Network Pricing and Enabling Metering Analysis

Prepared by ENERGEIA for the Energy Networks Association

November 2014

Executive Summary

Rising electricity bills across the country over the past five years are driving consumers, policymakers, regulators and the electricity supply industry in search of better ways of pricing electricity to encourage more efficient demand and investment patterns, and more equitable distribution of the associated costs and benefits.

The national policy response to rising prices, crystallised in the Australian Energy Market Commission's (AEMC) Power of Choice program of reforms, has focused on sending more Cost Reflective Price (CRP) signals, opening up the market for the enabling metering services and institutionalising demand-side response mechanisms. CRP signals ensure that customers are charged on the basis of the costs they impart on the system.

Distribution networks charges account for between 15% to 60% of the average retail electricity bill of 'small' customers using less than 100 MWh per annum depending on the network. These charges are mostly recovered through a network Inclining Block Tariff (IBT) or flat tariff using basic register metering.[1] The retail portion of the customer tariff typically also reflects the same IBT or flat structure.

Although energy based time-of-use (ToU) network tariffs have been available in most network areas in Australia on a voluntary basis for years, there has been almost no retailer marketing of these products to date, with the notable exception of EnergyAustralia in Victoria. Nevertheless, industry interest has grown in the potential use of Critical Peak Pricing (CPP), Maximum Demand (MD) based ToU tariffs and Declining Block Tariffs (DBT) to help address the issue of rising network prices.

In order to make efficient, equitable and effective decisions regarding the range of potentially more cost reflective network tariff options, the national policy debate requires information about their relative impact on customer bills in the near as well as longer-term. This measure of performance also specifically addresses the key criteria for change enshrined in the National Electricity Rules (the Rules), the National Electricity Objective (NEO).

The Energy Networks Association (ENA) engaged Energeia to assess the long-term customer bill impacts of the main cost reflective network tariff design options in order to inform the national debate. As part of this engagement, Energeia was also tasked with assessing key tariff and metering policy settings which could fast track and/or realise greater benefits to the community as a whole.

Energeia's Scope and Approach

Energeia undertook a network industry engagement process to agree network and retail tariff classes and specific forms to assess based on current industry plans and the national and international debate.

The tariff structures were assessed in terms of how efficiently they signalled the incremental network cost of supply (i.e. during peak) and the cost of the network service for a given class of customers. It should be noted that the assessment did not seek to identify which tariff structure is the most appropriate for any individual network. Rather, the assessment considered the relative benefits and potential shortcomings of each tariff category.

Energeia developed network tariffs for each of the National Electricity Market (NEM) jurisdictions. Each specific tariff design for a given jurisdiction reflected the key starting cost positions in that state in terms of average annual bills and published Long Run Marginal Costs (LRMC):

Table 1 – Tariff Designs Assessed

Customer Tariff Design	Tariff Label	Network Tariff	Retail Tariff
Inclining Block Tariff	IBT	3 Tier IBT	3 Tier IBT
Declining Block Tariff	DBT	3 Tier DBT	3 Tier DBT
Seasonal Time-of-Use Energy	SToU	3 Tier SToU	3 Tier SToU
Seasonal Time-of-Use Maximum Demand	MD+SToU	2 Tier MD	3 Tier SToU

Source: Energeia

An IBT was also developed as the base case against which the cost reflective tariff options were compared. Importantly, fixed charges for each jurisdiction were kept equal across each tariff option.

[1] Ausgrid and ACTewAGL have applied Time-of-Use (ToU) tariffs by default since 2006 and 2010, respectively.

Complementary, cost neutral retail tariffs were also developed that passed through the underlying network cost structure while recovering the same amount of revenue as the current reference retail tariff in each jurisdiction.

Energeia estimated the impacts of prospective tariff designs and associated policy settings on customer behaviour, industry costs and customer bills based on the integrated customer behaviour model developed to analyse the national business case for the deployment of smart grid technology as part of the Federal Government's $100 million *Smart Grid, Smart City* initiative.

Importantly, our modelling assumed that all customers adopting distributed energy resources (DER) including solar PV and/or storage would be assigned to the cost reflective tariff option except under the base case, where they remained on an IBT tariff. This metering policy assumption is consistent with common network industry practice of assigning small customers to a different tariff upon load modification or connection.

For each assessment year over a 20 year period, the model estimated the number of customers adopting the available voluntary tariff, adopting DER (and tariff), and those already on the tariff adopting DER. The impacts of these decisions on regulated revenue recovery, network investment costs and customer bills was then calculated, with tariffs in subsequent years adjusted to recover forgone revenue less reduced peak costs.

The MD+SToU scenario, which assumed customers adopting Distributed Energy Resources (DER) received a smart meter and were reassigned to a CRP, was then re-run and the net incremental benefits assessed assuming additional metering policy scenarios of:

- *New and Replacement Electricity Meters* – Smart meters for new and replacement meters with customers assigned to an MD+SToU tariff for new meters. This policy option is under review by jurisdictions who are to report back to the Council of Australian Governments (COAG) Energy Council;
- *Threshold* – Smart meters and MD+SToU tariff assigned to medium businesses, i.e. customers using more than 40MWh per annum.

Based on the modelling results, Energeia found significant differences between tariff design and meter policy setting options. These include differences in the timing, penetration, size and mix of DER technology and tariff adoption among customer segments, and associated impacts on industry costs and customer bills.

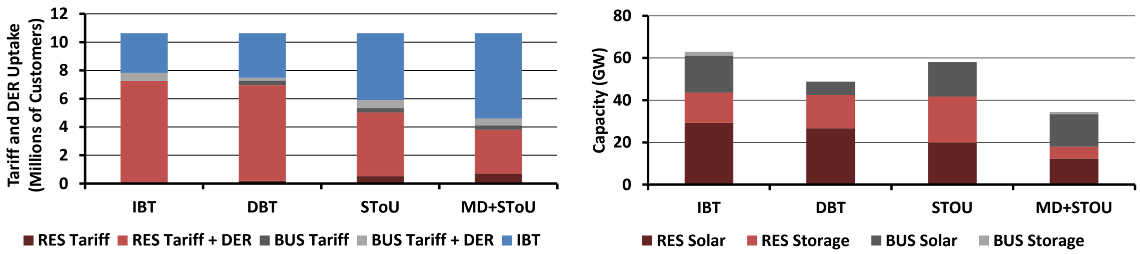
Customer Behaviour Impacts

Energeia's modelling shows that tariff design choices have a significant influence on customer behaviour, and in particular on their DER investment patterns. The less cost reflective the network tariff, the more likely customers are to invest in solar PV beyond efficient levels to reduce their own bills.

Figure 1 compares customer uptake of tariffs and technology over the 20 year forecast period by tariff scenario. IBT and DBT tariffs result in the highest overall level of DER penetration by the end of the period, with a key difference being DBT's lower percentage of business customers adopting DER. SToU and MD+SToU both show significantly lower rates of technology adoption overall due to reduced investment within the residential sector.

The main difference between the tariffs is in residential DER adoption rates, which is much higher under IBT and DBT due to the significantly stronger investment signal they provide for solar PV.

Figure 1 – Cumulative Tariff and Technology Adoption by Tariff Scenario to 2034



Source: Energeia

The associated estimated DER technology capacity mix is also presented in Figure 1 by tariff scenario. Again, the default IBT tariff results in the greatest DER capacity overall, as well as the highest level of residential and business solar capacity, but slightly lower residential storage than SToU. Business investment in DER is the lowest under DBT, while MD+SToU results in the lowest overall level of DER investment but distributes it more equally between the business and residential sectors.

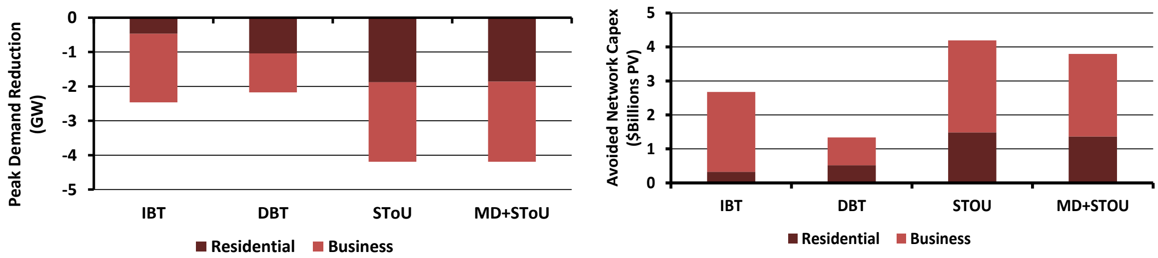
There is a significant difference in the level of residential storage adopted for SToU and MD+SToU. This is largely due to the over signalling of peak period network costs under the SToU tariff design, consistent with current industry practice. This cross subsidy leads to storage becoming cost effective earlier under SToU, and gives rise to four times greater investment compared to MD+SToU.

Network, Bill and Equity Impacts

Energeia's modelling results show significant variations among the tariff design options in terms of the overall impact on network peak demand, customer bills and cross subsidies.

Figure 2 presents Energeia's estimate of the total cumulative reduction in network peak demand by tariff and its corresponding reduction in network capex in present value terms. The modelling shows SToU and MD+SToU tariffs delivering almost twice as much network peak demand reduction and avoided capex as the IBT and DBT tariffs. The difference in avoided capex between IBT and DBT given their comparable levels of peak demand reduction are due to the DBT impacting network peak demand later in the assessment period with a corresponding lower present value of these avoided network investment costs.

Figure 2 – Cumulative Network Peak and Capex Reductions by Tariff Scenario to 2034



Source: Energeia

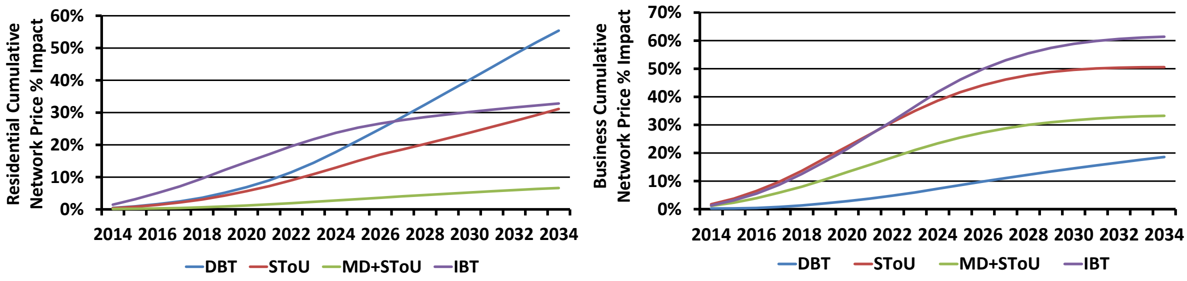
Comparing Figure 2 in light of Figure 1 shows which tariff is more effective in aligning DER investment to network benefits, i.e. which is more efficient. MD+SToU provides the same level of network benefits as SToU with about half the investment in residential solar PV and one fourth the investment in residential storage. Under DBT, customer investment in DER is almost as high as under IBT, but achieves less than half the network benefits.

MD+SToU delivers twice the benefits from storage compared with SToU due to its effect on storage operation. Under SToU, storage discharges as fast as possible during the peak period to maximise recharge using solar PV that would otherwise be exported at low value. Under MD-SToU, storage maximises return by targeting the customer's peak demand during the peak period, which is more closely aligned to the area's network peak.

Network prices are typically set by the regulator to recover efficient costs over a five year period. Prices are allowed to increase under a revenue cap to recover any shortfalls in revenue. Over time, cost reductions, for example due to lower network peak demand growth, lead to reductions in allowed revenue. This means that network revenue reductions that are higher than network cost reductions increase prices over time.

The cost reflectivity of network prices therefore impacts network price increases by aligning any reductions in network revenues to commensurate reductions in network costs. Energeia's modelling of the effectiveness of each tariff option in achieving this alignment of revenues and costs over time is shown in Figure 3.

Figure 3 – Cumulative Network Price Increases by Tariff Scenario and Customer Class to 2034



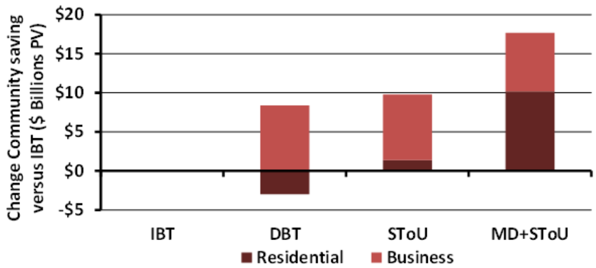
Source: Energeia

The modelling shows the impact of tariffs on network price increases varies widely between residential and business customers due to the misalignment of network revenues and cost reductions over time. MD+SToU performs the best overall, while SToU and IBT lead to between 30% and 60% network price increases for residential and business customers respectively. DBT varies by customer class, performing the worst for residential customers but best for business customers due to small businesses being unable to install solar PV.

When considering overall impact of the foregoing factors on customer bills it is also important to understand that network price increases to recover regulated revenues do not impact customer bills on a weighted average basis. The weighted average net impact of the various tariff designs, or 'community cost', is driven by cumulative avoided network costs, cumulative avoided retail charges and offsetting of cumulative cost of DER.

Figure 4 compares the present value of community electricity charges for network, retail and DER services over the 20 year study period under each tariff option relative to IBT. This provides an economic indicator of each tariff option's performance in terms of the overall community net benefits relative to IBT. It shows that moving to the most cost reflective MD+SToU tariff could save customers $17.7 billion in present value terms.

Figure 4 – Change in Community Savings by Tariff and Customer Class to 2034 Relative to IBT



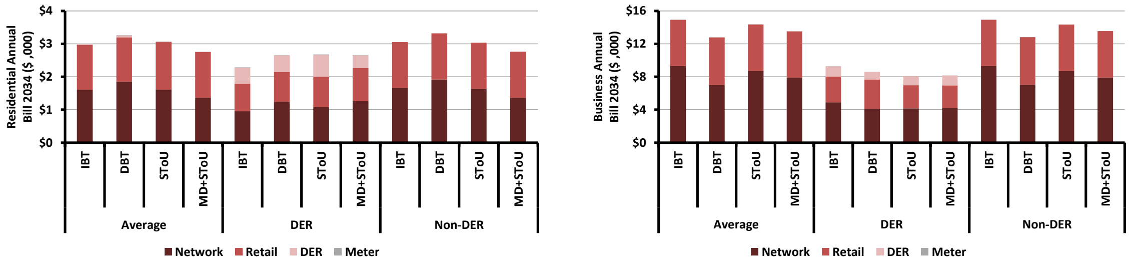
Source: Energeia

Energeia's modelling shows that moving to a DBT tariff could increase residential customer bills, mostly due to the deferment of DER adoption benefits until later in the forecast period. According to the modelling, residential customers are likely to be $10 billion better off under MD+SToU but only marginally better off under SToU.

Community costs for business under DBT are roughly equivalent to SToU and MD+SToU, but driven by different factors. Businesses save money by avoiding over investing in DER under DBT relative to IBT, while under SToU and MD+SToU, they save money by reducing network costs by investing more efficiently in DER relative to IBT.

Figure 5 presents the average customer bill by class and tariff design option by the end of the modelling period in 2034. Annual bills are further broken out according to whether or not a customer is adopting DER in that year compared to a passive customer remaining on IBT with no DER.

Figure 5 – Annual DER and Non-DER Customer Bills in 2034 by Tariff and Customer Class

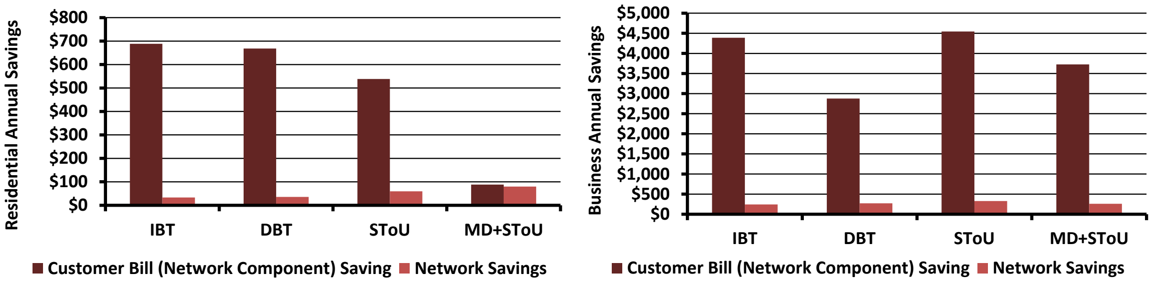


Source: Energeia

One of the key findings of Energeia's modelling is that without change, by 2034 the passive customer can be expected to pay a third more for their electricity than the equivalent customer who adopts DER. This effect declines significantly for the smart meter enabled tariffs, with MD+SToU resulting in the most equitable outcomes between residential customers with and without DER. MD+SToU performs comparatively well for both business and residential customers.

While this analysis shows that the more cost reflective the tariff, the lower the average bill overall and the smaller the difference between DER and non-DER customers, it does not necessarily reflect the level of cross-subsidies.

Figure 6 – DER Customer Bill Savings vs. Network Savings in 2034 by Tariff and Customer Class



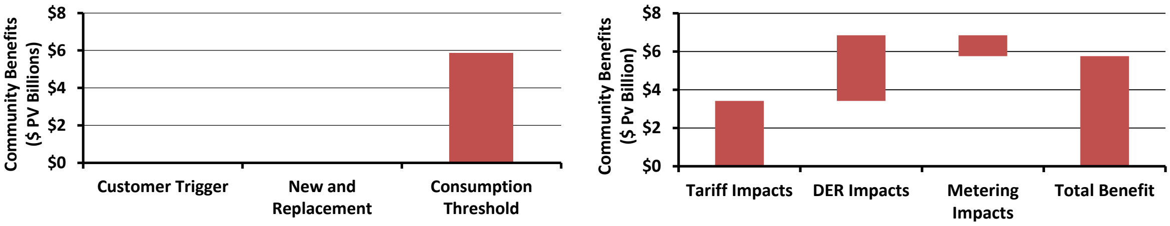
Source: Energeia

In order to understand the level of cross-subsidy between customers in the same class under each tariff design option, Energeia compared customer bills before and after adopting solar PV against the associated reduction in network costs due to peak demand reduction. Figure 6 shows that the more cost reflective the tariff, the lower the cross-subsidy and more equitable the bill outcomes, with MD+SToU delivering the lowest cross-subsidy for residential customers.

Metering Policy Impacts

Energeia's modelling results show that there is scope to improve the overall long-term net benefits to Australian electricity consumers through specific metering policy settings, as shown in Figure 7. Our modelling shows business customers would save an additional $5.8 billion in present value terms by networks accelerating the deployment of CRPs to larger business customers through targeted tariff and meter deployment.

Figure 7 – Incremental Benefits of Metering Policy Scenarios to 2034 Relative to Base Case



Source: Energeia

The net benefits of an accelerated deployment are mainly due to more efficient DER adoption and relatively high demand reduction per larger business customer. These savings have the potential to result in an additional $5.8 billion in net benefits on top of the $17.7 billion already identified.

While the new and replacement scenario, showed no net benefit, it is important to note that not all network benefits of smart metering infrastructure are included here. Therefore, the new and replacement policy may warrant further investigation where further benefits can be captured.

Conclusion

In summary, Energeia's modelling shows tariff design choices and metering policy settings will have a profound impact on future network price increases, customer bills and potential cross subsidies.

Our modelling results indicate that applying MD+SToU tariffs to existing business customers using more than 40MWh per annum and to new customers adopting DER could reduce customer bills by $23.5 billion over the next 20 years in present value terms. It would also reduce future network price increases by 60% to 70% and DER cross-subsidies by 50% to 90% compared to IBT over the same period.

