2 February 2015

Electricity Authority
PO Box 10041
WELLINGTON

Dear Authority,

Implications of evolving technologies for pricing of distribution services

Thank you for the opportunity to provide feedback on the Electricity Authority's (**Authority**) Consultation Paper *Implications of evolving technologies for pricing of distribution services* (**Consultation Paper**).

The Authority is right to be concerned about whether existing distribution pricing structures are durable[1].

New technologies will be transformational, distribution pricing must be fit for purpose

Contact is supportive of new technologies and agrees with the Authority that new technologies have the potential to transform how customers purchase and consume electricity in the future. Contact believes technologies such as solar, batteries and electric vehicles also have the ability to make a positive contribution to New Zealand's emissions profile. However, in order to enable efficient uptake of these technologies, and for the benefits to consumers and the country to be sensibly realised, pricing structures need to be in place that are equitable.

Based on what we see internationally, this transformation may accelerate over the next decade or so. To ensure the efficient and fair uptake of all new technologies it is imperative that distribution pricing (and other aspects of regulation around pricing) are fit-for-purpose over the long term.

In Contact's view the issues surrounding the current distribution pricing approach are well-articulated by the Electricity Authority in the Consultation Paper and Contact agrees with the majority of the Authority's conclusions, in particular that:

- new technologies will be transformational for consumers;
- the distribution prices consumers currently pay are not aligned with the services they buy.

[1] Consultation Paper page 32.

Distribution prices paid should be aligned with the services consumers buy

Contact agrees with the Authority that the price consumers pay for distribution services should better reflect the cost of providing the distribution service. Accordingly Contact supports a move to service based (cost-reflective) pricing where distribution prices more closely reflect the costs of providing distribution services to consumers, as soon as possible.

We note that currently:

- those with "peaky" loads (caused by either usage patterns or particular devices such as heat pumps and solar panels) are being cross subsidised by those with more "flat" load profiles[2;]
- current pricing is distorting the efficient uptake of emerging technologies, including:
    - dis-incentivising technologies like batteries and electric vehicles which currently have stronger underlying economics, and in the case of electric vehicles which have significant benefits for New Zealand Inc. through a reduction in New Zealand's transport emissions;
    - artificially boosting investment in solar before it is economic. While Contact is supportive of solar, we do not think its success should be at the expense of consumers without solar, who will pay higher distribution charges as a result of solar uptake, or other emerging technologies.

While this is a live issue, we anticipate this issue will only be exacerbated in the future, as current shortcomings with the pricing principles based approach are compounded by other new technologies.

Service based pricing should deliver the best long term outcomes for consumers

Contact agrees that service-based pricing is best placed to deliver long-term benefits for consumers. In our view distribution pricing should:

- be as simple as possible to facilitate consumer understanding and reduce unnecessary cost;
- be consistent nationally (as much as possible across network companies);
- be fair, service based and sending the right pricing signals (with little or no cross subsidies);
- be durable (fit for the future);
- minimise ongoing iterative annual changes (as is currently the case for many distributors)
- enable competition and customer demand to drive uptake.

An incremental approach to changing distribution pricing is likely to lead to continued confusion for customers and erosion of trust and goodwill for the electricity sector.

While a move to Time of Use (ToU) pricing may provide a step towards service based pricing, research from Australia suggests (please see Appendix 1) that this will not remove the significant cross-subsidisation between customers and that a move to fully cost reflective (service based) pricing is preferable.

Current principles based approach is not supporting simplicity or competition in new technologies

In Contact's view the current non-prescriptive pricing principles approach is not working and we disagree with the Authority's conclusion that distributors have strong incentives to change their pricing structures to meet the changing market.

Distributors' incentives are multi-faceted and complex, with other settings within the regulatory regime, such as Part 4 of the Commerce Act and Part 3 of the Electricity Industry Act, as well as distributors own diverse business interests, ownership structures and drivers e.g. listed companies versus community trusts, having the ability to influence distributors' incentives around pricing structures.

Further change to distribution pricing is needed to deliver long-term benefits to consumers

We do not believe that having defined the problem surrounding the current distribution pricing arrangements and quantified the potential inefficiency at between $2.7 billion and $5 billion (discounted NPV) [3], the Authority can simply leave the solution to 29 EDBs and their customers (retailers) to resolve on a network-by-network basis. Twenty nine different distribution pricing regimes is not only inefficient but the cost of this inefficiency is borne by consumers.

Our concern with the current non-mandated pricing principles approach is that any move to service based-pricing is likely to:

- result in up to 29 different distribution approaches[4] which cannot be easily communicated to customers;
- see a range of success levels in implementation;
- drive higher costs for consumers and retailers;
- take significantly longer than it would under a more mandated approach and allow cross-subsidies and poor signals to customers to continue. Analysis by NZIER shows there are significant benefits in making the change now versus delaying the change until later, with an inefficiency of $90-$700m in year two significantly less than the inefficiency which is present in year 10 - $1,600m-$5,800m.

We note that some networks are already moving towards service-based pricing and the lack of a single approach is resulting in diverging and sub-optimal price signals, increasing tariff complexity for consumers and cost.

[3] NZIER report, Effects of distribution charges on household investment in solar, p 16.
[4] This does not include the number of embedded networks.

While we accept there are some differences between networks, we do not think a voluntary network by network approach for matters as significant as this works.[5]

More prescriptive regulation of networks required to enable competition

Given the large number of networks in New Zealand, we consider that a more prescriptive process is needed for the re-setting of distribution pricing, and for this process to be incorporated into the Code. This process could regulate:

- Permitted distribution tariff types/designs, time periods
- The timing of any distribution tariff changes or increases
- Stakeholder consultation on the changes or increases run by the Authority
- Transitional provisions to reflect the materiality of the changes on stakeholders, giving them reasonable time to prepare for change.

Whilst this additional regulation may impose some cost to consumers, this cost is likely to be less than the long-term consumer benefits (including the benefits of the efficient uptake of new technology).

It is worth noting than in Australia EDBs are required to submit a pricing proposal to the Australian Energy Regulator (AER) in advance of each regulatory reset period, with proposals posted on the AER's website for public submission and approval by the AER. Before approving any change the AER must be satisfied the EDB complies with rule requirements (including LRMC-based pricing principles) and any applicable distribution determination and that all forecasts associated with the proposals are reasonable. EDBs are also required to maintain approved prices on their websites.

To ensure a well considered outcome in this space for consumers we recommend a cross-industry working group be established to work through and agree processes and principles. This will ensure that New Zealand's distribution charging regime is set up for New Zealand's long term benefit.

As it stands, the proposal to initiate distribution pricing structures may take 18 months for the Authority to land and another 12-18 months for distributors and retailers to respond to and execute. That's a three year old structure on emerging technology that is changing at pace.

For this reason, we think it would be useful for the Authority to work closely with industry to firm up a stance on what New Energy will look like by 2020 and beyond. There will be more solar homes, more EV's on the road, more charging station infrastructure and more battery types and technology. A distribution pricing structure that addresses the most likely scenarios for 2020 and beyond is what the industry should be working towards, as opposed to something that is fit for purpose now, but which will be three years old by implementation.

[5] We note the use of model use of systems agreements (MUoSA) has resulted in a variety of different agreement and virtually no Use of System Agreement being the same.

Change to distribution pricing brings risks, programmes for vulnerable consumers and communication must be in place

While the benefits of a move to service-based pricing are well articulated, such a change is not without risk as while some consumers will benefit, others will face bill increases as a result of the change. This risk needs to be well-understood and well-managed.

No matter how much sense a change makes from a service based/cost-reflective perspective, poorly executed demand pricing will only disengage customers and damage the reputation of the industry.

Consumer acceptance of service-based pricing and consumers' ability to manage any new pricing structure is critical for the successful roll out of service-based charging.

The criticality of these risks leads Contact to a number of conclusions, some of these conclusions need to be addressed by the Authority, while others will needs to be left to retailers. They are:

1. Any change to service-based pricing must be well-coordinated *across all network regions* – the Authority has a key role in this regard.
2. Ideally, the changes would adopt a uniform tariff design across all network regions (with differentiation driven only by a particular network's characteristics (load shape, spare capacity, growth projections, etc.)).
3. A nation-wide communication programme would precede the roll-out, supported by communications programmes by indiviual retailers.
4. The timing of the roll-out would be coordinated across networks.
5. Tools to enable consumers to manage the effect of the new tariff types must be made available as part of any roll out (it is not fair to apply a peak demand type tariff on a consumer if the consumer has no way of monitoring their real time peak consumption).
6. A mechanism for protecting the most vulnerable consumers must be agreed by industry before any roll out.
7. Significant consumer engagement will be required.
8. Given the contract with end customers sits with the retailer, retailers must continue to have the ability to deliver solutions customers' value and should not be stifled from innovating by distribution pricing.

This is a significant piece of work and one we recommend the Authority, together with the electricity industry, gives significant time and resource to. As The Lines Company's move to demand based pricing has shown, the importance of fit for purpose design, communication, information and the need for tools to assist in demand management cannot be underestimated. Likewise the reality of executing such a change is that this is unlikely to be able to be achieved without having some kind of transitional arrangements in place.

Most importantly given that any change may result in significant winners and losers, thought needs to be given to what can be done to assist the most vulnerable consumers in the event of any change.

Yours sincerely

Louise Griffin
Head of Regulatory Affairs and Government Relations

Response to questions

Q1.	What are your views on the scope of the Authority's review? Please give reasons for your answer.	In Contact's view the review has accurately identified the key issues facing the sector. Other areas the Authority may like to consider in its review include: • access costs/standards/terms and conditions for new technology connecting to the network (e.g. do we have central standards, governance over connection process for new technologies etc.). • the complexity resulting from the Authority and the Commission both having roles in setting distribution pricing. • whether the principles approach used currently works, or whether more prescriptive price setting rules are needed (as we have suggested throughout this submission) • the uncertainty created by the current transmission pricing methodology (TPM) and possible regional implications and ability to pass the possible cost increases through to consumers • the ease of implementation. • whether the large number of networks in New Zealand is delivering the best and most efficient long-term outcomes for consumers. What we are less convinced about is the Authority's proposed approach to dealing with the issues identified. There is evidence in New Zealand that non-mandated approaches in this space do not work, a key example being the model use of system agreement (MUoSA) which results in different approaches being taken by each EDB, no UOSA in New Zealand being the same and additional cost and complexity being borne by consumers. Currently every distributor is able to show compliance with the principles despite a wide range of designs – as one EDB has stated "we are all compliant". As they stand currently the pricing principles are already orientated towards service based pricing however these have largely not been adopted and the result is a regime that is distorting an efficient uptake of emerging technologies and creating significant cross-subsidies between consumers. Importantly this review needs to ensure consumers are at its core and that the outcome ensures the co-ordinated implementation of service-based pricing across NZ to ensure consumers are well positioned to manage the transition.

Q2.	What other technologies do consumers invest in or use that are likely to have a material effect on investment or operation of distribution networks? Please give reasons for your answer and an estimate of when you expect the technologies will have a material effect.	In our view the type of technology is irrelevant. What is important is ensuring fit for purpose, service-based pricing which future-proofs networks against whatever technologies come along in the future. Other technologies may include: • Other DG (e.g. micro wind) • Smart hot water • Inverters • Demand response capability • Many things we are yet to think of.
Q3.	What do you think about the Authority's concerns that existing distribution pricing structures do not reflect the costs of the different distribution services provided and may not be durable?	We agree with the Authority's concerns. However, in transitioning to service-based pricing there is a need to ensure durable tariff structures are put in place (where metering technology and system development allows), which reflect the long term cost of the network and the service provided to consumers. Putting pricing structures in place which only consider the short term capacity available in a network will result in inefficient signals being sent to consumers, inefficient investment by consumers and EDBs, tariffs requiring further adjustment at a later stage and confusion for consumers. That said, consumers' ability to pay needs to be taken into account.

Q4.	What is your view of the potential for a significant amount of inefficient investment in solar panels if distribution pricing structures continue to be based primarily on a consumption-based approach?	In our view there has already been a very material level of inefficient investment. Without a change to more mandated service-based pricing this will only increase over time. Ultimately the type of technology, be it solar, EVs, heat pumps or batteries is not the most important aspect. What is important is to have service-based pricing that is customer friendly, sends through the correct price signals and is durable for the future. Assuming this is in effect it should not matter what type of technology comes along as the prices will send through the right signals. A further benefit of real service-based pricing is that there is no discrimination against any consumer group and it will likely result in increased buy-in.
Q5.	What is your view of the potential for inefficient investment in distribution networks if there is a high uptake of electric vehicles and distribution pricing structures continue to be based primarily on a consumption-based approach?	Please see our response to question four above.

Q6.	What is your view of the potential for battery technology to defer or avoid investment to augment distribution networks?	Batteries are already economic today for some network upgrades and may have a material impact on future grid upgrades. However, it is worth noting that deferring network investment is just one of the many services that batteries can provide.
Q7.	What is your view of the potential for alternative distribution pricing structures to promote more efficient investment by consumers in heat pumps and / or LEDs?	Ultimately this depends on the structure, however service based (demand) tariffs are likely to suppress the uptake of heat pumps and promote the uptake of LED lighting and more efficient use of existing heat pumps. Likewise a move to service-based pricing may drive a move to gas heating (assuming heat pumps add to a typical household in terms of heat and peak load). Right now the uptake of heat pumps is likely to be increasing peak demand, causing network investment to be required and creating cross-subsidies between electricity consumers.

Q8.	What is your view of distributors' options for structuring their pricing?	While there are many different theoretical choices, some are better than others for the overall efficiency of the system. There is also a need to ensure pricing is not stopping competition and that consumers understand the drivers of the pricing and have the ability to react. Based on international examples (see Appendix 1) a move to ToU pricing will still enable significant cross-subsidies to occur. This will result in inefficient investment in emerging technologies, including solar PV. On this basis our preference is for distributors to move to service-based (demand) based pricing. However, as this may result in winners and losers, this may need to be phased in over time. Significant thought needs to be given to what can be done to assist those most vulnerable consumers in the event of any change. In order for this change to be successful there is also a need for more prescriptive application of this pricing. Right now 29 distributors can potentially change their pricing every year (and each year many do). This undermines customer confidence. A move to consistently apply pricing review timeframes, service-based pricing, measurement of peaks (e.g. monthly, annual) with phase-in periods and well-resourced education campaigns will help consumers. Continuous change in pricing structures by EDBs will create complexity for consumers and will not provide a stable platform from which consumers can make sound investments. The way distribution prices are structured should also not discriminate against particular user groups, including new connections and DG customers.

Q9.	What needs to occur for distributors to amend their distribution pricing structures to introduce more service-based pricing?	In some cases moving to service-based pricing will mean a large change in the way residential customers think about and use energy. Ensuring the right tools are in place to enable customers to be able to see and manage their electricity consumption at various times of the day and a well-resourced customer education campaign will be key to the success of any change. Significant consideration needs to be given to ensuring: • Appropriate assistance is in place for those vulnerable consumers who are impacted • Technology is in place to assist consumers with monitoring and controlling their electricity • Any change is well communicated. This issue is material. Service based pricing implemented poorly could have negative impacts for consumers and the industry. This is why in our view it needs to be carefully managed by the Authority.

Q10.	Would a change to the applicable rules encourage change to pricing structures?	Yes.
Q11.	What incentives could be introduced to encourage change?	Please refer to our response to question 12.

Q12.	What other options would ensure distribution pricing structures are service-based?	In our view the best option to ensure a move to service based pricing comes from a more prescriptive approach to the principles such as incorporating the pricing principles into the Code. An example could be making demand based pricing a Code requirement for all ICPs with advanced meters with communications should also be considered. This approach could include a requirement for EDBs to submit their pricing proposals to the Authority for release on their website, with comment sought by consumers and industry participants and, following submissions, the ability of the Authority to assess and approve (or reject) the proposal for compliance with the pricing principles in the Code. This would provide an open and transparent consultation process and ensure pricing structures, and future changes, are consistent with the pricing principles. Leaving the move to service based pricing to EDBs is likely to result in 29 different approaches, with varying degrees of "service-based" pricing being adopted. This will also result in unnecessary tariff complexity, which will be difficult to communicate to customers and will take too long. While we are pleased to see EDBs are currently trying to gain more alignment between themselves we also note this is likely to take years rather than months.

Q13.	Do you have any suggested improvements to the distribution pricing principles in Appendix B? What are your views on the recommendations made by Castalia noted above and in Appendix B?	In our view the principles appear largely fit-for-purpose so the main issue is the enforceability of the principles. We would like to see the Authority use greater power in this space and move to a Code based approach rather than the current light handed "principles" based approach (as discussed in response to Q12 above). The reason we recommend the principles being codified is that distributors are currently interpreting the pricing principles very differently. Castalia's recommendations[6] did not deal with the fact principles are not being adhered to or that they are weak. We recommend adding more prescriptive pricing principles for example pricing based on LRMC, with guidance on LRMC to ensure consistent service-based pricing across EDBs. Other opportunities which could be considered include specifying that fixed charges (c/day) cannot be any higher than the actual level of operating cost in the business (for example 20% of total bill), and consumption based charges for capital recovery (e.g. $/kW) cannot be any higher than the LRMC of the network. This will ensure that network pricing structures reflect underlying costs, and result in a level playing field between existing networks and competition from emerging technologies.

