On the inequity of flat-rate electricity tariffs

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Abstract
Proposals to reform default ‘flat-rate’ electricity tariffs are rarely met with enthusiasm by consumer groups or policymakers because they produce winners and losers. Proposals to initiate time-of-use rates will be met with cautious interest if the basis of customer participation is ‘opt-in’ but adverse selection is clearly more than a theoretical possibility. Existing flat-rate tariff structures, by definition, result in half the consumer base paying too much while the other half are cross-subsidised. Using the smart meter data of 160,000 residential customers from the Victorian region of Australia’s National Electricity Market, our tariff model reveals that households in financial hardship are the most adversely affected from existing flat-rate structures. Even after network tariff rebalancing, Hardship and Concession & Pensioner Households are, on average, beneficiaries of more cost-reflective tariff structures once Demand Response is accounted for.

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JEL Codes: D61, L94, L11 and Q40.

1. Introduction
In Australia, residential electricity prices are structured as conventional two-part tariffs comprising a fixed charge and a ‘flat-rate’ variable energy charge. The origin of the two-part tariff can be traced back to the electricity supply industry in 1892. The design by Hopkinson (1892) reflected the atypical cost characteristics of power systems – a non-storable commodity with a cost structure overwhelmingly driven by periodic demand rather than annual energy demand. Expected peak loads during extreme weather ‘critical event’ days drive system capacity, and capital-intensive capacity costs (as opposed to system marginal running costs) dominate the cost structure of electricity supply. The fixed and sunk capital costs of an electricity distribution system will typically comprise 70-80% of the total network cost structure. The Australian east coast generation fleet has a similar cost structure. The two-part tariff was theoretically designed to capture these characteristics – and originally comprised a demand charge (expressed in dollars per kilowatt or $/kW) reflecting peak capacity utilised by a customer, and a variable energy charge (expressed in cents per kilowatt hour or c/kWh) reflecting the real-time marginal running costs of the power system.

There was a difficulty with implementing the theoretically optimal two-part tariff, however. Power system peak load typically occurs on 12-15 critical event days each year. In order to levy the two-part tariff, and the demand charge in particular, the measurement of individual customer peak loads was necessary. In the 1890s and well beyond, the (mechanical) electricity meter could only measure total sales volume (kWh) at the quarterly meter read, or peak consumption (kW) but not both. In order to measure ‘peak load’ and the ‘time-of-use’, a second meter would be required. The high cost of meters meant that this could only be justified for large industrial consumers for most of the past 120 years. For households it was simply uneconomic to install two meters and so a surrogate demand charge would be required (i.e. a fixed charge). To be

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clear, most households in Australia still use this technology which requires a meter reader to physically inspect and manually record metered electricity use.

In Australia, the fixed charge is levied on a uniform basis and therefore involves an arbitrary, and by implication inequitable, allocation of fixed and sunk costs. A uniform fixed charge bears some relationship with direct connection costs, but no relationship with household peak loads during critical events. Moreover, in Australia the fixed charge has become a surprisingly small component of the two-part tariff. Given the nature and cost of the network, this further aggravates the inequity of existing tariff structures relative to the cost of supply.

The purpose of this article is to analyse inter- and intra-segment wealth transfers arising from existing flat-rate tariffs in the context of a power system experiencing suboptimal load growth.¹ We do this by contrasting existing flat rates with more cost-reflective Time-of-Use and Critical Peak Prices. We should emphasize that we do not attempt to redress the optimal level and structure of the fixed charge. Nor do we contemplate other tariff designs such as one dominated by a demand charge – an alternate solution which is at least as valid. Instead, in this article we focus on analysing inequities that exist by assessing the changes arising from a more cost-reflective time-differentiated structure and build on the applied analysis contained in Simshauser and Downer (2012).

Our analysis makes use of AGL Energy’s SAP HANA, an ultra-high speed in-memory computing appliance which enables us to work rapidly with a truly vast data set. Our modelling incorporates 2.8 billion meter reads from 160,000 smart meter customers in Victoria (i.e. 17,520 meter reads for each customer, representing a full year of half-hourly consumption data). Approximately 6000 of these households were matched with AGL Energy’s online household survey (one of Australia’s largest ongoing household surveys with more than 70,000 entries). This combination of data sources enables us to analyse inter- and intra-segment wealth transfers. By specifying a set of broadly representative household cohorts, our analysis of tariff reform should be of interest to the electricity industry, consumer groups and policymakers.

We have structured our article as follows. In Section 2, we review the relevant literature while in Section 3 we provide an overview of default electricity tariffs. In Section 4, we present average daily load shapes for five different household cohorts. Section 5 outlines our tariff model and pricing structures while Section 6 reviews model results. Our policy implications and concluding remarks follow.

2. Review of literature

Despite featuring prominently in microeconomic textbooks, two-part tariffs were not developed by theoretical economists but by electrical engineers in the 1890s – initially by Hopkinson (1892). The two-part tariff represented the means by which to charge electricity consumers in a fair, efficient and above all equitable basis – reflecting meticulous engineering cost analyses undertaken by these early power system engineers. From an applied perspective Wright (1896) from the United Kingdom and Greene (1896) from the United States demonstrated in considerable detail that the primary cost driver of their respective ‘central’ power systems was not variable production costs, but rather, the cost of installing and maintaining the capacity required to meet aggregate peak load.² Based on these principles, the early tariff engineers concluded that electricity prices should take the form of a ‘two-part tariff’ comprising a demand charge according to customer peak load ($/kW), and a variable energy charge based on the volume consumed (c/kWh).³ In a practical sense the limiting factor at the time (and for the ensuing

¹ By suboptimal load growth, we mean a power system with a deteriorating load factor.
² Variable power station fuel costs and network line losses are known to pale into insignificance by comparison to the investment commitment associated with building power station equipment and a network of poles and wires to meet peak summer loads.
³ A third charge reflecting the cost of connection was also suggested.
century or more) was the cost and availability of interval metering. Given this data constraint, at
the residential level the substitute for the demand charge would be the ‘fixed charge’. Early
applications of the residential fixed charge for electricity supply were driven by demographic
indices. In England for example, the fixed charge was linked to the number of bedrooms or the
rateable value of the property in question (Lewis, 1941). The fixed charge would be adopted by
the electricity industry around the world and in time the two-part tariff would be extended to
other industries such as gas supply, water supply, telecommunications, rail transport, the taxi
industry and so on.

