Development of New Cost Reflective Tariffs for Standard Asset Customers - Small

Prepared by ENERGEIA for
Ergon Energy

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1 Executive Summary

Ergon Energy's Network Tariff Strategy Review (the Review) aims to identify and implement the most appropriate structures and sustainable network tariff solutions for its customers.

Ergon Energy is currently reviewing its Network Tariff Strategy in light of:

- Rising electricity prices and affordability issues;
- The increasing visibility of Ergon Energy's network tariffs in the regulated retail electricity prices (or Notified Prices); and
- Changes in its operating environment (e.g. advances in technology such as metering, data management and communication).

The purpose of the Review is to document a strategic pathway that considers and, where necessary, delivers reforms to network tariffs in the short, medium and long term, taking into account customer and stakeholder inputs as well as economic, social, technical and logistical considerations.

Scope and Approach

As part of its Review, Energeia was engaged by Ergon Energy to develop a suite of new tariffs for customers who consume less than 100MWh per annum (otherwise known as Standard Asset Customers – Small [SAC-S]) to achieve the following tariff design objectives in support of the Review objectives:

- Increase cost reflectiveness of pricing signals
- Recover all approved revenues for each customer class
- Minimise tariff complexity to facilitate understanding and responsiveness
- Limit customer impacts from proposed tariff structures to within specified constraints

While proposed network tariffs structural changes are focussed toward better cost reflectivity, in order to minimise customer impact, increases due to the structural change have been limited so that customers are affected by no more than 10% compared to 2014-15 tariffs calculated on existing tariff structure. For small consumption customers where the increase will be more than 10% an absolute increase cap of $150 in the case of residential and business customers has been applied. Any increase or decrease due to structural change is assessed independently of increases in overall network charges for 2014-15.

Following a review of Ergon Energy's development process to date, feedback from the public consultation process[1] and a series of workshops with subject matter experts and specialist consultants, Energeia was tasked with developing the following specific tariffs planned for FY15:

- Business and residential Inclining Block
- Business and residential Time-of-Use

A more detailed description of these tariffs and how they differ from the current network tariff these customers have is outlined in the Tariff Implementation Report[2]. This report explains why Time-of-Use (ToU) is the new,

[1] Energeia, *Network Tariff Strategy Review Consultation Report*, October 2013.

[2] Frontier Economics, *Tariff Implementation Report*, October 2013.

more cost reflective tariff structure Ergon Energy is proposing for SAC-S customers over the medium to longer-term.

The transition of SAC-S customers on to an Inclining Block Tariff (IBT) is a supporting strategy to help manage the impact of increasing fixed charges on customers with relatively low levels of consumption. It is also being proposed to provide a mechanism by which to regulate the rate of voluntary selection of cost reflective prices, e.g. ToU.

Energeia's IBT development approach assessed the key IBT design parameters of block number, block sizing and block pricing levels to identify the combination that best achieved the design objectives. Tariffs were optimised for residential and business customer groups to determine if separate tariffs would deliver better outcomes against the design objectives.

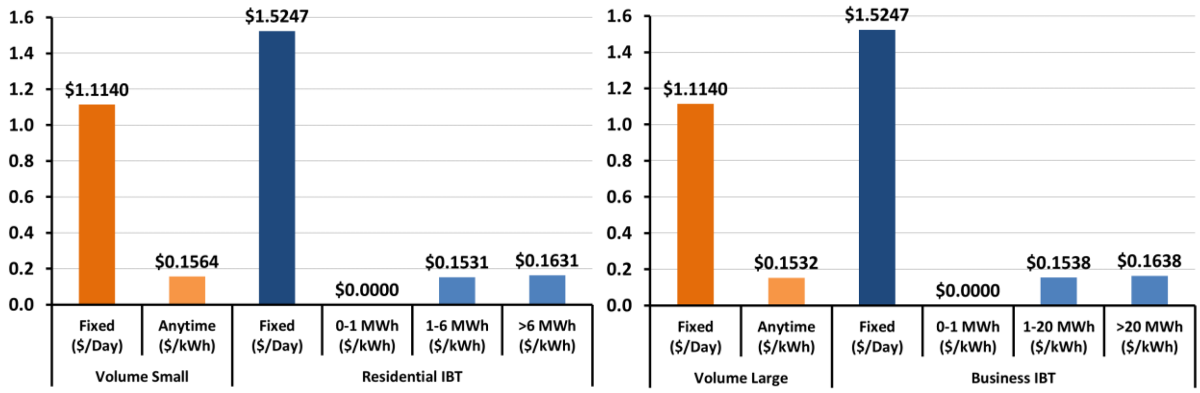
Energeia's ToU development approach assessed the key ToU design parameters of daily or seasonal structure, number of pricing tiers, tier start and end times and tier pricing to identify the combination that best achieved the design objectives. Tariffs were again optimised for residential and business customer groups to determine if separate tariffs would deliver better outcomes against the design objectives.

Proposed New Inclining Block Tariffs for Standard Asset Customers – Small

Energeia's assessment of alternative IBT options identified that a three tiered structure for each customer type delivered the best outcome. The proposed IBTs for SAC-S residential and business customers in FY15 in the East Zone are displayed in Figure 1 against the equivalent tariffs. The IBT's lower first and second block prices are being used to offset its higher daily fixed charge compared to the current equivalent tariff.

The equivalent tariffs shown in orange are the FY15 indicative rates for the SAC-S volume small tariff for residential customers and for the SAC-S volume large tariff for business customers.

