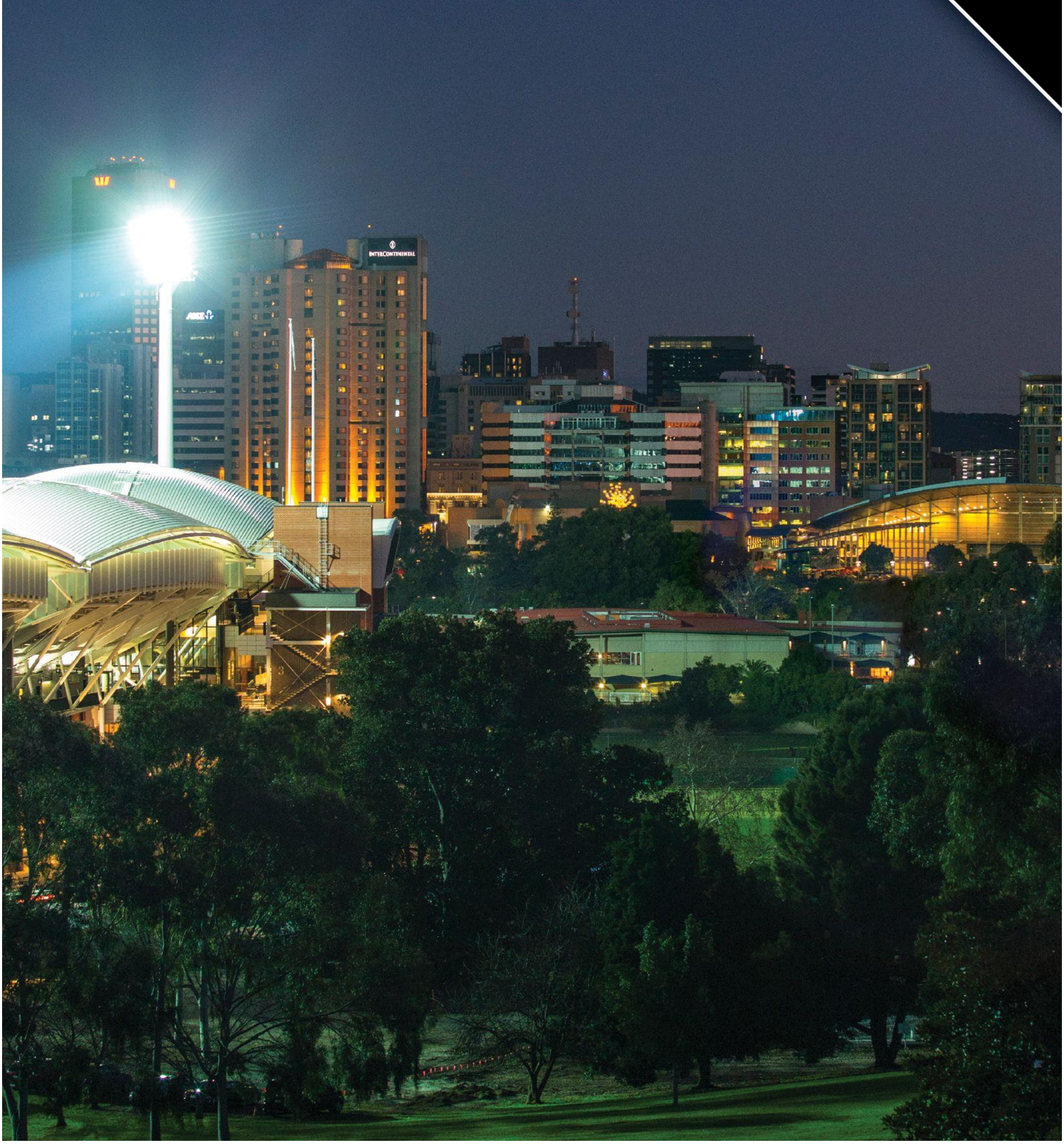
Attachment 5.3

Energeia:
Assessment of Future Tariff Scenarios for South Australia

July 2014

SA Power Networks



Assessment of Future Tariff Scenarios for South Australia

Prepared by ENERGEIA for SA Power Networks

July 2014

1 Executive Summary

Now, more than ever, consumer behaviour is impacting Australian electricity distribution network businesses. The wide scale uptake of solar PV, as well as consumer responses to increasing energy prices in recent years, is impacting network business, particularly in terms of costs and revenues.

In recognition of this, SA Power Networks engaged Energeia to undertake an assessment of the potential impact of a range of proposed tariff scenarios on consumer energy consumption and investment behaviour, network revenue, network costs and customer bills.

Scope and Approach

The assessment extended Energeia's customer behaviour model to consider the following four proposed tariff scenarios:

Tariff	Network Component	Retail Component	Abbreviation
1	Inclining Block Tariff	Inclining Block Tariff	IBT
2	Time of Use	Time of Use	ToU
3	Monthly Demand	Time of Use	MD + ToU
4	Monthly Demand	Dynamic Peak Price	MD + DPP

Table 1 – Tariff Types Assessed

Each tariff option was applied to five discrete customer segments across the residential and non-residential (<80kW connection) sectors. For each discrete segment, SA Power Networks provided a representative annual load profile in half hour increments.

All segments, with the exception of apartments, were able to take up distributed energy resources (DER) in the form of solar PV, storage and/or fuel cells with the exception of apartments due to physical or tenure constraints. However, customers adopting DER were required to switch to the new tariff type from their inclining block tariff.

Energeia's customer behaviour model assessed the impact of each tariff on each customer segment's energy usage patterns, DER Investment and the consequential impacts on their 30 minute load profile for each year of the twenty year forecast period.

The individual customer load profiles were then aggregated at the total segment level to determine the impact on network peak demand costs and revenue recovery. These impacts were then incorporated into a price feedback loop which influenced customer decisions in subsequent years.

The impacts of tariff scenarios were ultimately assessed in terms of their relative impacts on overall community energy costs and customer equity (i.e. level of cross-subsidy) by customer segment type.

Modelling Results

Energeia's assessment found that tariffs were likely to have a profound impact on customer equity, customer and industry investment patterns and community cost outcomes over the next twenty years. In broad terms, the more cost reflective the tariff option, the better the outcomes across all customer types.

Interestingly, the analysis highlighted that some customer segments, particularly small business customers, could see rapid adoption of DER over the coming years, which could lead to a large shift in costs from this customer group to remaining customers, depending on the tariff strategy.

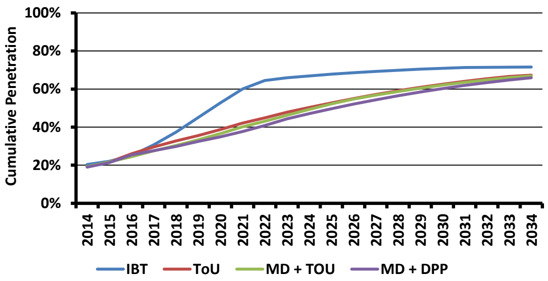
It is important to note that the individual tariffs modelled were adopted from existing examples and represent broader categories of tariffs. It is possible that more cost reflective versions of each category of tariff could lead to different outcomes.

Distributed Energy Resource Penetration

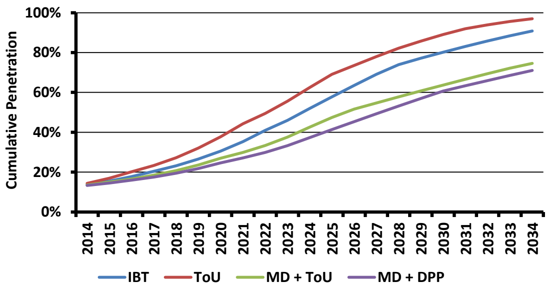
Figure 1 presents the results of Energeia's assessment of the impact of the tariff alternatives on the rate and timing of customer adoption of DER.

Figure 1 – Distributed Resource Penetration

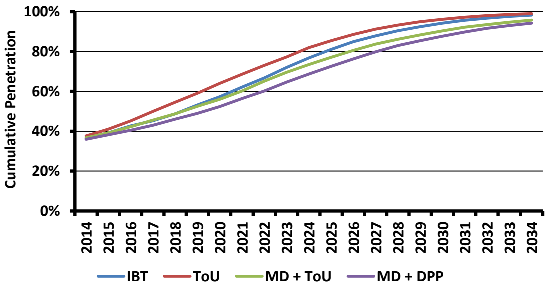
Residential



Small Business



Business



Source: Energeia

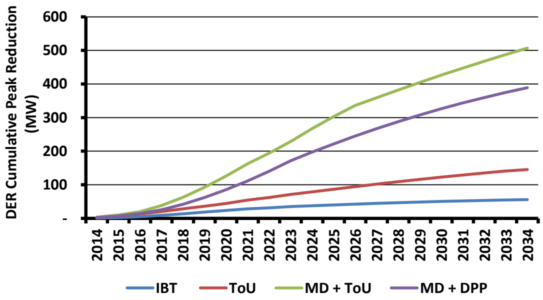
By the end of the modelling period, there is a small difference in outcomes for the residential and business segments, but a significant difference in the small business (SB) segment. Generally speaking, the capacity based options lead to the lowest overall rates of adoption due to lower customer incentives.

Network Peak Demand Reductions

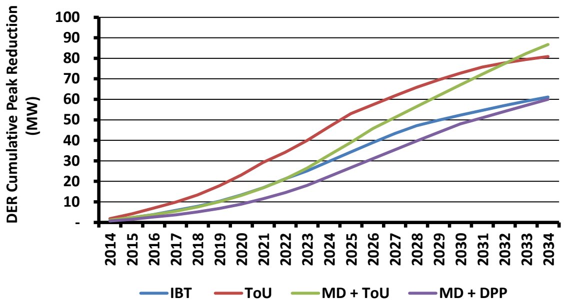
The penetration, mix and size of DER all contribute to the overall impact on network peak demand costs. Figure 2 presents the impact of the tariff alternatives on peak demand reduction with associated avoided network augmentation costs.

Figure 2 – DER Cumulative Peak reduction

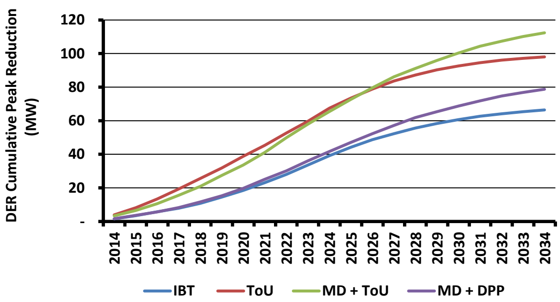
Residential



Small Business



Business



Source: Energeia

The modelling results show an interesting dichotomy in results between residential and business segments. The capacity based tariffs lead to a significantly greater reduction in peak demand in the residential sector, while it is ToU based tariffs that lead to this outcome for business customers.

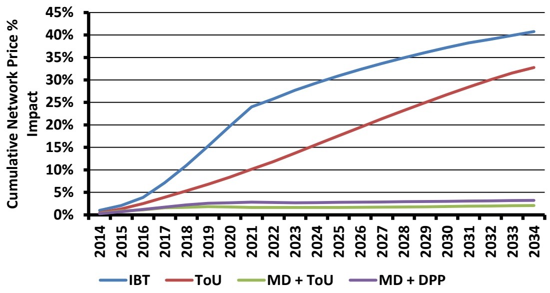
This key difference in the results is due to the overlap of solar PV generation with the peak demand of the modelled business customers, which is the strongest for small business. Nevertheless, the MD + ToU tariff drives the highest overall peak demand reduction across all modelled segments by the end of the assessment period.

Network Price Increases

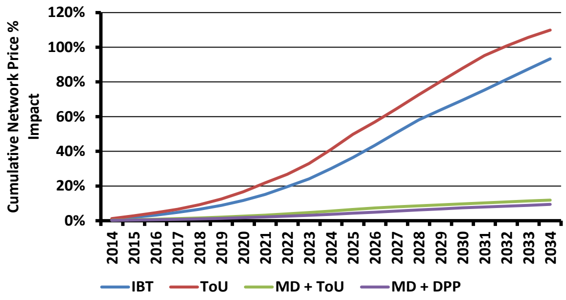
Network price increases due to the network feedback loop reflect the level of cross-subsidy from customers without DER to customers with DER. Additionally, where a customer reduces peak as a result of investment in DER, the reduction leads to a decrease in the need for revenue in the next period.

Figure 3 – DER Cumulative Network Price Impact

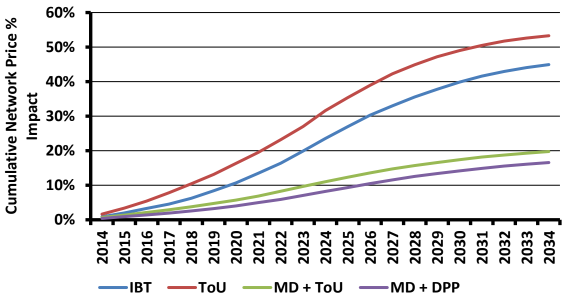
Residential



Small Business



Business



Source: Energeia

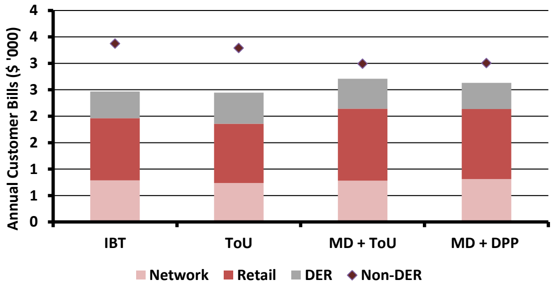
Figure 3 presents the results of Energeia's assessment of the impact of the tariff alternatives on cross subsidies and therefore future network price increases.

Customer Equity

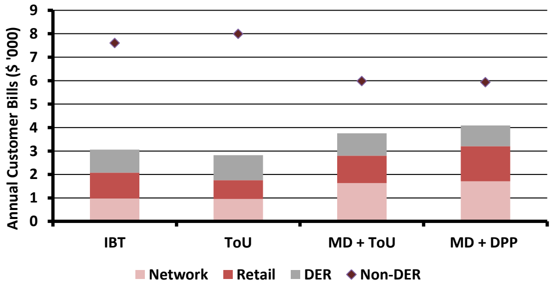
Figures 4 modelling shows the relative breakdown of annual network, retail and DER charges in 2034 for customers adopting DER compared to customers that have remained on the default IBT tariff.

Figure 4 – Annual Customer Bills by Sector, 2034

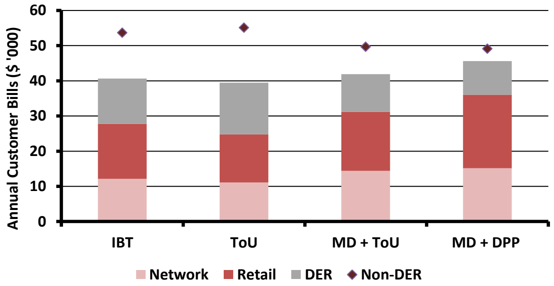
Residential



Small Business



Business



Source: Energeia

The key results of interest include the difference between annual bills of customers adopting and not adopting DER.

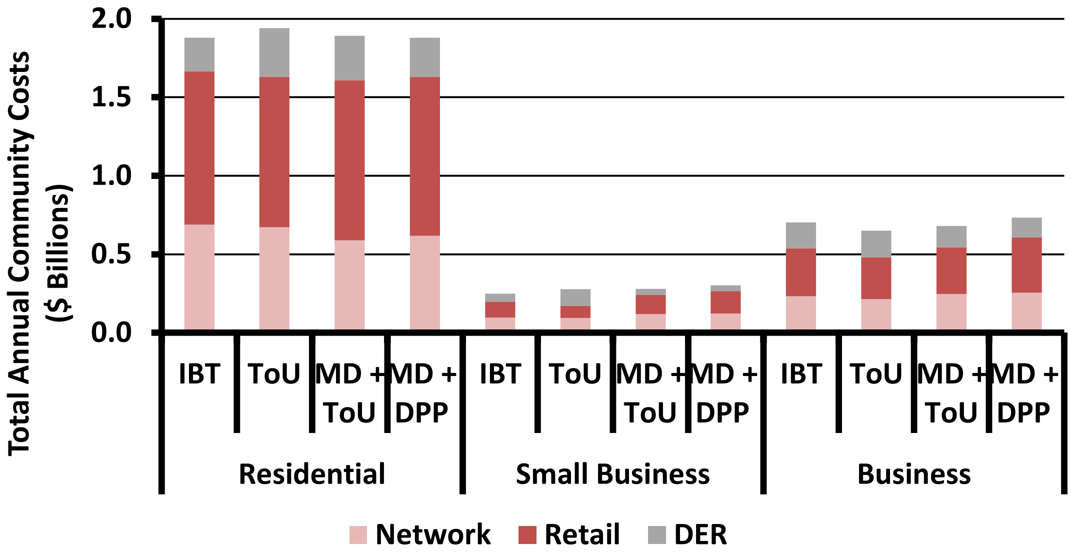
Overall, customer equity between those adopting DER and those remaining on IBT tariffs is maximised under the capacity tariffs, once adjustments have been made for the value of network peak reductions. This result is robust across customer segments.

Community Costs

Community costs are estimated by multiplying each customer's bill by the total number of customers with and without DER. This represents how much the whole community is paying for electricity, and is representative of the overall efficiency outcomes under each scenario.

Figure 5 shows the relative breakdown of network, retail and DER revenues across all customer segments in 2034 by tariff option.

Figure 5 – Total Annual Community Cost, 2034



Source: Energeia

Energeia's modelling shows that the choice in tariff strategy could lead to hundreds of millions of dollars per year in higher customer bills over the next twenty years. Interestingly, the optimal tariff for minimising future community-wide bills varies by customer segment, with small business showing an overall lower cost under an IBT tariff, while residential and business customer costs are lower under a MD + DPP and MD + ToU tariff respectively.

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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 the SA Power Networks 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 Introduction

Now, more than ever, consumer behaviour is impacting Australian electricity distribution network businesses. The wide scale uptake of solar PV within the residential sector, as well as consumer responses to increasing energy prices in recent years, is impacting network businesses in terms of reduced revenue.

This consumer behaviour can be separated into energy *use* decisions (short and long term elasticity of demand) and, energy *investment* decisions, specifically investment in Distributed Energy Resources (DER) as both a substitute and complement to centralised energy. In order to set efficient and equitable prices, networks are seeking to better understand these behaviours and the way in which consumers are likely to respond to different pricing signals.

In recognition of this, SA Power Networks has engaged Energeia to undertake an assessment of the impact of proposed tariff options, including more cost reflective tariffs, on consumer behaviour, network revenue, network costs and customer bills.

3.1 Purpose and Objectives

The objective of this report is to provide an assessment of consumers' behaviour within SA Power Networks' area in response to four proposed tariff options. The outcomes of the assessment will be used as inputs to SA Power Networks' pricing and metering strategy as part of its requirement to demonstrate prudency, efficiency and reasonableness under Clauses 6.5.6 and 6.5.7 of the National Electricity Rules.

In order to capture the effect of each tariff structure on SA Power Networks' customers, five discrete customer segments were analysed across the residential and non-residential sectors. For each of these five customer segments against each of the four proposed tariff options, the report provides an assessment of:

- Change in customer take up of distributed energy resources;
- Change in customer coincident network peak demand;
- Change in customer consumption;
- Impact on network net load profile;
- Increase in network prices required to recover revenue; and
- Changes in customer bills in response to all of the above.

3.2 Structure of this Report

The report is structured in three main sections as follows:

- **Section 1** – Provides an introduction to the overall scope and objectives of the report
- **Section 2** – Provides the assessment approach and modelling methodology adopted
- **Section 3** – Provides the detailed results of the assessment

3.3 Key Assumptions and Limitations

In interpreting the results in this report, the following key assumptions and limitations should be taken into account:

- The modelling underpinning this assessment was based on five individual customer loads considered by SA Power Networks to be representative of each of the five customer segments. The assessment is therefore limited in the extent to which these loads represent customers whose consumption patterns may differ materially from those provided. More detail on assumed customer loads is presented in 4.2.
- The proposed tariffs were normalised such that, for the five customer segments identified, the net impact of changing tariffs, but not changing behaviour was zero. The modelling necessarily requires this normalisation in order to create a scenario where customer decisions were in response to changes in consumption incentives rather than arbitrage. Tariff neutrality for the representative customers selected also ensured revenue neutrality for the network in the start year which was critical to the assessment. Energeia accepts that this would not be the case in reality as neither retailers nor networks can offer customer specific tariffs. It is understood that SA Power Networks has undertaken its own analysis to ensure revenue neutrality across its entire customer base for the tariffs selected. More information on the normalisation process and outcomes is presented in Section 4.1.1.
- The modelling is dependent on the assumed uptake rates of distributed energy resources for each customer segment. Uptake rates were developed by Energeia based on observed historical trends of uptake with respect to financial return on investment. More detail on the derived uptake rates is presented in Section 4.5.4.
- The financial return on investment for distributed energy resource technology and therefore the uptake rate in future years is dependent on Energeia's assumptions with respect to technology forward curves. These curves are in turn dependent on a range of assumptions relating to future global economic conditions. These assumptions are presented in Appendix 1.

3.3.1 Level of Uncertainty in Long-term Forecasts

The future is inherently uncertain. Views of the future are at best a reasonable indicator of likely outcomes given currently available information.

The analysis undertaken for this report is based on the most relevant information available, and represents a reasonable approach to estimating future outcomes given the assumptions of energy and technology pricing, customer behaviour and policy assumptions outlined in this report.

While the future is likely to unfold in unanticipated ways, and there are unlimited alternative combinations of assumptions that could be considered, Energeia is of the view that the assumptions underpinning this report could be reasonably expected to occur.

Furthermore, our approach to projecting the future is based on best practice industry methods, e.g. a regression based forecasting method, parameterised using historical data and observed trends.

In terms of accuracy, the estimates of future rates of customer adoption, sizing and mix of distributed energy resources, and the levels of network cross-subsidies and cost reductions, are all subject to model, assumption and inherent risk and uncertainty.

While unbiased errors tend to cancel out, feasible outcomes grow exponentially with time. Therefore the longer the timescale, the greater the uncertainty and therefore the likely margin of error.

4 Scope and Approach

The interaction between customer consumption patterns, uptake of DER and network costs and bill impacts is complex. This complexity necessitates some level of simplification in order to make the problem tractable. The scope and approach adopted by Energeia sought to achieve a balance between this simplification and accuracy of analysis required by SA Power Networks.

Section 4.1 to 4.4 provides an overview of the scope of the assessment including the tariff types assessed, the customer segmentation adopted and the technology options considered. Section 4.5 provides an overview of the model and underpinning assumptions which sought to replicate the complex interactions between tariffs, customer behaviour and network and billing impacts.

4.1 Tariffs

This project assessed four different tariff structures made up of a combination of network and retail components. The network components of the tariffs assessed represent either existing or proposed SA Power Networks tariffs. The retail component of the tariffs assessed represent either currently available tariffs under the standard contract offer or retail tariffs which have been trialled by various retailers and likely to become available to SA Power Networks' customers in the near future.

Table 2 – Tariff Types Assessed

Tariff	Network Component	Retail Component
1	Inclining Block Tariff	Inclining Block Tariff
2	Time Of Use	Time of Use
3	Monthly Demand	Time of Use
4	Monthly Demand	Dynamic Peak Price

Source: SA Power Networks

Table 2 summarises the four tariffs assessed.

4.1.1 Tariff Neutrality

For the purposes of this analysis, the proposed tariffs were normalised for 2014, such that for the five customer segments assessed, the net impact of changing tariffs, but not changing behaviour was zero. That is, these representative customers were no better or worse off under any of the tariffs.

The modelling necessarily required this normalisation in order to create a scenario where customer decisions were in response to changes in consumption incentives rather than tariff arbitrage. Tariff neutrality for the representative customers selected also ensured revenue neutrality for the network in the start year which is critical to the assessment.

The normalisation was undertaken for all network and retail tariffs against the Inclining Block Tariff (IBT) by varying the consumption based component for Maximum Demand (MD) and Dynamic Peak Price (DPP) until the annual bill under each tariff was the same.

This method was deemed to be least invasive in terms of the rate of DER uptake which is much more sensitive to peak prices and demand tariffs than off peak prices. This is consistent with the pricing principles as outlined in National Electricity Rules[1].

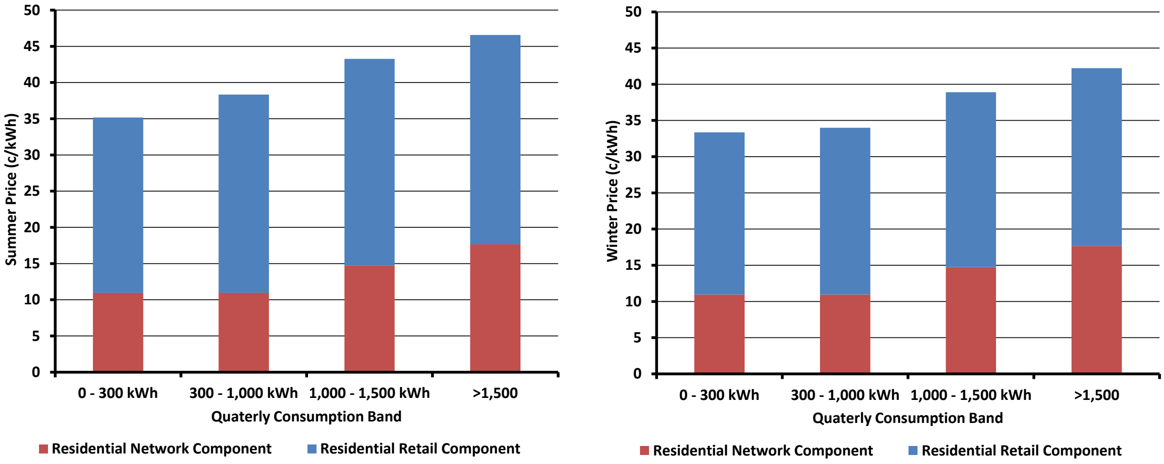
[1] National Electricity Rules, Version 61, clause 6.18.5

Each of the four tariff types is described in further detail below including both the actual values and post normalisation values used to represent 2014 values in the model. All tariffs are presented in 2014 $AUD and are GST exclusive.