[6] http://www.ea.govt.nz/search/?q=Castalia+Distribution+Pricing&s=&order=&cf=&ct=&dp=&action_search=Search

Q14.	Do you have any suggested improvements to the distribution pricing information disclosure requirements in Appendix B?	Yes. 1. There should be more prescription. Ideally there would be one set of rules for all EDBs, which don’t discriminate by technology or circumstance (e.g. a new customer joining the network). 2. The Authority should engage with consumers to get their perspectives. It is unlikely this will come through the submission process so may need to be done through qualitative research.

Q15.	What other issues with the current distribution pricing arrangements should the Authority address?	Right now there is a lack of consistency among networks which needs to be addressed in the short term. It will be important to ensure consistent pricing structures are adopted by EDBs, to minimise complexity for consumers and provide a stable platform from which consumers can consider and make investment choices.

Q16.	How will New Zealand-specific circumstances influence the effects of evolving technologies in this country?	In our view New Zealand's specific circumstances don't really influence the effects of evolving technologies. While the lack of government subsidies (feed-in-tariffs, net metering etc.) has meant evolving technologies have not impacted New Zealand as quickly in other markets, this has also meant that our regulations to deal with new technologies have not kept pace with other countries. However with technologies becoming commercial without subsidies, it is important the right regulatory frameworks are put in place quickly to ensure efficient investment and operation of energy markets. We should focus on building an enduring system rather than trying to pick technology winners.

	Additional comments	The Authority must be mindful of the cost of any such changes which are ultimately born by consumers. Our own experience with phase one of the retail data project suggests the Authority sigificantly under estimates the costs of change by many million dollars.

Appendix 1: Paper Network tariffs: resolving rate instability and hidden subsisidies

A paper for the SAO Advisory Customer Council – Utilities
Heidelberg, Germany, 16 October 2014
Paul Simshauser

Please refer to section 5.2 Two Part, Time-of-use and Three Part Demand Tariffs
Figure 12 and 13, 14 and 15

Network tariffs: resolving rate instability and hidden subsidies

A paper for the SAP Advisory Customer Council - Utilities
Heidelberg, Germany, 16 October 2014

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Abstract
In Southeast Queensland, 75% of households have an air-conditioner and 1-in-4 detached homes now have a rooftop Solar PV – one of the highest take-up rates in the world. Solar PV exceeded all expectations, but underpinning take-up rates are subsidy schemes funded by artificially raising tariffs above the regulated set-point, creating wealth transfers amongst electricity consumers. The structure of the two-part tariff is dominated by a flat-rate variable charge which amplifies wealth transfers through 'hidden subsidies'. In this article, using interval meter data at the customer switchboard circuit level, an optimal network tariff isolates the incidence of inequitable wealth transfers arising from air-conditioner and solar PV units. Results demonstrate a Demand Tariff substantially increases the efficiency and fairness of the price signal. Above all, a Demand Tariff reduces the structural instability of network prices given a rate-of-return regulatory constraint.

Keywords: Electricity Utilities, Electricity Prices, Demand Tariffs.
JEL Codes: D61, L94, L11 and Q40.

1. Introduction

In 2005 Australia's National Electricity Market (NEM) was identified as one of the world's best examples of an electricity industry microeconomic reform. Yet from 2007-2013, the NEM was one of the worst performing electricity markets in the world. Residential tariffs increased faster than any of Spain, Portugal and Germany – systems noted for extraordinary electricity price rises. In the Australian case, network tariff increases dominated price movements in most regions.[1] Reasons behind the initial surge in network tariffs are examined in Simshauser (2014) and so I do not propose to reproduce such analysis here. To summarise, misguided policy responding to blackouts in 2004 resulted in network reliability standards being tightened – considerably – and from 2007 an unprecedented wave of capital spending would follow.

In Australia, most distribution networks are 'revenue regulated' under 5-year rate cases. With tariffs rising at multiples of consumer price inflation to support the wave of capital spending, households responded by reducing consumption. Given revenue regulation, distribution network volumetric (kWh) losses in one year were offset by rate (c/kWh) increases the following year. These 'volumetric loss-induced' rate rises added a second layer of tariff increase to already sharply rising network prices. This in turn induced a further round of Demand Response, resulting in yet another round of tariff increases.

For networks, an additional problem emerged, however. The Federal Government initiated a policy of generous up-front capital subsidies for households that installed Solar PV units. State Governments initiated overlapping policy subsidies involving generous Premium Feed-in Tariffs. As was the case with most Solar FiT schemes, the Queensland policy was not funded by

♣ Paul Simshauser is Chief Economist at AGL Energy Ltd and Professor of Economics at Griffith University. See Section 9.
[1] The other drivers of tariff increases included the introduction of a $23/t carbon tax, rising renewable energy targets and energy efficiency schemes, and overlapping Solar PV subsidies at the State and Federal level. See Simshauser (2014).

government taxation revenue, but by adding a (third) layer of price increase to network tariffs. Subsequent volumetric-losses were intensified, and subsequent tariff increases amplified.

Three layers of compound tariff increases created an entirely new dimension to the problem – sharply rising 'hidden subsidies'. Because network tariffs are dominated by a flat-rate variable charge, periodic demand is mispriced. As a broad generalisation, households with air-conditioners are beneficiaries of 'hidden subsidies'. However, a large majority of customers have an air-conditioner, and therefore the extent of wealth transfers will have *'naturally diminished'*. Likewise, solar PV output is, in general, mismatched with household periodic demand, and thus a new series of 'hidden subsidies' was created. Average solar PV households avoid a disproportionately large component of network charges and this unintended or hidden subsidy is driving marginal investments in solar PV capacity above the (otherwise) efficient level.

The outcome of this conflation of variables is a highly unstable network tariff which increased by 112% in just five years in an ostensibly low inflationary environment.[2] Early evidence of Severance's (2011) *energy market death spiral* now exists in Southeast Queensland.[3] The purpose of this article is to identify an efficient, equitable and stable network tariff structure that accommodates solar PV and other distributed technology investments in a low growth environment. The structure of this article is as follows: Section 2 explores the precise nature of the problem being solved. Relevant literature is examined Section 3 while Section 4 provides an overview of the Tariff Model and data used in this research. Sections 5 and 6 present model results. Policy implications and concluding remarks follow.

2. The nature of the problem to be solved

Before examining optimal tariff design through a review of the literature and quantitative analysis, the nature of the problem being solved needs to be fully understood. The following analysis includes a review of a typical network element, network prices, and interval meter data from a group of typical Queensland households[4] measured at the customer switchboard circuit level. The latter data enables household load to be decomposed at a level of granularity not typically available to utilities, regulators or policymakers.

2.1 Australia's National Electricity Market

The NEM covers the eastern seaboard of Australia including the States (capital cities) of Queensland (Brisbane), New South Wales (Sydney), Victoria (Melbourne), South Australia (Adelaide), Tasmania (Hobart) and the Australian Capital Territory (Canberra) with a population of about 20.8 million. The 45,000MW interconnected system serves 8.3 million households and 1.1 million business customers. After experiencing growth of *ca.*2.6% per annum from 1990-2009, the NEM experienced its first year of negative demand growth in 2010 – a trend which has continued to the time of writing. This is illustrated in Figure 1. Also included in Figure 1 are annual load forecasts from 2010-2014 prepared by the Independent Market Operator, and superimposed on the RHS y-axis are retail-level residential tariffs for Southeast Queensland. As the forecasts illustrate, it took some time for the industry to adjust to the changing pattern of electricity load development.

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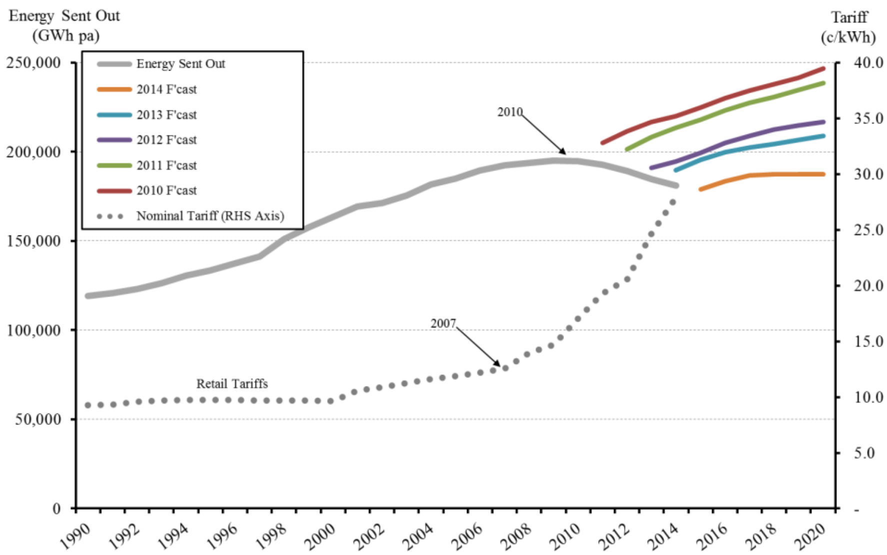
[2] For context, it previously took 23 years for headline residential tariffs to double in a comparatively high inflationary environment.
[3] As Severance (2011, p13) argued *…the unspoken fear of all utility managers is the "Death Spiral Scenario". In this nightmare, a utility commits to build new equipment. However, when electric rates are raised to pay for the new plant, the rate shock moves customers to cut their kWh use. The utility then raises its rates even higher – causing a further spiral as customers cut their use even more... In the final stages of that death spiral, the more affluent customers drastically cut purchases by implementing efficiency and on-site [solar PV] power, but the poorest customers have been unable to finance such measures...*
[4] AGL Energy Ltd partially funded a CSIRO residential smart meter load data study (2012-2013). See Ambrose et al. (2013).

Figure 1: **Energy sent out (1990-2014) & annual load forecasts (2010-2014)**



Source: Simshauser (2014).

2.2 The Southeast Queensland Network

Queensland has a total population of 4.5 million while the Southeast corner of Queensland has a population of 3.05 million. Southeast Queensland incorporates the capital city of Brisbane, the Gold Coast, the Sunshine Coast and the cities of Ipswich and Logan and has 1.36 million network connections including 1.24 million domestic customers and 120,000 Commercial & Industrial customers. The Southeast corner has a sub-tropical climate and housing stock not dissimilar to Southern California – an environment well suited for air-conditioner and rooftop Solar PV units. Table 1 provides Maximum Demand and Energy Demand for the Southeast Queensland Distribution Network. Note that the first year of negative growth occurred a year later than the NEM, in 2010/11.

Table 1: **Southeast Queensland Maximum Demand and Energy Demand 2008/09-2013/14**

Financial Year	Max Demand (MW)	YoY (%)	Energy (GWh)	YoY (%)
2008/09	4,499	8.6	23,175	4.3
2009/10	4,768	6.0	23,365	0.8
2010/11	4,687	-1.7	22,565	-3.4
2011/12	4,447	-5.1	22,144	-1.9
2012/13	4,475	0.6	22,105	-0.2
2013/14	4,373	-2.3	21,787	-1.4

Source: Company Reports

Queensland households are generally high electricity consumers with historic average consumption rates of 7500 kWh per annum. More recently, and following the sharp tariff increases highlighted in Figure 1, annual average consumption has declined to 6100 kWh per annum. Interval meter data used in this research (from 2012/13) averages 6500 kWh.

For much of the 2000s, the key challenge facing the Southeast Queensland distribution network was explosive growth in air-conditioning installations. Household incomes rose sharply from the late-1990s which coincided with rapid declines in the unit cost of air-conditioners. 36.3% of Southeast Queensland households had an air-conditioner in 2001, rising to 75% in 2014.[5] This is

[5] Of these, 33% of households now have three or more air-conditioning units (Simshauser, 2014).

significant because, as Section 2.4 subsequently reveals, the air-conditioner accounts for 17% of household load but 64% of peak demand on ‘critical event’ summer days.

With few exceptions, Southeast Queensland households do not have digital/interval meters. The default tariff is a conventional non-differentiated two-part structure with a uniform fixed rate of 59c per day and a uniform variable charge of 12c/kWh. By implication, households with air-conditioners pay a disproportionately small component of network charges. That is, air-conditioned households are cross-subsidised by non-air-conditioned households – they are beneficiaries of ‘hidden subsidies’.

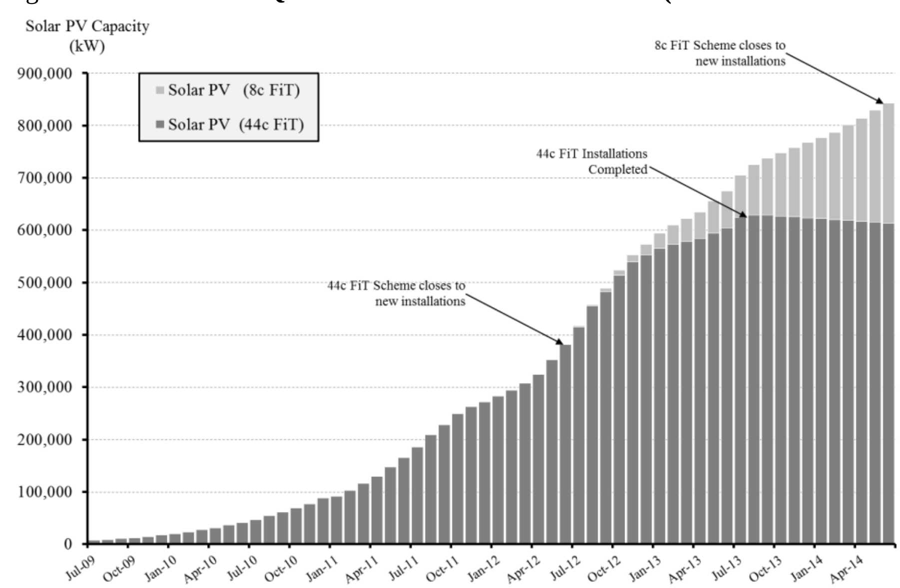
Tariff structures in Southeast Queensland were purposefully varied in an attempt to remedy the extent of hidden subsidies, viz. by removing a declining block structure. At the time, the reason for tariff reform was well communicated and implemented by policymakers with virtual indifference by the voting public. However, as the literature on tariff theory is at pains to highlight, flat and block rate tariffs are crude instruments for dealing with the peak load problem (Houthakker, 1951; Simshauser & Downer, 2012).

2.3 Solar PV Take-up Rates in Southeast Queensland

In 2008, a Federal policy was implemented which provided up-front capital subsidies to households that installed rooftop solar PV. The Federal Government initially funded the subsidy ‘on-balance sheet’ (i.e. forming part of the fiscal balance). However, consumer response to the capital subsidy was overwhelming and the fiscal budget allocation was quickly and significantly overrun. In 2009, instead of cancelling the policy it was redesigned so that funding was shifted to electricity consumers by raising electricity tariffs above the regulated set-point.

In 2010, the then Queensland State Government implemented an overlapping Premium FiT policy which would pay 44c/kWh for solar PV export (compared to a 17c/kWh retail rate) through to the year 2028. The Queensland FiT was also funded by electricity consumers, viz. by artificially raising network tariffs above the regulated set-point. Given combined Federal and State scheme subsidies and sharp tariff increases, the take-up rate of solar PV units in the 4500 MW Southeast Queensland system from 2009-2014 could only be described as breathtaking. This is illustrated in Figure 2.

Figure 2: **Southeast Queensland Solar PV Installations (Jul-2009 to Jun-2014)**

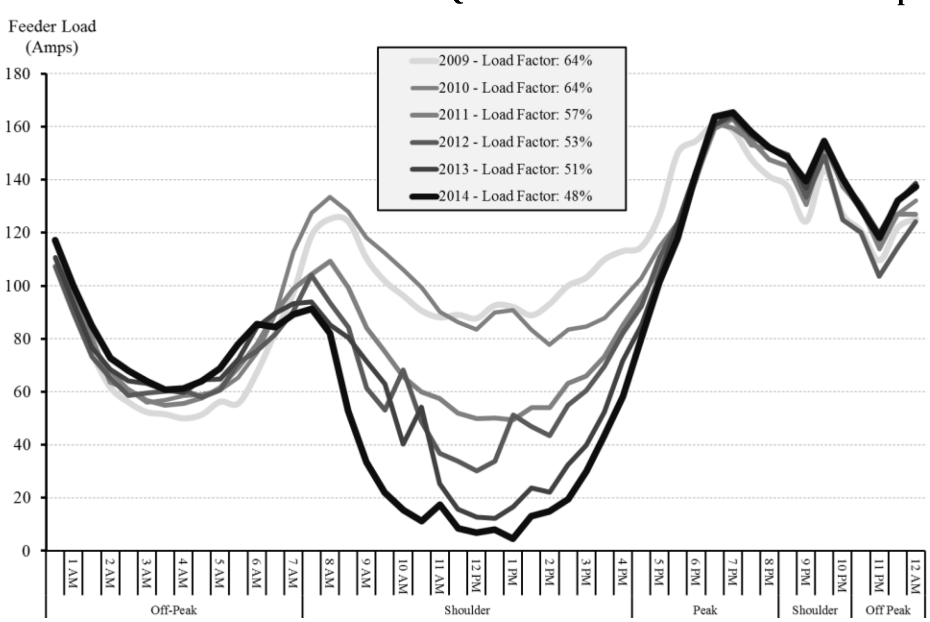


Under intense pressure from the publicly announced annual tariff increases, Queensland reduced its 44c/kWh Premium FiT to 8c/kWh in 2013. Policymakers expected the Premium FiT cut would *take the heat out of the market*, but installations accelerated and by June 2014, solar PV capacity in the 4500 MW network totalled 843.1 MW. Average system size in Southeast Queensland is 3.2 kW, and marginal installations during 2013/14 averaged 4.3kW. The State Government thus closed its FiT to new entrants from July 2014 but of the 1.24 million residential customers in Southeast Queensland, 200,000 had qualified for the 44c FiT through to the year 2028, with a further 65,000 on the 8c FiT.