Figure 1 – Proposed Inclining Block Tariffs for SAC Small Customers in FY 15 (East Zone)



Source: Ergon Energy, Energeia

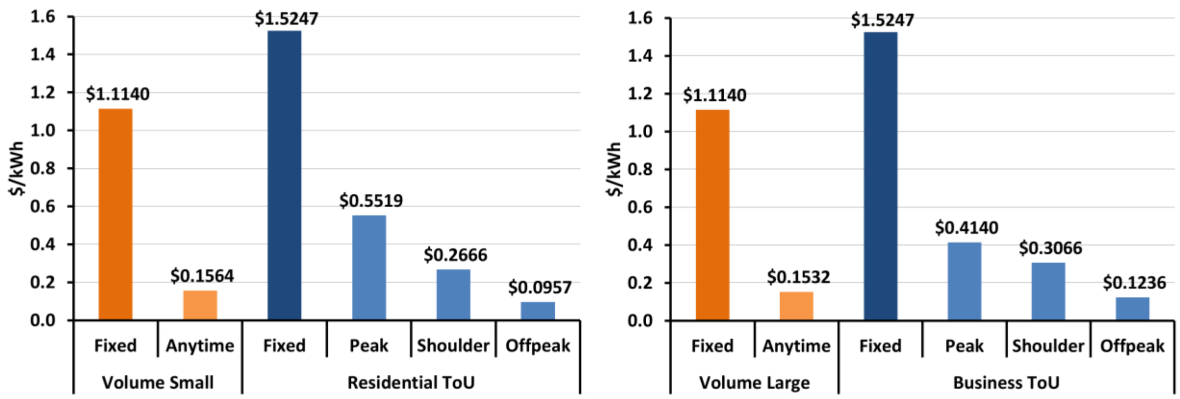
Transitioning customers to an IBT structure enables an increase in the level of revenue recovered through the more cost reflective fixed charge relative to relying exclusively on the anytime tariff. Increasing fixed charges using the current single anytime energy rate structure would result in a much higher impact on smaller customers, with an offsetting reduction for larger customers to achieve revenue neutrality.

Proposed New Voluntary Time-of-Use Tariffs for Standard Asset Customers – Small

Energeia's analysis of Ergon Energy's long-run-marginal-cost (LRMC) drivers in each of their network areas found a strongly seasonal dynamic, with the summer weekday peak loads across their zone substations 17% and 15% higher than comparable hours in winter or shoulder seasons for residential and business substations, respectively. The use of a three tier structure enabled a tariff that increases the cost reflectivity of around 80% of Ergon Energy's zone substations.

Again, the equivalent tariffs shown in orange are the FY15 indicative rates for the SAC-S volume small tariff for residential customers and for the SAC-S volume large tariff for business customers.

Figure 2 – Proposed Time-of-Use Tariffs for SAC Small Customers in FY 15 (East Zone)



Source: Energeia

Energeia's assessment of alternative ToU options concluded that a seasonal, three tiered structure for each customer type delivered the best outcome. The proposed ToU tariffs for SAC-S residential and business customers in FY15 in the East Zone are displayed in Figure 2 against the equivalent indicative anytime rates.

Figure 3 – Proposed Time-of-Use Periods for SAC Small Customers in FY 15 (East Zone)

Residential Customers			
Period	**Times**	**% Hours**	**% Consumption**
Peak	4:30pm to 9:00pm on Summer Weekdays	3.3%	4.6%
Shoulder	3:00-4:30pm and 9:00-9:30pm on Summer Weekdays and 3:00-9:30pm on Summer Weekends	3.4%	4.4%
Offpeak	All other times	93.2%	91.0%
Business Customers			
Period	**Times**	**% Hours**	**% Consumption**
Peak	11:30am to 5:30pm on Summer Weekdays	4.5%	6.3%
Shoulder	10:00-11:30am and 5.30-8:00pm on Summer Weekdays	3.0%	3.9%
Offpeak	All other times	92.6%	89.8%

Source: Energeia

Figure 3 presents the proposed time periods for residential and business ToU tariffs in Ergon Energy's East region. The peak period in both cases is limited to summer weekdays. The business tariff runs from 11:30am to 5:30pm, while the residential tariff starts later at around 4:30pm and runs until 9:00pm The shoulder period for businesses occurs only on summer weekdays, while the residential tariff also includes summer weekends.

Seasonal definitions have been aligned to those specified by the Australian bureau of metrology. For example, summer encompasses the months of December, January and February, winter includes June, July and August, and the remaining months are in the 'shoulder' seasons of autumn and spring.

Conclusions and Recommendations

Analysis undertaken as part of the Review has found the LRMC to Ergon Energy of meeting growth in peak demand is 170%-260% higher than the anytime energy rate currently being charged to small customers. This analysis also indicates that current rates over-signal the cost of off-peak consumption.

Current tariffs, if incorporated into retail tariffs, would potentially contribute to inefficient and cross-subsidised rates of growth in network peak demand. Tariff reform is an enabler of optimal investment by Ergon Energy in network infrastructure and optimal value from network access by end-users.

Based on our analysis of the information available to us and the network tariff design objectives, Energeia recommends transitioning to the proposed network tariffs as representing the best option for Ergon Energy to achieve the tariff design objectives, and in particular cost reflectivity.

Our detailed analysis of Ergon Energy's zone substation augmentation investment cost driver (peak demand) has demonstrated that a seasonal, three tier time of use tariff structure provides substantially greater cost reflectivity than a two-tier, daily structure in terms of:

- the number of zone substations that would see higher, more cost reflective peak or shoulder charges compared to the current anytime rate, and
- the alignment of incentives to reduce or shift peak demand with Ergon Energy's LRMC.

While this outcome varies from the approach proposed in Ergon Energy's initial tariff consultation, it is based on a significant amount of detailed analysis that had not been completed at that time.

