Electricity tariffs in a high-penetration renewable system – insights from Australia’s National Electricity Market

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There is a substantial literature on the efficient structural design of electricity rates. This existing work is largely focused on efficiently pricing the utilisation of existing technologies with significant fixed costs but also non-trivial variable running costs. There is comparatively less discussion about the interaction of regulated network tariffs, restructured wholesale market pricing and end-consumer rate design in a system with a very high penetration of renewables. This paper considers the various supply-chain segments in the Australian east-coast National Electricity Market (NEM) where significant adoption of renewable technologies has occurred. In the future, customers may be best served by 'fixed' or 'cap' style pricing contracts that allow unlimited energy consumption within a 'fixed' capacity band. This would be underpinned by economically regulated 'demand' tariffs for transmission and distribution networks and a liquid market for innovative derivative products alongside an efficient wholesale energy dispatch engine.

Keywords: electricity pricing; renewables; market design

JEL Codes: D04, D47, Q40, Q41, Q48

1. Introduction

The NEM has historically supplied electricity through a linear value chain made up of three components: contestable generation; regulated monopoly transmission and distribution networks; and deregulated, competitive retail services. Key to the original design of the NEM is the underlying combination of an ‘energy-only’ spot market and complementary financial derivative markets. This allows retailers to mitigate price risks associated with extreme spot price volatility.

Three key underlying issues are driving significant change within the NEM. Firstly, a significant reduction in the cost of renewable technologies has resulted in material uptake in embedded, ‘behind the meter’ solar PV. Secondly, climate change policy has driven significant uptake of large-scale renewables. Finally, electricity demand is fundamentally changing with underlying energy demand being ‘hollowed out’ but peak demand continuing to grow. The combination of these changing market dynamics is resulting in an increasing amount of the costs in the market being ‘fixed’ and fewer costs being ‘variable’.

This article considers how tariffs are evolving in Australia and some of the potential longer-term consequences of the significant changes in the industry that are occurring. Section 2 presents a very brief overview of the literature of electricity tariff design. A summary of the changes occurring within the market are presented in Section 3 with implications for wholesale markets and network tariffs presented in Section 4. Brief concluding remarks are contained in Section 5.

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2. Overview of end-user historical pricing methodologies (TIM)

Simshauser (2016) provides a very detailed summary of the literature in relation to tariff design. Over the past 100 years, tariff design has evolved from simple throughput charging to more ornate blends of: energy throughput charges; fixed charges; demand charges and pricing based upon time of use (ToU). Lewis (1941) established that pricing the level of customer demand during system ‘critical’ peak demand was a key part of an efficient pricing structure. This work was built on by Boiteux (1949), Nelson (1964), Williamson (1966), Turvey (1968), Joskow (1976), Bonbright et al. (1988) and others to establish that during ‘off-peak’ periods, tariffs should reflect system marginal running cost. During ‘peak’ demand periods, tariffs should reflect long-run marginal cost. These are important observations as they are based upon a system with heavy ‘sunk’ costs but non-trivial operating costs.

Australia’s tariff debate has largely been focused on the introduction of demand charges for regulated network tariffs. The Australian Electricity Market Commission has broadly supported this approach through the requirement that tariffs be ‘cost-reflective’. Simshauser (2016, p.108) notes that, ‘...a peak capacity-based ‘demand tariff’ is a more efficient, cost-reflective and equitable pricing structure’. But Passey et al (2017) argue the demand charges proposed by the networks in Australia are not ‘cost-reflective’. There are also arguments against demand tariffs from a consumer perspective. Dutschke and Paetz (2013) find that individual and societal advantages are not clear to consumers. Jeannert and Rai (2016) surveyed 53 households and found that they had no clear preference for peak demand tariffs.

However, much of this literature is relevant to the electricity system of the past. It is also grounded in assumptions around the proportion of costs being fixed and variable reflecting the operation of traditional networks and thermal generation such as coal and gas. As energy systems decarbonise, the nature of the cost structure will shift. Renewables such as wind and solar, and storage systems such as batteries and pumped hydro, are almost entirely ‘fixed cost’ investment propositions. The fuel is free and operating and maintenance costs are trivial. Furthermore, it is the end-user tariff that is most important and this is a combination of both the *wholesale* and *network* cost structure. It is therefore necessary for policy makers to consider how the electricity system is changing across the entire supply chain and to allow tariffs to evolve accordingly.