Contemporary applications of the two-part tariff in the Australian electricity supply industry are
dominated by the variable charge. That is, over time, the uniform fixed charge element of the
two-part tariff has decayed considerably. As our data later reveals, the fixed charge currently
comprises just 10% of the overall tariff structure for an average customer. For a power system
experiencing rapid underlying energy growth (e.g. due to rising appliance use such as air-
conditioners), a two-part tariff structure dominated by a ‘flat rate’ variable charge could be
argued as desirable against a range of tariff design criteria. But in a system experiencing sharply
rising peak load growth, declining underlying energy demand, or both, a two-part tariff with the
structure dominated by a flat rate variable charge does present certain difficulties. Above all, it
can become unstable and risks inducing an inefficient allocation of resources, thereby violating
other elements of conventional tariff design criteria (see for example Boiteux & Stasi, 1952;
Bonbright, 1961). This was the primary theoretical motivation of Hopkinson (1892) and the
unambiguous applied findings in both Wright (1896) and Greene (1896) because at the time,
these power systems were experiencing sharp and unsustainable growth in system peak load.

A key issue for the electricity industry and for policymakers is that with flat rate tariffs, the value
of peak energy is substantially under-priced while the value of off-peak energy is over-priced. The
absence of widespread time-differentiated pricing has been persistently identified as a critical
problem facing the efficiency of electricity systems by energy economists dating at least as far
back as Boiteux (1949), Dessus (1949), Houthakker (1951), Steiner (1957), Nelson (1964),
Turvey (1964), Joskow (1976), Crew & Kleindorfer (1976), and Wenders (1976).

Time-differentiated pricing need not be complex. As Boiteux & Stasi (1952, p.116-117) noted
long ago, two-part tariffs with ‘peak’, ‘full-use’ and ‘slack’ (i.e. peak, shoulder, off-peak) period
pricing is sufficient:

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.

More than a century has passed since the ideal theoretical tariff structure was specified
(Hopkinson, 1892; Greene; 1896; Wright, 1896), and more than half a century has passed since
energy economists generalised and optimised the principles for mass market application (Lewis,
1941; Boiteux, 1949; Houthakker, 1951; Boiteux & Stasi, 1952). Only recently, however, have smart meters become economically viable at the household level. In the case of Victoria, at the time of writing a mandated network monopoly roll-out of smart meters was in its final stages. The deregulation of metering services has also become a key thematic in other regions of Australia.7 These developments raise the prospect of meaningful electricity tariff reform, and the potential to substantially reduce inter- and intra-segment cross subsidies.

Faruqui & Malko (1983), Faruqui (2010a, 2010b), Faruqui & Sergici (2010, 2013), Faruqui, Sergici & Sharif (2010), Wood & Faruqui (2010), Faruqui & Palmer (2011), Simshauser & Downer (2012), Procter (2013), Nelson & Orton (2013), Hamer et al. (2014), Horowitz & Lave (2014), Fenwick et al. (2014) and others have all demonstrated that with the availability of smart meters, time-of-use tariff structures are capable of correcting market inefficiencies and inequities.8 Furthermore, the literature on price discrimination9, which is well summarised by Armstrong (2006, 2008), is clear that as firms in competitive markets access more ornate tariff structures, it has the effect of amplifying competition because they equip themselves with a new arsenal of weapons to attack competitors to gain market share, which in the event enhances consumer welfare. The combination of smart meters, time-differentiated structures and non-linear pricing more generally will invariably drive product innovations not possible in their absence.

Our experience, however, is that consumer groups approach the notion of default tariff reform with a concern that their constituents will be adversely affected by greater cost-reflective pricing (see for example Alexander, 2010; Brand, 2010; CUAC, 2010). Consumer group support is likely to be ‘cautiously optimistic’ if tariff reform is based on an ‘opt-in’ approach – where adverse selection must surely be more than a theoretical possibility. With the notable exception of St Vincent de Paul, most consumer groups in Australia argue that existing tariff structures should be made even ‘more simple’ – the logical extreme presumably being an average cost variable tariff (i.e. uniform flat price, no fixed/demand charge element). However, as our quantitative analysis subsequently reveals, such thinking is not supported by the evidence presented in this article.10

An average cost variable tariff is neither efficient nor equitable, and more importantly, when combined with sharply rising peak demand growth, contracting energy demand, or both, an average cost tariff structure may become unstable. The reason for this is that under either of these scenarios, the relevant fixed network costs are spread across fewer units of output. Under rate-of-return regulation, tariffs must be continuously increased to offset volumetric losses. To make matters worse, such rate structures will amplify the implicit or ‘hidden’ Solar Photovoltaic (Solar

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7 A generalised framework for the roll-out of smart meters has been agreed by policymakers in Australia. Specifically, in 2007 the Council of Australian Governments agreed to develop a National Smart Meter Framework based on a mandated rollout by distribution networks (i.e. where benefits outweighed costs). The Victorian mandated smart meter roll-out was not done well and since then, more recent reviews including those by the Australian Energy Market Commission have tended to favour a retailer-led competitive metering framework for future smart meter roll-outs (as is the case in New Zealand and Great Britain). See Nelson and Simshauser (2014).