4.1.2 Tariff Type 1 - Inclining Block Tariff

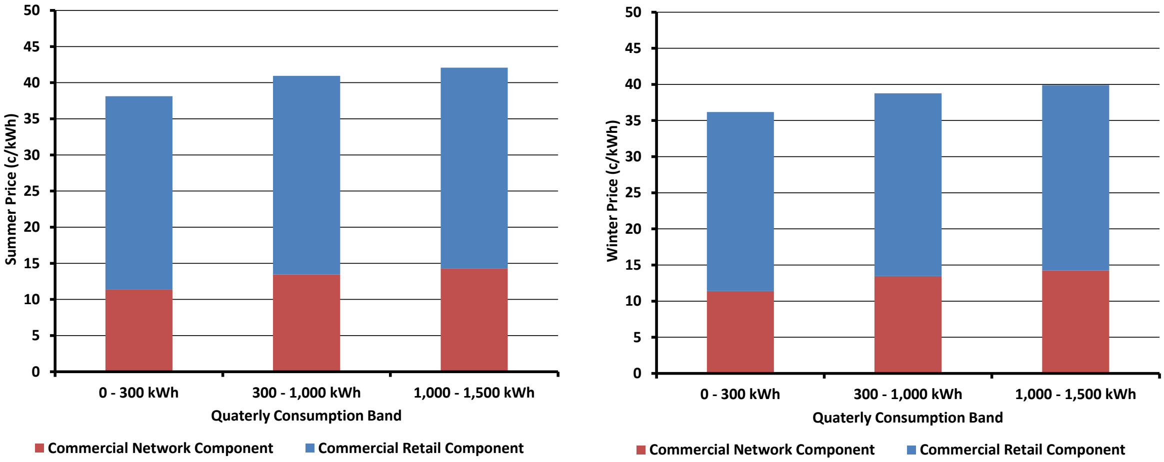
Currently, the majority of SA Power Networks' customers are on an Inclining Block Tariff (IBT). IBT is a consumption based tariff that charges at increasing rates per unit on incremental blocks. Energeia has modelled SA Power Networks' IBT structure combined with the current standard offer retail IBT structure to generate a business as usual (BaU) scenario for analysis. The structure of this tariff is presented in Figure 6 for residential customers and Figure 7 for non-residential customers.

Figure 6 – Tariff Type 1 (Inclining Block Tariff) Residential (Summer and Winter)



Source: SA Power Networks, Origin Energy

Figure 7 – Tariff Type 1 (Inclining Block Tariff) Commercial (Summer and Winter)



Source: SA Power Networks, Origin Energy

All tariffs were normalised against Tariff Type 1, therefore this tariff as presented in Figure 6 and Figure 7 was unchanged in the modelling task.

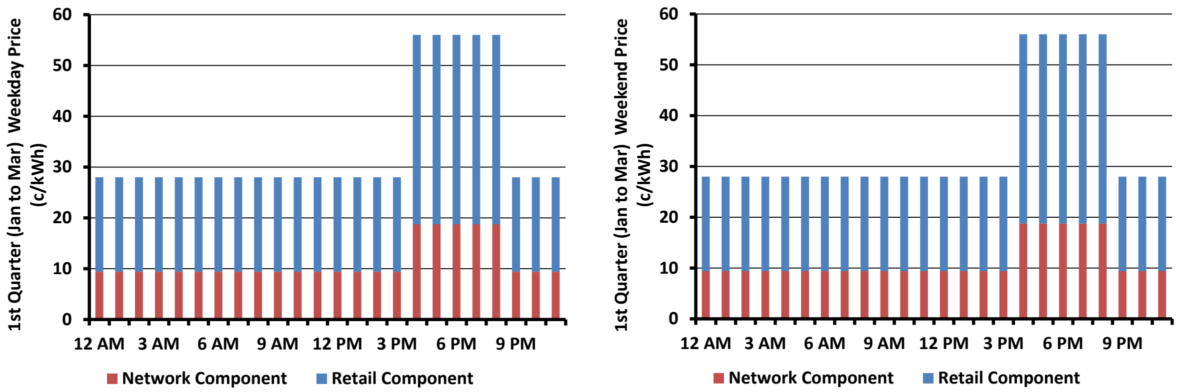
4.1.3 Tariff Type 2 – Time of Use Tariff

Like IBT, the Time of Use (ToU) tariff used in this analysis is also a consumption based tariff but varies depending on time of day, day of the week and the season. The price variations reflect the cost of energy supply for a given period.

The network ToU tariff modelled was designed by SA Power Networks as a two tiered seasonal ToU tariff structure with peak, and off-peak prices. It is noted that there is currently no standing offer ToU retail contract in SA. The retail component for time of use was developed in consultation with SA Power Networks based on a two tiered structure which reflects retail market drivers in response to the wholesale market.

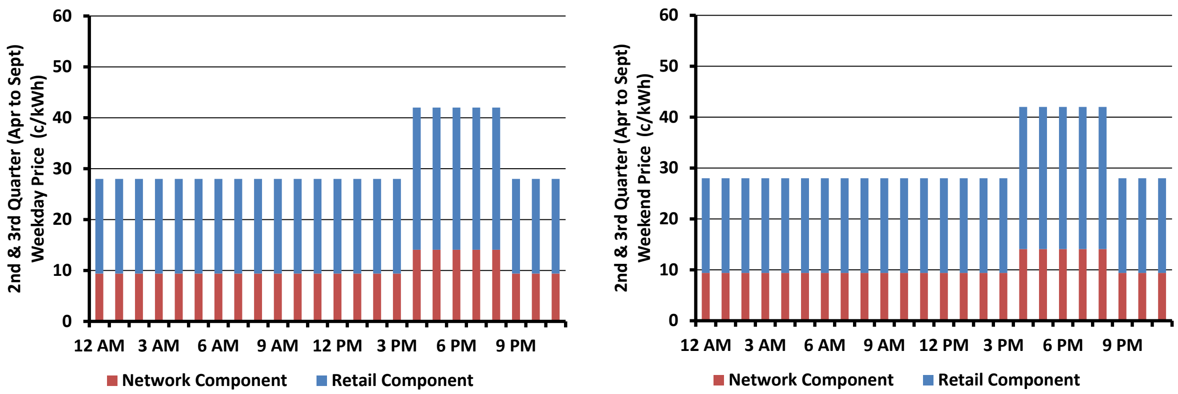
The structure of Tariff Type 2 for residential customers over different times of the year is presented in Figure 8 to Figure 10.

Figure 8 – Tariff Type 2 (Time of Use) 1st Quarter (January to March)



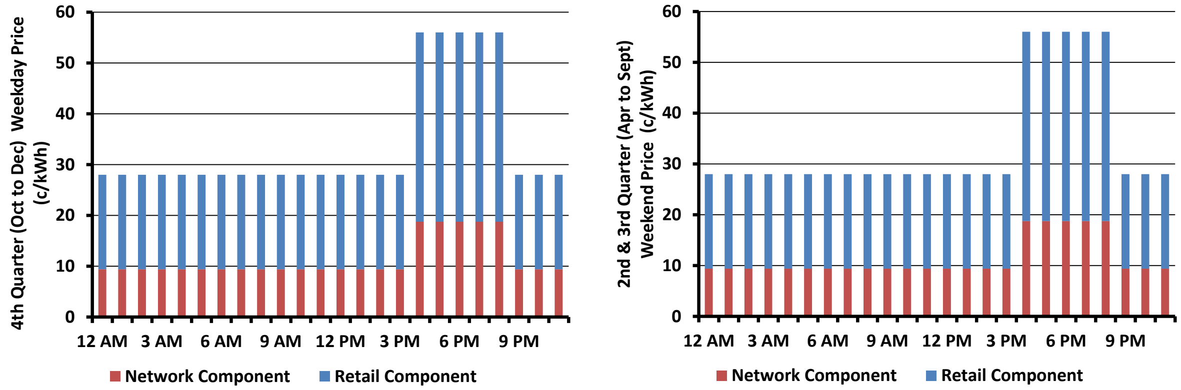
Source: SA Power Networks

Figure 9 – Tariff Type 2 (Time of Use) 2nd and 3rd Quarter (April to Sept)



Source: SA Power Networks

Figure 10 – Tariff Type 2 (Time of Use) 4th Quarter (Oct to Dec)



Source: SA Power Networks

This tariff as presented in Figure 8 to Figure 10 was unchanged in the modelling task.

4.1.4 Tariff Type 3 - Monthly Demand and Time of Use Tariff

Tariff Type 3 is comprised of SA Power Networks' Monthly Demand (MD) tariff which includes both a demand charge and a consumption charge and the retail time of use tariff as per Tariff Type 2. The structure of Tariff Type 3 for both residential and non-residential customers is presented in Table 3.

Table 3 – Tariff Type 3 (Monthly Demand and Time of Use Tariff)

Period	Network Tariff	Retail Tariff	Total
Consumption Component			
1st Quarter (Jan to Mar) Peak	7 c/kWh	24 c/kWh	31 c/kWh
1st Quarter (Jan to Mar) Off Peak		15 c/kWh	22 c/kWh
2nd, 3rd & 4th Quarter (Apr to Dec) Peak		20.9 c/kWh	27.9 c/kWh
2nd, 3rd & 4th Quarter (Apr to Dec) Quarter Off Peak		14.9 c/kWh	21.9 c/kWh
Peak Demand Component			
Summer Peak*	$30/kW per month		
Winter Peak*	$15/kW per month		
All Seasons Off Peak**	$7/kW per month		

* Based on the highest monthly half hourly demand during peak period of 4pm to 9pm

** Based on the highest half hourly demand each month during off-peak periods, to the extent that this capacity is greater than the highest peak period capacity.

Source: SA Power Networks

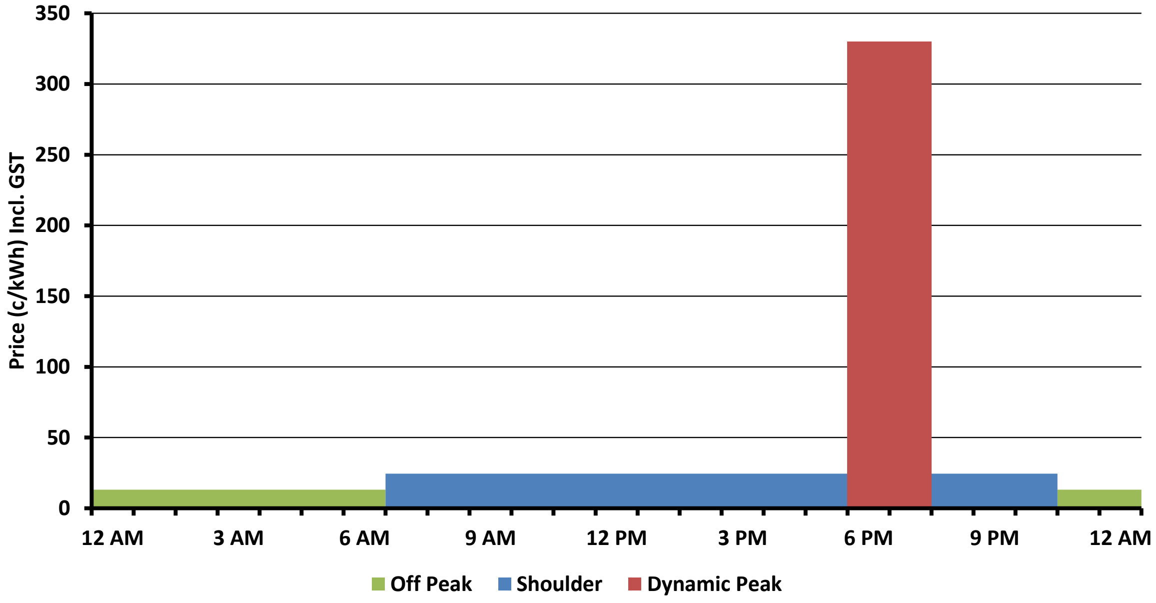
As a consequence of normalisation, the network any time consumption charge was decreased from the 7 c/KWh presented above to 6.5 c/kWh for residential customers and increased to 8.49 c/kWh for non-residential customers.

4.1.5 Tariff Type 4 – Monthly Demand and Dynamic Peak Price Tariff (DPP)

For the purposes of this assessment, Energeia based this tariff on the PriceSmart[2] tariff structure trialled under the Australian Government funded *Smart Grid, Smart City* program. An overview of this tariff is shown in Figure 11.

PriceSmart was created by reducing a three tiered ToU tariff structure to a two tiered ToU tariff by extending the shoulder period price through the peak period. Secondly, a dynamic peak price of $3.30/kWh was applied seven times per year to coincide with retailers' peak periods over a two hour period. The retailer, through email or text message, alerts the customer 24 hours in advance. Accordingly, all customer efforts during the peak period were assumed to have a diversity function of one (highly correlated impact).

Figure 11 – SGSC PriceSmart Tariff



Source: SGSC

For the remainder of the time it was assumed that the anytime consumption component of the network monthly demand charge applied as well as the retail time of use tariff as shown in Table 4.

[2] http://www.smartgridsmartcity.com.au/EnergyAustralia-trial/PowerSmart-solutions/PriceSmart.aspx

Table 4 – Tariff Type 4 (Dynamic Peak Price)

Period	Network Tariff	Retail Tariff	Total
Consumption Component			
1st Quarter (Jan to Mar) Peak	7 c/kWh	24 c/kWh	31 c/kWh
1st Quarter (Jan to Mar) Off Peak		15 c/kWh	22 c/kWh
2nd, 3rd & 4th Quarter (Apr to Dec) Peak		20.9 c/kWh	27.9 c/kWh
2nd, 3rd & 4th Quarter (Apr to Dec) Quarter Off Peak		14.9 c/kWh	21.9 c/kWh
Peak Demand Component			
Summer Peak*	$30/kW per month		
Winter Peak*	$15/kW per month		
All Seasons Off Peak**	$7/kW per month		

Source: SA Power Networks

As a consequence of normalisation, the off peak and shoulder winter retail tariff component was increased to 17.7 c/kWh instead of the 14.9 c/kWh and 28.3 c/kWh instead of 24 c/kWh respectively presented above.

4.2 Customer Segments

For the purposes of this assessment, customers were segmented into the following five customer types:

Residential

1. Residential with a gas connection;
2. Residential without a gas connection;
3. Apartments

Non-Residential

4. Small Business (SB) (consumption less than 10MWh per annum); and
5. Business (consumption 10-160MWh per annum).

A representative customer load for each segment was provided by SA Power Networks.

Section 4.2.1 outlines the approach to the segmentation as well as a description of the various attributes of each segment which informed the modelling assumptions.

4.2.1 Segmentation Approach

The five key customer segments were selected based on differences in annual load profile and physical characteristics, which were considered likely to give rise to differentiated approaches to:

- Short term and long term behaviour change in response to tariffs; and
- Investment in DER and energy efficiency.

Table 5 summarises which customer groups were assumed to be able to take up DER technologies based on physical characteristics alone.

Table 5 – Customer Eligibility to Adopt Various Technologies

Customer Type	Solar	Combined Heat and Power	Storage
Residential w/ Gas	✓	✓	✓
Residential w/ No Gas	✓	✗	✓
Apartment	✗	✗	✗
Business	✓	✓	✓
Small Business	✓	✓	✓

Source: Energeia

The five key customer groups were also selected to be collectively exhaustive of SA Power Networks' small customer base with the exception of customer groups rated greater than 80kVA. The analysis of these representative segments therefore provided an indicative assessment of the impact of a change in tariff structure on SA Power Networks' entire small customer base.

4.2.2 Residential

There are roughly 748,000 residential energy customers in SA. For the purpose of this assessment, these have been segmented as follows:

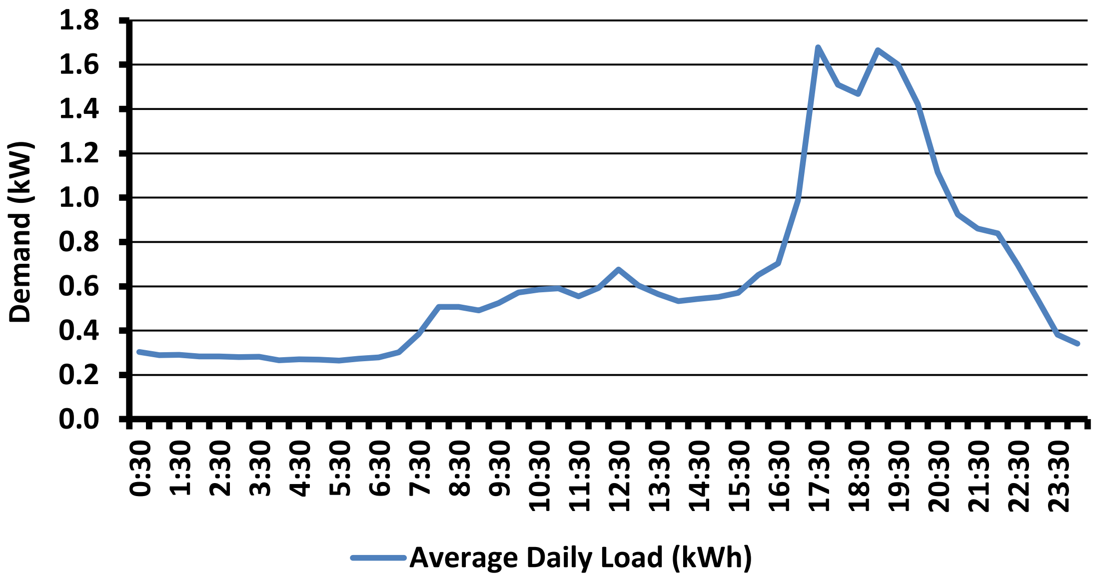
- Standalone houses; and
- Apartments.

This segmentation definition was selected to highlight the ability of customer sub groups to adopt DER. This following sections detail the characteristics of each of these customer groups and the implications for their assessment.

Standalone Houses

Residential standalone customers make up the majority of SA Power Networks' consumer base with 551,656 dwellings. The representative profile assessed is characterised by a customer with 5.6 MWh per annum consumption and a peak demand of 6.0 kW. A representative residential (standalone house) peak summer daily load profile is shown below in Figure 12.

Figure 12 – Residential (Standalone House) Average Daily Load Profile (Half Hourly)



Source: SA Power Networks

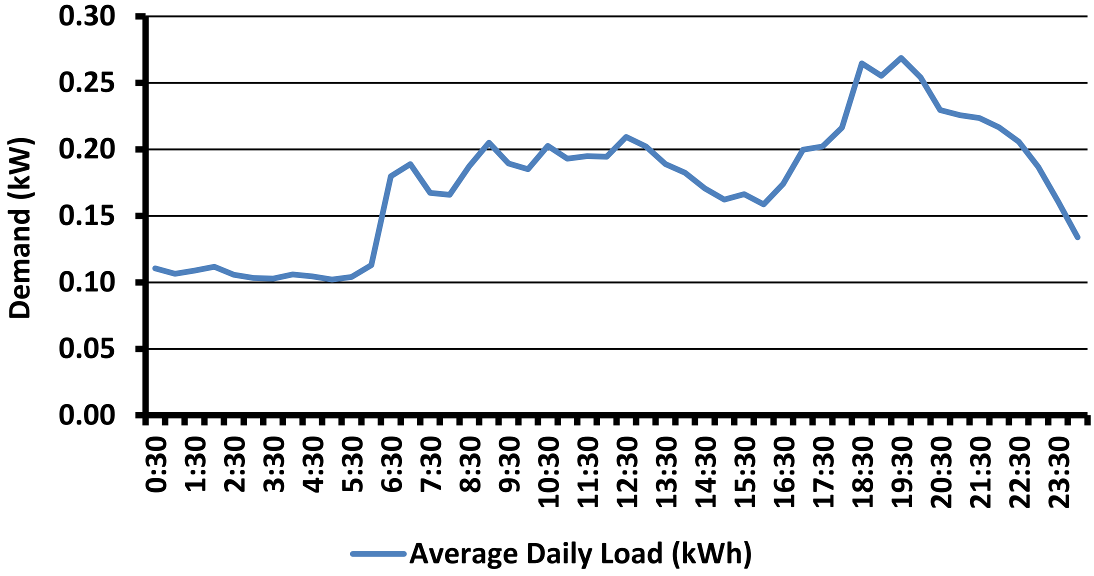
It was assumed that customers without reticulated gas were not able to effectively operate a CHP system, consistent with manufacturers' specifications. For this reason, the 42% of residential customers without a gas connection[3] were excluded from adopting CHP.

[3] ABS, Environmental Issues: Energy Use and Conservation, 4602.0.55.001, Energy Use and Conservation Tables, March 2011

Apartments

The half hourly customer load profile assessed for apartment profile was characterised by an annual consumption of 1.5 MWh and a peak demand of 3.4 kW. A graphical representation of an apartment peak summer daily load profile is shown below in Figure 13.

Figure 13 – Residential (Apartment) Average Daily Load Profile (Half Hourly)



Source: SA Power Networks

Apartments were assumed to not be able to adopt solar due to a lack of access to roof space as well as the existence of contractual issues relating to joint investment and sharing of benefits of solar PV. It was further assumed that apartments were not able to adopt CHP or battery systems because of substantial space requirements to accommodate these systems. Apartments therefore did not adopt any DER technology within the model.

4.2.3 Non-Residential

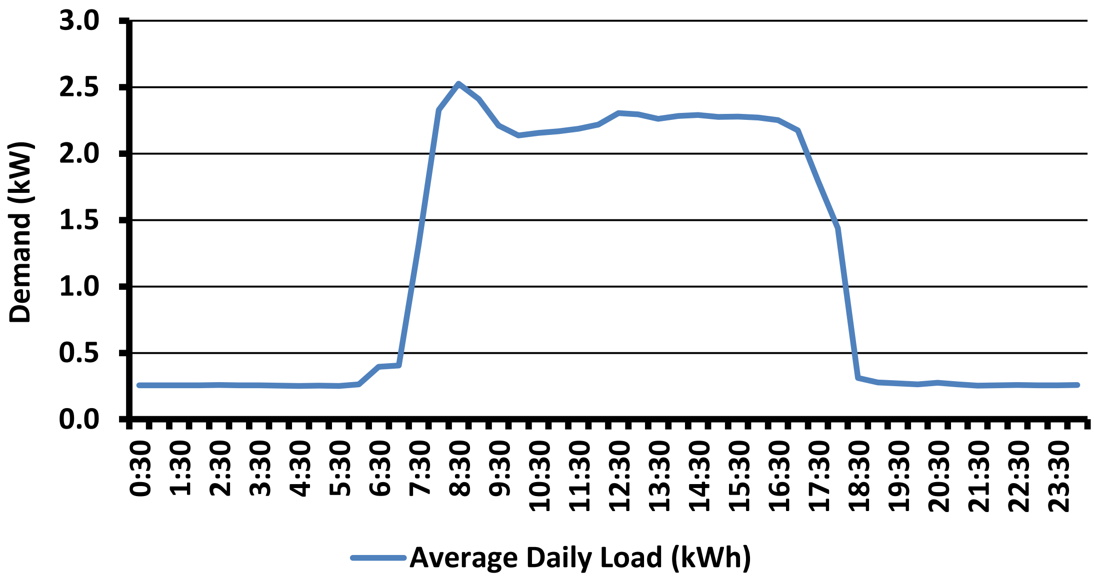
Energeia's scope of work extended to the analysis of non-residential customers rated up to 80 kVA only. Customers greater than 80 kVA were therefore excluded.

Small Business

The Small Business (SB) category was defined as business customers with annual consumption of less than 10 MWh per annum. There are roughly 62,500 small businesses customers in SA that fit this category. It was assumed that these customers operate out of standalone premises, either running their businesses from transformed residential premises or a small shop or office.

The small business profile provided by SA Power Networks had a peak demand of 3.4kW and a consumption of 10MWh. A representative small business summer weekday daily load profile is shown below in Figure 14

Figure 14 – SB Average Daily Load Profile (Half Hourly)



Source: SA Power Networks

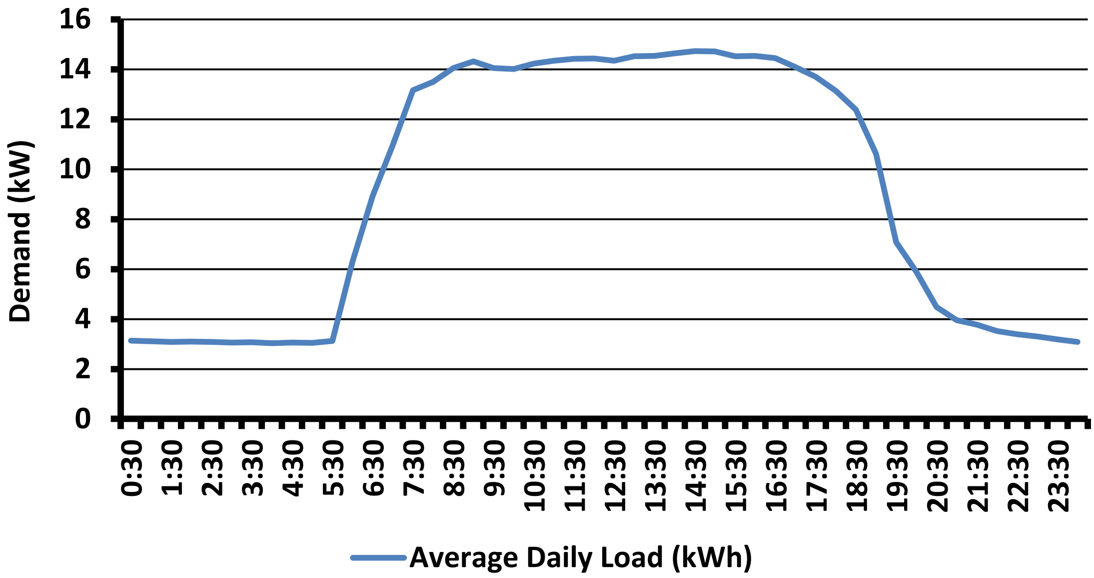
The SB premise's load profile was observed to have minimal weekend demand as so was assumed operate only Monday to Friday.

