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Harnessing electricity retail tariffs to support climate change policy

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Abstract

Legacy electricity retail tariffs are ill-adapted to future electricity systems and markets, particularly with regard to accommodating the multi-faceted shift toward decarbonisation. We examine how retail tariffs need to be reformed to not only meet the future revenue requirements of energy-suppliers and networks but also to help achieve the environmental objectives of the energy transition. While existing literature has explored the link between retail tariff structure design, wholesale markets and/or network cost recovery, there is less recognition of the impact of tariff structure design on environmental objectives. This paper reviews the demand responsiveness of household customers to electricity prices and implications of retail tariff structure and design for the policy targets of CO₂ emissions, energy efficiency, and renewable electricity generation, in addition to electricity system. A review of the literature provides a theoretical basis for price elasticity of demand and electricity retail tariff design, and we explore the environmental implications for future retail tariff design options via examples of various tariff structures in the EU and US. The research links the topics of emissions mitigation policy and market design, and should add empirical insights to the body of academic literature on future electricity markets. It should also be of interest to policy makers wishing to consider retail tariff structures that promote decarbonisation of the electricity system through multiple objectives of improved energy efficiency and increased shares of renewable electricity within future electricity markets.

1. Introduction

Decarbonisation of energy, and in particular electricity supply, is well underway through a variety of pathways around the world. While integrating new generation technologies, as well as accommodating dynamic energy demand, is causing disruption, transformation, and innovation at every scale, these effects can be particularly pronounced at the distribution level. The increasing expansion of distributed generation (DG) technologies like solar photovoltaics

(PV), a continued policy emphasis on energy efficiency and responsive demand, and considerable changes to the utility industry all require a realignment of the regulatory regime that governs retail electricity markets. Specifically, it is critical to understand what price signals consumers face, whether and how they respond by adjusting demand, and how those price signals interact with widespread availability of self-generation.

Legacy tariffs, initially architected to moderate unidirectional electricity flows from centralised generation sources to passive energy users, are poorly suited to facilitate the more dynamic retail electricity market that will ultimately deliver a decarbonised future. In addition to increasingly muddled price signals that arise from historical tariffs, their component elements are also charged in ways that may not fully and equitably distribute the cost of maintaining a functioning physical electricity grid. In this context, we aim to explore the question of which retail tariff structures are capable of delivering on environmental policy objectives – emissions reductions, renewable energy deployment, and efficiency energy consumption – while covering network costs and providing appropriate market signals to suppliers.

Existing literature has explored many aspects of the complex linkages between retail tariff structure design, wholesale markets, and network cost recovery. However, there is little empirical discussion of the impact of tariff structure design on emissions mitigation objectives. This paper examines the implications of retail tariff structure and design for the policy targets of CO₂ emissions, energy efficiency, and renewable electricity generation, in addition to electricity system cost recovery via a review of the literature and discussion of case studies that demonstrate emerging principles in rate design for a low-carbon future. The research links the topics of emissions mitigation policy and market design, and should add empirical insights to the body of academic literature on future electricity markets.

Critical to this discussion of electricity consumers' response to price signals under evolving rate structures is the question of whether consumers are indeed price-responsive, as demand for electricity is often thought to be inelastic, at least in broad terms. We therefore begin by noting the empirical basis for assuming that customers can and do adjust their total energy use when faced with price changes. We explore the potential for electricity pricing to shift the time incidence of demand, and corresponding approaches to measuring and communicating energy usage in a residential customer context. We further consider the interaction between tariff design and incentives for consumers to adopt DG, as well as emission outcomes associated with variation in retail tariffs, and alignment of retail pricing structures with utility and network

costs. Finally, we discuss applied examples of changes to rate design such as the introduction of demand charges for residential customers and fixed bill plans that provide consumers with cost certainty in exchange for higher rates. We conclude with summary comments on the continued tension within rate structures between utility cost recovery, fair treatment of ratepayers, and ultimately, the delivery of a low carbon energy system.

2 Review of the Literature on Electricity Retail Pricing

A key underlying premise of the potential for retail prices to affect energy demand is that customers respond to electricity prices. That is, in order for retail tariffs to successfully encourage customers to reduce or shift electricity consumption, customers' demand for electricity must be at least somewhat elastic. As long as consumers are indeed price-responsive, it is then meaningful to consider the price signals they receive, in the form of electricity fees or tariffs. We note that the channel by which tariff structure design can influence renewable electricity, energy efficiency and climate change objectives is initially through changing the amount, pattern, and type of consumer electricity demand. We therefore begin by exploring the empirical basis for the foundational concept of electricity price elasticity and changing demand, and go on to discuss the literature about how price signals arising from different rate structures can affect demand and generation CO₂ emissions, how rate structures interact with financial incentives for distributed generation (DG), and the implications for rate structures with respect to utility cost recovery.

2.1 Retail price elasticity of demand

There is a significant body of research that examines how electricity demand in the residential sector evolves in response to changes in electricity and other fuel prices with many estimates of energy price elasticities of demand. The price elasticity of demand is a measure of the extent to which the quantity of electricity demanded responds to a price change, all else being equal. It is a unit-less coefficient, obtained by dividing the percentage change in quantity demanded by the percentage change in price (Faruqui and George, 2002). The main methodological approach in most relevant studies is econometric panel data and cross-sectional analysis with historical price and consumption or expenditure data to create estimates of the price and income elasticity of demand for energy products/electricity. A recent meta-analysis on the price elasticity of energy demand by Labandeira et al. (2017) found that there were fewer studies of the electricity own-price elasticity of demand, compared with car fuels and natural gas.

Estimates of energy price elasticities vary across countries and regions and time periods due to differences in the underlying characteristics; Labandeira et al. find that the differences are mainly due to the sample period, the type of publication, the type of consumer considered, the estimation method used, and whether the data are pre- or post-1973, when the oil price shock caused economic recession and a transformation of energy prices more widely. Others have found that factors such as different development levels, pricing mechanisms, and climates also play a role. Short term and long term elasticities should be distinguished in reported results, with long-term elasticities usually higher as consumers take time to adjust their decisions in response to prices. Miller and Alberini (2016) report wide variation in the results of estimation of elasticities from three datasets (-0.2 to -0.8). They find that “changing the estimation technique, aggregating the data or selecting specific years from the panel dataset can double or halve the price elasticity, which remains less than one”. We summarise a representative sample of studies in Table 1, below.

Source	Tariffs examined	Reported metrics	Estimated values
Labandeira et al. (2017)	Absolute average electricity price	Meta analysis of price elasticity of electricity demand	ST: -0.126; LT: -0.365
Miller and Alberini (2016)	Review of literature on pricing	Price elasticity of demand	-0.24
Nakajima and Hamori (2010)	Average electricity retail prices	Change in price elasticity over time	
Schulte and Heindl (2017)	Change in average electricity price	Price elasticity of demand for electricity	(-0.43) – (-0.02)
Verbic et al (2017)	Impact of average electricity prices on country energy intensity	National correlation between energy intensity and electricity prices	Change of 1 eurocent changes energy intensity by -400kgtoe per 1000EUR
Rapson (2014)	Change in average electricity price	Electricity price elasticity	-0.7
Schulte and Heindl (2016)	Annual household average electricity	Electricity price elasticity	-0.45 - -0.50
Wang and Mogi (2017)	Absolute average electricity price	Price elasticity of demand for electricity	ST: -0.51 - -0.68
Faruqui and George (2002)	Peak pricing	Own price elasticity of demand at on-peak and off-peak times	ST: -0.3

He et al. (2014)	Absolute average electricity price	Price elasticity of demand for electricity	-0.03 - -0.02
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Table 1: Sample of studies with estimates of electricity price elasticity of demand

Note: ST and LT represent short-term and long-term elasticities respectively

Most price elasticity studies noted here are based on average electricity prices and do not investigate the impact of price structure on electricity consumption. Nonetheless, there are some key findings that arise from this evidence base. Firstly, electricity price elasticity of demand is inelastic (less than 1) but it is not completely inelastic – consumers do reduce their consumption when faced with higher prices, however a change in price generally delivers a proportionately lower change in electricity demand. Secondly, the range of electricity price elasticity of demand values is large. In their review of the literature, Labandeira et al. find short run energy price elasticities to range from -0.80 to 0.06 and the estimated average to be -0.13 in the short term and -0.37 in the long run. Thirdly, electricity price elasticities are somewhat lower than other energy product elasticities, with gasoline being the energy product with the highest elasticity (-0.29) and heating oil the lowest (-0.017) in the short-run. Finally, long run price elasticities are approximately 3 times larger than short run price elasticities, indicating that consumers take time to adjust their consumption in response to a change in electricity price.