3. What is changing in the Australian electricity market

Rapid technological change in the energy sector has contributed to significant fluctuations in capital allocation and withdrawals in Australia. The continued addition of very low short-run marginal cost renewable generation and the ‘merit-order effect’ of an ‘energy-only’ market design created a comparatively low wholesale electricity pricing environment and intense economic pressure on ageing surplus coal-fired generation. There were significant concerns about a ‘disorderly transition’ to renewables (see Nelson et al, 2015). These concerns have proven to be founded with temporal mismatches of retiring ‘firm’ thermal plant and underinvestment in new equivalent capacity.

Since 2012, ten coal fired power stations operating within the National Energy Market have closed, with more than 5,000 MW of capacity withdrawn from service. Around 75% of Australia’s thermal generation assets are older than their original engineering design life and replacement capacity which may have been viable a decade ago is no longer competitive. The cheapest form of ‘energy’ in Australia is now wind or solar PV and declining energy demand and climate change considerations have meant that investment in higher capacity factor thermal plant is not economic (Nelson, 2018 and Figure 1). Australia is now grappling with the challenge of integrating high proportions of large-scale and distributed renewable generation within its

electricity system in a manner than ensures reliable, affordable and low-emissions supply is forthcoming.

Figure 1: LRMC of generation projects in Australia¹

Source: Simshauser (2018)

Renewable (ex-discretionary hydro) generation is not considered to be dispatchable. With increasing renewable output, existing coal fired power stations are more frequently ramped to respond to the fluctuations in generation by wind and solar PV. This ramping ages coal-fired power stations, potentially eroding their reliability and possibly bringing forward their retirement. Mid-merit gas-fired power stations such as combined-cycle plant (CCGT) cannot compete with renewables or coal due to the east-coast gas market being chronically short of supply (see Simshauser, 2018). There is therefore a growing requirement for rapidly dispatchable ‘firm’ generation that can be made available to the market within 5 minutes.² Such plant is likely to be open-cycle gas plant or reciprocating engines in the short-term and possibly battery storage, pumped hydro or even hydrogen in the longer-term.

Customers are also playing an important role in the energy market transformation, driving a shift away from the traditional linear electricity supply chain, to a more decentralised and bi-directional market. Australia leads the world in the uptake of small-scale solar photovoltaic (PV) installations. Approximately 17% of households have a solar PV system installed, and in some regions, this exceeds 25%. The vast uptake of solar PV was originally driven by significant subsidies from Government, both in terms of savings related to upfront costs and premium rates for energy exported to the grid. However, even with the closure of most solar incentive schemes, solar PV installations are approaching a cumulative capacity of 7GW (see Figure 2) and are expected to continue to expand to 44% of residential properties or a total of 17 GW of installed capacity by 2040 (Bloomberg, 2017).

¹ It should be noted that these estimates are very conservative in relation to wind and solar. Recent project announcements in Australia indicate the cost of wind and solar is between \$45 and \$60 per MWh.

² The NEM is shifting from 30 minute to 5 minute financial settlement due to recent rule changes by the Australian Energy Market Commission (AEMC).

Figure 2: Solar PV installed capacity, monthly installations

Source: Industry data

The expansion of solar PV has had a significant impact on the demand profile of the overall system. AEMO predicts average midday demand will more than halve between now and 2030 due to this uptake in rooftop solar. AEMO also forecasts negative minimum demand for South Australia under certain conditions by 2027–28. But solar PV has done little to reduce peak system demand. With a hot summer climate, Australia’s peak electricity demand occurs in summer, early in the evenings when solar PV generation is minimal.

Nelson et al (2018) note that ongoing developments in the cost, availability and capability of distributed energy technologies continues to fundamentally alter the view of electricity supply as a homogenous good meeting a largely consistent consumer need. Moreover, the accompanying proliferation of novel business models offering innovative services for customers presents significant implications for price dispersion. These developments present opportunities to develop innovative pricing models that are more cost reflective and indicative of the increasing diversity of product and service offerings in the energy market.

4. Analysis of cost structures in high penetration renewable systems

4.1 Wholesale markets

The NEM is an energy-only market where generators are only paid for the energy they dispatch to the market, and not the capacity they make available. Generators bid into a market within a range that is centrally cleared and dispatched by the Australian Energy Market Operator (AEMO). The NEM wholesale price is extremely volatile and can increase from an average price of around \$80/MWh to the market price cap of \$14,200/MWh within a very short period when temperatures increase in summer or when the system loses generation as a result of unexpected events.