Additionally, the recommended tariffs:

- Reflect our detailed consideration of the key uncertainties and trade-offs inherent in progressing the first step of any significant tariff transition initiative
- Are consistent with the Tariff Implementation Plan and provide a mechanism for regulating the voluntary transfer of small customers to more cost reflective tariffs
- Are consistent with current national reforms aimed at making retail and network prices more cost reflective and providing greater customer choice
- Are fundamental to addressing the inefficiencies and cross subsidies in the current network structures that contribute to sub-optimal outcomes for Ergon Energy and its customers.

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2 Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information and guidance from Ergon Energy and publically available information. To the extent these reliances have been made, Energeia does not guarantee nor warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party should use or rely on the report for any purpose.

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3 Background

Rising peak demand and asset renewal has led to substantial increases in network tariffs over the past few years across Australia:

- Peak demand has increased expenditure on capacity augmentation
- Asset renewal has increased expenditure on asset replacement

The role of network and retail pricing in keeping industry costs as efficient as possible and fairly allocating industry costs on a user pays basis is increasingly the focus of national energy reform efforts.

The Australian Energy Market Commission (AEMC) recently completed its Power of Choice review[3], which made a number of recommendations for reforming network tariffs. These recommendations have largely been endorsed[4] by the Standing Council on Energy and Resources (SCER) and are reflected in their associated rule change.[5]

Proposed national tariff reforms largely revolve around the establishment of more cost reflective price signals. This is because the rate of growth in peak demand and how customers use the network are both driven to some degree by customer responses to the current pricing arrangements, for example:

- With the current pricing of network services during the 5% of peak demand hours set well below its cost to supply, end users are likely to over consume it relative to alternatives, which may be lower cost or offer more value.
- With the pricing of network services set well above its cost to supply for circa 90% of hours outside of peak and shoulder demand, end users may be over investing in reducing off-peak energy consumption to lower their bills.

Ergon Energy's Network Tariff Strategy Review (the Review) aims to identify and implement the most appropriate structures and sustainable network tariff solutions for its customers. Ergon Energy is currently reviewing its Network Tariff Strategy in light of:

- Rising electricity prices and affordability issues
- The increasing visibility of Ergon Energy's network tariffs in the regulated retail electricity prices (or Notified Prices); and
- Changes to its operating environment (e.g. advances in technology such as metering, data management and communication).

The purpose of the Review is to document a strategic pathway that considers and, where necessary, delivers reforms to network pricing in the short, medium and long term, taking into account customer and stakeholder inputs as well as economic, social, technical and logistical considerations.

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[3] AEMC, *Final Report, Power of Choice Review*, November 2012.

[4] SCER, *SCER Response to the Power of Choice Review*, March 2013.

[5] SCER, *Power of Choice – Distribution Pricing Principles – Proposed rule*, 13 September 2013.

4 Scope and Approach

As part of its Review, Energeia was engaged by Ergon Energy to develop a suite of new tariffs for customers who consume less than 100MWh per annum (otherwise known as Standard Asset Customers – Small [SAC-S]) to achieve the following tariff design objectives in support of the Review objectives:

- Increase cost reflectiveness of pricing signals
- Recover all approved revenues for each customer class
- Minimise tariff complexity to facilitate understanding and responsiveness
- Limit customer impacts from proposed tariff structures to within specified constraints

While proposed network tariffs structural changes are focussed toward better cost reflectivity, in order to minimise customer impact, increases due to the structural change have been limited so that customers are affected by no more than 10% compared to 2014-15 tariffs calculated on existing tariff structure. For small consumption customers where the increase will be more than 10% an absolute increase cap of $150 in the case of residential and business customers has been applied. Any increase or decrease due to structural change is assessed independently of increases in overall network charges for 2014-15.

Following a review of Ergon Energy's development process to date, feedback from the public consultation process[6] and a series of workshops with subject matter experts and specialist consultants, Energeia was tasked with developing the following specific tariffs planned for FY15:

- Business and residential Inclining Block
- Business and residential Time-of-Use

A more detailed description of these tariffs and how they differ from the current network tariff these customers have is outlined in the Tariff Implementation Report[7]. This report explains why Time-of-Use (ToU) is the new, more cost reflective tariff structure Ergon Energy is proposing for SAC-S customers over the medium to longer-term.

The transition of SAC-S customers on to an Inclining Block Tariff (IBT) is a supporting strategy to help manage the impact of increasing fixed charges on customers with relatively low levels of consumption. It is also being proposed to provide a mechanism by which to regulate the rate of voluntary selection of cost reflective prices, e.g. ToU.

4.1 *Inclining Block Tariffs*

Energeia's IBT development approach assessed the key IBT design parameters of block number, block sizing and block pricing levels to identify the combination that best achieved the design objectives. Tariffs were optimised for residential and business customer groups and assessed to determine if separate tariffs would deliver better outcomes against the design objectives.

[6] Energeia, *Network Tariff Strategy Review Consultation Report*, October 2013.

[7] Frontier Economics, *Tariff Implementation Report*, October 2013.

4.1.1 Design Objectives

The primary IBT design objectives for SAC-Small customers under Ergon's Network Pricing Strategy initiative are to:

1. Increase the cost reflectivity of tariffs
2. Limit customer impacts from increased fixed charges to within specified constraints
3. Provide a future lever to limit the rate of voluntary selection of cost reflective prices, e.g. Time-of-Use
4. Recover all approved revenues for the SAC-Small customer class
5. Minimise tariff complexity to facilitate understanding and responsiveness

In achieving these objectives, a constraint was placed by Ergon Energy on the maximum allowable annual bill impact experienced by residential and business customers due to the structural of no more than 10% compared to 2014-15 tariffs calculated on the existing tariff structure. For small consumption customers where the increase will be more than 10% an absolute increase cap of $150 in the case of residential and business customers has been applied. Any increase or decrease due to structural change is independent of increases in overall network charges for 2014-15.