In addition to understanding the impact of average electricity prices on consumers' total demand, it is also important to consider the effect of types of electricity price signals in shifting the time incidence of demand. Dynamic or time-of-use (TOU) pricing has been extensively examined for its potential to shift consumption from periods of scarcity to off-peak periods. Under TOU tariffs, electricity rates may vary on a daily or seasonal schedule to reflect the higher cost of providing sufficient capacity at peak times of the day or year, encouraging consumers to shift demand to cheaper, off-peak periods. Faruqui & Sergici (2010) report the structure and findings of 15 cases of application of a dynamic retail tariff in the residential sector. They find that dynamic pricing can be effective in changing consumption, in contrast to changes to flat rate pricing, to which consumers are typically less responsive. Empirical results show that on average, TOU pricing reduced peak consumption by 3-6 %, while critical peak pricing achieves peak demand mitigation of 13-20 %.¹ Notably, Faruqui & Sergici (2010) also find that critical peak pricing with enabling technologies or feedback information

¹ Under critical peak pricing, customers may be charged high rates for consumption during a specified number of peak days or periods throughout the year.

consumption significantly improves the impact of dynamic pricing on electricity demand and yields an average peak demand reduction between 27-44%.

Further studies which examine similar issues indicate that feedback information can improve the effectiveness of dynamic pricing in fostering responsive demand. For example, Jessoe & Rapson (2012) examine a sample of residential electricity customers in Connecticut and find that providing real time information increases the price elasticity of demand when consumers are charged a time-based tariff. The authors estimate that households that face a time varying price but receive no real-time communication decrease consumption by only 2-6% on average, while consumers who also receive real-time information via a home display reduce consumption by 11-14%.

Similar findings are obtained by Gans, Alberini, & Longo (2013) from the analysis of a natural experiment in Northern Ireland. The authors estimate that giving consumers access to real-time information can decrease electricity consumption by 11-17%, although other benefits may arise such as GHG emissions reduction and cost reduction for utilities. The impact of increasing the stock of information available for consumers is investigated by Carroll, Lyons, & Denny (2014) as well. Particularly, the authors analyse a smart meter randomised control trial in Ireland coupled with a TOU tariff. Consistent with the literature, the study shows that total demand is reduced by 1.8%, with an average peak reduction of 7.8%. This suggests that consumers may use real-time information to learn about their electricity consumption and changing their behaviour accordingly. This intuition is further explored by Cosmo & O'Hora, (2017), who confirm that when information feedback is available for consumers, they are subsequently inclined to change their consumption following dynamic price signals. Thus, consumers can behave in a rational way when they receive highly granular information and a time-varying price signal.

In summary, the literature on retail prices appears to demonstrate that consumers change their consumption of electricity in response to both the amount of the average electricity price and the type of price. Higher electricity prices can drive consumers to reduce their overall demand for electricity while a time-varying price signal coupled with granular information encourages consumers to shift the timing of their consumption to off-peak periods.

2.2 Retail tariffs and GHG emissions

Retail pricing influences GHG emissions both with respect to the overall quantity of electricity that needs to be produced, as well as the fuel mix characteristics of the generation required to

meet consumption. As discussed in section 2.1, on the demand side tariffs can provide financial incentives for the deployment of DG, decreasing overall electricity demand, and can also be used to encourage or even enforce indirect load control. On the supply side, changing the timing of electricity generation can also change the overall emissions intensity of generation in a given hour, potentially leading to more consumption being met with cleaner sources. We discuss the empirical experience here, noting that emissions reductions from changing electricity generation arising from responsive residential demand will always vary based on a jurisdiction's marginal fuel mix at a particular time, meaning the resulting impact is not proportionate.

Depending on the composition of the fuel mix, tariffs varying over time can incentivise electricity customers to align their consumption to the temporal variability of the GHG emissions of electricity production. In this case, the changes in demand induced by a time-based price signal reduce GHG emissions (Finenko & Cheah, 2016). Among the dynamic tariff options, real time pricing (RTP) represents an opportunity to improve the efficiency of electricity markets by enabling demand response. As opposed to other retail electricity tariffs, RTP sends a price signal that is directly linked to the wholesale market and consumers receive highly granular information. As such, under emissions-based RTP, customers could receive a combination of favourable pricing and real-time information to shift consumption to times when marginal emission rates are low. However, the effectiveness of RTP and other time-based tariffs as an instrument to foster GHG emissions savings is still unclear, as suggested by the findings reviewed in *Table A1* in the Appendix. In one example, Stoll, Brandt, & Nordström, (2014) compare the impact of three types of price signals on electricity generating emissions: time-based, wholesale price-based and emissions-based price signals. Although the resulting emissions savings vary across all country case studies, they find that in Sweden there is a clear trade-off between the economic efficiency of RTP and the resulting impact on GHG emissions, which increases by 36%. This is mainly due to the peak fuel mix of the Swedish electricity sector and the misalignment between intensity of supply and demand response.

Although RTP may increase system emissions in some circumstances, Madaeni et al. (2013) show that the combination of RTP and wind energy generation improves the cost effectiveness of reducing GHG emissions through the substitution of fossil fuel technologies with renewable energy. While the type of fuel used for baseload and peak generation limits the emissions benefit of wind energy, this is offset when wind energy is coupled with RTP, yielding higher emissions savings per unit of marginal dispatch cost. Kopsakangas-Savolainen et al (2017)

suggest that the extent of GHG emissions savings that can be induced by RTP is correlated to the hourly distribution of electricity consumption. Similarly, Ata, et al. (2016) argue that the composition of the fuel mix determines the GHG emissions impact of dynamic pricing. Particularly, the study suggests that the difference in the emissions intensity of baseload and peak generation drives the variability of results across electricity markets.

The existing studies highlight the key factors that need to be considered when evaluating the impact of dynamic retail tariffs on GHG emissions. In line with this literature, Bergaentzlé, Clastres, & Khalfallah (2014) suggest that the effectiveness of dynamic retail pricing, both as individual instruments and as a combination of tariff designs, varies across countries and is dependent on the composition of the fuel mix and the possibility for interconnection. Moreover, Kök, Shang, and Yucel (2016) show that the type of renewable resource available to produce electricity impacts the effect of different tariffs designs on GHG emissions. The authors show that a flat rate yields higher emissions savings, as it fosters higher investment in renewable energy than peak pricing. This holds if the output of the renewable resource is greater during peak rather than off-peak periods. If the opposite applies, then peak pricing results in higher investment in clean generation technologies.