9 To be clear, while the literature on price discrimination finds its roots in monopoly applications, a special strand emerged which analyses the role of differential prices in competitive industries. One of the original contributions on competitive markets came from Salop and Stiglitz (1977) which focused on informed (weak segment) and uninformed (strong segment) customers and was later extended by Katz (1984) although the use of completely inelastic demand functions limits welfare enhancements. The literature on non-linear pricing in symmetric markets (where firms agree on strong and weak customer segments) finds that uniform pricing will typically be lower than a default price but higher than marginal prices (Borenstein, 1985; Holmes 1989; Winter, 1997; Dobson and Waterston, 2006). In the event, the net effect on consumers is ambiguous. But Corts (1998) shows that in markets where firms do not agree on which customer segments are ‘strong’ and ‘weak’, the presence of price discrimination is likely to reduce overall prices and enhance consumer welfare. Bester and Petrukis (1996) find banning discrimination raises marginal prices and as with Shaffer and Zhang (2000), conclude that this always damages some consumer groups. Shaffer and Zhang (2000) also derive conditions by which all consumers can be damaged. Hvid and Waddam Price (2012) examined limits placed on non-linear pricing by an electricity regulator in the British energy market and found the response by firms to non-discrimination rules generated detrimental distributional effects and had a range of unintended adverse consequences. Specifically, they found that because the market was asymmetric with regards to which customers were strong and weak, the result was to raise all prices as the literature predicts. The regulator found in a post-implementation review that many indicators of competition had deteriorated and in the event, abandoned the policy.

10 Wood and Faruqui (2010) also provide counter evidence in relation to low income households.
PV) subsidies and can drive investment in PV systems above the efficient level (unnecessarily aggravating volumetric losses). Under these conditions it is not difficult to see how an average cost variable tariff has a particularly high propensity to induce an energy market death spiral (see for example Severance, 2011; Simshauser & Nelson, 2014). And as Boiteux & Stasi (1952) and Bonbright (1961) noted in their classic works, a crucial principle of good tariff design is price stability.

3. Review of existing default tariff structures

Our quantitative work starts by reviewing historic tariff levels and the structure of existing default tariffs. The former is of course the sole reason why electricity tariff reform warrants discussion at all. In this Section we present data from the Queensland region of Australia’s National Electricity Market, where we have a particularly long time series.

Figure 1 presents residential electricity tariffs from 1955-2015 in nominal (bar series) and real (line series) terms. Note also the ‘2009 Forecast’ markers (and ‘dashed line series’) which runs from 2008-2015. This price forecast, initially produced in 2009 and subsequently published in Simshauser, Nelson and Doan (2011), indicated that electricity tariffs would increase from 14.5/kWh to 29c/kWh between 2008-2015. As Simshauser and Nelson (2014) explain, tariffs would double in the space of just seven years in an ostensibly low inflation environment – and to put this into perspective, it took 23 years (from 1985 to 2008) for electricity tariffs to double previously – much of this in a high inflationary environment. The rapid doubling of residential electricity tariffs to 2015 seemed entirely predictable due to rising equipment costs, rising renewable energy subsidies, the introduction of carbon taxes, and above all, a tightening of reliability standards leading to rapid increases in transmission and distribution network investment to meet forecast peak demand growth.

11 Solar PV output peaks around the middle of the day whereas the peak load of many distribution network elements occurs between 4-9pm. Households with a Solar PV unit are ‘net metered’, meaning that variable network charges are avoided without any material reduction in the use of the distribution system during the 4-9pm peak period. This has resulted in considerable hidden cross-subsidies to Solar PV households, and financed by non-Solar PV households through the network tariff rebalancing process.

12 Simshauser and Nelson (2014) describe an energy market death spiral as a situation whereby contracting demand results in an increase in the price of electricity (i.e. to meet regulated revenues). This tariff increase induces a demand response, and in turn, a further round of price increases. Wealthier households respond by introducing Solar PV units, further reducing demand and driving yet another round of tariff increases, and so on. Our point here is that a death spiral is more likely when the variable charge dominates the structure of a two-part tariff.

13 If tariff stability becomes the primary objective function under conditions of volumetric losses, Time-of-Use tariff structures may not be the best solution. A two-part tariff combining a Demand Charge and Time-of-Use variable rates may produce more stable outcomes.

14 Simshauser and Nelson (2013) explain that the most recent surge in electricity tariffs should moderate through to 2020 due to the removal of the carbon tax, changes to renewable energy policies and subsidies, and the completion of the major capital expenditure cycle associated with networks.
The single largest contributor to the 2008-2015 increases would come from the regulated monopoly charges for electricity networks, with pricing set under five-year rate determinations by the Australian Energy Regulator. The five-year regulatory period spanned either side of the Global Financial Crisis and submissions by monopoly network businesses, and accepted by regulatory authorities, assumed strong growth in peak demand. This set the scene for record levels of capital investment in network infrastructure\textsuperscript{15} which in the event increased from $10 billion to almost $40 billion over the five year period to 2014 (Simshauser, Nelson and Doan, 2011). Tariffs were set to rise sharply. However, a problem emerged. The financial crisis of 2008-2009 took its toll on energy demand and by 2010 Australia experienced its first year of electricity demand contraction on record. Then, overlapping State and Federal Solar PV subsidies (and hidden subsidies arising from the existing two-part tariff structure) induced an over-investment in PV units – which further accelerated contractions in system electrical demand. Combined, this further aggravated tariff increases and led to further demand contractions.\textsuperscript{16} With network investment plans committed and regulated revenues assured, the price surge was predictable.