The traditional role of the Australian energy retailer has been to mitigate the price risk for customers by hedging against the volatility of the wholesale price, either through utilising a range of energy market derivatives such as swaps and caps, or by investing directly in generation facilities. Retail electricity markets are deregulated, and through minimising their risk in wholesale markets and procuring energy through competitive markets, retailers provide a range of offers to customers at different prices.

An important assumption that underpins the interaction between the forward contract market and the spot market is the ability of generators to ‘dispatch’ their energy at a time period of their choosing. At the time of market deregulation, this was simply assumed given the ability of coal, gas and hydro generators to control their output. However, the introduction of variable renewables (e.g. solar and wind) has fundamentally shifted the nature of derivatives given these resources are currently unable to be forward contracted.

The South Australian region of the NEM has some of the highest penetrations of non-hydro renewables of any electricity market with around 1,500 MW of wind and 700 MW of distributed solar PV (around 30% penetration of households). Such penetrations can be contrasted with the region’s peak demand of around 3,000 MW, average demand of between 1,000 and 1,500 MW and minimum demand of around 600 MW. South Australia is connected to other regions of the NEM through the Heywood transmission interconnector that is rated to around 500 MW. The Australian Energy Market Operator (AEMO) estimates that only 10% of wind capacity and 31% of solar capacity in South Australia can be relied upon at times of peak summer electricity demand (Nelson and Orton, 2016). Figure 3 shows the evolution of the wholesale energy-mix in the South Australian region over time since 2000. Wind and distributed solar (not shown in Figure 4 as it sits ‘behind the meter’) comprise around half the energy supplied into the region.

Figure 3: Wholesale energy-mix in the South Australian region of the NEM

Source: AEMO data

Figure 4: South Australian wind and non-wind (i.e. thermal) output

Figure 4 demonstrates why existing financial derivative markets (baseload swap contracts – pricing energy; and peak cap contracts – pricing capacity) cannot be used effectively to manage physical and financial risks within the region. Wind output is inherently uncertain and is

unsuitable for forward contracting in the absence of other financial arrangements. For example, non-dispatchable generators cannot be sure that they can generate to fund the payments required but could sell fixed-price ‘swaps’ and buy a cap to manage the risk associated with this. To date, wind generation has not been contracted except through long-dated PPA style agreements. Swap contracts are not offered by wind generators and ‘cap’ contracts are generally structured for price events above \$300 per MWh. Lower strike priced cap contracts are not available for smaller but more frequent price variations due to the variability of wind.³

To demonstrate how financial markets may evolve, Figure 5 shows how a ‘synthetic financial generator’ might be created to offer new financial derivative products in the South Australian region. Intermittent, non-contractible generation (i.e. wind) would sell ‘firm’ capacity (of around 1200 MW in our example) but with complementary plant (such as OCGT, demand-response, advanced batteries or pumped hydro) contracted to operate when the wind is not blowing. This concept has already begun to progress with over-the-counter (OTC) ‘wind-firm’ and ‘solar-firm’ contracts being traded in 2018 in a number of Australian NEM jurisdictions.

Figure 5: Synthetic financial generator concept

In our view, given the marginal cost of an extra unit of *energy* generation is trivial in this scenario during periods of both peak and non-peak demand⁴, the relevant pricing for the consumer is the long-run average cost of building an additional unit of ‘firm’ capacity required to meet the consumer’s maximum demand. This is particularly relevant given the forecasts of AEMO with regard to periods of ‘negative demand’ (recall previous Section). In practice, the NEM would continue to be an efficient market for dispatching *energy* resources efficiently but contract markets would evolve to facilitate this type of capacity pricing.

³ In a non-restructured retail market, this would not necessarily be a significant issue. The spot price would extract efficiencies and any ‘missing money’ could be recovered through blended utility rates. However, Australia’s restructured retail markets require financial derivative markets to sit alongside the spot market to facilitate efficient risk management by prudent retailers.

⁴ This assumes there is no specific correlation between renewable output and peak demand.

4.2 Network tariffs

The Australian regulatory framework requires network tariffs to recover the overall cost of the existing network. The specific tariffs in each jurisdiction are approved by the Australian Energy Regulator (AER) in a revenue determination process. Tariffs also need to signal to network users the impact of usage on future costs so that the network develops in an efficient manner. This is particularly important as usage patterns change with the adoption of new technology like PV and storage.

