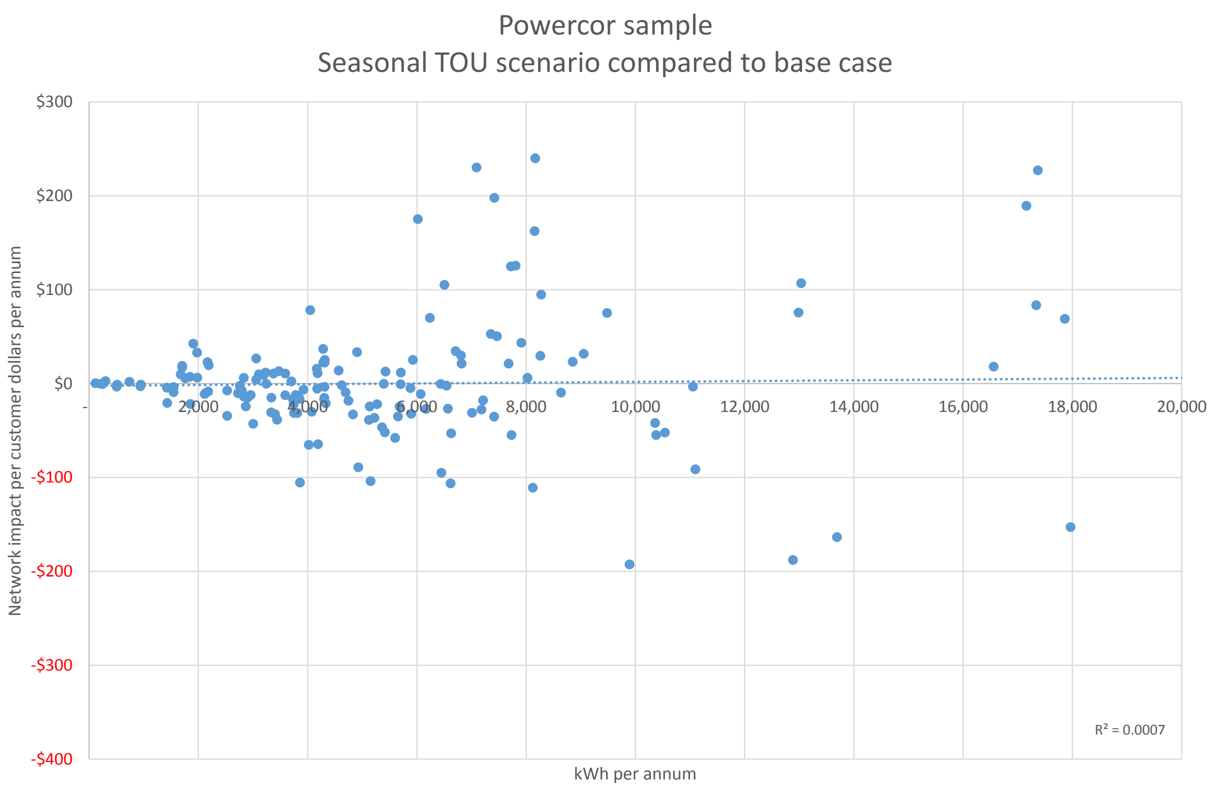
Note that for NSW the shoulder rate would apply in place of the peak rate in spring and autumn. Victorian tariffs don’t have a shoulder component and so the off-peak rate replaced the peak rate in the spring and autumn months.

The following graphs show the network cost impacts to each sample customer of a move from a simple price structure to a seasonal TOU structure. A positive number indicates that a customer is better off under the seasonal TOU compared to the base case.


Ausgrid sample
Seasonal TOU scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
-$400
Network impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.0154


Endeavour sample
Seasonal TOU scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
-$400
Network impact per customer dollars per annum
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.0029


CitiPower sample
Seasonal TOU scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
-$400
-
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
Network impact per customer dollars per annum
kWh per annum
R² = 0.0952


Powercor sample
Seasonal TOU scenario compared to base case
$300
$200
$100
$0
-$100
-$200
-$300
-$400
-
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
Network impact per customer dollars per annum
kWh per annum
R² = 0.0007

As with scenario 3 these graphs show a diverse range of impacts when compared across annual electricity consumptions, and no immediate trends are apparent. Note however that the impacts are relatively small. 87% of the network cost impacts under this structure were within $100 per year and 97% of the impacts were within $200 per year (both favourable and unfavourable impacts).

The table below shows results for NSW that are almost identical to scenario 3 in that there is an even split between customers who are better off and worse off if moved to seasonal TOU network structure. The Victorian results show that small customers in the CitiPower region are more likely to be better off with seasonal TOU, while for the Powercor region the results are split fairly evenly.

Customer impacts for seasonal TOU: NSW samples (Ausgrid and Endeavour)

Annual consumption	**Sample customers better off**	**Sample customers worse off**	
Less than 5 MWh	68	66	
Between 5 and 10 MWh	60	76	
Greater than 10 MWh	39	29	
Total	167	171	Total 338

Customer impacts for seasonal TOU: Victorian samples (CitiPower and Powercor)

Annual consumption	**Sample customers better off**	**Sample customers worse off**	
Less than 3.5 MWh	72	65	
Between 3.5 and 8 MWh	75	80	
Greater than 8 MWh	28	28	
Total	175	173	Total 348

Scenario 5 – Critical Peak Pricing (CPP)

The final scenario to be tested against the base case was a critical peak pricing (CPP) structure. This structure was included in the POC Final Report as being a cost reflective option. CPP is currently in use only in the SP AusNet network area where it is available for commercial and industrial customers on a voluntary basis. The tariffs include peak, shoulder and off-peak energy rates, standing charge, demand charge, and a critical demand charge. The critical demand charge is the average of the customer's demand in the five periods nominated by SP AusNet during the prior year. These periods are always during the times of 2pm and 6pm. Other networks such as Ausgrid and Endeavour have carried out trials with CPP structures.

For the analysis in this scenario it was necessary to construct a CPP tariff applicable for residential customers in NSW and Victoria. The constructed CPP tariffs were applied to the sample customers on a revenue neutral basis, ie. the same total revenue in each sample as the base case. A critical energy charge was set at $2/kWh which is based on a CPP price from the 2005 Ausgrid strategic pricing trial[14]. This is significantly higher than the normal time of use energy rates which would be levied at times outside of CPP events. The CPP price was applied to the sample data for four hours on the five maximum demand days recorded on each net system load profile (NSLP). The NSLP is a consumption profile that represents all customers in a network region with basic (type 6) metering and gives a good representation for small customers. The top five of these weekday peaks in each region are shown in the following tables.

Top five maximum NSLP demands in the Ausgrid area during 2012/13

Date	Time	MW
Monday 30 July	6.30pm – 7pm	1,729
Tuesday 31 July	6.30pm – 7pm	1,721
Wednesday 1 August	7pm – 6.30pm	1,703
Friday 10 August	6.30pm – 7pm	1,697
Wednesday 4 July	6.30pm – 7pm	1,677

All of these Ausgrid NSLP peaks occurred on winter evenings. The critical price was applied to the Ausgrid sample between the hours of 5pm and 9pm on the days shown in the above table.

Top five maximum NSLP demands in the Endeavour area during 2012/13

Date	Time	MW
Friday 18 January	4.30pm – 5pm	2,216
Tuesday 8 January	5.30pm – 6pm	2,085
Friday 11 January	5pm- 5.30pm	1,818
Friday 30 November	3.30pm – 4pm	1,691
Monday 24 December	2pm – 2.30pm	1,670

All of these Endeavour NSLP peaks occurred on summer or spring afternoons. The critical price was applied to the Endeavour sample between the hours of 2pm and 6pm on the days shown in the above table.

Top five maximum NSLP demands in the CitiPower area during 2012

Date	Time	MW
Monday 30 January	1pm – 1:30pm	337
Tuesday 24 January	3pm – 3:30pm	334
Tuesday 17 January	3:30pm – 4pm	323
Monday 23 January	3:30pm – 4pm	314
Wednesday 15 January	3pm – 3:30pm	311

These CitiPower NSLP peaks all occurred in January 2012. The critical peak price to be applied for the CitiPower sample was for the four hours from 1pm on the above days.

[14] Futura Consulting, Investigation of existing and plausible future demand side participation in the electricity market, December 2011, p69

Top five maximum NSLP demands in the Powercor area during 2012

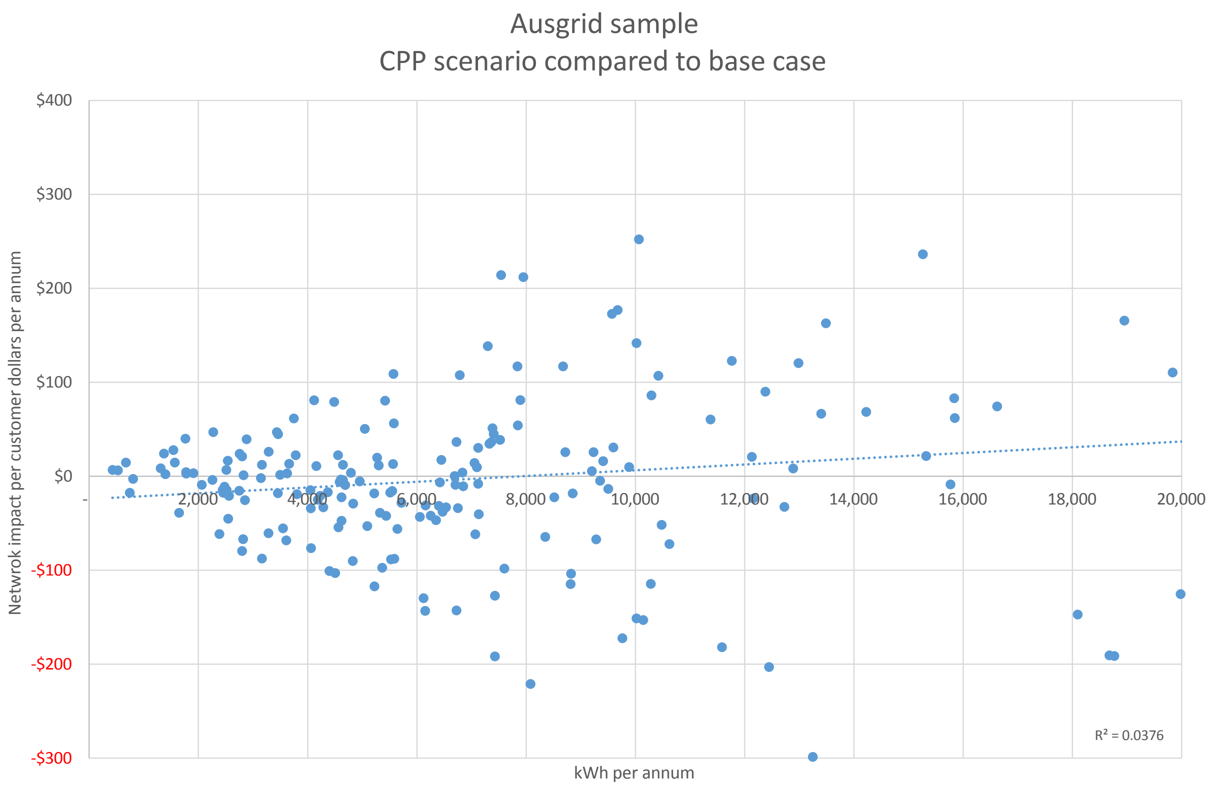
Date	Time	MW
Thursday 2 February	5pm – 5.30pm	1068
Tuesday 17 January	4.30pm – 5pm	925
Tuesday 24 January	4.30pm – 5pm	909
Monday 23 January	4.30pm – 5pm	885
Tuesday 3 January	4pm – 4.30pm	823

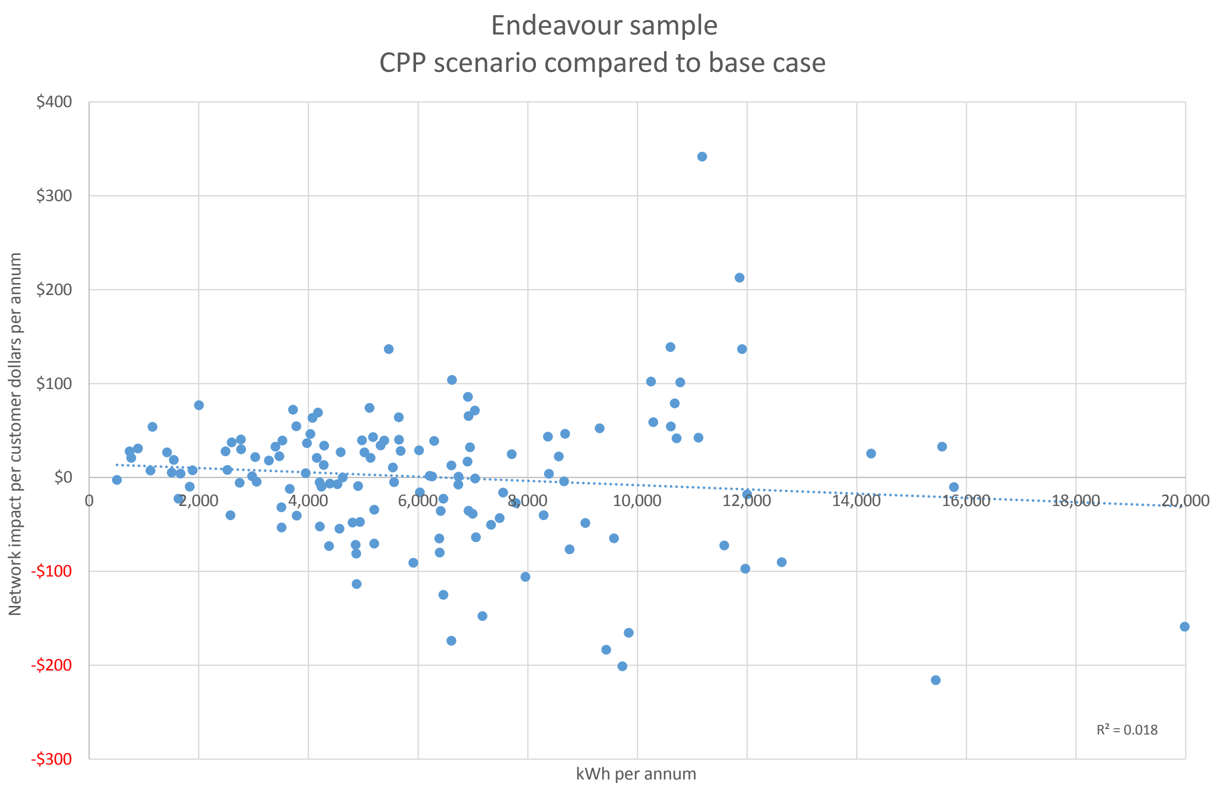
The Powercor NSLP peaks occurred in the summer months of 2012. The critical peak price for this sample was applied from 3pm to 7pm on the days shown above.