Nelson et al. (2012) estimated that cumulative Queensland FiT scheme costs (i.e. from 2012-2028) would equate to $2.0 billion. At the time, the solar PV lobby was critical of the assumptions used in the calculations yet by September 2014, cumulative scheme costs had surpassed $500 million, and the Queensland Government now estimates scheme costs will exceed $3.4 billion. This number appears to pale into insignificance by comparison to Germany's cumulative solar subsidy liability of *ca.*€108 billion (Frondel et al. 2013). However, Southeast Queensland is 3% of Germany's population and is therefore comparable.

While the FiT is closed to new customers, incremental solar PV installations at households with an average load shape avoid a disproportionately large component of network charges. Reduction in solar panel prices from ca.$9000/kW in 2009 to ca.$2500/kW in 2013, ongoing Federal subsidies and a network tariff design ill-equipped for such circumstances means that solar PV take-up rates continue at pace at the time of writing. Each month, 3000 new households (*ca.*13,700 kW) install a solar PV unit and avoid *ca.*$360 of network costs per annum (only *ca.*$90 of which can be described as *'efficiently avoided'* as the quantitative analysis in Section 5.2 later reveals). Given post-Federal-subsidy installation costs of *ca.*$5000 for a 3kW system, avoided network charges alone produce a 7.2% return. To clarify the nature of the problem, Figure 3 shows a typical network element in a coastal region of Southeast Queensland during spring. The Feeder services 2631 households, 52 business customers and accommodates 996 solar PV units (a 37% take-up rate) with average installed capacity of 2.84 kW.

Figure 3: **Network element in Southeast Queensland with 37% Solar PV Take-Up Rate**[6]

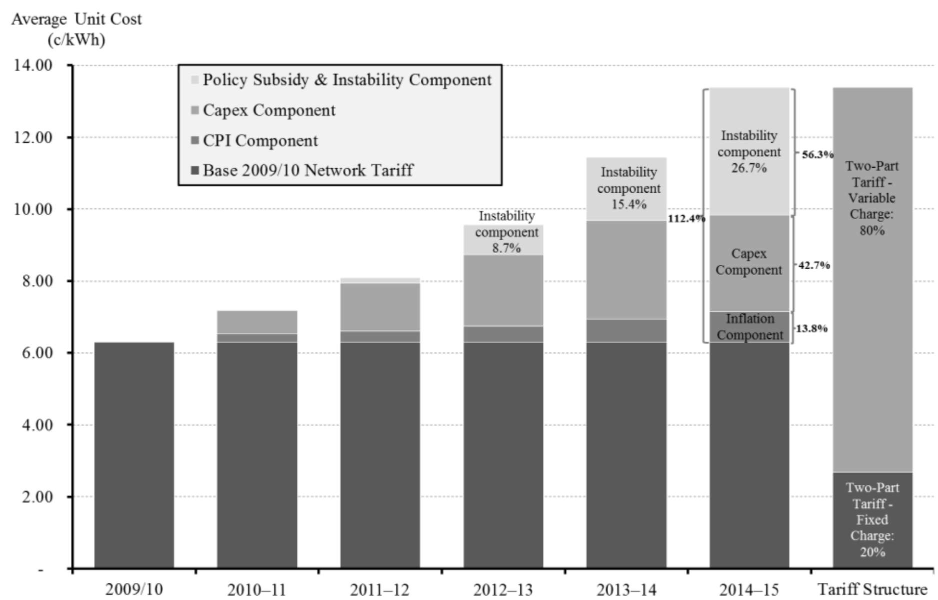


[6] Source: Energex. The load used is not weather corrected, and the day selected is the first October of each year.

Maximum demand is the primary driver of power system capacity. Based on Figure 3 data, network element peak demand (kW) increased +2.8% but energy demand (kWh) contracted by 22.9%. The implied load factor has thus fallen from 64% to 48%. Our principal problem is that network revenues are collected using energy demand (kWh) which is contracting rapidly while periodic demand is not. And unlike the air-conditioner, the flow of kWh through Solar PV units reverses rather than adds to total flows, and so tariff instability has become a serious problem. Ceteris paribus, to hold revenues constant under a conventional two-part tariff, the equivalent variable rate for this particular network element would need to rise by 98.7% between 2009-2014.

Given the conflation of variables, Southeast Queensland network prices have in fact increased by 112.4% between 2009/10 - 2014/15. This is illustrated in Figure 4 – the base rate of 6.3c/kWh is clearly marked in the first block. The second block in Figure 4 is consumer price inflation as measured for Queensland's capital city (Brisbane) and in aggregate accounts for 13.8 percentage points. Capital and operating expenditures to meet projected peak load growth and the tightening of network reliability standards set by government in 2004 accounts for the next 42.7 percentage points. The 'instability component' accounts for the final 56.3 percentage point rise and has been driven by other factors including Solar FiT subsidy costs and volumetric losses. The structure of the network tariff is illustrated by the final bar in Figure 4. In aggregate, the 'instability component' now comprises 26.7% of the overall network tariff.

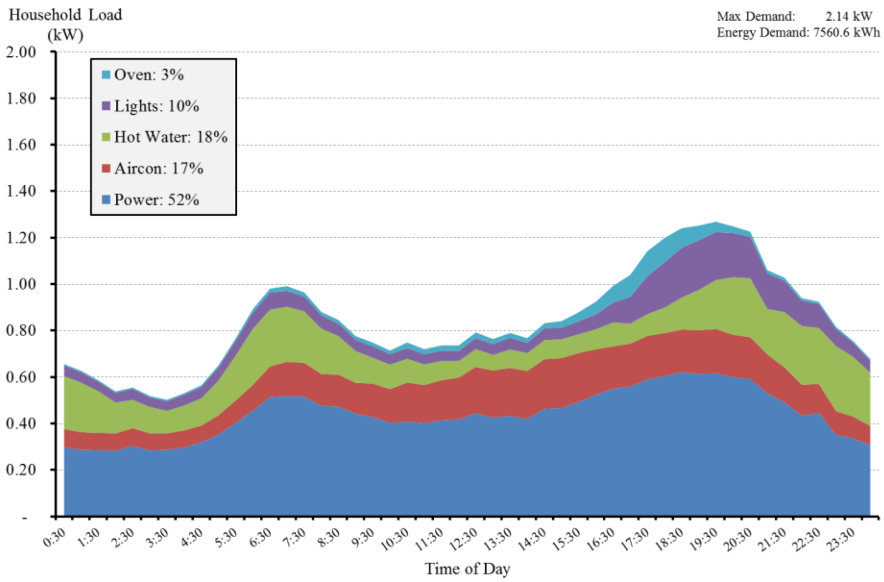
Figure 4: **Network tariff increases and the 'instability component' 2009/10 – 2014/15**



2.4 Household load measured at the customer switchboard circuit level

In order to further quantify instability component drivers, including 'hidden subsidies' streaming amongst household types, it is useful to isolate the composition of household load. During 2012/13, up to six digital meters were applied to each of 69 broadly representative Queensland households at the customer switchboard circuit level, thus separately measuring ½ hour load for 'general power' (e.g. fridge, clothes dryer, washing machines, toaster, kettle, clothes iron, computers, televisions, consoles etc), air-conditioning units, electric hot water systems, household lighting, oven and solar PV units. This load data is illustrated in Figure 5 which presents 52-week 'average weekday' final demand. Notice that general power accounts for 52% of household final demand, electric hot water (18%) and air-conditioning (17%) are next, followed by lighting (10%) and oven use (3%).

Figure 5: **Average weekday household load by appliance grouping**



The same aggregate annual data is presented in Table 2. The columns isolate energy demand (kWh) by switchboard circuit, and by Critical Peak, Peak, Shoulder and Off-Peak periods. Total household demand is 7,560.6 kWh and Critical Peak Maximum Demand is 2.14 kW.[7] Notice that air-conditioning load represents 17% of energy demand, but 64% of Critical Peak Maximum Demand (see last row – 'CP Max. Demand'). The Solar PV column is based on the average 3.2 kW system size with gross unit output totalling 4692.4 kWh. To be clear, not all Solar PV output is consumed by the household. 1,838.8 kWh (39.2%) is 'self-consumed' and the remaining 2,853.5 kWh (60.8%) of solar output is exported to the grid. The final data column defines household 'Net Demand' (i.e. grid-supplied) for those households with a Solar PV unit.

Table 2: **Composition of Household Load in 2012/13**

Period		Power		Air-Cond.		Hot Water		Lights		Oven		Total Demand	Solar PV	Net Demand
Critical Peak (CP)	(kWh)	58.5	41%	45.0	32%	14.7	10%	16.5	12%	7.1	5%	141.8	6.2	135.7
Peak	(kWh)	540.9	52%	140.8	14%	132.0	13%	158.1	15%	69.0	7%	1,040.8	76.0	966.1
Shoulder	(kWh)	2,212.1	53%	824.4	20%	620.5	15%	356.8	9%	137.2	3%	4,151.0	4,158.2	1,800.0
Off-Peak	(kWh)	1,129.4	51%	297.0	13%	589.9	26%	182.1	8%	28.6	1%	2,227.0	452.0	1,805.3
Energy Demand	(kWh)	3,940.9	52%	1,307.2	17%	1,357.0	18%	713.6	9%	241.8	3%	7,560.6	4,692.4	4,707.1
Solar PV Exports	(kWh)												2,853.5	
CP Max. Demand	(kW)	0.68	32%	1.38	64%	0.32	15%	0.24	11%	0.14	6%	2.14	0.44	2.09

While Figure 5 and Table 2 provide a useful overview of average household load there is considerable seasonal variation and the nature of the problem requires that this be examined in detail, especially the impact of air-conditioners and the contribution of Solar PV units during critical events. Seasonal variation in household load is marked as Figures 6 (summer) and Figure 7 (winter) illustrate. Notice in summer, the air-conditioner shifts to 54% of load, while in winter, the hot water system shifts to 25% of load. Average seasonal output from a 3.2 kW Solar PV unit has also been superimposed.

[7] Maximum Demand is measured across critical event days, defined as the 12 hottest and 12 coldest working weekdays each year. The maximum demand result in Table 2 is measured as one standard deviation above the mean (or in simple terms, the average of the top 10 events).

Figure 6: **Average household load - summer weekdays**

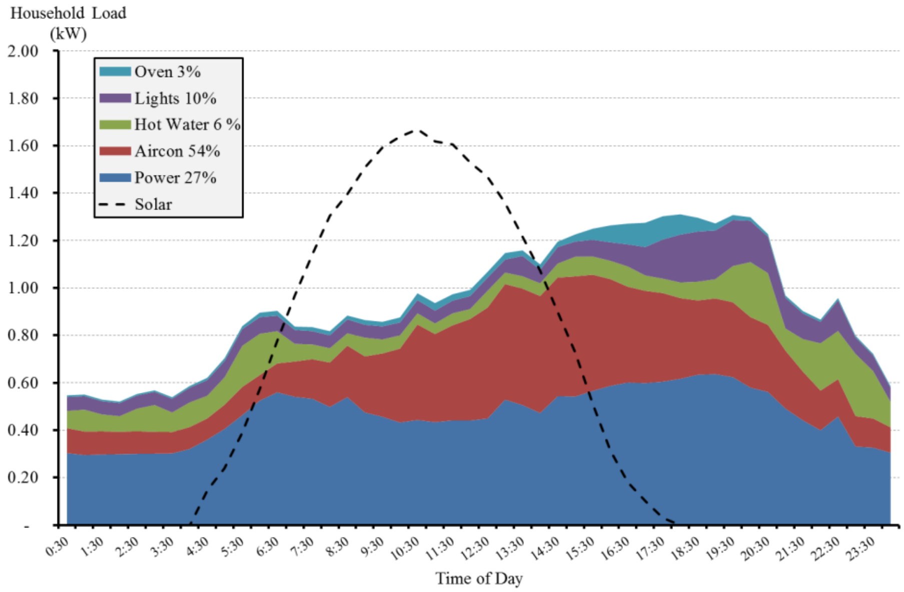
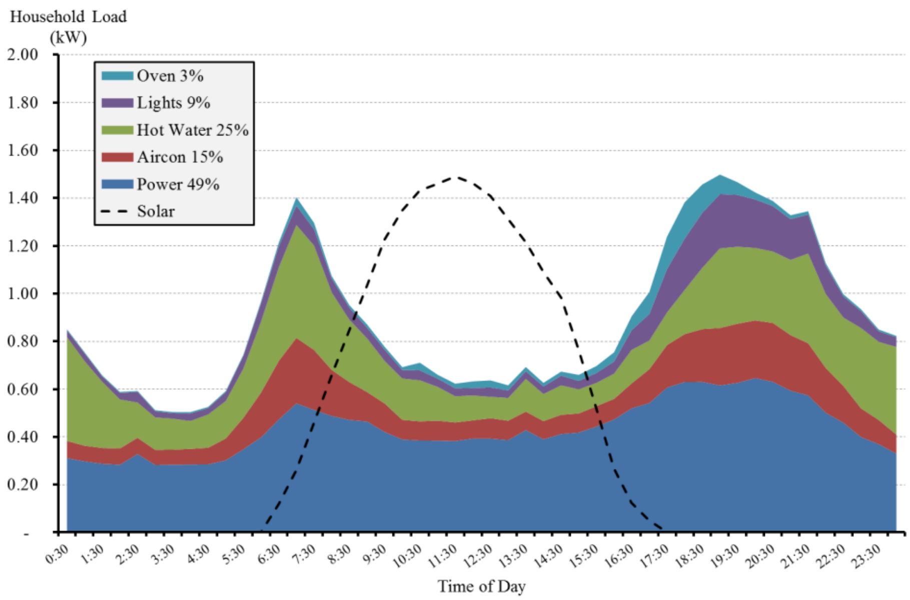


Figure 7: **Average household load – winter weekdays**



Household load on critical event days is illustrated in Figures 8 and 9. These data are important because final demand during these periods defines distribution network resource requirements. Note the change in the y-axis scale.

Figure 8: **Average household load during 'critical event' summer days**

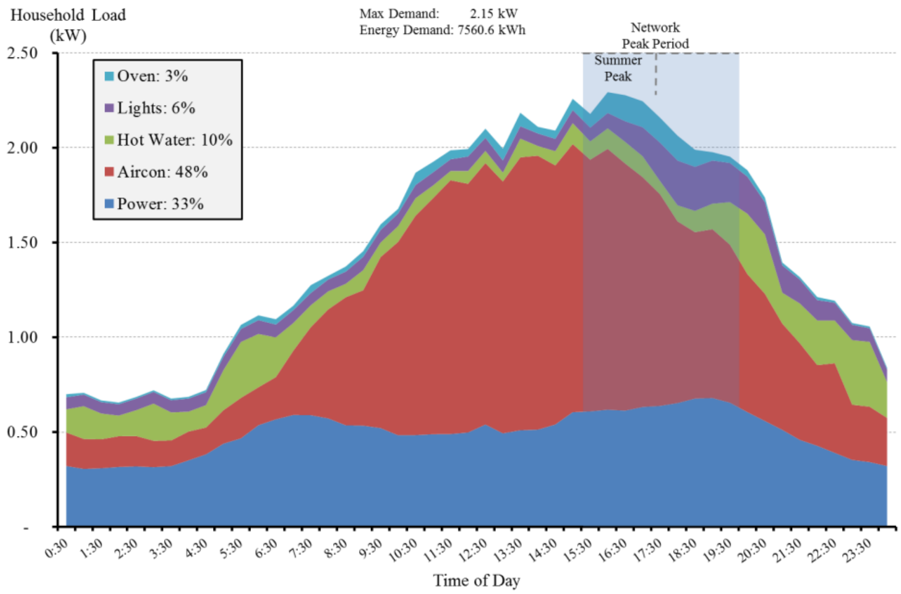
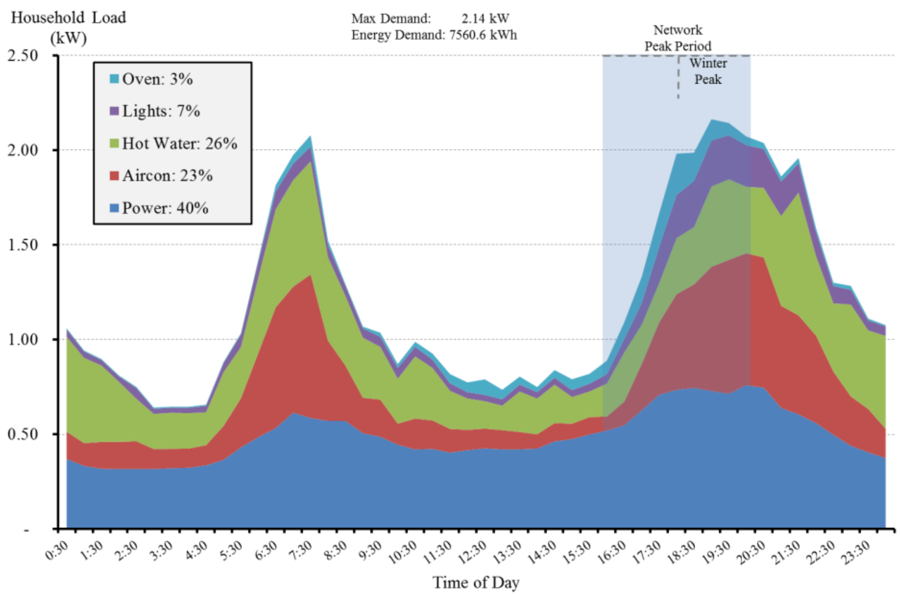


Figure 9: **Average household load during 'critical event' winter days**



Finally, Figures 10 and 11 illustrate Net Demand for households with a Solar PV for the critical summer and critical winter event days.