How tariffs are structured is presented in Figure 2. The first bar presents the actual cost elements of electricity supply, while the second bar presents the existing default tariff structure and the third bar is reflective of a typical discounted competitive market product using Queensland 2014 data. The default tariff comprises a fixed charge of $0.50 per day with a variable energy charge of 26.7c/kWh. For the typical Queensland household consuming 6,000 kWh per annum, 10\% of the total electricity bill of ca.$1750 per annum is levied by the fixed charge, whereas capacity-related industry fixed costs comprise 64\% of the total.\textsuperscript{17} Additionally, as noted earlier the fixed charge is applied at a uniform rate – regardless of household characteristics.

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\textsuperscript{15} Abnormally stringent reliability standards introduced during the mid-2000s contributed to overinvestment in Queensland.

\textsuperscript{16} The contraction of energy demand is thought to be the product of three primary drivers at the household level; (a) the own price elasticity of electricity, (b) the rising efficiency of new appliances, and (c) the sharp run-up in subsidised rooftop solar PV units.

\textsuperscript{17} Industry variable cost includes: generation fuel, carbon costs, 20\% of network costs, line losses and 52\% of retail costs.
4. Household load shapes

Until only a few years ago, all 8 million households connected to the distribution network in Australia’s National Electricity Market had a mechanical meter which was physically read four times per annum. Convention was for the household to receive a quarterly electricity bill which would tell the account holder how much electricity (in volumetric terms) had been consumed every 90 days and would reflect seasonality – but little more. However, the rising penetration of smart meters means that we now have a better understanding of household load shapes. In this article, we present five variations to our Overall Average household load shape based on demographic characteristic.

1. Working Couples, No Kids (n=2000);
2. Working Parents with Kids (n=2000);
3. Family, Parent at Home (n=2000);
4. Households in Hardship (n=1800);
5. Concession & Pensioner Households (n=60,000); and
6. Overall Average (n=160,000).\(^{18}\)

Note that n=2000 for cohorts 1-3, n=1800 for cohort 4 and n=60,000 for cohort 5. To be clear, in the context of the Overall Average, cohorts 4 and 5 are broadly representative of the customer base. Clearly, our sample size for demographic cohorts 1-3 are not – they are reflective of available data from AGL Energy Ltd’s on-line household survey, and, there are many other valid cohorts that we have missed (e.g. single parent household etc). As such, these cohorts should not in any way be considered exhaustive. Additionally, this is merely one of many different methods by which to analyse household cohorts. Other variables that could be used to segment the data include age of account holder, owners vs. renters, household income, product selected, and so on. However, with these qualifications, and for the purposes of our inquiry and analysis into the equity of existing tariff structures, this particular stratification of the data will, in our opinion, serve as useful and provide guidance to policymakers.

\(^{18}\) At the time of writing, AGL Energy Ltd had approximately 3.8 million customer accounts. This included 665,000 electricity customers in Victoria, and of these, 160,000 had a smart meter installed at least 12 months prior. Our analysis focuses on these 160,000 customers since we were able to analyse a full year of consumption data (i.e. 17520 half-hour intervals per household).
4.1 Working Couple, No Kids

Figure 3 illustrates the annual weekday average electricity consumption from two distinct household types. The x-axis measures the time of the day from 12 midnight through to 12 midnight, and the y-axis measures the household electricity load in approximate 19 kW. Our benchmark household load curve, referred to as the ‘Overall Average’ and represented by the dark grey line series, is based on 48 half-hour final demand data points for each workday and reflects the average of the 160,000 households from Victoria and their 2.803 billion meter reads throughout the year. It should be noted that this load curve does not represent peak summer or winter days. It is the annual weekday average, but is nonetheless a helpful graphical representation of our data for cohort comparison purposes. Figure 3 highlights that the Overall Average household uses 4.2 MWh per annum and that the peak load occurs at 7pm. It is worth noting that our data explicitly excludes hot water loads (i.e. most Victorian households have gas hot water, and those that do have an electric hot water system are a controlled load on a cost reflective tariff).

The light grey line plots our first cohort – Working Couples, No Kids. This cohort is dominated by young professionals living in central city locations with proportionately more account holders below 40 years of age, and a high proportion occupying rental properties (ca.40% vs. Overall Average of ca.25%). These households use only 3.7 MWh excluding hot water. Notice that during the day, they use very little electricity (i.e. nobody is home) and arrive home later than the Overall Average (i.e. their evening ramp-up is delayed by an hour).

![Figure 3: Annual average weekday load curve: Working Couples No Kids](image)

Source: AGL HANA.

4.2 Working Parents with Kids

In Figure 4 we present our household load for Working Parents with Kids. As Simshauser and Nelson (2014, p.30) explain, these households have:

...two or more uncontrollable consumers (that is, children) who are blissfully unaware and unmoved by the financial impact of the uncoordinated, and in many cases, simultaneous energy consumption decisions arising from the use of computers, game controls, televisions and heating and cooling devices...

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19 Our smart meter data is the accumulation of 30 minute consumption. Real-time data would oscillate around the mean result.
Households with children have noticeably larger morning and evening peaks. These account holders are dominated by 36-64 year olds in major and high growth metropolitan suburbs. With both parents working, the household organises itself earlier, and so the morning load commences its run-up earlier than average. Notice also that the addition of children to a household means that the afternoon ramp-up in load commences from about 3:30pm when children arrive home from school, whereas for Working Couples, no Kids, this occurs from 5pm or later when adults arrive home from work.