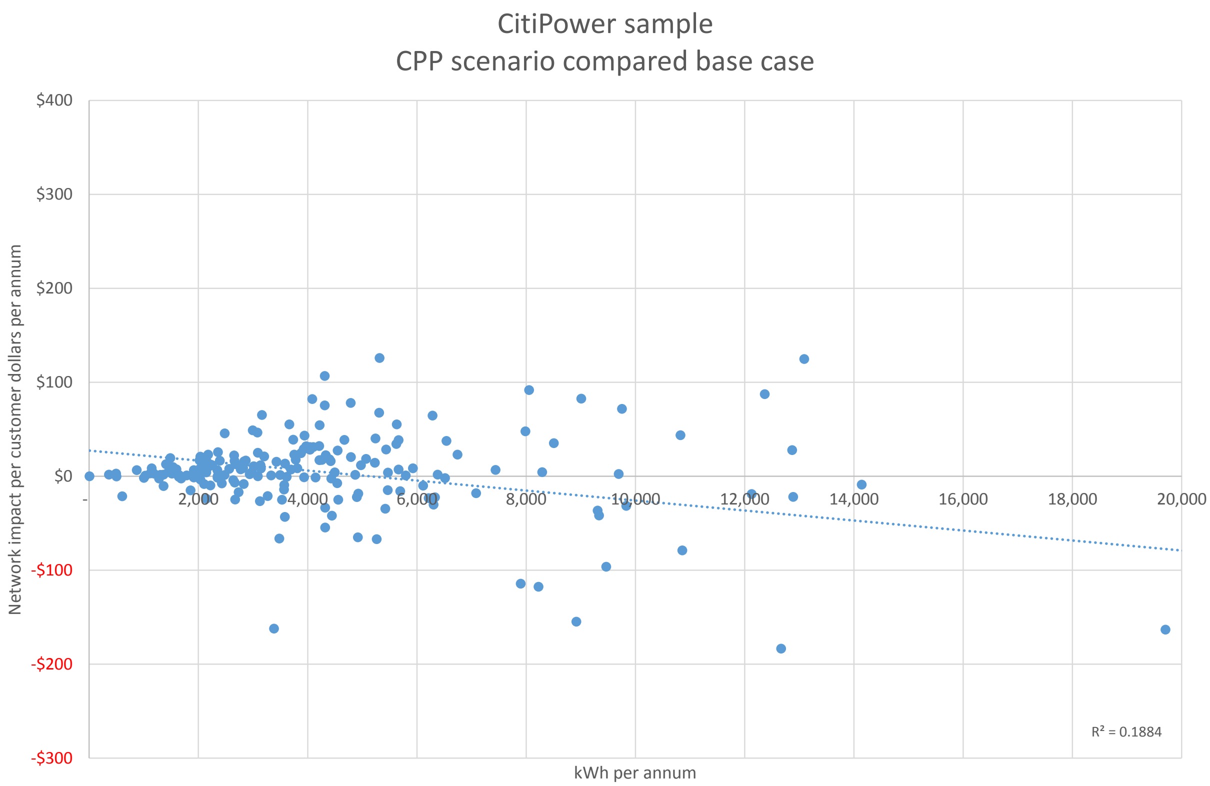
The CPP tariffs to be tested on each sample appear in the following table. These CPP tariffs have the same standing charges and off-peak energy rates as scenario 3 and 4 (and for the NSW samples the same shoulder rates). The peak rate was set so that revenue neutrality was maintained between the base case and each CPP scenario. The peak, shoulder, and off-peak times were as defined by each network area.

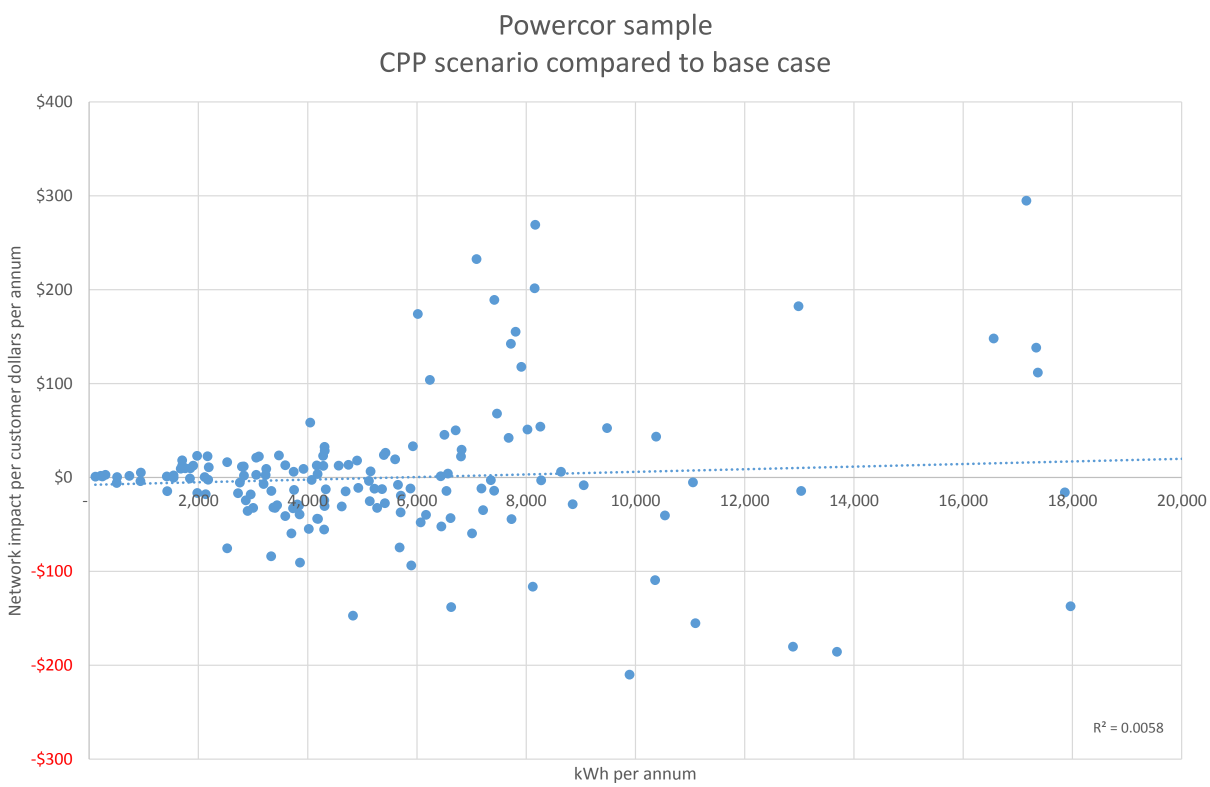
Charging parameter	**CPP tariff tested on Ausgrid sample**	**CPP tariff tested on Endeavour sample**	**CPP tariff tested on CitiPower sample**	**CPP tariff tested on Powercor sample**
Standing/fixed charge c/day	50.0	35.0	10.5	12.3
Peak energy c/kWh	20.7	15.4	7.7	8.7
Shoulder energy c/kWh	5.0	11.6	0	0
Off-peak energy c/kWh	2.6	4.9	1.5	1.7
Critical energy price c/kWh	200	200	200	200

The graphs below show the impacts to each customer in the sample of a move from a simple price structure to a CPP structure. A positive number indicates that a customer is better off under the seasonal time of use compared to the base case.


Ausgrid sample
CPP scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
Netwrok impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R^2 = 0.0376


Endeavour sample
CPP scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
Network impact per customer dollars per annum
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R^2 = 0.018


CitiPower sample
CPP scenario compared base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
Network impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.1884


Powercor sample
CPP scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
Network impact per customer dollars per annum
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.0058

The graphs above show a range of positive and negative impacts in all four samples. However the extent of the impacts is significantly less than in scenario 1 and 2. 85% of the network cost impacts under this structure were within $100 per year and 96% were within $200 per year for all states (including both the favourable and unfavourable impacts).

Compared to the time of use structures in scenarios 3 and 4, the split between customers who are better or worse off under a critical peak pricing structure is even for NSW, but in Victoria small customers are clearly better off. This is due to the results from the CitiPower region where 71% of small customers are better off with CPP structures. This is possibly because many metropolitan Melbourne residents are not at home when the critical pricing events would occur. Recent peak events in this network area occurred on weekdays between 1pm and 4pm.

Customer impacts for CPP: NSW samples (Ausgrid and Endeavour)

Annual consumption	Sample customers better off	Sample customers worse off	
Less than 5 MWh	68	66	
Between 5 and 10 MWh	64	72	
Greater than 10 MWh	41	27	
Total	173	165	Total 338

Customer impacts for CPP: Victorian samples (CitiPower and Powercor)

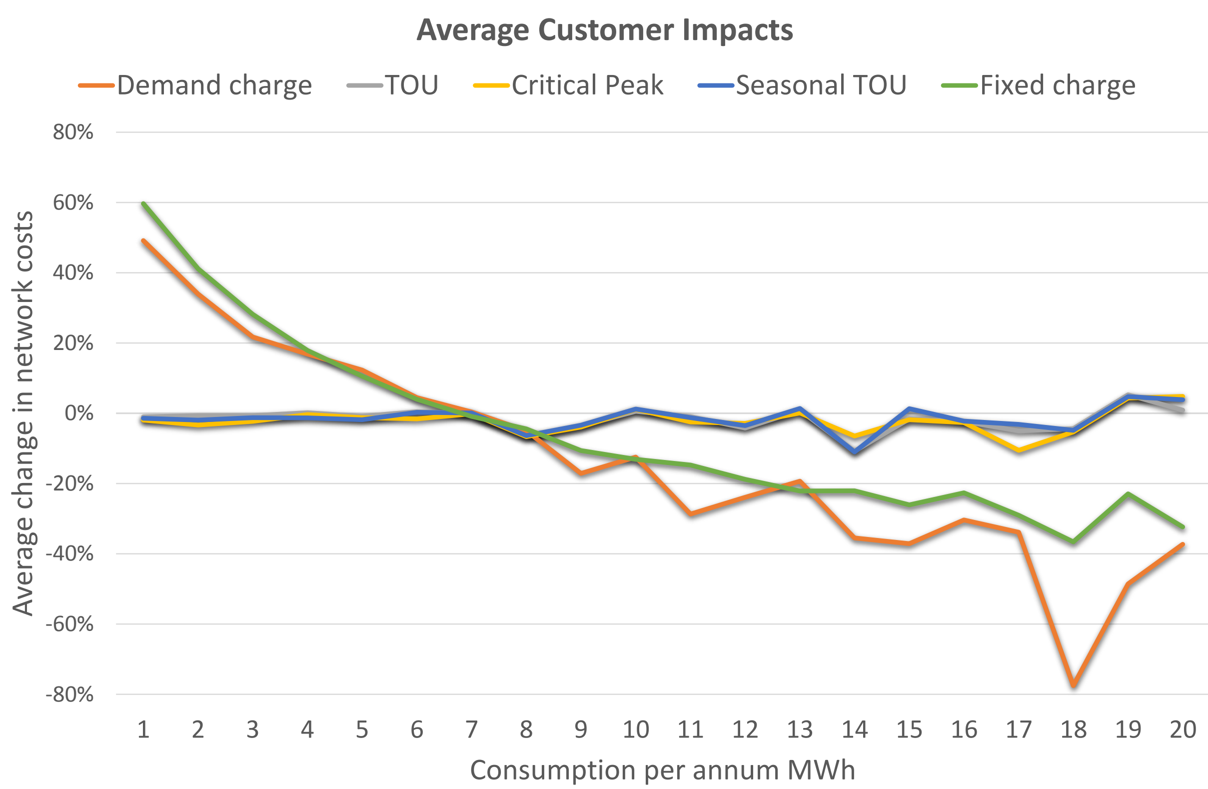
Annual consumption	Sample customers better off	Sample customers worse off	
Less than 3.5 MWh	91	46	
Between 3.5 and 8 MWh	83	72	
Greater than 8 MWh	25	31	
Total	199	149	Total 348