Importantly, our results assume customers will see the final tariff design modelled. However, there is no requirement for retailers to pass through the network structure or price signals, and they have not always done so in the past, e.g. when Ausgrid reassigned customers using over 15 MWh to ToU tariffs. Moving customers to cost reflective network tariffs that are not passed through in the retail structure will not achieve the same results.

Table of Contents

Table of Figures

Table of Tables

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 ENA and Australian electricity distribution networks, and on data from the *Smart Grid, Smart City* Information Clearinghouse 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 rely on it for any purpose.

For further information, please contact:

Energeia Pty Ltd

Level 23, Gold Fields House
1 Alfred Street
Sydney NSW 2000

T: +61 (0)2 8060 9772
E: info@energeia.com.au
W: www.energeia.com.au

Glossary

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Community costs	Overall cost of electricity supply to all customers including network costs, network charges, retail charges and DER costs
Cross subsidy	The difference between the costs to supply a customer and the amount the customer pays
CRP	Cost Reflective Prices
Cost reflective	The change in costs that an action causes in a system is exactly offset by change in revenue to the same system (marginal cost = marginal revenue)
DER	Distributed Energy Resources (includes solar PV and battery storage for the purposes of this report)
DBT	Declining Block Tariff
DNSP	Distribution Network Service Provider
IBT	Inclining Block Tariff
LRMC	Long Run Marginal Cost
MD+SToU	Maximum Demand and Seasonal Time of Use Tariff
NEM	National Electricity Market
NEO	National Electricity Objective
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NSW	New South Wales
SA	South Australia
SCER	Standing Council on Energy and Resources
SGSC	*Smart Grid, Smart City*
SToU	Seasonal Time of Use Tariff
ToU	Time of Use Tariff

1 Introduction

Australian electricity distribution network businesses are currently facing a series of critical and complex challenges driven, to a large extent, by changes in customer behaviour with respect to technology investment and in response to increasing electricity prices. These changes are most notable for small customers who, cumulatively, are responsible for about one third of overall consumption but a higher percentage of peak demand, the key cost driver of distribution networks.

Current tariff structures, which do not reflect network costs, can give rise to inefficient behaviour including investment behaviour. The cumulative impact of inefficient tariffs is becoming increasingly problematic for networks to manage. Without intervention, current trends are likely to lead to increased bill volatility, and rising levels of cross subsidisation both within and between different classes of customers.

Cost reflective pricing (CRP) has been recognised as a potential mechanism to address these challenges by driving:

- Optimal investment in Distributed Energy Resource (DER) technologies including storage and solar PV;
- Efficient levels of peak demand growth;
- Reduced cross subsidy of customers who invest in DER by those who do not;
- Optimal use of and investment in energy networks; and
- More efficient investment by the community as a whole.

A series of reviews of the current challenges has found existing small customer tariffs to be a key driver of the issues facing networks and have called for reforms to implement CRP. In response, a range of market and regulatory reforms are currently underway to facilitate the introduction of CRP.

1.1 Policy and Regulatory Context

Australian distribution network tariffs in the National Electricity Market (NEM) are regulated under Section 6 of the National Electricity Rules (NER) referred to as the Pricing Rules. These Pricing Rules require distribution networks to adhere to broad economic principles but are not prescriptive as to the ultimate structure or basis of tariffs.

The high cost of smart metering technology has up until recently limited the number of potential tariff classes and charging mechanisms. National reforms, aimed at increasing customer choice and demand side participation, have sought to exploit the fall in metering technology costs to establish more cost reflective pricing arrangements.

The following sections provide a high level overview of the current policy and regulatory framework and key reforms.

1.1.1 The National Electricity Rules

The Pricing Rules require that tariff classes group customers on an economically efficient basis avoiding unnecessary transaction costs[2], and that the revenue recovered by each tariff class lies on or between:[3]

1. An upper bound representing the stand alone cost of serving the retail customers in that class; and
2. A lower bound representing the avoidable cost of not serving those retail customers.

Prices should also be cost reflective and not distort efficient consumption, having regard to the associated transaction costs as well as customers' ability and likelihood to respond.

[2] AEMC, (2014), *National Electricity Rules*, Clause 6.18.3(d).

[3] Ibid, Clause 6.18.5(a).

1.1.2 The Power of Choice Review

The AEMC's Power of Choice review, which has initiated the regulatory changes in respect of metering services and network prices, was undertaken in response to a request from the Standing Council on Energy and Resources (SCER) in March 2011.

The principal thrust of the AEMC's Power of Choice review is to introduce regulatory arrangements that will facilitate customer choice through innovative electricity pricing arrangements.

In its Final Report, the AEMC recommended a range of network pricing and metering related policy and regulatory reforms for consideration by the SCER. The key recommendations relevant to pricing and metering policy scenarios include:[4]

- Introducing competition in metering services and developing a framework for smart meters and their services
    - Introduction of a framework in the NER that provides for competition in metering and related services for residential and small business consumers
    - Requiring smart meters to be installed in defined situations (i.e. new connections, refurbishments and replacements)
    - Removing the option of a government mandated roll out of smart meters in the National Electricity Law
- Providing appropriate consumer protection arrangements and gradually phasing in efficient and flexible pricing options
    - Introduction of cost reflective electricity distribution network pricing structures for residential and small business consumers
    - Revising the existing distribution pricing arrangements to provide better guidance for setting cost reflective distribution network tariffs
    - Arrangements for residential consumers that have low to medium consumption levels to have the option to remain on their existing retail price structure

SCER accepted most of these recommendations in principle, but directed that each state should have responsibility for determining its own minimum functional specification for new and replacement metering installations.[5] The next step in the process of implementing the agreed reforms was the development changes to the NER and NERR.

1.1.3 The COAG Energy Council Rule Changes

The COAG Energy Council has lodged separate NER and National Energy Retail Rules (NERR) Rule change requests to the AEMC implementing the accepted metering and network pricing reforms.

The proposed metering Rules would introduce new minimum smart metering functionality to achieve broader market benefits through certainty in the minimum level of smart meter functionality, performance and access.[6] The proposed minimum functional specification would not be a binding minimum standard unless prescribed by a jurisdiction. In other words, it would be a state-by-state standard, rather than a minimum national standard.

The two key changes to the Pricing Rules being proposed by the COAG Energy Council that are most relevant to assessing future pricing policy options include:

- Amending the existing distribution network pricing principles so that DNSPs set cost reflective network charges, and structure those charges, in a manner that is based on the LRMC of providing network services

[4] *Power of Choice, Final Report*, AEMC, 30 November 2012, page 14.

[5] SCER response to the Power of Choice Review, SCER, March 2013.

[6] SCER, Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services, Rule change request, October 2013.

- Requiring DNSPs to take into account the impacts on consumers of more efficient and flexible network structures and charges.

The AEMC is required to assess whether proposed changes to the NERR promote the National Energy Retail Objective (NERO). The NERO states that:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy.[7]

The AEMC is planning to make a final determination on both the Rule change requests in the last quarter of 2014 which will establish a new regime for network pricing and smart metering moving forward.

1.2 Structure of this Report

The report is structured in five main sections as follows:

- **Section 1 – Introduction** discusses the background to this report, namely the current industry and policy context related to cost reflective prices and smart metering;
- **Section 2 – Scope and Approach** outlines the high level steps involved in Energeia's assessment, the key issues arising and the specific methodologies and assumptions that have been applied;
- **Section 3 – Customer Behaviour Impacts** presents the key results of the four tariff scenarios on customer behaviour with respect to tariff and technology adoption, energy consumption and peak demand;
- **Section 4 – Industry and Community Impacts** presents a summary of the performance of each of the four tariffs in terms of industry and community costs and distributional effects among customer classes;
- **Section 5 – Metering Policy Scenarios** reports on the outcomes of two pricing and smart metering policy sub-scenarios in terms of their incremental customer, industry and community impacts.

1.3 Relationship to Previous Work

Energeia is constantly striving to improve the accuracy and reliability of its models through enhancements to modelling inputs, assumptions, methods and systems. These changes can lead to significant differences in results over time. However, each change is assessed to ensure it improves the accuracy and/or reliability of the modelling.

This project takes forward tariff design and customer behaviour modelling techniques Energeia has developed over the past five years, including the following recently completed projects:

- *Smart Grid, Smart City* (SGSC) analysis and reporting on behalf of Ausgrid; and
- *Assessment of Future Tariff Scenarios for South Australia* on behalf of SA Power Networks.

In comparing the results of this project to our recently completed work, it is important to note the following key differences and enhancements:

- Customer segmentation approach
- Peak demand impact assessment approach
- Representative customer profile selection approach
- Technology adoption model and parameterisation

Each of these changes and their expected impact on the results are summarised in the following sections.

[7] Ibid. page 25

1.3.1 Customer Segmentation Approach

The SGSC project involved around 2,000 customers grouped into 20 customer residential and business segments covering load up to 735 MWh per annum. Energeia has simplified the customer segmentation approach by reducing the number down to six customers and six segments. This simplification enables the complexity of the tariff design process which would be undertaken by network pricing managers in a real world scenario to be retained, but simplifies the system to which the process is applied in order to make the problem tractable.

For ENA analysis, the scope of customers has been reduced to include customers who consume up to 160 MWh per annum. This approach is consistent with the approach we adopted for our project with SA Power Networks, and reasonably covers the main differences due to customer size across tariffs.

1.3.2 Peak Demand Impact Assessment Approach

In the SGSC project, Energeia used its 2,000 customer sample to implement a ground breaking method for estimating changes in network peak demand due to customer behaviour change. The method allowed modelling of after diversity maximum demand for a given network type, asset type and year based on the mix of customers attached to the asset, their estimated behaviour change and its impact on overall customer diversity.

For the ENA and SA Power Network projects, we again used simplified peak demand impact assessment approaches to reduce modelling costs. For the ENA project, we applied an assumed peak demand reduction coefficient to the modelled reduction in individual customer demand. For this project, we used the simplified system of demand detailed in the next section to directly compare peak demand reductions across tariff designs.

1.3.3 Representative Customer Profile Selection

For the SGSC project, customers were randomly selected from Ausgrid's database to obtain a representative sample of customer profiles, which were then averaged to estimate DER uptake and peak demand impacts. For the SA Power Networks project, Energeia selected a single customer for each segment based on a range of screening criteria to minimise the chance of selecting a biased profile from among the three tariff options trialled. For this ENA project, Energeia expanded its criteria to specifically address the cost structure of each tariff design.

The customer profiles selected for this project drive the optimal sizing and mix of DER, which is higher on average than our SGSC results but comparable to our estimates in SA using a similar customer segmentation approach.

1.3.4 Technology Adoption Function and Parameterisation

The technology adoption function used in the SGSC project was based on a linear model Energeia had developed for its proprietary research clients based on analysis of the NSW solar PV market up to 2011. Energeia updated its core uptake model as part of the SA Power Network's project to reflect customer uptake of solar PV systems up to 2013. The modelling change significantly improved the model's performance in terms of R^2, the industry benchmark, but also results in significantly higher uptake rate estimates compared to the previous modelling approach.

2 Scope and Approach

The objective of this study is to provide a comparative assessment of the potential for various tariff options, including cost reflective network tariffs, and smart metering deployment policies to produce economically efficient outcomes for electricity consumers across the National Electricity Market (NEM).

The assessment specifically excludes:

- consideration of voltage management costs;
- consideration of businesses with an annual consumption of greater than 160 MWh
- the impact on retail sector revenue from changes in energy demand; and
- the impact on transmission networks or the generation sector as a result of changes.

It should be noted that the assessment does not seek to identify which tariff structure is the most appropriate for any individual network. Rather, the assessment considers the relative benefits and potential shortcomings of each broad category of tariff using specific, professionally developed tariff examples.

It should also be noted that although the assessment provides forecasts of DER uptake, these are a by-product of the analysis and do not necessarily represent Energeia's definitive view of likely future uptake. Moreover, the model has been configured to provide a comparative assessment of DER uptake under different tariff options, rather than forecast a forecast of DER uptake under the most likely mix of tariff options.

Energeia undertook the following scope of work to develop relevant, robust estimates of the impacts of various metering and pricing policies on customer behaviour and the associated impacts on the network sector and the customer community:

- industry engagement;
- design of cost reflective tariffs;
- modelling of customer behaviour impacts;
- modelling of industry and community impacts; and
- modelling of metering policy impacts.

The key issues associated with each component of work and Energeia's specific approach and methodology in each case are detailed in the following sections.

2.1 Industry Engagement

Energeia worked with the ENA to engage with Australia's Distribution Network Service Providers (DNSPs) on the most suitable tariff classes and customers to include in the assessment. The engagement process involved a tariff development workshop in Canberra in May 2014 and ongoing dialogue with DNSPs over the course of the project.

Based on the outcomes of the May workshop, it was agreed that the following customer level tariff structures and specific sub-structures would be designed and applied for this project:

1. Three-tier Inclining Block Tariff (IBT)
2. Three-tier Declining Block Tariff (DBT)
3. Seasonal Time-of-Use (SToU)
4. Maximum Demand and Seasonal Time-of-Use (MD+SToU)

IBT was selected as the baseline network tariff. The default residential and business tariff for customers less than <160 MWh varies by network business across Australia with the majority of networks offering either a flat or IBT tariff. IBT was selected rather than a flat tariff during the stakeholder workshop process and is considered to represent the most likely default tariff in the short term future. An IBT is currently offered by Ergon Energy, SA Power Networks, ACTewAGL and Endeavour Energy for certain customers.

Ensuring the choice of customer profiles did not bias the results required applying balanced selection criteria to ensure that the selected customer profiles were typical across each of the chosen tariff classes. DNSPs also agreed the final criteria for customer profile selection within each customer segment, with the full set of criteria including:

- annual consumption;
- annual maximum demand;
- coincident maximum demand;
- load factor (average demand divided by peak demand); and
- peak consumption divided by total consumption.

DNSPs were engaged in a second workshop in Melbourne in July 2014 to review the results of the tariff design step, and the modelling steps to provide feedback on the key assumptions, inputs and results. Outcomes from this meeting included revising the addressable market for solar PV to account for renters and customers in apartments.

2.2 Design of Tariffs

The approach to designing specific cost reflective tariffs for the purpose of an unbiased comparison ensured:

- prices were aligned to marginal costs where possible, particularly peak prices;
- residual revenue was recovered without distorting customer consumption decisions;
- revenue neutrality (both network and retail) was retained between tariff types at the customer class level (i.e. residential and business) for the base year; and
- tariffs reflected jurisdiction specific customer mixes, annual network revenue requirements and Long Run Marginal Cost (LRMC).

It is important to note that the tariffs designed reflect the costs of the simplified system of demand, and not any specific network.

The following sections detail the methodology applied and the resulting outcomes.

2.2.1 Aligning Prices to Marginal Costs

The key marginal cost facing the electricity supply industry is the incremental cost of adding additional capacity. The probability weighted incremental cost for a given customer largely depends on the current level of asset utilisation (available capacity relative to historical maximum demand) and the time of use. Marginal cost is typically close to zero for networks unless the use occurs during the peak period of the year in an asset approaching 100% utilisation.

For MD+SToU peak network prices were set to the LRMC reported or estimated for each DNSP, which are presented below. For SToU, the peak price was set slightly above LRMC. This was necessary to ensure revenue neutrality and an off peak price lower than both shoulder and peak and is consistent with current practice.

Shoulder prices were set relative to peak prices using estimates of customer price elasticity to avoid creating a new peak given the current ratio of peak to shoulder demand. Peak retail prices for the ToU tariff were set consistent with the current ratio of retail to network peak price observed in Ausgrid's network.

Inclining block and declining block tariffs are consumption based, and it is therefore not possible to directly align prices to marginal costs. Declining block tariffs are typically set to recover fixed and residual costs in the first and second blocks, with the last block set to only recover avoidable marginal costs, e.g. generator fuel costs.

2.2.2 Recovering Residual Revenues

As peak prices are only likely to recover a portion of overall system costs due to the highly fixed cost nature of the electricity supply industry, other tariff components are used to recover the ‘residual’ costs. These costs should be recovered in a manner that is least distorting to customer consumption decisions to maximise economic welfare, otherwise, customers may make sub-optimal consumption decisions.

The daily fixed charge was kept constant across each tariff, based on the current fixed costs faced in each jurisdiction. Residual costs were recovered by off-peak energy charges under the seasonal ToU tariff, and using an anytime energy charge under the MD+SToU structure, based on the proposed South Australian residential tariff.

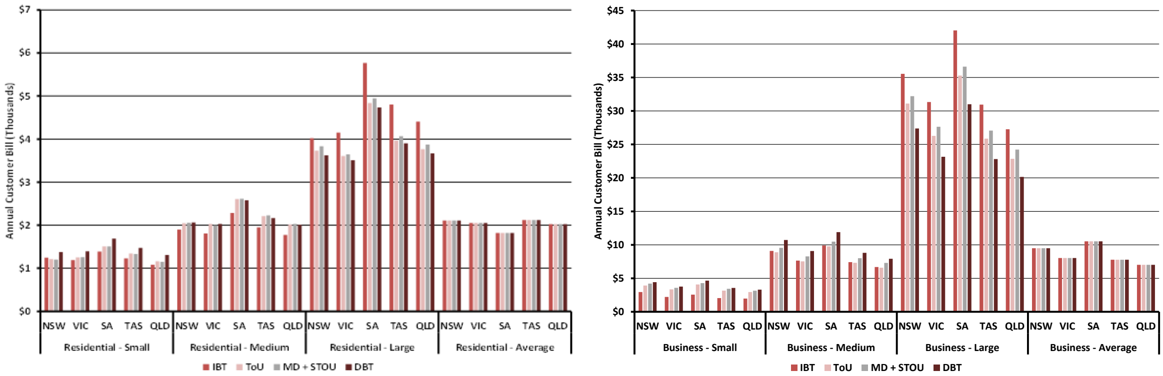
For the IBT tariffs, the ratio of first, second and third blocks were maintained, and the overall level of prices was increased until they recovered all targeted revenue. For the DBT tariff, the first two blocks were set to recover 80% of total charges, consistent with the largely fixed cost nature of the electricity supply industry.

2.2.3 Ensuring Revenue Neutrality

An unbiased comparison of tariff outcomes requires that they be revenue neutral to begin with. However, as different tariff structures have different distributions of cost outcomes, it is important to recognise that tariffs are unlikely to be cost neutral within each of the customer class sub-segments.

Energeia ensured that tariffs were neutral for each customer class within each jurisdiction using the system of demand described below for the base year. The results of our tariff balancing are presented in Figure 8.

Figure 8 – Annual Retail Bills by Customer Segment in the First Year of the Assessment Period



Source: Energeia

The tariff rebalancing demonstrates that smaller customers are likely to be generally advantaged by the IBT (except for small residential customers in NSW) seeing higher average bills on other tariffs, with the opposite effect for larger customers.

2.2.4 Localisation

Energeia’s cost reflective design process accounted for three main tariff localisation issues

- differences in customer populations;
- differences in starting year revenues; and
- differences in LRMC.

Customer populations were grouped into three segments by annual consumption, with the number of customers in each segment taken from publically available sources. Differences in customer populations among jurisdictions impacted the relative weighting of each segment within a class for tariff normalisation and aggregated calculations.

Table 2 – Customers by Segment and Jurisdiction

Segment	Annual MWh	NSW	QLD	SA	TAS	VIC
Res - Small	< 5.4	1,697,803	1,044,821	362,826	161,740	1,201,226
Res - Medium	5.4-9	737,870	498,037	139,189	58,869	498,771
Res - Large	> 9	842,805	456,646	144,365	57,765	550,338
Bus - Small	< 15	365,605	200,395	67,713	26,130	240,681
Bus - Medium	15-40	140,299	77,275	26,501	10,182	92,657
Bus - Large	40-160	93,877	51,101	17,621	6,608	61,565

Source: *Ausgrid*

Starting year revenues were calculated for each network area by applying the current base tariff (typically IBT) in each network area to the middle customer segment load profile (see Appendix 1). Each tariff, starting with the base case IBT tariff, was then parameterised to ensure it only recovered the same amount in the first year.