**Figure 4:** Annual average weekday load curve: Working Parents with Kids

![Annual average weekday load curve: Working Parents with Kids](image)

Source: AGL HANA.

### 4.3 Family, Parent at Home

In our next customer cohort, we examine a family comprising parents and children but unlike Figures 3 and 4, in this instance one adult is at home during the day. This results in a profoundly different load shape as Figure 5 demonstrates. In relative terms, these are large household customers at 5,700 kWh per annum ex-hot water load. They use more power during each half-hour interval with a noticeably strong consumption pattern during shoulder and peak periods.
4.4 Household in Hardship

Our next cohort is of special interest to our analysis, and should be to policymakers, because they represent the group of customers who can least tolerate inequities or inefficiencies in tariff design – Households in Hardship.20

This data took us by surprise. Following on from Simshauser and Nelson (2014), we had anticipated that Households in Hardship would be large users (i.e. large electricity bills), but we had not anticipated the extent of off-peak consumption. This may reflect variables such as the quality of materials used in the housing stock (e.g. limited insulation), a less inefficient electrical appliance stock, and some element of anthropogenic pattern driven by the circumstances facing

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20 For our purposes, ‘Households in Hardship’ are defined as those households who have the willingness, but not the financial capacity, to pay their electricity account. They have in turn been placed on AGL Energy’s ‘Staying Connected’ program.
these households. As Simshauser and Nelson (2014) indicated previously, the age of account holders in this cohort are dominated by 36-55 year olds with a median age of 44 years. Above all, because this cohort exhibits the most favourable load factor, they will be the most adversely affected from continued use of existing tariff structures. To be perfectly clear on this, consumer advocates seeking to retain simple flat tariffs or further simplify tariff structures by moving to a single variable rate are almost certainly (albeit inadvertently) doing more damage than good to this cohort – something we demonstrate quantitatively in Section 6.

4.5 Concession & Pensioner Households

Our final cohort is Concession & Pensioner Households which is dominated by account holders greater than 65 years of age and a very high ‘home ownership’ level of 86%. They are low energy users with annual volumes of 3,600 kWh.

![Figure 7: Annual average weekday load curve: Concession & Pensioner Households](image)

4.6 Demand Response

A crucial component of the following analysis is our assumptions around Demand Response. Our tariff model alters the rate structure from a uniform variable charge to time-differentiated variable charges, specifically, peak, shoulder and off-peak rates along with a ‘Critical Peak Price’ dynamically applied to 12 critical event days. In Figure 8, we present Faruqui and Sergici’s (2013) Demand Response summary from 163 tariff pilots from US, Australia and France amongst others. Each of the bars presents the average reduction in household peak demand (in percentage terms) from a change in tariff design.

There are six distinct sets of results in Figure 8 which rank the response by consumers to changes in rate structures. The first set of results (i.e. trials 1-42) present the average Demand Response by consumers during peak periods when customers are shifted from a uniform variable charge to time-of-use (TOU) charges. Note that Demand Response in these pilots, denoted TOU in Figure 8, resulted in an average peak reduction of 7.4%. When enabling Demand Response technology (TOU+Tech) was included (i.e. trials 43-65) the average peak reduction was 16.9%. The next set of pricing pilots involved a Peak-Time Rebate (PTR) product in which households are paid if their peak load is reduced and average a 13.6% reduction. When enabling technology is added the average reduction increases to 23.8%. The final trials involve Critical Peak Prices (CPP) and result in peak load reductions of 19.2% on average (which increases to 21.2% with enabling technology).
Hamer et al. (2014) find similar results for Queensland-based residential customers in their CPP pilot, with the average peak load reduction on critical event days also being 19%. So how do Australian households physically respond to Critical Peak Prices on event days? In their pricing pilot in Queensland, Hamer et al. (2014) surveyed how households responded during critical events – 8% found it difficult to respond, whereas 71% found it easy. A summary of their actions is provided in Figure 9.

From our perspective, an unexpected result in Hamer et al. (2014) was that low-use households were just as capable of shifting peak loads as medium- and high-use households. In our previous
research in this area (see Simshauser and Downer, 2012), we had explicitly assumed that households consuming less than 2500 kWh pa were price inelastic based on the findings in Reiss and White (2008). While this is no doubt valid in respect of own price elasticity, it is evidently not valid with respect to cross price elasticity effects. That is, low-use households such as Concession & Pensioners will probably not reduce their overall annual consumption levels, but they can and do respond to time-differentiated prices during critical events by shifting load as Figure 9 reveals (see also Wood & Faruqui, 2010). Accordingly, in our present analysis we assume an own price elasticity of -0.05 and a cross price elasticity of -0.10 with a load intercept of 0.55.\(^{21}\) The former is applied to all households consuming more than 2500kWh per annum while the latter is applied to all households.\(^{22}\)

5. Tariff Equalisation Model

In order to produce a generalised view of the cross-subsidies under existing two-part tariff structures, we utilise AGL Energy’s HANA and our Tariff Equalisation (TE) Model. This enables us to compare the annual charges of each household under the existing tariff structure with any alternate design. The underlying objective of the TE Model is to identify inter- and intra-segment cross subsidies subject to the constraint that that regulated network revenues are equalised (i.e. through network tariff rebalancing). To be perfectly clear, there is no increase in electricity network profits arising from the change in tariff structures, and if anything, electricity retailers and power generators face marginally lower net revenues.\(^{23}\) By implication, total consumer welfare is unambiguously enhanced in our model. However, within cohorts there are winners and losers. Our TE Model is structured as follows:

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

\[
i \in \{1 \ldots |H|\} \land h_i \in H
\]

Let \( P \) be the ordered set of all periods.