Increasing cost reflectiveness of pricing signals requires aligning end user prices to shared network cost drivers. Shared network costs are largely fixed, with the exception of augmentation capex, which is driven by increases in peak demand. IBT tariffs do not allow for pricing by Time-of-Use, so their contribution towards increasing cost reflectivity is through increasing the proportion of fixed charges in the short term, and providing a mechanism to regulate the voluntary adoption of ToU in the medium term.

IBTs enable the move towards higher fixed charges by mitigating their effect across customers of varying levels of consumption. Regulation of the bill impact of higher fixed charges is achieved by reducing the relative price of the first block to manage the impact of fixed charges on the total bill, and by increasing the relative price of the highest block whilst maintaining revenue neutrality.

Recovering all revenue requires that new tariffs achieve the same level of cost recovery as the existing tariff, i.e. the new tariff must be revenue neutral. Revenue neutrality is measured prior to any estimate of changes in consumption behaviour due to changes in pricing from current SAC-S tariffs and the price elasticity of demand.

Minimising tariff complexity means minimising the number of tariff variants and block rates wherever possible to improve customers' understanding and ability to respond to the pricing signals.

4.1.2 Development Approach

Energeia's approach to developing IBT tariffs for SAC-Small customers that best met the design objectives was to undertake the following analytical and optimisation steps:

1. Collect, assess and correct input data
2. Analyse block number and threshold combinations
3. Select and align tariff parameters to maximise objectives

The outcomes of Energeia's IBT development activities are reported in Section 5.

4.2 Time-of-Use Tariffs

Energeia's ToU development approach assessed the key ToU design parameters of daily or seasonal structure, number of pricing tiers, tier start and end times and tier pricing to identify the combination that best achieved the design objectives. Tariffs were again optimised for residential and business customer groups and assessed to determine if separate tariffs would deliver better outcomes against the design objectives.

4.2.1 Development Objectives

The primary ToU tariff design objectives for SAC-small customers under Ergon Energy's Network Pricing Strategy initiative are to:

1. Increase cost reflectiveness of pricing signals
2. Recover all approved revenues for each customer class
3. Minimise tariff complexity to facilitate understanding and responsiveness

Increasing cost reflectiveness of pricing signals requires aligning end user prices to the shared network cost structure and drivers. Network costs are largely fixed, with the exception of augmentation capex, which is driven by increases in peak demand. Peak demand has been defined for tariff design purposes to be at the Zone Substation (ZS) level.

Demand outside of peak periods can for the most part be met at low marginal cost. However, the closer a period's demand is to the peak level, the more likely it could set the peak in the future due to load growth and volatility. Shoulder periods therefore need to signal the risk that demand in that period could drive increases in peak demand. They can also be used to signal higher costs for less common peak periods.

Recovering all revenue requires that new tariffs achieve the same level of cost recovery as the existing tariff, i.e. the new tariff must be revenue neutral. Revenue neutrality is measured prior to any estimate of changes in consumption patterns due to changes in pricing from current SAC-S tariffs and the price elasticity of demand.

Minimising tariff complexity means minimising the number of measured quantities (e.g. kVA, kWh, kW), time periods, and start and end times wherever possible to improve customers' ability to understand and respond to the pricing signals. Greater simplicity may reduce cost reflectivity, so an appropriate balancing of objectives is required.

4.2.2 Development Approach

Energeia's approach to developing Time-of-Use tariffs for SAC customers that best met the design objectives was to undertake the following analytical and optimisation steps:

1. Collect, assess and correct input data
2. Analyse zone substation augmentation cost drivers
3. Select and align tariff parameters to maximise objectives

The following key interval and descriptive data was gathered from Ergon Energy's metering and billing systems:

1. 3 years of ZS data including interval, primary load type and location classification
2. 1 year of customer interval where available
3. 5 years of weather data

The collected data was then subjected to the following data quality checks, filters and corrections that resulted in an appropriate dataset for analysing ZS cost drivers and to optimise the tariff design:

1. Correct data to remove customer and ZS records that are incomplete
2. Correct data to remove systematic biases, such as a bias in sampled customers
3. Normalise data to consider the effects of statistical variation

The outcomes of Energeia's ToU development activities are reported in Section 6.

5 Inclining Block Tariffs

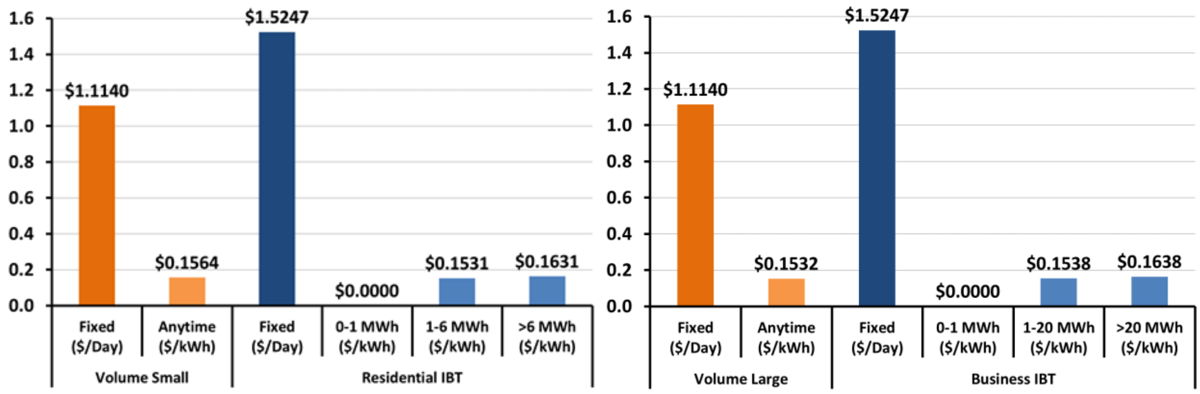
5.1 Proposed Blocks and Prices

An optimisation model was developed that allowed pricing and volume bands for up to five blocks to be assessed. The distribution of business and residential customers by annual consumption were input into this model, and a range of block numbers of varying consumption bandwidths were assessed for their ability to achieve the design objectives.