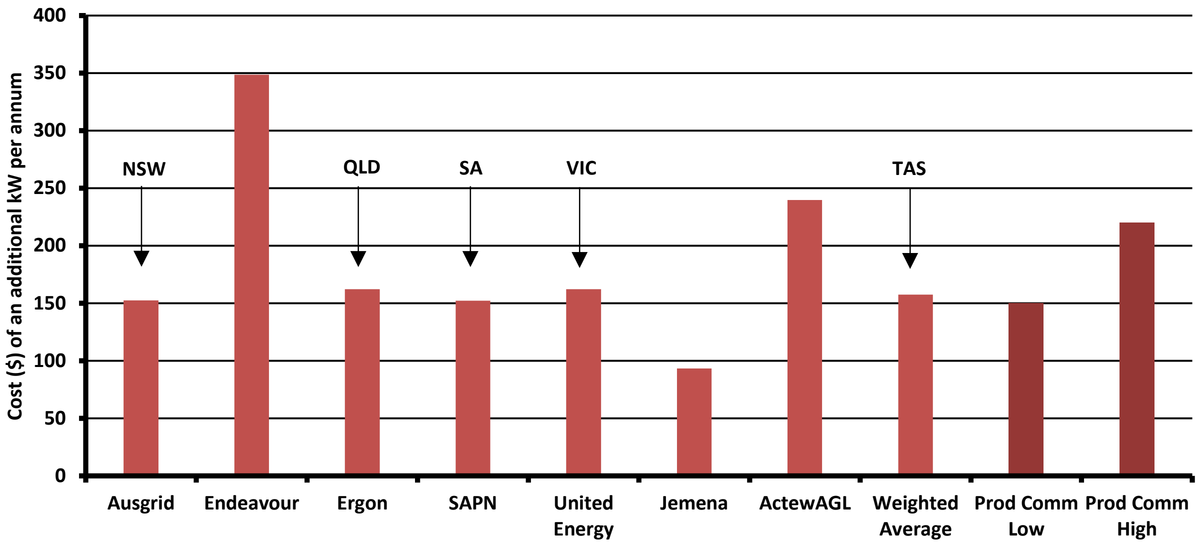
Table 3 – Base Year Tariffs by State, Customer and Sector

	QLD	NSW	SA	TAS	VIC
Residential					
Network	Energex: SAC Non Demand Residential Flat	Ausgrid: A010 Residential Inclining Block	SA Power Networks: Low Voltage Residential - Single Rate	Aurora: N01 - General Network-Residential	Powercor- Residential Single Rate
Retail	Origin: Domestic (Tariff 11)	Energy Australia: EA Basic Home (Peak Only)	Origin: Flexichoice (Residential)	Aurora: Residential Light and Power Tariff 31	AGL: Residential Tariff (GD/GR)
Business					
Network	Energex: SAC Non Demand Business Flat	Ausgrid: EA050 Small Business Inclining Cost	SA Power Networks Low Voltage Residential - Single Rate	Aurora: N02 - General Network-Business	Powercor: Non-Residential Single Rate
Retail	Origin: General Supply (Tariff 20)	EnergyAustralia: Basic Business (Peak Only)	Origin: Flexichoice (Business)	Aurora: Standing Offer Contestable Customer Fallback (AUR5914SS)	AGL: Business Trader (E1)

Source: Company websites

Figure 9 presents reported LRMCs at the LV level from DNSP's annual pricing reports where available, along with the range recently estimated by the Productivity Commission.

Figure 9 – Long Run Marginal Cost by Network



Source: Company websites, Productivity Commission, Energeia

Capital city network values were adopted where available, otherwise the most populous network. For Tasmania, where no values were available, a weighted average of all states was adopted.

2.3 Modelling Customer Behaviour Impacts

Energeia's approach to modelling of customer behaviour involved the:

- definition of three market segments each for residential and business customer classes;
- selection of representative customer profiles for each of the six customer segments;
- development of weighted average aggregate network load profile by customer class;
- identification of the peak, shoulder and off-peak periods by customer class;
- identification of the peak period coincident demand (for determining coincident demand reductions);
- estimation of own price elasticity effects for each tariff;
- estimation of uptake curves for tariffs and technologies;
- estimation of half-hourly load impacts by technology and tariff; and
- estimation of annual customer bills by retail, network and distributed energy resource charges.

The following sections detail the methodology applied and the resulting outcomes.

2.3.1 Customer Scoping and Selection

Developing a simplified system of demand that is nevertheless broadly representative of the range of customers across the range of tariff and policy scenarios is crucial to the integrity of any comparative assessment of tariffs. While energy based tariffs may use averaged load profiles, this approach is not feasible for maximum demand based tariffs so as to retain typical 'peakiness' observed in individual load profiles. Energeia's approach was to therefore select representative individual customer profiles based on the following fit-for-purpose selection criteria of how closely the representative profile matched the segment median in terms of:

- annual consumption;
- peak demand;
- load factor; and
- coincident maximum demand.

The selection criteria described above was applied to Energeia's database of over 2,000 customers available from the *Smart Grid, Smart City* Information Clearing House. These customers are therefore most representative of Ausgrid's network area, a largely summer peaking load with access to gas and controlled load hot water tariffs. This means that the load profiles are the least representative of winter peaking and tropical areas. Furthermore the selected customers are not subject to controlled load.

Table 4 presents the results of Energeia's assessment of 2,000 annual half hourly customer load profiles. Each of the segments is assumed to be able to adopt any tariff or technology, except for number 4, which is the small business segment. This segment is assumed to be in a suite or larger building, and not able to invest in solar PV. The addressable residential market for solar and storage was also reduced by the number of apartments.

Table 4 – Representative Customer Characteristics

Segment Definition				Representative Profile				
Number	**Name**	**Annual MWh**	**Roof Access**	**Annual kWh**	**Peak Demand (kW)**	**Load Factor (%)**	**Coincident Peak (kW)**	**Customer Mix**
1	Res - Small	1 - 5.4 MWh	✓	3,454	3.8	57%	1.4	45%
2	Res - Medium	5.4 - 9 MWh	✓	5,787	6.2	61%	2.9	19%
3	Res - Large	>9 MWh	✓	12,724	9.9	65%	7.1	21%
4	Bus - Small	0 - 15 MWh	✗	8,469	5.7	57%	0.3	9%
5	Bus – Medium	15 - 40 MWh	✓	24,717	10.8	58%	4.1	4%
6	Bus - Large	40 - 160 MWh	✓	92,859	27.4	67%	12.9	2%

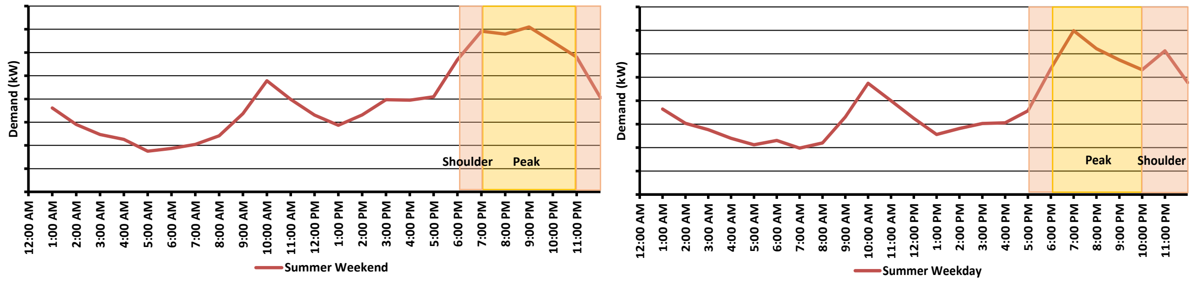
Source: Ausgrid

The load profiles of each selected customer by segment are displayed in Appendix 1.

2.3.2 Network Load Profiling

Energeia's approach to developing a simplified network load profile to model the impact of customer behaviour on peak demand management costs was to develop a NEM weighted, aggregated load for each customer class (see Figure 10 and Figure 11). Each customer class load profile was then used to define the peak, shoulder and off-peak periods, and to inform the expected network peak reduction given customer's demand reductions during the network peak period.

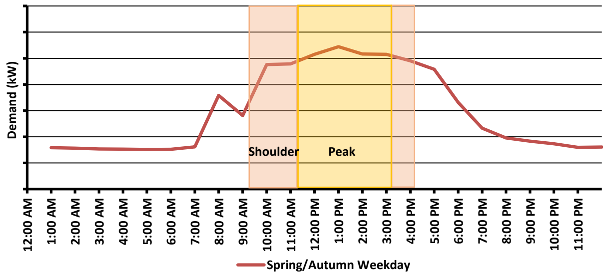
Figure 10 – Representative Annual Half Hourly Maximum Demand Profiles for Residential Customers



Source: Energeia

While the actual load profile on a given network asset will be a function of the mix of customer segments at that particular asset, Energeia's work in this area has found that the peak period typically reflects the dominant customer class, i.e. a residential or a business profile. The incidence of zone substations with a peak period that is somewhere in between the aggregated business and residential load profile is relatively low.

Figure 11 – Representative Annual Half Hourly Maximum Demand Profiles for Business Customers



Source: Energeia

Under such circumstances it is appropriate to set different network peak period definitions according to the customer class, rather than one that reflects the average system load (see Table 5). It is also appropriate to estimate the impact of peak demand reductions at the class level based on the expected coincidence of customer peak demand. The coincidence of customer peak demand for the load profiles selected was 84% for residential and 88% for business customer classes.

Table 5 – Cost Reflective Period Definitions by Customer Class

Residential Customers			
Period	**Times**	**% Hours**	**% Consumption**
Peak	6:00pm to 9:00pm on Summer Weekdays and 7:00pm to 11:00pm on Summer Weekends	3.4%	6.0%
Shoulder	5:00pm to 6:00pm and 9:00pm to 12:00am on Summer Weekdays and 5:00pm to 7:00pm and 11:00pm to 12:00am on Summer Weekends	7.7%	5.7%
Offpeak	All other times	88.9%	88.3%
Business Customers			
Period	**Times**	**% Hours**	**% Consumption**
Peak	11:00am to 3:00pm on Spring and Autumn Weekdays	6.0%	11.3%
Shoulder	9:00am to 11:00am and 3:00pm to 4:00pm on Spring and Autumn Weekdays and 11:00am to 1:00pm on Winter and Summer Weekdays	7.4%	13.1%
Offpeak	All other times	86.6%	75.6%

Source: Energeia

Energeia's classification of time of use periods for the simplified system of demand is based on maximum half hourly loads. While the resulting portrait of maximum demand is a composite, and does not reflect any particular day, it is in our view the most appropriate approach to defining the peak and should periods. In this case, the peak and shoulder periods are defined as the period where demand is within 95% and 90%, respectively, of the annual maximum demand.

2.3.3 Customer Behaviour

The three customer behaviours Energeia modelled were customers' own price elasticity, voluntary customer adoption of tariffs and customer adoption of distributed energy resources including solar PV and storage.

Energeia has developed a comprehensive proprietary database of Australian customer responses to cost reflective tariffs. While most Australian trials have made some of their data public, Energeia's review of the public domain literature has found that many of the original sources are no longer available online, and many of the secondary sources appear to be inconsistent with Energeia's own library of primary sources.

Energeia estimated the peak period demand impacts for each of the trialled tariffs based on its database of 11 Australian pilots, trials and implementations. The responses reflect differences in observed short-term and longer-term customer behaviour, as well differences between dynamic prices (e.g. critical peak) and static prices. While there are numerous trials of SToU, there is only one maximum demand style price response trial in Australia.[8]

Table 6 – Estimated Peak Demand Response by Tariff

Tariff Type	Short Term Response	Long Term Response	Average
DBT	0%	0%	0%
Time of Use	-8.30%	-2.40%	-5.30%
Maximum Demand	-19.20%	-16.20%	-17.70%

Source: Various pilots, trials and implementations

Modelling voluntary customer adoption of tariff options based on empirical data is difficult due to the trial based nature of most publically available datasets. There are no examples of DBT or MD+SToU tariffs being offered in Australia, and trials of SToU have typically offered significant inducements and no worse off guarantees that could bias the associated measures of customer response, where they have been published.

Energeia's approach was therefore to adopt the customer response rates to SToU tariffs from the *Smart Grid, Smart City* trial by customer size. While consistent SGSC results across tariffs suggests that residential customer response to MD+SToU and DBT tariffs is likely to be comparable, market experience and unpublished results from Ausgrid's Strategic Pricing Pilot suggest that business customer response rates would be much lower.

For customers adopting distributed energy resources including solar PV and/or storage, Energeia's modelling followed a two-step process. The first step was to estimate the optimal size and configuration of solar PV and storage for each customer segment in a given year, and then to estimate the uptake of this configuration in that year. The modelling and parameterisation process is detailed in Appendix 3.

2.3.4 Customer Bills

Customer bills are currently comprised of a retail and network portion. The retail portion includes the cost of purchasing wholesale market energy, hedging, operational retailing costs, and a margin. The network portion includes the allowed costs of transmission and network infrastructure. Some customers choosing to finance their solar PV purchase may also receive a monthly bill for their distributed energy resource investment.

Annual retail prices were assumed to remain constant in real terms over the period. Importantly, retail revenues avoided through customer adoption of DER was not recovered in subsequent periods. This approach may be overly simplistic in that retailers and generators are likely to respond to a reduction in their market shares, but it is unclear that this would lead to higher revenue overall for those sectors.

[8] The Rewards Based Tariffs trial of maximum demand style tariffs was jointly undertaken by Ergon Energy and Energex.

Under a revenue cap control mechanism, network revenues that are not recovered in a given year are added to the following year. In practice, networks seek to avoid this by including forecasts of DER uptake in their price setting process.

Energeia modelled this network tariff rebalancing effect each year for each customer class by estimating the amount of revenue avoided by new customers adopting DER in that year, and raising prices the next year to recover the outstanding amount, less any changes in peak demand management costs.

Energeia's model assumed customer investment in solar PV and storage would be financed, and that customers would pay an annualised amount each year to cover these costs.

2.4 Modelling Industry and Community Impacts

Developing an estimate of the overall industry and community impacts of alternative tariff and metering policy scenarios requires a robust framework for aggregating the individual customer effects on industry costs, industry revenues and distributional effects across the National Electricity Market (NEM). To ensure these effects are comparable and relevant to today's decision making, they must be calculated in present value terms.

Energeia's approach to modelling community and industry impacts involved estimating the total cumulative:

- peak demand management costs;
- annual industry revenues and prices;
- community costs; and
- customer cross-subsidies;

over the 20 year study period across each of the jurisdictions in the NEM in present value terms.

The following sections detail the methodology applied and the resulting outcomes.

2.4.1 Network Investment Costs

Energeia's approach to estimating network investment costs involved calculating the annual change in customer peak demand, applying a factor to adjust for the correlation of demand during the peak period, and then multiplying the resulting network peak reduction by LRMC in the given jurisdiction.

The basis of the peak demand reduction for each customer for each tariff is reported in Appendix 3. As customer load profiles were grown each year by AEMO's 2014 forecasts for peak and energy growth by state, the absolute size of tariff peak demand reductions increased over time. The size and nature of technology driven changes in peak demand also changed over time due to changes in the adopted configuration.

LRMC was then applied to the resulting reduction in coincident maximum demand reported in Section 3.3.2.

2.4.2 Annual Industry Revenue and Prices

Annual industry revenues were calculated each year by multiplying estimated network, retail and DER charges for customers on IBT, the voluntary tariff only, and the voluntary tariff with DER by their respective volumes. This calculation was completed on a customer class basis.

In any given year customer behaviour in terms of DER investment and behaviour change results in changes in network revenue and costs. Although customer investments assist networks in avoiding costs, the avoided cost is not necessarily commensurate with the avoided revenue. Therefore, under a revenue cap, networks must raise prices each year in order to recover any forgone revenue.

The resulting network price impact then acts as a feedback loop influencing customer investment in subsequent years. A detailed explanation of the price feedback loop is provided in Appendix 3.

2.4.3 Community Costs

Community costs refer to the overall cost of electricity supply to the community including network costs, network charges, retail charges and DER costs. For the purposes of the model this was determined as the sum total of all customer bills each year, including DER charges, discounted to present value terms. Declines in retail charges as a result of DER investment and behaviour change represent a community saving, partially offset by increases in DER charges. Declines in network charges, however only represent a community saving to the extent that they also result in a commensurate decline in network costs, otherwise these charges were recovered via price rises in subsequent years due to the price feedback loop.

This required modelling the dynamic changes in the mix of customers on the default tariffs, the voluntary tariffs only and the voluntary tariffs with DER, as well as the size and mix of DER adopted each year. The assumed rates of tariff adoption were reported in Section 3.1 and the uptake model used for DER is detailed in Appendix 3.

2.4.4 Customer Cross-Subsidies

Customer cross-subsidies between those with and without DER were estimated by comparing the total network revenue recovered by customers adopting voluntary tariffs with DER to customers remaining on the default tariff, less the cost savings from peak demand reductions, and dividing by the number of customers in each category.

In order to directly compare the cost reflectiveness across tariff design options, and therefore the tariff's effectiveness of addressing cross-subsidies, Energeia also calculated the customer bill and network impacts of adopting the same level and mix of DER for a given customer profile.

The difference in the network cost to serve compared to the difference in the annual bill provides a relative indication of the overall cost reflectiveness of each tariff design. Tariffs which more closely align to the underlying change in the cost to serve due to peak demand reduction also result in lower cross-subsidies.

2.5 Modelling Metering Policy Impacts

In consultation with the ENA, Energeia developed a set of metering and tariff scenarios that represented key metering policy options that could accelerate the take-up of cost-reflective network tariffs. Each of these scenarios was modelled assuming the most cost reflective tariff, MD+SToU and the incremental effects quantified. They were estimated on a stand-alone basis to allow consideration of either the impact of each policy option in isolation or the additive impact.

It is important to note that note that not all network benefits of smart metering infrastructure were included in the cost benefit assessment. The business case derived in this assessment is therefore considered conservative and may improve where potential network benefits are able to be captured from metering policies which encourage greater penetration of smart meter infrastructure.

2.5.1 Customer Trigger

The customer trigger scenario was adopted for the analysis of all tariffs. The scenarios for the metering policy alternatives of other triggers and a threshold was compared with the MD+SToU tariff scenario. Under the MD+STOU tariff scenario all customers requesting a metering alteration are required to install a smart meter at their own expense and adopt the MD+SToU tariff. This effectively requires customers adopting DER to be assigned to the MD+SToU tariff. This is consistent with industry practice where a customer changing load or connection can be assigned to a different tariff.

The assumed incremental average price of a smart meter under this scenario is $280 and a standard installation cost (i.e. $150/site).

2.5.2 New and Replacement Meters

The new and replacement meters scenario assumes all new connections will receive a smart meter and be assigned to the MD+SToU tariff by default, and that network driven meter replacements, e.g. due to condition or performance, will install a smart meter without the communications.

The assumed incremental average price of a smart meter for new meters is $220[9] which is also assigned to the MD+SToU tariff. For replacement meters the incremental average price is $90 as it is assumed that replacement customers are not assigned to the MD+SToU tariff and therefore do not require a communications module. The

[9] $280 minus the $60 cost of a conventional meter which would have been installed anyway

assumed installation cost of the meter for both new and replacement meters is not included in the estimate of incremental costs as in both situations a meter already had to be installed.

Replacement customers who adopt the voluntary tariff or the voluntary tariff and DER in future years are only required to pay for the communications module to be installed (around $120 for the module and $30 for the plug-and-play installation) rather than pay the full installation and smart metering cost.