In broad terms, the literature would suggest that there is scope for retail electricity tariffs to act as a tool of environmental policy for the electricity sector. Particularly, by using time-based pricing it is possible to reduce GHG emissions while improving the efficiency of retail markets in covering electricity system costs. However, the results are very dependent on the generating fuel mix and therefore the evaluation of the impact of the tariff should be based upon the correlation of the hourly intensity of electricity supply and the time distribution of renewable resources with the demand profile, perhaps via unit commitment modelling. The choice of a pricing instrument because of its environmental benefit may not be always consistent across electricity markets with the economic efficiency aspects of retail pricing and detailed, local analysis is required.

2.3 Retail tariffs and Distributed Generation

As noted in Sections 2.1 and 2.2, customers may reduce or redistribute their energy consumption on the basis of both electricity price and tariff structure. Another response to price signals can be to invest in on-site distributed generation (DG), by which a household produces its own electricity, reducing demand for electricity supply from the servicing utility. The availability of DG technologies at competitive prices and with government financial incentives

has increasingly led to DG deployment at scale in many jurisdictions. The proliferation of consumers who reduce demand by producing their own electricity – typically from solar PV – has had significant implications for electricity market design. Investment signals for renewable DG technologies are also shaped by the tariff structures through which energy suppliers, producers, and network operators recover costs from ratepayers. In addition to studies that examine the effect of these structural changes on utilities (discussed further in Section 2.4), a significant body of literature explores the relationship between distributed energy generation (mainly in the form of rooftop solar PV) and retail rates. These impacts are examined both in terms of the way in which tariff structures affect the economics of customer-sited DG, as well as more dynamically, how increased DG penetration over time can impact retail pricing, and by extension, customer economics. We review both categories of literature here.

2.3.1 Impact of Tariff Structures on DG Customer Economics

Several studies examine the impact of various rate structures on annual bill savings for homes with DG, comparing various combinations flat rates, tiered rates, time-of-use (TOU) pricing, real-time pricing (RTP), and net energy metering (NEM). Table A2, in the Appendix, summarises findings from a representative sample of relevant papers.

Overall, the literature indicates that TOU pricing is more favourable for DG customers compared with flat energy unit pricing. When TOU pricing is combined with block pricing, with increased rates for higher total demand, high energy users tend to realise greater savings compared with low energy users, as DG allows for reduction of overall demand, allowing energy-intensive households to avoid higher block rates. For example, Borenstein (2007) examines the impact on solar PV households in California when subject to both flat and TOU pricing. The analysis uses metered consumption data from customers serviced by California's two largest utilities, Pacific Gas and Electric (PGE) and Southern California Edison (SCE), to determine whether moving from flat to TOU pricing adversely impacts solar customers. Results indicate that only 5% of PGE customers are negatively impacted (all others enjoy bill savings), compared with half of SCE solar customers. This is due to the tiered structure of SCE's flat rate, compared with its TOU rate, which at the time of study was not tiered. Both the PGE flat rate and its TOU rate were tiered, and featured steeper block rates. As a result, large residential consumers benefit from moving away from tiered usage, where much of the electricity was charged at higher block rates. Low consumers, conversely, are hurt by paying a higher average price for their lower consumption levels. La Monaca and Ryan (2017) showed that in regions with low irradiance the economics of solar PV are worsened with two-part tariffs (comprising

volumetric energy and fixed components) compared with one-part energy-only flat rate tariffs. Subsequent studies appear largely consistent with these findings.

2.3.2 Dynamic effect of DG penetration (Feedback Cycle)

The literature discussed above explores the impact of changes in rate structure on bill savings or overall customer economics of solar PV in a static environment. That is, these effects do not consider how increasing penetration of DG (in the form of solar PV) may, over time, result in changes to retail rates and rate structures. In future scenarios with high residential solar PV deployment, a feedback cycle can occur as an increasing proportion of customers installing solar PV reduce their electricity bills, thereby reducing their contribution to overall network costs, causing utilities to raise rates. Higher rates, in turn, create a further incentive to install solar PV, leaving customers who are unable or disinclined to adopt solar PV to pay an increasingly high proportion of total grid costs, thereby cross-subsidizing PV households. *Table A3*, in the Appendix, examines the effect of the feedback cycle on either PV customer value/savings [VALUE], the time required to achieve PV penetration levels [PV PEN] as a result of changing price signals, or retail rates [RATE] charged to all customers.

Broadly, the literature indicates that while cross-subsidization principles tend to hold true, their adverse effect on non-DG customers can vary considerably, and tends to be meaningful at PV penetrations much higher than those observed at present in most markets (Johnson, 2017). Overall, only 1% of electricity in the US comes from solar, up to 6% - 8% in high PV markets Germany and Italy respectively; however, as rates vary at the sub-country level, local penetration provides more detailed context. The impact of increased PV penetration can also vary considerably depending on the presence of NEM, which can add considerable cost to non-PV electricity bills, particularly relative to solar resource, as shown by Janko et al (2016). Janko et al (2016) show, for example, that the impact on retail rates when 20% of homes adopt solar PV varied from an 8% rate increase in Seattle, WA, where solar resource is low, to a 24% increase in Pheonix, AZ, where solar resource is high. Another study, Dargouth (2016), examines instead the feedback effect that occurs when increasing PV penetration rates shift the peak production time, lowering market prices at that time, thereby reducing the value of PV for customers on a time-of-use tariff. Dargouth (2016) finds that as the value of solar PV falls due to the shift in peak pricing, distributed PV deployment could drop by 14% – 61%, depending on other rate design factors such as fixed bill charges and partial NEM.

2.4 Revenue and Tariff Regulation

We now turn from consumer response to the literature on the role of tariff structures on the ability of utilities to cover the costs of electricity production, transmission, and distribution. While the main focus of this paper is concerned with market signals to residential customers, the amount and time incidence of customer demand and tariff structure also have significant implications for electricity provider revenues. As such, in considering how tariffs should be structured, it is critical to distinguish between different bill components and their underlying cost drivers. In particular, identifying which costs are regulated (e.g. network costs) and which are able to be offset (e.g. energy supply costs) reveals the parameters or baseline costs with which tariffs must be aligned. In this section, we examine the literature on the requirements for retail tariffs to enable DSOs to adequately invest in network infrastructure, recover costs, and receive an appropriate rate of return, all while grid customers pay fair network prices.

Residential electricity retail tariffs are generally composed of three components: (1) energy and supply, (2) taxes and levies, and (3) network costs. In deregulated electricity markets, energy and supply prices (1) are fully deregulated for all customers reflecting the marginal costs of generating and supplying electric power to the end users. Dependent on national policies, taxes and levies (2) are imposed by governments. The final component of electricity tariff, the network costs (3) are regulated charges that ensure that network users receive value for money while the network companies earn a reasonable return on their activities. Network operators are regulated natural monopolies that are legally and functionally unbundled² from generation and supply, and energy regulators, among others, set their total allowed revenues. Low- to medium-voltage lines (local-level) are typically managed by a distribution system operator (DSO), while high- and very high- voltage lines are managed by transmission system operators (TSO). Because the end-user delivery of electricity happens mostly on the local grid level, distribution network charges represent the main share of network charges.

In addition to the three components named here, distribution tariff design must also reflect the reality of the rapid growth in distributed grid resources, including DG, and the additional network costs that may arise from both microgeneration as well as a range of other grid modernisation considerations. These costs can be discussed in the context of either the economic regulation of DSOs that allows additional revenues for the additional network costs from DG integration, or on the network tariff design for grid users that adequately reflects the

² Directive 2009/72/EC Concerning Common Rules for the Internal Market in Electricity and Repealing Directive 2003/54/EC, European Communities, 2009.

network costs in cost-causal and equitable manner. We focus on the latter, and assume that changes in the distribution tariff design for grid users do not affect the total allowed (regulated) revenue of the DSOs and only affect the costs between grid end users. This assumption has been held in previous studies that focus on the distribution tariff structure (Honkapuro, et al., 2017; Picciariello;Reneses;Frias;& Söder, 2015).