A three tier structure was found to be sufficient in both cases, achieving the same increase in fixed charges as five tier options. The three tier approach was therefore adopted in the interests of simplicity.

Figure 4 presents the proposed optimised IBT structures for residential and business customers. The IBT's lower block prices offset its higher daily fixed charge compared to the current equivalent tariffs.

Figure 4 – Comparison of Anytime and IBT Structure by Customer Type (East Zone)



Source: Ergon Energy, Energeia

For both residential and business customers, the key design constraint was the $150 maximum annual bill impact. The need for different IBTs for residential and business customers is evidenced by the significant variation in the optimised pricing of the respective blocks.

5.2 Key Risks and Issues

The relatively simple structure of IBT tariffs means that the risk of a sub-optimal tariff design is limited.

Ergon Energy provided a distribution of residential and business customers by consumption block, which was used to test the impact of various IBT configurations against the design objectives. Limitations in the data mean that the business customer IBT does not have the same level of granularity as the residential IBT. This could impact on the precision of the IBT structure, particularly around the breakpoint for the first block.

There is also the potential for impacts to be marginally higher or lower than modelled, particularly for business customers, due to the course grained nature of business customer consumption bands.

6 Time-of-Use Tariffs

6.1 Characterising Network Cost Drivers

The zone substation (ZS) cost driver analysis methodology should reflect the cost structure of meeting incremental load growth. This could be a simple average if the variable costs of shared network capacity augmentation are the most important factor, or normalised if project fixed costs are dominant.

Energeia adopted a simple averaging of ZS loads as the fixed costs associated with project and site establishment were understood to be less significant than project variable costs, and the correlation of areas with relatively large loads to augment capacity using relatively larger zone substations.

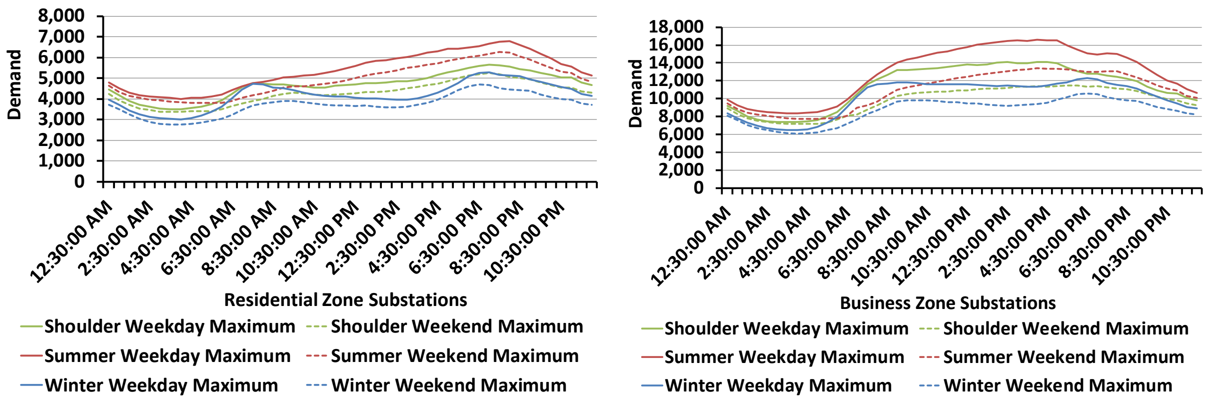
Zone substation loads already reflect diversity, so the annual half-hourly maximums were first calculated for each individual zone substation and then averaged across all zone substations in the group to generate the average maximum half-hourly load.

Zone substations were grouped into mainly residential (MPR) and mainly business (MCI) segment datasets to develop the following six representative maximum and average daily 30 minute load profiles:

1. Summer Season, Weekday
2. Summer Season, Weekend
3. Winter Season, Weekday
4. Winter Season, Weekend
5. Shoulder Season, Weekday
6. Shoulder Season, Weekend

The results of our peak demand profile development are shown in Figure 5. This approach to characterising peak demand reveals the zone wide timing and structure of annual peak demand. The relativities of seasonal and day type load profiles and the differences between mainly business or residential substations can also be seen. For example, the peak demand of mainly residential ZSs in the East Zone occurs around 8pm, while mainly business ZSs peak demand occurs around 5pm.

Figure 5 – Maximum 30-Minute Demand by Season, Day and Customer Type (East Zone)



Source: Ergon Energy, Energeia

Residential ZS load segmentation highlights the significantly higher summer weekday and weekend periods compared to alternative seasons and day types. By separating out the summer period from the other periods, it enables a much more cost reflective seasonal ToU structure to be defined. Adopting a daily ToU structure would not reflect the strongly seasonal pattern. Instead it would flatten and extend the peak period, which would reduce the level of prices and demand response during the summer peak period.

Business ZS load segmentation shows a different overall profile of consumption, with a flatter peak period and a greater demand reduction due to day-type. The summer weekend profile is significantly lower than the weekday profile, and lower than the shoulder season weekday profile. This analysis again supports the use of a seasonal weekday peak ToU structure to better target seasonality in peak demand.

The importance of accurately characterising and pricing the peak demand period can be illustrated by the impact of using a daily ToU structure on a summer season peaking system. Assuming the peak period (e.g. hours) and the day type (e.g. weekdays) were the same for each season, a load contributing to the seasonal peak in summer would only be charged 25% of the seasonal ToU price under a daily ToU structure, significantly under-signalling its cost to serve.