2.5.3 Threshold Rollout

Under the threshold rollout scenario all customers using more than 40MWh p.a. have a smart meter installed and are placed on to MD+SToU in the first five years. This cut off value was selected as is currently adopted by Ausgrid for the purposes of tariff classes. Other networks apply different thresholds, but tend not to apply thresholds below the 160MWh level.

The threshold rollout scenario reflects historical industry approaches to the deployment of cost reflective tariffs, for example in Ausgrid's network over the 2004 to 2009 regulatory period. Threshold rollouts have been cost effective by focusing investment on customers with the greatest expected demand response potential.

The scenario assumes a standard average smart meter cost and a standard installation cost (i.e. $430/site) paid for by the network (except for Victoria where it was assumed that the smart meter was already in place). Arguably, the scenario could include a higher average meter cost and installation cost due to the prevalence of three phase sites. We do not believe it would be reasonable to assume significant installation synergies as customers would most likely need to be scheduled, largely at the customer's convenience.

3 Customer Behaviour Impacts

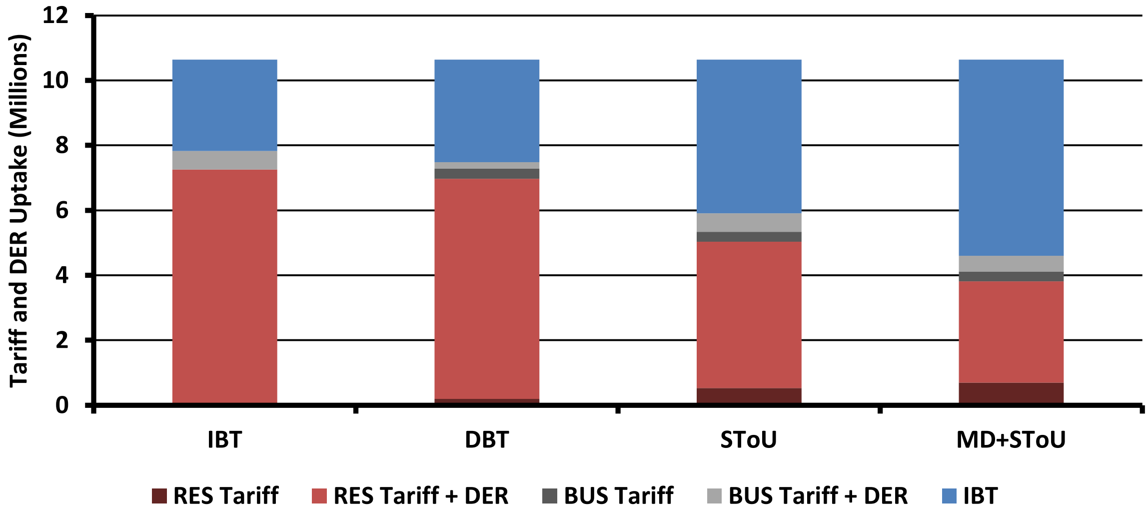
The following sections outline the results of Energeia's modelling of customer's response to each of the tariff design scenarios in terms of:

- tariff adoption;
- investment in DER technology; and
- electricity demand.

3.1 Tariff and Technology Adoption

Figure 12 compares the overall tariff and DER uptake for all customers under each of the four tariffs by 2034. Overall, tariff design significantly impacts relative rates of tariff and DER adoption by the end of the period, and drives very different outcomes across residential and business customers. In general, the smart meter enabled tariffs of SToU and MD+SToU result in a lower fraction of residential customers adopting DER by the end of the period than the IBT and DBT tariffs. Business response is more consistent, however, there is very little business adoption under DBT.

Figure 12 – Cumulative Number of Customers Adopting Tariff and DER by Tariff in 2034



Source: Energeia

Under the IBT scenario, all customers remain on an IBT tariff, including the 67% of customers that have adopted DER by 2034. The majority of these customers are residential. This is simply due to there being far more residential than business customers and the modelling assumption that small business customers are unable to adopt DER.

For DBT, slightly fewer customers (60%) take up DER by 2034. There are also a small number of customers who voluntarily take up the DBT tariff but do not take up DER (4%).

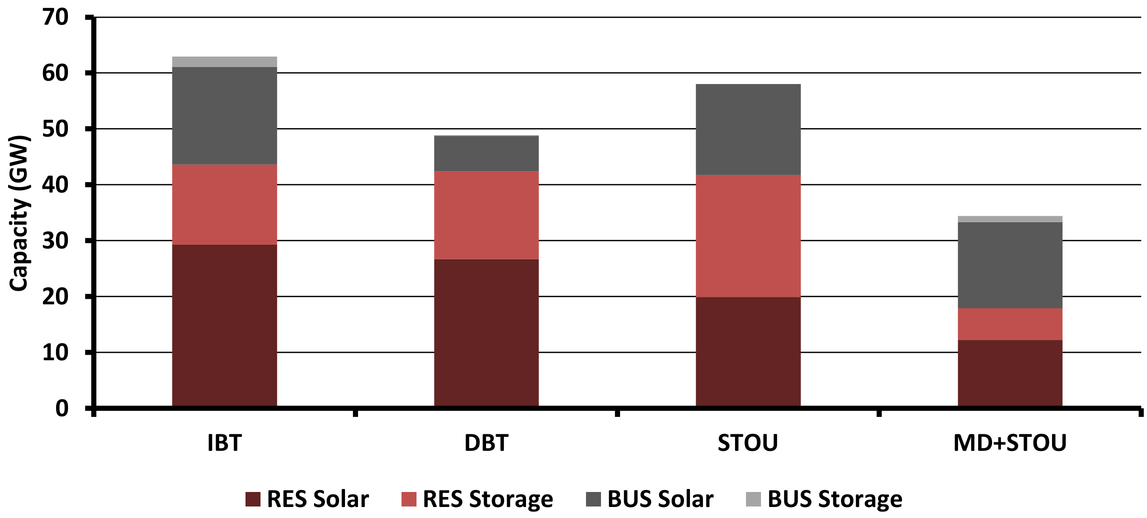
There are relatively few business customers who take up DER under the DBT scenario compared to the residential sector. This is due to the modelling assumption that only medium to large businesses are able to take up DER, but also due to the relatively low cost of the avoided third-tier of the tariff for these customers considering DER under a DBT. Whereas for the residential sector, there are a large number of small customers for whom solar PV provides a high return on investment by avoiding the high cost first tier of the tariff once they have transitioned to the DBT tariff.

For SToU and MD+SToU, relatively few residential customers take up DER, but there is still strong take up of DER in the business sector. This is due to the reduced ability of solar PV to target peak demand periods in the residential sector and therefore a lower return on DER investment under tariffs which value peak demand reduction. In the residential sector, a significant proportion of customers voluntarily take up the SToU and MD+SToU tariffs, but then do not take up DER, due to the low return on investment.

3.2 Distributed Energy Resource Investment

Figure 13 provides a comparison of the total installed DER capacity and mix by 2034 for each of the four tariff types. The results broadly mirror the relative levels of DER uptake based on customer adoption rates above. The main difference is in the relative solar PV to storage investment mix by capacity, which also varies by customer class. SToU and IBT result in the greatest storage capacity for residential and business customers, respectively, due mainly to over-signalling the value of avoided consumption.

Figure 13 – Comparison of Cumulative DER Uptake by Tariff in 2034



Source: Energeia

IBT gives rise to the greatest DER capacity of 63 GW by 2034. IBT incentivises the largest uptake of residential solar systems but relatively low amounts of storage. For business customers, IBT encourages the most solar PV and storage, mainly due to the large uptake at the end of the period when the cost of storage falls below the IBT price.

Under the DBT scenario, the residential sector adopts almost the same amount of solar and storage due to the same DBT pricing dynamics explained in the previous section favouring DER uptake by smaller residential customers. Initially these small customers are reluctant to take up DER as it will mean switching from the low cost IBT to DBT. However, once solar PV becomes sufficiently cost effective, the initial barrier to switching tariffs is breached. From this point, for small customers, DER is able to offset the higher value first tier of the tariff and becomes increasingly attractive.

Under DBT, solar PV uptake is less attractive for business customers due to the structure of the tariff and the high volume nature of the customers (recalling small business customers are excluded from taking up solar). For medium and large business customers, solar PV will predominantly offset the lower value blocks and is therefore less attractive.

The greatest amount of residential storage investment occurs under the SToU tariff (22 GW). For residential customers, storage is able to increase the value of solar PV generation both by capturing low priced export and shifting consumption from the peak period. This same effect is not observed for the business customers where solar generation is well aligned with peak periods and far less storage is able to be deployed during the peak period.

The level of solar PV adoption is consistent with the level of uptake under MD+SToU, so there is little impact on the relative size or mix of residential and business solar PV investment. The MD+SToU tariff elicits the second highest level of business sector storage (1 GW) due to it being an effective means of targeting short sharp demand peaks.

3.3 *Electricity Demand*

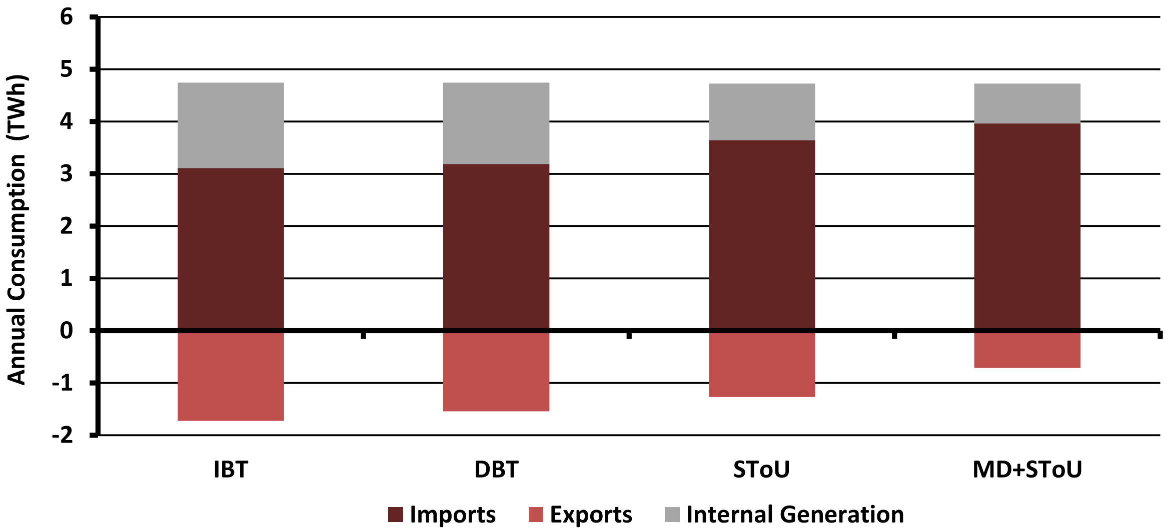
Energeia modelled the impact of customer response to each tariff in terms of overall consumption, grid consumption, grid exports and coincident peak demand. Individual customer peak demand was also modelled, but not reported here for brevity and because individual peak demand does not impact industry costs directly.

3.3.1 Internal, Imports and Exports

Figure 14 and Figure 15 present the results of Energeia's modelling of aggregate customer demand for electricity broken out by total internal generation, grid imports and grid exports for the residential and business classes respectively.

Overall, the more cost reflective, smart meter enabled tariffs of SToU and MD-SToU exhibit the lowest level of residential grid exports. Grid supplied energy is also much lower for residential customers under IBT and DBT than the others. There is little difference across the tariffs for business except DBT, which is due to its relatively low level of business solar PV adoption.

Figure 14 – Comparison of Residential Imports and Exports by Tariff in 2034

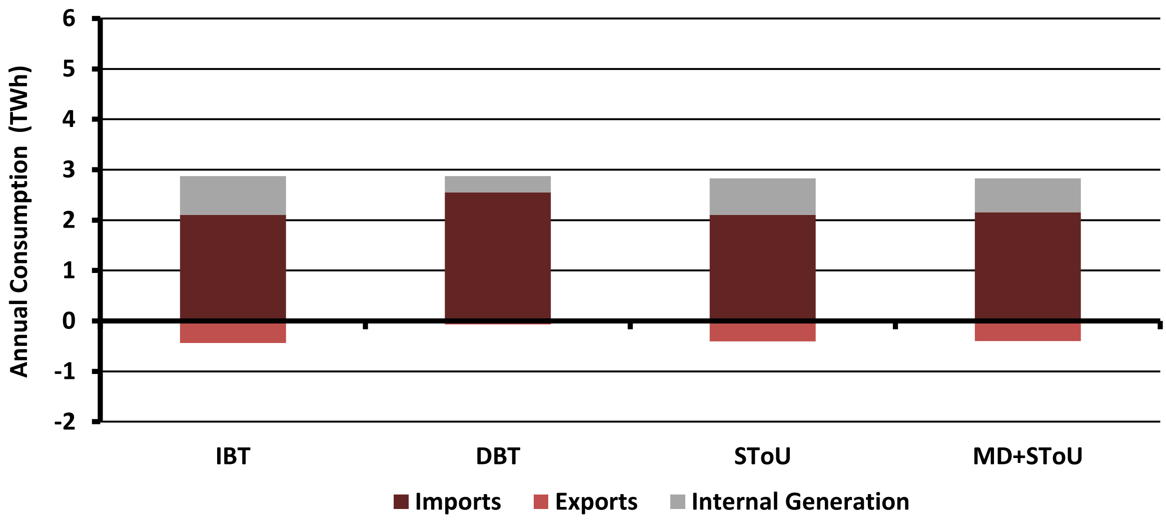


Source: Energeia

Residential consumption patterns are impacted by the effect of the tariffs and DER investment on their consumption profiles. There is relatively little overlap of solar PV generation and residential consumption profiles, as the majority of residential customers are not at home during the five days of the week when solar PV systems are generating. The more solar PV adopted, the greater the level of exports, all else being equal.

The impact of storage on residential customer profiles is driven by the tariff's impact on the storage algorithm. IBT and DBT tariffs lead to export minimisation behaviour as storage seeks to capitalise on cheap exported energy whose opportunity cost is $6-8 cents/kWh, by storing it and releasing it as soon as possible into consumption to be ready for the next amount of low cost exported energy. SToU encourages similar solar PV shifting, but only discharges during peak periods. For MD+SToU, storage only discharges when demand is near the annual peak, i.e. very little.

Figure 15 – Comparison of Business Imports and Exports by Tariff in 2034



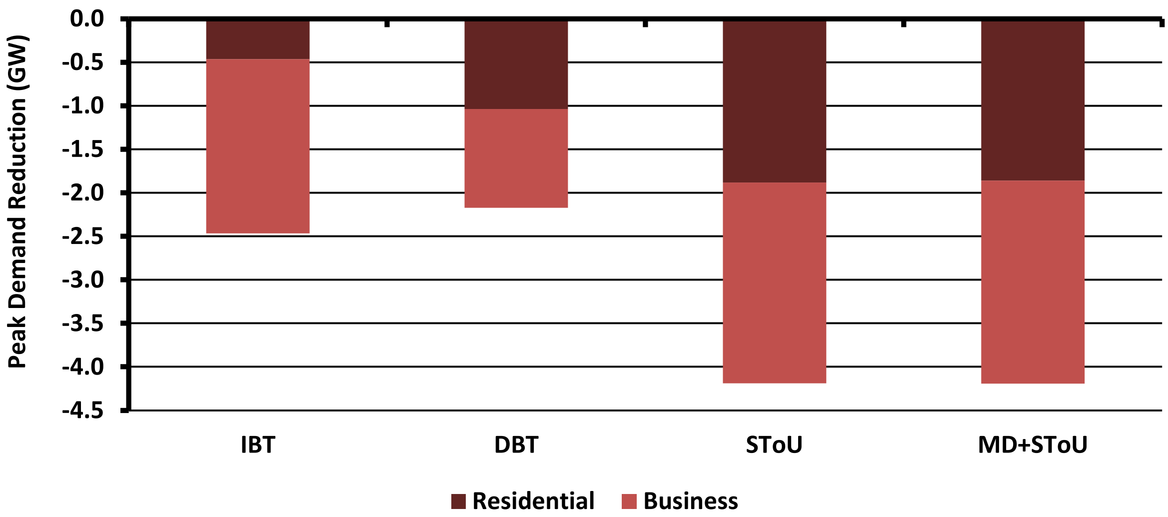
Source: Energeia

For business customers, consumption patterns are much more closely aligned to solar PV generation, reducing the amount of low cost solar PV exports available to charge the batteries. This reduces the cost effectiveness of storage for business customers all tariffs, but mainly impacts the lower priced IBT and DBT structures. MD+SToU provides a relatively strong signal for storage as it can work relatively efficiently to avoid short demand spikes occurring over the course of a day that could otherwise set a new maximum demand.

3.3.2 Peak Demand

Figure 16 compares the total peak demand reduction in 2034 brought about by DER and behaviour change under the four tariff options.

Figure 16 – Comparison of Annual Peak Demand Reduction by Tariff in 2034



Source: Energeia

The differences in peak demand reduction vary for each tariff dependent on the total DER uptake and the extent to which DER is able to effectively target the peak.

For IBT, there is significant peak demand reduction in the business sector (2.0 GW by 2034) due to the alignment of solar generation with peak. However, there is almost no peak demand reduction in the residential sector (0.5 GW) due to the poor alignment of solar PV output to residential customer loads during the evening peak period.

For DBT, there is greater peak demand reduction in the residential sector than IBT, despite their being less total DER capacity. This is due to far greater DER uptake by the small residential segment under DBT compared to IBT. This class contributes relatively more to system peak.

For the SToU and MD+SToU tariffs, the absolute level of peak demand reduction is greatest, due mainly to significantly greater residential storage and comparable business solar PV investment. MD+SToU provides the same level of peak demand reduction for less than half the amount of residential storage. This can be attributed to the impact of the more cost reflective MD+SToU on the residential storage's targeting of peak demand.

4 Industry and Community Impacts

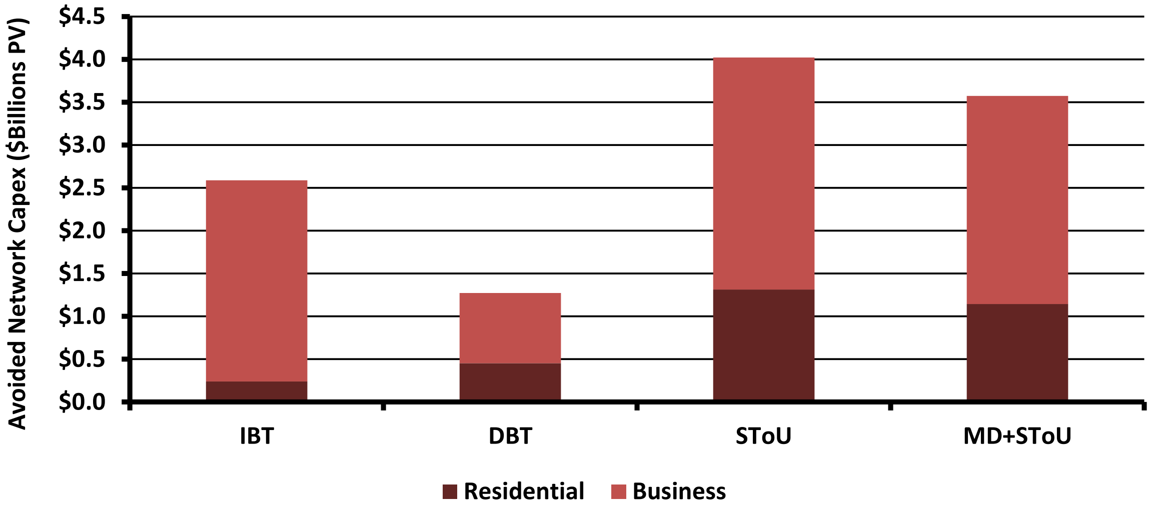
The following sections present the results of Energeia's modelling of network and community impacts in terms of:

- reduced network costs;
- under-recovery of network revenue;
- increases in network prices due mismatch of network cost and revenue reductions;
- total cumulative community costs;
- customer bills; and
- customer cross-subsidies.