The major costs for DSOs are sunk and fixed costs, typically representing around 60% and 20% of their total costs respectively, whereas operating costs take approximately 20% (Simshauser, 2016). This can vary depending on location, but conventionally aggregate network tariffs (excluding generation, carbon, and supply charges) follow a two-part structure which includes a fixed rate (€/period) and a uniform variable rate (€/kWh). The final residential customer may receive one bill, which incorporates networks, supply, and policy costs, two bills, which separate supply from network costs, or even three bills which separate supply, DSO, and TSO costs. As a result, the end-customer's actual comprehension of different charges, how they come about, and how they could potentially affect the costs of individual components by behavioural change may differ considerably by jurisdiction. Moreover, distribution tariffs that are based purely on uniform variable rate (e.g. one-part tariff with €/kWh) or that reflect sunk costs only marginally (e.g. two-part tariff with small fixed charge, €/kWh + €/period) will not reflect the economic reality DSOs face at very high rates of DG penetration. With the standard two-part distribution tariff, households with solar PV (or, indeed, those who invest in energy efficiency technologies that reduce overall demand but not peak instantaneous demand) may not pay network costs in proportion to their reliance on the grid, whereas households without PV (or who do not or cannot become more energy efficient) may have to pay higher rates to make up these costs (Simshauser, 2016). This is because households with PV may save on flat-rate variable charges, though their peak demand requires the same sunk and fixed cost investments from the DSO's perspective. As a result, some utilities have begun to evaluate three-part tariffs (e.g. €/kWh + €/period + €/kW/period) that add an additional capacity (demand) charge (€/kW/period), due to the non-trivial growth in distributed generation, such as PV. Such tariffs are explored further in Section 3.

In terms of ensuring that rates are aligned with the fair allocation of network costs, Eid, et al. (2014) show that the combination of net metering and pure volumetric tariffs is the most detrimental with respect to cross-subsidies, compared to alternative tariff structures, such as those that include capacity (demand) charges. Another analysis (Picciariello;Vergara;Reneses;Frias;& Söder, 2015) shows that substantial cross-subsidisation

from consumers to prosumers may occur, and that the magnitude of this effect depends on the amount of distributed generation connected to the grid and the network characteristics. Solutions to overcome cross-subsidization are typically capacity, demand, or power-based distribution tariffs (Tuunanen, Honkapuro, & Partanen, 2016) that include electricity demand charge (Simshauser, 2016). Tariffs with peak capacity components have been identified as more cost-reflective, equitable and sustainable from DSO's economic perspective (Honkapuro;Partanen;Tuunanen;& Niemelä, 2012).

3. Design Options for Future Retail Tariffs

From the previous section, we see that electricity retail tariffs can influence the pattern of consumer consumption of electricity but must also meet the revenue requirements of a modern electricity system. It is also clear that the emergence of DG and responsive demand is forcing changes to the way in which electricity is bought and sold both by utilities and suppliers, as well as by retail customers. Rate designs that accommodate these new realities are emerging in ways that may have varying impacts on uptake of renewables, investment in efficiency, and overall emissions. In this section we discuss options for the design of retail tariff structures within the context of traditional pricing theory that meet the requirements of future electricity markets but also environmental objectives as far as possible.

We begin with some principles of electricity retail tariff design and explore whether environmental objectives are implicit in that body of theory. We then provide some examples of retail rate structures which are of rising importance from a cost recovery perspective in the context of a high-renewable-penetration, high-efficiency future, and reflect on their capacity to align climate change and cost recovery objectives. While measuring these impacts is difficult in early stages, we highlight here some demonstrated examples of alternative tariff structures, as well as potential interaction with DG customers. We focus on pricing regimes in which consumer price signals are more reflective of variation in wholesale costs, and those which reflect the emergence of self-generating customers. We note that increasingly price differentiation rather than flat-rate energy unit pricing appears to more appropriate for a capital-intensive industry like energy, in which the service provided is heterogeneous on the basis of both time and location and increasingly operating costs are falling (Oseni & Pollitt, 2017).

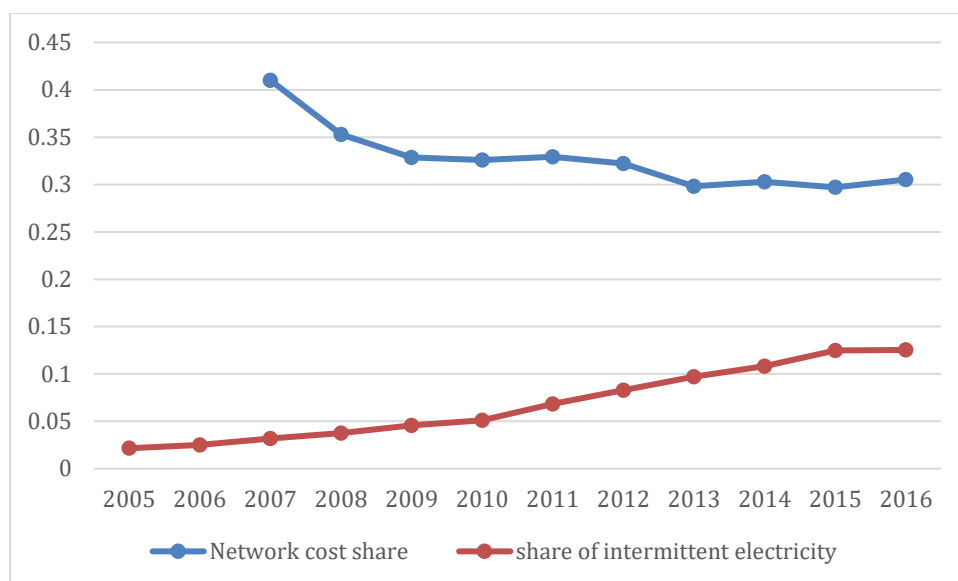
3.1 Principles of retail tariff design

The theory of the design of electricity retail pricing has historically been situated within the broader theory of public utility price setting. Although the electricity retail prices in many

jurisdictions are no longer regulated, they do demonstrate two main attributes of public utilities, namely the special public importance of the services they provide and the possession of technical characteristics that often lead to monopoly or ineffective forms of competition (Bonbright, 1961a). In the case of deregulated electricity markets, while retailers are competitive; transmission and distribution networks are natural monopolies and therefore these components of the retail price are usually regulated through a regulatory authority.

In public utility theory, tariff-setting should strive to achieve multiple functions, namely: efficiency, compensation to drive production, fairness, and optimal use and rationing (Bonbright, 1961b). In perfect competition, these functions should be in harmony with each other, however for regulated monopolies, these functions are likely to partially be in conflict and may require compromise.

To add complexity to this situation, in many jurisdictions electricity utilities are neither perfectly competitive nor a vertically-integrated monopoly. In Europe, for example, most countries' electricity utility companies have been deregulated (European Union, 2009). However, transmission and distribution networks are natural monopolies and therefore mostly remain state-owned. So while overall retail prices are deregulated, the components of the retail price relating to the network are set by the regulator. With increasing shares of distributed generation and lower generator revenues, higher fixed shares of the retail price may become reality and so the regulated portion of the retail price is likely to become more important in future years (Betzuge, Helm, & Roques, 2014). However, a high-level view of the average share of network costs of household retail prices across Europe in Figure 1 appears to show that the network cost share has not risen with rising shares of intermittent renewable electricity generation. Further detailed investigation of this data is needed.