Peak demand can move to different hours of the day, day types and seasons, depending on the load profile and in particular how close other 30 minute periods are to the global peak period. Natural variation in load due to weather and other random variations are a key driver of the peak demand period in a given year. Over time, systematic factors such as pricing differentials can impact on the relative growth rates between periods, and drive new global peaks.

6.2 Proposed Time-of-Use Periods

Analysis of the set of load profiles was undertaken to identify the set of periods that best reflect the network peak demand period, once random and systematic factors are taken into account. Prices were then determined for each period based on LRMC for the peak period, the effects of long-term price elasticity for the shoulder period, and cost recovery for the off-peak period. This analysis delivered:

- The set of periods that best reflected peak and shoulder demand across Ergon Energy's zone substations
- The peak and shoulder prices which recovered incremental network augmentation costs to serve incremental peak and shoulder loads
- The off-peak price that recovered the remainder of targeted revenue to ensure revenue neutrality following the increase of the fixed charge within the customer impact limit
- Reasonable adjustments to period definitions that resulted in a simplified tariff for customers and other market participants.

As the setting of the peak, shoulder and off-peak periods impacted the level of prices, it was necessary to undertake the analysis on an iterative basis. Initial period definitions and associated pricing levels were set and then refined, based on their achievement of the objectives. For example, widening the peak and shoulder periods reduces the risk of 'missing' a ZS peak, but this was constrained by the need to ensure peak prices only recovered the cost of incremental capacity and were higher than shoulder prices, which were in turn higher than off-peak prices.

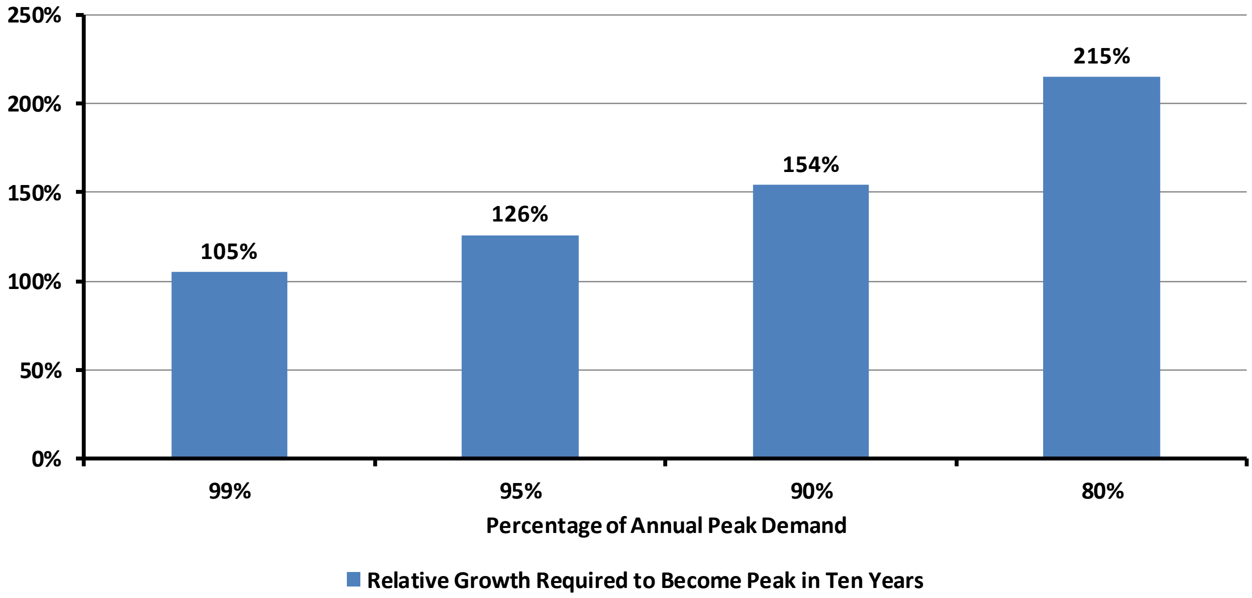
Each of the maximum hourly loads for each of the load profiles was divided by the highest maximum hour across all of the profiles in that segment (the global peak) to assess its likelihood of becoming a future global peak due to systematic factors such as price response (analysed and described further below) and to provide a ranking methodology for classifying the hour between the peak, shoulder and off-peak periods.

As with setting the seasonal peak period, it is important to correctly set the hourly peak period to avoid over or under signalling the cost of peak demand. Including hours that are unlikely to drive peak demand reduces the price per kWh and thereby the economic signal to loads operating in the period of peak demand. Conversely, not including peak load in the peak period encourages it to grow through lower shoulder prices.

Setting the threshold between peak and shoulder therefore requires balancing the risk of under and over signalling.

Energeia used a particular hours' annual maximum demand relative to the global peak hour to provide a measure of its relative likelihood of driving future augmentation capex by creating a new global peak demand. As illustrated in Figure 6, if a period is 5% lower than the peak (i.e. 95% of peak), it would have to grow at 126% of the peak period rate of growth over a 10 year period to become the new global peak period and likely driver of future augmentation expenditure. This highlights the importance of the pricing differential in determining the threshold value.

Figure 6 – Rate of Relative 10 Year Growth Required for a Given Period to Become the Peak Period



Source: Ergon Energy, Energeia

Threshold values, e.g. greater than 95% of annual peak, were set in order to categorise those half hourly periods that were most likely to contribute to peak demand growth as peak, and those less likely to but still at risk of contributing to peak demand growth were categorised as shoulder, e.g. greater than 90% of annual peak. Using a higher threshold for peak, e.g. 98%, would have reduced the number of peak hours but increased the risk of missing individual ZS peaks and the risk of price response driving a new global peak.