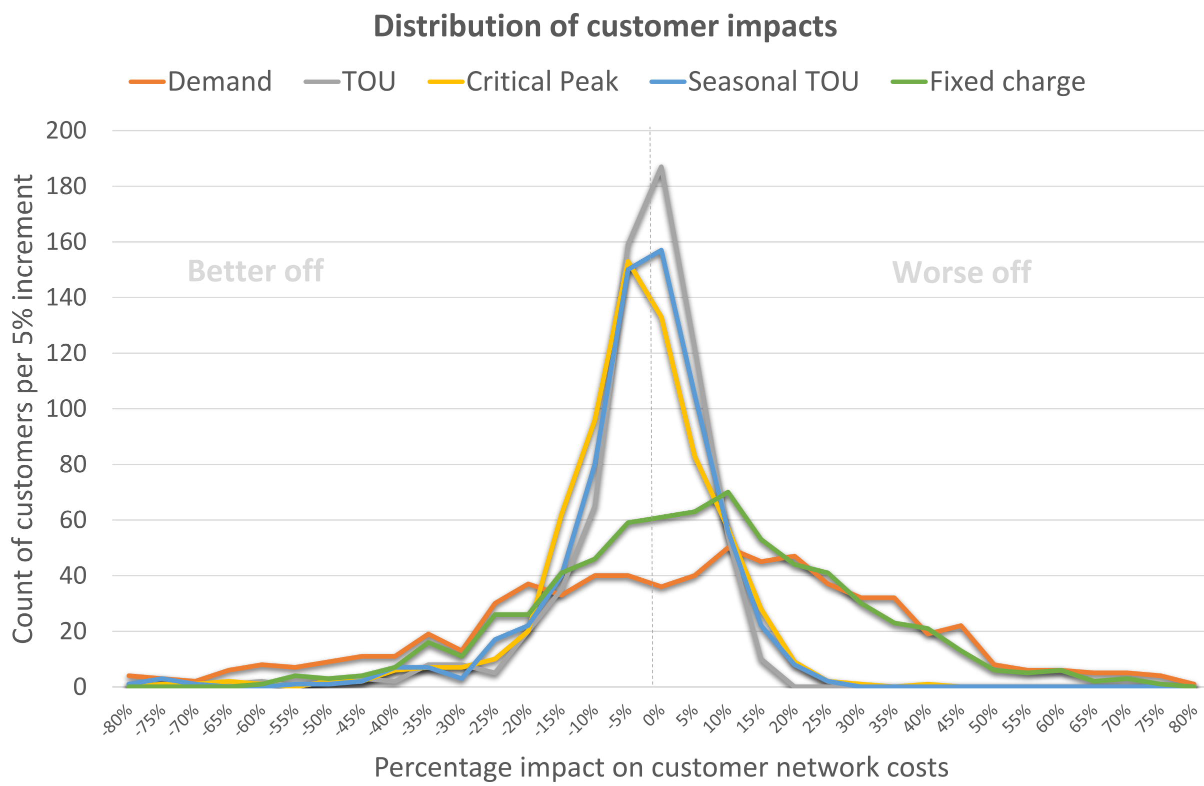
Summary

This analysis examined the cost reflective price structures from the POC Final Report with customer samples across four different network regions. The cost impacts for the sampled customers were compared to a base case to determine if they would be better off or worse off under a move to each cost reflective structure. A major finding of this research was that a move to either fixed standing charges or demand charges (for network) is more likely to impact small customers adversely than a move to time based energy structures (including seasonal time of use and CPP structures).

The CPP and TOU energy based structures were found to benefit small customers the most. 52% of small customers were found to be better off on seasonal TOU tariff and 59% better off on a CPP structure. 47% were better off on standard TOU. The two following graphs further support this finding. The first shows the average impacts for each scenario and the corresponding consumption. A positive percentage indicates that customers are worse off. Demand and fixed charges impact customers using up to approximately 7 MWh per annum on average. The second graph shows the distribution of the percentage impacts by count of customers. Most of the customers have changes to their network charges well within a range of -20% to 20% for the TOU, seasonal TOU, and CPP structures. For the fixed and demand charges the range is much wider and the adverse impacts extend to almost an 80% increase in network costs. Note that the graphs show all 686 customers in the study as they combine the results from the four samples.

The CPP can be considered the most cost reflective structure of the three as it provides a price specific to only five peak network demand events in a year. However the CPP structure does raise customer equity issues if a customer is unable to reduce or manage consumption during the critical periods. It is also important to note that the CitiPower results favour CPP structures significantly more than in the other network regions. 71% of the CitiPower small customers were better off with CPP, possibly because Melbourne metropolitan residents are less likely to be at home during the critical peak events. In contrast the seasonal TOU structure had more consistent results across all four network areas. The seasonal TOU structure can also be considered as more cost reflective than standard TOU as it narrows the definition of peak times to only the months when network peaks are most likely to occur. It also uses a price signal that is blunter yet easier to understand and avoids circumstances where a small customer may be unaware of critical price events and/or unable to respond by shifting consumption.





It is clear that a move to a greater use of fixed standing charges or demand charges would impact most small customers adversely. Small customers receive a degree of protection under their existing variable energy rate pricing, particularly where a small customer has a low load factor. An analysis of small customer load factors indicated that they are lower on average compared to large customers. It is important to note that without segmenting the sampled small customers further, it is not clear how load factors differ between vulnerable customers and other customers in the "small customer" grouping. This is because the customer data provided for this study did not include income or demographic information.

Two further considerations need to be mentioned with these results. The first is that no customer demand response is taken into account in the analysis. This means that the sample customer meter data was not adjusted to take into account the ability (or not) of a customer to manage its electricity consumption. This approach assumed that the sample customers used the same amount of electricity (and load profile) in all scenarios. Only a live customer trial could capture any reductions to electricity consumption as a result of a move to these cost reflective price structures. It is therefore acknowledged that the customers in the sample, while recipients of the theoretical prices in the desktop analysis, did not responded to the price signals. If demand response assumptions were applied to the data then the results would show that more customers are better off.

The second consideration is that only NSW and Victoria were tested for cost reflective price structures. If the analysis were run on data from other states there may be some variations in these results, due to a variety of reasons. The magnitude of customer network charges varies across states as well as the percentage share that they make up of an end-use customer invoice. These differences will have an influence on the annual dollar impacts calculated in each analysis. As mentioned earlier each state has different weather considerations and corresponding electricity load profiles. For example Queensland has only summer demand peaks while NSW has summer and winter network peaks. Other network areas have different time of use periods and different relative values between peak and off-peak rates. Energex (Queensland) defines peak times for residential customers as between 4pm and 8pm on weekdays, in contrast to the network regions included in this analysis.

6 Long Run Marginal Cost and Price Setting

The AEMC consultation paper on the IPART/SCER distribution tariff rule change stated that "pricing on the basis of LRMC is the approach most likely to result in cost reflective pricing"[15]. This chapter will review the implications of using Long Run Marginal Cost (LRMC) as a means of setting distribution prices and whether making its use mandatory will lead to better outcomes for consumers. It does not aim to compare the theoretical merits of different ways of calculating LRMC. It instead focuses on the practical implications for small customers during a move to cost reflective price structures, and how the pricing rules can more adequately protect the interests of these customers.

The current Distribution Pricing Rules require that distributors must take LRMC into account during the annual setting of prices. As Rule 6.18.5(b) states "A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class … must take into account the long run marginal cost for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates". The recent SCER rule change request proposes to amend this section of the NER and require that tariffs and charging parameters be based on LRMC. This change originates from the POC Final Report which proposed that LRMC become mandatory in the price setting. It stated that "Marginal cost is an important principle for efficient pricing, because presenting consumers with the opportunity costs of their consumption decisions should encourage consumption choices that trade off the value of consuming against its supply costs. This principle lies at the core of the POC Final Report and its focus on driving more flexible pricing options for consumers." [16] SCER's subsequent proposed amendments to the Distribution Pricing Rules do not provide a methodology for calculating LRMC, but it suggests the AER could include this in a guideline.

Defining LRMC

LRMC measures the incremental cost to the network of meeting an additional unit of customer demand. LRMC values are usually expressed in dollars per kVA of incremental demand. Ausgrid and SA Power Networks define LRMC in their annual pricing proposals using the average incremental cost (AIC) method:

$$\text{LRMC} = \frac{PV(\text{growth related capex}) + PV(\text{growth related opex})}{PV(\text{incremental demand})}$$

A review of the current year pricing proposals from each distributor indicates that the AIC method is the most commonly used approach used for the calculation of LRMC. Ausgrid, Endeavour, Essential Energy, Jemena, Energex, United Energy, ActewAGL and SA Power Networks have all confirmed that they use this method for their LRMC calculations. No other calculation method has been confirmed as being used in the current year pricing proposals (including the Turvey[17] method). It is interesting to note that in contrast the POC Final Report recommended that the Turvey approach be used in price setting, on the basis that AIC tends to "average out incremental costs over the period that demand is expected to

[15] AEMC consultation paper "Distribution Network Pricing Arrangements", 14 November 2013, p66
[16] AEMC Power of Choice Final Report 30 November 2012 p182
[17] The Turvey approach is defined in the POC Final Report as the present value of an increase in distribution businesses' costs due to a sustained one unit increase in demand for a particular network service.

change."[18] It also preferred an approach that was more consistent with LRMC theory rather than the practical considerations encountered in annual price setting.

A review of the pricing proposals indicated that using LRMC to set prices is far from a straightforward process, and that some inconsistencies exist in the information provided from each region. SP AusNet states in its proposal that "It is of course immensely difficult to accurately measure the long run marginal costs of consumption"[19]. It explains that there are challenges involved in obtaining accurate demand forecasts and cost estimates. Locational differences, accurate timing of investment decisions, and future technological advances are also given as limitations on using LRMC to set prices.

Using LRMC to set charging parameters can also be challenging. While several distributors published LRMC values by tariff class in their proposals, only two distributors showed LRMC values by charging parameter. No distributor put the LRMC estimates for all of their tariffs and charging parameters in the public domain. Five distributors did not show any LRMC values at all in their annual pricing proposals. A number of distributors highlighted the fact that price setting with LRMC should only be used for charging parameters that signal marginal costs, such as demand charges or peak energy charges.

However the SCER rule changes state that each charging parameter (including fixed standing charges) must be based on the LRMC of providing the service. SA Power Network says that using LRMC on fixed standing charges will be "unlikely to affect consumer consumption patterns"[20]. CitiPower states it "signals the long run marginal cost of supply through those tariff charging parameters with the greatest price elasticity of demand, namely the variable consumption charges that are based on the customers energy use and maximum demand"[21]. If the LRMC were applied to all charging parameters, including fixed and off-peak energy charges, it would dampen the impact and intention of using LRMC as a price signal.

Using LRMC on a locational basis

Locational price signals are important for distribution networks given that network augmentation and asset replacement costs are driven by local considerations. The SCER rule change proposes that tariffs and charging parameters must be set with regard to LRMC variations by customer location; "a provision which allows network charges to reflect, as appropriate, any geographic variations in costs caused by current and forecast constraints within the distribution network"[22]. Apart from the practical implications for distributors, one of the most significant impediments to network tariffs being determined on a locational basis is an increased complexity resulting in a potentially poor customer experience. There are also equity implications in network prices being calculated at a locational level. For example, if one residential consumer has electricity prices significantly higher than a neighbour it would appear to that consumer that they are being disadvantaged, particularly if they had sought competitive offers from retailers and couldn't match their neighbour's lower charges. This is currently the case at the boundaries between some distributors (eg. those on opposite sides of Silverwater Road in Sydney) but the issue would be greatly magnified.

A review of each distributor's annual price lists shows that there are currently 453 different network tariffs offered in the NEM. If public lighting and tariffs specific to individual sites are included this number would be significantly higher. Some of the reasons for such a large number of tariffs include

[18] AEMC Power of Choice Final Report 30 November 2012 p185
[19] SP Ausnet Annual Tariff Proposal 1 January 2013 p52
[20] SA Power Networks Annual Pricing Proposal 2013-14 24 May 2013 p63
[21] CitiPower 2013 Pricing Proposal 10 December 2012 p45
[22] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 September 2013 p7

feed-in tariff schemes, obsolete tariffs, stand-by tariffs, and the need to show different tariffs by metering and voltage types. There is also a wide range of different pricing structures offered across the network areas such as; seasonal energy or demand, time of use, inclining blocks, and critical peak pricing. If prices were to be calculated on a locational basis there is no doubt that the complexity of network pricing would increase. More complexity will add to the delays in the preparation of annual pricing proposals and the time required by the AER to approve a proposal.

Essential Energy states in its pricing proposal that "the LRMC approach to pricing is difficult to implement"[23] because economically efficient marginal costs and long run average costs were only found to be equal in locations where there is network congestion. This locational aspect is one of the major limitations of using LRMC to set network prices. Incremental demand drives investment at a locational level, not at a system wide level. This means that if the LRMC were to be used in price setting it should be calculated on a locational basis. For example the incremental demand as seen at a zone substation would be suitable to use in LRMC calculations. However obtaining the locational information is not always straightforward, as stated by ActewAGL: "in practice it is difficult to isolate incremental demand in existing network areas from demand forecasts for ActewAGL Distribution's overall network."[24]

Using demand to calculate LRMC only provides meaningful results when demand is increasing as opposed to situations where it is flat or in decline. For example if one zone substation has demand forecast to increase and another substation has demand in decline only the substation with the incremental demand would be captured as a marginal cost to which network revenue can be allocated. At a system level, peak electricity demand in the National Electricity Market has recently been either flat or declining[25]. These trends will create difficulties with marginal cost and network revenue allocation calculations. AEMO forecasts that an overall reduction of 728 MW in peak demand will occur in the current financial year. This is due to the rise in solar PV installation numbers, increased energy efficiency projections as a result of building standards, and changes in forecasts for industrial projects.

