APVI Submission to the AER's Issues Paper: ***Tariff Structure Statement Proposals, Queensland electricity DNSPs***

March 2016

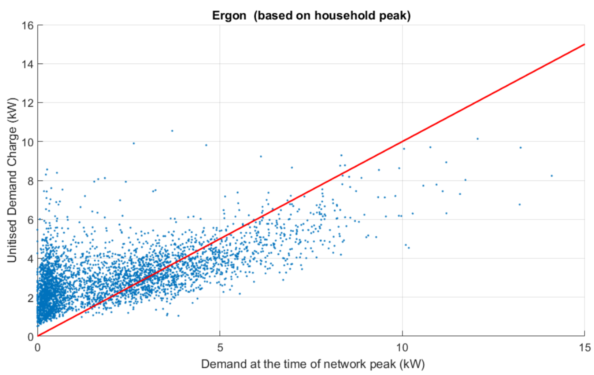
3 May 2016

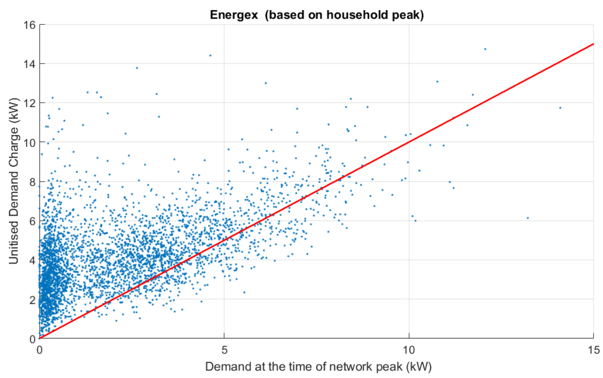
Summary of APVI Response

The **first section** of this submission assesses Ergon's Seasonal TOU Demand Residential East tariff and Energex's Residential Demand Tariff in terms of their cost-reflectivity, then discusses some consequences of their designs, and modifies those designs to improve their cost-reflectivity.

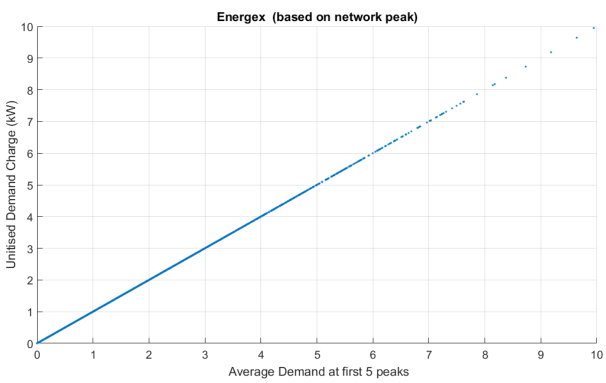
The key points are:

- Both tariffs result in a low correlation between the customers' payments and the costs they impose on the network. See figures below.





- Thus, households are likely to be charged for network augmentation at times when their demand is not affecting the cost of augmentation.
- Households are also being incentivised to reduce demand at the wrong times and hence have limited impact on reducing network expenditure.
- This results in a dead weight loss where, according to the data used here, a reduction of 1kW in the network annual peak requires a net annual reduction of about 220kW (Ergon) and 250kW (Energex) by the average customer, and a 'loss' of about 380kWh and 360kWh respectively.
- Applying the demand charge to the customers' demand at the time of the network monthly peaks only during summer and winter results in a much better correlation between the customers' payments and the costs they impose on the network – especially when applied to the top 5 network peaks and with any fixed and kWh charges separated out. See figure below.



- From the customer's point of view this tariff would look very similar to Ergon's and Energex's current demand tariffs but would apply only over the summer and winter months.

The **second section** of this submission addresses the AER Issues Paper's questions. In summary:

AER Question: (1): Until Ergon and Energex have developed tariffs that are more cost-reflective and so more fairly reflect the costs that customers impose on the network, their demand tariffs should definitely be on an opt in basis. Given that demand tariffs are designed to send a strong price signal to customers regarding their contribution to network costs, it makes sense to target customers based on their likely contribution to those costs. Thresholds such as SAPN's proposed 20MWh/annum, alterations such as new major appliances > 25amps and changes to three phase 44 power may well justify moving the customer to a demand tariff. However, a new inverter approval is most likely associated with a solar PV system and/or a battery system, which will, if anything, probably reduce a customer's peak, so it makes no sense to target them with a demand tariff.

AER Question: (3): The charging windows should be based on the anticipated constraints of the section of the network that serves those customers. However, this has to be balanced against the need for simplicity in designing tariffs.

AER Question: (4): Their tariff statements do sufficiently inform stakeholders on the times, days and months when the network is likely to be under most stress. However, as discussed above, they do not then justify the timing of the charging windows.

AER Question: (5): Combining the fixed and demand charge components means that large customers, either (i) never pay the fixed charge or (ii) the demand charge is less proportional to their demand peaks than it is for smaller customers. Thus, our position is that they should be kept separate.

AER Question: (6): Our work indicates that it is preferable to apply the demand charge over an average demand longer than the normal 30 minute period. The averaging period should extend prior to the network demand peak to help reduce transformer heating, not simply be an average of either side. Ergon's use of the average of the four highest demand days will help to reduce bill shock and, as discussed above, does not make the tariff more cost-reflective.

AER Question: (7): As discussed, this is a complicated issue and depends on Ergon's and Energex's load profiles. If they have a summer then winter peaking network then it is likely that a demand tariff applied all year is not necessary and will be inefficient.

Background Information on Ergon's and Energex's Cost-Reflective Pricing

This section provides background information on cost-reflective pricing and how well Ergon's and Energex's tariffs meet the AEMC's cost-reflectivity criteria. The APVI's answers to the AER Issues Paper's questions then reference this background information.

We have analysed Ergon's Seasonal TOU Demand Residential East (ERTOUD) tariff and Energex's Residential Demand Tariff proposed for 2017/18 using the load data from 3,876 households from the Smart Grid Smart City database for 2013. Although the SGSC households are based in NSW, their load profiles should not be too dissimilar to those in Queensland.

The aggregated load profile of the SGSC database, which is a proxy for the load profile of the network that serves them, peaks in summer at 6pm on Fri 18 Jan. As shown in Figure 1, about half of the individual houses actually peak in winter, with only 31% peaking in summer. A larger percentage of Queensland household loads may peak in summer, but analyses of these large datasets illustrate that, at an individual level, household loads peak throughout the year and also throughout the day.

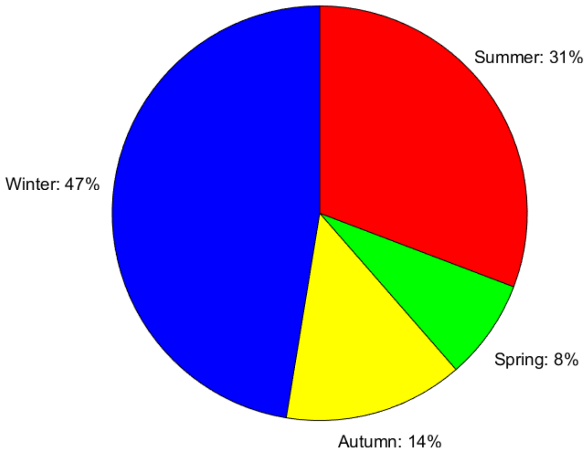


Figure 1. Season of Household peak

Both Ergon's Seasonal TOU Demand Residential East (ERTOUD) tariff and Energex's Residential Demand Tariff charge customers based on their monthly peak demand during a specified daily period – not their demand at the time of the network peak (which is what determines the network peak, and therefore the cost that households impose on the network).

Figure 2 and Figure 3 respectively compare each household's demand charge under Ergon's and Energex's Demand tariffs to their demand at the time of the network peak. The demand charge component of these tariffs has been 'unitised' – meaning that the monthly demand charges have been converted to an equivalent kW value.[1] We do this so that there is a more direct visual correlation

[1] For Energex, the net annual demand charge was taken to be $1/kW and this was divided by 12 to obtain the monthly unitised demand charge. The calculation for Ergon was more complicated because of the use of the average of the four highest demand days, but followed the same rationale. The addition of all the monthly demand charge rates equals 1.

between what a customer pays and the costs they impose on the network (represented by the red diagonal line), and because it makes different demand tariffs easier to compare.

All the households above the red line would receive a demand charge that is greater than their demand during the network's annual peak. This means that most houses are likely being charged more than they should be (generally those who are less responsible for the network peak).[2] This is a clear 'dead weight loss' – meaning that consumers are paying more than they should for a given good or service and so are consuming less than their optimum.

Thus, households are likely be charged for network augmentation at times when their demand is not necessarily affecting the cost of augmentation. This means that households may be incentivised to reduce demand at the wrong times and hence have limited impact on reducing network expenditure. The one caveat to this is that, over time, the original summer peaks could be reduced to the extent that the winter peaks become the new peaks. In this case, winter demand charges could be justified. This is discussed below. Of course, the inverse applies to a winter peaking network.

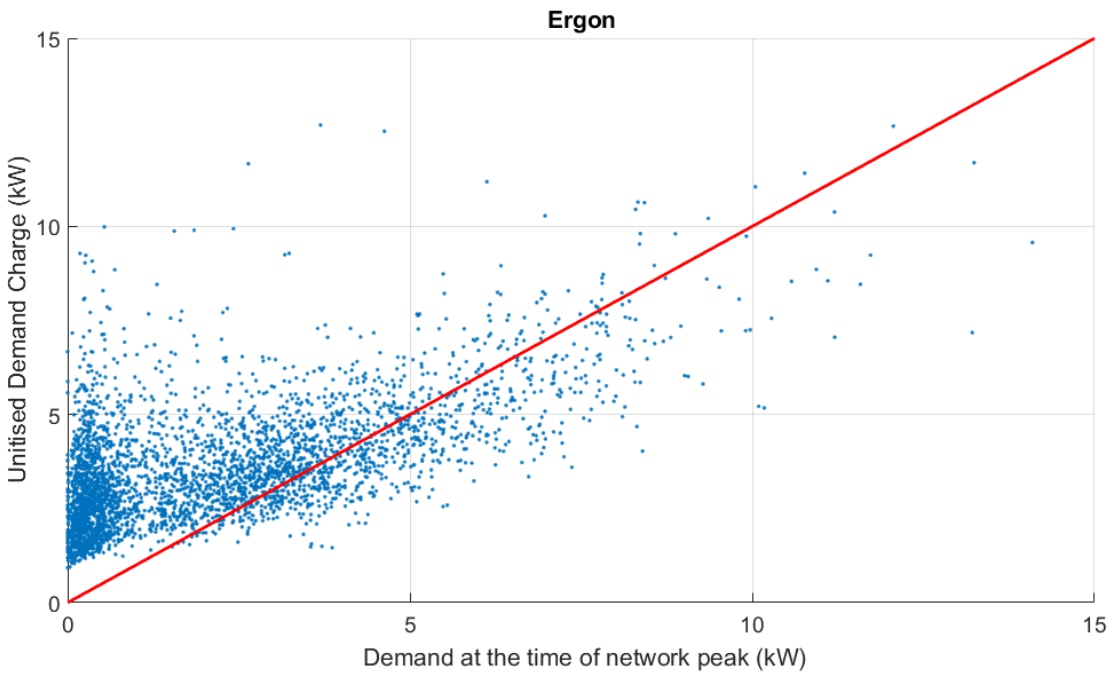


Figure 2. Unitised Demand Charge vs Demand at Time of Network Peak - Ergon

[2] Houses below the red line (generally those who are more responsible for the network peak) are being charged less than they should be.