Source: Eurostat data

Figure 1 Comparison of EU28 shares of intermittent electricity and network cost share of household electricity prices

Notes: share of intermittent electricity is the ratio of total wind and solar PV generation to total electricity generation in EU28. Network cost share is ratio of the average network price component to the average household electricity price (Band DC: 2500 – 5000 kWh per year)

A consideration not included explicitly in the four functions given above is any kind of environmental objective. Environmental values could implicitly be part of a compensatory objective if carbon constraints and markets exist and the price is passed through to consumers. However, even under those conditions, households do not usually have the information or price differentiation needed to enable them to choose less carbon-intensive electricity services. The fourth function incorporating demand-control or consumer-rationing is aligned with energy efficiency objectives and could encourage consumers to reduce electricity consumption or investing in energy-saving technologies but not motivate renewable or carbon emissions reduction behaviour.

As per Sakhrani and Parsons (2010), “*The tariff design must not only be influenced by the technical and economic characteristics of the system, but also the secondary policy objectives that policy makers wish to achieve, while allowing network companies to recover the costs of building and maintaining the network.*” When viewed through a security of supply prism, environmental objectives are secondary. The discussion of retail tariffs in the literature has not focussed on secondary environmental objectives, including climate, energy efficiency and renewable energy policy. However, with increasing pressure among policymakers to meet climate and energy policy targets, environmental considerations are moving up the priority

chain. Keeping this in mind, we now examine some empirical examples of some key emergent design options, and regard their potential to include environmental objectives.

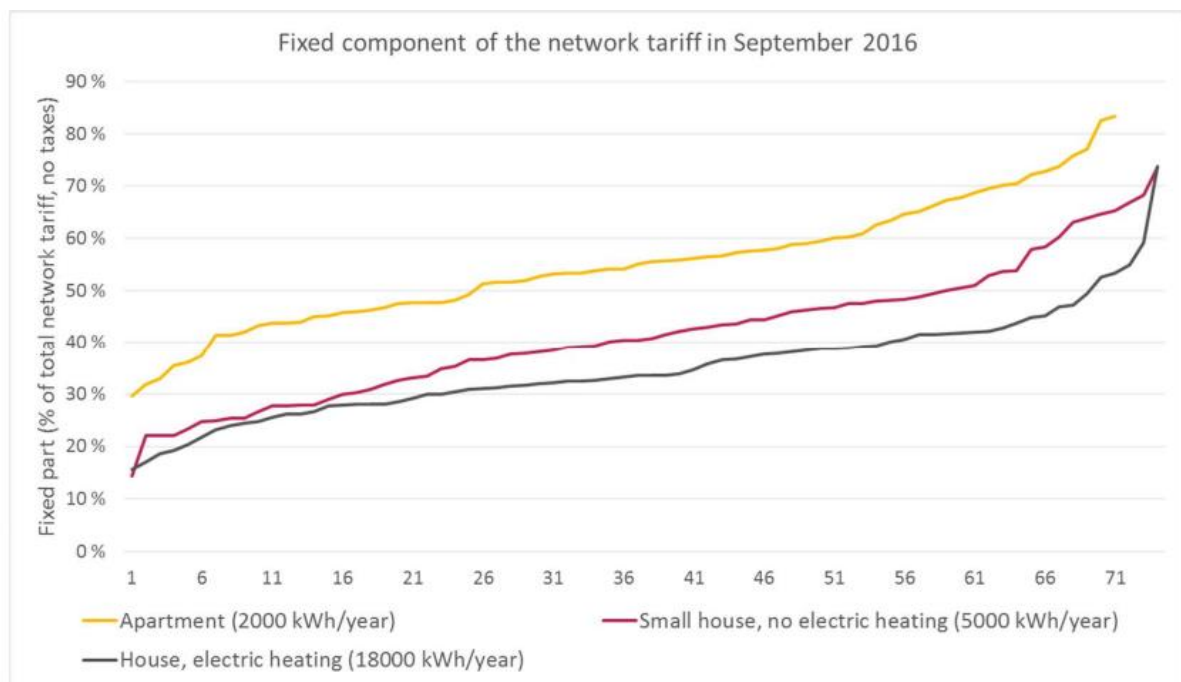
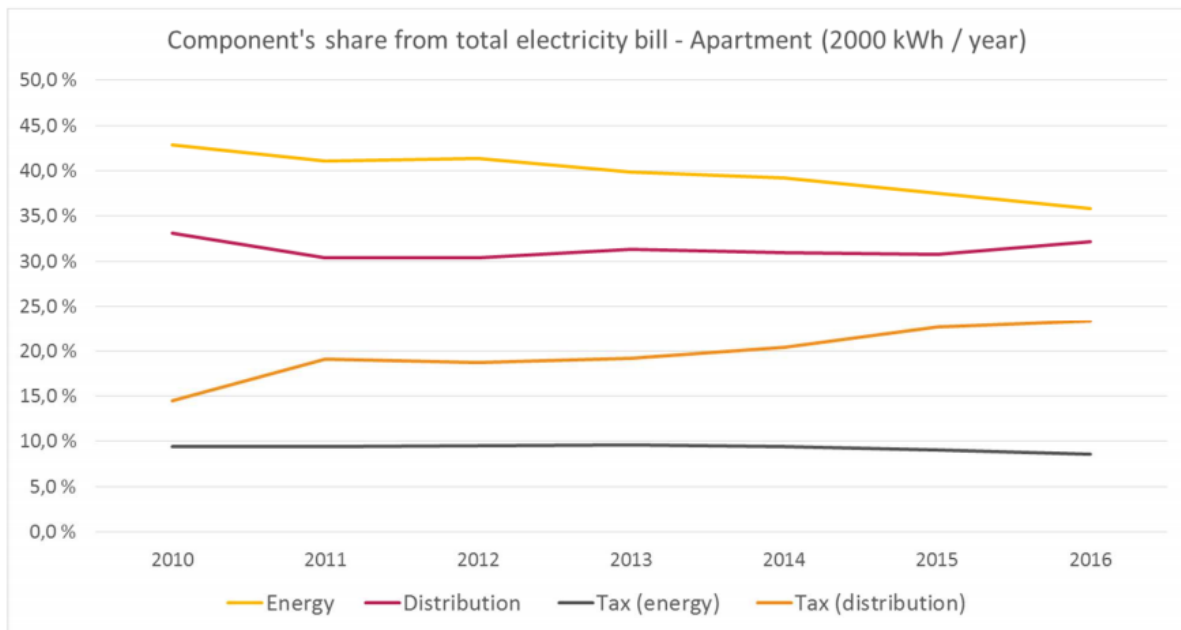
3.2 Demand Charges

As noted in Section 2.4, some utilities are considering implementation of demand charges for residential customers. Historically, demand charges have been applied more commonly in commercial and industrial rate classes, and constitute an additional bill payment based on the size of customers' peak usage. That is, demand charges effectively implement a fee based on the maximum amount of electricity the customer may draw from the grid throughout a time period, even if overall usage is low. Demand charges can be based on customers' demand during system peak hours, with the aim of better reflecting the direct generation and network costs that are driven by peak demand. However, in some cases they may only be based on highest demand during a given time interval, irrespective of whether demand occurs during peak or off-peak times and therefore do not promote reduction in peak demand. One of the main motivations for using demand charges is to prevent the possibility of cross-subsidization of grid users without DG (consumers) to those with distributed generation (prosumers) under one or two-part tariffs (Simshauser, 2016; Strielkowski, Štreimikienė, & Bilan, 2017).

3.2.1 Finland

In Finland, in addition to the national transmission system operator (TSO), there are over 70 privately and publically owned DSOs. The DSOs set their own tariffs in compliance with regulatory guidelines (Electricity Market Act, 588/2013, 24§ and 54§). These support the general energy policy goals, such as demand response, energy efficiency, equitability and cost-causality. Also, small electricity producers, i.e. households with roof-top PVs, are freed from distribution fees and can make directly an agreement with electricity suppliers who purchase their excess production.