\[
j \in \{1 \ldots |P|\} \land p_j \in P
\]

Let \( z \) be the number of period types. Let \( I_1 \) be the ‘peak’ period from 3pm to 9pm on all weekdays, excluding periods in \( I_4 \). Let \( I_2 \) be the ‘shoulder’ period from 9pm to 10pm on all days, and 7am to 3pm on all weekdays. Let \( I_3 \) be the ‘off-peak’ periods from 12am to 7am and 10pm to midnight on all weekdays and also all periods on weekends. Let \( I_4 \) be the ‘critical-peak’ periods from 3pm to 9pm on the 12 weekdays declared to be ‘critical’. Let \( I_{sp} \) be the ‘Standard Peak’ periods from 3pm to 9pm on all weekdays. Therefore:

\[
P = I_1 \cap I_2 \cap ... \cap I_z
\]

\[
I_{sp} = I_1 \cup I_4
\]

\[
\forall k, m | k \neq m: I_k \cap I_m = \{\}
\]

\(^{21}\)Given our load intercept of 0.55, this results in critical event load shifting of ca19%, peak load shifting of ca5% and a conservation effect of 2% per annum.

\(^{22}\)We note that the results from Figure 8 (and Hamer et al. 2014) reflect a set of electricity customers who have ‘opted in’ to a pilot study, and that we have uniformly applied these results across a much larger consumer base on a uniform basis.

\(^{23}\)As our modelling results in Section 6 reveal, we have adjusted tariffs to equalise network revenues, but have not adjusted tariffs to equalise generator or retailer revenues. We estimate short run negative impacts of 2.4%. The long run impact would be trivial for the reasons set out in Simshauser and Downer (2012), that is, after a period of dynamic adjustment the industry would face more favourable load factors, more predictable plant run times, better thermal efficiency, lower price risk and more stable consumer prices. Furthermore, the long run cost of inaction with respect to tariff reform would be far greater.
Let the number of Billing days be $d$ such that $d.48 = |P|$. Let $q_{ij}$ be quantity consumed by household $h_i$ in each period $p_j$. Let $T_f^m$ be the fixed charge that applies to each day, and $T_v^m$ be the flat-rate variable charge that applies to quantity consumed $q_{ij}$. Let $t_y^k$ be the smart meter variable tariff for period type $y$, and $T_y^v$ be the ordered set time-of-use tariffs:

$$y \in \{1 \ldots z\} \land t_y^k \in T_y^v$$

(6)

Let function $T_y^k(j)$ give the variable smart meter tariff for period $p_j$:

$$T_y^k(j) = t_y^k \cdot p_j \in I_k$$

(7)

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 $T_v^m$:

$$R_i^m = \sum_{i=1}^{[H]} \left( T_f^m \cdot d + \sum_{j=1}^{[P]} q_{ij} \cdot T_v^m \right)$$

(8)

To establish Total Revenues $R_i^v$ under a smart metering regime:

Let $R_i^v \equiv R_i^m \mid R_i^v = \sum_{i=1}^{[H]} \left( T_f^m \cdot d + \sum_{j=1}^{[P]} q_{ij} \cdot T_y^k(j) \right)$

(9)

6. Tariff Equalisation Model Results

Our primary objective is to analyse the extent of wealth transfers within and between household cohorts. We compare the annual electricity bills facing 160,000 households using the two products in Table 1, (1) Flat-Rate tariff, and (2) Time-of-Use plus Critical Peak Price (TOU+CPP) – both of which are set within two-part tariff structures. At no point in our analysis do we alter the fixed charge.

<table>
<thead>
<tr>
<th>Tariff Structure</th>
<th>Unit</th>
<th>Flat Rate</th>
<th>TOU+CPP</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Charge</td>
<td>c/day</td>
<td>100</td>
<td>100</td>
<td>All periods</td>
</tr>
<tr>
<td>Single Rate</td>
<td>c/kWh</td>
<td>25.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak Rate</td>
<td>c/kWh</td>
<td>33.2</td>
<td>3pm-9pm Workdays</td>
<td></td>
</tr>
<tr>
<td>Shoulder Rate</td>
<td>c/kWh</td>
<td>25.6</td>
<td>7am-3pm, 9pm-10pm*</td>
<td></td>
</tr>
<tr>
<td>Off Peak Rate</td>
<td>c/kWh</td>
<td>15.6</td>
<td>10pm-7am All Days</td>
<td></td>
</tr>
<tr>
<td>Critical Peak Price</td>
<td>c/kWh</td>
<td>85.0</td>
<td>12 Days, 3pm-9pm</td>
<td></td>
</tr>
</tbody>
</table>

*Shoulder Period on Weekends: 7am-10pm

In Section 4, we presented average weekday household load shapes by cohort. However there is considerable variation within each cohort. Figure 10 attempts to illustrate this by presenting 5th, 25th, 75th and 95th percentile consumption levels along with Cohort Median (dash marker) and Cohort Average (diamond marker).
Given the flat rate tariff in Table 1 and cohort consumption in Figure 10, the corresponding annual electricity bills are illustrated in Figure 11.

Figure 12 presents the first of our modelling results under more cost-reflective pricing and shows the distribution and intensity of wealth transfers amongst customers. There are two line series in Figure 12. Each presents the distribution of winners and losers after shifting from the flat rate tariff to Time-Of-Use plus Critical Peak Prices. The bold grey line is “All Households – before Demand Response”. Notice that this line crosses the x-axis origin at exactly 50%. This means that all households to the left of the 50% mark are immediately better-off on a Time-Of-Use tariff (i.e. lower left component of the propeller curve). The extent to which these households are better off is measured by the y-axis. The remaining 50% of households (to the right of 50%) are immediately worse-off. Under flat rate tariffs, it is these households that are being cross-
subsidised. That is, they have higher peak loads than average and cause greater power system operating costs.