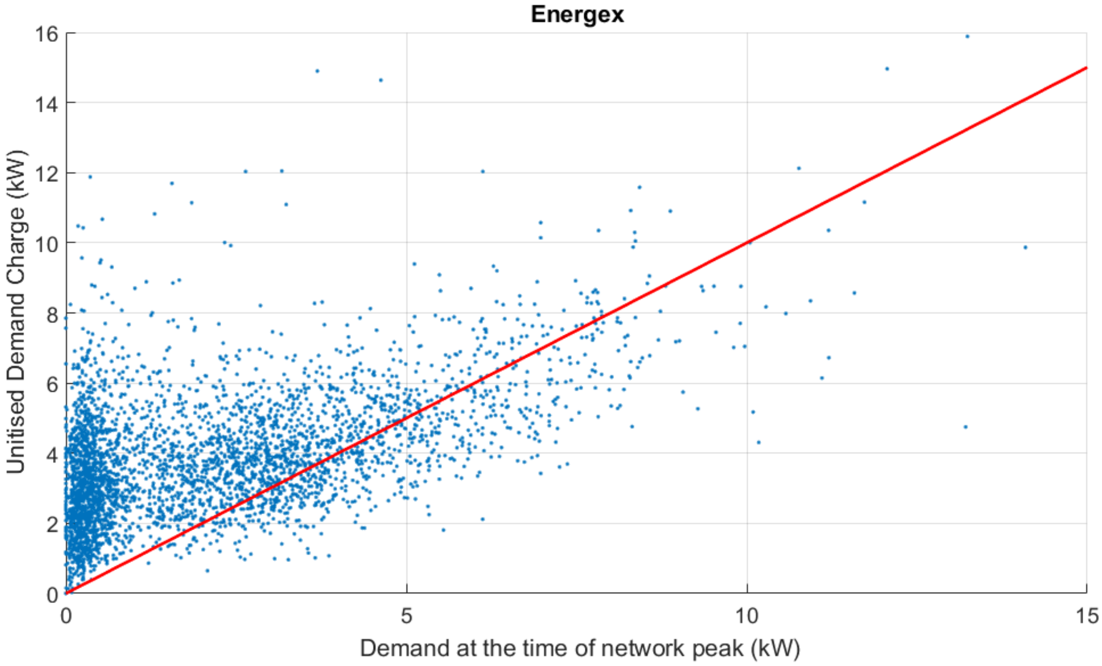


Figure 3. Unitised Demand Charge vs Demand at Time of Network Peak - Energex

This has an important implication for networks. If a demand charge is applied over a considerable period of time, households have a stronger incentive to install load control devices such as batteries – rather than just undertaking behavioural responses. Batteries are likely to be programmed to limit a household's peaks throughout the entire demand charge period, but not necessarily to minimise demand at the time of the network peak. As a result, although they may reduce a customer's bills, they may not be particularly effective at reducing the network's annual peak (or peaks). If a customer cannot afford a battery, they may choose some other form of control, such as having their grid connection capacity capped at a certain level. However, as above, this would mean their demand was being restricted when it is not necessarily affecting the cost of augmentation, resulting in a significant dead weight loss.

One way to quantify this dead weight loss is to calculate the reduction in the customers' peaks that is required to obtain a certain reduction in the network peak. Figure 4 and Figure 5 show this analysis for Ergon's and Energex's demand tariffs respectively. The left hand y axis shows the total reduction in average customer demand caused by it being capped at certain kW levels (x axis). The right hand y axis shows the corresponding reduction in the network peak – averaged per customer. The network calculations allow for the fact that, as one peak is reduced, another will become the peak, and so it must be reduced as well. Thus, the total peak reduction equals the old peak minus the new peak (which is most likely on a different day and a different season).

It can be seen that a reduction of 1kW in the network annual peak requires a net annual reduction of about 220kW and 250kW by the average customer for Ergon and Energex respectively. Another way to quantify this dead weight loss is to add up all the kWh a customer 'loses' because of the cap (or didn't lose but only because they paid for a battery). In this case, Ergon's and Energex's demand charge tariffs result in 380kWh and 360kWh being 'lost' for every 1kW network reduction respectively.

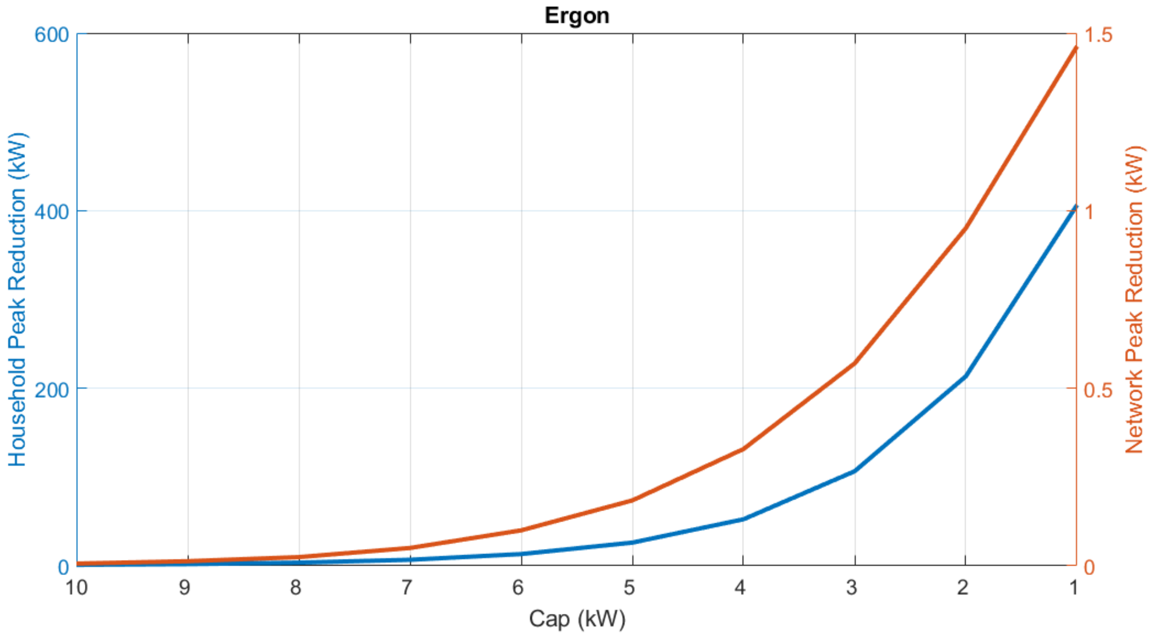


Figure 4. Household Peak Reduction vs Network Peak Reduction - Ergon

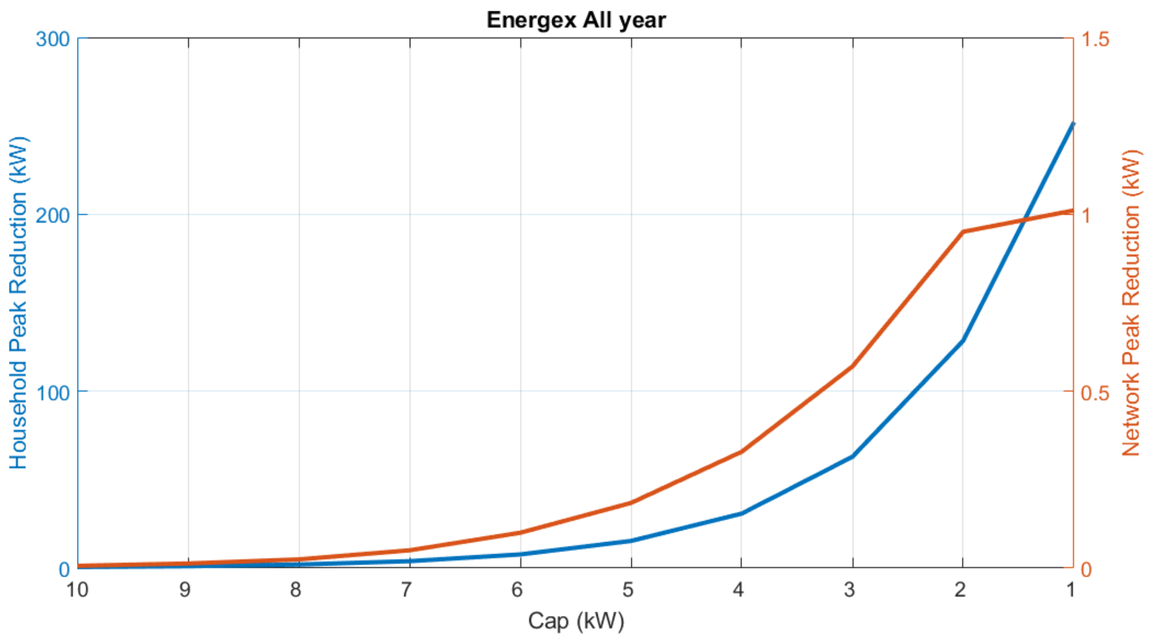


Figure 5. Household Peak Reduction vs Network Peak Reduction - Energex

Figure 6 and Figure 7 show that, as the cap (demand charge) is applied to fewer and fewer days (first removing the smallest peak day, then the next and so on) and so becomes more focused on the peak demand days, the amount of kW 'lost' to the customer reduces – at an increasing rate as you approach the annual peak day. This is an argument for both (i) reducing the number of months over which the demand tariff is applied, and (ii) focusing the demand charge periods onto the network's peak days not the customer's peaks.