Coincident Peak Demand (demand at times of greatest network utilisation)

SCER states in its network tariff rule change request that its proposed amendments to the Distribution Pricing Rules should allow for greater innovation and flexibility for network businesses to set more flexible pricing options that accurately reflect the costs of meeting peak demand on the network.[26] Its subsequent pricing rule amendment states that a tariff "must be determined having regard to … the additional costs associated with demand at greatest utilisation of the distribution network". This clause 6.18.5(b)(2) is referring to coincident peak demand. Coincident peak demand is usually defined as the highest value of the summated half hourly demand for a group of customers (or for one customer with multiple meters).

Peak demand does drive network augmentation costs but most commonly when measured at a local level. For example the coincident demand for all customers located under the same zone substation is a good indicator of the need for investment in that substation. Peak demand as measured for an entire network does not necessarily have a correlation with distribution augmentation costs because it represents the aggregated trends across many substations. It must be calculated on a locational basis to

[23] Essential Energy Annual network prices report 2013/14, 1 May 2013 p14
[24] ActewAGL Distribution 2013/14 Network Pricing Proposal, May 2013 p16
[25] AEMO National Electricity Forecast Report 2013 Executive Summary, p1
[26] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 Sept. 2013 p14

provide a useful indication of a need for distribution augmentation. However network tariffs usually aren't determined at such a level given the significant complexity and transaction costs involved (not to mention an adverse impact to a customer's understanding of prices). Each truly cost reflective price at a local level would have unique peak times and peak values.

Not all network costs are driven by marginal increases in peak demand. United Energy estimates that approximately 6% of its total annual revenue requirement recovers the cost of providing for peak demand[27]. The other costs are largely network sunk costs and asset replacement. This brings into question the merits of using LRMC as the only means of setting network prices.

Revenue residual recovery (with minimum distortion to efficient patterns of consumption)

The most significant impact of making an LRMC approach mandatory is that a revenue residual will be recovered from customers who are least able to respond to the efficient and flexible price signals. This residual is the amount that distributors will recover above LRMC to meet their applicable regulatory revenue decision. Currently distributors must only take LRMC into account in price setting which allows some flexibility for the allocation of revenue to tariffs. But if LRMC becomes the basis for all price setting, some tariffs and charging parameters could have zero LRMC values, if they represent areas with flat or declining demand. More building block revenue will be weighted on to other tariffs and charging parameters to ensure the total annual revenue is recovered. The NER require in clause 6.18.5(c) that residual revenue should be allocated so that it "minimally distort efficient patterns of consumption". This can be considered a form of Ramsay pricing, where the additional revenue is recovered from customers who are least able to respond to price signals. These are customers who do not receive pricing components that are based on marginal network costs, such as small customers receiving anytime energy rates. This would exacerbate the problem of a revenue residual being recovered on customers who are not able to manage or reduce their electricity consumption.

There are significant problems in using a Ramsey pricing approach to allocate a revenue residual. To allocate revenue so that it "minimally distorts efficient patterns of consumption" means that customers without flexible, efficient and cost reflective prices will be worse off. Ideally clause 6.18.5(c) should be amended so that it is consistent with the POC Final Report recommendations, which stated that the revenue residual should be allocated on a postage stamp basis to alleviate any material shift in sunk costs. "Accordingly… we propose this should be addressed by amending clause 6.18.5 (c) so that in the circumstance where the network business does not recover all its expected revenue through LRMC based prices then: the outstanding amount should be recovered in the form of a postage stamp charge spread across all tariff classes."[28] A postage stamp price is defined in the NER as where the price per unit is the same regardless of how much energy is used by the network user. It provides a better allocation method because the excess revenue is spread across all customers on the basis of the same dollar per unit value. It is recommended that customers who have not elected to move to cost reflective price structures have postage stamp allocations made on a dollar per kWh basis. The scenario results from earlier in this paper show that small customers are better off with energy based structures.

Most distribution businesses should not need to use a Ramsay pricing approach in price setting. The principle behind Ramsay pricing is that it ensures a supplier can maximise revenue and reduce recovery risk by increasing prices for customers that are least able to shift or manage their electricity use. The AER is favouring a transition to a revenue cap and from July 2014 NSW distribution businesses will be

[27] United Energy submission to AEMC rule change consultation, 19 December 2013, p2

[28] AEMC Power of Choice Final Report 30 November 2012 p188-9

recovering their revenue under this approach[29]. Victorian and South Australia will be still subject to a weighted average price cap (WAPC) form of regulation until 2015. Under the WAPC a distributor faces electricity volume risk when recovering its annual revenue. For example, if a major manufacturing operation ceased operations part way through a financial year, the network could not recoup the forgone distribution revenue. The move to a revenue cap means that there will be no risk to volumes or revenue recovery for the distributors because any revenue that isn't recovered in one year (due to falling demand) can be recovered in the subsequent year.

The review of the 2013 annual pricing proposals of all 13 electricity distributors indicated that most had a revenue residual to allocate above LRMC. This residual is the additional amount required for a distributor to meet its revenue determination entitlement. Essential Energy (in its Attachment 2) found that its network prices lie above the long run marginal cost of supply across its tariff classes and throughout a range of consumption bands. Endeavour's approach is to determine LRMC for one charging parameter and then allocate a residue to the remaining charging parameters: "…it is important that one charging parameter of the tariff reflects the marginal cost of supply… and for a second charging parameter to recover the remaining costs…"[30]. This approach is supported by a statement from Endeavour's consultant (p.69) that states "supplying services at marginal cost may not be financially sustainable".

Jemena stated in its proposal that its "…average revenues can be expected to exceed LRMC in most cases" [31]. This creates a residual that is recovered from customers "… since the building block revenue is greater than LRMC … not every tariff class and tariff parameter can be set with reference to LRMC and it would not be appropriate to do so." Where a charging parameter is not recovering LRMC it is viewed as recovering historic costs such as the return on sunk assets.

Energex was also unable to use LRMC as the basis to recover its full revenue for the current year. Its regulated revenue from the building block model was greater than the revenue generated from the LRMC calculations. It states that "the charging parameters outlined … are applied to allow for any shortfall in expected revenue"[32].

SA Power Networks shows in its proposal that the LRMC falls below all tariffs necessary to recover the revenue requirement for the 2013/14 year, indicating that a residual is necessary. This residual is recovered "in the least distortionary manner possible"[33]. This distributor provides the most information on how it uses LRMC to construct charging components as these cost values are shown separately for demand and energy charging parameters. They also include estimates for LRMC for off-peak charging parameters. The network states that LRMC in an anytime energy component will be of influence as a price signal "to a much less significant extent" and that fixed charges will be "unlikely to affect consumer consumption patterns". This highlights a problem with the SCER rule change which would see all charging parameters based on LRMC.

The 2013 LRMC values for CitiPower and Powercor were all below the expected revenue for each tariff class with the exception of the sub-transmission tariff classes. If charging parameters were set taking into account LRMC, both CitiPower and Powercor would have a revenue shortfall. This residual is recovered via fixed charges and anytime energy charges. In its recent rule change submission to the AEMC, CitiPower/Powercor stated that "If prices are strictly based on LRMC, there would be a significant

[29] AER Stage 1 Framework and approach paper, March 2013, p10
[30] Endeavour Energy Direct Control Services Annual Pricing Proposal, 30 April 2013, p70
[31] JEN Pricing Proposal 2013, 31 October 2012 p24
[32] Energex Pricing Proposal 2013/14, 30 April 2013, p35
[33] SA Power Networks Annual Pricing Proposal 2013/14, 24 May 2013, p64

residual amount which would need to be smeared across the customer base in order to ensure cost recovery. The Businesses urge the AEMC to recognise that a strict application of LRMC will result in significant under recovery"[34]. United Energy also made a submission to the recent AEMC rule change and identified a similar issue with excess residual revenue and the challenge mandatory use of LRMC would create "…UE potentially has a large component of so called residual costs"[35].

From the review of proposals and submissions from the distributors, it is clear that large revenue residuals would be created if the AIC method of LRMC was used as the basis for tariffs and charging parameters. This has significant implications for small and vulnerable customers as pricing rule 6.18.5(c) requires that distributors must allocate this residual revenue to customers who are least able to manage their consumption.

Regulation of Transmission Prices

In contrast to the distribution pricing principles, the transmission pricing principles in the NER do not require prices to be based on, or have given regard to LRMC. The principles do say that the transmission prices for recovery of the locational component must be based on demand at times of greatest utilisation of the network and for which network investment is most likely to be contemplated. Transmission pricing proposals can be compliant under these principles without the TNSP having to show that each pricing component is consistent with AIC (or Turvey) marginal cost calculations. There is a clear inconsistency between LRMC being a mandatory requirement in distribution component price setting, compared to it being considered as a broad concept applicable to only one component of transmission pricing. The regulation of distribution and transmission prices in the NEM is governed by the same set of rules (the NER) and the same regulator, and yet the underlying basis to the cost allocation and price setting for each network is different.

7 Component Rebalancing and Side Constraints

The POC Final Report recommended that the transition to cost reflectivity be gradual. "We recommend… a gradual phasing in of efficient and flexible retail pricing options for residential and small business customers through the introduction of cost reflective electricity distribution network pricing structures."[36] To ensure that the proposed changes are gradual, there needs to be effective price control rules in place. This chapter considers the existing control mechanisms for annual price changes in the existing Distribution Pricing Rules and reviews how the changes proposed by SCER will impact these mechanisms. Priority is given to the implications for small customers of these changes, including the avoidance of price shocks or a sudden rebalancing of charging components.

The current price control formula in Section 6.18 of the Distribution Pricing Rules limits sudden changes in revenue recovery between tariff classes. Tariff classes are groups of tariffs with customers that have similar connection characteristics. Distributors use voltage level, meter type, annual energy consumption, and residential/business classifications as the main criteria of allocating customers to tariff classes. For example most distributors have a residential tariff class or a low voltage tariff class. A number of different small customer tariffs are used to recover revenue for each of these tariff classes. A residential tariff class may include one tariff with a block structure and another tariff with a time of use

[34] CitiPower/Powercor submission to AEMC rule change consultation paper, 19 December 2013, p2
[35] United Energy submission to AEMC rule change consultation paper, 19 December 2013, p2
[36] AEMC Power of Choice Final Report, 30 November 2012, p170

structure. A low voltage tariff class is likely to have separate tariff or tariffs for residential customers compared to business customers.

An example of distribution tariff classes, tariffs, and charging parameters

Tariff class	Tariff	Charging parameters			
		Fixed charge c/day	Peak c/kWh	Off-peak c/kWh	Demand $/kVA
Low voltage supplies	Residential				
	Small Business				
	Unmetered				
High voltage supplies	Standard service				

Changes to distribution revenue recovery across **tariff classes** must be no more that the "permissible percentage", which is the product of CPI, a 2% side constraint, and the AER's X factors. While this price control limits sudden changes in revenue recovery at a high level, it doesn't regulate revenue recovery across **tariffs** and **charging parameters**. This is an important omission in the price regulation of distribution revenue. If a network wishes to rebalance revenues across tariffs or charging components, it needs only to "take into account the long run marginal cost for the service" as per pricing rule 6.18.5(b)(1). This means that in theory a distributor could move all of its revenue recovery for a tariff class onto a fixed charge, if it had demonstrated to the AER that it had considered the LRMC of the service. As shown in the fixed charge scenario in chapter 5 of this paper customers would have limited options for minimising their network costs. The existing Distribution Pricing Rules and those proposed by SCER do not present ways of limiting these sudden price shocks. While the customer consultation proposals from IPART and SCER will give consumers an early warning of future changes, it also important that these reforms extend to the regulation of prices. This will avoid the significant variations across charging parameters that have occurred since the Distribution Pricing Rules were first used in 2009. Amendments to these rules are urgently required in this area.

Note that both the SCER rule change request and the POC Final Report discuss removing all side constraints from the NER. This was based on an assumption that the proposed Pricing Structures Statement will provide adequate regulation of pricing structures and tariff movements at the start of the regulatory period. Until the Rule change including the proposed Pricing Structures Statement (PSS) is finalised it should be acknowledged that there are currently no rules preventing significant revenue rebalancing across charging parameters or tariffs within a tariff class. One solution is to continue to regulate pricing on an annual basis by introducing additional side constraint limits to both charging parameters and individual tariffs within a tariff class.

The PSS should be designed so that there is a balance between certainty for customers and flexibility for distributors. It would be difficult to set prices every five years given variations due to volatile transmission settlement residues, and to a lesser extent, CPI. Therefore it would make sense for price structures to be confirmed in the five yearly PSS and for distributers to set the pricing values for these structures in the annual pricing proposals. The SCER rule change doesn't provide specific criteria on what the AER should approve in a PSS: "The AER must approve a Distribution Network Service Provider's proposed pricing structure statement if the AER is satisfied that the statement gives effect to and is consistent with the pricing principles for direct control services."[37] The rules should state exactly what the AER will be approving in the PSS, apart from ensuring that it is consistent with the pricing principles. Note that the proposed approach won't prevent sudden component rebalancing, and an additional side constraint on charging parameters and tariffs will achieve better outcomes for customers in subsequent regulatory periods.