Figure 10: **Solar PV Household 'net load' during critical event summer days**

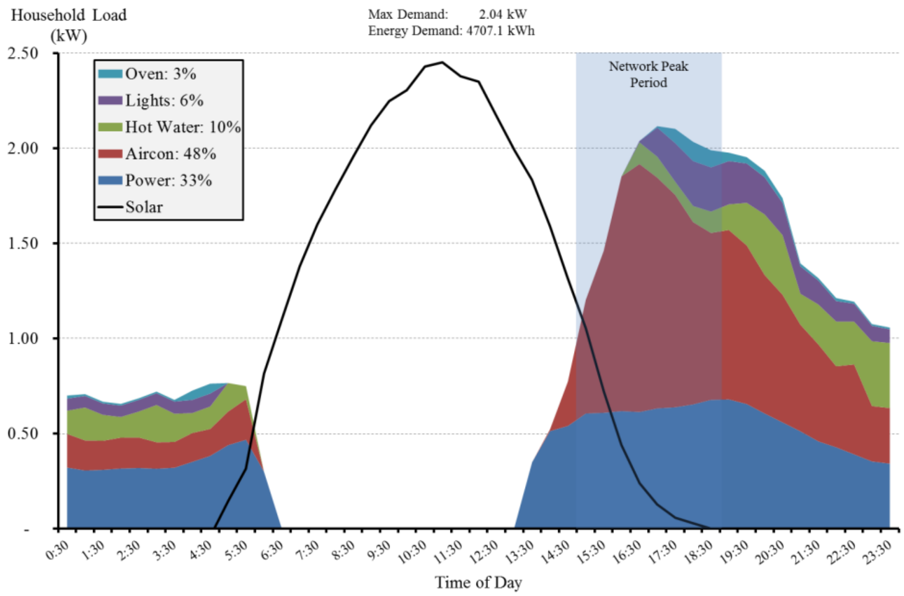
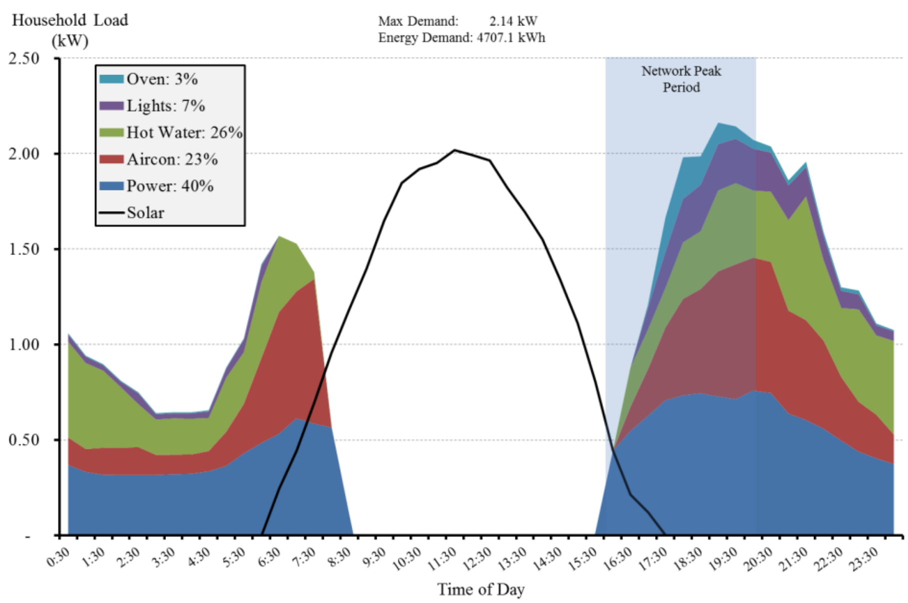


Figure 11: **Solar PV Household 'net load' during critical event winter days**



The nature of the problem being solved can therefore be summarised as follows. The two-part network tariff has a fixed/variable structural split of 20/80. A tariff dominated by the variable rate is well-suited to a high energy demand growth environment, a high inflationary environment, or both. It is not at all well suited to *'modern conditions'* of load contraction because, holding regulated revenues constant, sequential tariff increases will be required. Tariff instability will induce demand response and subsidised solar PV will aggravate load contraction, and hidden subsidies will rise in materiality. Thus the structure of the two-part tariff requires major surgery, which leads us to the review of literature on tariff design.

3. Review of Literature on Optimal Tariff Design

Through discussions with Dr Ahmad Faruqui (among the world's top electricity tariff economists) of *The Brattle Group* it would seem that no jurisdiction has designed, structured and implemented a regulated tariff to deal with non-trivial take-up rates of solar PV with the intended purpose of tariff stability. As Brown & Faruqui (2014, p.13) observe, with such high solar PV take-up rates, *the problem facing utilities and regulators in Australia may be more severe than in other jurisdictions.'* Evidence of an early onset *energy market death spiral* does seem to exist and therefore Southeast Queensland can be considered one of a number of *global flashpoints*. There is little merit in Australian policymakers seeking guidance from other jurisdictions from around the world – none face a challenge any more serious than Southeast Queensland and we are yet to see a jurisdictional policymaker adequately resolve the matter.

The purpose of this survey of the literature is to review the origins of tariff design and the optimal pricing of electricity – literature which spans 120 years of cumulative theoretical and applied knowledge. The principles most relevant to the problem to be solved will thus form the focus. This is important because, as Bonbright et al (1988, p.380) observed *'the practical rate expert would look in vain to any general theory of public utility rates for a scientific method of reaching the socially optimum solution'*. In other words, there is no handbook or formula which prescribes the optimal tariff structure to dynamically solve for all matter of issues faced by a power system.

That said, the nature of the problems in the 2010s are not dissimilar to those faced by the central power systems ('centrals') in the late-1890s, viz. rapidly deteriorating load factors caused by *'short use*[8]*'* electricity consumers and the consequential instability of tariffs, increasingly paid for by *'long use'* consumers. Accordingly, as famous *Electricité de France* economists Boiteux & Stasi (1952, p.92) once noted *'it is comforting to know that the problem being attacked has a determinate answer, even though the solution is not self-evident'*.

While this article is focused on network tariffs, much of the literature which follows focuses on the total system (i.e. covering generation and networks) or generation plant. Readers should not be distracted by the asset under examination because the characteristics most relevant to the problem – viz. high sunk costs, low marginal running costs, sub-additive production costs, sub-additive transaction costs, joint cost causality, zero inventories to smooth production schedules, plant capacity driven by periodic demand and substantial periods of idle capacity – are common to both generation and distribution network assets.

3.1 Background to tariff design

From inception in the 1880s, central electricity supply systems faced two major problems; (1) a cost structure dominated by sunk capacity costs, and (2) a non-storable commodity with periodic demand, later known as 'the peak load problem'. These conditions led to the creation and widespread application of the Two-Part Tariff. Although common in introductory economic textbooks, the structure was designed by power system engineers, and, first applied in the electricity industry. Economists entered the tariff design process from 1911, although the more dominant theoretical and applied contributions would not emerge until 1938-1952.

It is necessary to provide some added context for this review of literature on optimal tariff design because the focus primarily covers the period 1892-1976. This is not to suggest that works from the 1980s onwards somehow lack importance, or relevance. There has indeed been very substantial theoretical and applied work undertaken on optimal tariff design from the 1980s. However, this research focuses on Time-of-Use pricing structures to deal with the peak load

[8] In the early literature by rate engineers, the terms 'short use' and 'long use' were used extensively to describe those households that used electric current for lighting purposes for very short periods (i.e. short use consumers) and other consumers who were more desirable loads (i.e. long use consumers). See for example Hopkinson (1892), Wright (1896), Greene (1896) and Doherty (1900).

problem in high growth environments (see for example Malko & Faruqui, 1983). A rich set of contemporary literature exists on Time-of-Use and Dynamic Pricing under conditions of peak load growth given falling costs of digital metering equipment (Faruqui, 2010a, 2010b; Faruqui & Sergici, 2010, 2013; Faruqui, Sergici & Sharif, 2010; Wood & Faruqui, 2010; Faruqui & Palmer, 2011; Simshauser & Downer, 2012; 2014; Procter, 2013; Nelson & Orton, 2013; Energex & Ergon, 2014; Horowitz & Lave, 2014; Fenwick et al., 2014). In this research, *Time-of-Use* constructs are treated as generally accepted and applied accordingly.

The nature of the present problem, however, has additional dimensions to that of a standard episode of peak load growth and thus *Time-of-Use* structures are necessary but not sufficient. Underlying energy is being progressively *hollowed-out* through technological innovation and peak load is largely stagnant if not marginally declining. These dimensions mean that, as a remedy, *Time-of-Use* prices set within a conventional two-part tariff structure will face natural limits to the restoration of tariff stability, enhanced allocative and distributional efficiency.

3.2 Rate Engineers: identification and equitable allocation of total cost

In the late 19th century when electricity was first marketed as a rival to gas, it was sold like all other commodities – on the basis of a 'variable rate' in line with typical consumer preferences for the pricing of goods and services. However, variable rate tariffs became highly unstable and were pointing historically profitable businesses towards bankruptcy due to a proliferation of 'short use' consumers[9], rising peak load and poor capacity factors. Tariffs based on historic average cost were clearly suboptimal under conditions of a peak load problem as Greene (1896), a manager of a 'central' in the United States, explained:

> *In the Spring of 1889 the use of meters was adopted exclusively. The rate charged was one cent per ampere-hour on 50-volt current, regardless of the amount consumed. Lights were added very rapidly… In 1892, however, a very apparent falling off in the net earnings in proportion to the new capital invested was noticed. It became evident that something was wrong… it was found that only 25 per cent of residence consumers and 55 per cent of other classes used sufficient current to furnish a paying investment… To find that too much business was undermining the stability of the company and jeopardizing its success was startling… (Greene, 1896, pp23-24).*

Simultaneously, Wright (1896, p.44) who managed a 'central' in England observed that:

> *To charge the same amount for the electricity consumed by 100 lamps burning for 4 hours a day as that by 40 lamps burning for one hour per day is manifestly unjust to the 'longer user' as only a quarter of the plant and copper are required… The practice of charging profitable and unprofitable consumers the same price per unit must necessarily have the effect of keeping the average cost and price higher…*

As Hausman and Neufeld (1989, p.83) would explain over 100 years later, *the establishment of a single, uniform price charged to all customers under all conditions would be disastrous*. Both Greene (1896) and Wright (1896) concluded that the optimal pricing structure should be based on the principles first espoused by the famous British electrical-utility engineer and academic, Prof. John Hopkinson in 1883. Hopkinson (1892) identified two broad cost categories of electricity supply, 'standing costs' and 'running costs'. He demonstrated that the ideal electricity tariff would be comprised of a variable energy charge (c/kWh) and a demand charge ($/kW), the latter based on the individual customer's peak load over the prior 12 month period. Of these, the demand charge was demonstrated to be most important because the cost of electricity supply was dominated by sunk capacity costs necessarily incurred to meet periodic demand. Marginal

[9] Peak load was rising rapidly due to demand from consumers using electricity for lighting purposes only.

running costs (i.e. mainly coal) were shown to be trivial in relative terms. Hopkinson (1892), Greene (1896) and Wright (1896) outlined in considerable detail the cost elements of electricity supply, and demonstrated that costs moved with peak demand. Thus, while forming an essential element of introductory microeconomic textbooks, it was electrical engineers who developed the two-part tariff.

Doherty (1900) would later construct a three-part tariff which had the effect of reducing the Demand Charge element and introducing a Fixed Charge based on (non-trivial) capital and operating costs driven by the number of utility customers – such as local connection, meters, meter reading costs, and customer billing. Hopkinson's two-part tariff was adopted by the British electricity industry in the late-1800s, while in 1921 it was applied to the British telephone system, and gas legislation was also modified to allow its application in that industry (Lewis, 1941). In Australia, New Zealand, UK, Canada, Germany, USA the Two-Part Tariff is the dominant utility pricing structure while in France, Italy, Spain, South Korea and Japan the fixed component of the two-part tariff is structured in the form of a Demand Charge.[10] Hledik (2014) notes nine utilities in the US offer residential two-part demand tariffs ('opt-in' basis).

3.3 Energy Economists: periodic demand, marginal cost pricing and consumer incentives

The design and the application of two-part tariffs were imperfect, however. First, industrial consumer metered kW maximum demand was not time-stamped, and so the Demand Charge was applied using individual customer maximum demand.[11] Second, residential customers only had an accumulation meter measuring kWh, not kW. A simple fixed charge was levied instead, typically based on a demographic index (e.g. number of bedrooms, property value).

Economists were absent from the tariff design debate until 1911, when the first published article appeared in the *American Economic Review*. The article would focus on the efficient recovery of the power system's non-trivial capital costs. Clark (1911, p.473-477) noted that relying on a uniform variable rate would be destructive, and while acknowledging that the electricity industry's two-part tariff was superior to the alternatives at the time, he had reservations on the use of individual maximum demand:

> *A uniform rate – so much per kilowatt hour – would be sure to be wrong… only in one type of public utility, viz., electric light and power plants – has this problem [of large capital costs] been generally worked out to anything approaching a clean-cut solution. Now, on the cost or "responsibility" theory, how should this be shared amongst the consumers?*

The general concern of using individual maximum demand was further amplified by Watkins (1921) who produced the first economic text dealing exclusively with electricity pricing. Watkins would primarily focus on how idle capacity in off-peak periods could be better utilised to lower overall costs, and, would argue this potential was the only justification for ornate tariff structures.[12] Lewis (1941, p.250-254) was more direct in defining the efficient solution:

[10] At the time of writing, electricity prices in Australia are structured as conventional two-part tariffs comprising a Fixed Charge (c/day) and a variable Energy Charge (c/kWh). In their survey of jurisdictions, Aspinall et al. (2014) note two-part tariffs also represent the dominant pricing structure in New Zealand, UK, Canada, Germany, USA, Belgium (Three-Part) and Denmark (Four-Part) while in France, Italy, Spain, South Korea and Japan the fixed component of the two-part tariff is more representative of a Demand Charge, through either coincident (metered) peak load, or non-coincident contracted demand (i.e. size of the connection). However, as Brown & Faruqui (2014) note, variable charges dominate the structures.

[11] One implication of this was that the sum of maximum demands would exceed system maximum demand. Hopkinson (1892), aware of this shortcoming, and observed his method would over-recover revenues. This in turn led to extensive probabilistic equations to adjust for demand diversity, and became somewhat of a science itself (Lewis, 1941).

[12] Ironically, this coincided with the first engineering textbook dedicated to the topic of tariff design. Hausman and Neufeld (1989) provide an interesting account of these two books devoted to electricity pricing. Both books were published in 1921 – the first by Hugo Eisenmenger (a Rate Engineer) and second by George Watkins (a Regulatory Economist).

> *…[T]he principles of two-part charging are not widely known or understood… The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak… [T]he true essence of the problem is that marginal costs are greater at the peak than at other times. To put the matter loosely, capital costs are to be allocated exclusively to consumers taking at the peak, and in proportion to the amount each takes at that time…*

The comparative elegance of ornate tariff structures developed by the early Rate Engineers was acknowledged in economics but a philosophical divergence would emerge in terms of implementation. Rate Engineers focused on fully allocating power system cost elements as equitably as possible based on approximate causation, but, largely took the load curve and plant utilisation rates as given. Economists on the other hand would focus on the effect that pricing structures would have on consumer incentives and on how system efficiency and plant utilisation could be enhanced using ornate structures. However, both Rate Engineers and Tariff Economists would be forced to spend an inordinate amount of attention dealing with the problem of efficient recovery of the industry's overwhelming sunk capital costs (Hausman & Neufeld, 1989).[13]

If Rate Engineers can be credited with the first step in maximising system efficiency and welfare through the development of ornate tariff structures, economist Harold Hotelling can be credited with the next significant (albeit incomplete) step towards tariff optimality and welfare maximisation through his famous 1938 article on the application of marginal cost pricing. Hotelling (1938) argued that electricity tariffs should not be set according to average cost, but system marginal running cost, with some component 'capacity charge' applied as demand approaches the limits of supply.[14] However, a key implication was that while revenues from marginal cost pricing would cover variable production costs, they would fall well short of adequately recovering sunk capital costs. Hotelling (1938) argued any shortfall would be more efficiently recovered through the taxation system than by using a uniform average cost tariff.[15]

Coase (1946) acknowledged Hotelling's (1938) solution would be beneficial by increasing the utilisation and efficiency of otherwise idle power system capacity during off-peak periods. However, Coase (1946) observed it was inferior to a multi-part tariff because strict marginal cost pricing would greatly aggravate an already complex peak load problem.