However, the continuous trend of increasing share of fixed charges in network tariffs and price hikes by the largest DSO Caruna in early 2016 sparked a debate about the efficiency of the current two-part network tariffs in Finland. The two main arguments are that the volumetric network tariffs do not reflect the cost structure dominated by sunk costs, and that end-customers cannot influence the fixed price component in their bills. The second point further leads to inefficient usage of the distribution network resources overall.



Source: Finnish Energy Authority, 2017.

Figure 2: Components of electricity household retail bills in Finland

Power based network tariffs, or demand charges, were implemented until recently only for industrial (large) customers. However, to address the identified limitations, two DSOs from the cities of Lahti and Helsinki (Lahti Energia and HELEN) have begun to roll-out power tariffs also to small customers. The DSO HELEN has rolled out power tariffs to its 18,000 small

customers on 1st July 2017. The structure of their three-part network tariff consists of a monthly fixed charge, a monthly power charge, and a volumetric energy consumption charge (day and night pricing). Currently, both DSOs charge approximately 0.78 €/kW/month which is calculated from the hourly demand peak from the last twelve months. This implies that customers with steady demand will have a smaller power charge compared to customers with peaky demand. Hence, both DSOs and customer's objectives meet when customers can respond to the power charge price signal and reduce peak demand³ and the DSOs can better utilise available resources without the need to expand infrastructure to accommodate infrequent demand peaks. However, whether basing the power tariff on a twelve-month hourly peak demand is the most cost-reflective way for DSOs' sunk costs may be questioned. Multiple alternatives are being discussed (Honkapuro, et al., 2017), such as more frequent peak demand measures or based on demand coinciding with system-wide critical peak.

3.2.2 Massachusetts

In contrast to Finland, the introduction of demand charges in Massachusetts has been driven more directly by increasingly penetration of DG in the form of solar PV. According to installation figures published by the Solar Energy Industry Association (SEIA), the state of Massachusetts has one of the highest rates of solar adoption in the US with more than 2,000 MW of solar, or 7.75% of total electricity. Residential solar as a percentage of total installations peaked in 2015 at approximately 46% in 2015 (SEAI, 2018), and rooftop solar is projected to reach nearly 8% penetration (as a percentage of electricity generation) by 2030 (Barbose, 2017). Massachusetts residents have historically had access to a range of state and federal incentive programmes to encourage adoption of rooftop PV, including net-metering, low-interest solar loans, the Investment Tax Credit, and compensation for production of solar renewable energy credits (SRECs) for compliance under the Massachusetts Renewable Portfolio Standard (RPS) (current listing of incentives available in DSIRE, 2018).

In early 2018, Massachusetts utility Eversource became the first regulated utility in the US to win approval for a three part tariff for DG customers, which would implement a demand-based charge between \$2.21/kW and \$2.71/kW per month, depending on residential rate class. New proposed rates in Massachusetts also include a customer charge of \$10.88 - \$13.89 per month, and changes to rate availability will remove the option for net-metering customers to avail of a TOU tariff (MA DPU, 2018). Though the utility's justification for the rate change was based

³ Every household is equipped with a smart meter in Finland and individuals can access own historical electricity consumption in hourly frequency via Internet.

on the need to ensure parity supporting a network sized for peak demand, the newly implemented demand charge will be based on the customer's highest 15 minutes of usage, even if this usage interval occurs outside of the system peak (Trabish, 2018). Demand charges are uncommon in the US, and have not historically been implemented on a mandatory basis. In 2014, just nine US utilities offered rates with a demand-charge component on a voluntary basis, though only two saw meaningful enrolment (8-10% of customers, compared with less than 1% in other states) in these programmes (Hledek, 2014).

The magnitude of the effect of demand charges on the overall financial performance of solar PV in Massachusetts remains to be measured under the new regulatory regime. However, as an additional bill component, demand charges generally add at least moderately to overall electricity bills, reducing the value of solar to the PV system owner.⁴ The effect of this change on long-term adoption will likely depend upon the degree to which bill savings for solar PV owners decrease, as well as the interaction with other policy changes and continued cost reductions in the installed cost of PV.

With single bills incorporating demand charges in with other components, the price signal to customers is less clear and as such limited. However, in Finland where customers receive two separate bills (network and energy), customers are better able to see the price implications of their peak demand and reduce accordingly.⁵

3.3 Fixed Bills

Flat billing or "all-you-can-eat" for electricity, similar to typical pricing approaches for mobile telephone service, is often mentioned as a model that is likely to gain prominence in coming years due to cost recovery concerns. Historically, however, flat billing has not been common: Vatter and Barney (2015) list seven utilities that had fixed bill programs in effect in 2009, and note that the Georgia Power FlatBill programme was the country's largest, with approximately 150,000 customers in 2015. Neenan et al (2016) use choice modelling to gauge customer interest in TOU and flat billing tariff options, and find that for a simulated market, 62% of customers would choose to keep a conventional (flat volumetric) rate, 27% would choose a TOU rate, and only 11% would choose flat billing.

⁴ But in some cases bills may actually decrease with demand charges; for example if the volumetric part of the network tariff declines, customers with steady demand may even save costs.

⁵ There is an additional consideration here as to consumers' ability to understand the information communicated through different billing approaches; such concerns are relevant but fall outside the scope of this review.

In terms of prospective interaction with DG and impact on bill savings, it is not clear how a utility offering a flat bill retail tariff would reflect the presence of rooftop PV generation. A detailed forecast for the PV system based on size and capacity factor could provide the basis by which a utility might adjust a customer's flat bill amount. A forecast based on hourly production might limit the benefit of the PV system only to the customer's hourly self-consumption of rooftop PV, while a monthly forecast could account for a higher rate of self-consumption (netted over total demand and total generation in a month), providing a higher value of solar for the system owner. While this structure design allows utilities to cover infrastructure costs, it is not well-aligned with environmental objectives, as customers have little incentive to reduce or shift their electricity consumption or invest in renewable energy.

In the state of Georgia, USA, fixed tariffs are available in a fully regulated electricity market (Georgia PSC, 2018). The single, investor-owned electric utility, Georgia Power Georgia Power offers a range of rate options, including the Standard Service, with increasing block pricing in the summer and decreasing block pricing in the winter, a Smart Usage plan aimed at mitigating both total maximum demand and peak energy use, and a tariff specifically for Electric Vehicle (EV) owners offering highly discounted rates during super off-peak hours. Notably, Georgia Power also offers a FlatBill tariff, in which customers are charged a fixed, monthly rate based on 12 months of historical electricity use. While the plan does not require a true-up payment where annual energy usage exceeds the historical basis, the utility issues a new FlatBill offer at the beginning of the next 12-month period reflecting any update to projected usage. Per the Public Service Commission, Georgia Power may include in the FlatBill tariff a risk adder of no more than 10% to compensate for the risk of increased usage due to weather or non-weather related conditions (Georgia Power, 2011).

3.4 Net metering

Under net metering, electricity customers with on-site generation capabilities, such as rooftop solar PV, may offset their total usage by the amount of self-generation and be compensated for excess generation. This behind-the-meter arrangement allows customers to be billed only for the net amount of electricity they draw from the grid. Application of net metering varies, but some customers may be permitted only to self-consume the amount of electricity generated, while others may accrue credit for excess generation produced (i.e. in cases where total daily or monthly on-site generation is higher than total consumption). Dargouth et al (2011) provide a review of existing literature. Net metering is particularly common in the US where 41 states plus the District of Columbia and three territories had mandatory net metering rules in place,

as of July 2016 (DSIRE, 2016). As of 2013, Germany employed hourly net-metering, the Netherlands and Belgium permitted yearly net metering, Turkey allowed for daily net-metering, the UK and Spain allowed for self-consumption, and Italy allowed for net-billing.