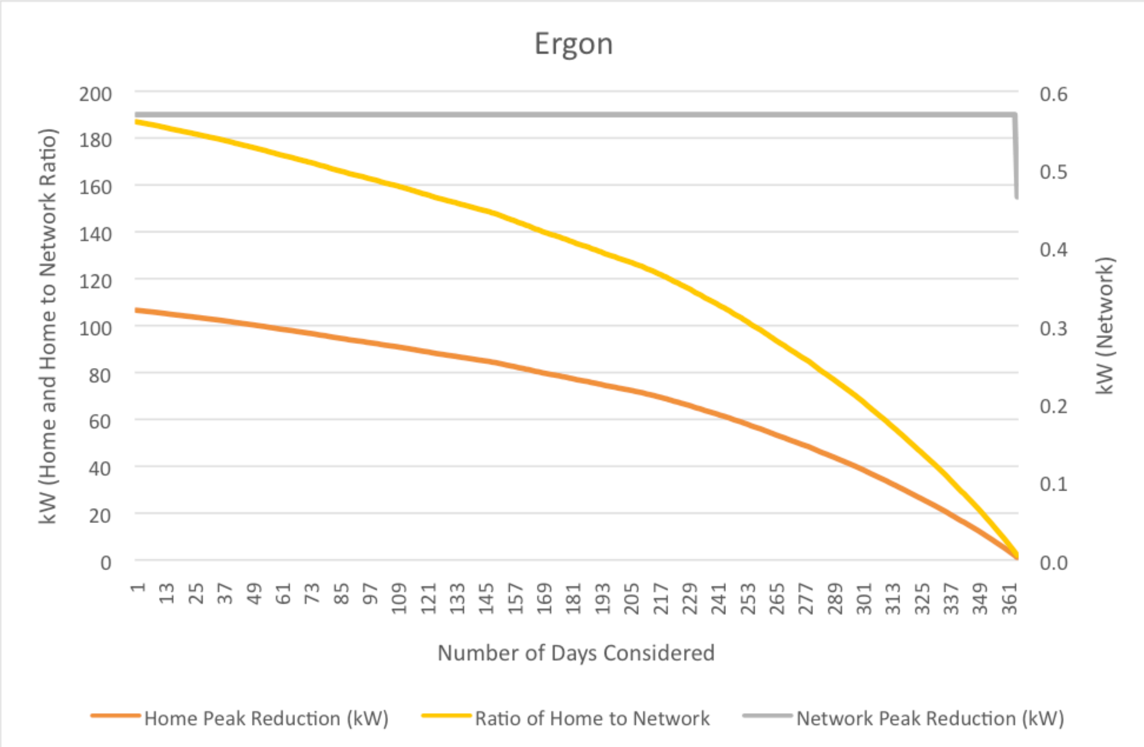


Figure 6. Impact of Number of Demand Charge Days on kW 'lost' - Ergon

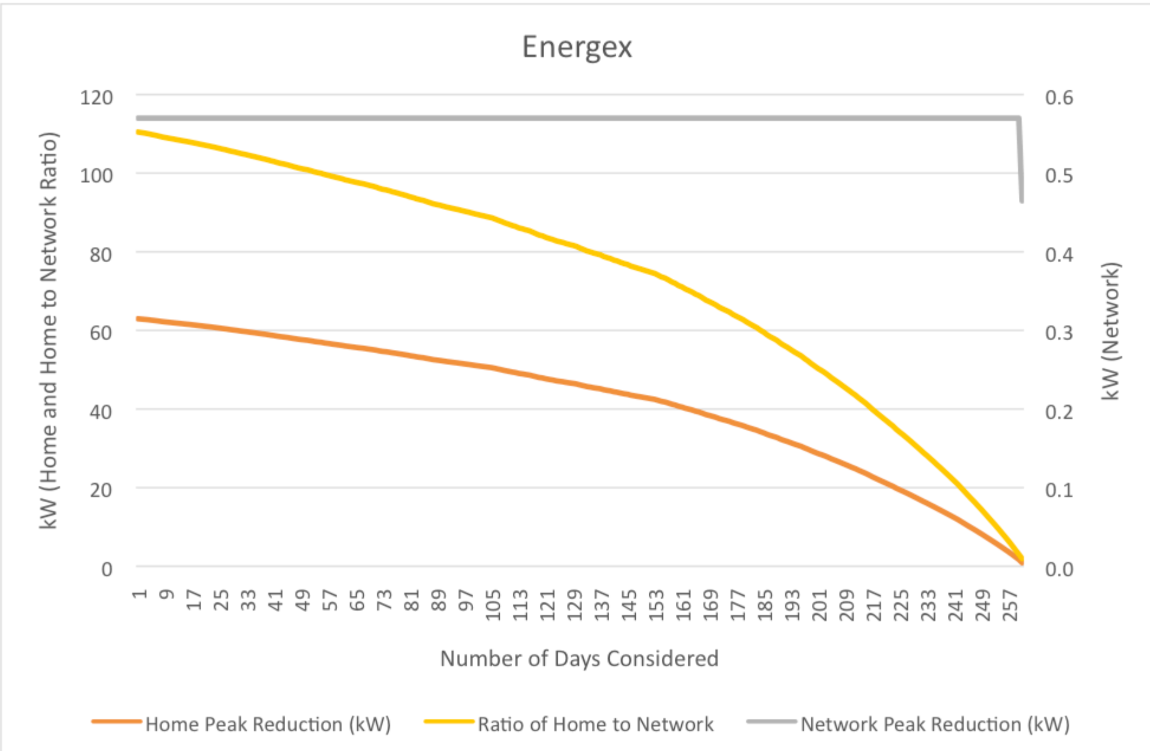


Figure 7. Impact of Number of Demand Charge Days on kW 'lost' - Energex

However, there is also an argument for increasing the number of periods over which the demand charge is applied, but only when the demand charge is applied to the times of the network peaks, not the customer peaks. This is because comparing the unitised demand charge to a single network peak doesn't take into account the fact that, if that peak is reduced, then the next peak will be the problem - and so networks need to set their tariffs in anticipation of that occurring.[3]

In addition, applying the demand charge to a single annual network peak is likely to lead to 'bill shock' for some households. In a particular year a household may, for some reason, have unusually high demand during the network's annual peak. Taking an 'averaging' approach can therefore reduce the impact of such events.

Figure 8 and Figure 9 show the effect of increasing the number of peaks over which the impact of the demand charge is assessed. The first (red line) point on the x axis represents the correlation between the customers' unitised demand charges based on SAPN's demand charge tariff, which uses the customers' monthly demand peaks), and their demand at the time of the network's annual peak. The first (blue line) point shows the correlation coefficient, but for when the customers' unitised demand charges are based on the customers' demand at the time of the network peak. The next point on the x axis again shows these correlation coefficients, but this time compared to the customers' average demand at the time of the two highest network peaks, and so on

For Ergon, as more peaks are included, the correlation coefficient initially increases. This is because the demand charge is higher in the summer months and so including more summer month peaks increases the correlation with the total impact of the demand charge. As winter peaks are included, where the demand charge rate is lower, the correlation rapidly decreases, then as more autumn, spring and then summer peaks are included, the correlation increases again.

For Energex, as more peaks are included, the correlation coefficient increases then remains more constant because the demand charge is the same for every month.

For both Ergon and Energex it can also be seen that the correlation coefficient is higher when the demand charge is based on the customer demand at the time of the network peak, not on the customer peak demand.

Note that this is not an argument for applying the demand charge to all months – only to those months where peaks are likely to occur, which in this case is summer and winter. As stated above, this analysis has been performed using data from the Sydney area. Where the summer peak is much greater than the winter peak (and occurs on more days), the Demand Tariff summer rate should be higher than the non-summer rate – as occurs for Ergon but not Energex. It is likely that their autumn and spring peaks are even lower, and so no tariff should be applied in those seasons at all.

[3] Of course, if the network has been built to meet the larger summer peaks then the smaller winter peaks won't matter – unless peak demand as a whole increases, OR, you want to decrease the size of the network.

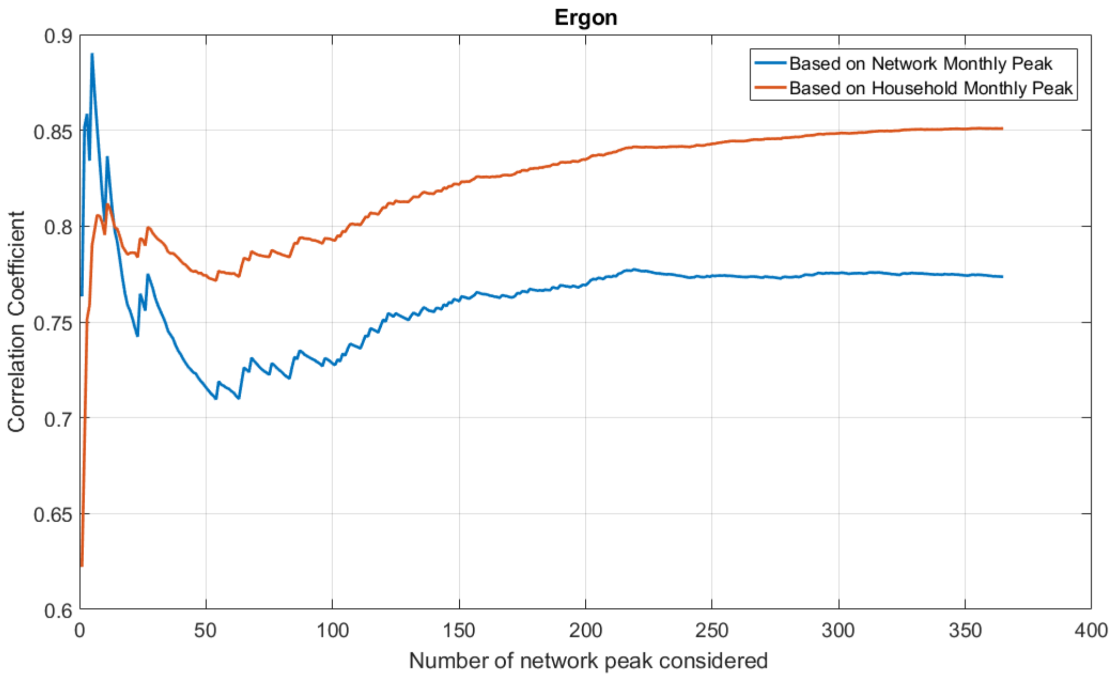


Figure 8. Impact on Correlation Coefficient of Increasing the Number of Peak Days - Ergon