The contribution by Lewis (1941) was important for its practical guidance on the application of ornate tariff structures. Acknowledging metering limitations, he concluded indices used to construct fixed charges (e.g. number of bedrooms) may be more or less reasonable estimates of coincident peak use, and that the two-part tariff probably represented the best method available to allocate capital costs at the time. Furthermore, while Lewis (1941) suggested time-differentiated tariff structures would be superior, it did not follow that the two-part tariff was an undesirable method of recovering capital costs.

The contribution of Lewis (1941) was crucial for other reasons. The clarity he provided as to why ornate structures existed at all remains valid in 2014. Ornate tariff structures found in the electricity supply industry are largely foreign to competitive markets. In the economist's simple model of perfect competition, the ease of entry (and the absence of sub-additive costs) forces all firms to recoup their sunk costs through uniform variable rates. Lewis (1941) examined how pricing structures develop where sunk-capital commitments are large and characterised by asset specificity. He observed that, in such industries, ornate structures such as two-part tariffs, pay-in-advance, take-or-pay contracts, and exclusive contracts are all methods by which firms (in a

[13] Interestingly enough, because electricity storage is costly, it enhanced the prospect of using non-linear pricing and of price discrimination in the pursuit of joint cost recovery, based on load profiles and demand elasticity, respectively.
[14] See also Ng (1987) for an excellent discussion applied to water utilities.
[15] Of course, this assumes a government is willing and able to raise tax for this express purpose.

variety of industries) mitigate the ex-post performance risk of capital-intensive plant characterised by specificity. As Lewis (1941, p267-268) noted of the two-part tariff, *there is nothing in this inherently contrary to the public interest*.

Up until this point, system average cost, (short run) system marginal running cost and long run marginal cost remained irreconcilable and thus the two-part tariff took on a considerable importance in terms of minimising the arbitrary recovery of sunk costs. That is, until a major breakthrough in 1949 by *Electricité de France's* Chief Economist, Marcel Boiteux.

3.4 Reconciling short run and long run marginal cost – Boiteux & Houthakker

Nelson (1964), Williamson (1966), Turvey (1968), Joskow (1976), Bonbright et al. (1988) and others generally ascribe the practical application of marginal cost pricing of electricity to Boiteux (1949) and to Houthakker (1951). Boiteux and Houthakker simultaneously reconciled the evident and non-trivial gap between short and long run marginal cost, and substantially reconciled marginal cost with average total cost. The way in which Boiteux (1949) reconciled short and long run cost, an issue that had bedevilled economists up until this point, was courtesy of a fundamental proposition: given optimal investment policy, when generating capacity is operating at its optimum, price set at marginal cost exactly equals the marginal cost of the marginal plant, which in turn is equal to the average cost of the marginal plant.[16] This of course requires prices be constantly set on a forward looking basis, which in the contemporary Australian utility context is referred to as the 'greenfields' method of analysis:

> *Provided there is an optimal investment policy, short-term pricing is also long-term pricing and there is no longer any contradiction between the two… the need to keep rates steady (which has nothing to do with the marginal theory) makes long-term policy preferable to the instantaneous optimum use of investment; the underlying principle of this is to fix rates equivalent to what the differential costs would be if the plant were constantly at correct capacity, that is, rates equivalent to the development [long run marginal]) costs… Boiteux (1949, p.70-71).*

How this translates into a schedule of optimal prices is in off-peak periods where there is idle capacity, tariffs are set to system marginal running cost. In peak periods, price is set to long run marginal cost. Prices in peak periods therefore reflect system marginal cost plus the marginal cost of capacity *less* expected savings arising from the addition of new plant in off peak periods (see Footnote #16). However as Boiteux would caution on many instances (see Boiteux, 1949, 1956; Boiteux and Stasi, 1952;) while the Fixed Charge ($/kW) appears along with a unit cost (c/kWh) during peak periods, the Fixed Charge makes a contribution to the cost of capacity, but is not equal to the cost of capacity.

The long list of explicit and implicit assumptions underpinning these propositions is difficult to achieve in practice, and so Boiteux (1956) would explain that, as a series of 'absolute general conclusions': (1) prices should be set according to optimal plant-size regardless of the actual successive phases of over- and under-capacity; (2) doing so will result in deficits during 'over-equipment' and excess profits during 'under-equipment' events; and (3) deficits or excess profits

[16] To see how optimal investment policy, short-term and long-term pricing is reconciled for a fleet of power stations under the conditions envisaged by Boiteux (1949), let ξ_i^1 and ξ_i^2 be gross margin in period *i* before and after plant expansion, where price p_i^k applies to each period *i* and let ƅ_i^k be system marginal running cost. Let β_e be the capacity cost of the new plant, and Б_e be the marginal running cost of the new plant, with ƅ_i^1 and ƅ_i^2 being system marginal running costs before and after the addition of new plant. Let Q_i equal demand growth to be serviced in each hour and θ_e be output to be produced by the new plant each hour. Optimal investment will proceed at the margin when the following condition becomes binding:

$$PV\left(\sum_{i=0}^{n}\left(\frac{\xi_i^1+\xi_i^2}{2}\right).Q_i+\left(\frac{\text{ƅ}_i^1+\text{ƅ}_i^2}{2}-\text{Б}_e\right).\theta_i\right)-\beta_e\geq 0 \mid \xi_k=\left(p_i^k-\text{ƅ}_i^k\right)$$

would be further amplified by the extent to which the marginal cost of new entrant plant varied relative to the combined sunk and marginal running costs of the existing fleet.

Boiteux's (1949, 1956) propositions for the optimal pricing of generation would find support with Turvey (1964, 1968) while the application of marginal cost pricing for retail electricity tariffs was developed in Houthakker (1951). Steiner (1957) would later incorporate the peak load pricing principles in the context of Demand Response. Williamson (1966) extended the analysis to include plant indivisibility, which has the effect of creating problems not solvable by investment policy – thus enabling short run benefits of price flexibility to be assessed against Boiteux's (1949) more practical principle of price stability. The principles were further refined for the pricing of generation in Crew & Kleindorfer (1976) and Wenders (1976) in which it was demonstrated that even in off-peak periods, some marginal element of capacity cost should be incorporated due to economic substitution between base and intermediate plant, and intermediate and peaking plant. While much of this research focused on the optimal pricing of generating plant (Boiteux, 1949, Steiner, 1957; Turvey, 1964, Turvey, 1968; Joskow, 1976; Crew & Kleindorfer, 1976; Wenders, 1976), as noted at the outset the principles can be generalised to network tariff design. Boiteux and Stasi (1952), however, would deal specifically with network tariffs, which as Nelson (1964, p.xvii) would later suggest:

> *To volunteer an editorial opinion, the articles by Boiteux (1949) and Boiteux & Stasi (1951) have never been rivalled in the public utility field as analyses of how and why demand affects the allocation of costs – first assuming no uncertainty; then adding a stochastic analysis to a more nearly traditional exercise in comparative statics.*

3.5 Boiteux & Stasi: optimal pricing for distribution networks

In Boiteux & Stasi (1952), the arbitrary character of sunk capital costs was explored along with how they are best allocated for power generation, transmission and the distribution network. As with Boiteux (1949), they would exploit the relationship between optimal expansion costs and existing plant costs when operating at optimal capacity, noting that with this as the basis the arbitrariness of the capacity cost allocation process is largely eliminated.

While the principles of peak load pricing are broadly the same, there is an added complexity associated with distribution network pricing because there is not a single system-wide peak load, unlike generation and transmission plant. Within a distribution network, some elements peak during summer, others in winter. Additionally, some elements will peak during the day, others still in the early evening. How Boiteux & Stasi (1952) approached this more complex area of tariff design commenced with the principle that capacity costs should ideally appear in prices associated with the consumption *responsible* for that capacity, and consequently distinguished between three distinct distribution network asset classes:

1. The collective network, whose capacity depends on the average consumption of customers at the time of the collective peak (Time-of-Use Charges per kWh based on marginal cost principles);
2. The individual connection, which is directly determined by the personal peak of the customer (Fixed Charge)[17]; and
3. The intermediate or 'semi-individual' network, whose capacity depends particularly on the volatility of each customer's consumption in peak periods (Demand Charge, applied at the marginal cost of expansion per kW).

How Demand Tariffs ($/kW) were theoretically prescribed was ingenious. Long run marginal costs were concluded to be driven by three demand parameters; average customer demand,

[17] The individual network costs were prescribed according to contracted demand capacity (i.e. in the form of a fixed charge).

customer demand volatility (i.e. which drives planning margins), and correlation with network peak. Once the maximum demand, the standard deviation of that demand and the coincident peak correlation coefficient were known, responsibility for network facilities could be exactly determined. However, being mindful of the requirement to translate theory into practice, with regard to residential customers Boiteux & Stasi (1952, p.113) explained that, amongst other constraints:

> *…it should be remarked, first of all, that semi-individual networks may have quite clearly different peak times according to the nature of the clientele they supply. But it is hardly possible to allow for this diversity in practice, and it must be assumed, therefore, that all these networks have the same peak time, which coincides with the peak tariff position for the collective network.*

The relevance of reviewing Boiteux (1949), Boiteux & Stasi (1952) in some detail is that, as Turvey (1968) argued, the concepts of the *EdF economists* could be practically (and pragmatically) used by electricity utilities in the determination of consumer tariffs. Turvey (1964) observed on one hand that English-speaking tariff economists mainly addressed their clinical analyses to other economists. The French economists connected with *EdF* on the other hand were focused on principles for practical implementation. This is not to suggest that the French economists lacked academic rigour. As Nelson (1964, p.viii) would explain in considerable detail, Boiteux and the other *EdF* economists were executing ground-breaking theoretical research that could be fully applied in practice, with *EdF* serving as a distinct stimulus for far reaching and more sophisticated economic research than their English-speaking counterparts:

> *As against the Anglo-Saxon tendency to favour implicit theories disguised as a collection of facts, French economic thought runs more in the direction of using a theoretical model as a generalised instrument for polarizing the scatter of events. Paradoxically, this trend is especially marked amongst [EdF's] non-academic economists…*

In 1957, *EdF* would roll-out its *'Tarif Vert'* which applied the generation and network pricing principles outlined above to industrial customers on a nodal basis. Lacking access to digital meter data at the residential level, Boiteux & Stasi (1952) would prescribe a two-part tariff with a variable energy rate, and contracted maximum demand charge – a structure which can be observed in France to this day.[18]

However a residual and non-trivial problem remained. Boiteux (1956) and Turvey (1964) observed that while short and long run marginal costs in a declining cost industry under optimal running conditions had been reconciled, it did not ensure financial equilibrium or revenue adequacy in practice. The reasons for this can be many and varied – plant in-service will almost certainly deviate from optimality, and, past decisions may not align with future requirements. If revenue adequacy forms a constraint, then the optimum structure of tariffs will necessarily be altered. Indeed, as Hausman & Neufeld (1989), Boiteux & Stasi (1952), Turvey (1968) and others explain, optimal electricity tariff design depends quite precisely on the stated objective function. This leads us to *The Bonbright Principles.*

[18] As with the principles applied to generation plant, while Boiteux & Stasi's (1952) residential network price had a fixed (subscription or notional kW) charge and a variable energy charge (c/kWh), the fixed charge did not necessarily correspond to capacity costs, nor did energy charges necessarily correspond to operating costs, despite the apparent *raison d'être* of two part tariffs. Boiteux & Stasi (1952) would observe that the fixed and sunk capacity costs are so important to generation and distribution that a strict application of the principle via pricing would lead to tariffs that were entirely impractical, and therefore, some component of fixed costs is ideally converted through to the variable charge. Although to be perfectly clear, the extent to which this occurs is really a matter of judgement.

3.6 The Bonbright Principles

James Bonbright was an Energy Regulator and Professor of Finance at Columbia University and published his *Principles of Public Utility Rates* in 1961. Danielsen & Kamerschen (1987)[19] would later observe that Bonbright's (1961) seminal works represent one of two great economic treatises of the 20th Century dealing with regulatory principles of public utilities.[20] As with Boiteux (1949, 1956), Houthakker (1951) and Turvey (1964, 1968), Bonbright's (1961) contribution was grounded in theory but with a distinctly applied focus. Not all of the works outlined thus far were well-suited for a residential market. As Turvey (1968, p105) observed[21], the theoretically optimal tariff is complex to implement and complexity costs money – which means the theoretically optimal tariff is unlikely to be optimal in practice (and he added *'consumers probably won't like it much'*).

Why the Bonbright (1961) principles are so important is that they relax another crucial (albeit implicit) assumption underpinning the early economic literature on marginal cost pricing of electricity – perfect capital markets. In the works of Boiteux, Houthakker, Turvey, the utilities in question are government-owned, with pliable budgets and most importantly, the explicit backing of a sovereign nation (credit rating) in which to safely issue debt under all conditions to fund agreed expansion.

As a generalisation, economists that specialise in the field of electricity tariffs rarely interface directly with capital markets. Yet, the electricity industry is the world's most capital-intensive and the third largest sectoral issuer of debt, behind governments and banks, respectively (Simshauser, 2010). This is important. Outcomes from five-year network rate cases need to be thought of as repeated games with the cost-of-capital 'at stake' and this therefore limits the ability to apply strict marginal cost principles. As Crawford (2014) explains in the case of Australian networks, capital-related costs account for 65% of a network tariff (i.e. return on, and return of, capital comprising 49% and 16% of the price, respectively). This is not to suggest that the principles of marginal cost can be ignored in the tariff setting process. On the contrary, the comparison of marginal cost with existing tariffs provides guidance regarding directional change. What matters is that whatever practical steps that may exist are taken, and are taken in the right direction (Turvey, 1968).

Bonbright (1961) would explain that (apart from metering constraints) the biggest issue in tariff design is the inherent conflict between cost-reflectivity and simplicity. While the two volumes of Kahn (1970, 1971) are generally considered more comprehensive, Bonbright (1961, p.288) established what would become widely regarded as the 'accepted criteria' for reasonable tariffs (viz. eight principles for tariff determinations contained in Bonbright (1961), with Bonbright et al. (1988) later adding two more principles) as follows:

1. Simplicity of tariff design
2. Freedom from controversy as to proper interpretation
3. Effectiveness in meeting total revenues
4. Revenue stability

[19] Contained as the prelude in Bonbright et al. (1987).
[20] The other being Alfred Kahn's two volumes published in 1970 and 1971, respectively.
[21] In a somewhat scathing assessment of the theoretical contributions from Steiner (1957) and Williamson (1966) in particular, Turvey (1968, p.105) would observe that …*the impossibility of working out a tariff structure which conforms to the ideal and takes into account all of the problems dealt with in the last section does not matter too much. The cost of applying it would be prohibitive. This point has not, of course, escaped our authors who stare at it boldly in the face and then march straight on in the apparent belief that they have reconciled theoretical virtuosity with praiseworthy realism. The assumption that metering, billing and account-collection costs are unaffected by the complexity of the tariff enables the optimal tariff structure to be conceived by Williamson and others as involving one price for each period. They are, presumably, talking in terms of kilowatt-hours and implicitly assume both that electricity is freely available at the quoted price for all purposes at all times and that the kilowatt-hour is the only relevant electrical quantity. Once we give more than lip service to tariff costs, however, these implicit assumptions must be dropped.*

5. Tariff stability
6. Fairness in the apportionment of sunk costs
7. Avoidance of undue discrimination
8. Static efficiency of rates (i.e. encourage optimum use and minimise waste)
9. Reflection of all externalities
10. Dynamic efficiency of products in response to technological innovation and changing demand-supply conditions

Three of these principles were considered of primary importance, (8) static efficiency, (3) revenue adequacy and (6) the fair allocation of sunk costs. At the time (5) tariff stability was considered 'secondary criteria'.[22]

3.7 Summary

No rational discussion on tariffs is possible without reference to an objective function – that is, what the tariff structure is designed to achieve. Boiteux & Stasi (1952) argued that in practice the term *'tariff policy'* cannot be used to justify a system of prices that oscillates by a factor of three over the business cycle merely because of accidental excess capacity and the pursuit of strictly theoretically elegant pricing structures. That is, with any tariff structure it is necessary to distinguish between essential parameters and secondary variables – that is, the objective of tariff policy is more important than economic elegance:

> *It is out of the question to allow for all the special circumstances which determine customer responsibility for distribution facilities. The object of the tariff-making process is to encourage customers to adopt the pattern of consumption which is least costly for society. But the tariff structure must be simple enough to be understood – otherwise it will be useless – and making it effective must be economical enough for the anticipated gain to society from more rational behaviour by the customer to be clearly greater than the commercial outlays incurred to induce such behaviour… (Boiteux & Stasi, 1952, p.116)*

In 1961, Bonbright considered tariff stability to be of secondary importance. From post-World War II through to the early-2000s, electricity systems experienced sharp increases in load, and these conditions were well suited for tariff structures dominated by the variable charge. However, if the late Prof. Bonbright could observe the instability of tariffs and their distortionary effects on the Southeast Queensland network, he would, in my opinion, conclude it to be of primary importance – just as it was 120 years ago in the era of Hopkinson (1892), Greene (1896), Wright (1896) and Doherty (1900), when the ornate tariff structures were first devised.