Iterative analysis showed 95% and 90% for shoulder and off-peak period thresholds provided the best balance of pricing relativities, cost reflectiveness and zone-wide peak period alignment. The resulting peak, shoulder and off-peak period definitions are given in Figure 7. They represent as simple a structure as possible, balancing overall cost reflectiveness with ease of understanding.

For residential and business customers in the East Zone, the peak period occurs only during summer weekdays, and each lasts about five hours. The shoulder period for business is limited to summer weekdays, while the residential structure also includes summer weekends.

Seasonal definitions have been aligned to those specified by the Australian bureau of metrology. For example, summer encompasses the months of December, January and February, winter includes June, July and August, and the remaining months are in the 'shoulder' seasons of autumn and spring.

Figure 7 – ToU Periods for Residential and Business Customers (East Zone)

Residential Customers			
Period	**Times**	**% Hours**	**% Consumption**
Peak	4:30pm to 9:00pm on Summer Weekdays	3.3%	4.6%
Shoulder	3:00-4:30pm and 9:00-9:30pm on Summer Weekdays and 3:00-9:30pm on Summer Weekends	3.4%	4.4%
Offpeak	All other times	93.2%	91.0%
Business Customers			
Period	**Times**	**% Hours**	**% Consumption**
Peak	11:30am to 5:30pm on Summer Weekdays	4.5%	6.3%
Shoulder	10:00-11:30am and 5.30-8:00pm on Summer Weekdays	3.0%	3.9%
Offpeak	All other times	92.6%	89.8%

Source: Energeia

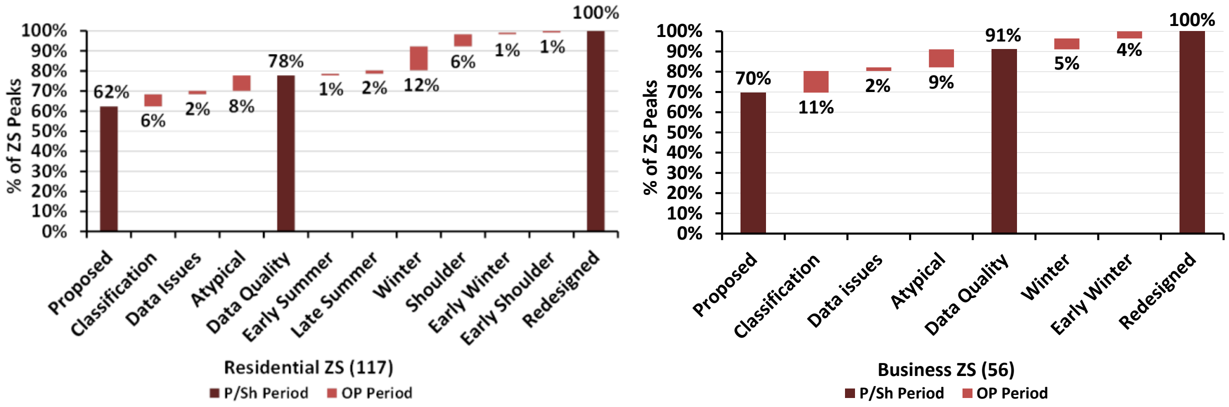
The resulting definition of off-peak periods were then compared to the actual distribution of peak periods of the underlying set of residential ZS to assess the systemic risk of off-peak prices resulting in undesirable increases in peak demand growth. As peak and shoulder prices are higher than the current anytime price, the key risk is in the off-peak. Figure 8 presents the results of the analysis, which produced a distribution of ZS peaks by type relative to the proposed peak, shoulder and off-peak periods.

Figure 8 – Distribution of ZS Peaks across ToU Period Definitions by ZS Type (East Zone)

Source: Ergon Energy, Energeia

The initial finding of around 30-40% of zone substation peaks falling outside of the peak and shoulder period was investigated to determine whether the time periods should be changed to better address zone substation diversity. The results of the analysis are presented in Figure 9, which shows that about half of the variation and around 20% of total zone substation variation might be addressed by changing the definition of the off-peak period. The rest of the variation appears due to data quality issues including incorrect classification and incorrect peaks in the data.

Figure 9 – Drivers of Variation in Zone Substation Loads (East Zone)



Source: Ergon Energy, Energeia

Energeia's analysis of the drivers of variation among residential ZSs in the East Zone found that the winter peak was the main factor, accounting for 12% of ZS in the group. However, adding a winter shoulder would reduce the shoulder pricing signal by around 50% for the remaining 80% of zone substation loads, so this change was not pursued. As the other drivers represented a lower percentage of the total population, changes to the structure were less likely to be appropriate. A similar analysis of the commercial structure resulted in a similar conclusion to not modify the proposed tariff design.

Managing the impact of the proposed ToU tariffs on the winter peaking portion of Ergon Energy's network would therefore be best addressed through a different ToU pricing structure.

6.3 Proposed Time-of-Use Prices

Ergon Energy has set the avoidable cost of incremental shared network capacity at $162/kVA/year in the East Zone based on previous modelling results.