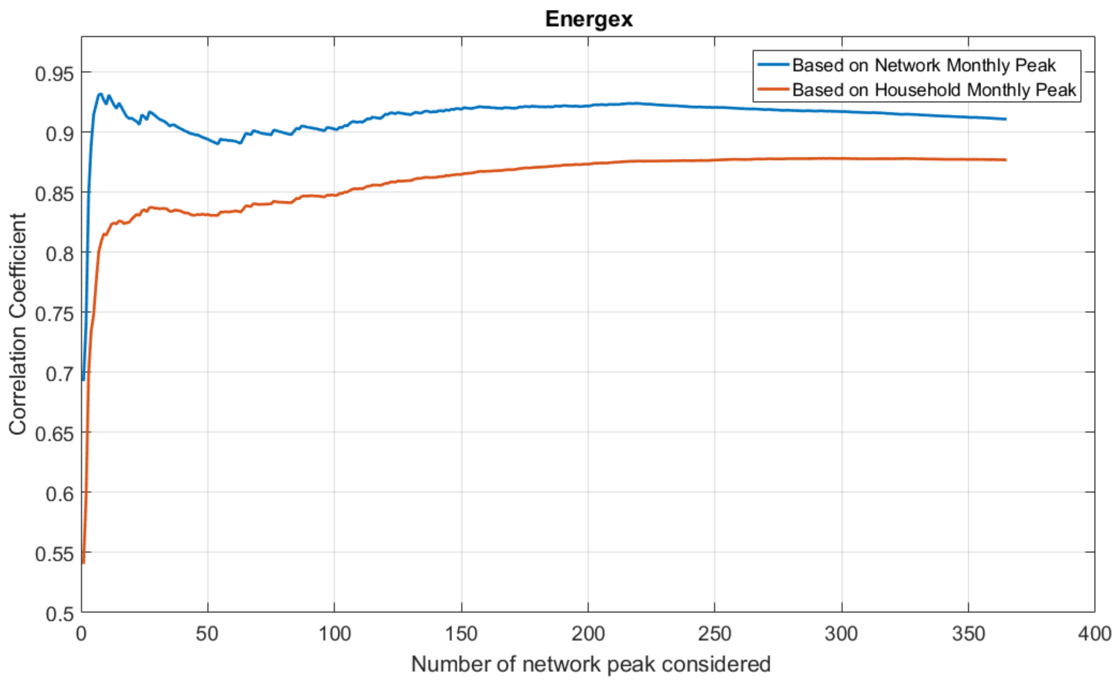


Figure 9. Impact on Correlation Coefficient of Increasing the Number of Peak Days - Energex

Figure 10 and Figure 11 show the impacts of applying Ergon's and Energex's demand charges only to the summer (Dec – Feb) and winter (June – Aug) months. As expected, this shows that the correlation coefficient is initially higher (peaking when 5 network peaks are considered).

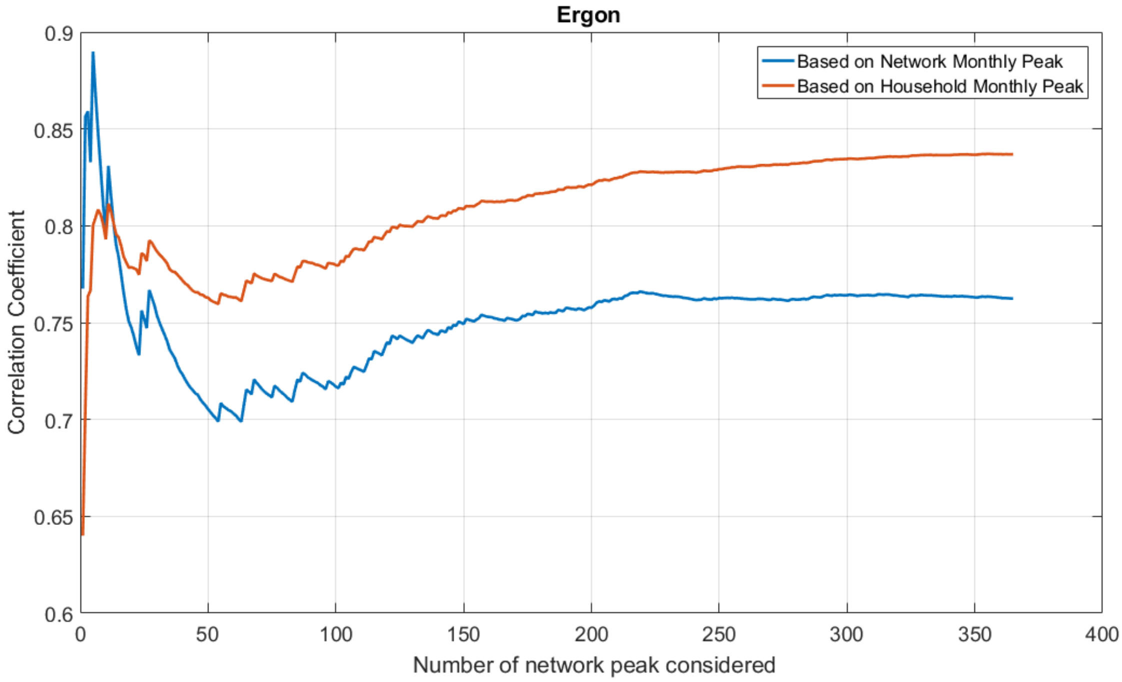


Figure 10. Impact on Correlation Coefficient of Increasing the Number of Peak Days – only summer and winter months – Ergon

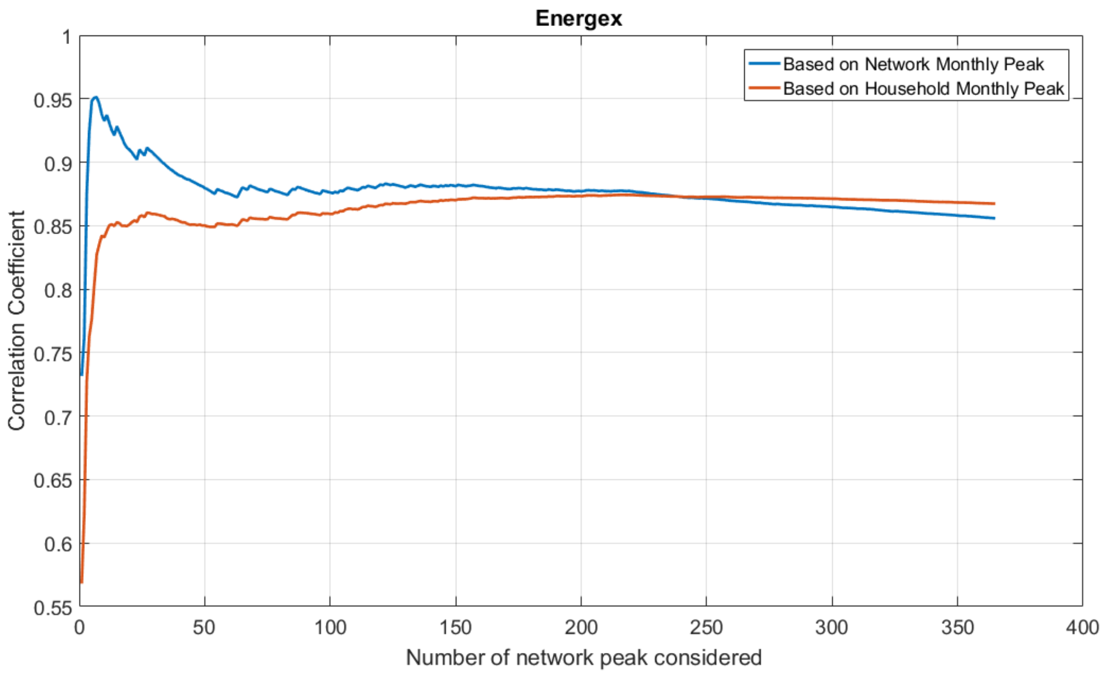


Figure 11. Impact on Correlation Coefficient of Increasing the Number of Peak Days – only summer and winter months - Energex

Figure 12 and Figure 13 show the same charts as in Figure 2 and Figure 3, but for Ergon's and Energex's optimised tariffs respectively, when the top 5 network demand peaks are considered. It can be seen that there is a much better correlation between the demand charge and the customers' demand at the time of the network peaks.

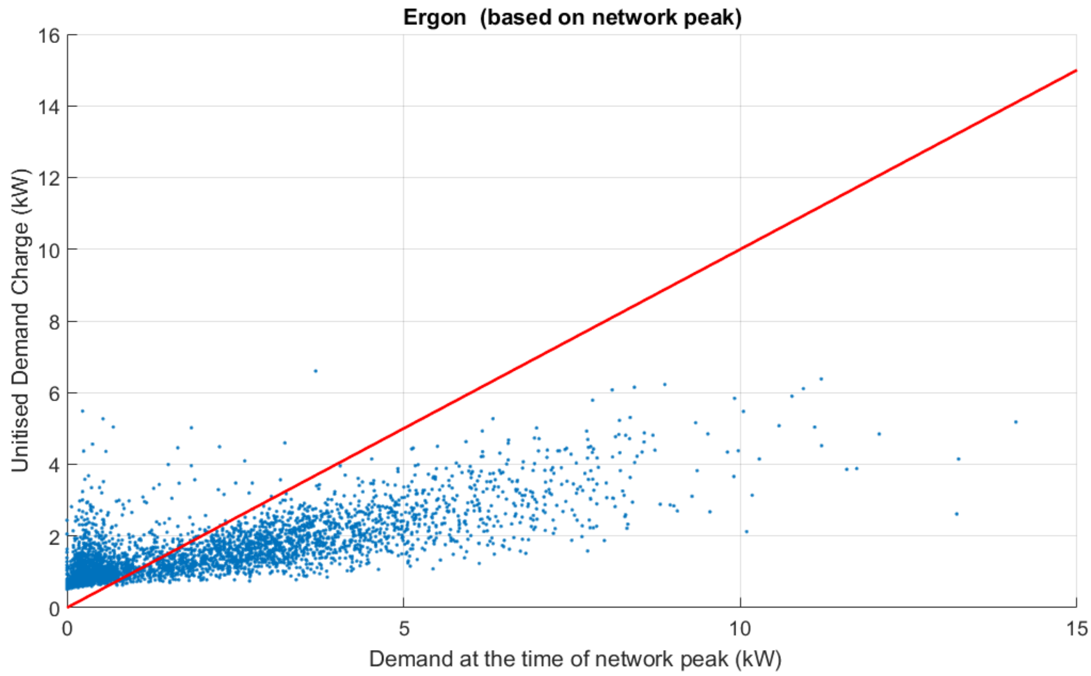


Figure 12. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Demand at Time of Network Peak – Ergon optimised tariff