8 ABILITY OF SMALL CUSTOMERS TO RESPOND

The POC Final Report proposes a number of initiatives to protect vulnerable customers during a transition to cost reflective pricing. It acknowledges that unless these initiatives are adopted the flexible pricing reforms will not succeed. The report states: "Those who consume most of their energy at peak times and are unable to adjust their consumption patterns may be worse off. For some consumers on low incomes this could lead to financial distress, affecting their ability to pay their electricity retail bills. We consider that unless the needs of these consumers are specifically addressed, it is unlikely that such flexible pricing options will attract broad public acceptance"[38]. This chapter draws attention to the recommendations from the POC Final Report which were not included in the SCER rule change. It also reviews other issues affecting small customers in a move to cost reflective pricing.

In the move toward greater cost reflectivity consumers who have low incomes, low energy literacy or limited ability to load shift may be worse off. Flexible pricing structures mean that informed customers can benefit by making consumption decisions but uninformed consumers are unable to participate in the transition. Many of the existing network pricing structures (such as inclining block tariffs) do not require a significant level of engagement from the electricity consumer. This is beneficial for customers who have low energy literacy such as the elderly and non-English speaking consumers as they will be charged the same regardless of the level of their engagement or interest in their energy supply. However the introduction of new flexible price structures will enable informed customers to respond to price signals and to reduce their energy costs and there is a risk that customers who are not responding to price signals will be disadvantaged via comparatively higher network costs.

One important aspect of the POC Final Report was that small customers will not be required to move to flexible, efficient and cost reflective prices unless they elect to do so. However the SCER rule change proposal did not acknowledge this and under its amendments all customers (including small and vulnerable customers) will be included in price setting based on marginal cost. Note that the POC Final Report defines a vulnerable customer as "one that is affected by changes to pricing structures which results in a deterioration in their ability to manage their electricity consumption."[39] The author of this paper does not agree with this definition as it assumes, under normal circumstances, that vulnerable customers are currently in a position to manage their consumption.

The POC Final Report stated that governments should review concession schemes for those customers with a limited capacity to respond to cost reflective price structures. It also suggested that the National Energy Customer Framework (NECF) hardship indicators be extended to cover how hardship customers are managing the transition to flexible pricing. It stated that: "We therefore advise the AER to also

[37] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 Sept. 2013 p21
[38] AEMC Power of Choice Final Report, 30 November 2012, p161
[39] AEMC Power of Choice Final Report, 30 November 2012, p165

require retailers to monitor and report on the impacts of flexible pricing on consumers in hardship programs"[40]. The recent SCER rule change paper doesn't discuss this important recommendation and whether changes should be made to the NECF.

The POC Final Report acknowledged the importance of consumer engagement. "Eliciting consumer engagement is a critical aspect of realising the benefits of flexible pricing and this will depend on how the transition is managed."[41] It also stated that a comprehensive education campaign should be introduced for demand charging, and that state governments should consider whether there is a role for third parties that have good access to a range of consumers to support such information campaigns. While SCER acknowledged the importance of consumer engagement, no rule amendments were added in their rule change that included these considerations. "As part of the AEMC POC Final Report, it was highlighted that consumer engagement and participation will be critical if the benefits of flexible pricing options are to be realised."[42] This is another important aspect of the POC that was not included in the SCER rule change.

The SCER rule change process presents a unique opportunity for a uniform approach to small customer distribution pricing across all 13 distributors in the NEM. Consideration should be given to a new pricing principle that requires all distributors to offer a hardship tariff. This tariff would be exempt from the allocation of any residual revenue under the current pricing clause 6.18.5(c). The price structure would be as simple as possible and ideally would feature a single variable rate with no standing charge. The POC Final Report stated that "… we consider that jurisdictions should tailor the consumption thresholds to their specific market conditions"[43]. A mandated hardship tariff wouldn't need different consumption thresholds across jurisdictions as it would be a single variable rate. But the value of the anytime energy rate would need to vary across jurisdictions given different cost structures across the distribution regions. Eligibility for the tariff would be defined in Part 3 of the Retail Rules and would be coordinated as part of each electricity retailer's mandated customer hardship policy. Retailers would request that the local network transfer a customer to the tariff via the well-established MSATS processes.

The existing Distribution Pricing Principles require in 6.18.5(b)(2)(ii) that tariffs and charging parameters be determined having regard to "whether customers of the relevant tariff class are able or likely to respond to price signals". Both the POC Final Report and the SCER rule change request propose replacing this clause with "how the tariff may impact retail customers within the relevant tariff class". In a move to cost reflective pricing it would surely be useful to understand if customers are able to take advantage of the price signals. The replacement clause is a weaker substitute and it does not explain how distributors should provide meaningful commentary on potential customer impacts. The reasons given for this change were that the current clause may encourage revenue to be shifted to consumers that are least likely to respond and adjust their behaviour. It is therefore inconsistent that SCER have included this amendment to clause 6.18.5(b)(2)(ii) but have not replaced the revenue residual allocation clause 6.18.5(c) with a requirement for a postage stamp method (for example an allocation on an energy based rate). This was a recommendation in the POC Final Report.

A significant challenge with any reform to network pricing structures is that electricity retailers don't always pass price signals through to the end use customer. Electricity retailers have also had significant

[40] AEMC Power of Choice Final Report, 30 November 2012, p169
[41] AEMC Power of Choice Final Report, 30 November 2012, p161
[42] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 Sept. 2013 p9
[43] AEMC Power of Choice Final Report, 30 November 2012, p176

difficulties in accommodating existing network price structures in their billing systems, as was seen in the submissions to IPART/SCER consultation in December 2013. If the cost reflective initiatives undertaken by the networks are not passed through the customer will not be able respond and the efficiency objectives will not be met.

One major limitation to the introduction of cost reflective price structures for small consumers is customer metering installations. Most small customers have metering that can only measure a single value for energy consumption, and which cannot record the time of the usage (or demand). The POC Final Report acknowledged this: "We consider that the full benefits of DSP are unlikely to be achieved without deployment of smart meters and cost reflective pricing for consumers."[44] The SCER rule change states that "Consumers are generally provided with flat or inclining block pricing structures which do not necessarily signal the time-varying costs associated with their consumption on network and electricity supply costs. Therefore, most consumers are currently unable to capture the value of changing their electricity consumption patterns."[45] However both the POC and the SCER rule change recommended that the distribution tariffs be set with regard to demand at times of greatest utilisation. This raises uncertainty on what assumptions will be made by distributors when setting tariffs and charging parameters for customers who do not have time of use metering.

Further initiatives could be included in the NER or AER guideline to protect small customers who are unable to respond to efficient, flexible and cost reflective prices. Even if the revenue residual were allocated through a postage stamp basis, small customers who have not elected for cost reflective prices could still be impacted. The more informed customers can shift their electricity consumption in response to price signals, but vulnerable customers cannot. As the regulatory environment moves toward revenue caps it means that small customers may be required to bear the savings achieved by the informed customers who respond to the new price signals.

9 CONCLUSION

This research paper assessed the implications for small customers if network tariff structures became more cost reflective. It reviewed the current pricing rules in the NER and the proposals to amend the rules that will make cost reflectivity a core part of the network price setting process. It also drew attention to aspects of the POC Final Report which were not included in the SCER rule change proposal.

The move toward cost reflectivity could see a variety of customer outcomes depending on the pricing structures that becomes part of the transition. A greater use of standing charges and demand based components is likely to impact small customers adversely. Time based energy rates were found to impact small customers to the least extent, and these structures could be used as a reasonable compromise between the drive toward cost reflective pricing structures and the need to protect the interests of vulnerable customers.

The research highlighted a number of challenges with basing network prices on LRMC. These include the likelihood of significant revenue residuals being created, and that the existing NER encourage this recovery to be allocated to customers who are least able to manage their energy consumption. Revenue

[44] AEMC Power of Choice Final Report, 30 November 2012, p159

[45] Standing Council on Energy Resources Senior Committee of Officials rule change to AEMC 18 Sept. 2013 p5

allocation to tariffs using LRMC also becomes problematic in an environment of declining electricity demand. Network tariffs aren't often calculated on a locational basis but an LRMC approach would suggest that this should occur. Until these challenges are resolved it would make sense for LRMC to not become a more important part of the price setting process.

The current NER and proposed changes do not address network tariff component rebalancing. The existing NER side constraints don't prevent sudden movements of revenue between network tariffs and their individual charging components. To prevent small customers being impacted adversely any reforms to the NER pricing principles must consider these limitations.

A Retail Rule mandated hardship tariff that has simple price structures is one way of protecting vulnerable customers from any adverse impacts of a move to cost reflectivity.

10 ACKNOWLEDGEMENTS

The analysis presented in this paper would not have been possible without the contribution of the customer data from CitiPower, Powercor, Endeavour and Ausgrid. Thank you to the pricing teams in each of these network companies for making this data available.

Thank you to Mark Byrne, Consumer Advocate, Total Environment Centre, for your support and advocacy of this project.