For the purposes of this research, I will define the optimal tariff structure as being a Three-Part Demand Tariff. The fixed charge is designed to cover fixed operating costs, a time-of-use variable rate to cover nominal variable costs, and a Demand Charge covering sunk costs based on coincident maximum demand. That is, the primary instrument is a demand tariff (Hopkinson, 19892; Wright, 1896; Greene, 1896) applied on the economic principle of coincident peak demand (Watkins, 1921; Lewis, 1941; Coase, 1946; Boiteux, 1949; Houthakker, 1951; Boiteux & Stasi, 1952), along with a fixed customer charge (Doherty, 1900; Lewis, 1941; Boiteux & Stasi, 1952) and variable rates based on the time-of-use structures (Houthakker, 1951; Faruqui – several citations). To be clear, the existing Two-Part Tariff comprising a uniform fixed charge and uniform variable rate based on average cost is neither optimal nor efficient, and will be equitable

[22] A contemporary set of Rate Criteria was produced by the Demand Response Research Center (Lawrence Berkley National Laboratory) in 2007. Criteria included (1) economic efficiency in consumption and production, (2) equity between customers, and between utility and customers, (3) revenue stability for the utility, (4) Bill stability for the customer, and (5) Customer satisfaction. Regulators tend to put significant weight on avoiding rate shock. For further details, see Faruqui, Hledik & Neenan (2007).

to a given customer segment only by chance. It will, on average, entail substantial intra-segment wealth transfers.

4. Tariff Model and Residential Load Assumptions

The Tariff Model which follows produces a generalised view of customer wealth transfers and system-wide annual tariff revenues based on the existing tariff structure and other alternate designs, subject to the constraint that network revenues are equalised. The underlying objective of the model is to isolate inter-segment consumer wealth transfers. Unlike the Tariff Model contained in Simshauser & Downer (2014) which considered supply chain costs of generation, transmission, distribution and retail, in this version of the Tariff Model only network tariffs are considered. To be clear, in all subsequent results there are no short run changes to network profits despite changes to tariff structures.

4.1 Tariff Model

The purpose and objective of alternate structures tests for stability, and enhanced allocative and distributional efficiency. In the long run, total welfare will be unambiguously enhanced through a more optimal tariff design. However relative to the status quo, within customer segments there will be clear winners and losers. The Tariff Model is structured as follows:

Let H be the set of all households specified in the model.

$$i \in \{1 \dots |H|\} \wedge h_i \in H \tag{1}$$

Let P be the ordered set of all half-hour periods.

$$j \in \{1 \dots |P|\} \wedge p_j \in P \tag{2}$$

Let z be the number of period types. Let I_1 be 'peak' periods from 4pm to 8pm on all working weekdays, excluding periods in I_4. Let I_2 be 'shoulder' periods from 8pm to 10pm on all days, 7am to 4pm on all days, and 4pm to 8pm on non-work days. Let I_3 be 'off-peak' periods from 12am to 7am and 10pm to midnight on all days. Let I_4 be dynamic 'critical-peak' periods from 4pm to 8pm on the 12 working weekdays declared to be 'critical' in winter and in summer. Let I_{sp} be the 'Standard Peak' periods from 4pm to 8pm on all working weekdays. Therefore:

$$P = I_1 \cup I_2 \cup \dots I_z \mid z = 4 \tag{3}$$

$$I_{sp} = I_1 \cup I_4 \tag{4}$$

$$\forall k, m | k \neq m, k \neq sp, m \neq sp : I_k \cap I_m = \{\} \tag{5}$$

Let D be the ordered set of all billing days, and d_k be the ordered set of periods within the billing day b.

$$b \in \{1 \dots |D|\} \wedge d_b \in D \wedge \exists p_j \in d_b \wedge |d_b| = 48 \tag{6}$$

$$\forall k, m | k \neq m, : d_k \cap d_m = \{\} \tag{7}$$

Let φ_{ij} be total household quantity consumed by household h_i in each period p_j. Let pv_{ij} be total solar PV quantity produced by household h_i in each period p_j if any. Let q_{ij} be the grid-supplied metered quantity (i.e. Net Demand) consumed by household h_i in each period p_j.

$$q_{ij} = \sum_{j=1}^{|P|} Max\left[\left(\varphi_{ij} - pv_{ij}\right), 0\right] \quad (8)$$

Let T_f^m be the fixed charge that applies to each day b, and T_v^m be the flat-rate variable charge that applies to quantity consumed q_{ij}. Let t_y^s be the digital meter variable tariff for period type y, and T_v^s be the ordered set time-of-use tariffs:

$$y \in \{1 \dots z\} \wedge t_y^s \in T_v^s \quad (9)$$

Let function $\mathrm{T}_v^s(j)$ give the digital meter tariff for period p_j:

$$\mathrm{T}_v^s(j) = t_k^s, p_j \in I_k \quad (10)$$

Let δ be the Demand Tariff (expressed in \$/kW) and w_{ib} be the calculated Maximum Demand (measured in kW) for household h_i on billing day b for all billing days in I_4 and z_i be the Mean+1StdDev of all w_{ib} for each household h_i.

$$\forall b, i | d_b \cap I_4 \neq \{\}: w_{ib} = Max\left[q_{ij}.2 | p_j \in \{d_b \cap I_4\}\right] \quad (11)$$

$$\forall b, i | d_b \cap I_4 \neq \{\}: z_i = Stdev[w_{ib}] + 1 \quad (12)$$

To establish Total Revenues R_i^m under a mechanical meter regime with the conventional two part tariff comprising daily fixed charge T_f^m and variable energy charge T_v^m

$$R_i^m = \sum_{i=1}^{|H|} \left(T_f^m . |D| + \sum_{j=1}^{|P|} q_{ij} . T_v^m \right) \quad (13)$$

To establish Total Revenues R_i^s using a Demand Tariff δ and Time-of-Use rates T_v^s based on interval meter data:

$$Let\ R_i^s \equiv R_i^m |\ R_i^s = \sum_{i=1}^{|H|} \left(T_f^s . |D| + \sum_{j=1}^{|P|} q_{ij} . \mathrm{T}_v^s(j) + z_i . \delta\right) \quad (14)$$

4.2 **Residential load – key assumptions**

To keep modelling results tractable, four average household types are modelled with the details outlined in Table 3. Households are distinguished by air-conditioner and solar PV units based on Southeast Queensland take-up rates. That is, 75% of the 1.24 million households are assumed to have an air-conditioner (Household B and D), and 261,508 households are assumed to have a solar PV unit (Household C and D. Household A has neither an air-conditioner nor solar PV unit). Note in Table 3 that 90% of solar PV households are assumed to have an air-conditioning unit, and by implication, 10% do not. Household details including customer numbers, maximum demand (kW) and energy demand (kWh), electrical apparatus and annual network costs (at existing Two-Part Tariff rates) are included in Table 3.

Table 3: **Key load assumptions – 1.24 million Southeast Queensland households**

Financial Year 2012/13	Household Configuration (Main Apparatus)			
	Household A	Household B	Household C	Household D
	No air-conditioner	+Air-conditioner	No air-condioner	+Air-conditioner
	No Solar PV	No Solar PV	+3.2 kW Solar PV	+3.2 kW Solar PV
Maximum Demand (kW)	1.41	2.14	1.40	2.09
Critical Peak (kWh)	96.8	141.8	90.7	135.7
Peak (kWh)	900.0	1,040.8	825.8	966.1
Shoulder (kWh)	3,326.6	4,151.0	1,381.5	1,800.0
Off-Peak (kWh)	1,930.0	2,227.0	1,522.1	1,805.3
Total Energy (kWh)	6,253.4	7,560.6	3,820.1	4,707.1
Air-Conditioner (kW)*	0.00	0.74	0.00	0.74
Air-Conditioner (kWh)	0.0	1,307.3	0.0	1,307.3
Solar PV (kW)	0.0	0.0	3.2	3.2
Solar PV (kWh)	0.0	0.0	4,692.4	4,692.4
Solar Exports (kWh)	0.0	0.0	2,259.1	1,838.8
Solar-Consumed (kWh)	0.0	0.0	2,433.4	2,853.6
Customer Numbers	283,849	694,643	26,151	235,357
Customer Share (%)	39.4	96.4	3.6	32.7
Gross Demand (kWh)	6,253.4	7,560.6	6,253.4	7,560.6
Net Demand (kWh)	6,253.4	7,560.6	3,820.0	4,707.0
Base Tariff (Annual Cost)	$1,006.14	$1,171.37	$698.57	$810.69
*Peak load based on one standard deviation above the mean on critical event days.				

While not depicted in Table 3, Total Network Revenue from the household segment is $1,308.3 million. Within this Total Network Revenue for the residential segment is the cost of the Premium FiT. Official data as at 30 June 2014 shows that of the 261,508 households with Solar PV, 200,491 (76.7%) are on the 44c FiT with the remaining 60,017 households on the 8c FiT. Based on the assumptions in Table 3, total FiT costs are therefore $175.1 million.[23] As the FiT subsidy is not funded by State Government but by artificially raising network tariffs above the regulated set-point, the $175.1 million is ostensibly a synthetic tax of 15.5% on the segment. A further $47.3 million[24] (4.2%) in synthetic taxes are collected from residential customers to fund the Federal Government solar subsidy (retail level tariff) and will be incorporated in certain analyses.

5. Network Tariff Design & Tariff Model Results

Comparative tariffs used in this research are set out in Table 4 (Two-Part, Time-of-Use, Three-Part Demand Tariff). In defining the optimal Three-Part Demand Tariff, this research assumes the three relevant network cost categories are fixed costs (20%), variable costs (20%) and sunk costs (60%), respectively. In all cases, the fixed charge is designed to recover fixed costs. It is how variable and sunk costs are priced and recovered that differs.

In an ideal world, the Demand Charge would be set to long run marginal cost of network expansion. In the analysis that follows, the Demand Charge has been purposefully raised above LRMC levels to $261/kW (+41.1%) in order to meet the regulated revenue constraint. If the Demand Tariff was set to LRMC, network regulated revenues would be under-recovered by -$198.8 million (-17.5%). In addition, the requirement to fund Solar PV subsidy costs requires that the Demand Charge be increased further, from $261/kW to $315/kW (+70.3 % above LRMC)[25]. In simultaneous research on this topic, Brown & Faruqui (2014) argued residual costs

[23] The official result for Southeast Queensland was $212 million, and therefore in the analysis that follows the results are understated.
[24] A rate of $5.75/MWh was used and has been drawn from the Queensland Competition Authority's tariff determination for 2013/14. As this number is the SRES scheme cost, it will include some element of subsidies provided to solar hot water systems.
[25] Using a 20% Fixed, 20% Variable and 60% Demand split for Standard Asset Customers in Energex's *Annual Pricing Proposal 2014-15* results in average network charges of 0.59c/day, 3.1c/kWh and $311/kW. This provides a useful check against the modelling results within this article, which were calculated to be 61.7c/day, 2.979c/kWh and $315/kW.

are best recovered through varying the Fixed Charge. This is a valid prescription to the 'residual cost' problem, and one that may well be more durable.

Table 4: **Two-Part, Time-of-Use and Demand Tariff structures**

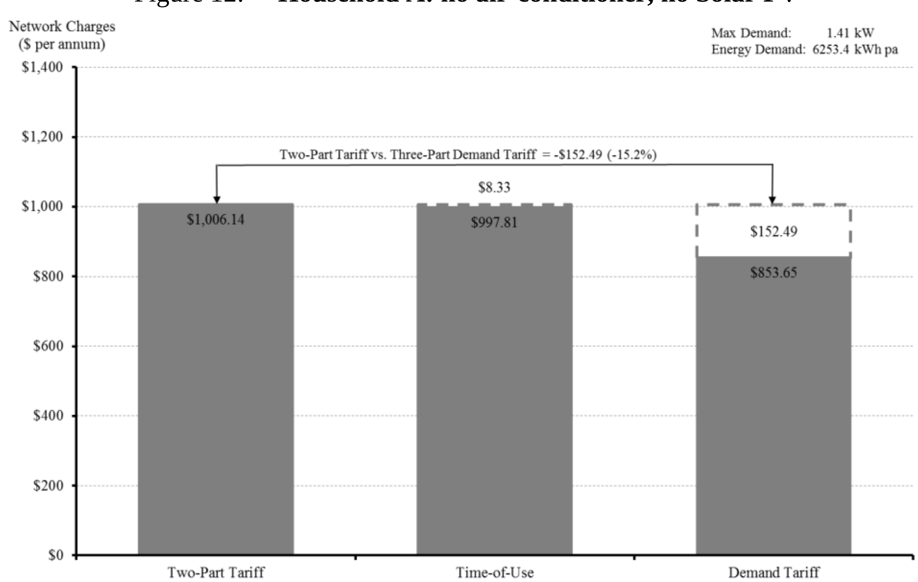
Tariff Structure	Fixed Costs	Sunk Costs	Variable Costs
	20%	60%	20%
Two-Part Tariff	59.1c/day	-- Uniform Variable Rate 12.64c/kWh --	
Time-of-Use Tariff	59.1c/day	-- Peak Rate 26.94c/kWh --	
		-- Shoulder Rate 11.38c/kWh --	
		-- Off-Peak Rate 6.95c/kWh --	
Three-Part Demand	61.7c/day	Demand $261-315/kW*	Critical 11.59c/kWh
Tariff			Peak 6.41c/kWh
			Shoulder 2.71c/kWh
			Off-Peak 1.66c/kWh

*Assumed long run marginal cost (of $215/kva) will under-recover annual revenue requirements

5.2 Two-Part, Time-of-Use and Three-Part Demand Tariffs

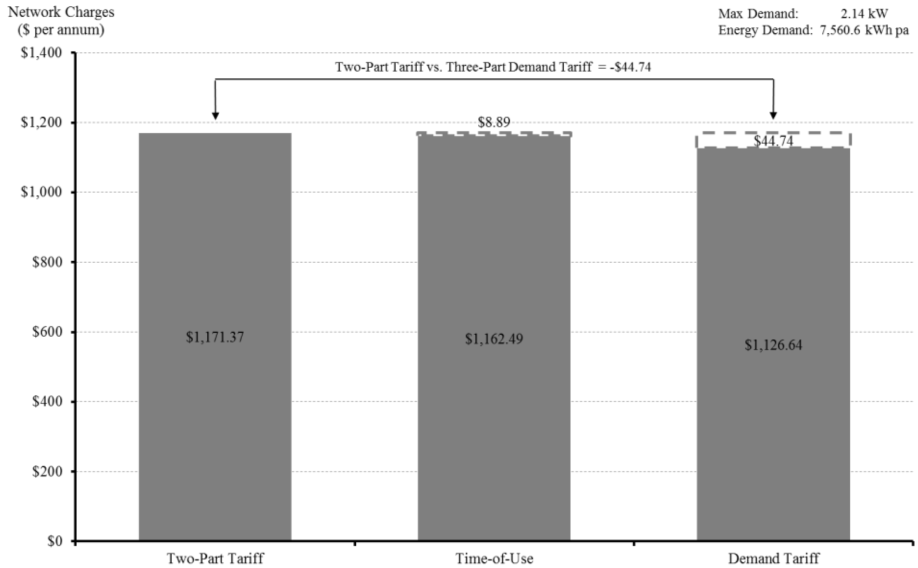
Tariff Model results for Household A (no air-conditioner, no solar PV) are illustrated in Figure 12. Household A's are adversely affected by current tariff structures and bear the cost incidence of *hidden subsidies* associated with air-conditioners and solar PV units. How this is transmitted through network charges is via the dominance of the flat-rate volumetric charge, which means the tariff is *fully loaded* to cover the hidden costs of air-conditioners that intensify periodic demand, and, to cover the volumetric losses of 'hollowed-out load curves' arising from solar PV (which do little to alleviate the periodic demand of average households). Shifting to a Demand Tariff leads to a net reduction in network charges for Household A of -$152.49 per annum (-15.2%).

Figure 12: **Household A: no air-conditioner, no Solar PV**



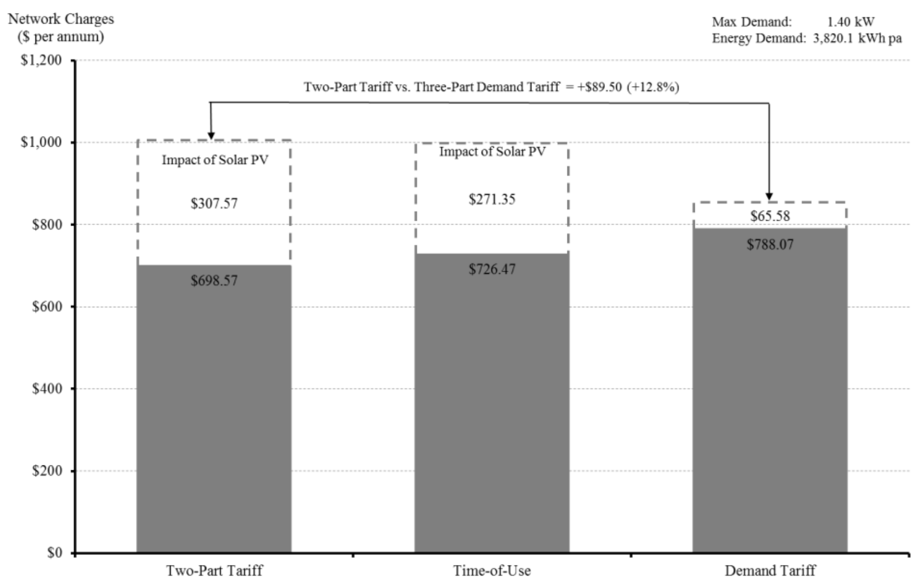
Results for Household B (+air conditioner, no solar PV) are provided in Figure 13. These households are beneficiaries of 'hidden air-conditioner subsidies' but bear the cost incidence of 'hidden solar PV subsidies'. The net effect of facing an optimal tariff structure is that network charges fall by -$44.74 or -3.8% per annum.