The costs of electricity distribution networks are largely independent of changes in energy consumption (kWh) with network costs largely driven by the need to provide capacity to meet a network's peak demand (kW). The incremental cost of replacing or expanding the network will be different from the total cost of the existing network and one of the challenges for tariff design is to provide correct price signals while recovering total costs.

To date, small electricity users in Australia and internationally have been charged for their share of network costs based largely on their energy consumption. A variable rate has historically been used as it:

- served as a reasonable proxy for demand, especially in conjunction with inclining or declining variable rates for consumption blocks;
- was readily accepted by consumers; and
- was considered fair when compared to higher fixed charges which had a disproportional impact on small consumers (i.e. pensioners)⁵.

Energy efficiency, the use of new technologies that allow customers to self-generate, and structural changes to the Australian economy are leading to declining total electricity consumption. However, network peak demand, which drives network costs, is not declining. Household investment in self-generation allows customers to reduce their contribution to network charges without reducing their peak demand on the system (see Simshauser, 2016). The relationship between energy consumption and peak demand no longer holds and using volumetric network charges is driving inefficiencies not previously seen in the electricity industry.

At the same time, the consumption patterns of individual customers are becoming more diverse and the investment decisions that customers are making can have significant consequences for future network costs. Reforming tariffs to better reflect networks cost drivers is being promoted in Australia as providing many benefits. It will encourage better use of the existing network infrastructure and inform customer investments that minimise system costs. Tariff reform can also help avoid a situation where some customers are able to make investments that reduce their network charges but increase network charges for other customers.

Network tariff reform has focussed on introducing peak demand charges and/or increased fixed charges for small customers' usage of the network. The options being explored by Australian electricity distribution networks are highlighted in Table 1. These network tariffs are aimed at being more cost reflective in that the customers' contribution to network costs better reflects the drivers of future network cost. This should promote economic efficiency and ultimately lead to lower prices overall. Importantly, customers will still be able to increase or lower their network costs through their electricity usage behaviour.

While most networks still rely on fixed and volumetric distribution charges, time-varying rates and demand charges are becoming more common. As highlighted in Table 1, Australian network

⁵ Brown & Faruqui (2014)

tariff reform is highly focussed on reducing the weight on the volumetric energy charge component and increasing the weight on fixed and/or demand charge components. In keeping with one of the key Bonbright (1961) principles, it is likely that the shift to demand tariffs will be progressively rather than immediately implemented.

Demand charges are based on a consumer's maximum demand (kW) during those hours of the month in which total network demand is at a maximum. Since most capital investments on the distribution network are driven by peak demand, Australian networks are stating that charging for demand will better align the price that consumers pay with the costs that they are imposing on the system. To date, demand charges have been used widely in various forms for commercial and industrial customers across the NEM.

Table 1: Network Options for Cost reflective network tariffs

<i>Network</i>	<i>State</i>	<i>Proposed future tariffs structures for small customers</i>
Energy Queensland	QLD	<p>Have introduced an opt-in demand based residential tariff including coverage of hot water load.</p> <p>Now trialling a demand subscription type of network tariff based on a variable monthly fixed charge for customers based on their nominated usage band during peak times in Summer. Consists of a low variable rate paid (\$/kWh) applied to total annual consumption, the monthly fixed charge (\$/month) and a 'top-up' rate (\$/kWh/summer month) which is applied to any consumption above the customers band limit on any day between the Summers months of November to March.</p> <p>The network charge is primarily linked to customer usage of the network between 4 pm and 9 pm in the summer season of November to March with a top-up charge paid for the maximum demand observed above the band in a given month.</p>
Ausgrid	NSW	<p>Signalling the introduction of demand pricing structures available to small customers.</p> <p>For current Time-of-Use (ToU) tariffs, focussed on increasing fixed charges and reducing volumetric components in off-peak and shoulder periods. Incentivise customers on flat tariffs to move to ToU structures.</p>
Essential	NSW	Demand-based network charges are default tariffs for small and residential customers with digital meters but ToU tariffs remain as an opt-out option. Continued reduction in variable rates and commensurate increases in fixed charges.
Endeavour	NSW	<p>Introducing opt-in demand tariffs for residential and small business customers which include seasonal demand charges.</p> <p>Assigning all new customers with interval meters to a 'transitional' demand tariff with the seasonal demand charges becoming cost reflective over time.</p>
Evoenergy	ACT	<p>Since 1 December 2017, have introduced demand tariffs as default tariffs for all residential and small business customers with type 4 meters. The demand charge relates to peak hours 5-8pm, for all days of the week.</p> <p>Time-of-Use tariffs are default for all other new residential and small business customers without interval meters. All tariffs with flat energy components are being changed to TOU components.</p>
Citipower Powercor United Energy Jemena Ausnet	VIC	<p>Victorian networks already have Opt-in Demand Tariffs for all residential and small business customers.</p> <p>Networks are currently considering either:</p> <ul style="list-style-type: none"> increasing the utilisation of the demand tariffs by mandatory assignment of customers to them; or amending the demand tariff structures into a demand subscription type model with larger monthly fixed charges based on customers' varying demand profiles. <p>The Victorian networks are also considering whether to apply bulk charging of network cost to the retailer based on aggregate demand of the retailer's customer base rather than associating network cost with individual customers. This would provide even greater disparity of network costs between retailers.</p>
SA Power Networks	SA	<p>Opt-in cost-reflective Demand tariffs for small business and residential customers with the network charge linked to customers' maximum demand between 4pm to 9pm. Varied rates also apply to shoulder periods.</p> <p>Mandatory assignment to a Demand tariff for 3-phase customers with progressive increases in cost-reflectivity until 2022.</p>