Small business premises were assumed to have similar physical constraints to residential buildings and therefore for the purposes of this analysis were assumed to be able to take up solar PV up to the maximum system size constraint for residential buildings. Small businesses were also assumed to be exposed to non-residential tariff structures and to have access to reticulated gas.

Business

For the business customer segment, a representative non-residential profile with a consumption of 80MWh per annum consumption and a peak demand of 53.2 kW was used. A graphical representation of a representative business summer daily load profile is shown below in Figure 15.

Figure 15 – Business Average Daily Load Profile (Half Hourly)



Source: SA Power Network

The total number of business customers within SA Power Networks area is 33,600[4] and the total number of commercial buildings identified in SA is 17,100 buildings[5]. It was assumed that all 17,100 customers in standalone non-residential buildings have access to gas and operate as a sole tenant, and were therefore able to adopt CHP, storage and/or solar PV. All non-residential premises were also assumed to have access to mains gas to enable CHP adoption.

4.3 Distributed Energy Resource Technologies

For the purposes of this assessment, it was assumed that each customer has the option to invest in DER over time. It was further assumed that those customers who chose to invest selected the segment's optimal configuration of DER technologies based on the highest net present value of each possible combination.

The technologies available for selection by the customer were:

- Solar PV;
- Combined Heat and Power (CHP); and
- Storage.

The following section details the assumptions with respect to technology characteristics and operating modes which impacted the financial return.

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[4] SA Power Networks email correspondence, 19th February 2014

[5] Geoscience Australia

4.3.1 Solar PV

Solar PV systems were assumed to be of the roof mounted mono-crystalline type due to the relative prevalence of this type of system in the market and the relatively high efficiency per unit area of roof space compared to polycrystalline and amorphous thin film types.

The solar PV generation profile applied in the modelling was derived from the National Renewable Energy Laboratory's (NREL) Renewable Resource Data Centre[6]. NREL's historical weather and solar radiation patterns for SA were used to estimate energy outputs from solar PV panels specifically for SA.

The size of the solar PV system was restricted by each customer's roof size and shading from trees and other buildings. In order to inform the analysis of the potential constraints for solar PV sizing, Energeia undertook a survey of roof sizes in Adelaide. This research suggests a maximum system size, after accounting for shading and aspect, for residential and business premises of 15kW and 90kW respectively[7].

4.3.2 Combined Head and Power (CHP)

The CHP technology assumed was a solid oxide fuel cell generating electrical and heat energy. The particular technology assessed was modelled on the BlueGen product. This technology is best operated as a base load power plant as described by BlueGen[8]. In keeping with the manufacturer's recommendations, a flat base load profile was created to represent the system's output, which was scaled depending on the size of the unit selected.

There were a number of constraints on the adoption of CHP systems including physical size and availability and access to reticulated gas.

A BlueGen CHP system has a mass of 25kg for a 2kW system[9]. Therefore the size of residential units was restricted to 10kW, or just over 125kg and the size of business units to 30kW, roughly 375kg. Experience from Australian trials suggested that the need to use cranes to lift and support these systems limits their installations.

Whilst units up to 30kW are not currently available, a customer wanting a larger system could stack smaller systems in parallel to achieve the 30kW effective capacity.

As discussed in Section 4.2.2, apartments were assumed to have insufficient space to install a CHP system. Additionally, CHP requires mains gas to operate and is there for only available to customers with reticulated gas.

The final constraint on CHP was its commercial availability within the Australian market. Whilst BlueGen has recently left the Australian market, they are still in operation, having moved all production to Germany in late 2012[10] to take advantage of better economic conditions. It was assumed that the advanced renewable energy market of Germany and the positive regulatory supports of nations such as

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[6] National Renewable Energy Labs, PV Watts™ A Performance Calculator for Grid-Connected PV Systems http://rredc.nrel.gov/solar/calculators/pvwatts/version1/International/inputv1_intl.cgi

[7] Roof size based Energeia empirical research

[8] BlueGen Case Study: A Bright Sustainable Future with BlueGen, http://www.bluegen.info/Assets/Files/(EN).Bright.Sustainable.Future.With.BlueGen.pdf

[9] Ceramic Fuel Cells Limited, May 2009. *Introducing: BlueGen. Modular Generator, Clean Power and Heat.* http://www.cfcl.com.au/Assets/Files/20090522_CFCL_BlueGen_Launch_22May09.pdf

[10] Parkinson, G (2012), *Ceramic Fuel Cells packs is bags and moves the Europe,* Oct 2012, http://reneweconomy.com.au/2012/ceramic-fuel-cells-packs-its-bags-and-moves-to-europe-47229

Japan[11] will result in continued product advancement. It was therefore assumed that CHP systems will once again become available in Australia from 2016. Accordingly, no CHP system adoption was allowed until 2016.

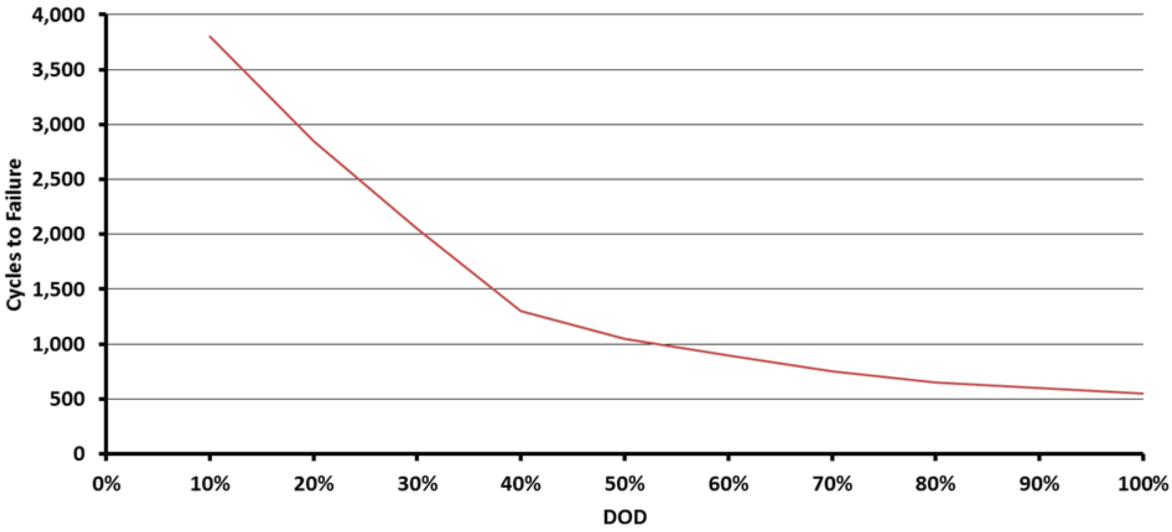
4.3.3 Storage

A range of storage options were screened to determine the most cost effective solution for each tariff type. Lead acid storage technology was utilised for all customers due to its comparatively low capital cost and the fact that it is an established technology.

The lead acid battery was assumed to have a life span of the lesser of seven years or around 1,000 cycles[12]. The annualised cost of the battery is therefore the greater of the value of annual depreciation or the cost of the battery divided by the total number of battery cycles per year.

Further, the total number of cycles to failure is dependent on the depth of discharge. This relationship for lead acid batteries is shown in Figure 16.

Figure 16 – Depth of Discharge (DOD) for Lead Acid Batteries



Source: Risø National Laboratory [13]

This relationship implies that in order to increase the lifespan of storage systems, they should either be used frequently for short periods at a low depth of discharge, or used relatively infrequently at a greater depth of discharge.

The inclusion of storage provided an added level of complexity to the modelling task as it interacted with the customer's load, distributed generation output and the tariff structure assumed. The following section describes the battery algorithm that drove charging and discharging of the battery and its interaction with distributed generation depending on the prevailing tariff.

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[11] Pentland, W. (2012) *Japan Moves the Needle on CHP,* April 2012 http://www.forbes.com/sites/williampentland/2012/03/04/japan-moves-the-needle-on-micro-chp/

[12] 1,000 cycles is based on a usage pattern at an average 50% depth of discharge

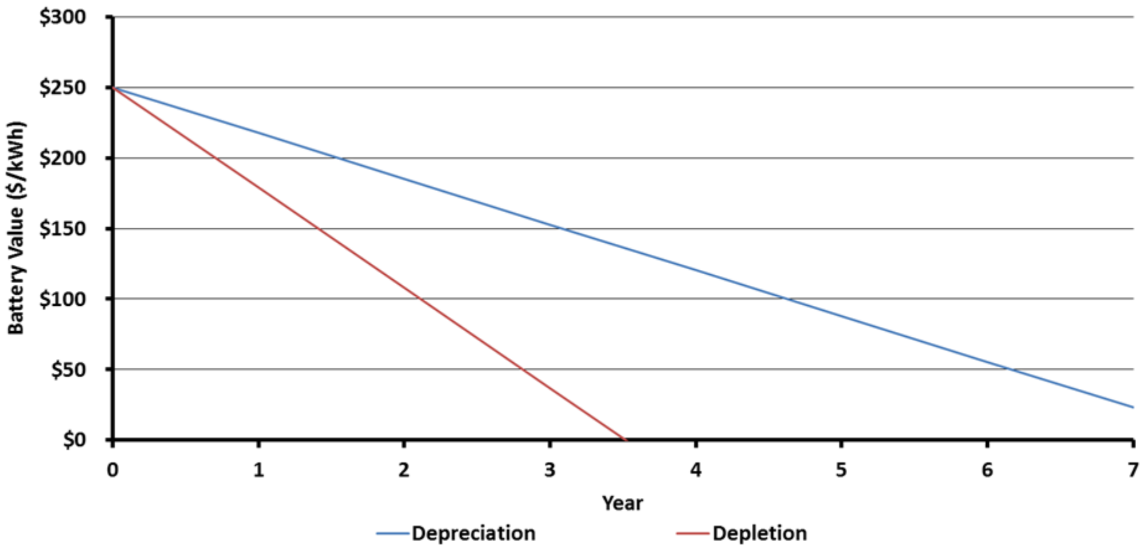
[13] Bindner, H., Cronin, T., Lundsager, p., Manwell, J.F. Abdulwahid, U., Baring-Gould, I., (2005) *Lifetime Modelling of Lead Acid Batteries,* Risø National Laboratory, April 2005, p23

Tariff Type 1 (IBT)

Because of the volume nature of IBT, if a customer was facing this tariff, the storage algorithm worked to simply to soak up any excess generation, and then discharge at any point where the battery has a charge higher than its set depth of discharge and where the customer has energy import demand.

The maximum depth of discharge under IBT was set at 50% to allow the customer to benefit from a large number of charging cycles. This only occurred where the costs, including costs of storage depletion and depreciation, were less than the benefits.

Figure 17 – Storage Lifespan Tariff Type 1



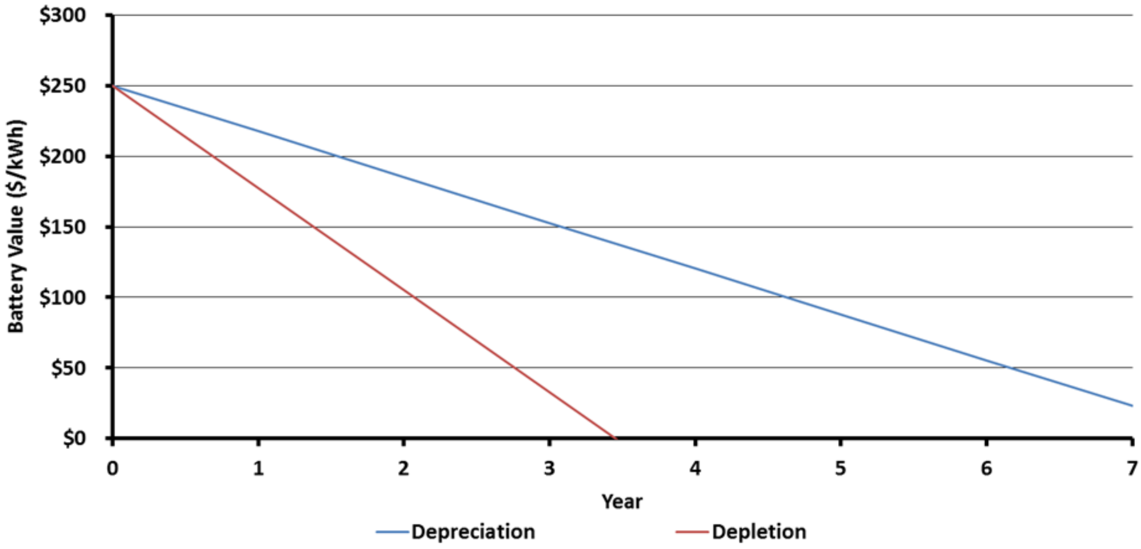
Source: Energeia

As a result of these settings, the battery lifespan was limited by the depletion as shown in Figure 17.

Tariff Type 2 (Time of Use)

A customer on a ToU tariff operated their battery in a similar way to those under IBT but with the added constraint of optimising the value of the battery by only discharging during peak periods. Again the depth of discharge was set at 50% to optimise the number of charging cycles.

Figure 18 – Storage Lifespan Tariff Type 2



Source: Energeia

As a result of these settings the battery lifespan for Tariff Type 2 is limited by the depletion as shown in Figure 18, very similar to that for Tariff Type 1.

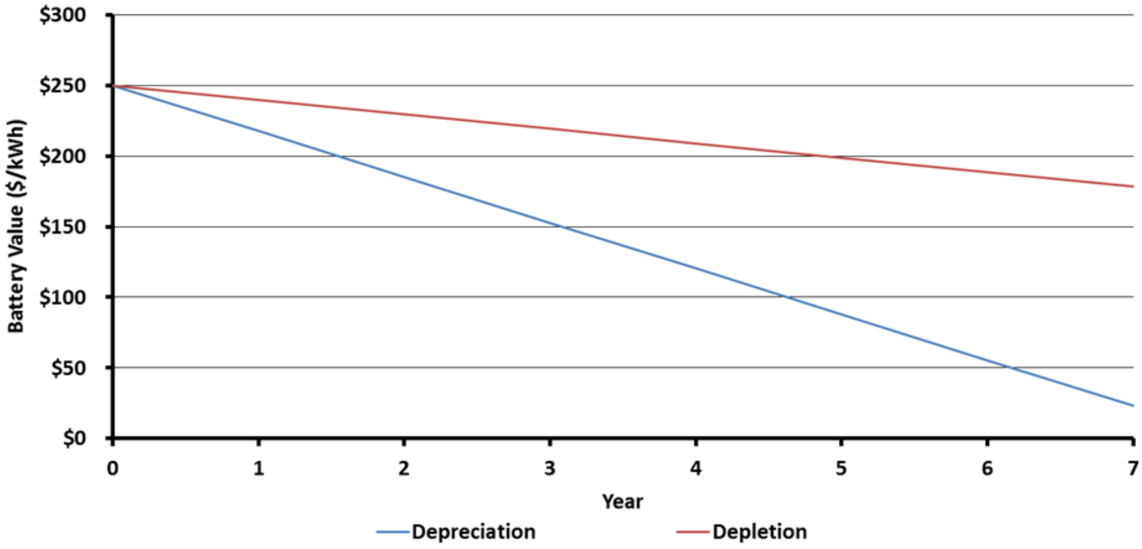
Tariff Type 3 (Maximum Demand and Time of Use)

The MD tariff added a step change in modelling complexity. As the tariff was no longer a purely consumption based tariff, it required a more sophisticated battery algorithm.

To maximise the return on investment, a customer on a MD tariff sought to cut their largest peaks during peak periods of the month. By operating the battery in this way a customer was able to discharge the battery at times when the avoided peak was worth up to $30/kW (depending on the season).

Under the MD tariff the storage algorithm assumed a maximum depth of discharge of 90% to provide more impact. It is assumed that the discharge was set based on the customer's historic energy consumption and weather forecasts in order to discharge as the customer approached its peak demand for the month. This approach limited the number of cycles per peak period as the higher depth of discharge resulted in an accelerated depletion of the battery, but at a higher rate of return. As a result of these settings the battery lifespan was limited by the depreciation as shown in Figure 19.

Figure 19 – Storage Lifespan Tariff Type 3



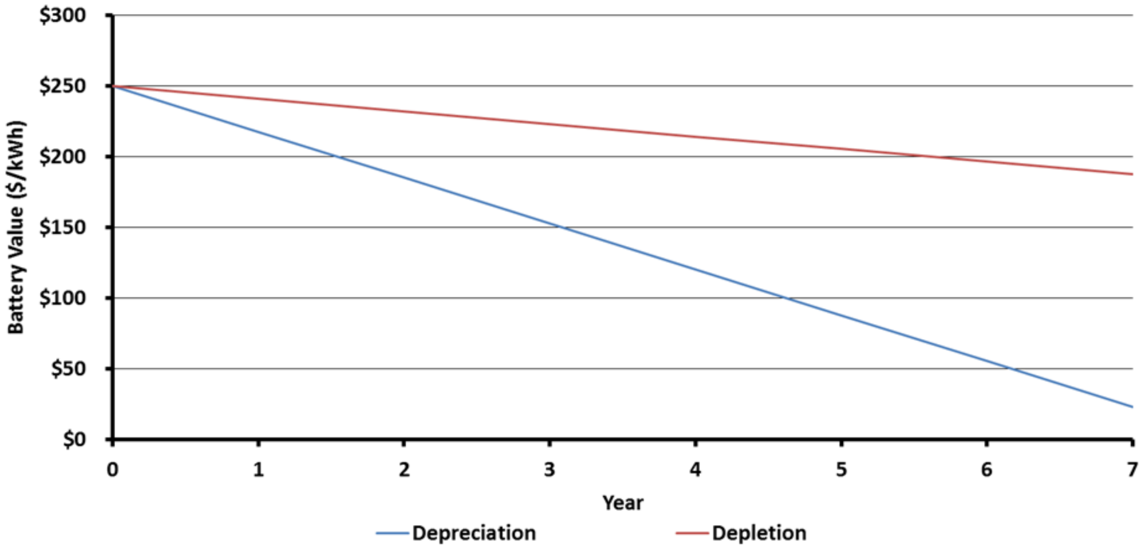
Source: Energeia

Tariff Type 4 (Dynamic Peak Price)

As discussed in Section 4.1.5, under a DPP retail tariff, customers were provided retail price spike signals over a period of two hours. As a result of this assumption, under DPP, all batteries are assumed to discharge during the peak event. The system wide reduction in peak demand under the DPP tariff from batteries was equal to the summation of the battery capacity (at 90% depth of discharge) of all batteries divided by the length of the peak event period.

Battery recharging was prioritised under this tariff. This means that the battery was recharged as soon as the DPP ended so that it could be ready for the next opportunity. Mains supply was therefore used if no distributed generation export was available.

Figure 20 – Storage Lifespan Tariff Type 4



Source: Energeia

As a result of these setting the battery lifespan was limited by the seven year depreciation as shown in Figure 20.

4.4 Smart Metering

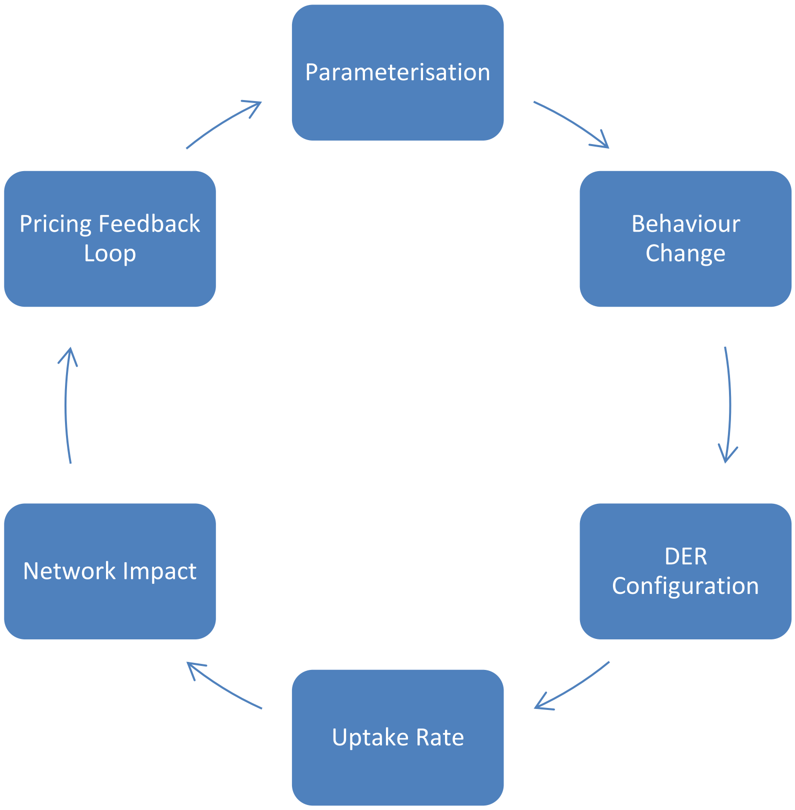
Because of the time and capacity information assessed under dynamic tariffs, it was assumed that under these tariffs an increased functionality meter was required as part of the investment in DER. This additional functionality enables networks to verify performance for the purpose of determining network benefits and determining bills.

The model has assumed the installation of a smart meter with each product adoption. This had the effect of adding an additional cost to each DER installation. However, each smart meter was assumed to be capable of managing multiple technologies and was considered a fixed cost spread over the suite of products adopted.

4.5 Modelling Methodology

The modelling process can be separated into six overarching steps. Because of the interdependencies of these components, the modelling was run each year in an iterative process as shown by Figure 21.

Figure 21 – Model Operating Process



Source: Energeia

The following section details each of the modelling components and their interactions.

4.5.1 Parameterisation

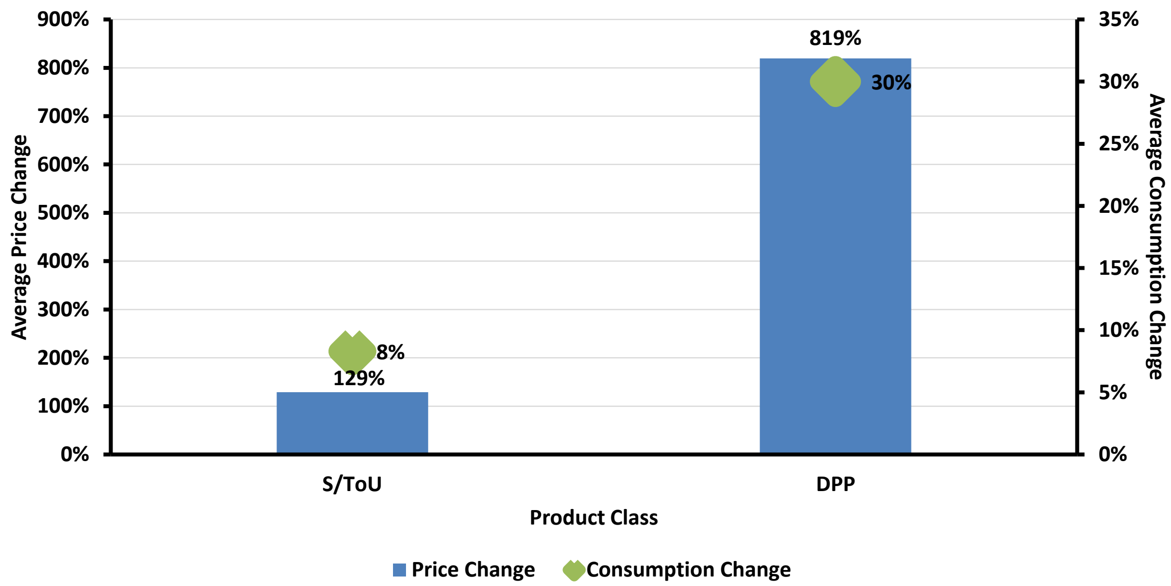
At the beginning of each year the model was updated for customer demand growth, population growth, retail energy price changes (gas and electricity) and technology price changes. The changes to these underlying parameters were important for setting the framework within which the model operated. Importantly, the parameterisation stage fed back the impact of network costs and revenues on network prices as a result of customer behaviour in the previous year.

4.5.2 Behaviour Change

Customer behavioural responses to tariffs varied greatly depending on the tariff structure and prices. To inform this analysis, Energeia performed in-depth research into Australian and overseas customer tariff trials and literature covering over 19 trials and 81 data points (See Appendix 2 for details). The data was collated and assessed to estimate consumer behaviour outcomes under the three different tariffs (using IBT as a baseline) over the short and longer term by time of use.

The research showed a clear grouping of results around each of the ToU and DPP tariffs. Figure 22 shows the change in price during the peak period and the associated short term behavioural impact change in energy demand during that period.

Figure 22 – Consumer Short-term Behavioural Response



Source: Energeia, Essential Energy, Ergon Energy, Ausgrid, Endeavour, Origin Energy, Synergy, Energex

Interestingly, the research showed that changes in peak demand as a result of shifting to ToU diminish from a short term impact of 8.3% to a long-term impact of 2.4%. For DPP, the short term behaviour change is more likely to be sustained as the incentive only exists over a very short time frame (fourteen hours a year). There was very little literature identified for trials of MD tariffs. Of the 19 sourced identified, only one Swedish trial provided data on short and long term responses in the residential sector[14].

For simplification, the average of the short and long term change was applied to the customer's load profile where ToU and MD tariffs were adopted. For DPP tariffs, the short term impact on peak demand was assumed to be sustained.

The net change on a customer's peak demand as a result of the various tariffs is summarised in Table 6. As expected the response has been greatest under the DPP and lowest under the ToU tariff.