4.1 Reduced Network Costs

Figure 17 compares the cumulative avoided network capex in present value terms for each of the four tariff options. This shows that the total avoided network augmentation capex varies from between $1.2 billion for DBT to $4.0 billion for SToU. The results largely reflect differences in peak demand reduction, except for DBT. Most of DBT's peak demand occurs late in the period, which impacts its relative performance in present value terms.

Figure 17 – Comparison of Cumulative Avoided Network Capex by Tariff to 2034



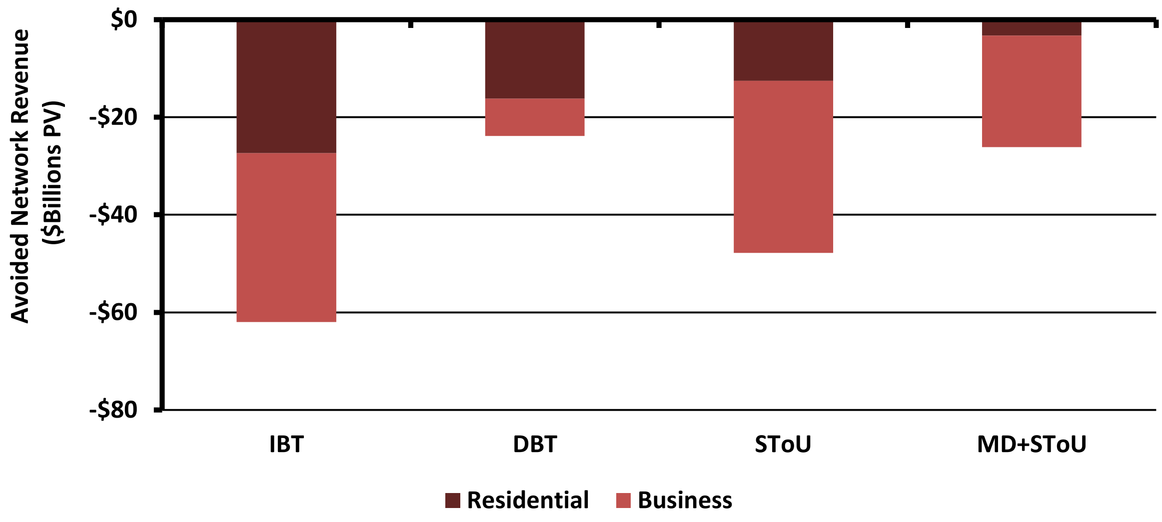
Source: Energeia

SToU and MD+SToU are shown to result in the same overall level of peak demand reduction, but the peak demand reduction for MD+SToU has a reduced value in present value terms. This is due a greater proportion of peak demand reduction for MD+SToU occurring later in the period due as storage technologies become sufficiently cost effective to reduce residential peak period demand.

4.2 Avoided Network Revenue

Figure 18 shows the corresponding cumulative avoided network revenue for each tariff option over the period from 2014 to 2034. The avoided network revenue occurs as a result of reduced customer bills due to changes in consumption either because of the voluntary take up of the smart meter enabled tariffs or investment in DER tariff driven behaviour change and/or investment in DER. Where this revenue reduction is not offset by an equivalent reduction in network costs, for example through reduced augmentation capex, the revenue must be recovered in the next period.

Figure 18 – Comparison of Cumulative Avoided Network Revenue by Tariff to 2034



Source: Energeia

The avoided network revenue under IBT is by far the greatest of all tariff options with $62 billion avoided over the assessment period in present value terms. This is as a result of the significant capacity of solar installed under this tariff option incentivised by a tariff which does not reflect network costs.

Under DBT, avoided network revenue is dramatically reduced, particularly for the business sector due to much lower levels of DER investment. Avoided network revenue for the residential segment under DBT is still significant due to the large number of small residential customers who take up DER later in the assessment period.

For SToU and MD+SToU, business sector adoption of solar PV erodes revenue from the volume based components of the tariff. This effect is more pronounced for SToU than MD+SToU due to the larger value of the volume component in off-peak times. The avoided network revenue for the residential sector for these tariffs is much lower than the business sector due to the comparatively lower solar PV uptake.

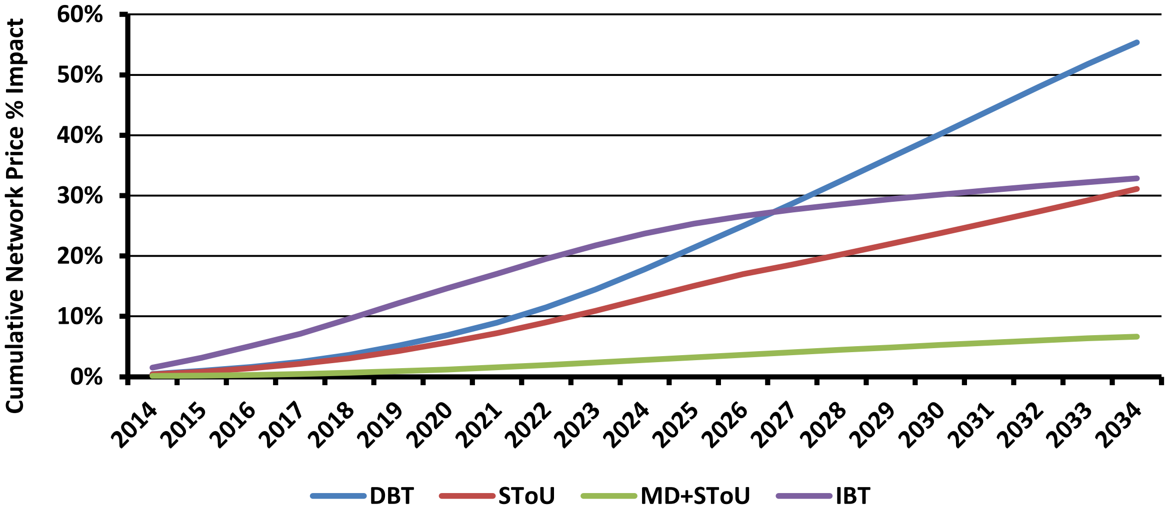
4.3 Network Prices

The avoided network revenue shown in Figure 17 is between seven and twenty four times the avoided network capex shown in Figure 17. This discrepancy implies that although customer investments assist networks in avoiding costs, the avoided cost is not commensurate with the avoided revenue. Therefore, under a revenue cap, networks must raise prices each year in order to recover forgone revenue.

The price increase over time to recoup revenue in real terms is shown in Figure 19 for the residential tariff class and Figure 20 for the business tariff class (revenue recovery occurs on a class basis). The analysis shows there is significant variation in the timing and level of network price increases due to cross-subsidisation (changes in bills that do not reflect a change in underlying costs), and that the effect varies across customer classes as well.

Figure 19 shows that for residential customers, DBT exhibits the lowest price increase initially, but also the greatest price increase by the end of the period. This is due to the forestalling of DER investment for the first four years until DER prices fall to a threshold point, after which time the structure accelerates uptake for the large number of small residential customers.

Figure 19 – Cumulative Network Price Impact for Residential Segments by Tariff to 2034



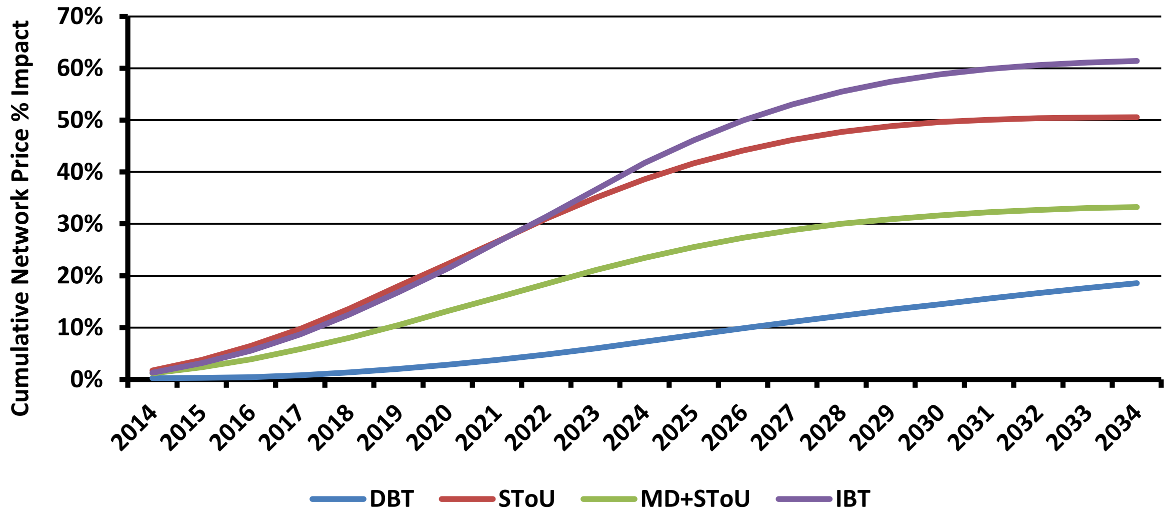
Source: Energeia

SToU still results in price rises of 31% by 2034, less than the DBT but comparable to the IBT tariff. This is due to the significant over-signalling of the value of avoided average peak period consumption, and its reliance on volume based components to recover residual revenues in the face of solar PV impacts.

MD+SToU performs the best of all tariffs by far, containing network price rises to 7% by 2034 for the residential class. While the tariff is cost reflective with respect to LRMC, it results in some avoided network revenue in excess of avoided network costs due to the volume based residual cost recovery component of the tariff. The impact on this residual component is however relatively minor due to the low levels of DER uptake in the residential sector.

Figure 20 shows that for business customers, the greatest price rise is under IBT, reaching 61% by the end of the period. This is due to IBT driving the largest amount of solar PV investment, which while reducing business peak demand, exposes a large amount of volume based revenue being offset by solar PV generation.

Figure 20 – Cumulative Network Price Impact for Business Segments by Tariff to 2034



Source: Energeia

Surprisingly, DBT has the lowest network price increase for the business sector due to the low level of solar PV investment. This is even lower than MD+SToU due to the latter's much greater investment in solar PV by business customers. This highlights the sometimes conflicting objectives of tariff design, as the cost effective investment in solar PV under MD+SToU also leads to an increase in cross-subsidies due to the retention of the volume based component. Reducing the cross-subsidy through a DBT results in higher cost network asset capex.

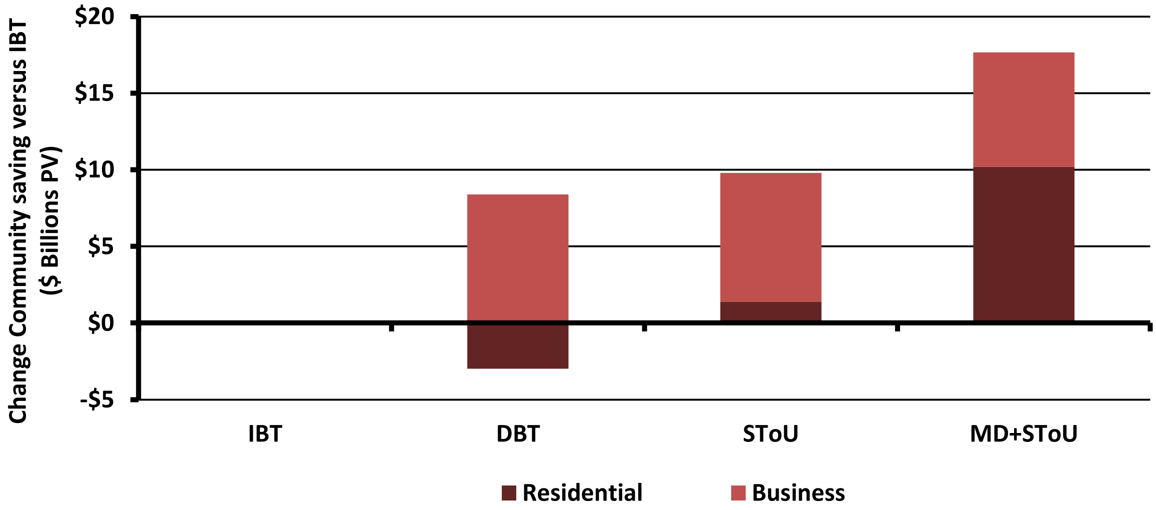
In the early years, until around 2021, SToU has the highest network price increase, along with IBT. This is because this tariff encourages the fastest uptake of DER in the business sector so that maximum DER penetration occurs earlier than for all other tariffs. However, the avoided network revenue per unit of capacity installed is lower under SToU compared to IBT. This is because large and medium business, responsible for all DER uptake in the business sector, offset the higher value IBT consumption blocks avoiding more revenue than is possible under the SToU tariff.

MD+SToU, while performing better than IBT and SToU, still has a significant network price rise of 33% by the end of the period. This is due to the large uptake of solar PV to offset business peak demand, which also offsets significant consumption outside of the peak periods and erodes network revenue from the residual tariff component.

4.4 Community Costs

Figure 21 shows the incremental community costs for electricity in the NEM over the period from 2014 to 2034 compared to IBT. Community costs reflect the weighted average of customer bills over time discounted to present value. As community costs ignore the effects of cross-subsidies, they reflect the comparative productive (least cost peak demand) and dynamic efficiency of the tariff options over the 20 year assessment period.

Figure 21 – Change in Cumulative Bill Costs for the Community versus IBT (including DER costs)



Source: Energeia

These results are arguably the most important of all those presented thus far, as they speak directly to the National Electricity Objective (NEO).

The results show that for the business sector there are benefits under each of the alternative tariffs. DBT community costs for business are roughly equivalent to SToU and MD+SToU, but driven by different factors. For SToU and MDSTOU for the business sector, there are additional DER costs, but reduced network investment costs and reduced retail charges. While for DBT there are reduced DER costs but very little avoided network costs or additional retail charges. The net result is that DBT community costs for business are around the same as STOU and MD+SToU but for different reasons.

For residential customers, material community savings compared to IBT are only realised under MD+SToU. Under DBT there are material community costs compared to IBT due mostly to the fast rate of DER uptake by small residential customers late in the assessment period once the tariff barrier is breached.

The analysis confirms that the more cost reflective the tariff, the greater the long-term savings for all electricity consumers. However, it is also important to note that these savings are uneven between residential and business customers.

4.5 Customer Bills

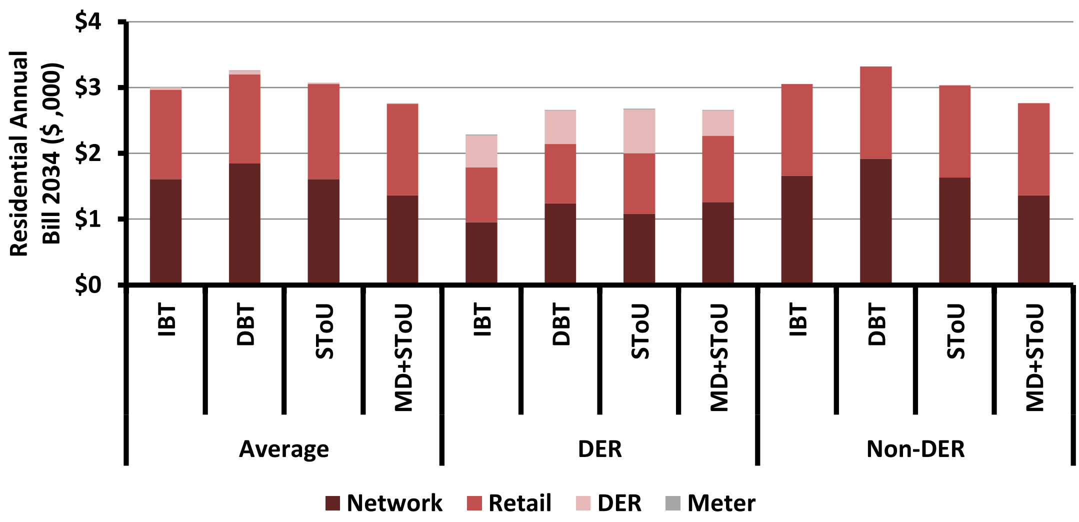
Energeia's modelling shows tariff design choices have a significant impact on the difference in customer bills between customers who adopt DER and those that do not, i.e. remain passive over the period or take up a tariff but not DER. While this can occur where adopting DER reduces their overall cost to serve, our analysis shows that the main driver is the cost reflectiveness of the tariff and its long-term impact on cross-subsidy levels. The lower the level of cost reflectiveness, the greater the level of cross-subsidy in favour of DER customers and the worse off passive customers become.

Figure 22 plus Table 7 (Residential) and Figure 24 plus Table 8 (Business) show the divergence in bills by 2034 for each tariff option for two different customer types:

- Those who take up the new tariff but do not adopt DER; and
- Those who take up the new tariff and adopt DER.

Figure 22 and Table 7 shows that for residential customers, the greatest bill divergence for customers with and without DER by 2034 is for IBT, closely followed by DBT. The non-DER customers under IBT and DBT subsidise both the network investment costs and residual costs for the DER customers. The lowest divergence occurs under MD+SToU followed by SToU.

Figure 22 – Electricity Bills by Residential Customer Sub-Class and Tariff in 2034



Source: Energeia

Table 7 – Electricity Bills by Residential Customer Sub-Class and Tariff in 2034

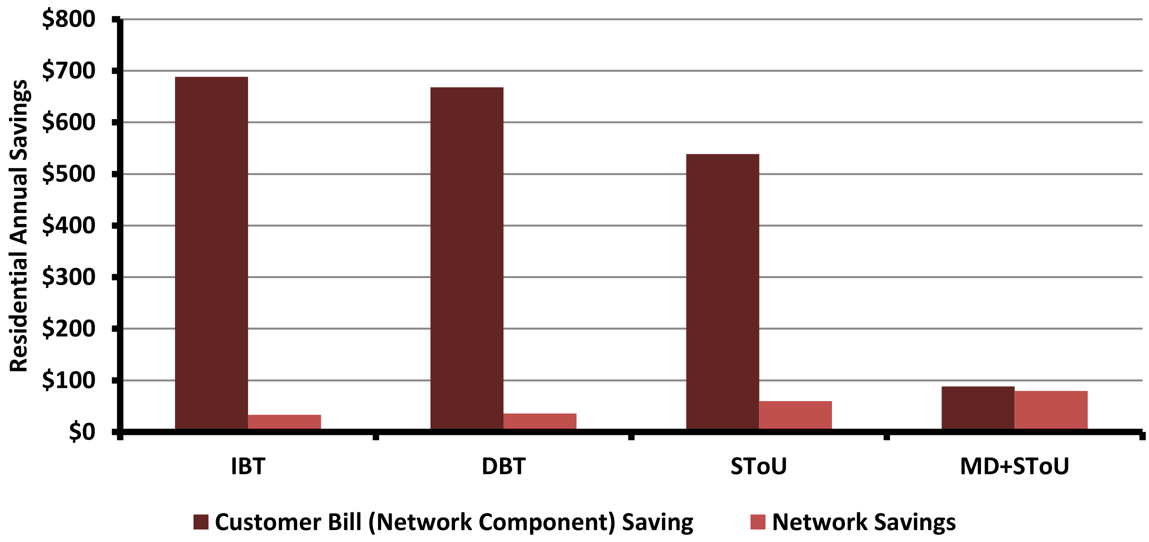
Customer		Annual Bills ($ '000)			
		Network	Retail	DER	Meter
Average	IBT	1.61	1.36	0.03	0.01
	DBT	1.85	1.35	0.05	0.01
	SToU	1.61	1.44	0.02	0.01
	MD+SToU	1.36	1.39	0.01	0.00
DER	IBT	0.95	0.83	0.49	0.01
	DBT	1.24	0.90	0.51	0.01
	SToU	1.08	0.92	0.67	0.01
	MD+SToU	1.26	1.01	0.38	0.01
Non-DER	IBT	1.65	1.40	-	-
	DBT	1.92	1.40	-	-
	SToU	1.63	1.40	-	-
	MD+SToU	1.36	1.40	-	-

Source: Energeia

Determining how much of the difference in bills is due to the cross-subsidy requires comparing the network savings relative to the bill savings across the tariffs. We have presented the average for the residential class in Figure 23. This analysis reveals that there are significant savings on the network component of customers' bills as a result of increased DER uptake leading lower grid consumption under IBT and DBT, SToU. However,there is minimal benefit in terms of cost savings to the network through peak demand reduction as a result of these tariffs.