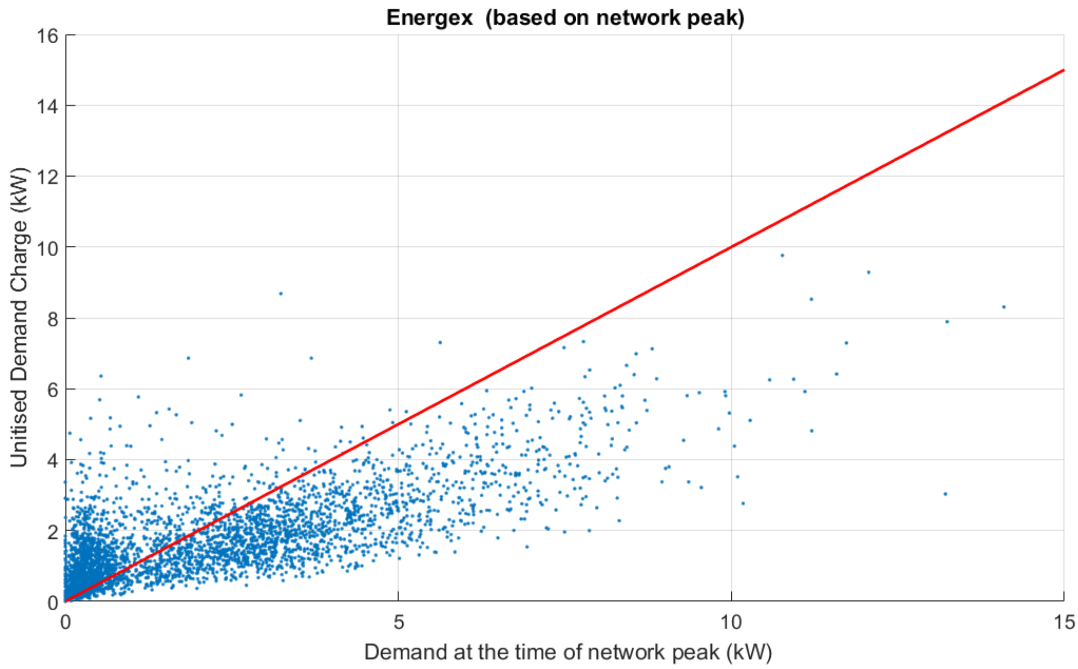


Figure 13. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Demand at Time of Network Peak – Energex optimised tariff

One way to take into account the fact that if the highest network peak is reduced, then the next peak will become the problem, is to assess the demand charge with respect to the customer demand at the time of a number of the highest peaks – not just the highest.

Thus, Figure 14 and Figure 15 show the same charts as in Figure 12 and Figure 13 respectively, but compare the unitised demand charge to the average household demand at the time of the top 5 network peaks. These peaks were chosen because they resulted in the highest correlation coefficient in Figure 10 and Figure 11. They include the peaks above 6,410 kW in the chart in the APVI's answer to Question 7 below. It can be seen that there is an even better correlation between the demand charge and the customers' demand at the time of the network peaks. Of course, these 5 peaks were chosen ex post (after the fact), but analysis of a selection of different SAPN substation load profiles should identify the number of peaks that is suitable to apply as an average.

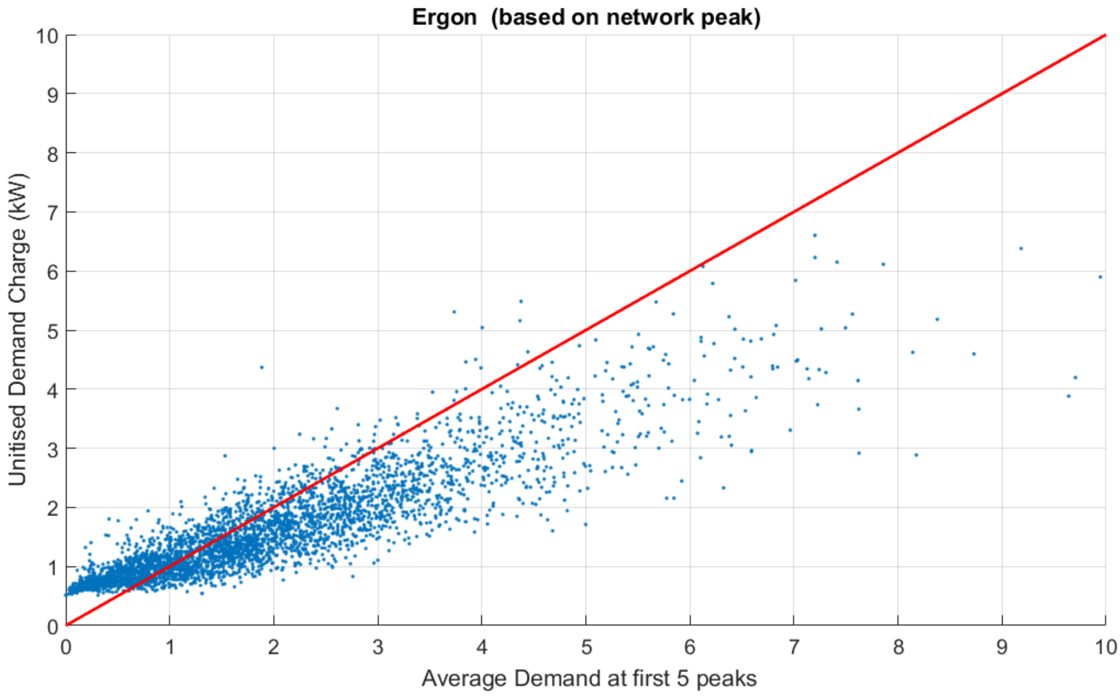


Figure 14. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Average Demand at Time of 5 Highest Network Peaks – only summer and winter months - Ergon

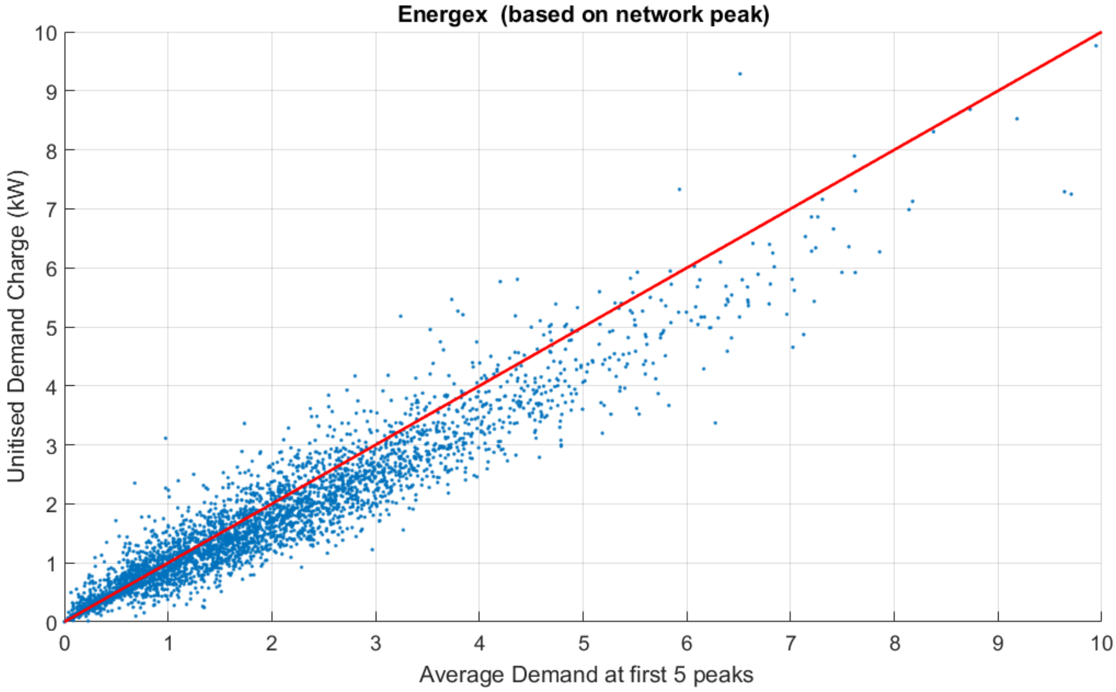


Figure 15. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Average Demand at Time of 5 Highest Network Peaks – only summer and winter months - Energex

Figure 16 and Figure 17 then shows the same chart as Figure 12 and Figure 13 but for Ergon's and Energex's normal demand charge tariffs (based on household demand peaks and for every month). There is a greater vertical spread in the data points (meaning a greater variation in demand charges between customers who impose the same costs on the network).

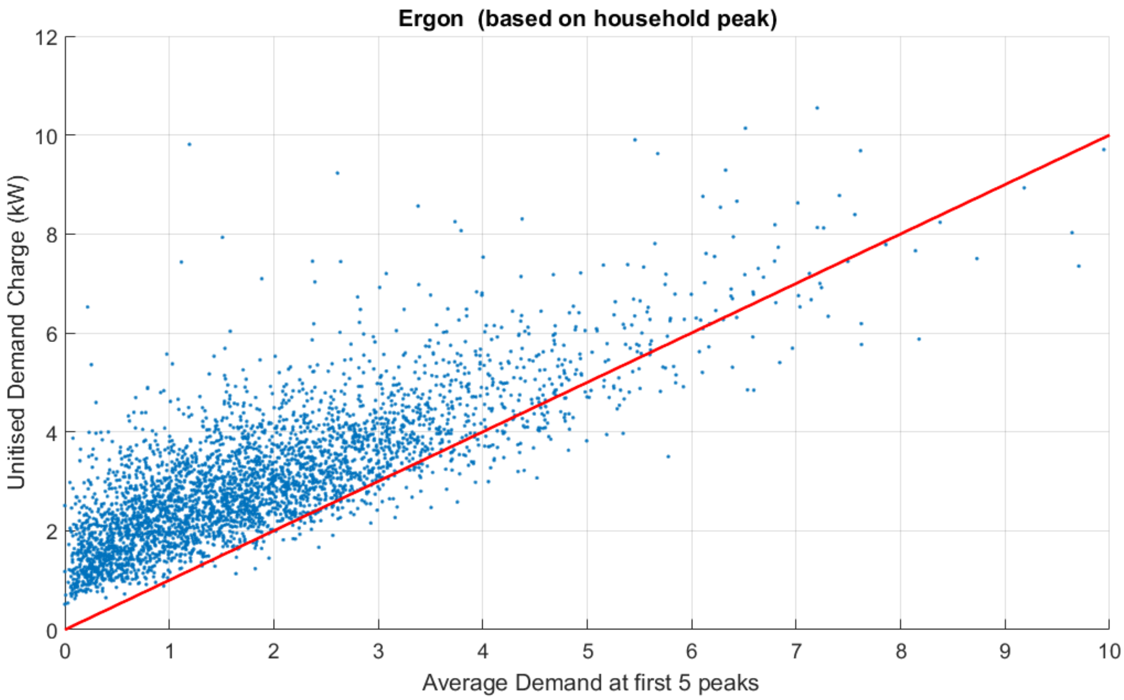


Figure 16. Unitised Demand Charge vs Average Demand at Time of 5 Highest Network Peaks – Ergon's standard demand tariff