[14] Bartusch C., Wallin, F., Odlare, M., Vassileva, I., Wester, L., (2011) *Introducing a demand based electricity distribution tariff in the residential sector: Demand response and customer perception*, Energy Policy 39 (2011) 5008–5025

Table 6 – Consumer Peak Demand Response (% Reduction)

Tariff Type	Short Term Response	Long Term Response	Average
Time of Use	8.3%	2.4%	5.3%
Dynamic Peak Price	30%	30%	30%
Maximum Demand	-19.2%	-16.2%	-17.7%

Source: Energeia

These values were applied to customers' load profiles within the model depending on the tariff adopted.

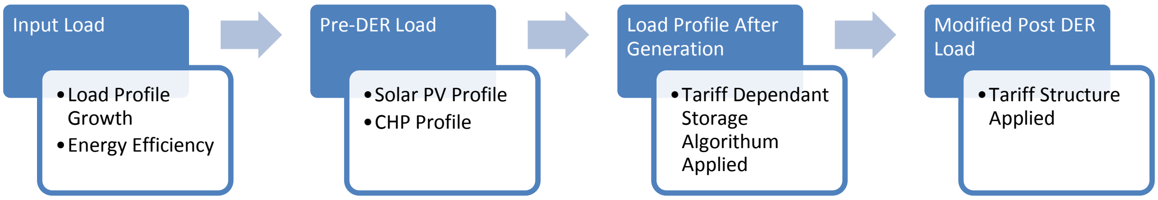
4.5.3 DER Configuration

The objective of the DER model was to identify and value the optimal DER configuration.

The model used half-hourly data of a SA Power Networks-supplied representative load profile for each customer segment to determine a benchmark annual bill (bill with no DER) and alternative bills including technology costs under each permutation of technology adoption (up to the constraint level of that particular customer and technology set). The model cycled through each possible combination of technology adoption for each representative customer segment and identified the configuration that delivered the best financial outcome (net present value).

The model assessed the customer's alternative bill by applying the selected tariff structure to the import load (customer load profile minus price elasticity effects in the year before adopting DER) using half hourly incremental data. The load was impacted under all potential DER configurations as described in Figure 23.

Figure 23 – Load Modification

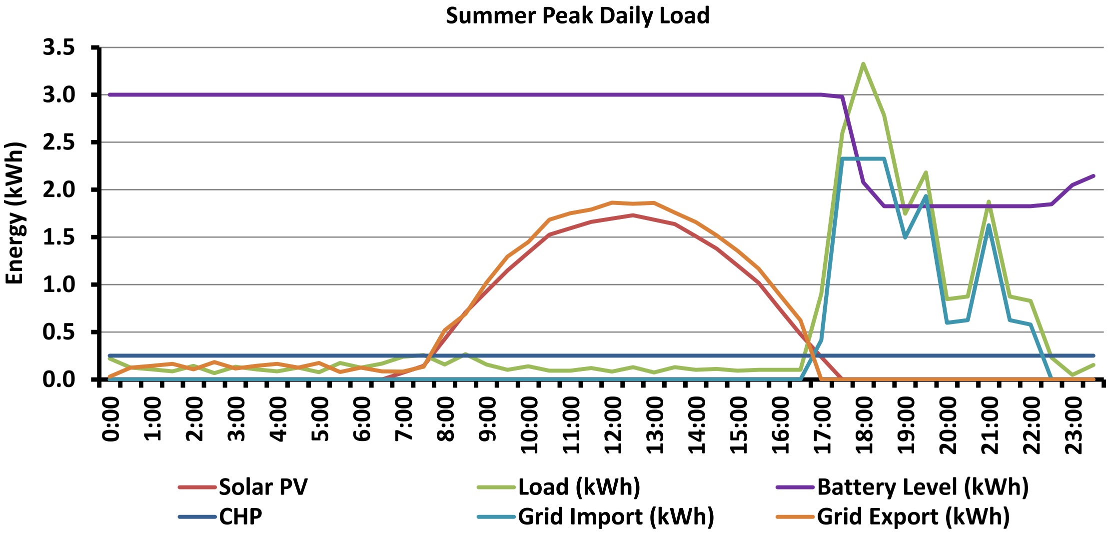


Source: Energeia

An example of a half hourly load profile and the effects of an annual capacity based network tariff are illustrated in Figure 24 (note this is half hourly kWhs). The original customer profile minus the price elasticity effects (light green) is impacted by each of the different generation technologies which are solar PV between 8am and 5pm and CHP throughout the whole day. Further, as this is a dynamic tariff, the dispatch of the battery over the peak event can be clearly seen to clip the customer's peak and commence recharging with excess CHP generation after 22:00. In this example, the 1.5kW (power) 3 kWh (energy) battery is being dispatched to shave the summer peak day demand.

The aggregate impact of the technology on the customer's resulting load profile at the grid level is also observed (Grid Import and Grid Export).

Figure 24 – Customer Level Technology Operation (Summer Peak Day)



Source: Energeia

Using the process described in the example above, the new customer bill was derived using the new import profile, with the export profile receiving the FiT that was assumed to be available in the given year. The net present value of the particular investment profile was calculated using a 15 year investment horizon for each decision. The new bill and DER capital and operation costs were compared against all configurations in order to choose the most beneficial option for the customer in each year. In this way the optimal configuration decision was selected for each customer group.

4.5.4 Uptake Rates

Analysis of solar PV adoption shows that customer financial incentives are the key driving factor for the adoption of DER technology. Better rates of return on investment (ROI) generally lead to a greater number of customers investing in the technology. Energeia's customer behaviour model uses a relationship between historical ROI and solar PV penetration rates to estimate the uptake of distributed resources configuration in a given year.

The uptake model was based on actual historical data on system pricing and customer adoption patterns that has been built up over the 10 years of the solar market in Australia.

The relationship used historical data for the *average* size system installed in any one year to determine the ROI. However, while customers are trending towards the selection of the optimal size system, this has not necessarily been the case historically. Therefore, when assessing the historical relationship between uptake and ROI there is an over estimation of uptake in any one year. A review of historical data indicated that the difference in the ROI of optimal sized systems and the average size systems is approximately 13%. Accordingly, the relationship was reduced at implementation by 13% to account for this difference.

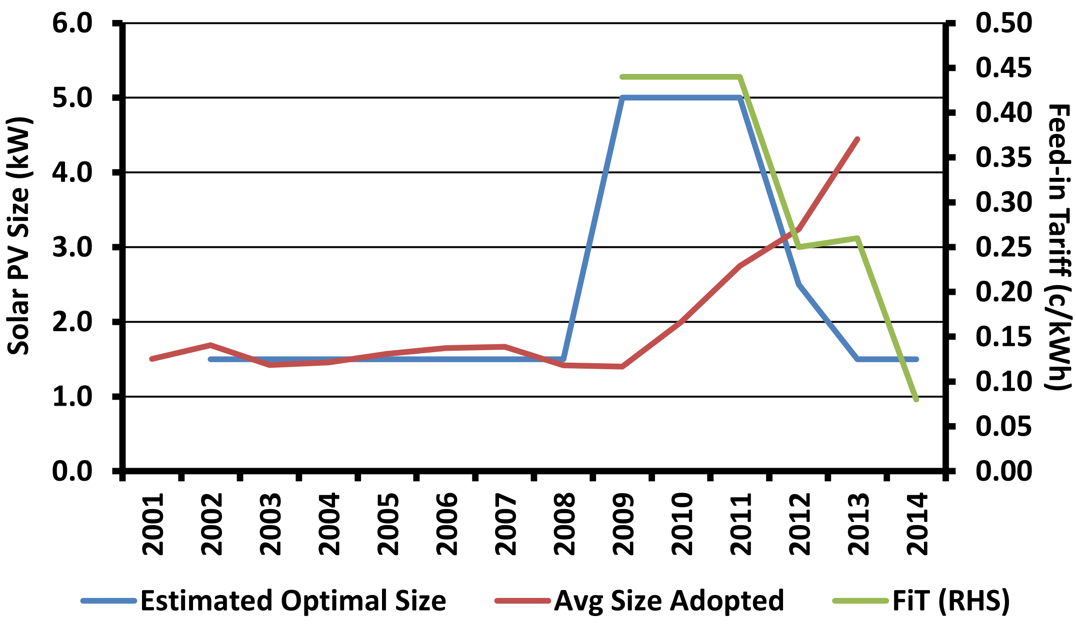
The uptake rate was applied to remaining available market (those who have not adopted DER in a previous period) to find the discrete number of customers taking up DER in that year.

Similarly to the residential market, the non-residential relationship uses the average size system. Because the non-residential market has only had significant uptake over the last three years there is limited data and quarterly uptake rates were utilised.

A review of historical data indicated that the difference in the ROI of optimal sized systems and the average size systems in the non-residential sector has been approximately 35%. The relationship is therefore adjusted by a factor of 35% to account for the difference between the optimal size system and the average size system adopted.

A review of historical data also indicated that there is a two to three year lag on residential system sizes related to policy changes, specifically the impact of FiTs, which drives configuration outcomes as system size increase above internal demand during the sunlight hours. This impact is not only due to delays in information dissemination, but also to stock lags as vendors must clear old stock before reacting to new policy impacts on market configurations. As can be seen by Figure 25 the system size lags the optimal size by roughly three years.

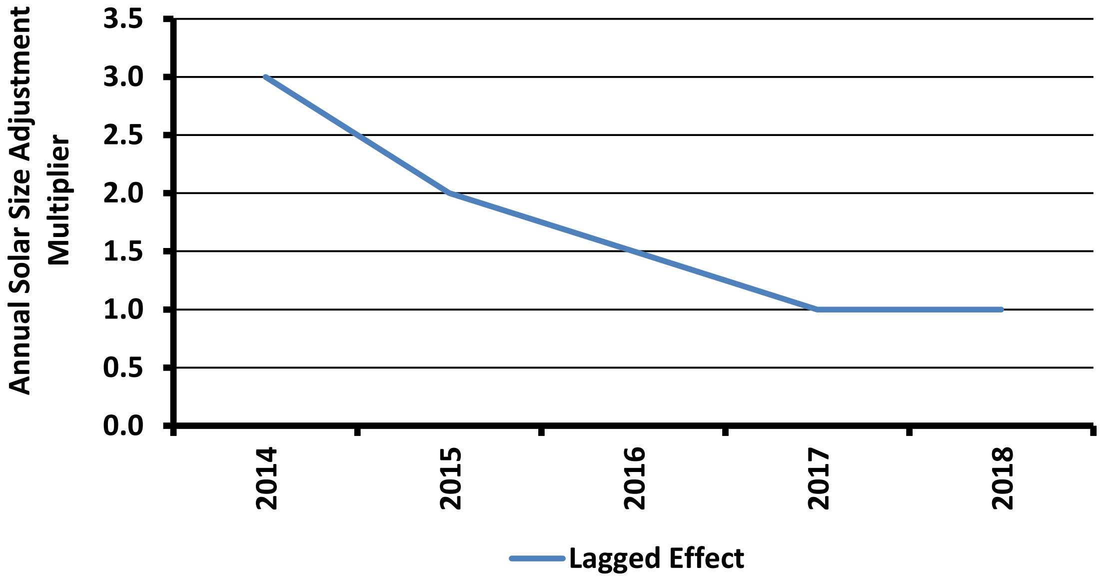
Figure 25 – Relationship between Size and Policy Changes



This also shows that the impact of the removal of the premium FiT in 2013, as the final favourable solar system support, has yet to be observed in terms of a reduced size of PV systems closer to the optimal.

Accordingly, the customer configuration assumed in the model for residential customers included a lagged sizing impact. This lagged impact was implemented to adjust customer optimal configuration and flowed through to the customer uptake rate that is discussed in Section 4.5.4.

Figure 26 – Lagged Information Impact



Since there are not expected to be further premium FiT supports, the impact of the sizing adjustment dissipated over the first three years and was removed by 2017 as shown in Figure 26.

4.5.5 Network Impact

In order to assess the impact of customer outcomes at the aggregate level, the customer peak and consumption impacts were aggregated up to the customer market segment level. The five market segments were further aggregated to provide the total impact on overall consumption and peak demand, which are critical metrics for both networks and retailers.

Peak Demand

Network peak demand was calculated as the sum of each customer's after diversity maximum demand (ADMD). ADMD represents the level of the customer's own peak demand that coincides with the network's peak demand. The relationship between a customer's peak and the network peak is defined by the diversity factor. In order to calculate a customer's ADMD, a customer's peak demand was multiplied by a diversity factor of 0.5 supplied by SA Power Networks.

Consumption

Market consumption was calculated as the sum of all the individual customers' consumption after behavioural, load growth and DER impacts.

4.5.6 Pricing Feedback Loop

In order to capture the interaction between customer responses and network costs and revenues the model incorporated a pricing feedback loop. The feedback loop captured the revenue and peak cost impacts relative to business as usual and used them to adjust the annual price change. This interaction was designed to synthesise the impact of consumer behavioural changes and investment decisions in DER as they relate to network revenues and augmentation cost.

Where a customer's decision resulted in a decrease in their bill without a corresponding decrease in network costs, network prices were increased in the following year to prevent under-recovery of network revenue. Inversely, if the customer's actions result in lower network peak demand, the reduced cost of network augmentation was captured by being fed back via reduction in the price growth rate.

4.6 Key Exogenous Assumptions

The exogenous economic variables were key inputs to the modelling process which provided the framework within which tariff options were assessed. These included macroeconomic assumptions, energy prices and technology prices. The exogenous assumptions are represented in a scenario that reflects an internally consistent story that described a likely future state of the world.

Energeia has used AEMO's National Electricity Forecasting Reports (NEFR) as the basis of the economic variable outlooks. Both consumption and peak demand growth are based upon the NEFR 2013 report. The NEFR only reports one state wide growth rate for peak demand and consumption, which was applied to all the load profiles analysed.

The NEFR assumptions were supplemented by Energeia's expertise in the areas of technology learning curve modelling. In particular, future pricing curves for emerging technologies were estimated based on past experience of solar PV technology learning curves and research into forecasts of pricing curves for each of the individual technologies.

A full list of the scenario assumptions as well as all the other inputs used to feed this model can be found in Appendix 1.

5 Modelling Results

This section is structured to report the results in terms of:

1. The individual customer decision with respect to DER investment for each segment;
2. The impact on customer load profiles as a result of behaviour change and DER investment;
3. The level of DER penetration for each customer segment;
4. The aggregated impact for each customer segment;
5. Costs and revenues for each customer segment;
6. The resultant impact of all of the above on customer bills for each segment; and
7. The system level impacts in terms of peak demand and total consumption reduction.

The analysis found that having reticulated gas made little difference to residential customers, as none of the customers segments adopted CHP products. Therefore both residential customers with and without gas are presented together in this report.

Furthermore due to the restrictions placed on customers living in apartments, these customers did not pick up any DER devices. Therefore the results for customers in apartments are only presented in the final section in consideration of the total market wide impacts.

5.1 Customer Results

Section 5.1 presents the results of each tariff scenario at the individual customer level in terms of optimal DER configuration and the impact of adoption on each customer's peak demand and total consumption.

5.1.1 Distributed Energy Resource Configuration

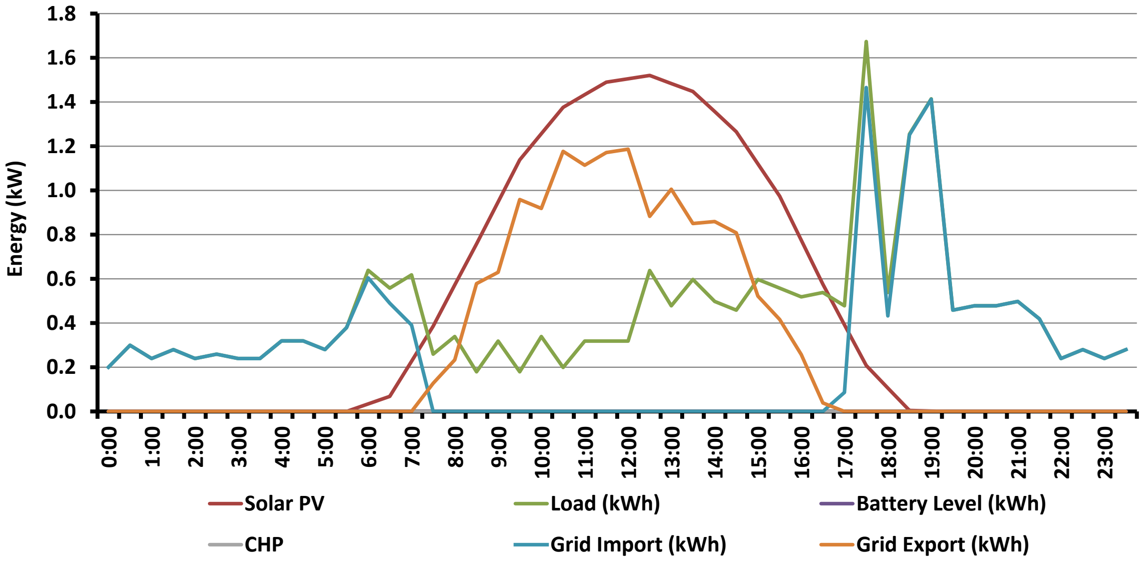
The differences in customer loads as discussed in Section 4.2 gave rise to diverse DER investment decisions. The DER configuration was also influenced by tariff type.

Residential

Residential customer loads are typically characterised by low consumption during the day and high consumption in the morning and afternoon when residents prepare for, and return from, work or school. These activities result in an average load profile which is relatively "peaky" and does not necessarily correlate well with the solar generation profile.

A representative residential typical summer daily load profile and its alignment to a 2kW solar PV generation profile is shown below in Figure 27.

Figure 27 – Residential Customer's Typical Summer Daily Load Import



Source: Energeia

The interaction between the residential customer load and even a relatively small solar PV profile results in significant exports to the grid without reducing the customer's consumption or peak demand significantly.

The optimal size of DER adopted by residential customers is dependent on the underlying tariff structure. Accordingly, Figure 28 shows the optimal DER configuration under each tariff for each year of the assessment period.

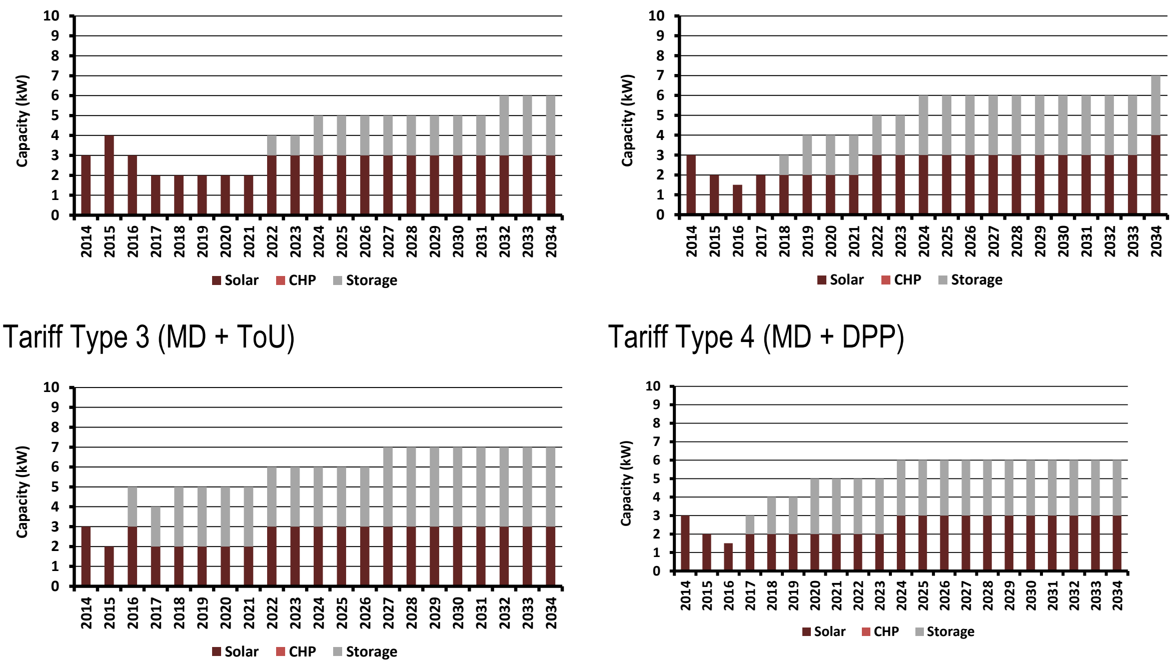
Figure 28 – Residential Adopter's Distributed Energy Resource Configuration

Tariff Type 1 (IBT)

Tariff Type 2 (ToU)

Tariff Type 3 (MD + ToU)

Tariff Type 4 (MD + DPP)



Source: Energeia

In the early years (2014-2015), it is clear that solar PV is cheaper than the most expensive component price of tariff which incentivises the uptake of solar PV systems to offset internal consumption under all tariffs. The higher peak price of Tariff Type 2 results in a higher system size adoption than under the other tariffs.

The removal of the FiT results in oversized systems in the first two years as vendors clear stock and customers adjust to a low FiT environment. The market is returns to equilibrium by 2017 with system sizes stabilising.

In 2022, the optimal solar PV size increases for Tariff Type 1 as a result of lower solar prices offsetting both the top and second tier of the prevailing tariff. The systems are still more expensive than the FiT and so export is minimised by the purchase of storage.

Tariff Type 2 provides sufficient price differential by 2018 for the purchase of a battery to shift load from peak to off peak and to partially internalise solar generation.

The combined value of the peak component of Tariff Type 3 and the high consumption value of the retail ToU component results in adoption of a 2kW storage system by 2016.

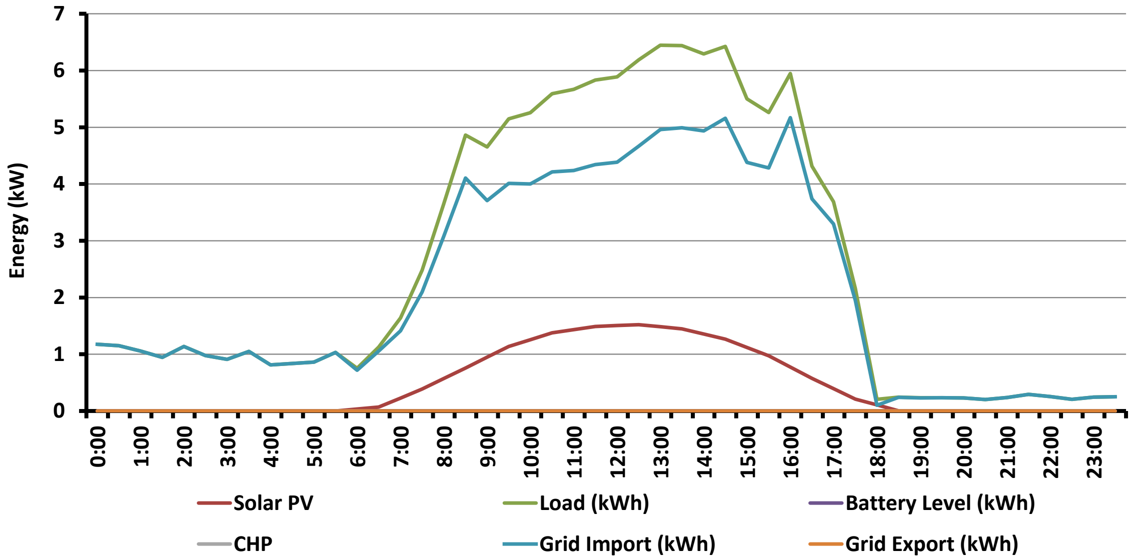
For Tariff Type 4, the price of storage does not drop sufficiently to address peak demand until 2017.

During this later stage, the falling price of storage systems means that they are adopted in larger sizes by customers on Tariff Type 3 and 4 to further reduce monthly maximum demand as well as to shift consumption away from peak times, or peak events.

Small Business

The SB customer has a similar size peak demand to the residential customer, but a much higher load profile with total consumption three times as large as for residential customer. In this sense, the load profile much more closely resembles a scaled business customer. The peak demand of the SB customer also falls within solar PV generation times. Figure 29 shows the typical summer daily load of a SB customer with a 2 kW solar PV generation profile.

Figure 29 – SB Customer's Typical Summer Daily Load Import



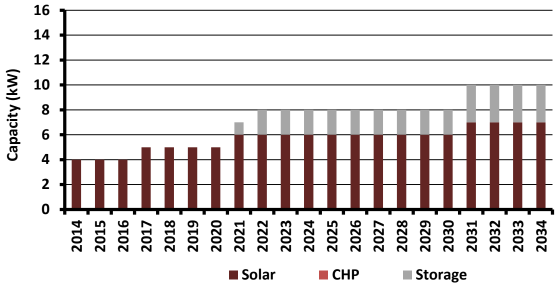
Source: Energeia

The profile shows the high correlation between solar PV generation, and SB demand as well as the length of peak which would need to be reduced to offset a monthly demand charge.

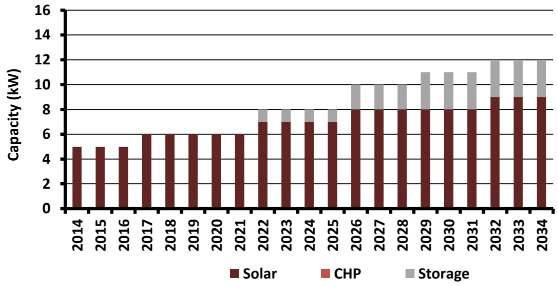
These attributes give rise to the optimal DER configurations for the SB customer shown in Figure 30 for all four tariff types and for each year of the assessment period.