The large differences between what a DER customer saves on annual network bills and the resulting savings to the network under IBT ($655) and DBT ($633) leads to the significant cross-subsidies effects observed for these tariffs. In contrast under MD+SToU and SToU, the relatively lower DER uptake results in reduced network bill savings for the average residential customer. However as these tariffs provide a stronger incentive to adopt storage to reduce demand during peak periods, there are greater savings to the network. Ultimately this results in the lowest cross subsidy between DER and non-DER customer for MD+SToU as shown in Figure 22 above.

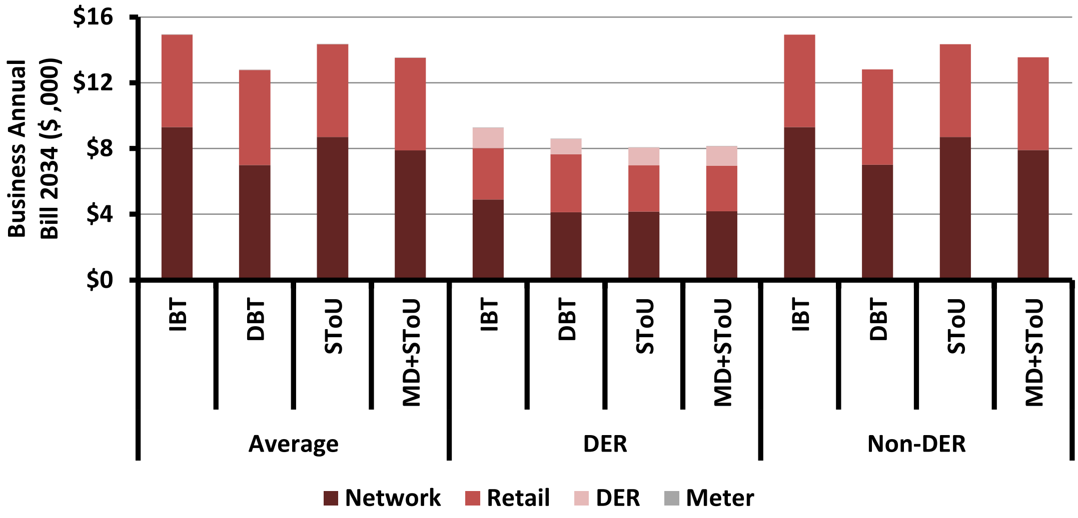
Figure 23 – Average Residential Bill Savings vs. Network Savings by Tariff in 2034



Source: Energeia

Figure 24 and Table 8 shows that for business customers, the greatest bill divergence by 2034 between passive customers and DER customers is for IBT and SToU customers. The lowest divergence occurs under the DBT and MD+SToU tariffs.

Figure 24 – Electricity Bills by Business Customer Sub-Class and Tariff in 2034



Source: Energeia

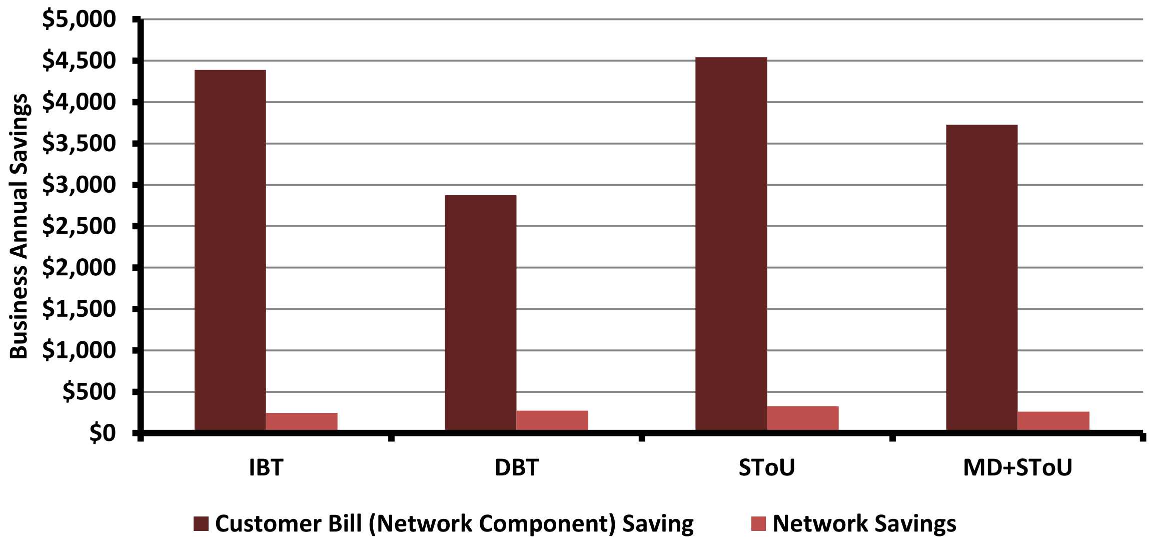
Table 8 – Electricity Bills by Business Customer Sub-Class and Tariff in 2034

Customer		Annual Bills ($ '000) Network	Retail	DER	Meter
Average	IBT	9.30	5.62	0.00	0.01
	DBT	6.99	5.77	0.01	0.01
	SToU	8.70	5.64	0.00	0.01
	MD+SToU	7.89	5.62	0.01	0.00
DER	IBT	4.91	3.10	1.24	0.01
	DBT	4.13	3.53	0.93	0.01
	SToU	4.15	2.82	1.09	0.01
	MD+SToU	4.17	2.78	1.18	0.01
Non-DER	IBT	9.31	5.62	-	-
	DBT	7.02	5.79	-	-
	SToU	8.71	5.64	-	-
	MD+SToU	7.91	5.63	-	-

Source: Energeia

The bill differences between DER and non-DER customers are an indication of the cross subsidy. However at least part of the difference is due to the retail component of the bill and does not therefore direct reflect the network cross subsidy effect. The results of Energeia's modelling for business customer cross subsidies are presented for the average business customer in Figure 25, which shows the difference between DER customer savings on network bills through increased DER uptake and the savings to the network from avoided network capex as a result of DER-driven peak demand reduction. IBT and SToU exhibit the greatest differences between a DER customer's savings on network bills and network savings through reduced peak demand, amounting to $4,145 and $4,218 per DER customer per year respectively. This underpins the significant cross subsidies experienced under these tariffs. The level of subsidy is lower for the other tariffs, particularly for DBT, which is around $2,604 per DER customer per year.

Figure 25 – Average Business Customer Bill Savings vs. Network Savings by Tariff in 2034



Source: Energeia

It is important to emphasise that the current lack of cost reflectivity in network and retail tariffs means that there are a wide range of cross-subsidies in place, not just related to DER. These include well known examples of those without gas appliances and air-conditioning subsidising those with these appliances.

5 Metering Policy Impacts

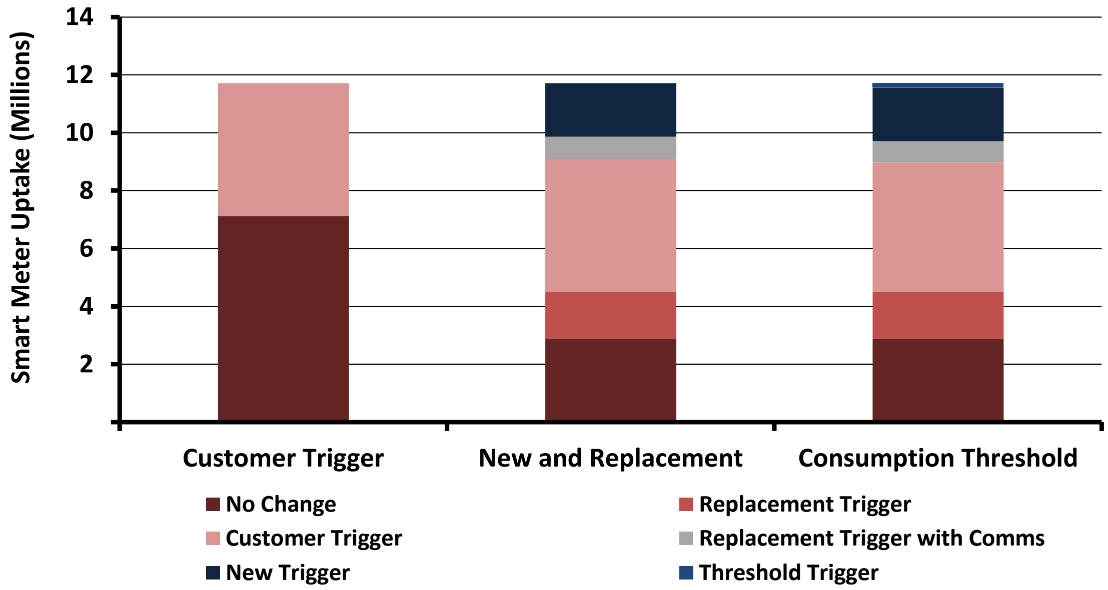
This section presents the results of Energeia's modelling of the impacts of various smart metering and tariff policy setting scenarios on customer, community and industry costs relative to the MD+SToU scenario results. The impacts are therefore incremental to the impacts already identified in Section 4 where smart meters and the MD+SToU tariff were only deployed on a voluntary basis, i.e. the customer triggered policy scenario.

The results presented in this section determine whether there is likely to be *additional* benefit from more progressive smart metering and tariff policy scenarios compared to the customer triggered policy scenario.

5.1 Metering and Tariff Impacts

Figure 26 shows the penetration of smart meter uptake by the end of the period by trigger type for each policy scenario. The new and replacement meter and consumption threshold policies increase the number of meters installed by the end of the period by about 4.2 million (difference in dark red) and the number of customers installing DER by around 1 million respectively.

Figure 26 – Smart Meter Uptake under Policy Scenarios



Source: Energeia

For the base case customer trigger scenario, there is approximately 39% penetration of smart meters across the community by the end of the period driven by voluntary tariff uptake as well customer decisions to adopt DER.

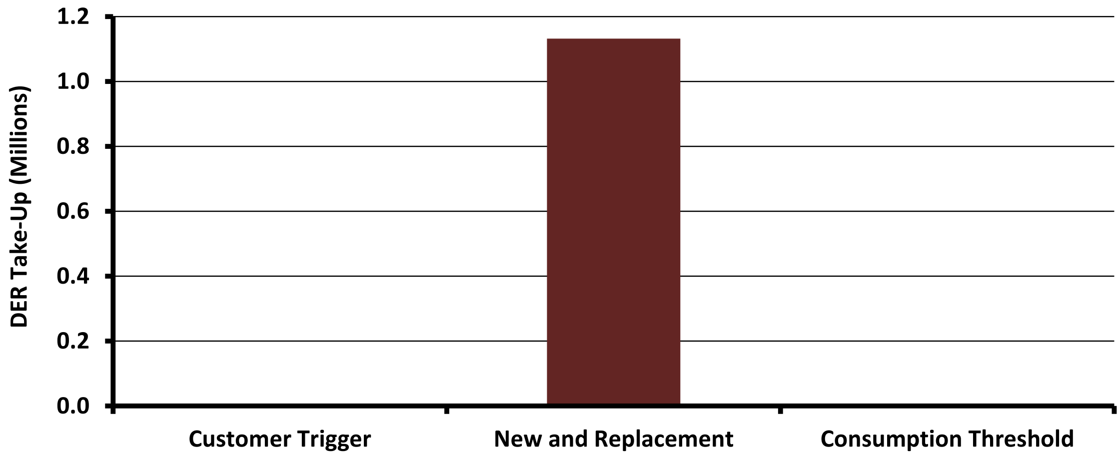
For the new and replacement meter scenario, penetration increases to 75% of the population by 2034. The increased uptake is due to additional triggers for smart meters and tariff adoption for new customers and replacement customers who are provided with an inactivated smart meter (without comms) but are not required to take up the MD+SToU. Of the replacement customers, 15% activate their smart meter (add comms) by voluntarily taking up the MD+SToU tariff or by taking it up when they choose to install DER.

The same final penetration level of around 75% is realised for the consumption threshold trigger. The difference in this scenario is that the take up occurs sooner for larger business customers over the maximum 40 MWh mandatory threshold trigger rather than the large customers' own decision to adopt a tariff and/or DER.

5.2 Distributed Energy Resource Impacts

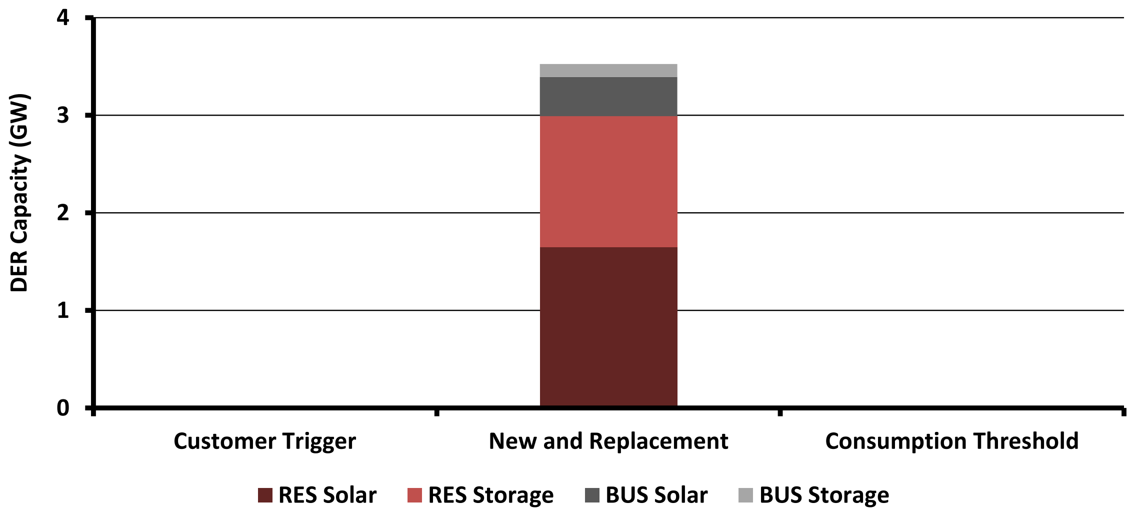
Figure 27 shows the resulting DER uptake under each policy scenario by total penetration and capacity respectively. Overall, the modelled new and replacement meter policy intervention scenarios increase customer DER adoption by over 1 million or around 10% more customers by the end of the modelling period. The consumption threshold has no overall impact on DER uptake.

Figure 27 – DER Uptake (Penetration) under Policy Scenarios



Source: Energeia

Figure 28 – DER Uptake (Capacity) under Policy Scenarios



Source: Energeia

The DER uptake in the base customer trigger scenario is equivalent to the DER uptake as described in Section 3 with approximately 28% of customers with DER and a total capacity 34.4 GW by the end of the period.

The DER uptake under the new and replacement meter policy scenario increases to 38% of total customers and a total capacity of 37.9GW, or around 10% higher than the base case. The increased uptake is due to two reasons. Firstly, assignment of new and threshold customers onto the MD+SToU tariff eliminates the tariff barrier which previously prevented customers who were better off under IBT from making the choice to be assigned to the MD+SToU tariff.

The second and less dominant driver is the improved return on investment for DER technology for all customers who save money on the cost of a smart meter installation (under the new and replacement meter policy and threshold triggers).

No additional DER is adopted under the consumption threshold as this threshold trigger does not materially impact the large business's decisions to adopt DER. These customers face a high return on investment for DER under a MD+SToU tariff and will tend to make the decision to switch tariff and adopt DER on a voluntary basis without any mandatory trigger.

5.3 Industry and Community Impacts

In Section 4, it was determined that the MD+SToU under the customer trigger scenario results in $17.7 billion in savings to the community. Under the different policy scenarios, further community benefits are realised depending on the extent of DER and tariff take up. Generally the greater the DER and tariff take up the greater benefit to the network in terms of avoided capex, but this also comes at the cost of the enabling SMI infrastructure.

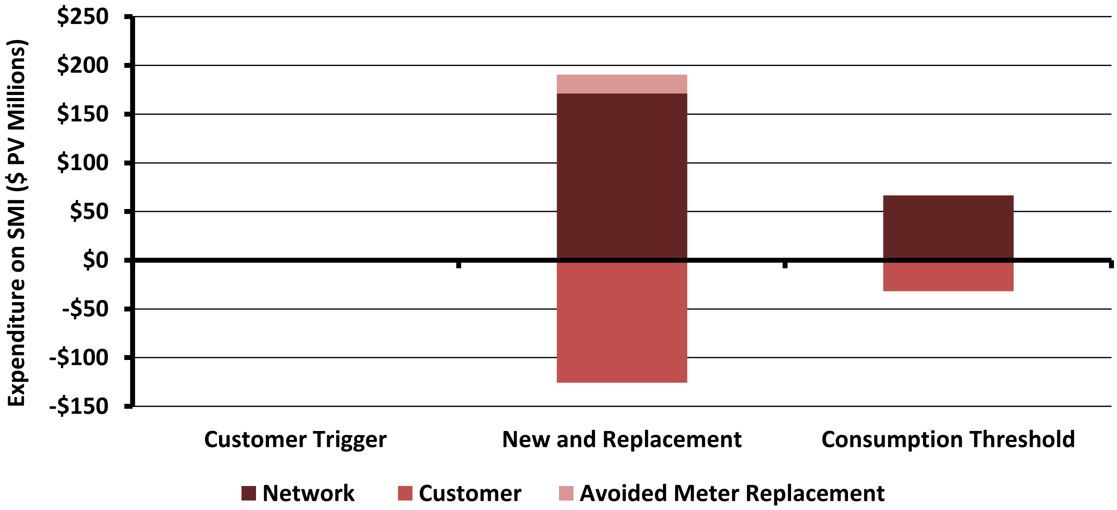
The following sections outline the additive impacts of the two additional metering policy scenarios which give rise to incremental net benefits (or costs) compared to the customer trigger policy scenario.

5.3.1 Capital Expenditure

Figure 29 shows the total additional net capital expenditure on smart meter infrastructure in present value terms over the 20 year period by policy scenario. This includes both the additional cost of smart meters as well as the added avoided expenditure on conventional meters which would otherwise have been replaced. The additional capital expenditure is broken down into assumed customer and network investment components.[10]

As expected, Energeia's modelling results show that as the number of meters increase across the scenarios, the total level of net capital expenditure required also increases by between $45 million for the new and replacement policy scenario and up to $35 million for the consumption threshold trigger scenario.

Figure 29 – Total SMI Capital Expenditure for Policy Scenarios



Source: Energeia

Under both scenarios compared with the customer trigger scenario, there is a decrease in the customer investment in metering due to greater network funded deployment, but higher metering investment overall.