Figure 13: **Household B: + air-conditioner, no Solar PV**



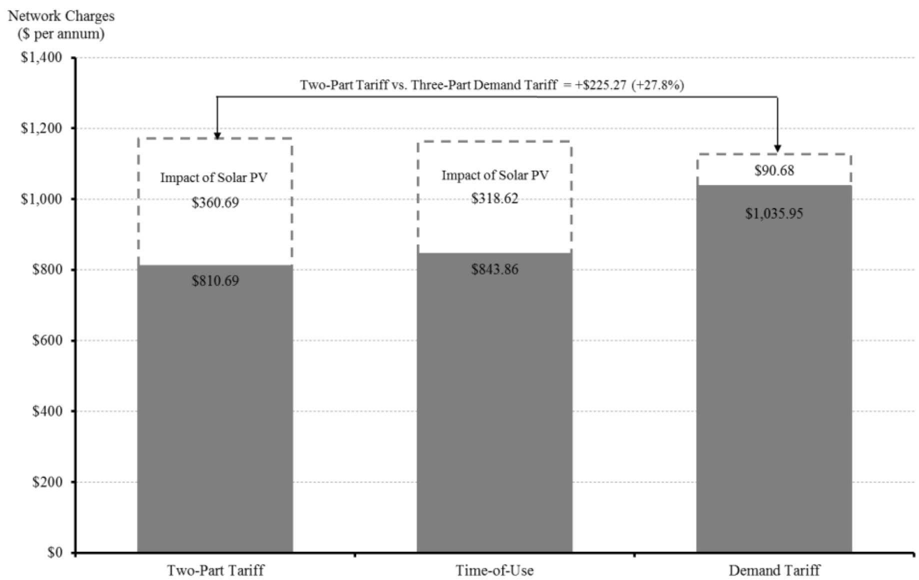
Results for Household C (no air-conditioner, +solar PV) are illustrated in Figure 14 and incorporate a direct comparison with Household A to isolate solar PV impacts. Household C's bear the cost of 'hidden' air-conditioner subsidies but are beneficiaries of hidden solar PV subsidies (and in aggregate are net beneficiaries). Under a Demand Tariff, network charges would rise from $698.57 to $788.07, an increase of +$89.50 (+12.8%) per annum. Most crucially, notice that under the Two-Part Tariff, Household C avoids $307.57 through the addition of a 3.2kW Solar PV (i.e. by comparison to Household A which has an identical load, but no Solar PV unit). However, when facing the Demand Tariff, Household C avoids only $65.58 because its periodic load has been more efficiently priced. Under a Two-Part Tariff, a substantial hidden (i.e. distortionary) incentive therefore exists to install solar PV.

Figure 14: **Household C: no air-conditioner, + Solar PV**



Finally, Household D, the largest beneficiary of hidden subsidies, has both an air-conditioner and solar PV unit. Household D's currently pay $810.69. Network charges rise by +$225.27 (+27.8%) to $1035.95 under a Demand Tariff. As with Household C, under the Two-Part Tariff D-Type households avoid $360.69 through the addition of a 3.2kW Solar PV (i.e. by comparison to Household B which has identical load but no Solar PV). When facing the Demand Tariff, avoided network charges reduce to a more efficient level (-$90.68).

Figure 15: **Household D: +air-conditioner +Solar PV**



5.3 The anatomy of wealth transfers

In Section 5.2, the magnitude of individual household hidden subsidies was revealed. Next, the Tariff Model has been used to 'isolate and unpack' the estimated total flow of hidden wealth transfers with the results provided in Table 5. Note that Households A and C (i.e. no air-conditioner) pay an additional $78.12 per annum whereas Households B and D (i.e. with air-conditioner) avoid $26.04 per annum (see column 'Y'). Gross 'hidden' wealth transfers associated with air-conditioners therefore amount to $24.2 million per annum.

The flow of hidden wealth transfers arising from solar PV units (see column 'Z') from the 978,492 households without a solar unit amounts to $70.3 million in additional network charges (i.e. $71.82 per household). Table 5 notes the total flow of hidden subsidies from both electrical apparatus is $94.5 million.

Table 5: **The anatomy of 'hidden' wealth transfers (air-conditioner and solar PV units)**

Household Type	Customer Numbers	Air-Con. Wealth Transfers	Solar PV Wealth Transfers	Air-Con. Wealth Transfers	Solar PV Wealth Transfers	Net Wealth Transfers
	X	Y	Z	(X x Y)	(X x Z)	(Y + Z).X
A. No Air-Con No PV	283,849	-$78.12	-$74.37	-$22,173,702	-$21,110,749	-$43,284,451
B. Air-Con No PV	694,643	$26.04	-$70.78	$18,088,029	-$49,165,287	-$31,077,259
C. No Air-Con + PV	26,151	-$78.12	$167.62	-$2,042,862	$4,383,358	$2,340,496
D. Air-Con+PV	235,357	$26.04	$199.23	$6,128,535	$46,889,440	$53,017,975
Network Revenue Loss*	-	-	-	-	$19,003,238	$19,003,238
Total/Net	1,240,000			$0	$0	$0
Gross Hidden Wealth Transfers				$24,216,564	$70,276,036	$94,492,600
*Variable rate tariff avoided by households due to Solar PV output						

Total (hidden + explicit) wealth transfers are considerably larger. Table 6 combines all solar PV subsidy sources outlined in Table 5 and Section 4.2, and totals $292.7 million. Total subsidy flows are equivalent to 25.8% of underlying (pre-FiT) network revenues – or $236.07 per household. Note that the Federal policy is collected by energy retailers, however since the tone of default retail tariffs are driven by regulated structures[26] it is helpful for it to be included as a sensitivity to the present analysis.

Table 6: **Hidden & explicit Solar PV subsidies**

Subsidy Source	Gross	Ex-Federal Subsidy
Hidden Solar	$70,276,036	$70,276,036
State Solar FiT	$175,100,894	$175,100,894
Federal Solar Subsidy	$47,349,339	$0
Total Hidden & Explicit	$292,726,269	$245,376,931
Network Revenues	$1,133,247,688	$1,085,898,350
% of Turnover	25.8%	22.6%

The effect of the FiT policy subsidy is to distort the price signal that Household Types *should* face by raising network tariffs substantially (+15.5%)[27] above the regulated set-point. The Federal subsidy adds a further +4.2% in equivalent terms (albeit levied at the retail level).

5.4 **Isolating the value of cumulative wealth transfers**

An optimal tariff structure can correct hidden subsidies and enhance the distributional equity and efficiency of distortionary policy subsidy costs. But to be clear, the only way to eliminate subsidy distortions is to redesign policy funding arrangements. In this section, the Tariff Model is used to isolate and then remove the various subsidy categories (hidden, Federal and State) by tracing the total flow of wealth transfers amongst household types.

Figure 16 presents the cumulative analysis of wealth transfers for Household A (no air-conditioner, no solar PV). The first bar sets out current network charges ($1006.14) and Federal PV subsidy costs (+$35.96), totalling $1042.10. The second bar introduces the Demand Tariff which has the effect of correcting 'hidden subsidies' with charges reducing to $882.55. The third bar assumes the incidence of the Federal PV subsidy is moved back to the Federal Government's fiscal accounts (where it was initially funded). Network charges fall to $853.65.
The final bar assumes the FiT subsidy is moved to the State Government Balance Sheet with total network charges falling to $746.78.[28] In aggregate, under an optimal network tariff and unwinding all policy subsidy costs, Household A faces network charges of $746.78 per annum (-$295.32 or -39.5%). Put another way, Household Type A currently pays +$295.32 (+39.5%) more than they should. Of this, +15.9 percentage points are hidden subsidies (air-conditioner and solar PV), while the remaining +13.5 percentage points relate to explicit funding of Federal and State solar PV policies.

[26] Retailers are not obliged to mirror the network tariff structure, although deviating from it creates revenue risks (i.e. both positive and negative risks) for a competitive retailer.
[27] Combined, the State FiT subsidy of $175.1m and Federal Solar Subsidy of $47.3m represent a 19.6% increase in underlying Network Revenues of $1,133.2m.
[28] Four days before this paper was presented in Germany, the Queensland Government announced that upon successfully leasing their electricity network assets, $3.4 billion of the transaction proceeds would be set aside to fund the FiT liability, thus shifting the cost back to Queensland's fiscal accounts.

Figure 16: **Household A (no air-con, no solar PV) cumulative wealth transfers**

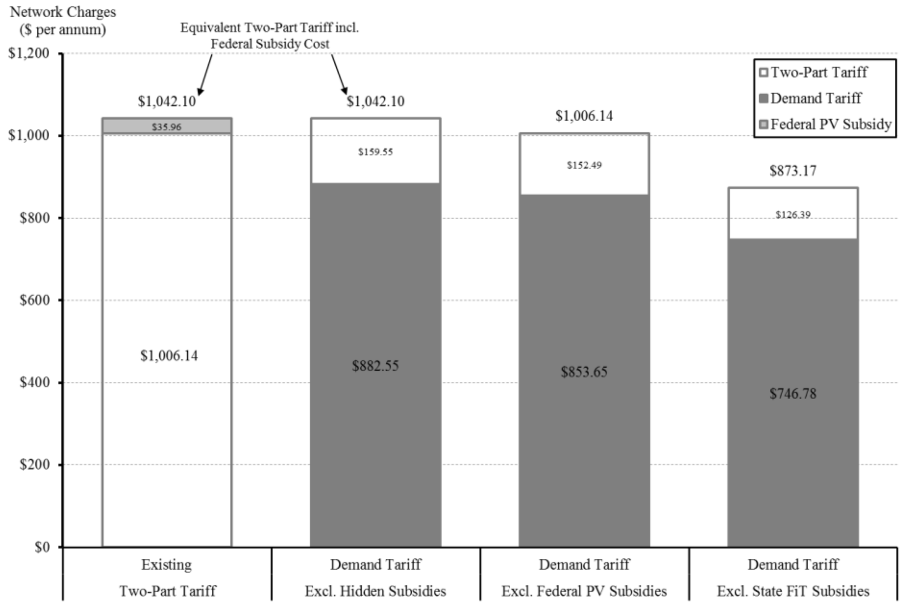


Figure 17 presents the equivalent analysis for Household B. Household Type B currently pays $1,214.85 or +$241.61 (+24.8%) more than they should. Of this, +4.8 percentage points are 'net' hidden subsidies (+air-conditioner and -solar PV), while the remaining +20.0 percentage points relate to explicit funding of the Federal and the State solar PV policies.

Figure 17: **Household B (+ air-con, no solar PV) cumulative wealth transfers**

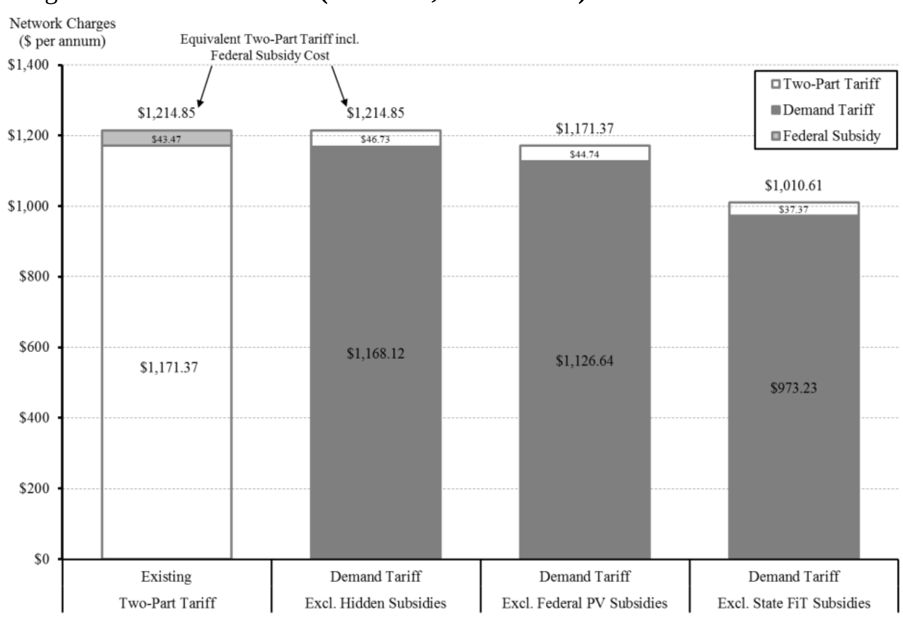


Figure 18 presents the cumulative analysis for Household C. Recall that Household C bears the costs of air-conditioner hidden subsidies but are beneficiaries of hidden solar PV subsidies, with the latter outweighing the former. Consequently, a move to the optimal network tariff means increasing the annual charges from $720.54 to $813.99 (+$93.45 or +13.0%) in the first instance. As subsidy scheme costs are progressively unwound, costs fall to $692.24 (-$28.30 or -3.9%).

Figure 18: **Household C (no air-con, +solar PV) cumulative wealth transfers**

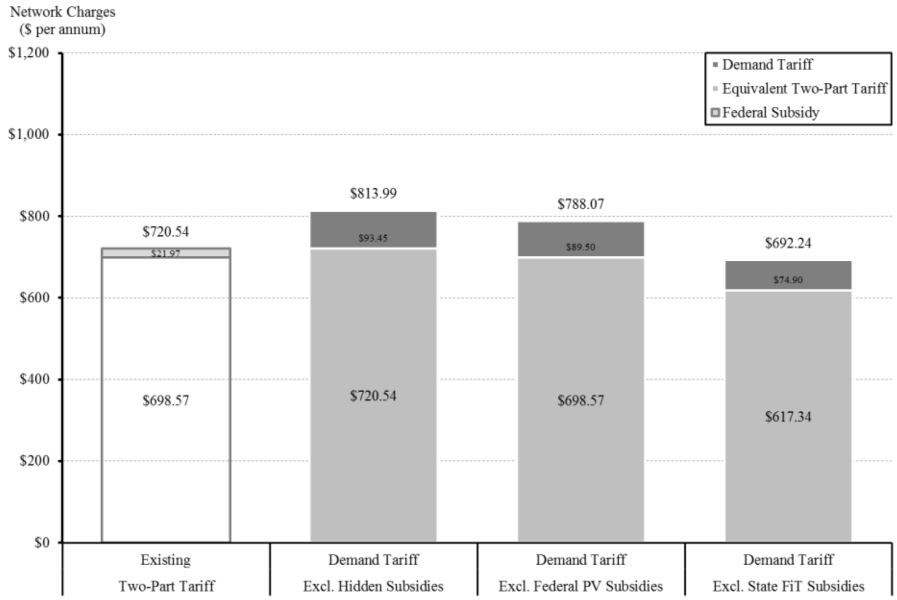
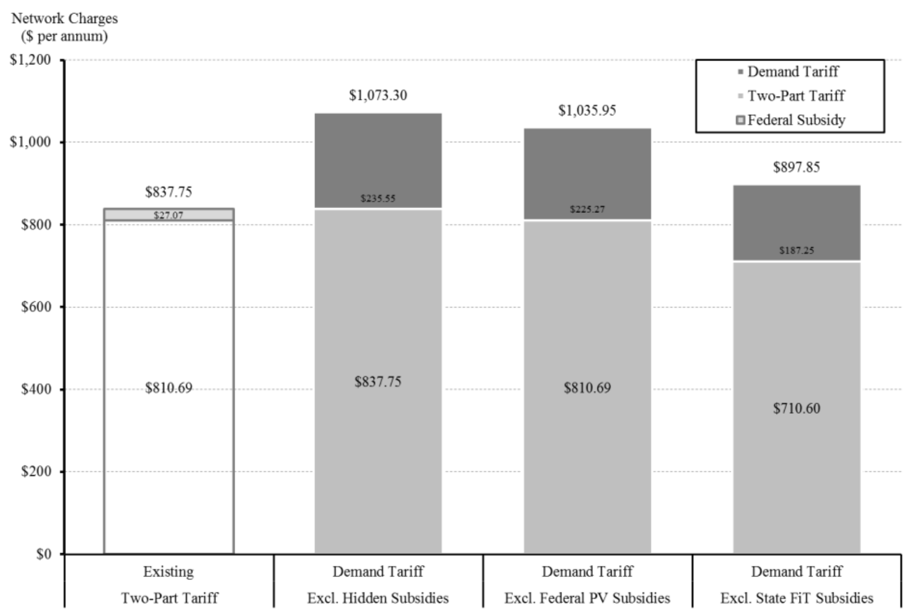


Figure 19 presents the cumulative analysis for Household D, households which receive hidden air-conditioner and solar PV subsidies. Optimal network tariffs increase the charges facing these households from $837.75 to $1073.30 (+$235.55 or +28.1%) in the first instance. As the explicit subsidy scheme costs are progressively unwound, network charges land at $897.85 (+$60.10).