Figure 30 – SB Distributed Energy Resource Configuration

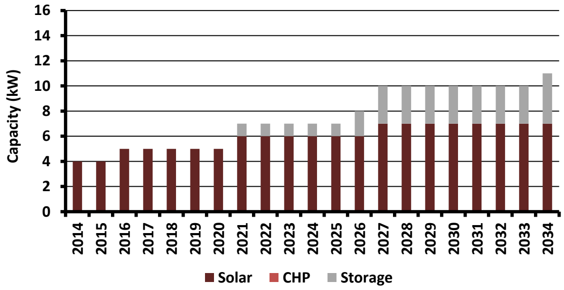
Tariff Type 1 (IBT)



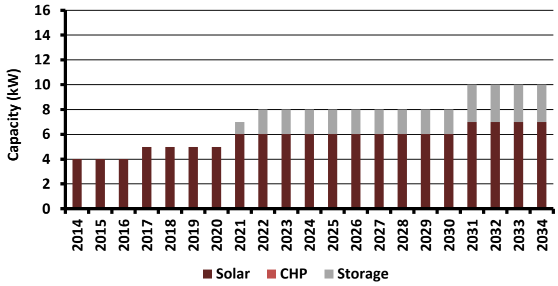
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

The optimal size solar PV system for SB customer ramps up in the early years due to the alignment of solar generation and consumption profiles for all tariff types.

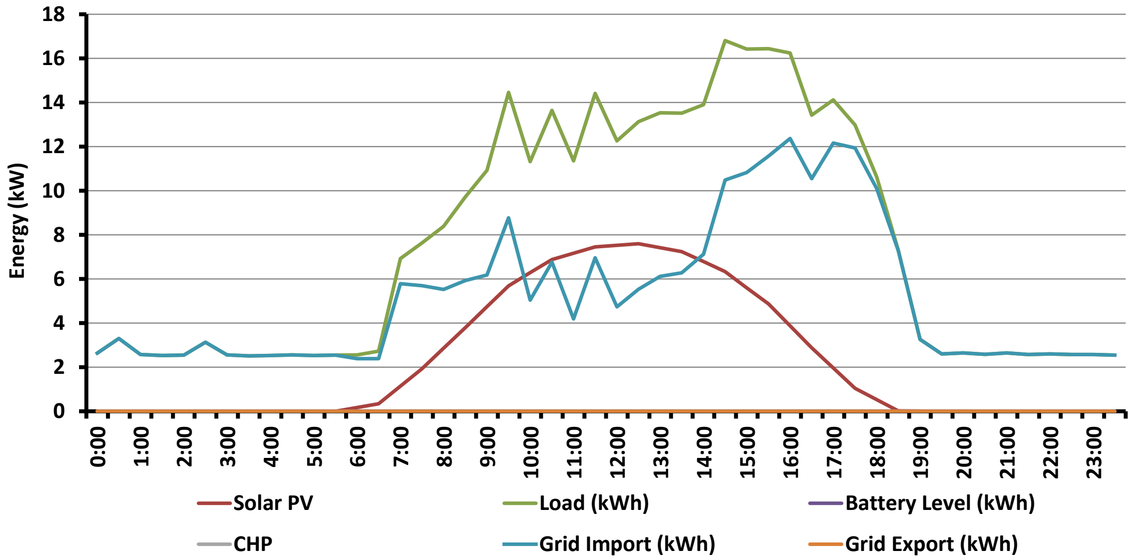
Storage becomes viable under the consumption based tariffs (Tariff Type 1 and 2) from 2021 and 2022 respectively, where the combination of solar and storage becomes cheaper than the highest tier of these tariffs. The storage is smaller in size compared to the residential customers due to a relatively smaller component of exported energy.

Solar is able to target monthly maximum demand, such that storage is not economical for this purpose under either of the maximum demand tariffs (Tariff Type 3 and 4) until 2021. Storage is adopted under Tariff Type 3 and Tariff Type 4 from 2021. The greater returns from ToU consumption component under Tariff Type 3 means that there is more solar available and hence greater peak reduction under this tariff compared to Tariff Type 4 which has a much lower consumption component.

Business

Business customers, characterised by long flat peaks during the day, are more aligned to solar PV generation. Figure 31 demonstrates the correlation between a business customer's existing typical daily load in summer, and generation profile of a 10 kW solar system.

Figure 31 – Business Customer's Typical Summer Daily Load Import



Source: Energeia

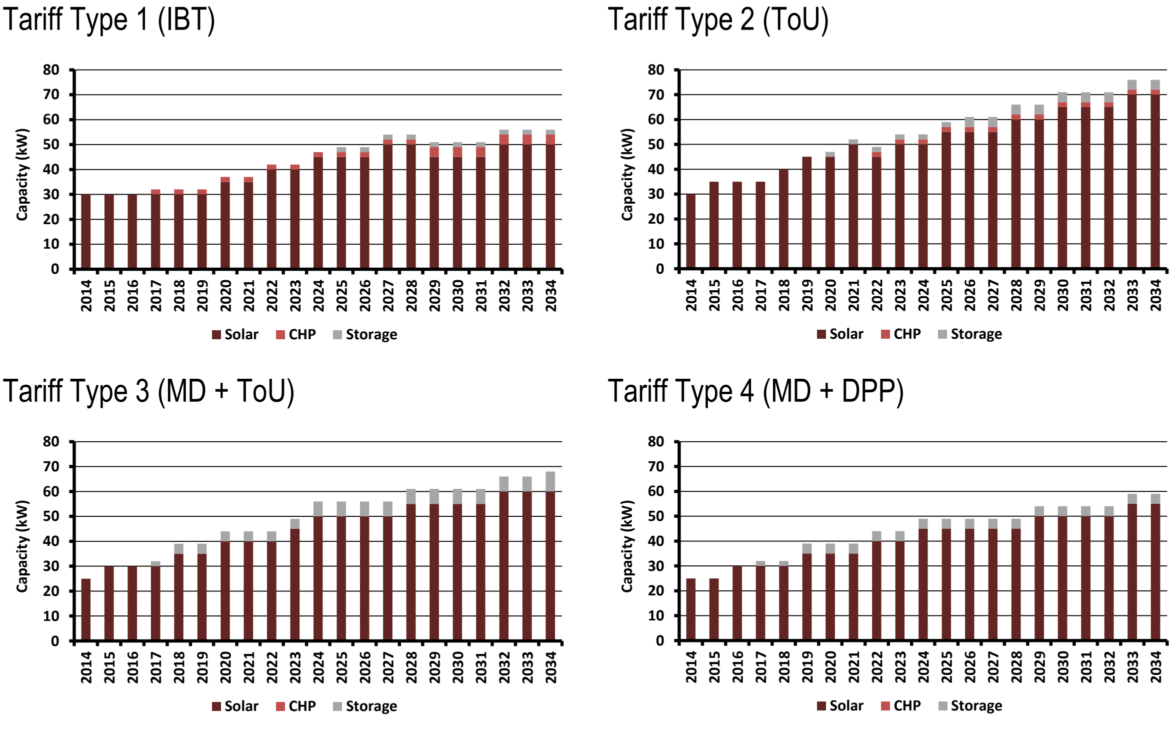
As a result of the generation and consumption alignment, there is no requirement to export surplus generation for this particular size system, unlike the residential sector.

Fuel cells (or Combined Heat and Power) are also more attractive to business customers than residential customers due to the significant base load energy consumption which can be offset by a CHP unit in continuous operation.

Further, because of the large flat peaks, storage requires significant capacity in order to be effective in decreasing the business peak under a monthly demand charge. Accordingly, the benefit of storage for business customers is typically insufficient to cover the cost of the storage solution.

These properties all influence the optimal business DER adoption under each of the four tariffs as shown in Figure 32.

Figure 32 – Business Distributed Energy Resource Configuration



Source: Energeia

In the early years, solar PV is attractive to business customers under all tariff types. The consumption based tariffs (Tariff Type 1 and 2) incentivise slightly larger sized systems.

Solar PV systems become incrementally more attractive under Tariff Type 2 from 2018 due to the decreasing price of solar being able to offset the next tier components of the tariff.

In 2017 and 2022, CHP becomes viable for the Tariff Type 1 and Tariff Type 2 respectively, offsetting their consumption at all times. CHP does not become cost effective for any other tariff over the entire assessment period due to the lower rates during off peak times when CHP continues to operate.

Storage is adopted by business customers as early as 2017 under Tariff Type 3 and Tariff Type 4 to reduce the monthly demand charge and for Tariff Type 4, to offset consumption during the high priced dynamic peak events which occur seven times a year over a two hour period.

Storage is not adopted by the pure ToU tariff (Tariff Type 2) until 2020 to shift the remaining consumption in peak periods to off peak times and to internalise solar generation.

By the end of the assessment period, the storage size is greatest for those business customers on Tariff Type 3, where storage can be utilised to effectively target both the monthly maximum demand and to internalise solar exports.

5.1.2 Customer Peak Demand Impacts

The following section details the impact of DER on peak at the customer level.

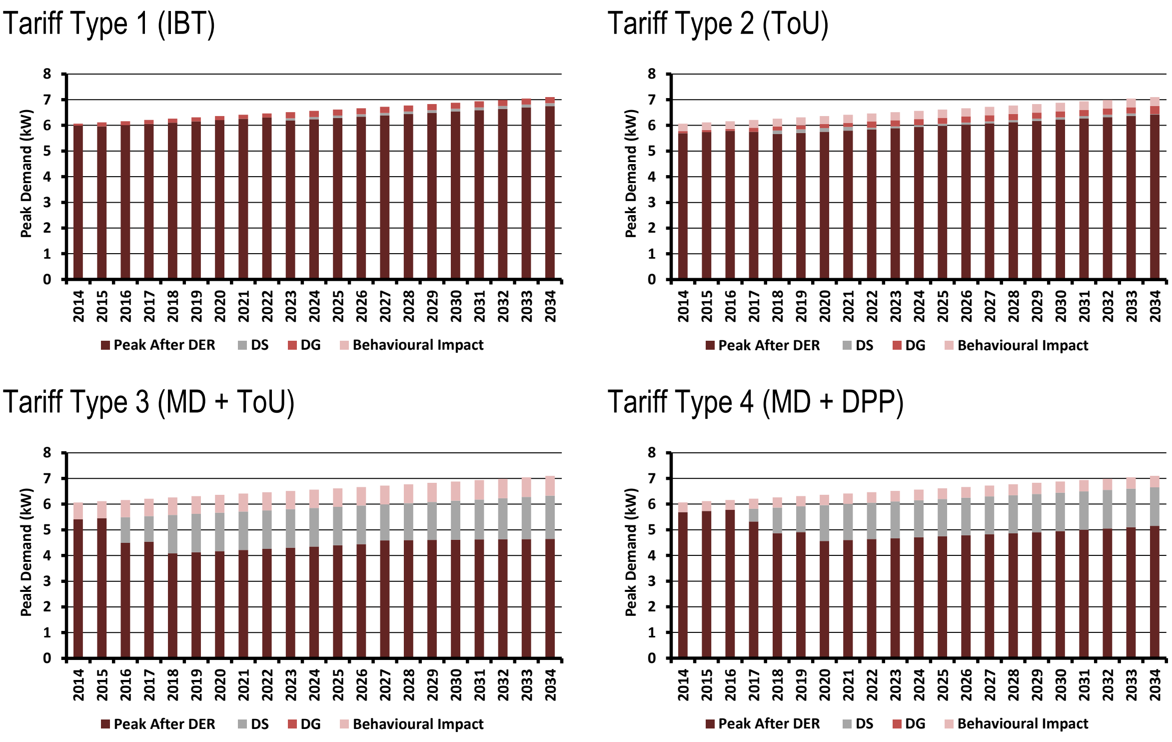
Total peak demand in this section represents the customer's demand after behaviour change effects have been applied as described in 4.5.2 and the uptake and operation of DER.

It should be noted that this section presents the impact on the customer's own individual peak and not the network peak. Accordingly, when aggregating up to the network level the aggregate peak impact is reduced based on the coincidence of individual customer peak demand, an effect known as diversity. The assumed diversity is 50% as described in Section 4.5.5.

Residential

Figure 33 presents the change in peak demand for the selected residential customer as a result of both behaviour change in response to pricing signals and DER adoption for each of the four tariff types. It should be noted that total peak is rising over the assessment due to key exogenous assumptions with respect to underlying growth in peak demand per capita (see Section 4.6).

Figure 33 – Residential Customer Peak Demand



Source: Energeia

Under the consumption based tariffs (types 1 and 2), solar PV reduces customer peak demand by only a small fraction due to the poor correlation between solar PV generation and customer peak.

Customer behaviour change to reduce demand under Tariffs Type 3 and 4 is better aligned to network peak demand. This is apparent by the lower peak period before DER under these tariffs. Interestingly, this reduces peak demand that would otherwise be reduced by solar, pushing the peak outside of the solar PV generation window. As a result, under types 3 and 4, solar PV has no impact on the residential customer's peak demand, which is instead reduced by customer investment in storage.

Customers on Tariff Type 3 have a consistently lower peak demand than any other tariff throughout the modelling period, due to the behaviour changes during the maximum demand and the peak time of use period, and the impact of DER.

Intuitively, one would expect the greatest reduction in peak demand to come from Tariff Type 4, due to the strong signalling of the MD and DPP components. However, a DPP price signal occurs at market peak events rather than that of an individual customer.

The adoption of distributed storage results in a clear peak reduction in Tariff Type 3 and Tariff Type 4 structures. The impact is greatest under Tariff Type 3 due to the added benefit of larger storage. In

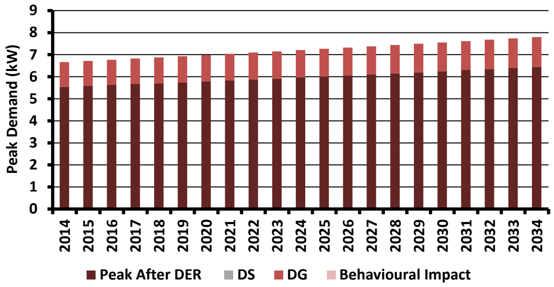
2034, residential customers under Tariff Type 4 reduce their peak by more than 1.6kW when compared to Tariff Type 1.

Small Business

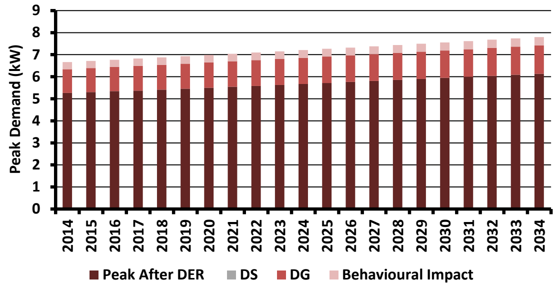
The selected SB customer peak demand is also impacted by behaviour change and DER investment as shown in Figure 34 for each of the four tariff types.

Figure 34 – SB Customer Peak Demand

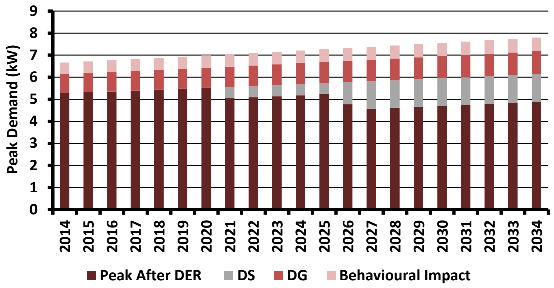
Tariff Type 1 (IBT)



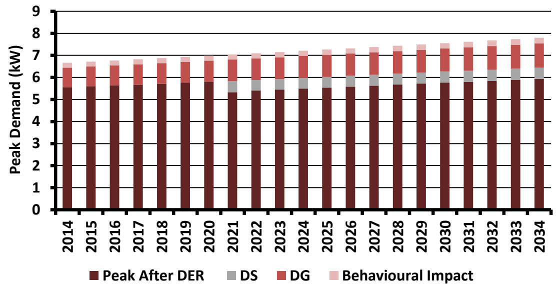
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

Due to the strong overlap of solar PV generation with the selected SB load profile, distributed generation has the greatest contribution to reduction in individual customer peak demand under all tariffs except Tariff Type 3 where large storage systems dominate.

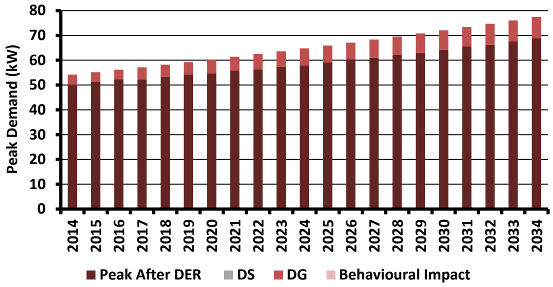
By the end of the assessment period the greatest reduction in peak demand of all the tariffs is for Tariff Type 3 customers. For these customers, the combination of behaviour change aimed at the individual peak, solar PV and storage to offset monthly maximum demand, results in a peak demand reduction of approximately 37% by 2034.

Business

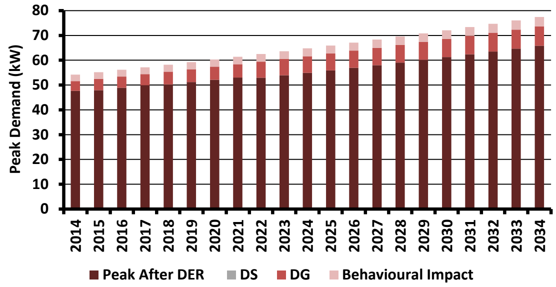
Figure 35 presents the change in peak demand for the selected business customer as a result of both behaviour change in response to pricing signals and DER adoption for each of the four tariff types.

Figure 35 – Business Customer Peak Demand

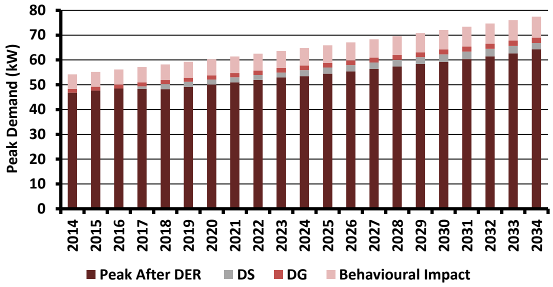
Tariff Type 1 (IBT)



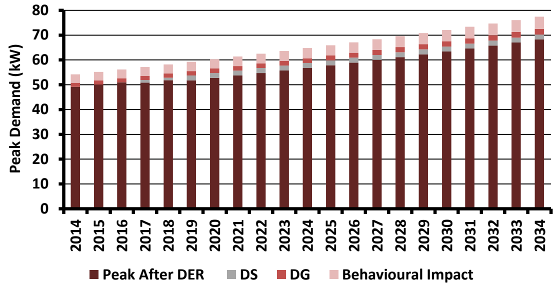
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

Due to correlation between solar PV generation and business customers' peak demand, distributed generation has an influence on the customer's peak demand. This effect is more pronounced under the consumption based tariffs (Tariff Type 1 and 2), which encourages larger solar PV systems.

As with residential customers, the behaviour change impact of Tariff Type 3 and to a lesser extent Tariff Type 4 is stronger than the consumption based tariffs. The behaviour change impact is less for Tariff Type 4 than for Tariff Type 3 due to the DPP price signal occurring at market peak events rather than for the individual customer peak.

5.1.3 Customer Consumption

This section describes the level of internal generation, exports and imports from the grid for a customer adopting the optimal DER for each year of the assessment period. This is indicative of the relative reduction in grid consumption, customer bills and therefore reduction in network revenue likely to be faced by the network.

A key finding is that the reduction in revenue from reduced grid consumption is partially offset via the maximum demand component of Tariff Type 3 and 4. Accordingly, under Tariff Type 1 and 2, customer reductions in grid consumption will have the greatest impact on network revenues.

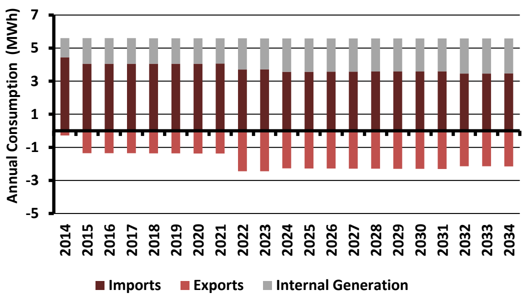
It should be noted that no assumption was made with respect to inverter disconnection under high voltage conditions associated high levels of grid export. That is, there was no network based constraint on grid export applied in this analysis.

Residential

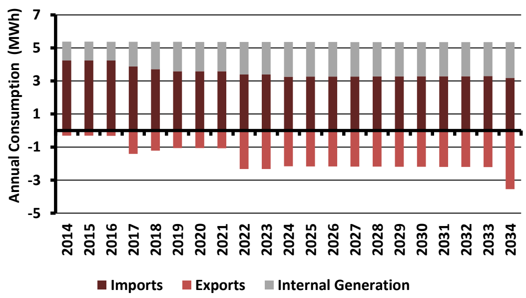
Figure 36 presents the change in residential annual consumption as a result of both behaviour change and DER adoption for customers adopting DER in each year of the assessment period.

Figure 36 – Residential Customer Annual Consumption

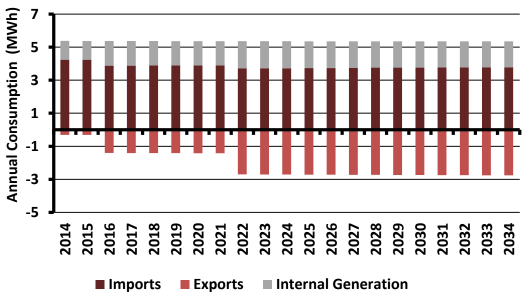
Tariff Type 1 (IBT)



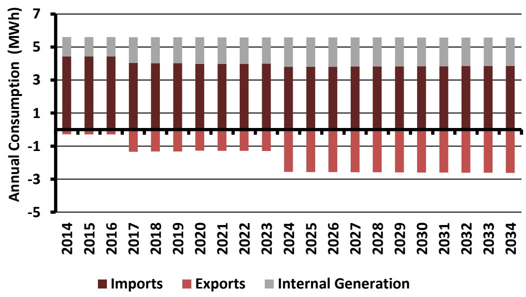
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

Due to the high solar PV take up under the consumption based tariffs (Tariff Type 1 and 2), residential customers show a significant decrease in grid imports and increase in grid exports over the assessment period. In particular, a large step change in exports is observed in 2022 for Tariff Type 1 and Tariff Type 2 as a result of the increase in size of systems installed in this year. The exports are curbed by larger storage for Tariff Type 2, but due to a larger solar system in 2034 under Tariff Type 2, the exports are highest under this tariff.

By 2034, customers under Tariff Type 1 are exporting almost the same amount of energy as they are importing, whilst customers on Tariff Type 2, due to larger solar PV system size, are exporting more than they are importing. This large amount of export could create power quality issues not assessed as part of this project.

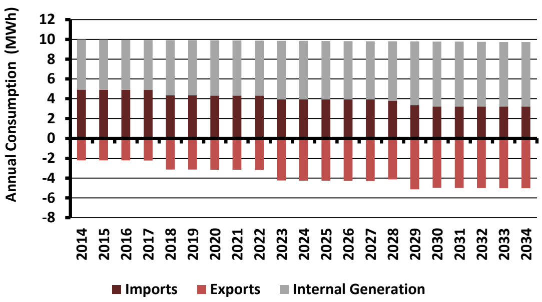
Figure 36 also shows Tariff Types 3 and 4 with greater exports and greater internal consumption compared to Tariff Type 1. This is because of the greater storage to generation ratio and the use of storage to address peaks during DPP and Monthly Demand periods rather than for the internalisation of solar generation.

Small Business

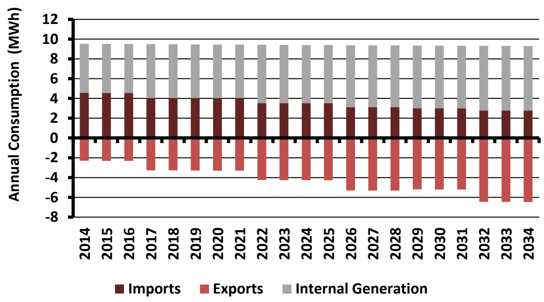
Figure 37 presents the same change in annual consumption by tariff, but this time for SB customers.

Figure 37 – SB Customer Annual Consumption

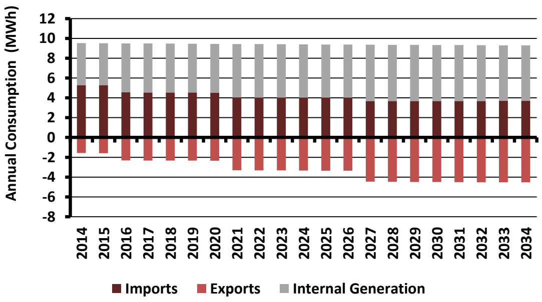
Tariff Type 1 (IBT)



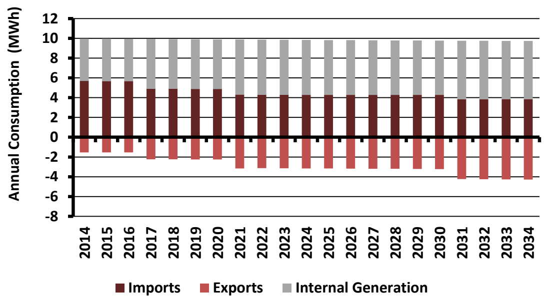
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

The results for SB are striking in terms of the dramatic reduction in grid consumption under all tariffs by the end of the assessment period. By the end of the assessment period, exports are significantly greater than imports under Tariff Type 1 and 2, potentially creating power quality issues.

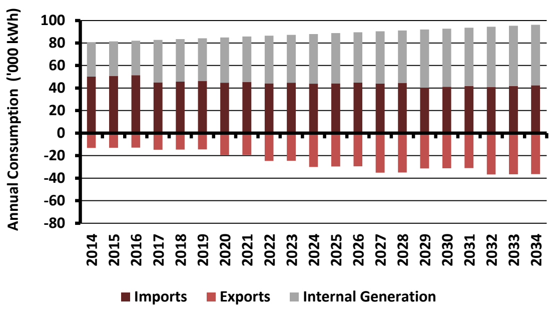
The DER adoption under Tariff Type 3 and 4 also results in a significant reduction in grid consumption. However, the reduced network reliance on the consumption component of these tariffs for revenue results in a lower network price impact.