5.3.2 Operational Expenditure

The total net operational expenditure on smart meter infrastructure reported here is comprised of:

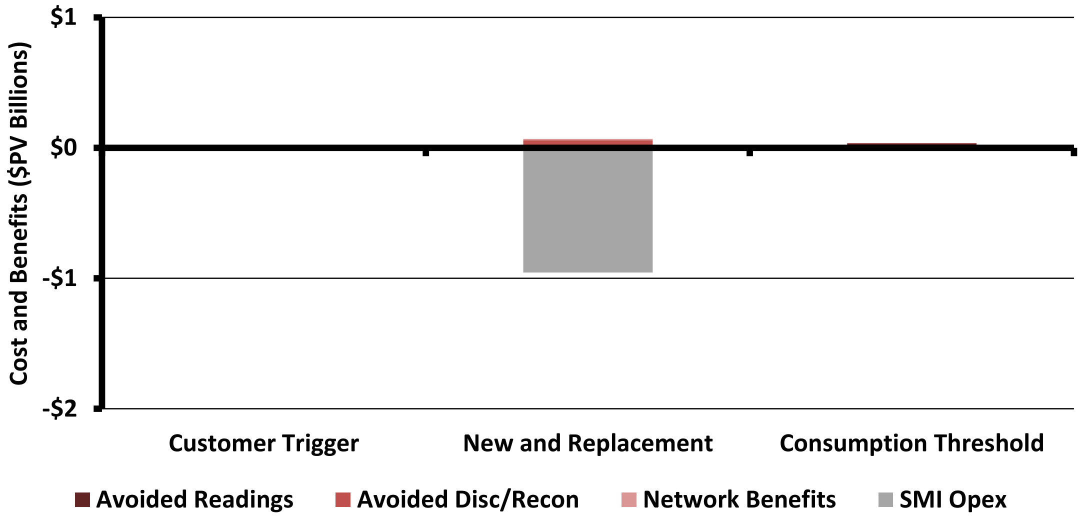
- SMI opex (IT and comms);
- Avoided manual meter readings;
- Avoided energisations, de-energisations, disconnections and reconnections; and

[10] It should be noted that with the advent of metering contestability this expenditure may be incurred by a network, retailer or indeed any other third party entering the market. For the purpose of this assessment, costs and benefits accruing to the meter provider have been nominated as "network" costs and benefits.

- Other avoided network benefits (LV power quality surveys and load surveys).[11]

The additional contribution of these additional opex costs and benefits is shown in Figure 30 below. For the purpose of this assessment these are all considered ‘network’ costs and benefits, however, customers will ultimately pay for these costs in their bills through market forces and/or the regulatory process.

Figure 30 – Total SMI Operational Expenditure for Policy Scenarios



Source: Energeia

The new and replacement meter scenario generates around $1 billion of additional opex costs in present value terms associated with IT and communications for the smart meter infrastructure. The additional opex benefits are relatively small result in an overall net operational cost of $887 million compared to the customer trigger scenario.

The customer threshold demonstrates negligible additional operational expenditure compared to the customer trigger scenario as an equivalent number of meters is ultimately deployed.

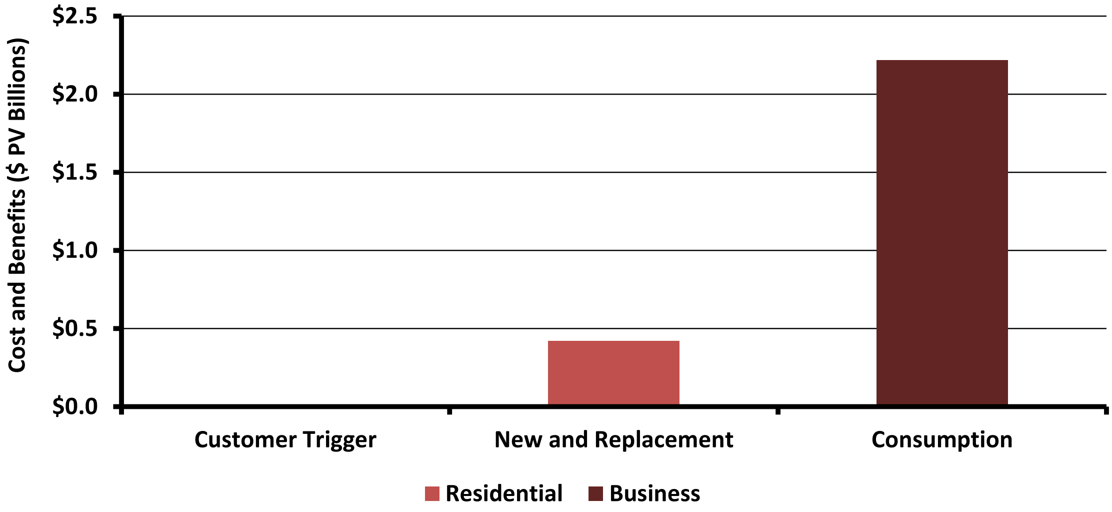
5.3.3 Indirect benefits

In addition to the direct capex and opex benefits, there are also potential indirect benefits enabled by greater deployment of cost reflective tariffs and smart meter infrastructure. Together, they increase peak demand reduction, reduce network capex costs, and reduce the total cost of supply to consumers via DER.

Figure 31 presents the additional avoided network capex for each policy scenario compared to the customer trigger scenario for both the business and residential class.

[11] Importantly, this assessment did not include the full range of benefits Energeia identified in its separate report for the ENA on the range of potential network benefits from smart metering.

Figure 31 – Indirect Benefits (Avoided Network Capex) for Policy Scenarios



Source: Energeia

Under the new and replacement meter policy, the additional DER uptake, combined with reduction in peak demand due to behaviour change under the MD+SToU tariff results in an additional $0.4 billion in benefits than under the customer trigger scenario.

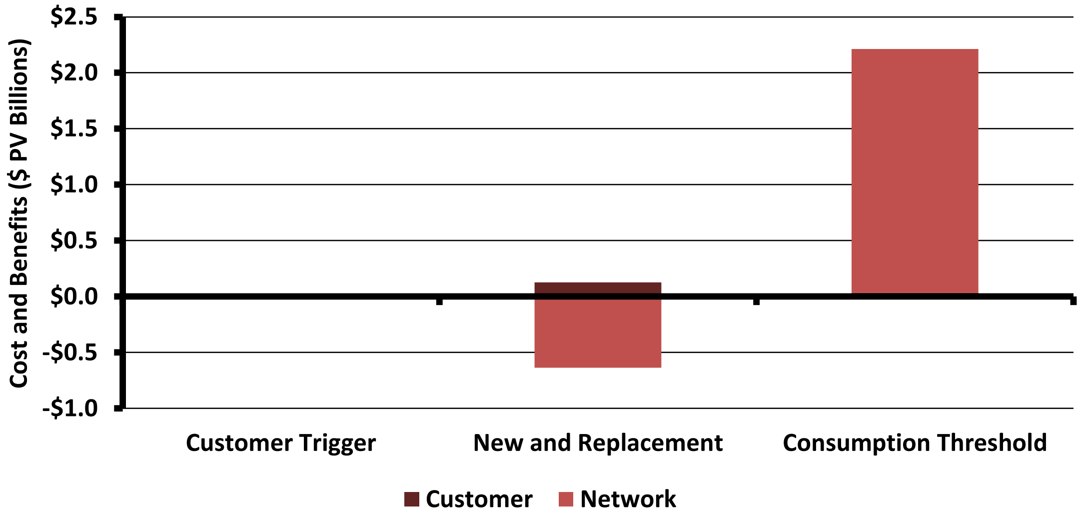
For the consumption threshold, even though the total DER uptake and tariff assignment is no different to the customer trigger scenario, the DER uptake for business occurs much earlier in the period and so in present value terms provides an additional $2.2 billion in benefit.

5.3.4 Combined Network Benefits

Figure 32 shows the total network benefits as a result of alternative policy scenarios by combining the direct and indirect benefits and costs shown in Figure 29, Figure 30 and Figure 31. This shows that that the additional network and customer benefits of the new and replacement meter policy do not offset the additional metering capex and opex resulting in a net cost of $511 million.

For the consumption threshold, the additional indirect benefits associated with bringing forward the peak demand reduction for large consumers provides a total benefit of $2.2 billion.

Figure 32 – Benefits (Network and Customer) for Policy Scenarios



These results do not include the avoided retail expenditure which occurs as a result of the additional DER uptake under the new and replacement meter scenario and the earlier DER uptake which occurs under both the new and replacement meter scenario and consumption threshold scenario.

5.3.5 Total Additional Net Benefits

Total additional net benefits across the 20 year modelling period compared to the customer trigger policy scenario are shown in Figure 33. This includes the network and customer benefits as described in Section 5.3.4 as well as the avoided retail costs from additional DER uptake.

Figure 33 – Total Additional Net Benefits of Policy Scenarios (including Indirect Benefits)

Source: Energeia

Despite the additional retail benefits, the community benefit of $17.7 billion identified under the customer trigger scenario in Section 4 is no further improved by the new and replacement meter scenario.

The consumption threshold gives an additional benefit of $5.8 billion of which $3.6 billion is saved from the retail sector. This gives a total net community benefit of approximately $23.5 billion over the 20 year period in present value terms where there is both a customer and consumption threshold trigger in place.

It is worth noting that the consumption threshold scenario also increases equity between residential and business customer classes relative to the new and replacement meter scenario. This is because business customers realise greater incremental savings under this scenario relative to the new and replacement meter scenario.

Appendix 1 – Customer Load Profiles by Segment

Selected Residential Customers

Figure 34 – Small Residential Average Annual, Summer Weekday and Weekend Daily Load Profile[12]

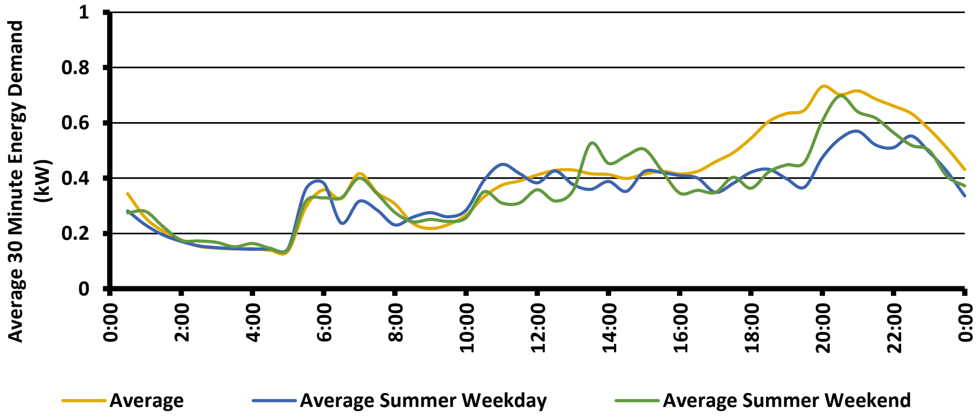


Figure 35 – Medium Residential Average Annual, Summer Weekday and Weekend Daily Load Profile

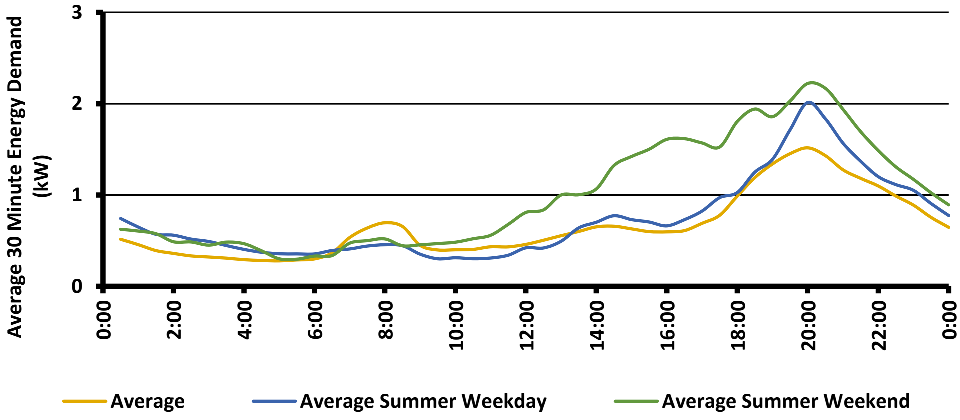
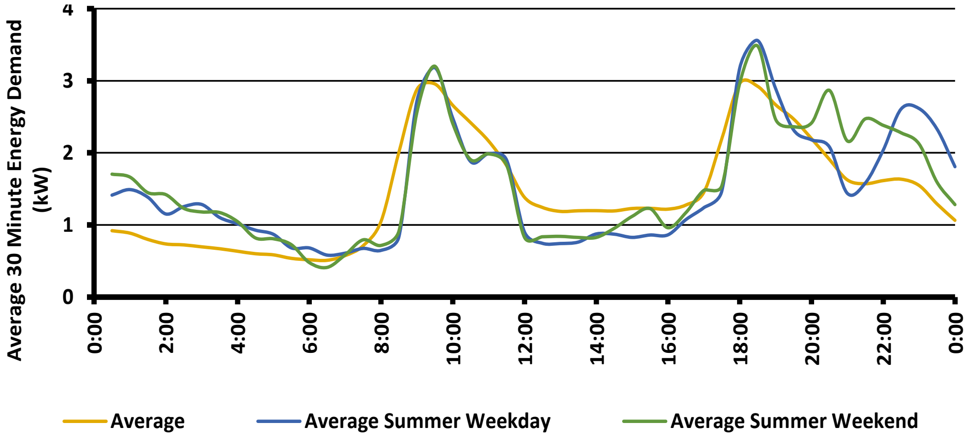


Figure 36 – Large Residential Average Annual, Summer Weekday and Weekend Daily Load Profile



Selected Business Customers

Figure 37 – Small Business Average Annual, Summer Weekday and Weekend Daily Load Profile

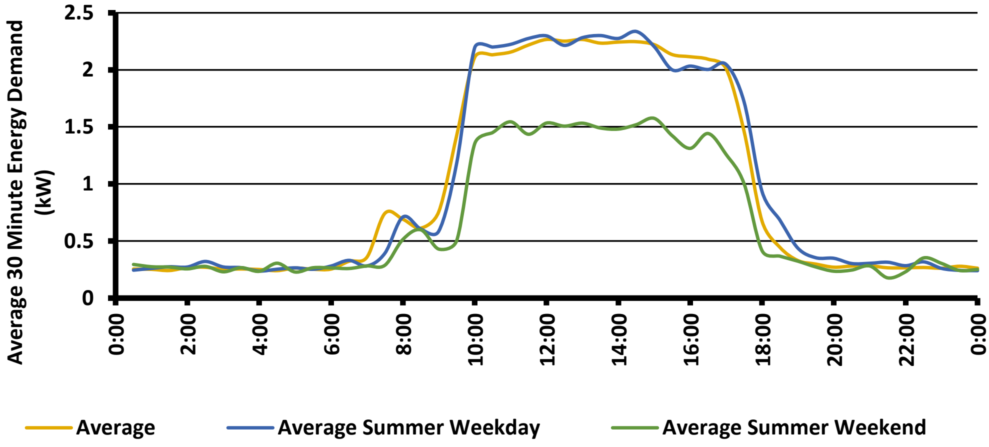


Figure 38 – Medium Business Average Annual, Summer Weekday and Weekend Daily Load Profile

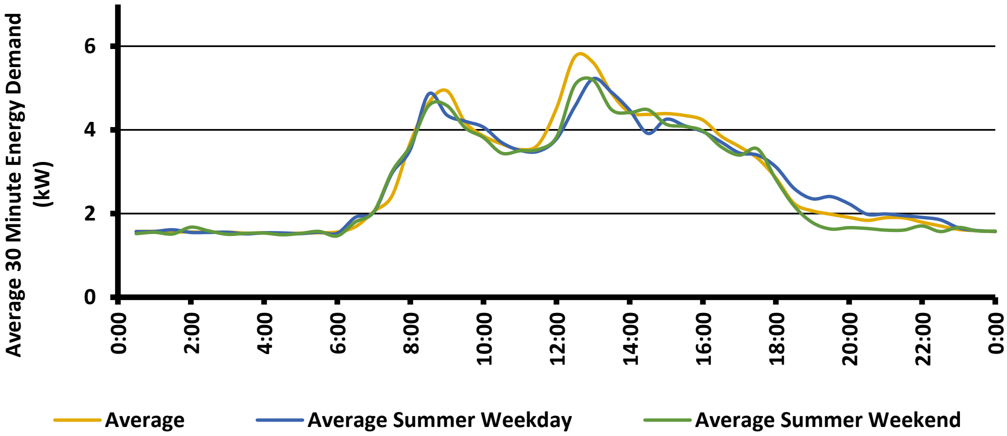
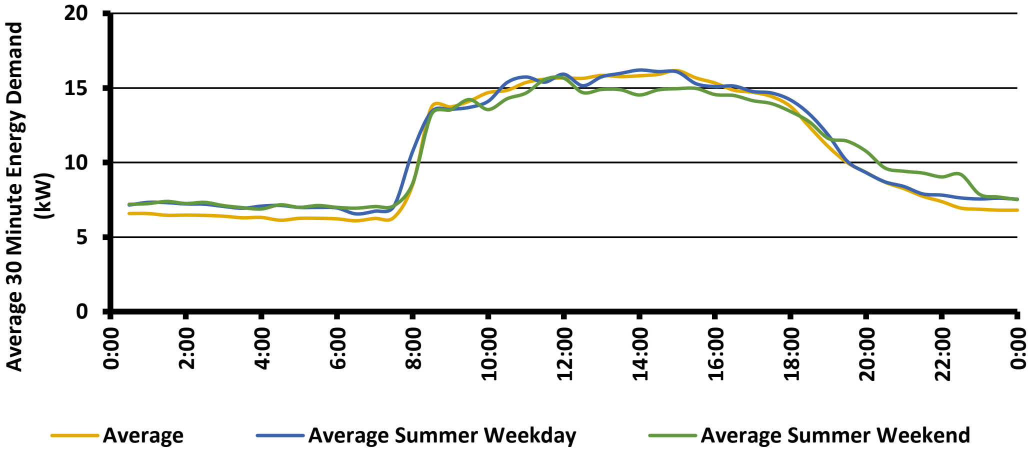


Figure 39 – Large Business Average Annual, Summer Weekday and Weekend Daily Load Profile



Appendix 2 – Tariffs by Customer and State

Inclining Block Tariffs

Table 9 – Residential IBT Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Block 1 (c/kWh)	11.23	14.21	11.01	13.95	8.54
	Block 2 (c/kWh)	14.19	16.91	14.57	19.46	10.55
	Block 3 (c/kWh)	18.28	21.42	19.00	25.83	13.50
	Fixed ($/day)	0.48	0.43	0.31	0.43	0.20
Retail	Block 1 (c/kWh)	13.90	13.18	20.41	10.14	14.42
	Block 2 (c/kWh)	17.57	12.11	27.00	14.15	17.83
	Block 3 (c/kWh)	22.62	9.91	35.22	18.78	22.81
	Fixed ($/day)	0.70	0.35	0.48	0.62	0.85
Total	Block 1 (c/kWh)	25.13	27.39	31.42	24.09	22.96
	Block 2 (c/kWh)	31.76	29.02	41.57	33.60	28.38
	Block 3 (c/kWh)	40.91	31.33	54.22	44.61	36.31
	Fixed ($/day)	1.18	0.78	0.79	1.05	1.05

Table 10 – Business IBT Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Block 1 (c/kWh)	8.98	12.67	9.24	11.39	9.52
	Block 2 (c/kWh)	15.85	22.26	16.11	20.21	16.76
	Fixed ($/day)	0.80	1.35	0.31	0.43	0.20
Retail	Block 1 (c/kWh)	8.14	15.05	17.79	8.07	10.23
	Block 2 (c/kWh)	14.36	16.57	31.02	14.31	18.02
	Fixed ($/day)	0.63	0.30	0.44	0.65	1.30
Total	Block 1 (c/kWh)	17.12	27.72	27.04	19.46	19.75
	Block 2 (c/kWh)	30.21	38.83	47.14	34.53	34.78
	Fixed ($/day)	1.43	1.65	0.75	1.08	1.50