Figure 19: **Household D (+air-con +solar PV) cumulative wealth transfers**



The point worth noting in this latter analysis is that Household Type D currently pay less than a cost-reflective tariff even after unwinding the costs of subsidy schemes.

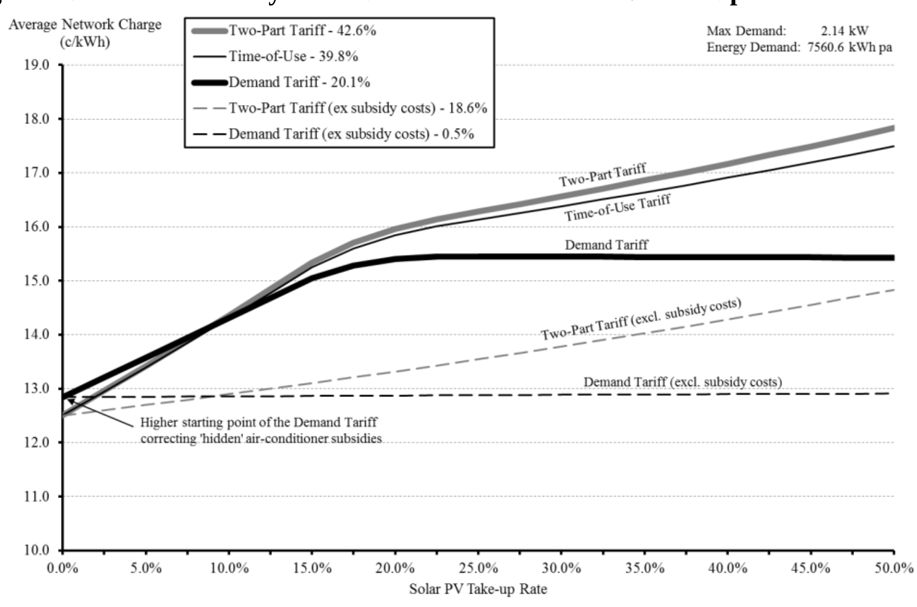
6. Network tariff stability

The analysis set out in Section 5 demonstrates optimal network tariffs are capable of unwinding hidden subsidies and in this sense better meet a criteria of ‘fairness’. We know from the Review of Literature that a Three-Part Demand Tariff with the demand charge set at LRMC meets the principles of economic efficiency. Deliberately raising the Demand Charge above LRMC meets the regulated revenue requirement. But does this tariff meet the 'stability' criteria? To specifically address this inquiry, the Tariff Model has been used to analyse progressive Solar PV Take-up Rates, from 0% to 50% of the residential customer base. The modelling has been structured to reflect the progression of FiT policy arrangements in Southeast Queensland and the eventual closure of the 44c FiT scheme.[29]

Bunzl (2010, p.8-9) argued that policy settings should be designed in light of Rawls' famous phrase, *'from behind the veil of ignorance'*. That is, the policymaker should not know whether they are rich or poor, renter or owner, and so on. And in doing so, *'I would do well to decide with an eye on making the worst-case alternative… I ought to focus on being both poor and having a peakier load than average.'* With this in mind, the analysis that follows focuses on the behaviour of the three pricing systems (Two-Part, Time-of-Use, Demand Tariff) for households without PV systems, with and without air-conditioning units (i.e. Households A and B) because these are the households with the greatest adverse exposure to wealth transfers.

The analysis of tariff instability for Household Type B is presented in Figure 20, where the y-axis measures the overall average rate paid under the various pricing systems holding load constant. The x-axis measures the corresponding Solar PV Take-up Rate of the entire 1.24 million residential customers in Southeast Queensland. Note that tariff stability is measured with, and without, explicit solar subsidy costs.

Figure 20: **Tariff Stability for Household B with Solar PV Take-up Rates from 0-50%**

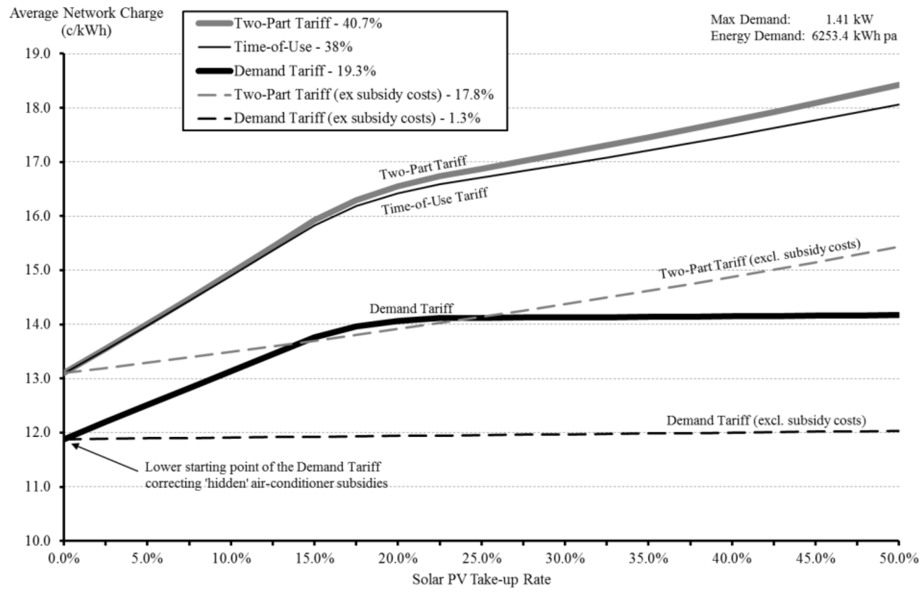


There are four key points arising from Figure 20. First, the Two-Part Tariff is the most volatile pricing system, with total 'rate variation' of +/-42.6% for solar PV take-up rates of 0-50%. Second, a Time-of-Use Tariff is largely ineffective in moderating volatility, rising by +/-39.8%. Third, the Demand Tariff (excl. subsidy costs) is almost completely stable under the take-up rate envelope modelled, rising by just +0.5%. And finally, within the solar PV subsidy range experienced by Southeast Queensland (i.e. 21% take-up rates before the FiT scheme was closed), while the Demand Tariff cannot eliminate price instability it is more successful in moderating the degree of tariff instability (i.e. +/-20.1% for the Demand Tariff compared to +/-29.1% for the Two-Part Tariff).

[29] As Figures 20 and 21 indicate, this is clearly important to capture in modelling.

Equivalent results for Household A are presented in Figure 21, and the same general findings apply – the Demand Tariff is a more stable pricing system under the conditions that exist in Southeast Queensland.

Figure 21: **Tariff Stability for Household A with Solar PV Take-up Rates from 0-50%**



7. Policy Implications and concluding remarks

The problem being solved is a distribution network characterised by regulated revenues, a Two-Part Tariff dominated by the variable charge, contracting energy demand and an associated price spiral amplified by a non-trivial take-up of solar PV units. In summary, the Two-Part Tariff structure has become unstable. While the analysis in this article focused on the conditions in Southeast Queensland, the causes and implications can be generalised to any jurisdiction displaying these characteristics (e.g. South Australia, Western Australia, California, Arizona, Kansas, Idaho, South Africa, Brazil etc).

In analysing Southeast Queensland, network tariffs were separated into four components; base, consumer price inflation, capital expenditure and an ‘instability component’. The latter was found to dominate tariff movements over the past 3-4 years and now comprises more than ¼ of the total network price. This suggests that the Two-Part Tariff is no longer fit for purpose Using interval meter data at the customer switchboard circuit level, modelling results revealed variable energy charges produce hidden subsidies for households with air-conditioners, and for households with solar PV units. The extent of hidden wealth transfers was found to be material – representing 8.7% of network revenues. When explicit solar PV policy subsidies were added, wealth transfers amounted to 22.6% of network revenues.

The Review of Literature surveyed the history of electricity tariff theory, which is a special branch of welfare economics. Between 1892-1900, ‘Rate Engineers’ pioneered ornate tariff structures comprising a low variable rate (c/kWh), a high demand charge ($/kW), and later, a fixed charge reflecting customer costs after discovering a uniform variable rate was unstable given periodic demand. From 1911, economists would refine the principles to be applied to maximise welfare, static efficiency and distributional equity with the major work undertaken from 1938-1952, viz. peak load pricing based on coincident maximum demand, and pricing at marginal cost.

Electricité de France received special honours for its ground-breaking work in reconciling economic theory with practice – Boiteux (1949) and virtually simultaneously, Houthakker (1951) in Great Britain, would reconcile the dilemma arising from the apparent gap between short and long run marginal cost. That said, *EdF*'s famous Chief Economist retained reservations on reconciling marginal cost pricing with average total cost.[30] While Hotelling (1938), Lewis (1941), Boiteux (1949, 1956), Houthakker (1951) and Turvey (1964, 1968) can be collectively credited for progressively initiating the principles of tariff design and peak load pricing, if there is a criticism that can be levelled at their combined works, it is their implicit assumption of perfect capital markets. In France and in Great Britain, power systems were government-owned and had the implicit financial backing of a sovereign nation. Bonbright (1961), a Professor of Finance and an Energy Regulator presiding over privately-owned power systems in the United States, understood the implications of applying economic theory when sovereign governments were *not* funding a power system – specifically, that sunk costs were not as *pliable* as economic theory suggests. The Bonbright Principles (1961) thus accounted for the fact that capital-related costs typically drive 65% of final tariffs, and that the incidence of those costs involve a repeated game of five-year rate cases.

Tariffs should be guided by economic theory but application must be moderated according to the harsh realities of real-world corporate finance and public policy objectives. The Bonbright Principles can be condensed down to static efficiency, simplicity and revenue adequacy. In high growth, high inflationary environments, these were ideal.

Stability was considered of 'secondary importance' because rate instability was rarely observed in high growth environments. In this article, I have argued that in a low inflation, low energy demand growth environment with technological disruption and a regulated revenue constraint, network tariff stability must be added to primary criteria. And, given the conditions that exist in Southeast Queensland, tariff stability for consumers must be a prime consideration. Figures 20 and 21 provided quantitative evidence as to why this is the case; the Two-Part Tariff increases on a linear basis[31] with solar PV take-up rates. The primary purpose of this article, therefore, was to analyse the stability or *behaviour* of existing Two-Part Tariffs along with two other valid tariff designs (Time-of-Use, Three-Part Demand Tariff) with a focus on allocative efficiency and fairness.

The three prominent tariff designs were applied to four representative Household Types using granular digital-meter data measured at the customer switchboard circuit level to isolate the impact of air-conditioners and solar PV units. These two electrical apparatus are widely suspected to be mispriced under existing Two-Part Tariffs. The quantitative analysis in this article provided insight as to the extent of that mispricing.[32]

With stability being the prime focus, the Demand Tariff was found to be superior. On static efficiency and associated wealth transfers under the existing Two-Part Tariff, the air-conditioner – long suspected of being heavily subsidised – was evident. But the magnitude of hidden subsidies for the average air-conditioned household was surprisingly modest at $26.04 per annum. Evidently, the appliance cost is substantially (but not fully) recovered given the heavy use of air-conditioners throughout the year in Queensland. That said, the hidden subsidy paid by

[30] Boiteux's reservation here was due to the fact that *EdF's* had a stated profit objective function of 7% return per annum

[31] A first approximation was found to be: Variable Rate = 12.64c/kWh + (Solar Take-up Rate % x 4.63676c/kWh). This holds for any rate of Solar Take-up between 0-50%.

[32] The primary insight arising out of the Simshauser & Downer (2014) study of 160,000 households in Victoria was the extent of load shape variation amongst different household cohorts, and within those cohorts, the extent of load shape dispersion. Clearly, the analysis in this article lacks load variation and dispersion. That said, the underlying load shapes and solar PV traces provide suitable averages from which further analysis can be undertaken.

non-air-conditioned households represented almost 10% of their optimal network charge.[33] Additionally, large households where peak loads no doubt run from 4-8+ kW, were not examined. If they were, dramatically larger wealth transfers would be revealed.[34]

One of the more important findings in this research was the combined hidden subsidy received by households with an air-conditioner and a solar PV unit. The air-conditioner adds to critical peak demand, and solar PV does little to alleviate it. Such households were found to be beneficiaries of a -28.1% hidden subsidy. Households in financial hardship are unlikely to dominate this consumer segment as Hledik (2014) explains. On the contrary, based on the results in Simshauser & Downer (2014), they are almost certainly bearing the cost incidence of hidden subsidies. Ironically, Federal and State solar PV policies then compound the wealth transfers. The most sobering finding in this research was network charges for households without an air-conditioner and without a solar PV unit – total network charges were found to be +$295 or +39.5% higher than they should be.

Even if demand tariffs are implemented, modelling results revealed network prices are more volatile than they need be due to the requirement to fund solar PV policy subsidies. There can be sound reasons for subsidising emerging technologies – but using electricity consumption (kWh) as the variable to collect a synthetic tax to fund policy initiatives (of any kind) is regressive, and amplifies the price spiral. The requirement for network (and retail) businesses to raise synthetic taxes to fund politically popular policies by artificially raising electricity tariffs is clearly a significant problem, and above all, unfair. The dominant component of aggregate wealth transfers was found to be policy subsidy-related. And, as Figures 20 and 21 make clear, only when policy subsidies cease can tariff trajectories stabilise. From a policy perspective, solar PV subsidies should therefore be funded 'on government balance sheet'. If State and Federal schemes cannot be taken on-balance sheet, they should be closed to new entrants. Although as Helm (2014) explains, from a political perspective, removing subsidy schemes is evidently much harder than introducing them.

A logical question is, why are demand tariffs not widely used at the residential level? The lack of digital meters is a constraint (albeit one which could be overcome through a series 'deemed household load profiles' with an option to self-install a digital meter for more accurate reads). And historically, the Two-Part Tariff combined with block-rate structures essentially served as a proxy.[35] Variable prices are what consumers are familiar with, and therefore have wide acceptance. Brown & Faruqui (2014) observe that historically, the variable rate was considered a 'fair' mechanism for recovering residual costs whereas using a fixed charge was considered *too blunt an instrument* given its proportional impact on small consumers (i.e. pensioners). Besides which, the price elasticity of household electricity demand has historically been low and thus using variable rates was non-distortionary. Energy efficient appliances and solar PV units have annihilated this proposition.

Network tariff increases in Southeast Queensland have been very substantial and amplified – considerably – by the costs of solar PV policy subsidies. Network charges based on a uniform variable rate are helpful from a customer familiarity perspective, but violate the most widely accepted canon of 'fair pricing' – viz. pricing at cost (Bonbright, 1961). Using variable rates as the primary driver of network tariffs is driving inefficiencies not previously seen in the electricity industry – a situation that has changed within the last 3-4 years. Subsidised solar PV has essentially changed the price elasticity of energy demand. When deployed, solar PV units result

[33] Recall from Table 5 that hidden air-conditioning wealth transfers were -$78.12 and optimal network charges for Household A were $853.65 under the Demand Tariff.
[34] Brown and Faruqui (2014) consider such cases.
[35] Declining Block Tariffs were often used to mirror a demand charge (see Bonbright et al, 1988). However, as household maximum demand increased through air-conditioning units, it was thought that an Inclining Block Tariff may better replicate a Demand Tariff.

in a non-trivial reduction in (grid-supplied) household electrical demand. Calculations for Households C and D indicate load reductions of 37.7 - 38.9%. Yet, critical event maximum demand of Household C and D reduced by just 0.6 - 2.4%. So while the rationale behind demand tariffs is complex, as a first approximation the structure better reflects the two main cost elements of electricity; capacity and energy.

From the perspective of fairness, modelled results of the existing Two-Part Tariff in Southeast Queensland were stark. The Three-Part Demand Tariff, structured as a fixed charge (20% of revenues), demand charge (60% of revenues) and variable energy charge (20% of revenues) produced a substantially more efficient outcome, holding regulated network revenues constant. Under this design, households face costs more commensurate with their use of the network.

Variable energy charges (20% of revenue) were structured on the basis of dynamic Time-of-Use rates. While this adds to economic efficiency, it adds complexity and in this instance a uniform variable rate will lose little in terms of efficiency. The dominance of the demand charge captures the cost and incidence of peak loads – at least for average Household Types presented in this article.[36] To change default pricing structures from a simple Two-Part Tariff to a more ornate Three-Part Demand Tariff will of course produce winners and losers. But this is a question of ‘how to transition’, not a reason to accept an unfair status quo.

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[36] While not presented, results from the Tariff Model indicated that changing the variable charge from ‘dynamic TOU’ to a ‘uniform rate’ shifted network costs by just +/-1.1% for each Household Type. Households with higher/lower load factors than average would experience considerably greater variation.

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9. Declaration by the author

The author of this working paper is employed by AGL Energy Ltd. While the working paper represents the views of the author, the research was undertaken to inform AGL Energy's public position in relation to electricity market reform.

Earlier drafts of the paper were reviewed by the AGL Applied Economic and Policy Research Council and comments made by Council members were gratefully received by the author. The role of the Council is not to endorse working papers but provide constructive review. All opinions, statements, errors and omissions are those of the author and should not in any way be attributed to the Council and its members. Members of the Council are Elizabeth Nosworthy, the Hon. Patrick Conlon, Prof. Christine Smith, Prof. Stephen Gray, Prof. Judith McNeill, Keith Orchison, Tony Brinker and Carlo Botto.