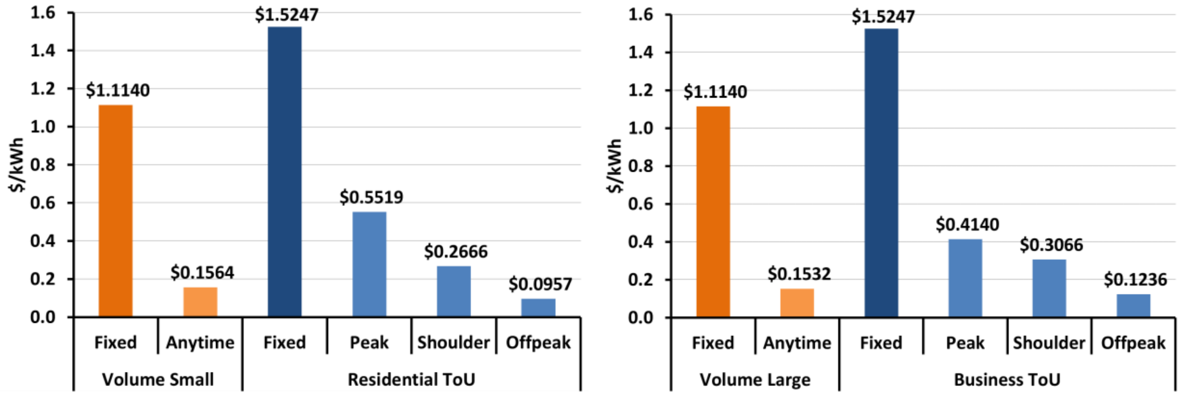
Depending on the assumed price elasticity and price relativities, pricing could have a significant impact on the relative rates of growth between the peak and shoulder periods. Peak and shoulder prices are higher than anytime prices, so economic theory tells us that they should drive a reduction in relative demand, but at different rates proportional to their relative increase. Price responsiveness is therefore an important consideration when determining the optimal pricing differential between peak and shoulder pricing periods.

The effect of proposed peak and shoulder prices on long run consumption patterns, and in particular the relativities of peak and shoulder period consumption, was assessed to ensure they would be unlikely to systematically create a new peak over a ten year period. Assuming a 95% of peak period threshold for the shoulder period, current anytime rates, an LRMC of $162/kVA/year and long-run price elasticity of demand of -0.18, shoulder LRMCs of $155/kVA/year and $146/kVA/year were estimated for residential and business customers in the East Zone, respectively.

Due to the asymmetric risk of lower prices driving an increase in peak demand, the shoulder LRMC was allowed to move upwards but not downwards to better achieve other pricing objectives – mainly to ensure that the price per kWh was kept between peak and off-peak periods.

The peak and shoulder period prices are translated from $/kVA/year to $/kWh by dividing it by the number of hours 1 kVA would accrue across each period. The off-peak rate is calculated as the price needed to recover the remaining revenue net of the increase in the fixed price. Figure 10 presents the results of the pricing analysis for the residential ToU price, and shows the correct relationships have been achieved for each component relative to cost drivers.

Figure 10 – ToU Pricing by Period and Customer Type (East Zone)



Source: Energeia

It is generally accepted that peak prices should be higher than shoulder prices, which should in turn be higher than off-peaks. Although this may be true on a $/kVA/year basis, the length of the period can lead to unintuitive outcomes on a $/kWh basis. Thresholds were adjusted where necessary to manage this relationship. The thresholds were also adjusted to ensure that the shoulder and peak prices were higher than the anytime price.

The final step in the process was to review the resulting tariff structures to see if there was any opportunity to simplify them to improve customer understanding and responsiveness. For example modifying the period start or end time to align periods across season or day types, and therefore make the resulting ToU structure more uniform.

6.4 Key Risks and Issues

Limitations in the availability of robust data on substation and customer populations, and the limited time available to produce the initial structures increase the risk that the draft tariff structures are sub-optimal. The following actions have been identified to address this risk:

1. Including additional years to the analytical frame
2. Analysis of billing records to validate the zone substation classifications

Due to the limited availability of customer load data, the initial analysis was undertaken for the 2012 period only. Now that the ZS dataset has been selected as the most appropriate basis for the design, the additional years of data should be taken into consideration to improve the accuracy of the weather and statistical normalisation process.

There is a high level of reliance on Ergon Energy's ZS categorisation. It would be prudent to validate the categorisation using billing data, which is provided in quarterly read records for most customers.

7 Conclusions and Recommendations

Analysis undertaken as part of the Review has found the LRMC to Ergon Energy of meeting growth in peak demand is 170%-260% higher than the anytime energy rate currently being charged to small customers. This analysis also indicates that current rates over-signal the cost of off-peak consumption.

Current tariffs, if incorporated into retail tariffs, would potentially contribute to inefficient and cross-subsidised rates of growth in network peak demand. Tariff reform is an enabler of optimal investment by Ergon Energy in network infrastructure and optimal value from network access by end-users.

Based on our analysis of the information available to us and the network tariff design objectives, Energeia recommends transitioning to the proposed network tariffs as representing the best option for Ergon Energy to achieve the tariff design objectives, and in particular cost reflectivity.

Our detailed analysis of Ergon Energy's zone substation augmentation investment cost driver (peak demand) has demonstrated that a seasonal, three tier time of use tariff structure provides substantially greater cost reflectivity than a two-tier, daily structure in terms of:

- the number of zone substations that would see higher, more cost reflective peak or shoulder charges compared to the current anytime rate, and
- the alignment of incentives to reduce or shift peak demand with Ergon Energy's LRMC.

While this outcome varies from the approach proposed in Ergon Energy's initial tariff consultation, it is based on a significant amount of detailed analysis that had not been completed at that time.

Additionally, the recommended tariffs:

- Reflect our detailed consideration of the key uncertainties and trade-offs inherent in progressing the first step of any significant tariff transition initiative
- Are consistent with the Tariff Implementation Plan and provide a mechanism for regulating the voluntary transfer of small customers to more cost reflective tariffs
- Are consistent with current national reforms aimed at making retail and network prices more cost reflective and providing greater customer choice
- Are fundamental to addressing the inefficiencies and cross subsidies in the current network structures that contribute to sub-optimal outcomes for Ergon Energy and its customers.