**Figure 12: Existing tariff inequities – All Households**

The thin grey line is the “All Households – after Demand Response”. Here we apply the own price elasticity (i.e. load conservation effect) and cross price elasticity (i.e. load shifting effect) estimates outlined earlier. This results in average household load reductions of ca19% during critical demand events, about 5% during standard peak periods and a conservation effect of ca2% per annum. Notice that the x-axis cross-over point shifts from 50% to 75% – meaning that three quarters of customers would eventually be better off once the tariff structure is understood and behaviour adjusts accordingly. However, 25% of customers would be worse off, albeit prior to network tariff rebalancing.

Figure 13 presents the modelling results for all household cohorts before Demand Response. In this instance, total industry revenues arising from the change in tariff design are equivalent. The primary affect is to identify the wealth transfers between, and within, the various household cohorts. The results reveal that the largest ‘immediate winners’ from a change to more cost reflective tariffs is the ‘Hardship’ cohort with 65% better off. But to be sure, 35% are immediately worse off. At the other extreme is the ‘Parent at Home’ cohort, with 67% immediately worse off, and 33% immediately better off. The Figure 13 Legend identifies the mix of immediate winners and immediate losers for each cohort.

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Network tariff rebalancing requires that retail-level tariffs be increased by 1.4% (i.e. a 4.5% increase on variable rates charged by the networks, holding the fixed charge constant). This has the effect of shifting the cross-over point from 75% back to 64% as Figure 15 subsequently reveals.
In Figure 14 we progress the results by applying our demand elasticity estimates to account for Demand Response. The cross-over points for all cohorts subsequently shift to the right and the Overall Average shifts from 50% to 75%. Our largest winner cohort, Households in Hardship, moves from 65% to 87%, while the most prevalent loser in Figure 13, Parent at Home, shifts from 33% to 67%. Note however that overall, 25% of households remain worse-off despite a Demand Response. Furthermore, we have not rebalanced network tariffs. In practical terms, this means that short run industry revenues are lower by 2.4%.

In Figure 15 we complete the analysis by rebalancing network tariffs to produce a revenue equivalent outcome for networks (and as noted earlier, by implication, some marginal short run loss remains within the competitive electricity retailing and power generation segments). Tariff rebalancing requires that variable rates associated with the network increase by 4.5% (or about 1.8% at the retail level), holding the fixed charge component constant. This has the effect of shifting the cross-over points to the left, with the Overall Average shifting from 75% back to...
64%. Our cohort that benefits most, Households in Hardship, now has 79% winners and 21% losers. At the other extreme, the Parent at Home has 54% winners and 46% losers.

**Figure 15:** Household wealth transfers after Demand Response, after tariff rebalancing

The final set of results we examine (in the context of Figure 11) is the distribution of winners and losers by customer cohort in ‘dollar terms’. This is presented in Figure 16. This is yet another result which took us by surprise. While we had understood in percentage terms the prominence of ‘winners’ amongst Households in Hardship, we had not anticipated the extent of the *absolute dollar gains* (or electricity account reductions) accruing to Hardship winners, and simultaneously, the small adverse financial impact accumulating to Hardship losers. Notice the pitch of the Households in Hardship propeller curve is considerably steeper for the winners, and flatter for losers, by comparison to all other cohorts and the Overall Average benchmark.

**Figure 16:** Household wealth transfers after Demand Response, after tariff rebalancing

It is worth also briefly discussing the extremities of Figure 16. By comparison to the status quo, the 95th percentile ‘loser’ households in all categories after Demand Response and after network
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outlining the tariffs with an option to ‘opt

reform by

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carbon tax.

tariff

articles in 2007 to 9,000

price’

considerable

Simshauser and Laochummanvanit (2012) demonstrate

increases at multipl

variable charge

2012). In

$1.6 billion per annum on the

our prior modelling revealed that over time those productivity gains could equate to as much as

$440.56 per annum.

7. Policy recommendations and concluding remarks

In our prior work in this area, we argued that the benefits of shifting to time-of-use tariffs included slower growth in peak demand, delayed or avoided network augmentation, improvements to power system load factors, more predictable plant run times, an increase in the thermal efficiency of the plant stock, delayed requirements for costly peak load generation equipment and above all, greater tariff stability (and therefore enhanced welfare). There will always be an extended period of dynamic adjustment in achieving such productivity gains, but our prior modelling revealed that over time those productivity gains could equate to as much as $1.6 billion per annum on the Australian east coast electricity grid (Simshauser and Downer, 2012). In the present analysis, we have demonstrated that existing tariffs dominated by a flat variable charge is inequitable. From an economics perspective, the case for default tariff reform is as clear as it is unremarkable.

But like most microeconomic reforms, winners and losers arise when benchmarked against (an inequitable) status quo. Accordingly, framing the case for reform is important. Energy costs represent about 2.6% of average household expenditure25 and pales into insignificance by comparison to other essential goods and services such as housing (18%), food and beverages (16.5%) and transport (15.6%).26 So in theory, tariff reform should be relatively straightforward in a stable cost environment.