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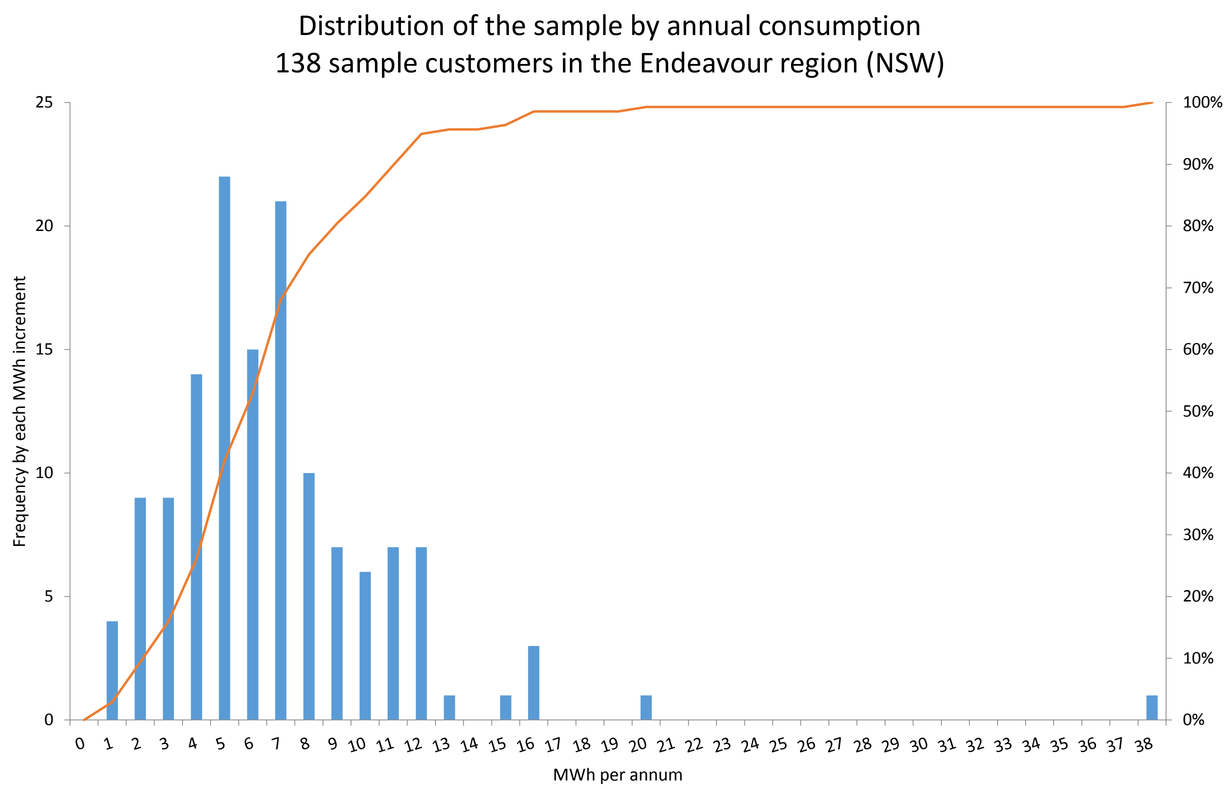
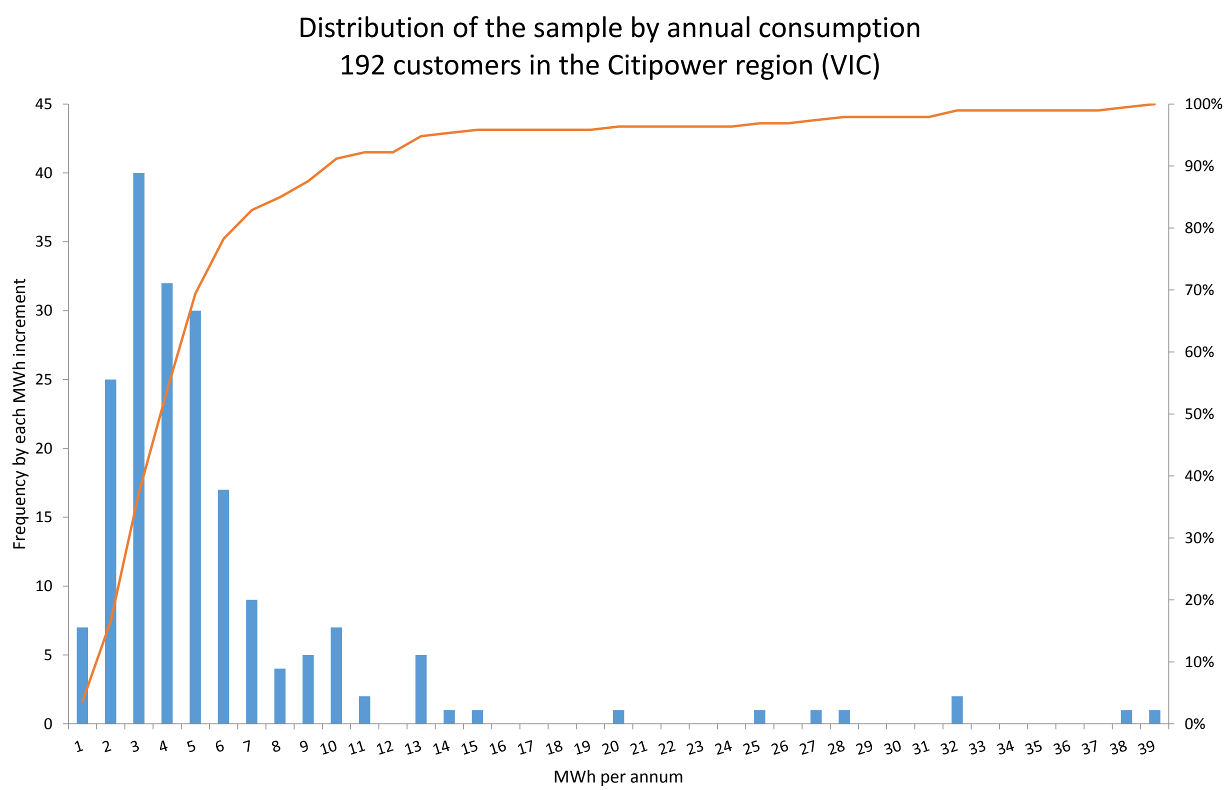
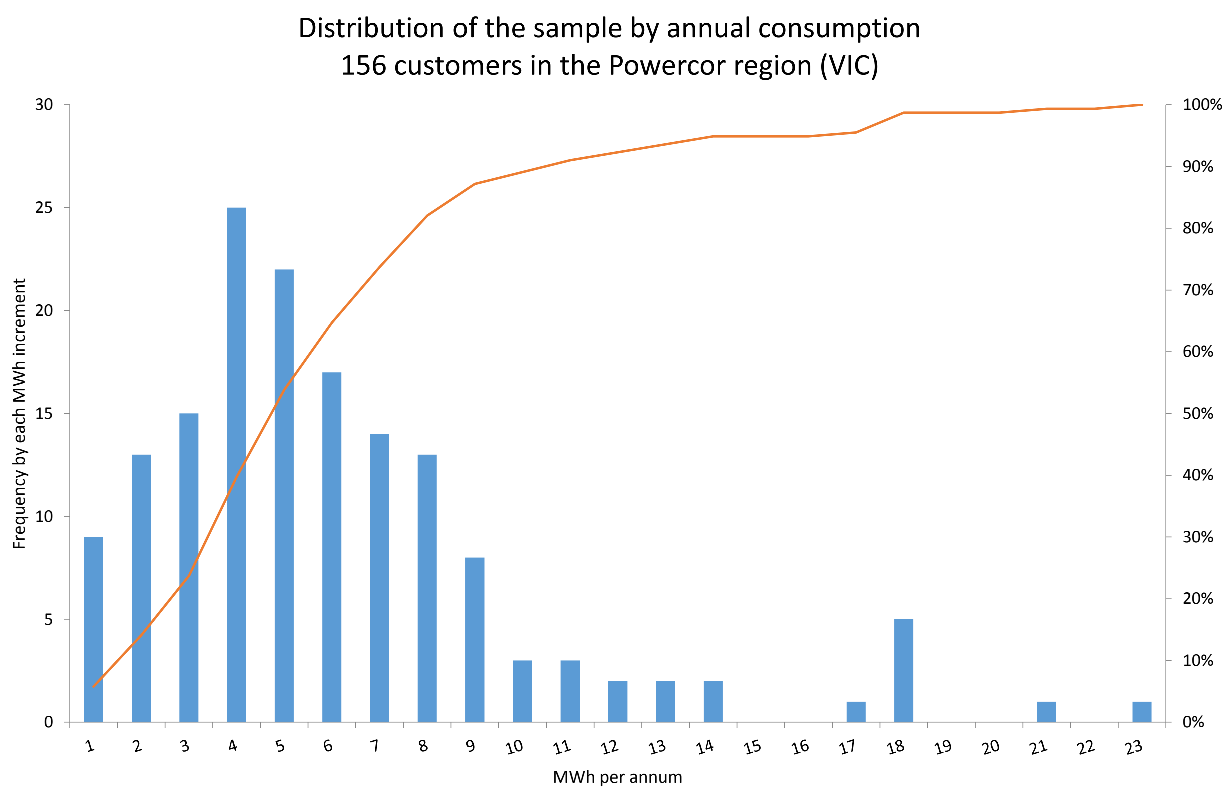
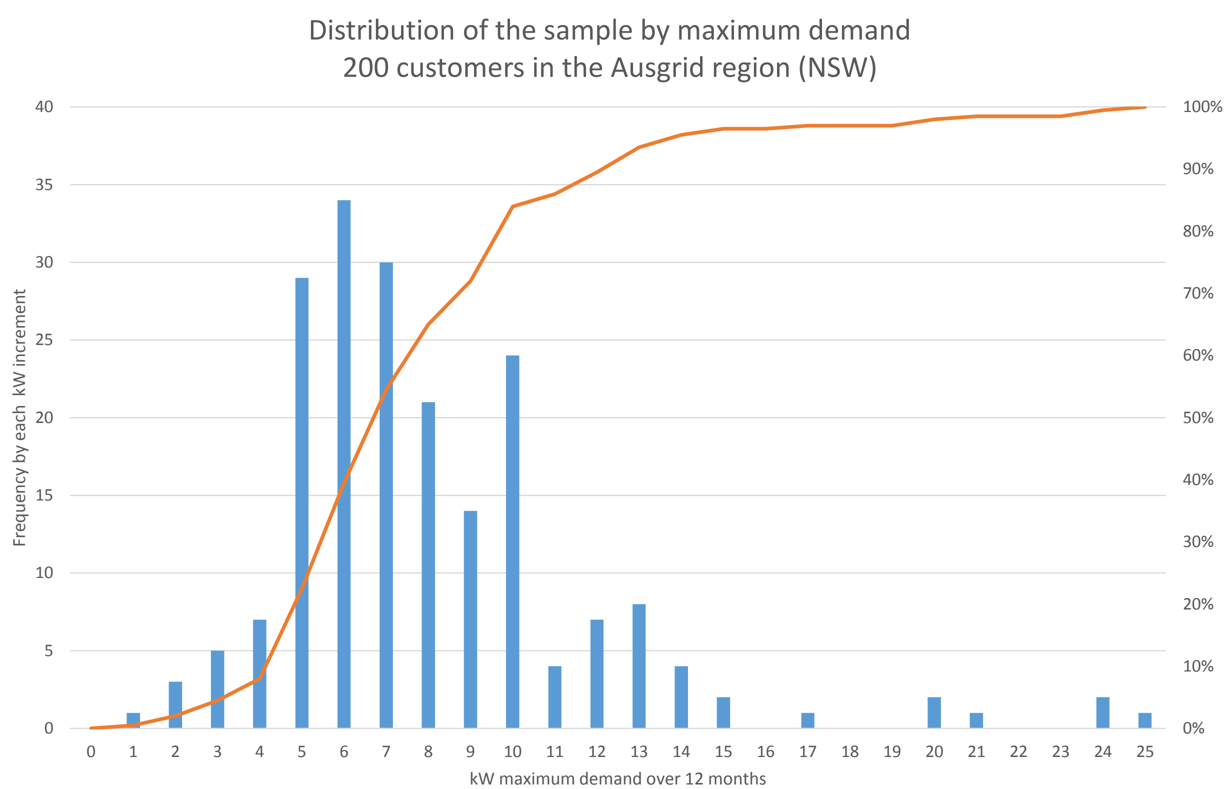
Thank you for your invaluable commentary and suggestions.