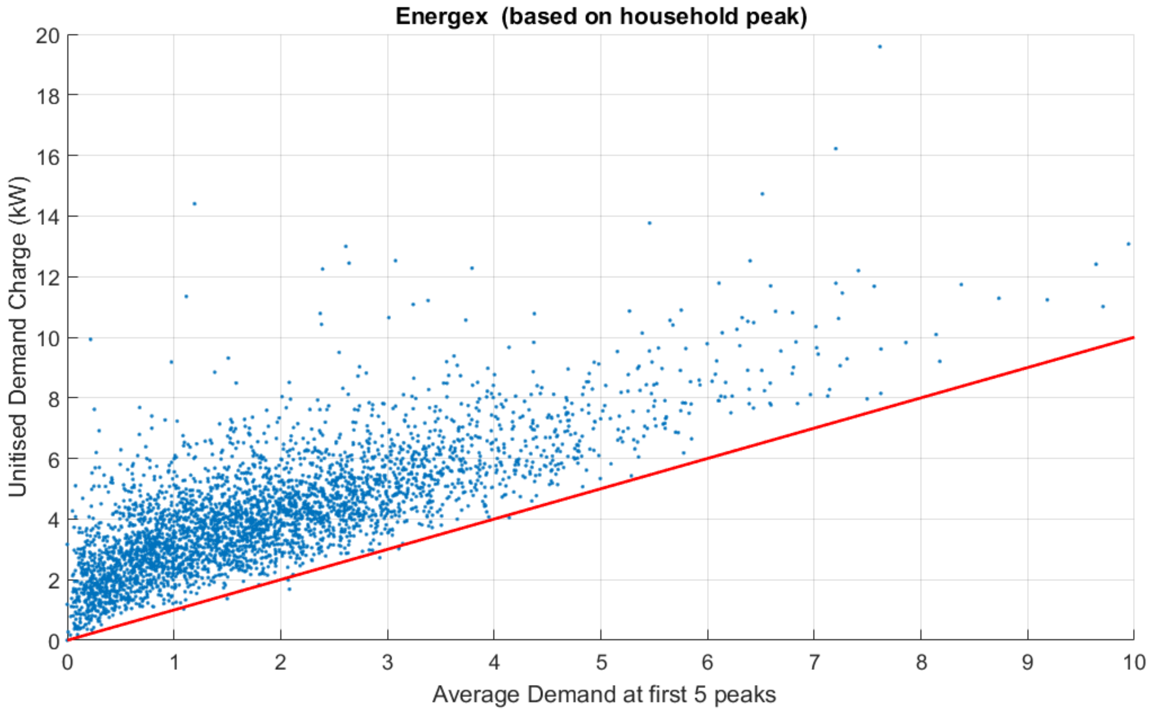


Figure 17. Unitised Demand Charge vs Average Demand at Time of 5 Highest Network Peaks – Energex's standard demand tariff

It can be seen that in Figure 14 above (Ergon), as the customer demand increases, it appears that the unitised demand charge does not increase as much as it should as customers place higher demands on the network. This is because Ergon incorporates their fixed daily charge into the demand charge as the 3kW minimum for all non-summer months. Removal of this min 3kW charge from the autumn and spring months (when the demand charge component doesn't apply), results in the chart in Figure 18, which has a much better correlation.

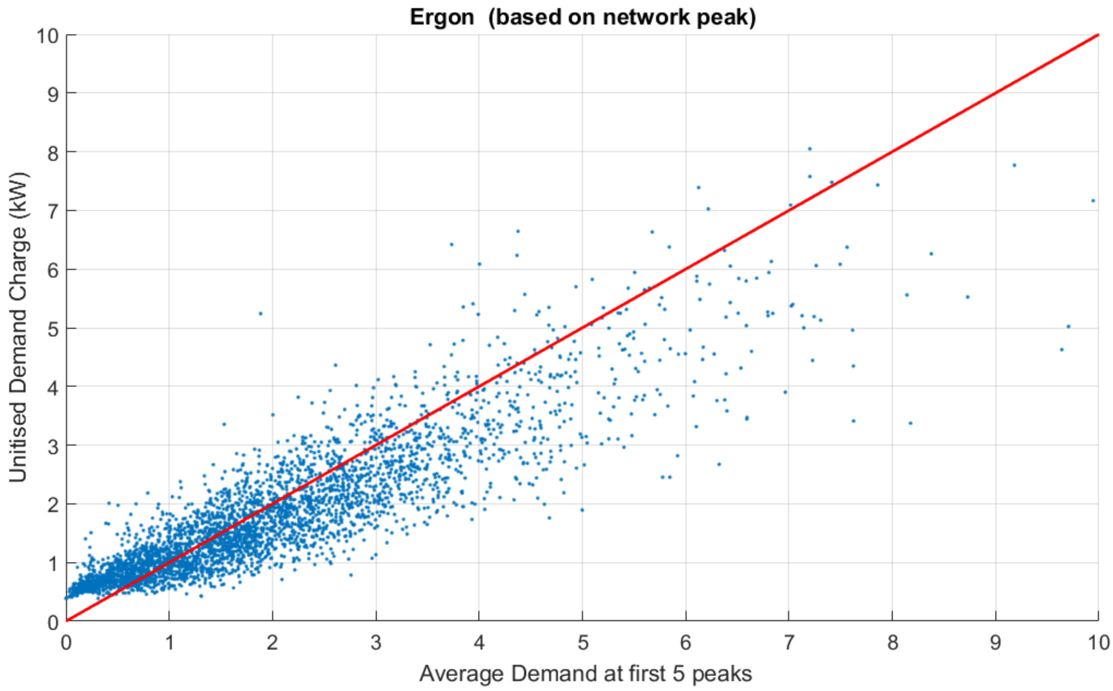


Figure 18. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Average Demand at Time of 5 Highest Network Peaks – only summer and winter months, with min 3kW charge removed - Ergon

The final step is to alter the demand charge tariff so that instead of it being based on the customer's demand at the time of the monthly network peak, it is based on the customer's demand at the time of the network's 5 annual peaks. This results in the charts in Figure 19 (Ergon) and Figure 20 (Energex), where the Ergon data is hidden behind the red line of correlation and the Energex red line has been removed so the data points can be seen.

They show a very good correlation between what the customer pays and the costs they impose on the network. This is of course expected because the demand charge is applied to the customers' demand at the time of the highest network peaks, and then we are comparing this to the average demand at the network's 5 highest peaks. However, it also shows that aligning the times at which the demand charge is applied with the times of the network peaks results in a highly cost-reflective tariff. Note that inclusion of the fixed daily and kWh usage charges would result in the points being more vertically scattered.

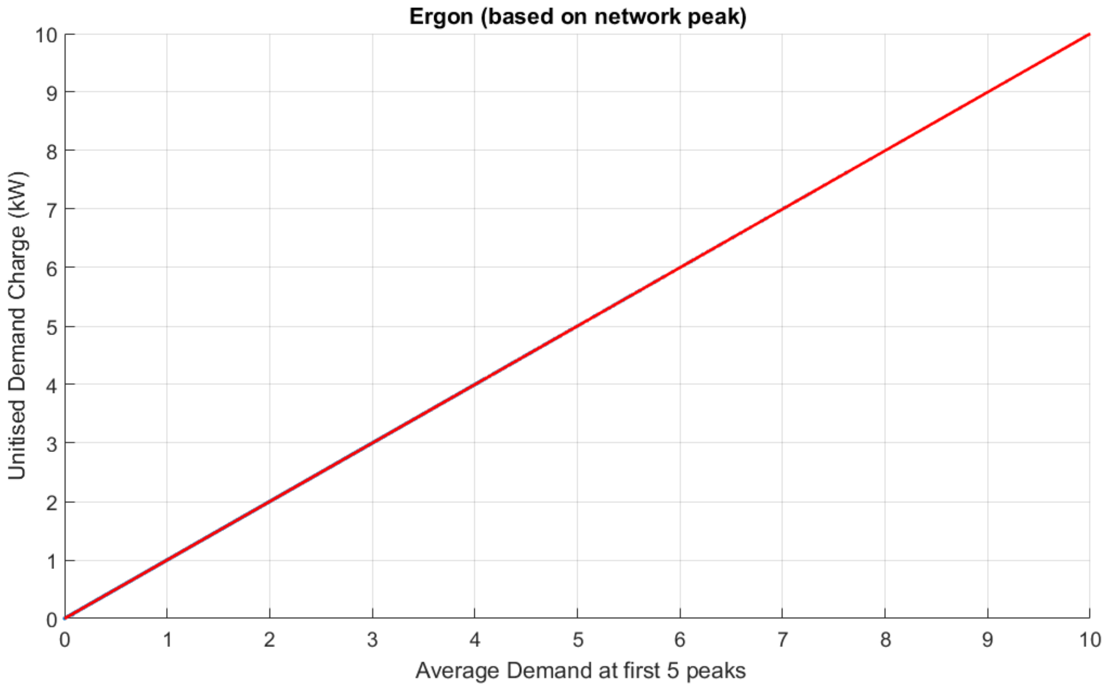


Figure 19. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Average Demand at Time of 5 Highest Network Peaks – only summer and winter months, with min 3kW charge removed, with demand charge applied to customer demand at network's 5 annual peaks - Ergon

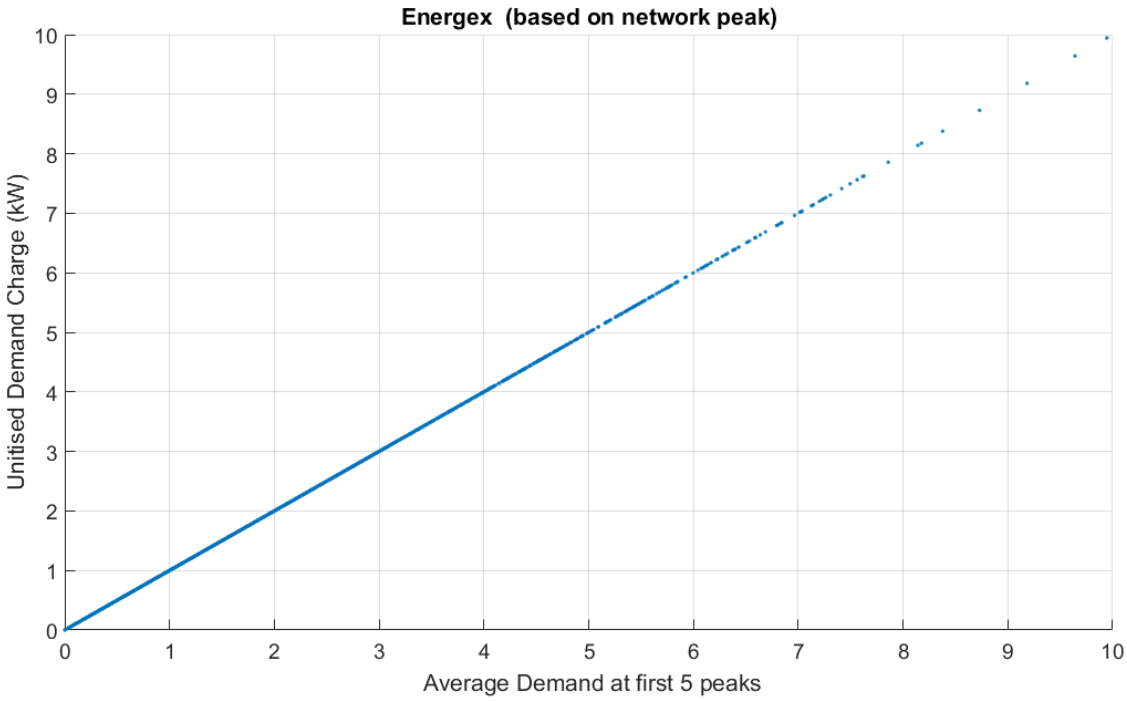


Figure 20. Unitised Demand Charge based on Customer Demand at Time of Network Peak vs Average Demand at Time of 5 Highest Network Peaks – only summer and winter months, with demand charge applied to customer demand at network's 5 annual peaks - Energex

Thus, it appears possible to improve Ergon's and Energex's demand charge tariffs. Of course, this sort of analysis would need to be performed using load data from their network areas. It would need to:

- take into consideration the need to minimise the number of peak days assessed, for example by focusing only on summer and winter months (to reduce the amount of kW and kWh 'lost' to the customer, and so minimise the dead weight loss),
- yet also allow sufficient network peak days to be assessed (to reduce the chance of bill shock and make the tariff more relevant to multiple network peak periods - although this is entirely dependent on the level of demand response), and
- adjust the level of the demand charge as well as the variable and fixed components.