Business

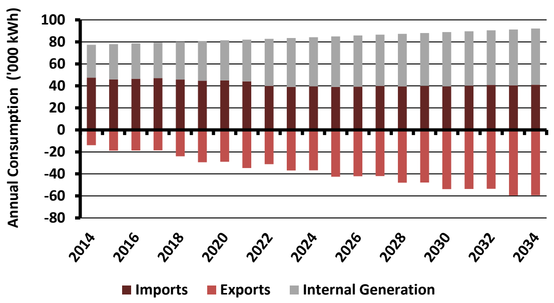
Figure 38 presents the change in Business customers' annual consumption as a result of both behaviour change and DER adoption for customers adopting DER in each year of the assessment period.

Figure 38 – Business Customer Annual Consumption

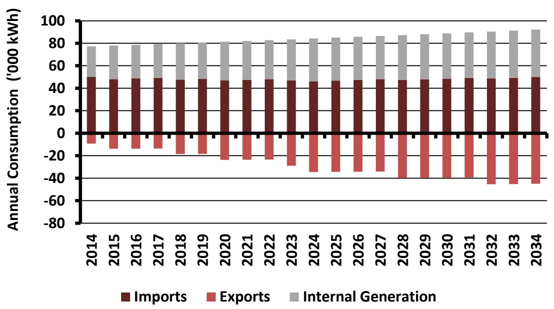
Tariff Type 1 (IBT)



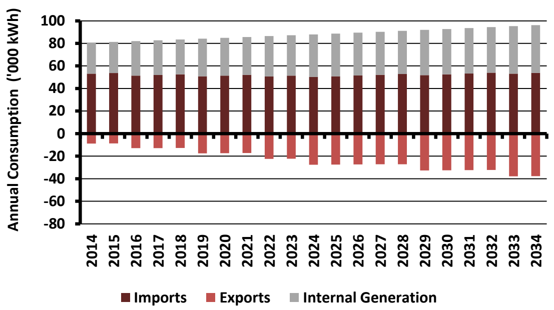
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

For business customers, grid imports fall significantly under all tariffs such that internal generation supplies up to 56% of consumption by the end of the assessment period.

The larger solar system size under Tariff Type 2 results in the greatest reduction in import and the greatest export. Tariffs Type 1 and 2 have the same internal generation despite Tariff Type 2 adopting significantly larger systems. This suggests that adopting more than 50kW of solar leads to significantly greater export of energy for each incremental unit of adoption.

Tariff 3 and 4 reduce internal generation but increase export compared to Tariff Type 1 due to larger solar and also larger storage systems.

Exports under Tariff Type 2 are projected to be 50% greater than that of the other tariffs by 2034 which, under current arrangements, could require augmentation of the local network or constraints on the inverter to prevent over voltage occurrences.

5.2 Customer Segment Outcomes

Understanding how individual customer decisions affected the network required aggregation, firstly to the customer segment level and then secondly to the network level.

The first step in aggregating up from the individual to the segment level was to estimate the number of customers adopting the DER configuration in each year. The level of DER capacity was then estimated as the optimised configuration in each year multiplied by the number of adopters in that year. This was then used to estimate the impact of DER configurations at the segment and network level.

5.2.1 Distributed Energy Resource Penetration

The following section describes the outcomes for adoption and penetration rates of DER. The adoption and penetration was based on each customer's calculated return on investment for the optimised DER configuration which is also presented here.

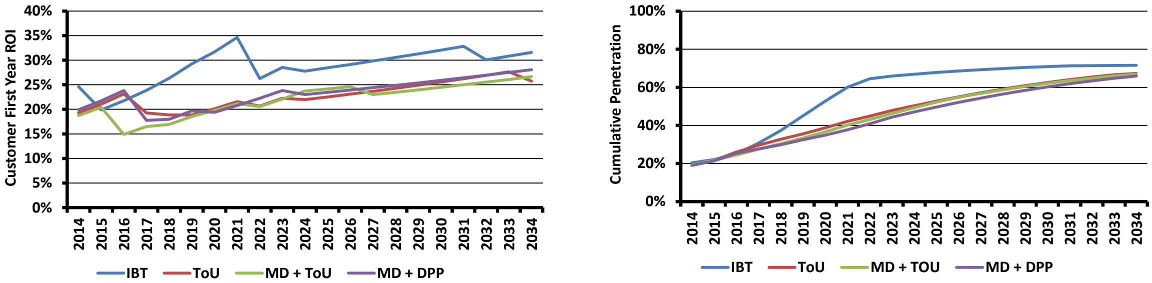
For all these results, the rate of increase in penetration at any one time is proportional to both the ROI and the size of the market at that same point in time.

Residential

Figure 39 shows the return on investment for the optimised DER configuration and corresponding cumulative DER penetration for the residential segment over the assessment period for the four tariff options.

Of note when interpreting this chart is that there is a proportion of the market which is unable to adopt DER. This is due to the assumption that customers living in apartments and town houses are unable to adopt DER due to physical and tenure constraints.

Figure 39 – Total Residential DER ROI and Corresponding Penetration



Source: Energeia

The return on investment for the optimal DER configuration over time is subject to sharp changes in the optimal DER configuration as solar PV sizes reach key thresholds and storage systems become viable.

Penetration under Tariff Type 1 increases quickly and approaches the maximum penetration almost ten years before the end of the period. This is due to the strong financial incentive to decrease consumption under this tariff. The ROI for all other tariffs remains relatively similar and follows similar penetration paths with Tariff Type 3 appearing to consistently remain below the other tariffs in terms of ROI and penetration.

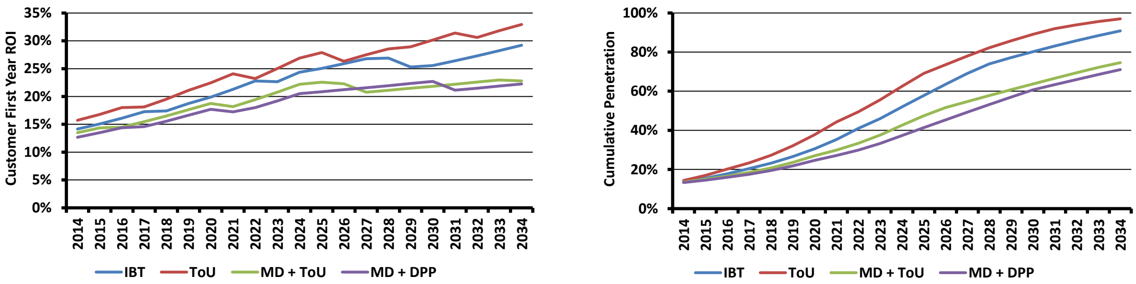
ROI also increases over time across all tariffs as the feedback loop internalises the reduced network revenue recovery into the following year network component of the tariff price. This price increase further incentivises the uptake of DER.

As penetration rates increase, the available market declines and so, despite an increasing incentive to adopt, the absolute number of adopters decreases. Because of this dwindling available market the incremental impact of the feedback loop is most noticeable in the early period and weakens once high levels of adoption is achieved.

Small Business

Figure 40 shows the return on investment for the optimised DER configuration for the SB segment and the corresponding cumulative DER. The information is again presented for the four tariff options.

Figure 40 – SB DER ROI and Corresponding Penetration



Source: Energeia

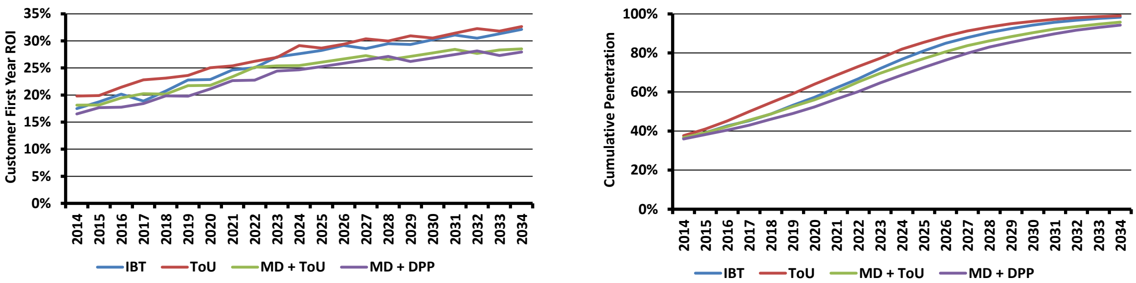
The penetration of DER within the SB sector is lower than both the business and residential sectors for all tariffs. This is due mostly due to a lower penetration starting point as ROI values are broadly similar to the business sector

There is an even greater difference in DER penetration between the consumption based tariffs (Tariff Type 1 and 2) and the Tariff Type 3 and 4 for SBs compared to business customers. This is due to the more pronounced difference in ROI between tariffs for SBs compared to other non-residential customers.

Business

Figure 41 shows the return on investment for the optimised DER configuration for the business segment and the corresponding cumulative DER. The information is presented for the four tariff options.

Figure 41 – Business DER ROI and Corresponding Penetration



Source: Energeia

The penetration of DER within the business sector is slower than the residential sector for all tariffs in the early years. This is due to the higher ROI values for the residential sector in the earlier years of the assessment period.

The higher return on investment under Tariff Type 2 stimulates higher early adoption rates, but this effect is weakened during the later years when the remaining available market shrinks. At this point the penetration under the other tariffs begins to catch up and bridge the gap, especially for tariff Type 1.

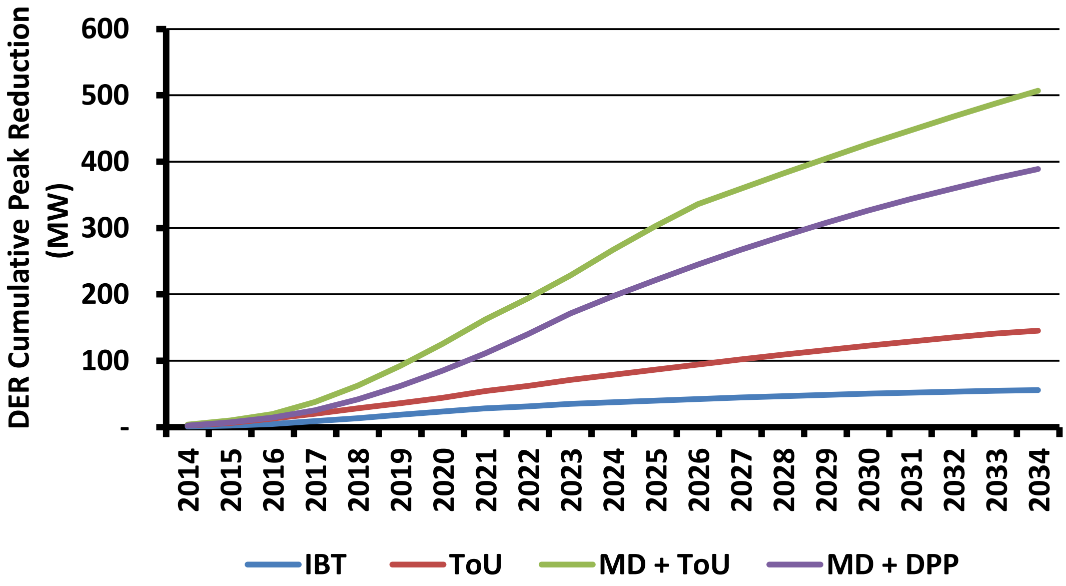
5.2.2 Customer Segment Peak Reduction

The following section presents the results of modelling the aggregated peak demand reduction within each customer segment. It assumes that only customers who adopt DER move onto a new tariff. Customers who do not adopt DER remain on Tariff Type 1.

Residential

Figure 42 describes the cumulative ADMD residential peak reduction from DER achieved under each tariff modelled over the 20 year forecast period.

Figure 42 – Residential Cumulative Peak Reduction



Source: Energeia

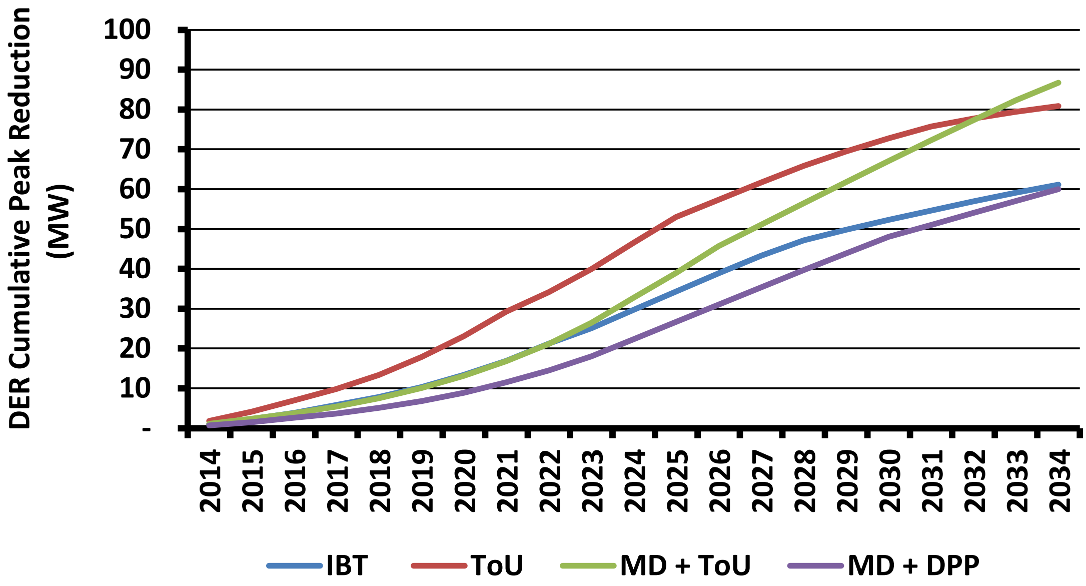
At the aggregated level for the residential segment, the choice of tariff leads to large variations in peak demand reduction by the end of the assessment period. In the initial years, solar PV under all tariffs leads to some peak demand reduction. From 2017, when monthly demand tariff supports storage adoption, the peak reduction increases substantially under tariff types 3 and 4.

By the end of the assessment period, Tariff Type 3 drives larger storage systems and greater adoption that results in the greatest impact on peak demand. This is despite the greater peak reduction per customer that is achieved under Tariff Type 4, which directly targets the network's rather than individual customer peak.

Small Business

Figure 43 describes the cumulative SB peak reduction achieved under each tariff modelled over the 20 year forecast period.

Figure 43 – SB Cumulative Peak Reduction



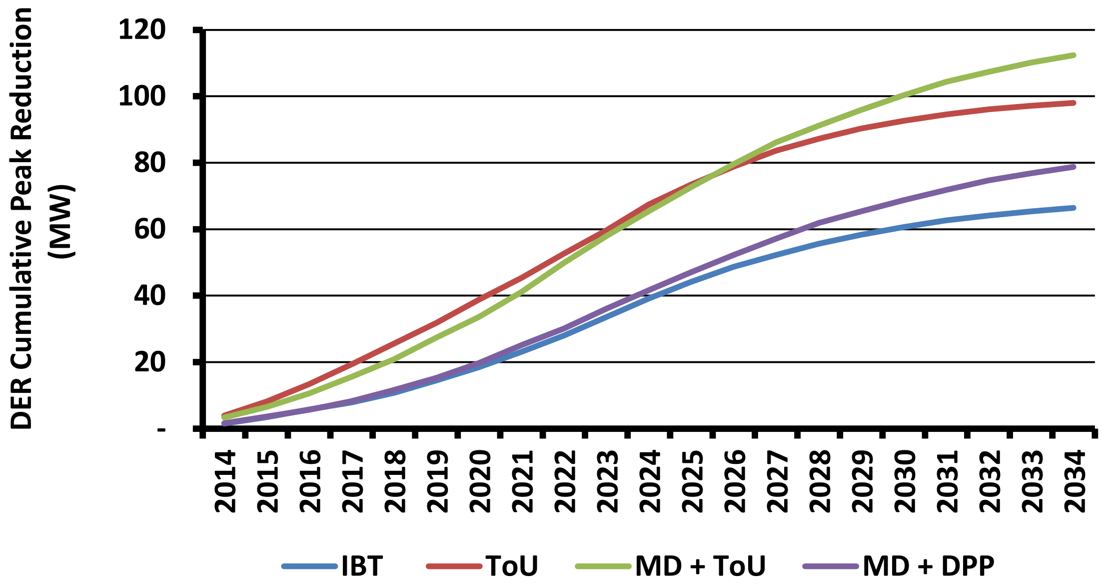
Source: Energeia

The SB's coincidence of load and solar generation results in greater peak reduction under consumption based tariffs than for residential customers. As storage prevalence increases under Tariff Type 3 and 4, in later years, the peak reduction impact for these tariffs begins to pick up with Tariff Type 3 resulting in the most cumulative peak reduction by 2034. It should be noted that because of the lower penetration rate, a MW peak reduction under the two capacity tariffs (Tariff Types 3 and 4) implies a much great impact per customer compared to the consumption tariffs (Tariff Types 1 and 2).

Business

Figure 44 describes the cumulative business peak reduction achieved under each tariff modelled over the 20 year forecast period.

Figure 44 – Business Cumulative Peak Reduction



Source: Energeia

Similarly to the residential results, the business peak reduction is highest under Tariff Type 3, However, the consumption based tariffs (Tariff Type 1 and 2) show relatively more demand management under the capacity based tariffs (Tariff Type 3 and 4) than the residential sector. This is due to the correlation between solar PV and the load profile, as explained above in 5.1.1, coupled with the greater DER uptake rate for the business sector under these tariffs.

5.2.3 Segment Consumption Impacts

The underlying consumption growth rate in the model is based on AEMO's forecast which predicts negative growth in consumption per capita. However, the impact of increasing customer numbers means that underlying market demand is positive.

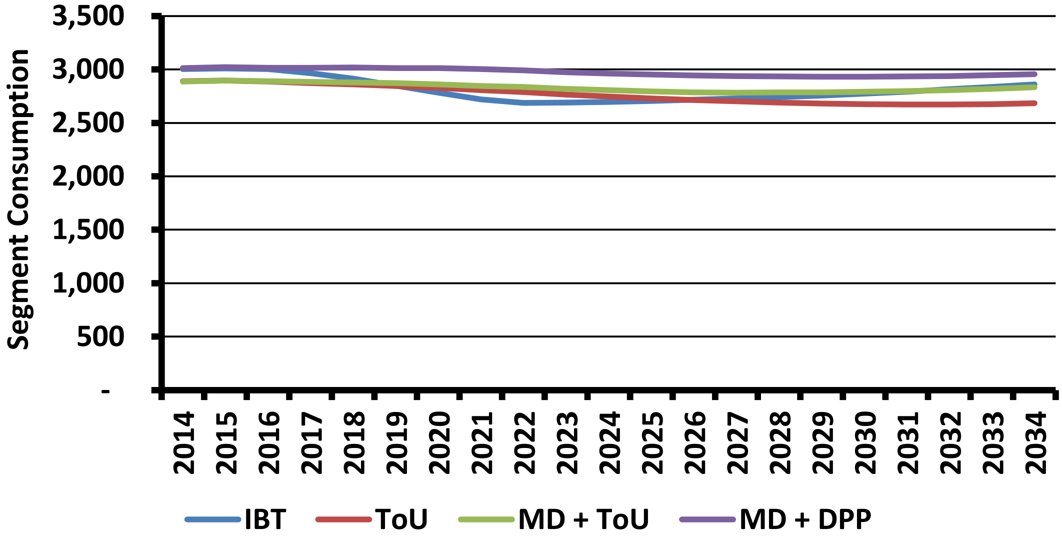
The impact of DER and behaviour change has the potential to reduce total consumption and therefore network revenue for some customer segments.

The results presented below assume that only customers who adopt DER move onto a new tariff. Customers who do not adopt DER remain on Tariff Type 1.

Residential

Figure 45 shows the total cumulative reduction in consumption for the residential segment by tariff type. These results include both those who adopt and who do not adopt DER.

Figure 45 – Residential Segment Cumulative Consumption



Source: Energeia

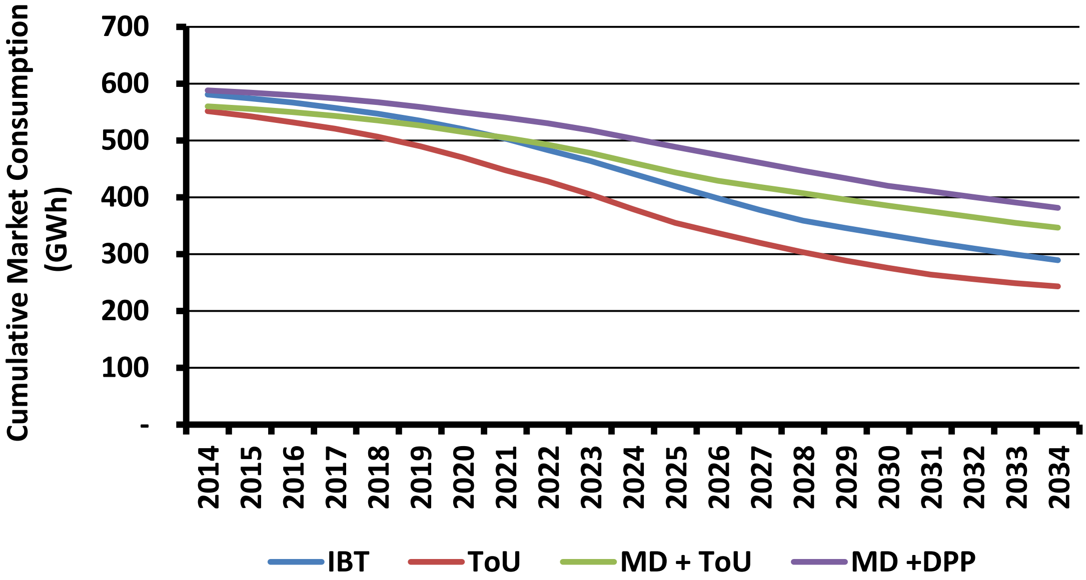
These results show that total consumption in the residential segment reduces over time for all tariff options with the exception of Tariff Type 4 which remains relatively flat.

Customers on the Tariff Type 2 and 3 reduce their consumption considerably in the early years due to behavioural and DER impacts as penetration increases, but when penetration starts to approach saturation, the reduction in consumption subsides, but does not recover to original rates during the assessment period.

Small Business

Figure 46 shows the total cumulative reduction in consumption for the SB segment.

Figure 46 – SB Segment Cumulative Consumption



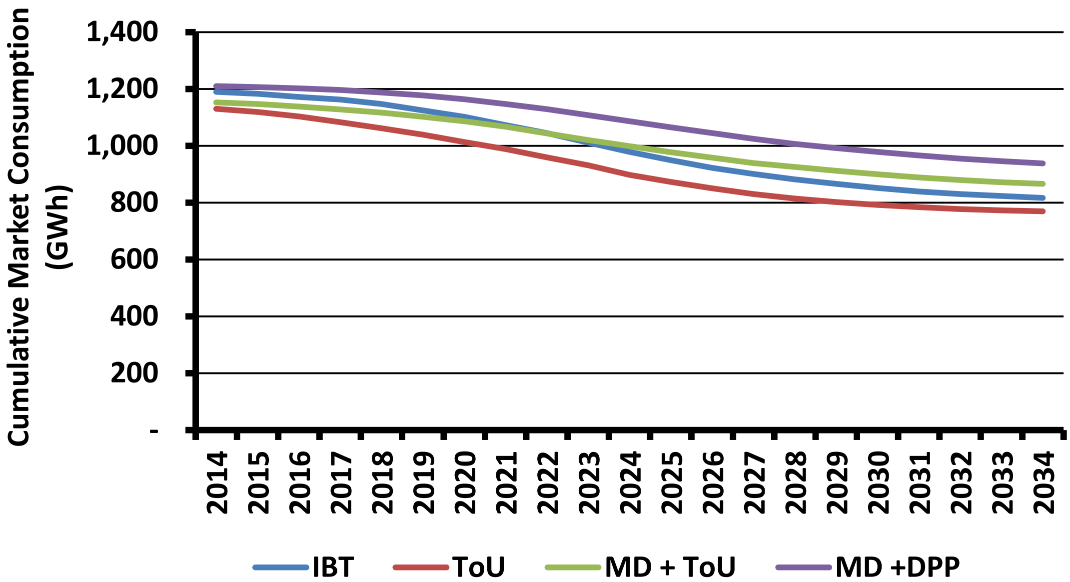
Source: Energeia

The reduction in consumption for the SB sector is the most pronounced. SB customers experience the highest consumption reduction under the consumption based tariffs due to high uptake of distributed generation able to be used more for internal generation than for export.

Business

Figure 47 shows the total cumulative reduction in consumption for the business segment by tariff type including all customers who both adopt and do not adopt DER.

Figure 47 – Business Segment Cumulative Consumption



Source: Energeia

As for the residential sector, the greatest reduction in consumption is under the consumption tariffs (Tariff Type 1 and 2). The reduction is even more pronounced for the business sector due its wide scale adoption of solar PV to offset base load consumption and reduced exports when compared to the residential sector even for Tariff Type 4.

5.2.4 Network Price Impacts

The final step in interpreting the interaction between the tariff, network and customer is in understanding the network price feedback loop. The aim of the feedback loop is to simulate the interplay of network revenue, costs and prices.

The feedback loops works by quantifying for each year:

- The total network revenue gap as a result of avoided network charges; and
- The reduced network costs as a result in peak demand reductions.