A modified demand tariff that is being trialled by the Queensland distribution network is a demand subscription tariff. This requires customers to ‘subscribe’ to a demand level and pay a monthly fixed charge for that level of demand in peak periods. A low volumetric charge means that consumption outside the peak period has low incremental cost to the consumer. The tariff also provides the option of the customer deviating from the nominated demand level if needed but the customers will pay a higher price for every extra unit of demand during the summer peak period. This demand subscription tariff better reflects the marginal cost to the network of electricity consumption outside of peak periods but also signals the high cost of any additional peak demand during the summer period.

Figure 6: Current and potential network charges, fixed and variable

Figure 6 highlights the potential impact of new network tariff structures by analysing an average residential customer that uses 4,000 kWh per annum under the current fixed/variable network tariff and under the proposed demand subscription (DS) tariff, dependent on the customer’s demand profile. The split between fixed and variable costs is also shown. The customer pays an average of \$150 per MWh under current network tariffs and pays around the same under the demand subscription tariff if they subscribe to the band 4 demand level. Note however, the fixed and variable components of the bill have reversed. If this customer consumes less of its 4000 kWh during the summer peak period, then it may be able to subscribe to a lower level (band 2 or 3) and pay much cheaper network charges. However, if the customer subscribes to a lower band but then consumes more energy in the summer peak than it has nominated, the peak demand exceedance charges are significant, and the customer will pay more. Under the demand subscription model, customers pay greatly different amounts dependent on usage in peak periods which better reflects the customer contribution to network cost.

Another important outcome of this network reform is the impact on the marginal cost of consumption for customers. As shown Figure 7, the current network tariff has an average cost of \$150 per MWh but the marginal cost to the customer for every additional MWh is zero. Under the demand subscription model, any consumption in peak or off-peak times has a marginal cost of

less than \$20/MWh as long the usage in peak periods remains below the demand subscription level. If the customer uses electricity in peak periods at a level beyond its subscription band then the marginal cost is commensurately high.

Figure 7: Cost of an additional MWh of consumption

5. Concluding remarks

There is an ongoing shift in the Australian electricity system towards renewable energy. As these technologies are almost entirely ‘fixed cost’ in nature, Australia’s electricity tariffs are beginning to evolve to reflect this. Networks are beginning to trial demand ‘subscription’ offerings and wholesale derivative markets are beginning to price the unique qualities of renewables and firming technologies. Nelson et al (2018) make the observation that digital technologies will allow pricing to be unique across the supply chain for each customer for each time period. This will result in price signals dynamically reflecting costs for the first time in the history of the sector.

Ultimately though, it will be the way in which the retailer packages up these cost structures that will impact on consumers. There is little reason to think that new retailer ‘subscription’ models will not evolve in the future. Customer ‘peak demand’ could be priced through a fixed cost subscription payment. Retailers will price the long-run average cost of building an additional unit of ‘firm’ capacity required to meet the consumer’s demand during a system peak event. This contrasts with the dominant thinking in the literature as the marginal cost of an extra unit of *energy* is trivial in high penetration renewable systems during periods of both peak and non-peak demand (due to the emergence of energy storage).

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