But what does the customer 'see'?

A further level of complication is how to translate the final demand charge structure into a retail tariff. This may not be as complicated as it seems. Analysis of the SGSC data shows that all the top 35 peaks are in either summer or winter, and all bar one are between 5.30pm and 7.30pm. This is not necessarily the case for all networks, but it is likely for residential areas.

Figure 21 shows the network's annual peak demand day for an average household (ie. the network's load profile), as well as the summer average. As is currently the case, the household would only be presented with a 'demand charge window' during which the demand charge may be applied – for example only in the summer and winter months. If the peak was expected to occur in the 6pm to 6.30pm period, the 'window' could be fairly broad - from 3.30pm to 7.30pm (in order to capture a demand peak at a different time and to spread any demand response over a wider area to help flatten the peak).[4] This sets the price signal that the household 'sees'. However, the 'demand charge period', which determines the cost faced by the household, would only be applied over a shorter time and to an average of the household's demand during, for example, the top 5 network peaks, over the 2 hour period (4.30 to 6.30pm) discussed above.

Note that this will still result in a fair amount of dead weight loss because the demand charge window is being applied to all the summer and winter months. The only way to avoid this is to use more of a critical peak charge where the customer is notified of a peak event beforehand.

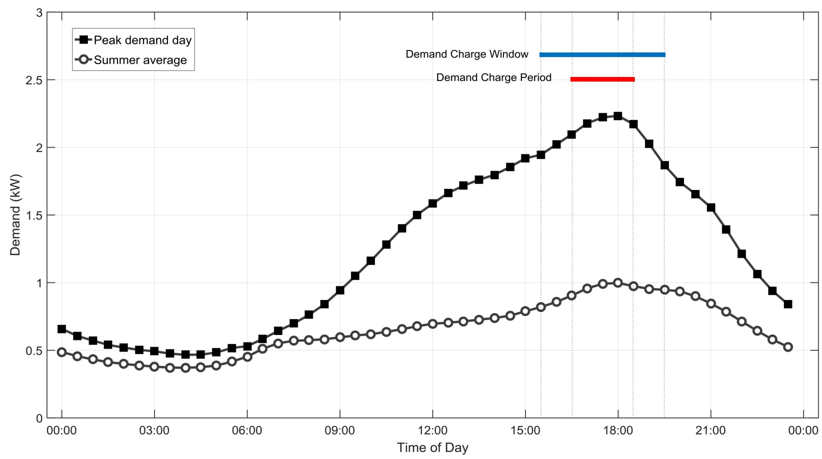


Figure 21. Sumer Peak and Average Demand Days, with Demand charge Window and Period

[4] All the SGSC top 20 peaks occurred between 5.30 and 7.30pm.

Allocation of residual costs

As discussed in the AEMC's Rule Determination 'National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014', in addition to cost-reflectivity, fairness is an important criterion when designing tariffs. Fairness applies not only to allocation of the short-term costs (LRMC) to those most responsible for them, but also allocation of historical responsibility.

Allocation of these sunk or 'residual' costs is another ongoing area of research for the APVI. Whereas the above discussion relates to the structure of the tariff, the allocation of residual costs is more relevant to how the network operator's costs are assigned to the different components of that structure – while minimising distortions to the forward looking price signal and therefore distortions to consumer behaviour.

We note that Energex intends to allocate the entire residual cost component to a mix of the fixed cost component and the variable cost component, with none being applied to the demand charge component.

Allocation to the variable cost component

One reason for not allocating payment for the residual costs to the variable cost component is that the variable costs make up such a small proportion of a DNSP's costs, and so this would not be economically efficient. In other words, it would provide a price signal that reduced kWh use below that which is efficient, including at times when the network is underutilised and the cost of that use is close to zero.

There also appears to be little correlation between annual consumption and contribution to the network peak, and so allocation of the residual costs to the variable component would not help with the fairness criterion (ie. that those most responsible for the size of the network should pay for it).

The only argument for allocating all payment for the residual costs to the variable cost component appears to be that this would avoid altering the LMRC price signal. However, as discussed below, this likely overemphasises the relevance of the LRMC price signal.

Of course, where the customer's tariff does not have a demand-based component, allocating some payment for the residual costs to the variable component would be fairer than assigning it all to the daily service availability charge.

Allocation to the demand-based component

The main argument for not allocating payment for the residual costs to the demand-based component is that such allocation would amplify the LRMC signal and so not be economically efficient. However, it is important to recognise that the LRMC price signal is in no way sacrosanct. There are two main reasons for this.

The first reason is that any LRMC signal seen by customers in the real world will not be economically efficient regardless. Strictly speaking, cost-reflective pricing requires the price to be set equal to the marginal cost for each customer, which of course is not practical. Instead, the LRMC is averaged across a whole class of customers, and so for a particular customer will not be accurate. The AEMC's Final Determination allows either the Average Incremental Cost method or the Perturbation or 'Turvey' method to be used to calculate the LRMC even though these produce quite different values, further decreasing accuracy. In addition, this calculated LRMC is, by necessity, an average across a broad geographical area, which will include sections of the network with quite different augmentation requirements (including sections of the network from low voltage through to transmission) and costs. For many networks this calculated LRMC is then used to create very different demand charges depending on the month (which implies that it costs different amounts to augment the same network at different times of the year).

The second reason is that householders are not perfectly economically rational and so should not be treated as 'homo economicus'. They do not have perfect access to all the information required to make a decision and do not make decisions in a purely rational manner ie. they have what is known as bounded rationality.[5] This means that even when faced with a perfect LRMC price signal, two different householders may react in quite different ways.

In addition, the LRMC price signal effectively assigns only a 'single year' augmentation cost to a particular customer, with the remaining residual costs (that make up the bulk of the cost) paid by all customers. It is arguable that at least a proportion of those residual costs should be added to the LRMC price signal in order to make customers more aware of the consequences of their actions.

Thus, in order to make tariffs fairer, there is certainly scope to explore allocation of the residual costs to a demand-based component, and to a lesser extent to the usage component. Before this, and as discussed in detail above, it is important to ensure that the underlying tariff structure is as efficient and fair as possible.

Responses to AER Issues Paper Questions

AER Question: (1): What are the advantages and disadvantages of Energex and Ergon Energy proposing demand (kW) tariffs on an opt in basis rather than as the default tariffs (when appropriate metering capability is available)?

APVI Response

Until they have developed tariffs that are more cost-reflective and so more fairly reflect the costs that customers impose on the network, their demand tariffs should definitely be on an opt in basis. Once they are more cost-reflective then targeting customers based on thresholds or altered connections could make sense.

Given that demand tariffs are designed to send a strong price signal to customers regarding their contribution to network costs, it makes sense to target customers based on their likely contribution to those costs. The following is based on our submission to the SAPN TSS but is relevant to Ergon and Energex.

Threshold customers: There is some correlation between a customer's annual demand and their contribution to the network peak, and so it is likely that high-use 'threshold' customers bear more of the responsibility for the size of the network, and therefore its cost – both in the current year and historically. It therefore makes sense for these customers to be targeted for a demand-based tariff. The threshold of 20MWh/annum proposed by SAPN is about triple the SA residential average and so it may be appropriate to gradually reduce this threshold over time.

Altered connections: Alterations such as new major appliances > 25amps and changes to three phase 44 power may well justify moving the customer to a transitional demand charge, because these alterations may increase the customer's demand peaks and therefore the costs they impose on the network. A 25amp appliance at 240V has a power rating of 6kW, which is significant.

An alteration, such as a new inverter approval, is most likely associated with a solar PV system (or some other form of distributed generation) and/or a battery system. The most likely impact that they will have on the customer's demand peak is to reduce it, and so it makes no sense to target them with a demand charge tariff. Although an interval meter may be required for a demand charge tariff to be implemented, this does not mean that a demand charge tariff should be implemented just because an

[5] This is where a person's rationality is limited by the available information, the tractability of the decision problem, the cognitive limitations of their minds, and the time available to make the decision.

interval meter is installed.

If a DNSP's intention is to target technologies that really do increase costs to other customers, they would target air conditioners (A/C). A/Cs have been shown to be primarily responsible for the increases in network size and therefore costs to customers, however, unlike solar PV systems, they also increase revenue to networks – both through increased sales and an increased Regulated Asset Base.

The 25amp threshold proposed by SAPN is equivalent to a 6kW A/C load, which is very large. Reducing both this threshold and the 20MWh/annum threshold, over time, would appear to be a much more appropriate approach to phasing in demand charge tariffs than targeting technologies just because they reduce a DNSP's income.

AER Question: (3): What are the advantages and disadvantages of using the times, days and months of anticipated constraints on network assets to set charging windows for a demand tariff, as opposed to observations of past demand on the network as a whole?

APVI Response

If the aim of the demand charge tariff is to signal to customers the times when it is most expensive to use the network, then the charging windows should be based on the anticipated constraints of the section of the network that serves those customers. However, this has to be balanced against the need for simplicity in designing different tariffs for customers in different sections of the network. Once the optimal tariff structure has been designed, then it should be possible to alter the size of the different components of that tariff for different substations and locations.

AER Question: (4): Do Energex and Ergon Energy's tariff statements (or related materials) sufficiently inform stakeholders on the times, days and months when the network is likely to be under most stress and therefore the ideal timing of the charging windows?