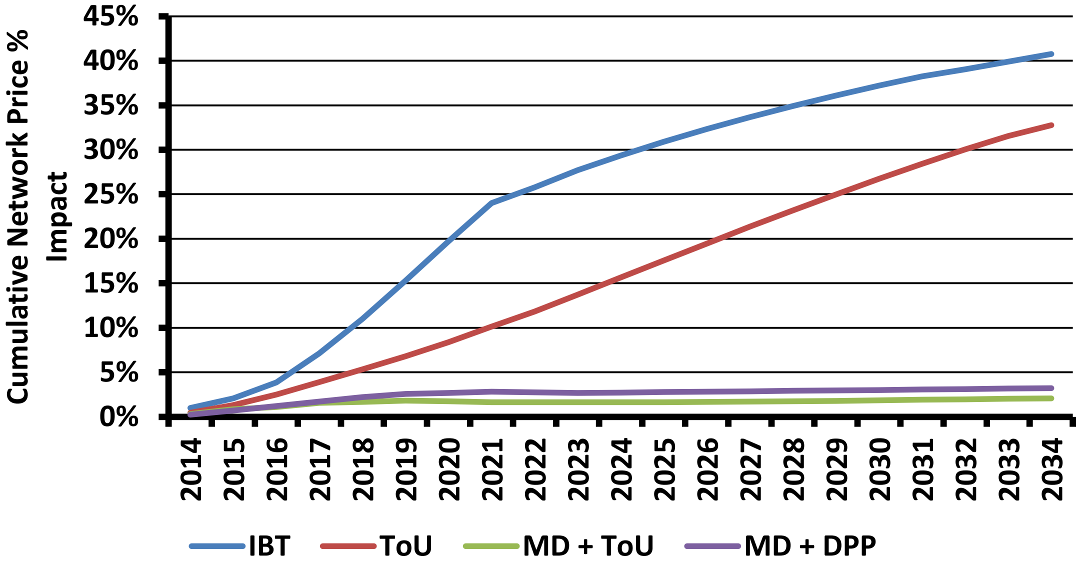
Where the reduction in revenue is greater than the reduction in costs, then a price rise will occur for the network component of the tariff for the following year.

Where network price rises occur as a result of the feedback loop, customers who have not adopted DER and retain a high dependency on grid consumption are impacted to a greater extent than those customers who have adopted DER. This, in effect, results in a cross subsidy from customers without DER to customers with DER and further incentivises additional adoption of DER within the market.

Residential

Figure 48 below shows the network pricing impacts for the residential sector as a result of behaviour change and DER.

Figure 48 – Residential Segment Cumulative Network Price Impact



Source: Energeia

The results demonstrate the increased impact on network prices under the consumption based tariffs (Tariff Type 1 and 2) compared to the capacity based tariffs (Tariff Type 3 and 4). The price impact reaches almost 40% by the end of the period. The increase is most pronounced in the early years of Tariff Type 1 due to the fast rate of annual adoption over this period.

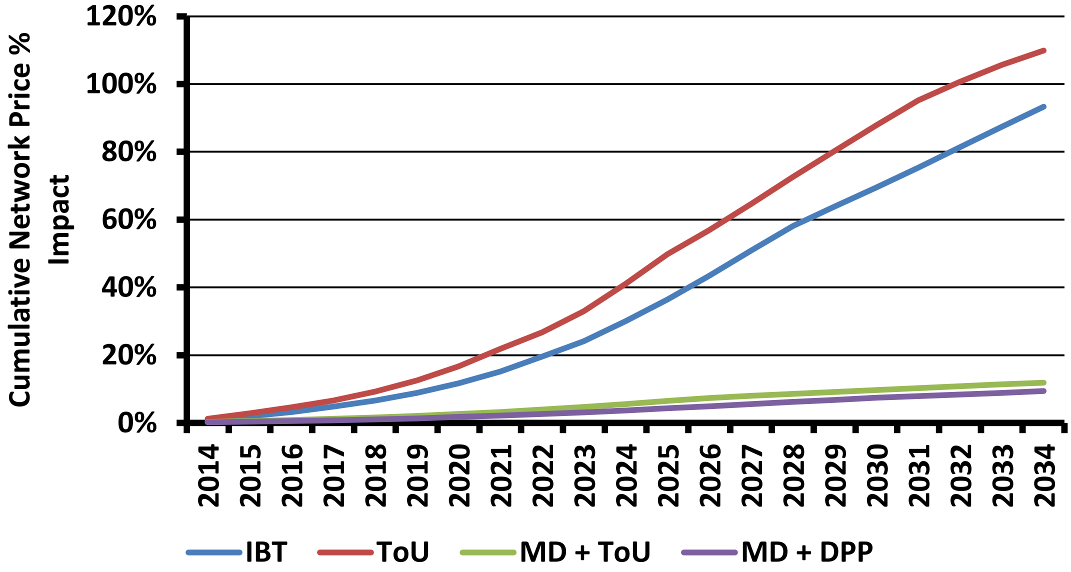
Also apparent is the declining incremental impact of cross subsidy as penetration increases and the dwindling available market results in a small absolute take up number.

The capacity based maximum demand tariffs (Tariff Type 3 and 4) have a lesser impact on network prices of less than 5%, and therefore reduce the cross subsidy effect within the segment. The lower network price by the end of the period for these tariffs is due to both reduced rate of network spending associated with peak demand reduction and weaker reductions in revenue.

Small Business

Figure 49 below shows the network pricing impacts for the SB sector as a result of behaviour change and DER.

Figure 49 – SB Segment Cumulative Network Price Impact



Source: Energeia

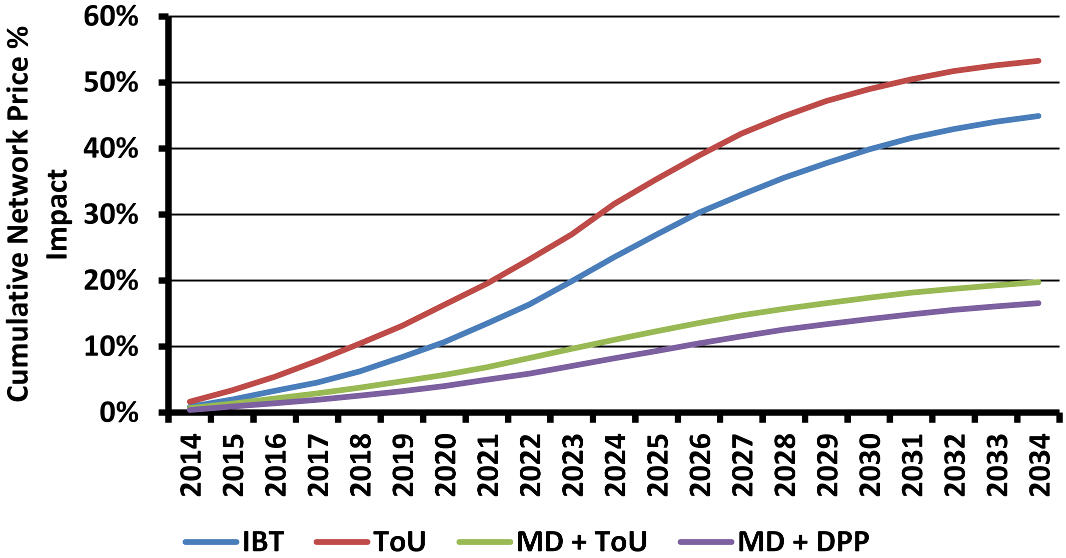
The high level of solar generation relative to total consumption and the strong penetration rate results in an 110% increase in the network prices of the SB segment relative to 2014 under the consumption based tariffs by 2034.

The two monthly demand tariff structures both alleviate the need for significant price increases due to cross subsidy, limiting the total price rise to less than 12% over the 20 year forecast period.

Business

Figure 50 below shows the network pricing impacts for the residential sector as a result of behaviour change and DER.

Figure 50 – Business Segment Cumulative Network Price Impact



Source: Energeia

Due to the high consumption reduction under both IBT and ToU, network revenues fall faster than avoided network costs, increasing prices. The result is roughly a 50% price rise over the 20 years under the consumption based tariffs (Tariff Type 1 and 2).

Both of the monthly demand tariffs restrict price increases to around 20% over the 20 years. This is due to the stronger link between revenue and costs to the network under this tariff.

5.3 Customer Bill Impacts

Customer bills change over time as a result of DER adoption, behaviour change and the network price impacts determined by the feedback loop. The annual customer bill for each segment is presented below in terms of:

- Annualised DER costs;
- Grid electricity charges (network component); and
- Grid electricity charges (retail component).

The annual customer bill is presented for the customer who adopts DER in the given year. The annual bill is compared to a Non-DER customer on an IBT tariff who does not adopt DER.

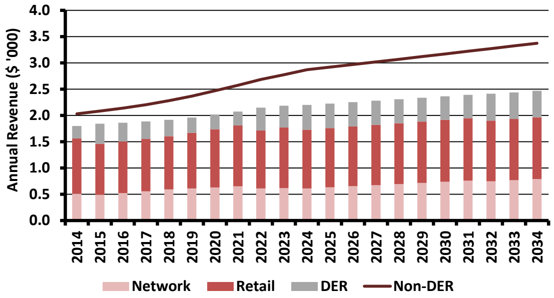
All bills are presented in 2014 real dollars.

Residential

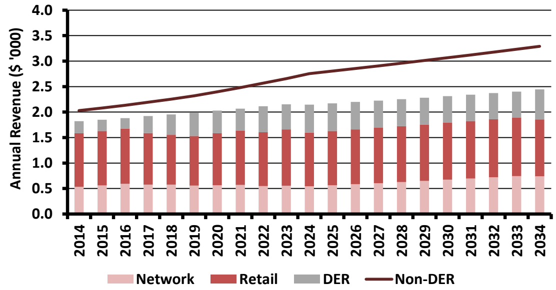
Figure 51 shows the customer bill for each year for the representative residential customer who adopts DER and changes tariff and compares this with the equivalent non-DER residential customer who remains on Tariff Type 1.

Figure 51 – Residential Customer Bill Comparison

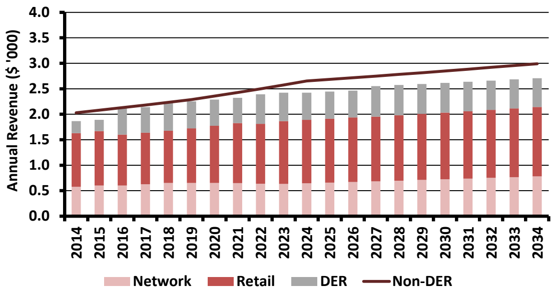
Tariff Type 1 (IBT)



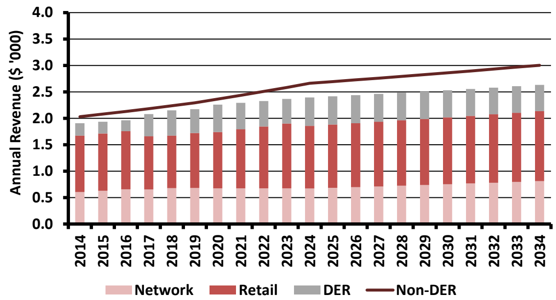
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

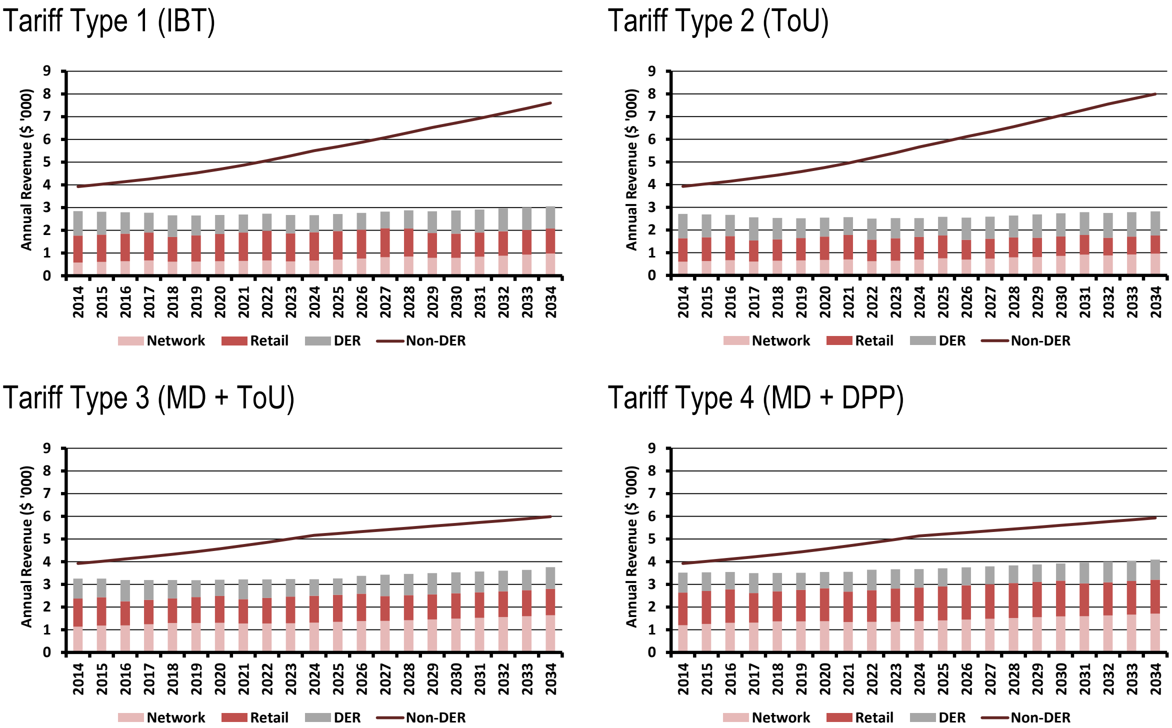
Due to the influence of the feedback loop on network tariffs, non-DER customers under both consumption based tariffs experience significant increases in their bill, paying roughly 50% more than the equivalent customer who has adopted DER in 2034.

Under Tariff Type 3 and 4, the difference in annual bill between DER and non-DER customers is approximately 15% or $500 by 2034, implying less cross subsidisation.

Small Business

Figure 52 shows the customer bill for each year for the representative SB customer who adopt DER and changes tariff and compares this with the equivalent non-DER SB customer who remains on Tariff Type 1.

Figure 52 – SB Customer Bill Comparison



Source: Energeia

The SB segment demonstrates the greatest bill contrast in terms of the divergence between the DER and non-DER customers for all tariff scenarios. Whist the divergence is clearly more pronounced under the consumption based tariffs, there is still a significant customer subsidy impact under the two MD tariffs.

This divergence is because of the very high level of coincidence between the SB load and solar generation which allows the SB customer to significantly reduce their bill under all scenarios.

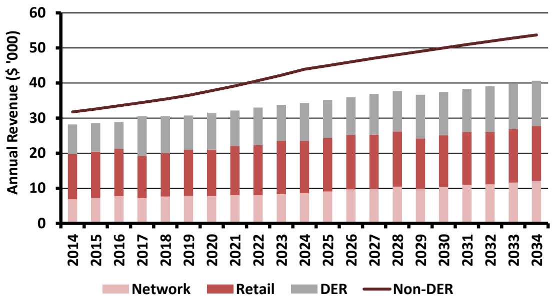
Under the consumption based tariffs, the ability of the DER customer to avoid the network charges leads to higher network price increases (as discussed in Section 5.2.4) that provide strong ROI and in turn promote greater penetration of DER.

Business

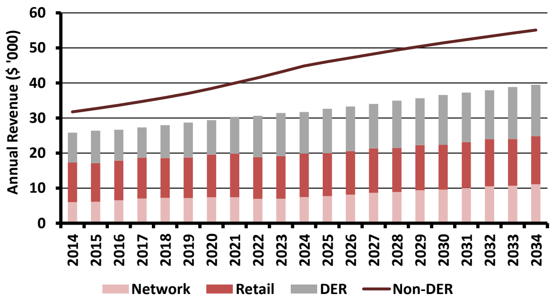
Figure 53 shows the customer bill for each year for the representative business customer who adopts DER and changes tariff and compares this with the equivalent non-DER business customer who remains on Tariff Type 1.

Figure 53 – Business Customer Bill Comparison

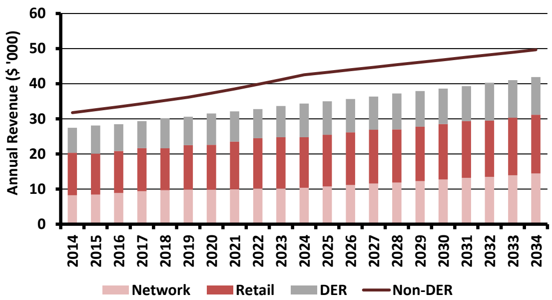
Tariff Type 1 (IBT)



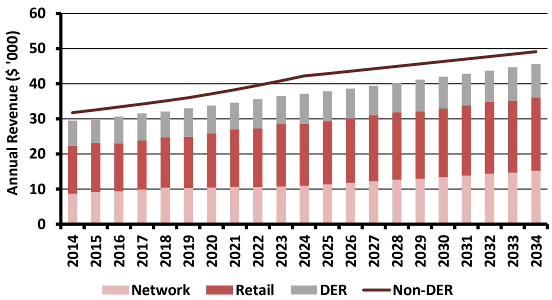
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

As with the SB segment, the non-DER business customer bill is higher than the business customer adopting DER as networks seek to recover revenue via increased consumption based prices. The two maximum demand tariffs (Tariff Type 3 and 4) both result in smaller divergence between DER and non-DER customers. Notably, the Tariff Type 4 scenario results in all business customers paying the same bill throughout the forecast horizon.

5.3.1 Community Total Costs

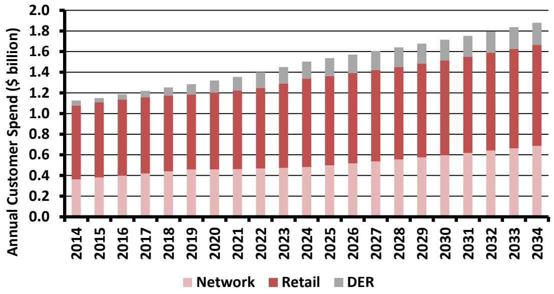
The total cost of energy to the customer segment is equal to the summation of retail and network component of all customers plus the cumulative annualised cost of DER investment. The following section describes the total cost of energy for each of the customer segments combined

Residential

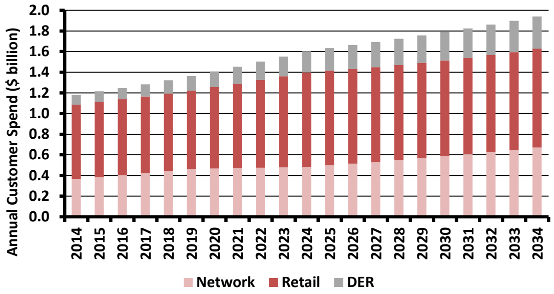
Figure 54 shows the revenue for residential segment under each of the tariff types.

Figure 54 – Residential Customer Total costs

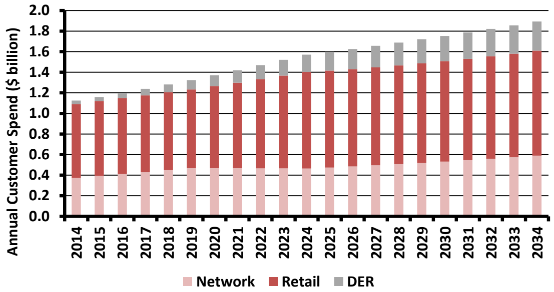
Tariff Type 1 (IBT)



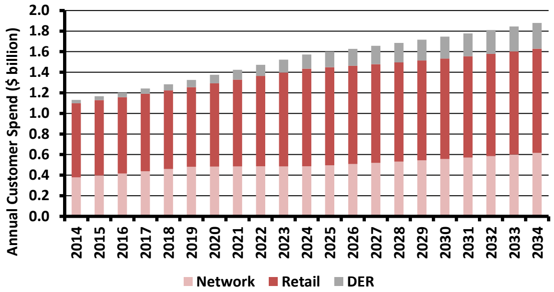
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

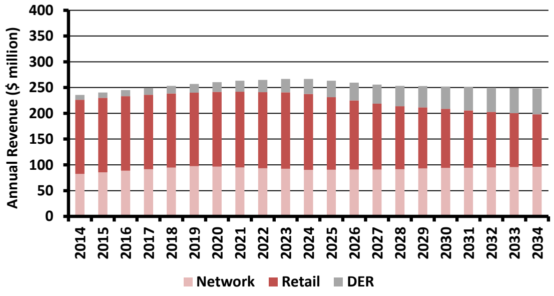
Figure 54 shows that although the annual bill for individual non-DER and DER customers is highest under the IBT and ToU tariffs, the total cost of energy to the residential segment is similar. The driver of this outcome is the high penetration of DER customers under both of these tariffs. This is because the total cost of energy for the individual DER customer under IBT and ToU is substantially less than the total cost of the non-DER customers' bills under either of the two monthly demand tariffs.

Small Business

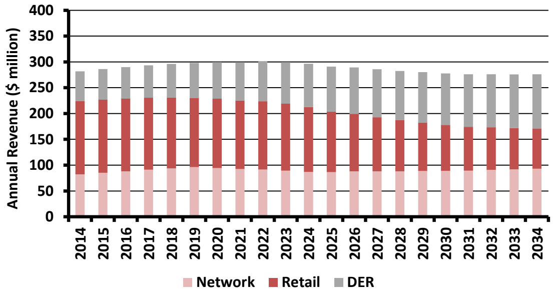
Figure 55 shows the total cost of energy for all SB customers.

Figure 55 – SB Customer Total costs

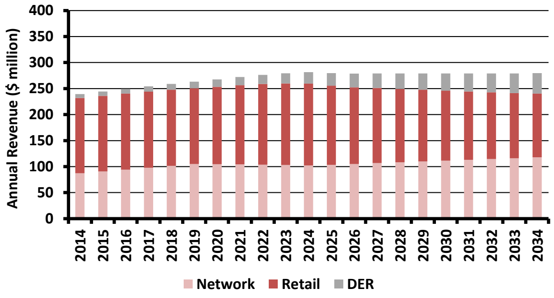
Tariff Type 1 (IBT)



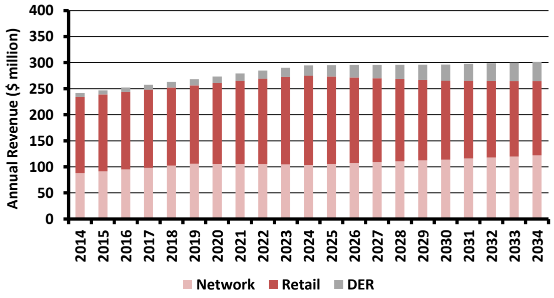
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

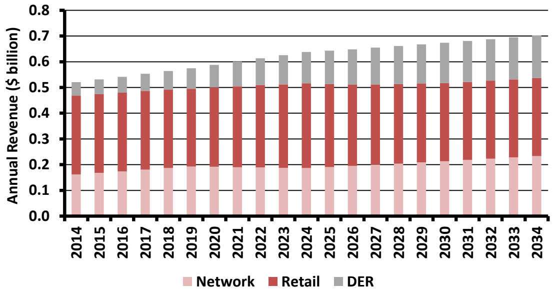
As the DER penetration rate gets very high, the incremental customers adopting are a small percentage of the total population by the end of the period. Accordingly, there is a real reduction in the cost of energy for these customers but a limited impact on the weighted feedback loop and the cost of total energy. Further, because there is no retail feedback, customers are able to reduce the retail component of their bill with a resultant real decrease in this component as shown by the decline in total retail revenue across all tariffs.

Business

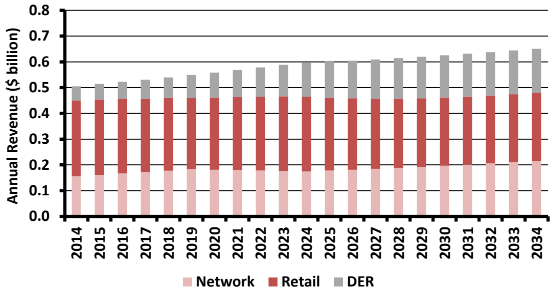
Figure 56 shows the total cost of energy for all Business customers.

Figure 56 – Business Customer Total costs

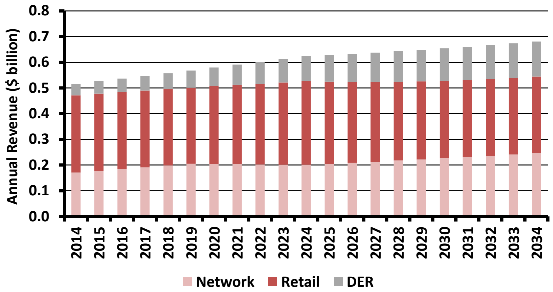
Tariff Type 1 (IBT)



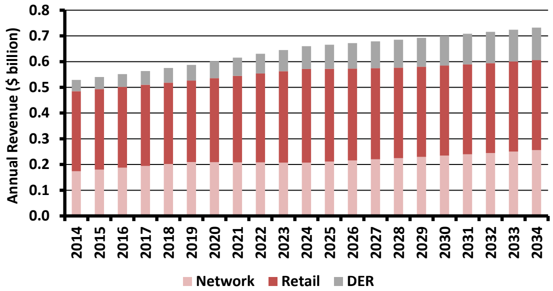
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

The outcomes for the commercial customer segment are varied. The ToU tariff results in the lowest total cost of energy followed by the two monthly demand tariffs. The result is driven by the strong relationship between solar and bills with the solar investment providing significant bill relief under the ToU structure.

It should be noted that whilst some customers will be better off under Tariff Type 1 and Tariff Type 2, this will be at the expense of significantly greater bills for non-DER customers due to the cross subsidy effect.

5.4 System Level Analysis

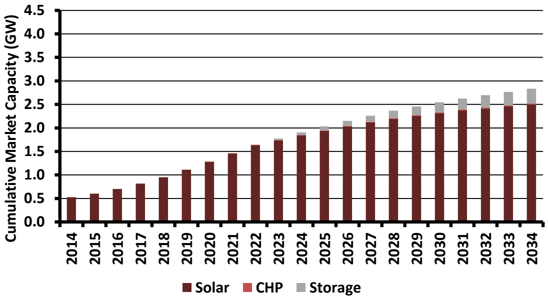
To interpret the system level impacts, the customer segments are combined to represent SA as a whole. It is important to note that this market is being built up from only five representative market customers and is based on the assumptions as outlined in Section 4 and Appendix 1.