Declining Block Tariffs

Table 11 – Residential DBT Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Block 1 (c/kWh)	14.14	17.63	14.02	17.97	7.06
	Block 2 (c/kWh)	12.28	15.03	12.35	16.12	6.09
	Block 3 (c/kWh)	9.22	10.8	9.58	13.03	4.5
	Fixed ($/day)	0.48	0.43	0.31	0.43	0.2
Retail	Block 1 (c/kWh)	17.5	13.41	25.98	13.06	21.7
	Block 2 (c/kWh)	15.19	11.43	22.88	11.72	18.71
	Block 3 (c/kWh)	11.41	8.22	17.76	9.47	13.82
	Fixed ($/day)	0.07	0.35	0.48	0.62	0.85
Total	Block 1 (c/kWh)	31.64	31.04	40	31.03	28.75
	Block 2 (c/kWh)	27.47	26.46	35.23	27.84	24.79
	Block 3 (c/kWh)	20.63	19.02	27.34	22.5	18.31
	Fixed ($/day)	0.55	0.78	0.78	1.05	1.05

Table 12 – Business DBT Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Block 1 (c/kWh)	17.25	24.33	17.69	21.88	18.28
	Block 2 (c/kWh)	13.32	18.75	13.62	16.94	14.10
	Block 3 (c/kWh)	8.29	11.61	8.42	10.61	8.75
	Fixed ($/day)	0.80	1.35	0.31	0.43	0.18
Retail	Block 1 (c/kWh)	15.63	20.70	34.05	15.49	19.65
	Block 2 (c/kWh)	12.07	15.95	26.21	11.99	15.16
	Block 3 (c/kWh)	7.51	9.87	16.20	7.51	9.41
	Fixed ($/day)	0.63	0.30	0.44	0.65	1.32
Total	Block 1 (c/kWh)	32.89	45.03	51.74	37.36	37.93
	Block 2 (c/kWh)	25.40	34.71	39.83	28.94	29.27
	Block 3(c/kWh)	15.79	21.48	24.62	18.12	18.16
	Fixed ($/day)	1.43	1.65	0.75	1.08	1.50

Seasonal Time of Use Tariffs

Table 13 – Residential Seasonal ToU Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Peak (c/kWh)	0.65	0.65	0.65	0.65	0.65
	Shoulder (c/kWh)	0.26	0.26	0.26	0.26	0.26
	Off Peak (c/kWh)	0.09	0.12	0.09	0.13	0.05
	Fixed ($/day)	0.48	0.43	0.31	0.43	0.20
Retail	Peak (c/kWh)	0.57	0.53	0.91	0.57	0.46
	Shoulder (c/kWh)	0.23	0.22	0.37	0.23	0.19
	Off Peak (c/kWh)	0.13	0.09	0.19	0.09	0.15
	Fixed ($/day)	0.07	0.35	0.48	0.62	0.85
Total	Peak (c/kWh)	1.22	1.18	1.55	1.22	1.10
	Shoulder (c/kWh)	0.50	0.48	0.64	0.50	0.45
	Off Peak (c/kWh)	0.22	0.21	0.28	0.22	0.20
	Fixed ($/day)	0.55	0.78	0.78	1.05	1.05

Table 14 – Business Seasonal ToU Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Peak (c/kWh)	0.30	0.30	0.30	0.30	0.30
	Shoulder (c/kWh)	0.22	0.22	0.22	0.22	0.22
	Off Peak (c/kWh)	0.09	0.17	0.10	0.14	0.10
	Fixed ($/day)	0.80	1.35	0.31	0.43	0.20
Retail	Peak (c/kWh)	0.16	0.33	0.42	0.23	0.23
	Shoulder (c/kWh)	0.15	0.29	0.36	0.20	0.21
	Off Peak (c/kWh)	0.11	0.11	0.22	0.09	0.13
	Fixed ($/day)	0.63	0.30	0.44	0.65	1.32
Total	Peak (c/kWh)	0.46	0.63	0.72	0.53	0.53
	Shoulder (c/kWh)	0.37	0.51	0.58	0.42	0.43
	Off Peak (c/kWh)	0.20	0.28	0.32	0.23	0.24
	Fixed ($/day)	1.43	1.65	0.75	1.08	1.50

Maximum Demand Tariffs

Table 15 – Residential Maximum Demand and Seasonal ToU Tariffs per State

Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Max Demand ($/kVA/month)	23.22	21.83	21.79	22.54	23.22
	Off Peak (c/kWh)	0.08	0.12	0.09	0.12	0.05
	Fixed ($/day)	0.48	0.43	0.31	0.43	0.20
Retail	Peak (c/kWh)	0.57	0.53	0.91	0.57	0.46
	Shoulder (c/kWh)	0.23	0.22	0.37	0.23	0.19
	Off Peak (c/kWh)	0.13	0.09	0.19	0.09	0.15
	Fixed ($/day)	0.07	0.35	0.48	0.62	0.85
Total	Max Demand ($/kVA/month)	23.22	21.83	21.79	22.54	23.22
	Peak (c/kWh)	0.66	0.65	1.00	0.70	0.51
	Shoulder (c/kWh)	0.32	0.34	0.46	0.36	0.24
	Off Peak (c/kWh)	0.21	0.20	0.28	0.21	0.20
	Fixed ($/day)	0.55	0.78	0.78	1.05	1.05

Table 16 – Business Maximum Demand and Seasonal ToU Tariffs per State

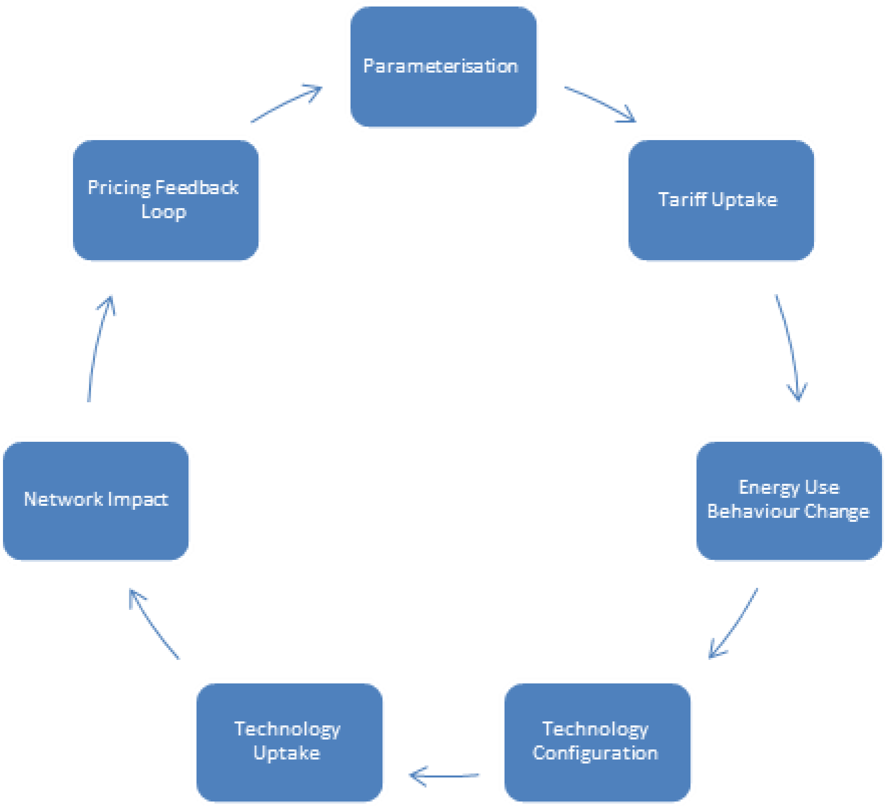
Tariff Component		QLD	NSW	SA	TAS	VIC
Network	Max Demand ($/kVA/month)	23.22	21.83	21.79	22.54	23.22
	Off Peak (c/kWh)	0.08	0.12	0.09	0.12	0.05
	Fixed ($/day)	0.48	0.43	0.31	0.43	0.20
Retail	Peak (c/kWh)	0.57	0.53	0.91	0.57	0.46
	Shoulder (c/kWh)	0.23	0.22	0.37	0.23	0.19
	Off Peak (c/kWh)	0.13	0.09	0.19	0.09	0.15
	Fixed ($/day)	0.07	0.35	0.48	0.62	0.85
Total	Max Demand ($/kVA/month)	23.22	21.83	21.79	22.54	23.22
	Peak (c/kWh)	0.66	0.65	1.00	0.70	0.51
	Shoulder (c/kWh)	0.32	0.34	0.46	0.36	0.24
	Off Peak (c/kWh)	0.21	0.20	0.28	0.21	0.20
	Fixed ($/day)	0.55	0.78	0.78	1.05	1.05

Appendix 3 – Energeia's Customer Behaviour Model

The customer behaviour model estimated customer uptake of different technologies (solar PV, battery storage) and tariffs, and the impact of this behaviour on system and load shapes, peak demand and network and revenues. In the case of this assessment it does this for each of the 6 customer segments in the 5 NEM states across the 20 year assessment period.

In order to capture the impact of changes in customer consumption had on network costs and revenues the model incorporated a network pricing feedback loop. The feedback loop meant the annual network tariff was adjusted in response to the behavioural change effects had on network revenues and augmentation costs.

Figure 40 – Interactions between Customer Behavioural Responses and Pricing Feedback Loop



Parameterisation

At the beginning of each year the model was updated for changes in customer demand growth; population growth; inflation rate; retail, network and wholesale energy price changes; feed-in-tariff price changes; and technology cost changes. The changes to these underlying parameters were important for setting the framework within which the model operated. Importantly, the parameterisation stage also included dynamic network tariffs that were adjusted each year via a feedback loop to take in account the impact of network costs and revenues on network prices as a result of customer behaviour in the previous year.

Voluntary Tariff Uptake

The modelling of tariff uptake assumed that customers adopted a tariff subject to their return on investment, where the investment was assumed to be equivalent to the cost of a smart meter. This generally implied that customers who were better off on an alternative tariff sought to switch tariffs as soon as possible.

Table 17 shows the assumed percentage of customers in the various segments who would voluntarily take up a tariff, irrespective of their return on investment. This was applied consistently in the modelling to all tariffs.

Table 17 – Voluntary Tariff Uptake Rate per annum

Customer Segment	Uptake Rate (% p.a.)
Small Residential	1.98 %
Medium Residential	0.59 %
Large Residential	0.51 %
Small Business	1.98 %
Medium Business	0.59 %
Large Business	0.51 %
Weighted Average Market Constrained Take-up Rate	15 %

A small proportion of customers despite being worse off under a new tariff were still assumed to make the switch. This reflects a real world scenario where some customers would still switch to a new tariff, even if they were not financially better off from doing so. Such customers may switch as a result of either believing that they could change behaviour under a new tariff in order to achieve a positive return on investment or not being provided with sufficient information to make an informed and rational decision. These low take up rates were based on observed rates of tariff uptake in the Smart Grid, Smart City customer trials where customers were not provided with any knowledge of potential bill savings prior to signing up to a tariff.

It was assumed that all customers who switch to a new tariff would install a smart meter. Therefore a constraint was applied which took into account the likelihood of there being supply chain constraints that would restrict the number of customers who were able to receive a smart meter installation within an annual period, and therefore take up a new tariff. As a result a maximum limit was placed on the level of tariff uptake within any given year to a maximum of 15% of total residential or business customers which gave rise to the take up rates presented in Table 14. This was based on previous observations of supply constraints in the energy market.

An assumption was also made in the modelling whereby if the benefit from moving onto a new tariff was greater than 20% a customer's take up of the tariff would be fast tracked and they would switch within the same year.

Energy Use 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. 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.

For TOU the research showed a clear grouping of results that indicated changes in peak demand as a consequence of shifting to TOU diminishes from a short term impact of 8.3% to a long-term impact of 2.4%. There was very little literature identified for trials of MD tariff. Of the 19 sourced identified, only one Swedish trial provided data on short and long term responses in the residential sector[13]

As the structure of a DBT tariff is consumption-based and offers no incentive to a customer to reduce peak demand, there is no peak demand response to DBT.

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.

The net change on a customer's peak demand as a result of the various tariffs is summarised in Table 18.

[13] 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 18 – Consumer Peak Demand Response (% Reduction)

Tariff Type	Short Term Response	Long Term Response	Average
DBT	0%	0%	0%
Time of Use	8.3%	2.4%	5.3%
Maximum Demand	-19.2%	-16.2%	-17.7%

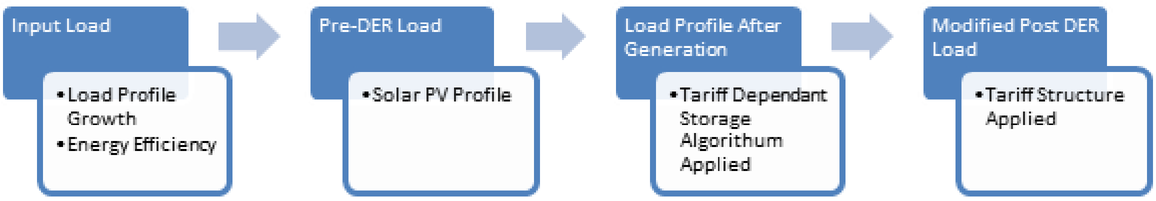
Technology Configuration

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

The model used half-hourly data of a 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 and return on investment).

The model assessed the customer's 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 41.

Figure 41 – Load Modification Process

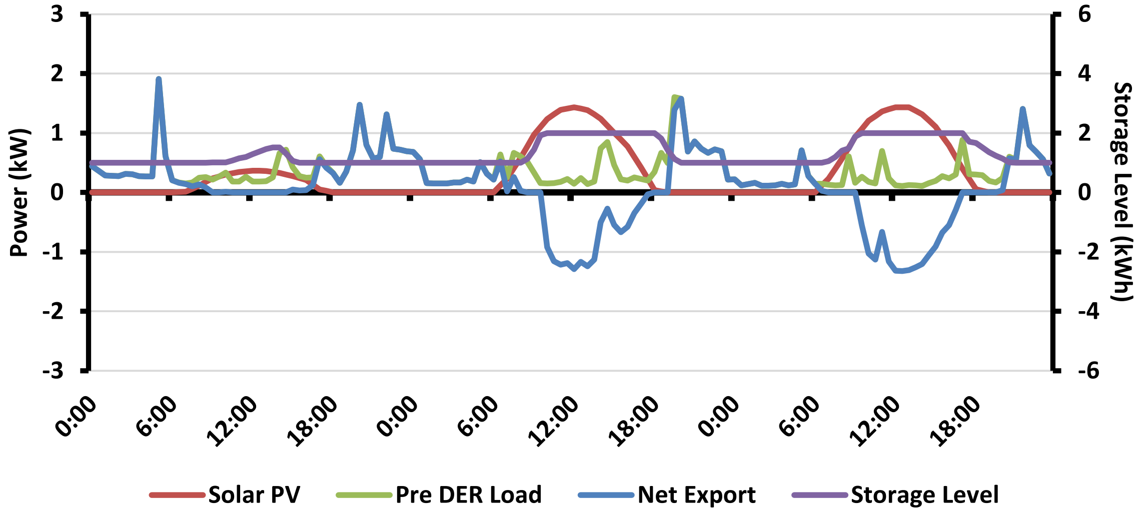


Source: Energeia

An example of the effect of an annual time of use tariff on the half hourly load profile for a small residential customers in New South Wales illustrated in Figure 42. The original customer profile minus the price elasticity effects (Pre-DER load) is impacted by solar PV generation between summer sunlight hours (8am and 5pm). Further, as this is a dynamic tariff, the dispatch of the battery over the peak event can be clearly seen to reduce the customer's peak. In this example, the 1 kW (power) 2 kWh (energy) battery (Storage Level) 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).

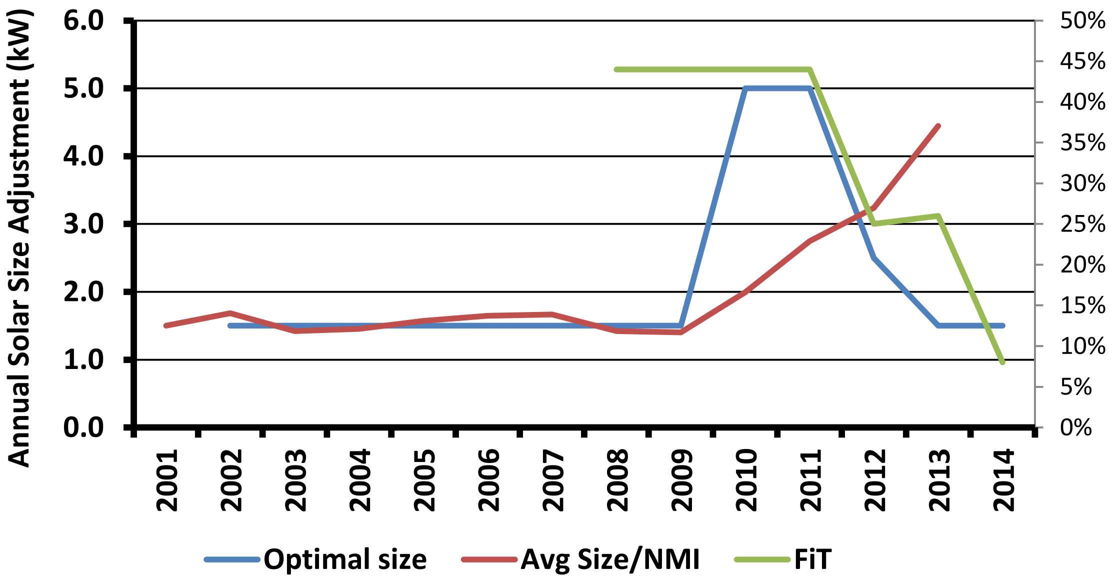
Figure 42 – Small Residential Customer in NSW Technology Operation (includes maximum storage day)



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 investment decision was selected for each customer group.

A review of historical data indicated that there is a two to three year lag on system sizes related to policy changes, specifically the impact of FiTs which drives customer financial outcomes as system size increase above internal demand during the sunlight hours. This impact is not only due to 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 43 the system size lags the optimal size by roughly three years.

Figure 43 – Relationship between the Size of the PV generating facility 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.

This lag effect has not been included in the model and so at least for the early years the system sizes reported are likely to be smaller than actual systems observed in the market.

Technology Uptake

Customer financial incentive were 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. The model used a relationship between ROI and solar PV penetration rates to estimate the uptake 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 using the optimal size ROI in the relationship above, would result in 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 business relationship uses the average size system. Because the business 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 business 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.

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 six customer 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 peak correlation factor of 0.84 for residential segments and 0.88 for business segments.

Consumption

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

Pricing Feedback Loop

In order to capture the impact of changes in customer consumption had on network costs and revenues the model incorporated a network pricing feedback loop. The feedback loop meant the annual network tariff was adjusted in response to the behavioural change effects had on network revenues and augmentation costs. 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, the network sought to recover this lost revenue via price increases in the next year. 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.

Appendix 4 – 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.

<u>Energeia's Relevant Experience</u>

Our relevant project experience includes:

- Development of a national business case for the deployment of smart grid technology on behalf of Ausgrid as part of the $100M *Smart Grid, Smart City* project for the Department of Industry;
- Review of Ausgrid's, Endeavour Energy's and Essential Energy's Type 5 and 6 Metering Alternative Control Service submissions to the AER for the 2014-19 Determination process for the DNSPs;
- Review of ACTewAGL's Type 5 and 6 Metering Alternative Control Service submissions to the AER for the 2014-19 Determination process for ACTewAGL;
- Review of DNSP proposed 2009-11 and 2012-15 Advanced Metering Infrastructure (AMI) expenditure in Victoria for the AER;
- Design of a range of maximum demand tariffs for residential and small business customers for Ausgrid as part of a pricing trial;
- Design of Ergon Energy's Time-of-Use network tariffs for small to medium size customers for 2014/15; and
- Development of a long-term outlook for customer adoption of distributed energy resources in South Australia under a range of tariff scenarios.