However, we highlighted in Figure 1 that electricity tariffs have increased sharply since 2008. Simshauser and Laochummanvanit (2012) demonstrated that sharp tariff increases have generated considerable (and understandably, adverse) media interest with coverage of the term ‘electricity price’ experiencing a six-fold increase in regions of the National Electricity Market, from 1,654 articles in 2007 to 9,000+ articles in 2012. This heightened media was a product of year-on-year tariff increases at multiples of general inflation rates and the imposition of a deeply unpopular carbon tax. Consequently, the ‘political will’ to undertake tariff reform must have diminished. Even the Australian Energy Market Commission (2011) presented cautious advice on tariff reform by recommending that medium-size residential customers be able to ‘opt-out’ of default time-of-use pricing while small residential customers should be left on existing flat rate default tariffs with an option to ‘opt-in’ to time-of-use prices. In the absence of quantitative evidence outlining the extent and intensity of winners and losers, such advice represents a pragmatic approach to reform.

Our objective has been to provide policymakers with missing evidence on the extent and intensity of existing inter- and intra-segment cross-subsidies. Our initial analysis showed that under a flat rate tariff, half the consumer base is being overcharged, while the other half is being cross-subsidised. The ‘Parent at Home’ cohort was found to receive the highest level of cross-subsidy. These cross-subsidies are essentially financed by ‘Households in Hardship’ and ‘Working Couples’ amongst others. Although to be clear, cross-subsidies occur within and across all segments.

25 For households in the lowest income quintile, energy represents 4.0% of total expenditure.

26 See ABS (2011) 6530.0 Household Expenditure Survey.
Using our elasticity estimates, we found Demand Response was material during critical event days – reducing aggregate household peak load by 19%, on average. And because the majority of that response was associated with load shifting rather than conservation effects, the impact on industry revenues was only 2.4% before tariff rebalancing. Once Demand Response was taken into account, all customer cohorts benefited considerably. We found that 75% of customers were better off, and even the cohort with the large proportion of losers (Parent at Home) reduced its losers from 67% to just 31%.

For completeness, we analysed the impact of network tariff rebalancing which, given existing network regulation in Australia, would be required to ensure regulated returns are met. To meet this constraint we increased network time-of-use rates by 4.5% (and retail-level variable rates by ca.1.8%) and held the fixed charge constant. Yet even after doing so, 64% of customers were better-off with the gains most prevalent amongst Households in Hardship, followed by Working Couples and then Concession & Pensioners. The Parent at Home cohort was split 54/46 in terms of winner/loser. At the extremes, relative to the status quo the 95th percentile ‘loser’ households after Demand Response and after network tariff rebalancing face bill increases of no more than 5% or $58.40 on average. However, the final 5% of losers, in some cases, faced increases up to 16% or $440 per annum.

Experience from US pilots indicates that where flat tariffs are the default product, less than 20% of customers will ‘opt-in’. If more cost-reflective time-differentiated tariffs represent the product default, less than 20% of customers will ‘opt-out’ (Hoch, 2014). This suggests the structure of the default tariff is important. However, from an implementation perspective, how low income households are dealt with will clearly be important if their position deteriorates after reform. Smart meters enable more cost-reflective pricing, but they also facilitate accurate monthly billing. Mandating monthly billing should be considered an important log-rolling policy to aide household budgeting and minimise the incidence of bill shock. And to the extent that unwinding inter- and intra-segment cross-subsidies produces adverse outcomes for households poorly-equipped to accommodate the financial impact of such reform, Australia’s ‘tax and transfers system’ noted for its ability to provide targeted adjustment assistance, should be used. And ultimately, the electricity industry, policymakers and consumer groups must work together to ensure that the position of vulnerable customers (e.g. non-English speaking backgrounds, mental illness and so on) is optimised and that they are on the right product for their circumstances (Nelson & Reid, 2014).

In this article, we presented distributional efficiency impacts from restructuring existing flat-rate tariffs to a time-of-use and dynamic critical peak pricing structure, as outlined in Table 1. What we did not consider was changing the structure of the two-part tariff (i.e. raising the fixed charge and reducing the time-of-use rates). Nor did we consider other plausible tariff solutions such as a demand charge. As we highlighted earlier, given recent contractions in energy demand and the manner in which networks are currently regulated in Australia, a two-part tariff dominated by the variable charge component may become unstable if volumes continue to decrease. These are limitations of our analysis and are clearly important areas for further research.

With these limitations acknowledged, the most surprising result from our analysis of household winners and losers are those associated with the Households in Hardship cohort who are overwhelmingly better off after default tariff reform. A key issue for policymakers is, however, that households formally declared as being in financial hardship are typically a small percentage

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27 In an ideal world, critical peak products would be applied on a targeted basis at the network element level; applying to winter days for customers connected into winter peaking elements and to summer days for customers connected into summer peaking elements. In the era of Boiteux & Stasi (1952), such possibilities were simply ruled-out as technically impossible. But rapid advances in information system and telecommunications technology means that such products are far more than a theoretical possibility. Such innovative thinking should be encouraged by policymakers because if generalised, it will further maximise welfare.
of the overall customer base. Simshauser and Nelson (2014) analysed approximately ¼ of the 8 million residential customers in the National Electricity Market and found that such households represent about 1-2% of the total. In their analysis a further 13-14% of households showed various signs of potential financial distress – with the median age of the household account holder being 44 years of age with larger than average electricity accounts. This tends to indicate that analysing the impacts on the Family cohorts (i.e. Hardship, Parent at Home, Working Parents Family) is important. What is less clear to us is whether the 13-14% of households identified in Simshauser and Nelson (2014) have load shapes closer to ‘Hardship’ (i.e. largest beneficiaries from tariff reform) or closer to ‘Parent at Home’ (i.e. largest losers from tariff reform). This also represents an area requiring further research.

8. References


9. Declaration by the authors

The authors of this working paper are employed by AGL Energy Ltd. While the working paper represents the views of the authors, the research was undertaken to inform AGL Energy’s public position in relation to electricity market development and 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 authors. 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 authors 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.