5.4.1 System Level DER Capacity

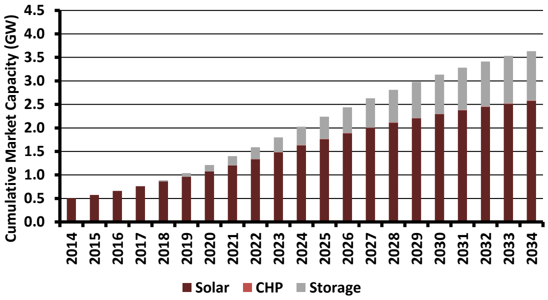
Figure 57 shows the total cumulative adoption of DER for all customer segments under each tariff type.

Figure 57 – Total Cumulative DER Adoption

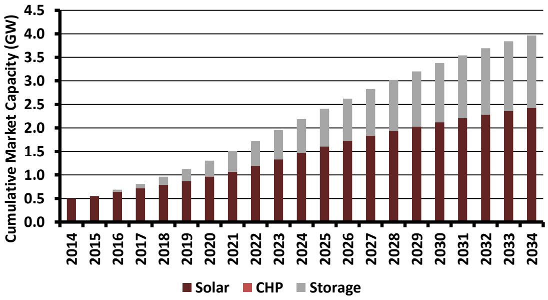
Tariff Type 1 (IBT)



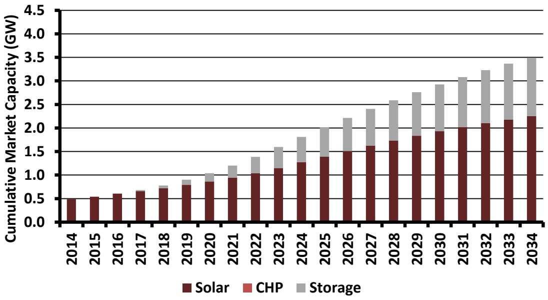
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

Solar PV dominates the DER capacity such that an additional 2.5 GW of capacity is installed by 2034, under the consumption based tariffs, resulting in a large decrease in grid consumption. Under the monthly demand tariffs, solar PV adoption is roughly 100 to 300MW less compared to under the consumption based tariffs by 2034.

Small amounts of CHP are adopted under Tariff Types 1and 2 from 2019 and 2022 respectively due solely to adoption within the non-residential sector.

By 2034, significant storage is installed under all tariff types from all segments with the maximum (over 1.5GW of storage) for Tariff Type 3.

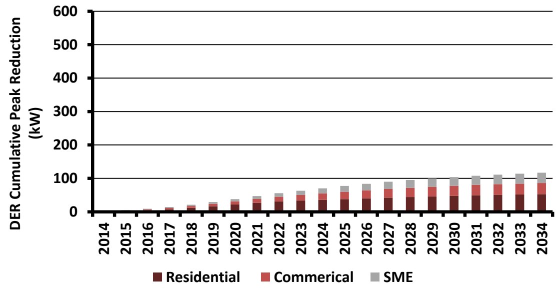
5.4.2 System Level Peak Reduction

The total market peak reduction is less than the summation of the individual customer segments as it is reduced by the effect of diversity. The assumption here of 50% diversity insinuates that each of the customers' peak demand has, on average, a 50% coincidence with the peak of the network.

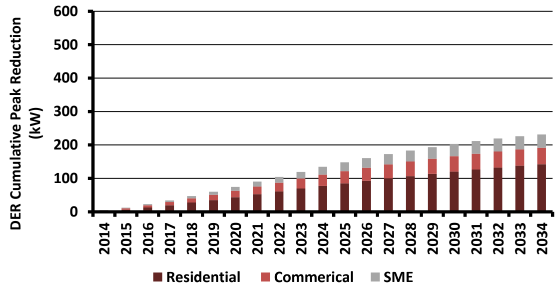
Figure 58 presents the total reduction in the system peak demand under each tariff by customer segment, assuming that those customers who adopt DER adopt the new tariff with the remainder on IBT.

Figure 58 – Cumulative System Level Peak Reduction

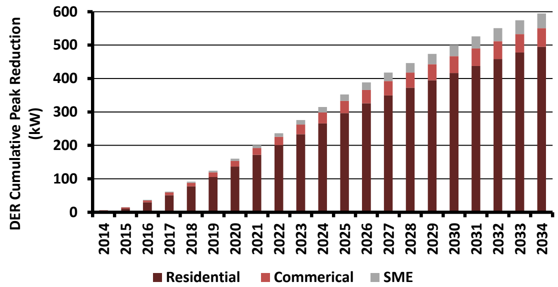
Tariff Type 1 (IBT)



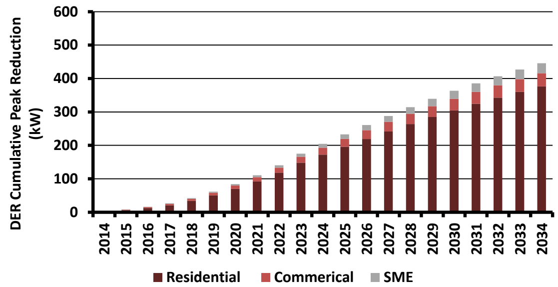
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

Residential customers have much more impact on total peak due to both storage uptake on a per customer basis and the large number of customers, almost ten times as many as the non-residential segment.

These results imply that the high solar PV uptake in the residential sector under the consumption based tariffs have less of an impact on peak demand than the increased storage uptake of the Tariff Type 3 and Tariff Type 4 scenario.

The non-residential (both SB and business) peak demand is reduced much more significantly relative to the number of participants due to the high coincidence of peak demand and solar generation but has a small overall impact on the system wide peak reduction.

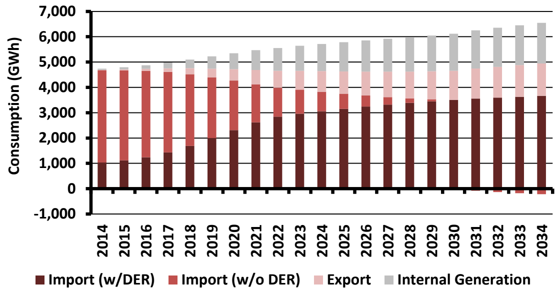
5.4.3 System Level Consumption

As explored in the previous sections, where a tariff structure discourages high consumption, customers act to reduce their consumption through incorporating cheaper distributed generation alternatives.

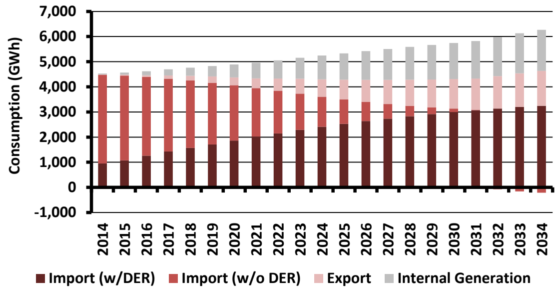
Figure 59 shows the cumulative market consumption in terms of imports from the grid, internal generation and exports. In interpreting these results it is important to note that exports from DER are assumed to offset import to non-DER customers and the grid import for these customers has been decreased accordingly. Network revenue would therefore be recovered from the export and import components, but not the internal generation.

Figure 59 – Cumulative Market Consumption

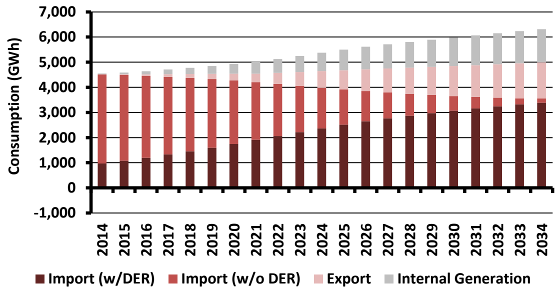
Tariff Type 1 (IBT)



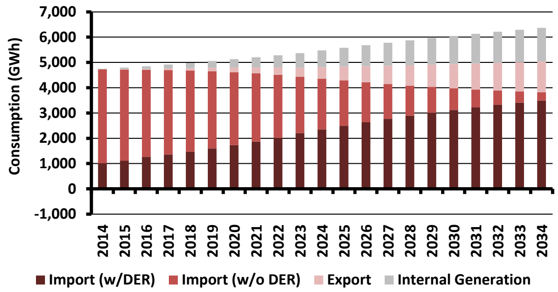
Tariff Type 2 (ToU)



Tariff Type 3 (MD + ToU)



Tariff Type 4 (MD + DPP)



Source: Energeia

Under all tariffs there is a reduction in energy supplied by centralised generation (imports). Under Tariff Type 1 and Tariff Type 2, where network revenue is directly related to consumption, this consumption decline gives rise to network price increases and a corresponding divergence in bills between customers adopting and not adopting DER. For the maximum demand tariff (Tariff Type 3 and 4) these effects are less pronounced as revenue is more strongly related to peak demand.

In the upper charts, negative export flows can be observed under Tariff Type 1 and Tariff Type 2 which suggests excess generation at the network wide level at some points in time. This outcome is likely to signal incremental augmentation requirements or containment of customer inverters due to over voltage issues not assessed as part of this project.

6 Appendix 1 – Assumptions

6.1 Financial Modelling Assumptions

The key assumptions in assessing customers' economically optimal DER configuration and the return on investment include:

- Decisions are made based on a 15 year asset life span.
- All customer purchases are made using financing at the customers' weighted average cost of capital assumed to be 10%
- All purchases of distributed energy resources with a dynamic tariff require the installation of a smart meter
- There is no new adoption considered within the project meaning that once a customer has purchased a particular configuration of energy resources they cannot upgrade or change that configuration
- Customer decisions are inclusive of all costs including:
    - Bill benefits are calculated in half hourly increments to capture the interaction between different energy resources and the customer's load to calculate the correct export revenues.
    - The annual cost of financing capital expenditure (net of any government subsidies or rebates), operation and maintenance costs including any fuel costs, installation costs and network connection costs where appropriate (i.e. solar PV systems over 30kw).

6.2 Exogenous Macroeconomic Assumptions

The exogenous variables are based on the scenario work undertaken by Energeia as part of this project.

Key summary statistics are show in Table A1

Variable	Years 0-5	Years 5 - 10	Years 10+
Feed-in Tariff Growth Rate (%/Annum)	-15.0%	-5.0%	-5.0%
Network Underlying Price Growth (%/Annum)	4.00%	0.00%	2.00%
Retail Price Growth (%/Annum)	3.00%	3.00%	0.00%
Wholesale Price Growth (%/Annum)	1.00%	5.00%	1.00%
Housing Growth Rate (%/Annum)	1.00%	1.00%	1.00%
Energy Efficiency off-peak (%/Annum)	-0.40%	-0.40%	-0.40%
Energy Efficiency peak (%/Annum)	-0.20%	-0.20%	-0.20%
Consumption Peak Growth Rate (%/Annum)	2.00%	2.00%	2.00%

Table A1 – Summary of Exogenous variable growth rates

- Energy efficiency impacts are based on AEMO's 2012 NTNDP
- Price growth rates based on scenario planning process

6.3 Technology Assumptions

The following section details the key assumptions for each of the individual technologies

6.3.1 Solar

Constraints

- based on research into the average size of roofs, customers are constrained to a maximum of 10 kw capacity and 90 kw capacity of solar PV for residential and commercial customers respectively

Technical Configuration

- Mono crystalline is assumed with a 0.15 kW/m^2 efficiency
- Solar systems are assumed to be installed facing north (in-line with the Clean Energy Regulator's guidelines)
- Generation is calculated using radiation levels at the state capital

System Operation

- Solar radiation assumes half hourly values for the capital of each state per the National Renewable Energy Laboratory PV Watts calculator[15]. This calculator is parameterised by weather data for SA.

Maintenance and Replacement

- Solar PV is assumed to last 15 years with no operational or maintenance expenditure for the panels or inverter

6.3.2 CHP

Constraints

- Residential CHP systems only become available to the mass market from 2016
- CHP systems can be no larger than 10 kW for residential and 30 kw for commercial customers

Technical Configuration

- Solid oxide fuel cell technology used in modeling due to relatively high power-to-heat ratio
- Efficiency of the CHP system is calculated excluding the hot water load

System Operation

- CHP systems operate at a constant output throughout the year at 100% all the time in line with manufacturer recommendations

Maintenance and Replacement

- The replacement of the "stack" is assumed after 7 years
- Fuel costs and efficiencies of system are taken into account based on

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[15] Available from NREL's website: http://rredc.nrel.gov/solar/calculators/pvwatts/version1/

6.3.3 Storage

Constraints

- Due to physical limitations, household and commercial customers are assumed to be constrained to a maximum storage size of 10 kWh

Technical configuration

- Lead acid battery assumed for customer storage technology

System operation

- Battery algorithm set to maximise customer benefit based on the tariff that the customer is assumed to be on

Technology Learning Curves – Solar PV

Future pricing curves for emerging technologies have been estimated based on past experiences of technology evolution, such solar PV, and detailed analysis into the cost of construction, components and current quantities of production.

In assessing the forward curves for solar PV Energeia relied on its experience in developing product price forecasts including publishing reports on solar PV, battery storage and micro generators. A broad range of international forecasts were assessed to inform a detailed forecast of the economies of scale, component costs and technology advancements that may impact the individual technology pricing curves.

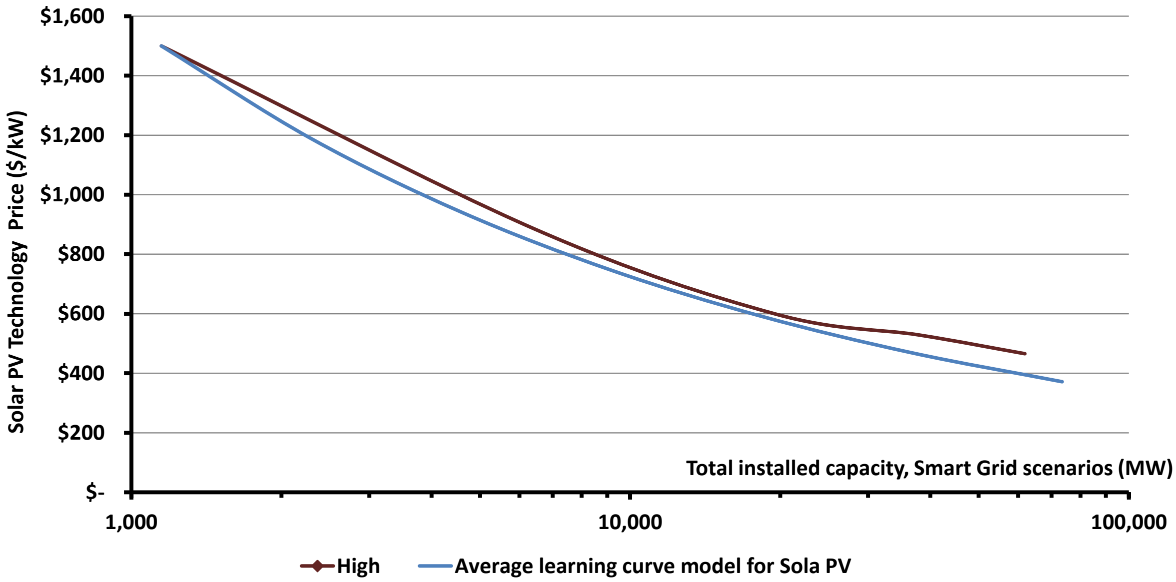

Figure A1 – Solar PV learning Curves[16]

The pricing curves for solar PV reflect key scenario assumptions regarding the impact of greater competition in the inverter market and the commercialisation of building integrated PV (BIPV) and organic technologies including solar roof tiles and solar paint or dyes.

[16] The International Renewable Energy Agency (2012), *Solar Photovoltaics*, Renewable Energy Technologies: Cost Analysis Series Volume 1: Power Sector issue 4/5

Technology Learning Curves – Battery Storage

Similar to the other emerging technology pricing curves thorough industry research (over 10 different forecasts were assessed) was undertaken including assessment of technology options (lead-acid, lithium-ion, redox flow, nickel), prices and industry expectations, market share and quantities.

Technology Learning Curves – Fuel Cells

The pricing curves for fuel cells reflect key scenario assumptions regarding the level of international investment in R&D and capability development, relative rates of cost decline among the fuel cell technologies due to economies of scale and technology breakthroughs in materials.

Whilst, in the Australian context, there is currently limited investment in fuel cell technology, internationally there is strong investment (exacerbated since the Japanese earth quake in 2010). Key summary of learning curve inputs are shown in Table A2

Technology	Capex 2014	Years 0-5	Years 5 - 10	Years 10+
Micro Inverter ($/kW)	**$1,000**	**-33.5%**	**-2.5%**	**-2.5%**
Install ($)	**$400**	**0.0%**	**-2.5%**	**-2.5%**
Solar PV Price ($/kW)	**$2,650**	**-5.5%**	**-3.5%**	**-0.8%**
CHP Price ($/kW)	**$21,000**	**-13%**	**-5%**	**-1%**
Battery Price ($/kWh)	**$250**	**0.0%**	**0.0%**	**0.0%**
Smart Meter CAPEX ($/meter)	**$328**	**-15.0%**	**-12.5%**	**-7.5%**

Table A2 – Summary of Technology Capital Cost and Learning Curves

7 Appendix 2 – Trial References

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8 Appendix 3 – Quality Assurance

8.1.1 Energeia's Quality Management System

The assessment was undertaken in accordance with the principles and procedures of Energeia's Quality Management System. Our QMS is based on the international standard ISO 9001:2008 and the equivalent AS/NZS 9001:2008. An overview of our QMS is provided in Appendix 3. Details of the quality assurance process applied to the modelling process are discussed below.

8.1.2 Quality Assurance of Modelling, Calculations and Analysis

Energeia adopts specific procedures for all our modelling, calculation and analytical tasks to ensure our results are rigorous, error free and fit for purpose.

To achieve this aim each analytical task is assigned:

- A lead developer responsible for model development and version control;
- A QA lead responsible for developing the quality assurance plan and implementation of quality assurance checks; and
- A manager responsible for final sign off and verification that the QA processes have been completed in accordance with Energeia's QMS requirements.

Planning and Design Stage

At the planning and design stage the lead developer and QA lead will develop and agree to a QA Plan which identifies:

- The relevant inputs and associated checks required including benchmarking and reasonableness checks;
- The required outputs and associated checks including benchmarking and reasonableness tests;
- In built checks (such as checksums);
- Manual checks (such as sensitivity tests); and
- Logic or formulae which require subject matter expert review.

For each of these checks, the QA Plan assigns a checker (usually the QA lead) and a timeframe for the review. This will include checks during both the development stage and at model finalisation.

Development Stage

During the development of the model, the model lead must:

- Track inputs and outputs across the model through the use of colour coding of cells
- Avoid the use of hard coding, long formulas or poor formula layout, (i.e. direct calculations preferred over the use of index functions)
- Track model version using a version control tab
- Ensure that the QA Plan is implemented and updated

Review Stage

Once the modelling task is complete, the model is reviewed against a QA Checklist prior to finalising of and reporting of the results. The QA Checklist must be completed by the model lead (self-check) as well as by at least one suitably qualified and experienced person (the QA lead).

The QA checklist ensures that:

- All sources, assumptions and inputs are documented;
- All references are checked to correct cells;
- All formulas are correctly entered; and
- All checks including subject matter expert checks have been undertaken as per the QA Plan and approved.

9 Appendix 4 – Quality Management System

Energeia's QMS is based on the international standard ISO 9001:2008 and the equivalent AS/NZS 9001:2008.

The objectives of Energeia's Quality Management System are to:

- Ensure all deliverables meet or exceed clients' expectations and Energeia's own standards for high quality;
- Provide evidence of the quality assurance processes in place; and
- Enable the continual improvement of the total delivery process.

Our Quality Management System is based on the following nine principles:

QUALITY ASSURANCE POLICY STATEMENT

Energeia strives to provide our clients with the highest level of quality in terms of:

- Rigorous, error free and fit for purpose analytics; and
- Clear, concise and accurate communication of findings and information.

Commitment to quality at all levels of the business is essential to our mission to consistently provide sound and evidence based advice to empower our clients in their decision making processes.

Client focus: We explicitly understand our current and future customer needs and aim to meet and where possible, exceed our client expectations.

Leadership: Our leaders have a vision and direction which is underpinned by high quality work. Our leaders set an example and have high expectations of quality of delivery from both themselves and other staff. Leadership exists at all levels within the business.

Involvement of people: All staff understand their responsibility for quality management and are fully motivated and committed to achieving the quality objectives.

Process approach: We adopt a process based approach to quality management whereby quality procedures are incorporated within all aspects of our planning, development, delivery and review tasks at both the project and business scale.

Systems approach to management: We adopt a structured systematic approach to quality management which seeks to achieve our quality objectives using the most effective and efficient methods to identify understand and manage all interrelated processes as a system.

Continual improvement: We seek to continually improve our quality management system by monitoring, evaluation and review of performance against clear and concise measures.

Factual approach to decision making: We ensure evidence based decision making across the total delivery process by ensuring that data and information is accurate, reliable and analysed using valid methods.

Transparency: We ensure that our assumptions and reasoning underpinning our decision making processes are transparent and accessible to those who need it.

Mutually beneficial supplier, subconsultant and partner relationships: We value mutual beneficial relationships with our suppliers, subconsultants and partners. These relationships allow us to benefit from optimised costs and resources, clear and open communication and being able to share knowledge and plans on market changes and client expectations.

10 Appendix 5 – About Energeia

Energeia Pty Ltd (Energeia) based in Sydney, Australia, brings together a group of hand-picked, exceptionally qualified, high calibre individuals with demonstrated track records of success within the energy industry and energy specialist academia in Australia, America and the UK.

Energeia specialises in providing professional research, advisory and technical services in the following areas:

- Smart networks and smart metering
- Network planning and design
- Policy and regulation
- Demand management and energy efficiency
- Sustainable energy and development
- Energy product development and pricing
- Personal energy management
- Energy storage
- Electric vehicles and charging infrastructure
- Generation, including Combined Heat and Power (CHP)
- Renewables, including geothermal, wind and solar PV
- Wholesale and retail electricity markets

The quality of our work is supported by our energy-only focus, which helps ensure that our research and advice reflects a deep understanding of the issues, and is often based on first-hand experience within industry or as a practitioner of theoretical economic concepts in an energy context.

Energeia's Relevant Experience

Energeia's recent smart metering and smart grid related engagements are summarised below.

Review of Victorian DNSPs' 2009-11 Advanced Metering Infrastructure Budgets

The Australian Energy Regulator engaged Energeia to undertake a review of Victorian Distribution Network Service Providers' (DNSPs) 2009-2011 budget proposals for Advanced Metering Infrastructure against the regulatory criteria specified in the revised Order in Council.

Review of Advanced Metering Infrastructure Enabled Load Control Performance Levels

A Victorian DNSP engaged Energeia to undertake a review of current load control enabling performance levels and to make recommendations considering the impact of updated use case benefits and communications cost information.

Review of Overseas Regulation of Smart Metering Information for Customers

An Australian jurisdictional regulator engaged Energeia to review the arrangements in place in comparable overseas jurisdictions and the experience of EnergyAustralia during their roll out of interval meters and ToU pricing to nearly 140,000 customers using between 15 MWh and 160 MWh per annum (p.a.).

Best Practice Regulation of Smart Metering

A smart metering vendor engaged Energeia to identify policy and regulatory options for improving the smart meter deployment in Victoria. The engagement included a detailed review of leading international smart metering deployments in California, Texas, Pennsylvania, Ontario and Sweden.

International Smart Meter Based Energy Retailing: Review and Recommendations

A top-tier Australian energy retailer engaged Energeia undertake a review of international deployments of smart metering and ToU based products to identify innovation and key lessons learned. The purpose of the engagement was to identify innovative products that the retailer could consider deploying across its smart meter enabled customer base.

Smart Meter Enabled Retail Product Development and Trialling

An Australian energy retailer engaged Energeia to support the design, development, justification and trialling of three innovative smart meter enabled electricity pricing plans that would save customers money, improve the retailer's margin and reduce customer churn.

Smart Meter Enabled Network Product Development and Trialling

A NSW DNSP engaged Energeia to support the design, development, justification and trialling of innovative, smart meter enabled network tariffs that could reduce network investment costs, save end user customers money and improve retailer margins. The engagement included the design of a robust sampling approach that would enable the rigorous quantitative assessment of product impacts on key performance indicators.

Review of Advanced Metering Infrastructure Related Threats and Opportunities in Australia

A top-tier Australian energy retailer engaged Energeia to undertake a review of emerging threats and opportunities in the electricity sector as it transitions to a more intelligent platform (smart grid) over the next five to ten years. The key area of focus was the deployment of advanced metering infrastructure and related customer energy technologies, products and services.

Smart Grid Design and Development

Energeia was engaged by a major Australian utility to develop a smart grid solution for minimising the costs and carbon intensity of generating power in a remote island energy system. The engagement included designing a fit-for-purpose smart grid concept, developing functional and technical specifications, supporting market engagement, modelling project costs and benefits, and developing the project business case.

Smart Grid, Smart City Proposal Support

Energeia was engaged by a DNSP to support the development of their winning proposal for the $100M Smart Grid, Smart City project. The engagement included the development of a retailer value proposition and engagement strategy, development of the project's delivery and operating models, and development of related proposal documentation.

Network of the Future Design

A top tier field services provider engaged Energeia to support the development of a Network and Substation of the Future concept design and development roadmap. The engagement included researching international best practice, facilitating a number of concept development workshops with project stakeholders, developing the client proposal, and sourcing the skilled resources needed to deliver it.

Future Operating Model Design

An Australian DNSP engaged Energeia to support the development of their Future Operating Model blueprint and roadmap to 2026. The engagement included facilitating a series of whole-of-business workshops to gain strategic alignment on the DNSP's future customers, network and organisation, and the development of documentation to support stakeholder engagement and communication.

Embedded Networks for Electric Vehicles

Energeia was engaged by a leading electric vehicle infrastructure company to review the existing market arrangements around embedded networks and to provide recommendations regarding how these arrangements may be used to support the deployment of electric vehicle charging infrastructure.