Net metering rewards self-generation, however because every kWh of generation is effectively awarded at the same rate (the retail price of electricity offset or credited), it does not incentivize self-consumption. This effectively acts as the opposite of demand response, in that customers have no incentive to modify their demand profile, and behind-the-meter variations in load will be a function of the generation profile ((Darghouth, Barbose, & Wiser, 2014). Eid et al. (2014) note that net-metering has significant impacts on DSO cost recovery. However, depending upon the structure of individual schemes, net-metering could reward energy efficiency by reducing household demand, thereby increasing the amount of net export for which residential generators are compensated.

Net metering reduces behind-the-meter energy usage, and therefore leads to lower revenues for utilities. Jurisdictions that employ two-part tariffs to separate out the portion of retail charges that cover energy-only expenses and those which cover network and/or capacity costs may not be adversely affected with respect to covering those costs. Net-metering can also lead to distributional issues relative to tariff structure, in particular fixed charges; an equitable distribution of these charges is complex and has led to politically fraught tariff adjustments in some locations (see for example Davies and Carley, 2017)). An example of net metering is in the state of California in the United States described in the next subsection.

3.5 Time-varying electricity pricing

Under time-of-use (TOU) tariffs, electricity rates may vary on a daily or seasonal schedule to reflect the higher cost of providing sufficient capacity at peak times of the day or year, encouraging consumers to shift demand to cheaper, off-peak periods (Faruqui and Sergici, 2013). TOU pricing can be more broadly categorized as a price-based type of demand-side response, which aims to mitigate the inefficiency that arises when fixed retail rates do not encourage customers to respond to the volatility present in wholesale markets. It is a blunter version of RTP in which retail rates may reflect hourly or monthly variation in wholesale prices, but which may provide too frequent or detailed price signals with which customers may not be equipped to engage. Feedback tools such as in-house displays on smart meters, as discussed in the literature review in section 2, greatly increase the influence of variable pricing.

TOU pricing typically rewards household generators if higher prices coincide with times of high solar PV production, which is often the case both on a diurnal and seasonal basis. However, TOU pricing may also negatively affect the value of a PV system, as users with high demand during peak hours may suffer from higher costs under TOU pricing that offset the value of adding PV generation (Borenstein, 2007). TOU pricing in practice may have varying effects on household energy efficiency. If TOU pricing offers a general price signal to consumers about their cost of electricity, they may curtail their overall consumption, increasing energy efficiency but having limited impact on overall demand profile. However, if TOU pricing has its desired effect of shifting load to off-peak hours, consumption may remain at the same quantity, with little efficiency improvement.

Comparing RTP and TOU pricing, Borenstein (2005) finds that RTP pricing can reduce peak-generation overall, and damp down high-variable cost peaker generation, providing greater efficiency and social gains than more simplified TOU pricing. However, Celebi and Fuller (2012) point out that while RTP pricing corrects the mismatch in peak and off-peak pricing more precisely, TOU pricing may be more practical, as it allows for the fact that consumers may not have the tools or information required to respond to real-time fluctuations.

3.5.1 California

The importance of retail rates that can cover costs is particularly salient in California in light of the much-analysed energy crisis of 2000-2001, in which market manipulation by producers and other factors led to an 800% increase in wholesale prices, but retail rates were fixed, and thus suppliers had to provide power at a large loss. These costs were ultimately born by rate-payers, as the state rescued financially ruined utilities through bond issuance, which continues to be serviced by funds raised via a volumetric charge on customer bills.

California has a Renewable Portfolio Standard (RPS) requirement that the state meet 33% of its electricity needs from renewable sources by 2020 and 50% by 2030 (DSIRE, 2017). Integrating such a proportion of generation from variable sources will certainly require increasing operational flexibility, and therefore more responsive end-users. Furthermore, Bushnell (2004) and Navarro and Shames (2014) cite lack of price-responsive demand as a key cause of the California energy crisis. Indeed, an International Energy Agency (IEA) report cites a finding by Hirst and Kirby (2001) that a 5% reduction of demand during the California energy crisis would have curbed the highest wholesale prices by 50%. In order to remedy this, the state's suppliers now offer either tiered or time-of-use tariffs for residential customers, and

additional demand response measures for commercial and industrial customers are also in place.

The state also offers net metering arrangements that allow solar PV customers to be credited back for surplus power generation. In 2015, nearly a quarter of California's electricity needs were met with renewable sources, and at 7.5% of generation in 2014, California became the first state in the U.S. to achieve more than 5% generation from utility-scale solar. This figure increased to nearly 10% of generation when distributed solar is included (EIA, 2016). Cai et al. (2013) analyse the California rate structure and note the relationship between cost recovery and distribution relative to tiered rates. That is, because higher tier customers tend to adopt distributed PV under net-metering, this leads to an increase in net-metering costs, and a higher proportion of distribution costs borne by low-income customers. Given California's strong uptake of net-metering, it is clear that the current tariff structures are likely to require adjustment in order to meet future costs.

Conclusions

This paper has considered how the design of electricity retail tariff structures can be extended from cost recovery considerations to support climate and clean energy objectives. Most OECD and many non-OECD countries have set targets to increase energy efficiency and renewable energy penetration and to reduce CO₂ emissions. Responsive, low-carbon consumer demand will be critical to delivering on these objectives. Consumers can respond to electricity retail prices by changing the pattern and amount of their consumption of electricity. Without good quality, real-time information via technologies such as smart meters, the scale of impact to do so is more limited but the price elasticity literature demonstrates there is an impact nonetheless.

Most retail tariff structure theory and analysis is concerned with a design that promotes efficient operation of the electricity system. Public utility pricing theory would suggest that electricity tariffs should promote productivity, efficiency, fairness and optimal use of electricity. We argue that in the absence of well-functioning carbon markets, environmental policy objectives may not be implicitly included in tariff-setting considerations. Even in the presence of carbon prices, the retail price likely does not reflect the instantaneous CO₂ emissions from the electricity consumed. For these reasons, there is a clear need to examine the impact of current and future retail tariff designs on environmental targets.

In this review, we have taken as given the network cost recovery requirements of future electricity generators and network operators. We have then tried to unite this literature with

insights from studies on customer responses to electricity prices to examine how retail tariff structures could be designed to accommodate cost recovery concerns while providing incentives to consumers to support environmental policy objectives.

In most jurisdictions, electricity retail tariffs are typically one or two-part tariffs, where two part tariffs comprise a fixed and variable (energy-only) portion of the customer's bill. Varying-rate tariffs have long been considered to provide a more efficient price signal to consumers to reduce load at diurnal and seasonal peaks, with varying results on the times in the day and season. As noted, a three-part tariff, made up of demand charges, fixed charges, and variable energy-only pricing, is an emerging structure that may hold advantages for retail tariffs in electricity markets with high shares of renewable electricity generation. The example of Finland provides an illuminating example for how future tariff structures might develop. Specifically, three-part-tariffs provide a means to achieve multiple objectives within the tariff structure. The fixed charge component can cover infrastructure costs, even in future scenarios of reduced demand through energy efficiency and individual solar PV generation. These rates can be set by the regulator and be guided by regulatory economic principles as past retail tariffs. The energy-only component can be a time-variant rate to give consumers incentives to reduce load at peak times. Finally, the demand charge component should send a signal to reduce system peak demand.