APVI Response

Their tariff statements do sufficiently inform stakeholders on the times, days and months when the network is likely to be under most stress. However, as discussed above, they do not then justify the timing of the charging windows.

AER Question: (5): What are the advantages and disadvantages of Ergon Energy's proposal to have a minimum level of demand in demand based tariffs instead of including a direct fixed charge component? How does this compare to gradually ramping up the demand charge component to reflect long run marginal cost over time?

APVI Response

The fixed charge is meant to cover the fixed costs, and the demand charge component is meant to cover costs related to demand peaks. Combining them means that large customers (who in each month always have a demand peak above the threshold), either (i) never pay the fixed charge or (ii) the demand charge is less proportional to their demand peaks than it is for smaller customers. Thus, our position is that they should be kept separate.

Gradually ramping up the demand charge component seems to be a separate issue. It is used to reduce the impact of the demand charge component and is a good idea – along with the other approach we discuss above to reduce bill shock.

<u>**AER Question:** (6): What are the advantages and disadvantages of calculating a demand tariff based on a single 30 minute maximum demand period within the charging window (Energex) as opposed to the average of the four highest days of demand recorded within the charging window (Ergon Energy)?</u>

APVI Response

Our work indicates that it is preferable to apply the demand charge over an average demand longer than the normal 30 minute period.[6] Ergon's use of the average of the four highest demand days will help to reduce bill shock and, as discussed above, does not make the tariff more cost-reflective.

Although the AER stated in it's SAPN Issues Paper that it would serve to further average and weaken a price signal that itself is already highly averaged, the price signal that the customer receives, and which influences their behaviour, is more the demand charge window, not the half hour peak, since most households would have little idea of when their own demand peak is.

A longer charging period will help to reduce bill shock for customers, but it can also help to charge customers more fairly based on their actual contribution to network constraints.

Networks are not just a static piece of equipment, but themselves have characteristics that change over time in the short term. As network demand increases, components such as transformers heat up, and it is the heat build-up that eventually results in a capacity constraint. Thus, it is not so much an instantaneous peak that limits the network but more the 'area under the curve' that results from the peak demand and the time over which it occurs. In this case, a price signal should also be directed prior to the peak – which will not only help to pre-cool transformers, but should also help to direct demand to later in the day, when it is cooler.

Thus, the averaging period should extend prior to the network demand peak, not simply be an average of either side of the network demand peak.

Networks also need to signal to households a period over which the demand charge may be applied. For a given section of the network, it should be possible to identify a period during the day (say 5 hours) that spans the network's likely demand peaks. From the household's point of view, this approach should be no more complicated than the demand charges currently available.

Figure 22 (which is a repeat of Figure 21 above) shows the network's annual peak demand day for an average household, as well as the summer average. As is currently the case, the household would only be presented with a 'demand charge window' during which the demand charge may be applied – for example only in the summer and winter months, or possibly all year. If the peak was expected to occur in the 6pm to 6.30pm period, the 'window' could be fairly broad - from 3.30pm to 7.30pm (in order to capture a demand peak at a different time and to spread any demand response over a wider area to help flatten the peak).[7] This sets the price signal that the household 'sees'. However, the 'demand charge period', which determines the cost faced by the household, would only be applied over a shorter time and to an average of the household's demand during, for example, the top 5 network peaks, over the 2 hour period (4.30 to 6.30pm) discussed above.

[6] We have not incorporated this into the work described above because the benefits of pre-cooling of transformers etc is a demand-response and so wouldn't show up in the 'static' modelling used here.

[7] All the SGSC top 20 peaks occurred between 5.30 and 7.30pm.

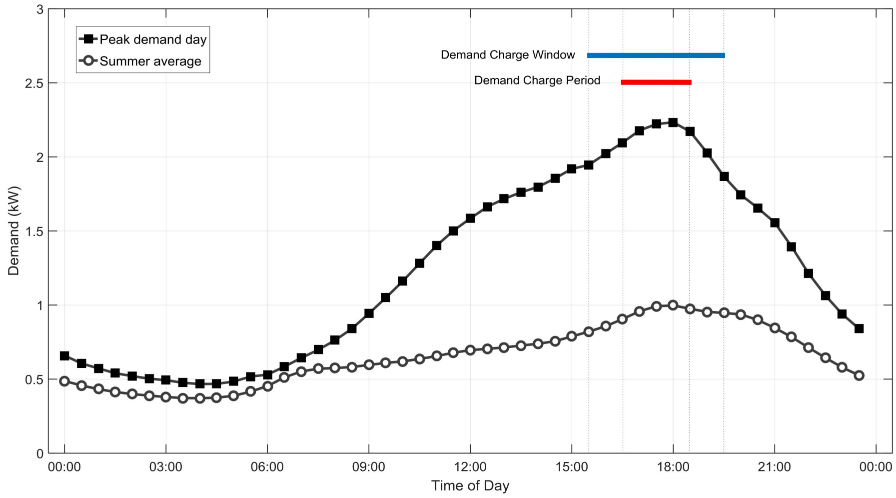


Figure 22. Sumer Peak and Average Demand Days, with Demand charge Window and Period

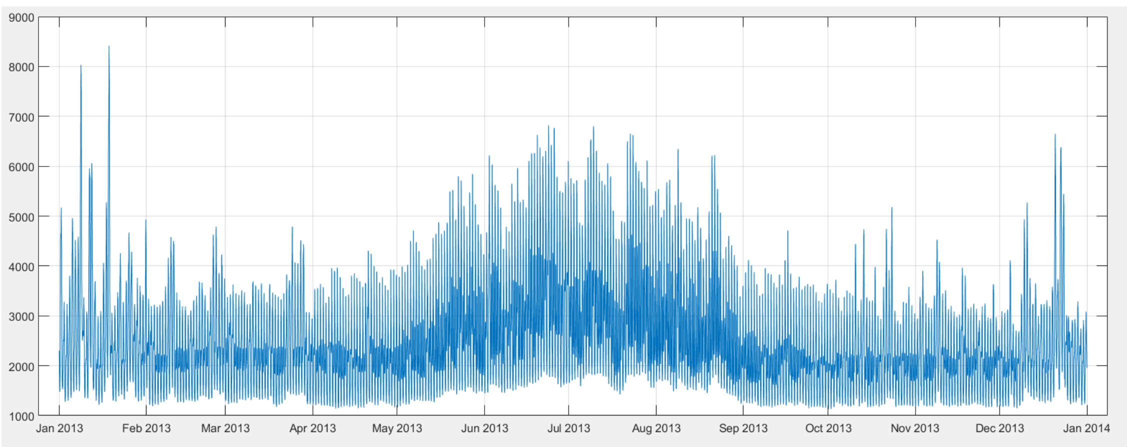
AER Question: (7): What are the advantages and disadvantages of incorporating seasonal variations in tariff components, whereby the value of one or more tariff components increases or decreases depending on the time of year?

APVI Response

This is actually a very complicated issue, and made even harder to answer by the lack of data specific for the Ergon and Energex networks. The chart below shows the aggregated half hourly demand for the 3,876 households from the Smart Grid Smart City database for 2013.

Although the annual peak is in summer, of the top 50 days, only six days are in summer 1st, 2nd, 5th, 11th, 24th, and 27th). All the rest are in winter. This means that if only the summer days are targeted in the demand charge, and customers respond, the winter days will quickly become the peak days. Of course, if the network has already been sized to meet the summer peaks, the winter peaks will not be a problem – unless demand in general increases, or, if there is a genuine desire to really reduce customer costs and so reduce the size of the network over time.

Thus, depending on Ergon's and Energex's feeder profiles, they could start with summer demand charges only, then, depending on the customer response, add in a winter demand tariff component.



Attachment A: Background on the APVI

The APVI is an independent Institute comprising companies, government agencies, individuals, universities and research institutions with an interest in solar photovoltaic electricity. In addition to Australian activities, we provide the structure through which Australia participates in the International Energy Agency (IEA) PVPS (Photovoltaic Power Systems) and SHC (Solar Heating and Cooling) programmes, which in turn are made up of a number of activities concerning PV and solar system performance and implementation. Further information is available from www.apvi.org.au.

APVI Objective

The objective of the APVI is to support the increased development and use of PV via research, analysis and information.

APVI subscription provides:

Information

- Australian PV data and information
- Standards impacting on PV applications
- Up to date information on new PV developments around the world (research, product development, policy, marketing strategies) as well as issues arising
- Access to PV sites and PV data from around the world
- International experiences with strategies, standards, technologies and policies

Networking

- Opportunity to participate in Australian and international projects, with associated shared knowledge and understanding
- Access to Australian and international PV networks (PV industry, government, researchers) which can be invaluable in business, research or policy development or information exchange generally
- Opportunity to meet regularly and discuss specific issues which are of local, as well as international interest. This provides opportunities for joint work, reduces duplication of effort and keeps everyone up to date on current issues.

Marketing Australian Products and Expertise

- Opportunities for Australian input (and hence influence on) PV guidelines and standards development. This ensures both that Australian products are not excluded from international markets and that Australian product developers are aware of likely international guidelines.
- Using the information and networks detailed above to promote Australian products and expertise.
- Working with international network partners to further develop products and services.
- Using the network to enter into new markets and open new business opportunities in Australia.

The International Energy Agency Programmes

PV Power Systems (IEA PVPS)

- **Mission:** *To enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems*
- **Focus** (26 countries, 5 associates)
  - PV technology development
  - Competitive PV markets
  - Environmentally & economically sustainable PV industry
  - Policy recommendations and strategies
  - Neutral and unbiased information

Australia currently participates in:

PVPS Task 1: Information Dissemination

PVPS Task 9: PV Services for Regional Development

PVPS Task 13: PV System Performance

PVPS Task 14: High Penetration PV in Electricity Grids.

Solar Heating & Cooling (IEA SHC)

- **Mission:** *International collaboration to fulfil the vision of solar thermal energy meeting 50% of low temperature heating and cooling demand by 2050*
- **Focus** (21 countries, 2 associates)
  - Components
  - Systems
  - Integration into energy system
  - Design and planning tools
  - Training and capacity building

Current Australian participation:

- SHC Task 51 – PV in Urban Environments
- SHC Task 48 – Quality Assurance Support Measures for Solar Cooling Systems
- SHC Task 47 – Solar renovation of non-residential buildings
- SHC Task 46 - Solar Resource Assessment and Forecasting
- SHC Task 43 - Solar Rating & Certification Procedures
- SHC Task 42 - Compact Thermal Energy Storage
- SHC Task 40 - Net Zero Energy Solar Buildings

For further information on the Australian PV Association visit: **www.apvi.org.au**

For further information on the IEA PVPS Programmes visit **www.iea-pvps.org** **and** **www.iea-shc.org**