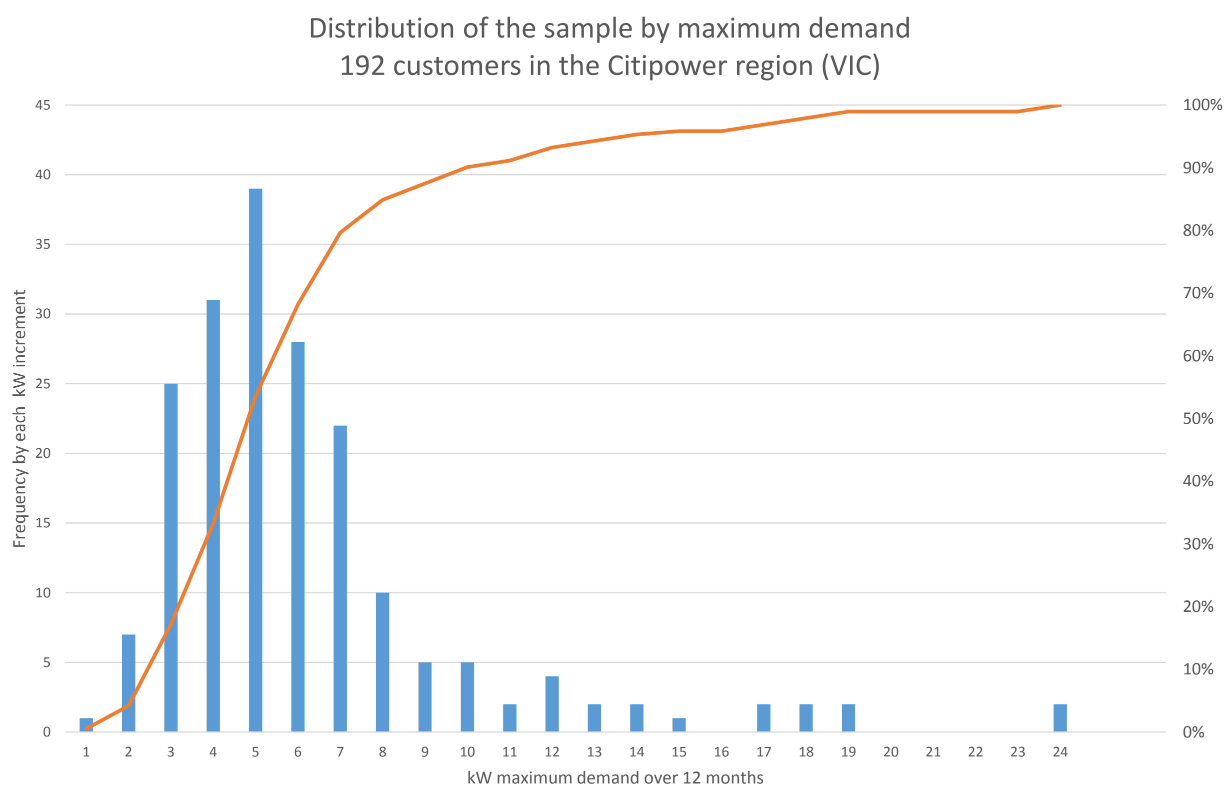
11 Appendix - Additional Graphs

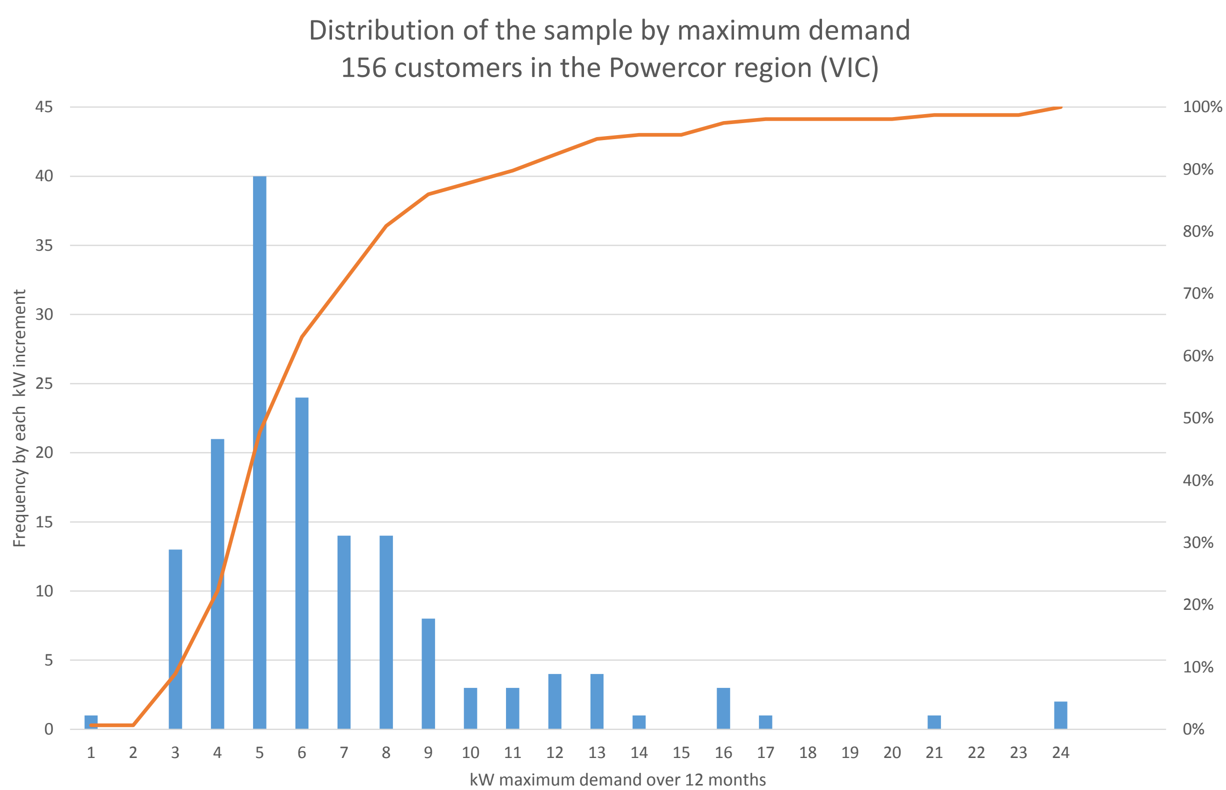


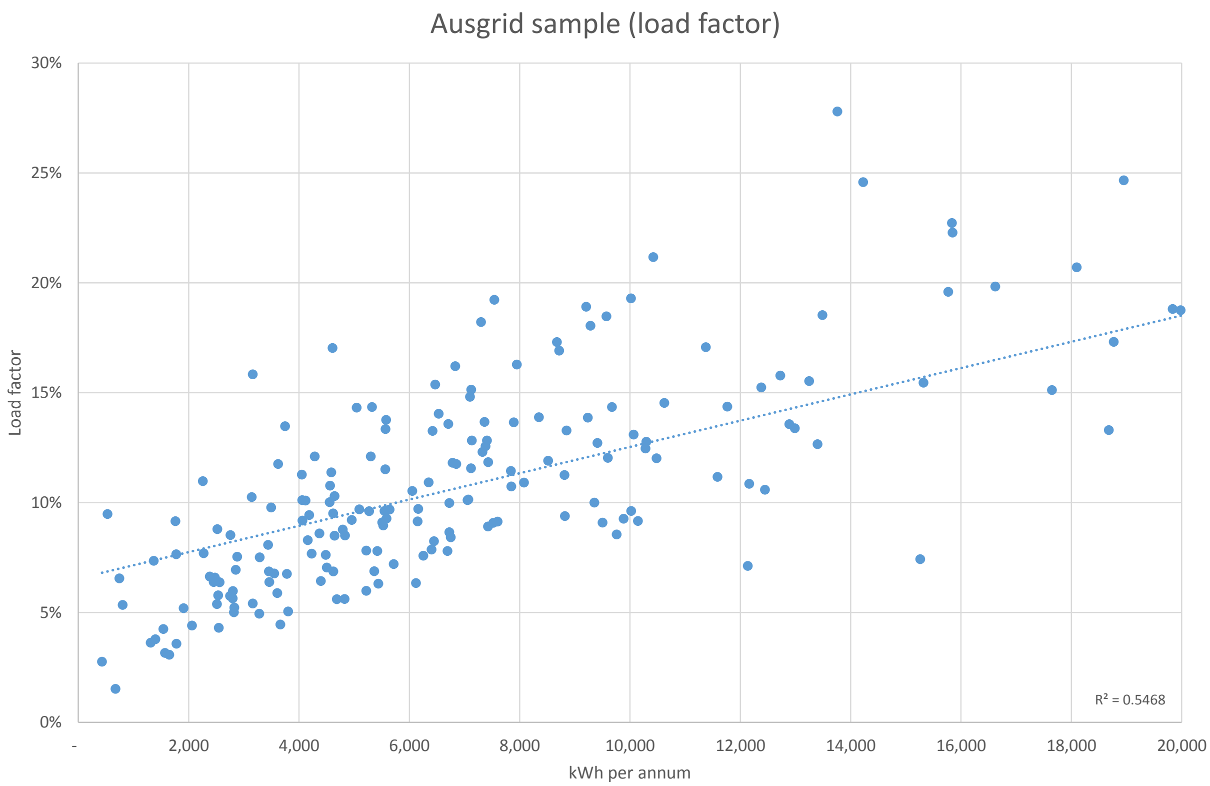


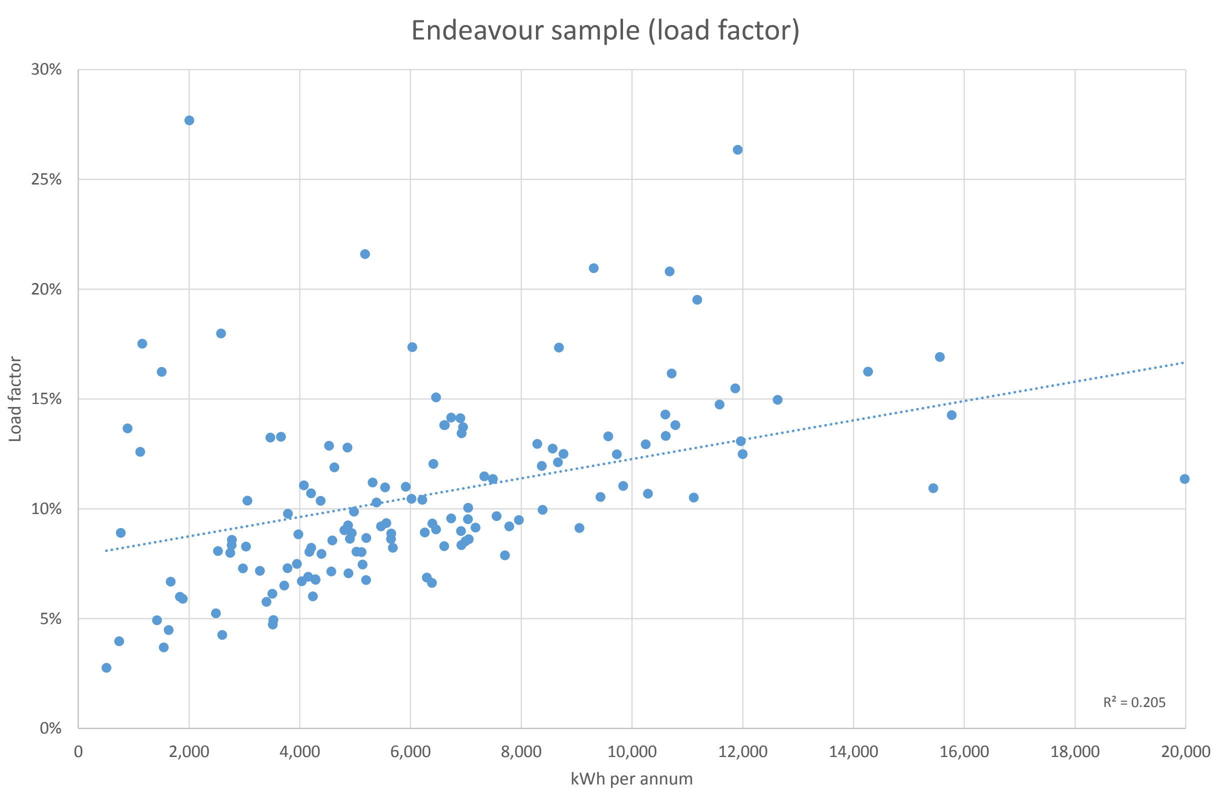

Distribution of the sample by annual consumption
156 customers in the Powercor region (VIC)
Frequency by each MWh increment
MWh per annum
0
5
10
15
20
25
30
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23

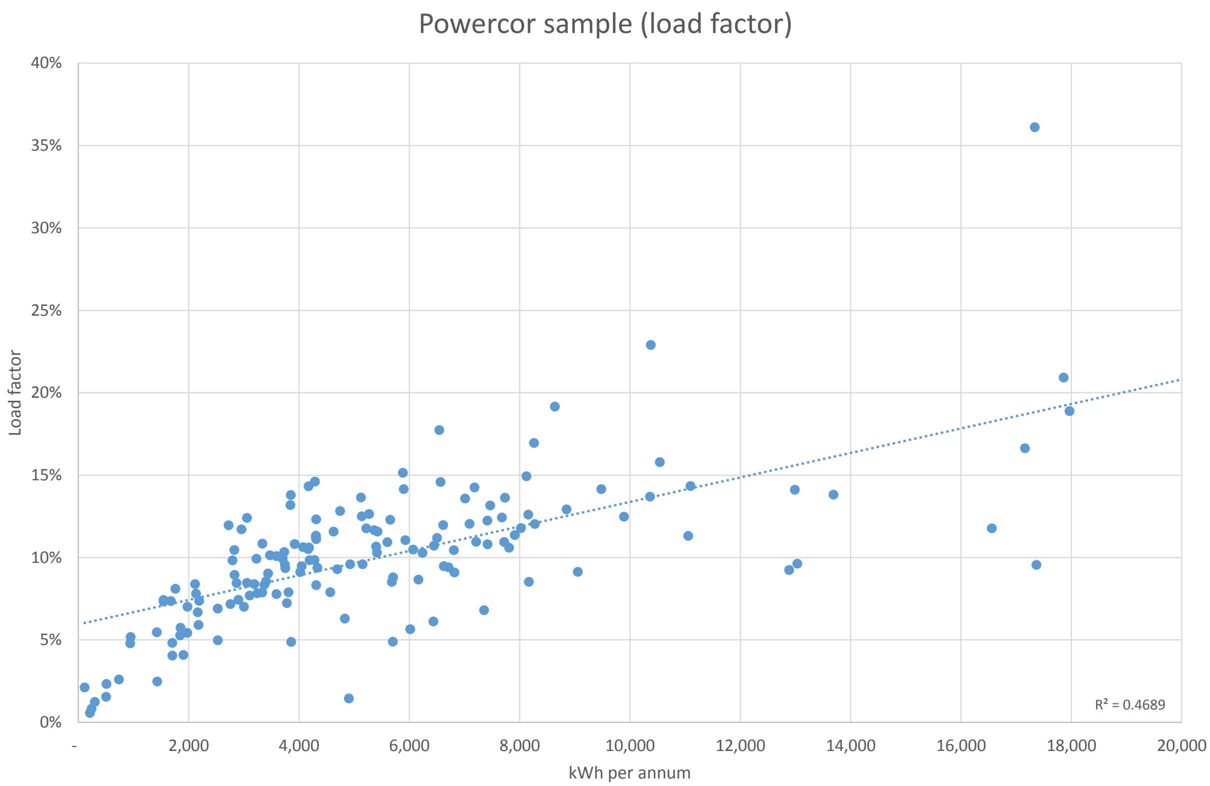

Distribution of the sample by maximum demand
200 customers in the Ausgrid region (NSW)
Frequency by each kW increment
kW maximum demand over 12 months
0
5
10
15
20
25
30
35
40
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25


Distribution of the sample by maximum demand
192 customers in the Citipower region (VIC)
Frequency by each kW increment
kW maximum demand over 12 months
0
5
10
15
20
25
30
35
40
45
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


Distribution of the sample by maximum demand
156 customers in the Powercor region (VIC)
Frequency by each kW increment
kW maximum demand over 12 months
0
5
10
15
20
25
30
35
40
45
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


Ausgrid sample (load factor)
30%
25%
20%
15%
10%
5%
0%
Load factor
-
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R^2 = 0.5468


Endeavour sample (load factor)
30%
25%
20%
15%
10%
5%
0%
Load factor
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R^2 = 0.205


Powercor sample (load factor)
40%
35%
30%
25%
20%
15%
10%
5%
0%
Load factor
R² = 0.4689
-
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum

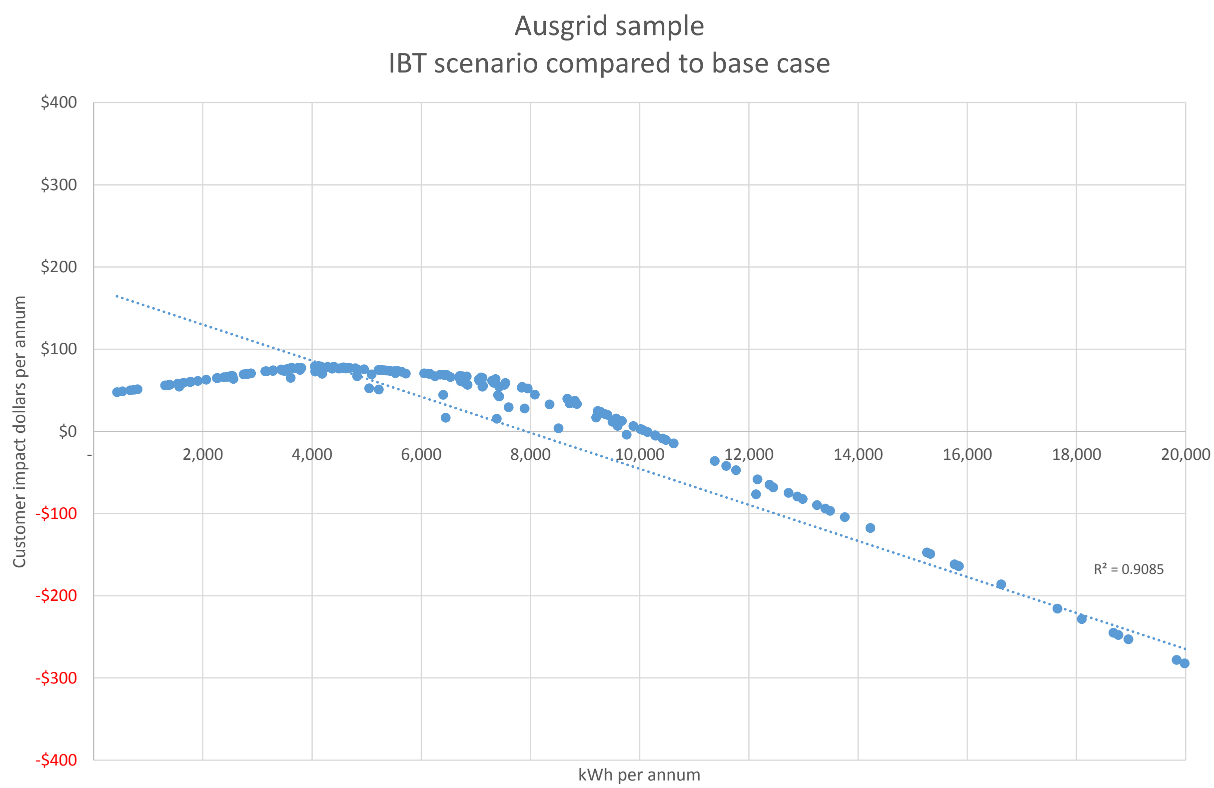
12 APPENDIX - NETWORK PRICES

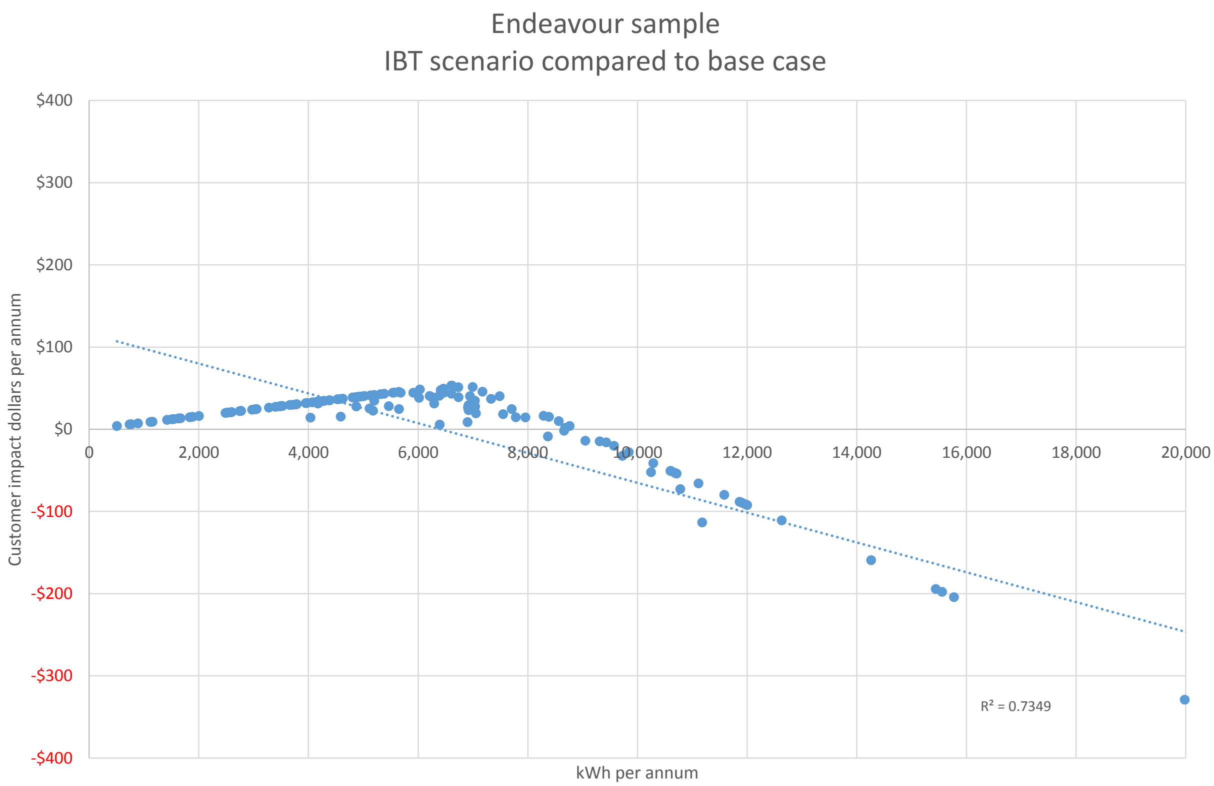
The following table shows the actual network prices that each sample customer received at the time its electricity data was metered. These prices and corresponding volumes were used to calculate the total network revenue in each sample region. This revenue was the amount used in the base case and all scenarios to ensure that revenue neutrality was maintained in the network cost analysis and graphs.

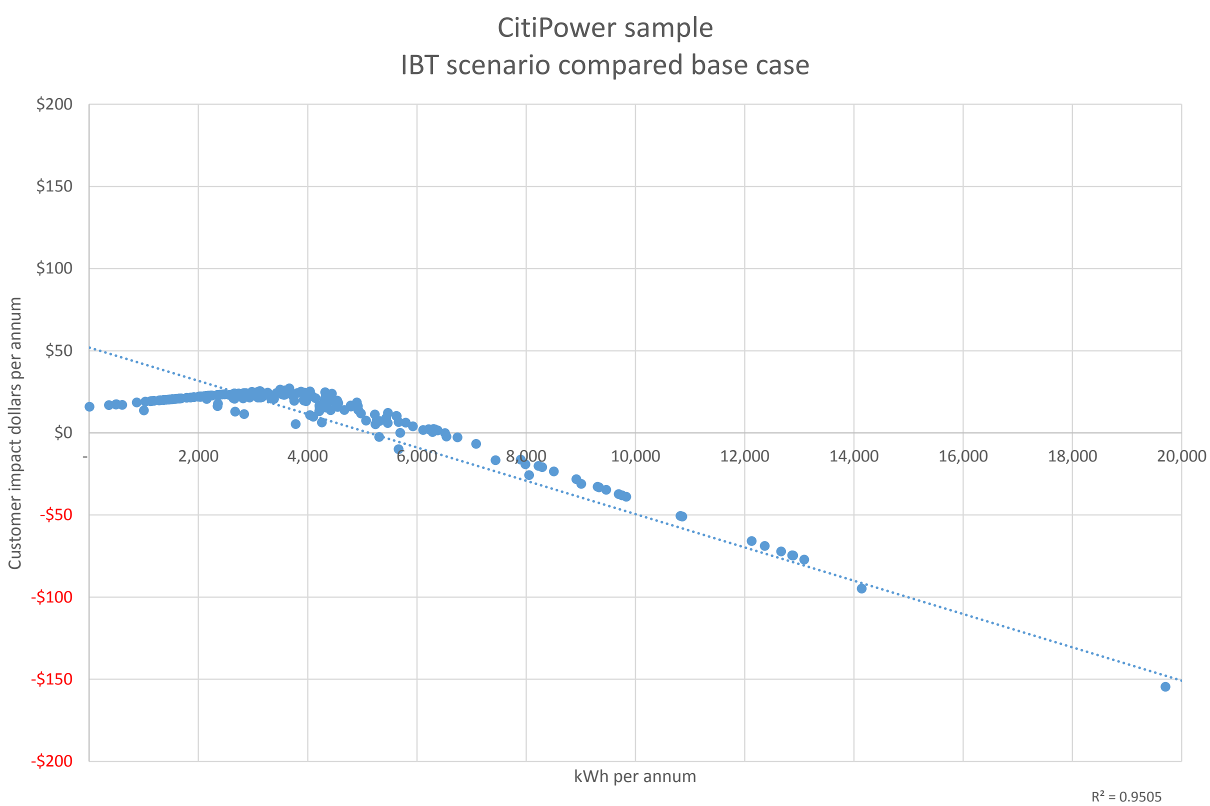
Distributor	Tariff code	Fixed charge	Peak Energy	Shoulder Energy	Off-peak Energy	IBT block 1	IBT block 2	IBT block 3	No. of customers	Total energy	Revenue
		c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh		MWh pa	000 $
Ausgrid	EA025	50.0	25.5	5.0	2.6				200	1,585.2	$169.49
Endeavour	N70	35.0				10.8	14.6		138	884.6	$120.15
CitiPower	C1R	6.2				5.2	6.8		47	203.0	$12.75
CitiPower	C1RB	5.1				4.3	5.4		17	59.8	$3.02
CitiPower	C2R	13.4	9.3		1.6				22	113.1	$6.99
CitiPower	C3R	13.4	9.3		1.6				54	391.3	$25.21
CitiPower	C2RB	12.5	7.3		1.5				20	82.0	$4.28
CitiPower	C3RB	12.5	7.3		1.5				32	134.5	$7.30
Total CitiPower									192	983.7	$59.56
Powercor	D1	10.7				7.5	8.7	9.8	43	236.2	$11.02
Powercor	D2*	13.1	1.9			12.0	13.3	14.0	6	29.4	$2.55
Powercor	D3*	13.1	1.9			12.0	13.3	14.0	107	613.1	$47.53
Total Powercor									156	878.7	$61.10

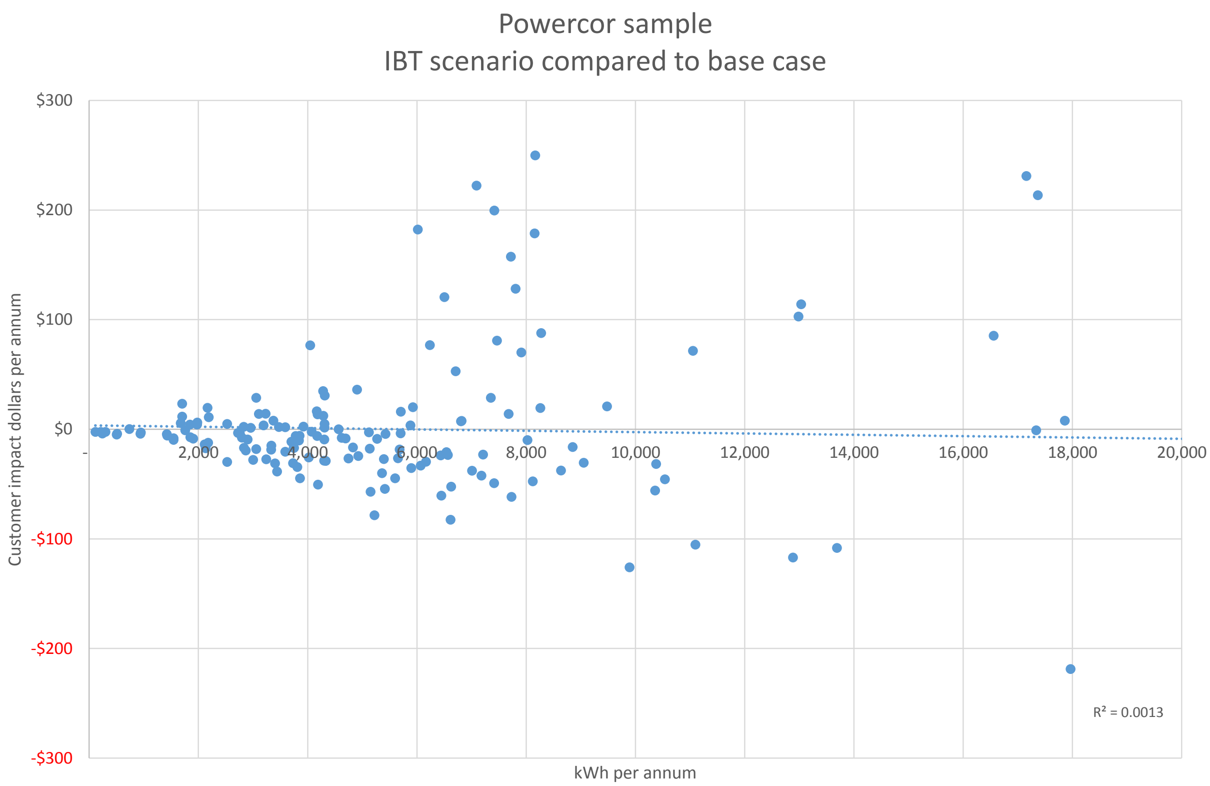
13 APPENDIX - INCLINING BLOCK TARIFF

In response to peer review feedback, an additional scenario was run that compares inclining block structures (IBT) to the base case. This scenario was not included in the main section of this report as inclining block wasn't included as a cost reflective price structure in the POC Final Report. The graphs that compare a constructed IBT to the base case are shown below. As before revenue neutrality relative to the base case was maintained. A positive number indicates that a customer would be better off under this structure. Note that the results in the Powercor graph do not follow the same trend as Ausgrid, Endeavour and CitiPower. This is because the Powercor inclining block only applies during peak times. In off-peak times (11pm to 7am) a flat rate applies. This creates a graph that appears more closely aligned with the results from the TOU scenarios.




Endeavour sample
IBT scenario compared to base case
$400
$300
$200
$100
$0
-$100
-$200
-$300
-$400
Customer impact dollars per annum
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.7349


CitiPower sample
IBT scenario compared base case
$200
$150
$100
$50
$0
-$50
-$100
-$150
-$200
Customer impact dollars per annum
-
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.9505



Powercor sample
IBT scenario compared to base case
$300
$200
$100
$0
-$100
-$200
-$300
Customer impact dollars per annum
-
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
20,000
kWh per annum
R² = 0.0013

14 Appendix - List of Acronyms

AEMC	Australian Energy Market Commission
AEMO	Australia Energy Market Operator
AER	Australian Energy Regulator
IPART	Independent Pricing and Regulatory Tribunal
kWh	kilowatt-hour
MWh	Megawatt-hour
MW	Megawatt
MSATS	Market Settlements and Transfer Solution
NER	National Electricity Rules
NSLP	Net System Load Profile
NECF	National Energy Customer Framework
PSS	Pricing Structures Statement
POC	AEMC Power Of Choice Final Report
SCER	Standing Council on Energy Resources
TNSP	Transmission Network Service Provider
WAPC	Weighted average price cap
WACC	Weighted average cost of capital