These three components differ in their potential to support environmental objectives. A proportionately high fixed charge component in the retail tariff reduces the incentive for consumers to invest in energy efficiency or self-generating technologies in line with renewable energy targets, but does ensure that network costs are covered irrespective of energy efficiency or DG deployment. Variable, per unit energy pricing, combined with good feedback information, gives price signals to consumers to reduce their energy consumption overall and at peak times. This component could also be included in a more efficient net metering scheme or time-varying rate if desired. This will help energy efficiency and renewable energy targets. Finally, demand charges allow another price signal to improve the efficiency of operation by incentivising lower demand at peak times.

The way in which bill components are communicated to customers is also critical to the efficacy of tariff structures to drive responsive demand. A single electricity bill not clearly distinguishing between different cost components would blunt any price signal sent to consumers. This effect could be mitigated by generating either separate bills for energy and

network costs, or clearly explaining the cost structure in a single bill that would allow consumers to react to price signals. Provided that bills are clear and easy to read, and are accompanied by additional, accessible energy consumption information, this differentiation of bill components could provide customers with stronger incentives to engage in emissions-reducing behaviour.

Additional, more detailed analysis is needed to understand the full environmental impacts of a retail tariff structure in any jurisdiction. There are many uncertainties on the path from designing retail price signals and changing consumer demand to reducing system greenhouse gas emissions. These can include the many factors that influence decision-making and the sensitivity of a consumer to respond to a change in electricity price, such as their living conditions, information, and behavioural issues. Even once the level and timing of electricity consumption is known, the fuel mix and hence CO₂ emissions from the required electricity is not, depending on the local endowment of fuels, the legacy generating plant available, and the availability of intermittent renewable electricity. From this perspective, it is likely that the optimal retail tariff structure will depend most of all on local factors, although in the longer-term the most certainty from price signals can be gained through full decarbonisation of the electricity. Until then the impact of the various retail tariff structures on CO₂ emissions could be explored through further demand simulation and unit commitment modelling of different fuel mix and generation scenarios. Further exploration is also needed of the welfare implications of the tariff structures, especially to understand whether measures are needed to ensure that high shares of fixed components are not regressive.

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Appendices –Tables summarising the literature*Table A1: Impact of retail tariff on GHG emissions*

Reference	Tariff	Findings
Stoll, Brandt, & Nordström, (2014)	<ul style="list-style-type: none"> · ToU · RTP · based signal In each case 1 kWh shift from peak to off-peak is assumed. The simulation is run over a year for Great Britain and Sweden, 125 days for Ontario.	Great Britain ToU 10% savings RTP 12% savings based signal 14% savings Ontario ToU 4% savings RTP 30% savings based signal 30% Sweden RTP 36% increase
Madaeni, Member, Sioshansi, & Member, (2013)	RTP The results of the model are relative to Texas for one year.	13% emissions savings and 11-12% emissions savings

Kopsakangas-Savolainen, Mattinen, Manninen, & Nissinen, (2017)	RTP The authors compare different households with the same overall consumption but different load profiles. Finland is used as a case study.	Case 1 Different hourly consumption: 1-6% GHG emissions savings for one year. Case 2 Load shifting to a lower emissions hour: 3% equivalent savings for one week. Case 3 Smart timing of electric heating: 36.9% GHG emissions savings within a day.
Holland & Mansur, (2006)	RTP PJM electricity market, with a constant price elasticity of 0.1.	Hourly fossil emissions with a 100% adoption rate: 0.75% increase 0.26% increase 0.16% decrease

Ata, Duran, & Islegen, (2016)	<ul style="list-style-type: none"> · Annual ToU · Seasonal ToU · RTP <p>Results are for one year, using Ireland as a case study.</p>	<p>Monopoly Annual ToU: 0% Seasonal ToU: 0% RTP: 0.03% emissions savings</p> <p>Perfect Competition Annual ToU: 0.31% increase in emissions Seasonal ToU: 0.34% increase in emissions RTP: 0.37%</p>
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Table A2: Sample of studies examining price impacts of rate structure on distributed generation

Study	Tariff	Findings
Borenstein (2007)	High Demand Customers (10,000 kWh/year): Flat rate + block pricing → TOU rate + block pricing	Solar customers would save on average \$173/year by switching from a tiered flat rate to a tiered TOU rate
Borenstein (2007)	Medium Demand Customers (6,000 kWh/year): Flat rate + block pricing → TOU rate + block pricing	Solar customers would save on average \$133 per year by switching from a tiered flat rate to a tiered TOU rate
Borenstein (2007)	High Demand Customers (10,000 kWh/year): Flat rate + block pricing → TOU rate	Solar customers would save on average \$108 per year by switching from a tiered flat rate to a non-tiered TOU rate
Borenstein (2007)	Medium Demand Customers (6,000 kWh/year): Flat rate + block pricing → TOU rate	Solar customers would on average pay \$37 more per year switching from a tiered flat rate to a non-tiered TOU rate
Dargouth et al (2011)	TOU + NEM with tiered pricing; value in different usage tiers under steep block pricing	For solar customers with 50% PV-to-load ratio, TOU tariff provided savings of \$0.12/kWh for low usage customers to \$0.36-\$0.46/kWh for high usage customers when block pricing was spread across 5 steep levels, a variation of more than 300%

Dargouth et al (2011)	TOU + NEM with tiered pricing; value in different usage tiers under limited block pricing	For solar customers with 50% PV-to-load ratio, TOU tariff provided savings of \$0.14/kWh for low usage customers to \$0.24-\$0.29/kWh for high usage customers when block pricing was spread across 2 tiers, a variation of less than 100%
Dargouth et al (2014) part 1	TOU + NEM compared to flat rate + NEM	Solar customers under a TOU tariff increased bill savings by 13% compared with flat pricing
Dargouth et al (2014) part 1	RTP + NEM compared to flat rate + NEM	Solar customers under an RTP tariff increased bill savings by 1% compared with flat pricing
Bird et al (2015)	Standard rate (Volumetric + base charge + NEM) compared to standard rate + added fixed charge	Solar customers on a standard rate who were billed an additional \$10 monthly fixed charge saw bill increases of 14-17%, depending on the utility, and those who were billed an additional \$50 fixed charge saw bill increases of 72-87%.
Bird et al (2015)	Standard rate (Volumetric + base charge + NEM) compared to standard rate + minimum bill	Solar customers on a standard rate who were subject to a \$10 monthly minimum bill saw no increases (with a one exception of 6%), while those under a \$50 monthly minimum bill saw modest increases of 3-12%.
Bird et al (2015)	Standard rate (Volumetric + base charge + NEM) compared to standard rate with demand-based rate	Solar customers subject to demand-based rates saw bill impacts ranging from a decrease of 7% to an increase of 89%, depending on utility. Non-PV customers, by comparison, nearly all saw bill decreases as a result of the introduction of demand-based rates.
Oliva (2017)	TOU + export tariff (lower than retail rate)	Presents comparative bill savings and lost network revenue from PV alone, PV + Lighting EE, PV + Hot Water EE PV + Refrigeration EE, and PV + AC EE. Annual savings range from nearly \$600 with only PV to nearly \$800 with PV + refrigeration or AC EE

Table A3: Sample of studies exploring the feedback cycle of PV penetration

Study	Market Structure	Findings
Dargouth (2014)	Flat rate + NEM with 33% RE compared to Flat rate + NEM base case	[VALUE] 33% RE penetration leads to PV customers receiving a 7% increase in value of bill savings
Dargouth (2014)	TOU + NEM with 33% RE compared to TOU + NEM base case	[VALUE] 33% RE penetration leads to PV customers receiving 14% less in bill savings due to lower rates during times of high generation (i.e. due to peak-shifting)

Dargouth (2014)	RTP + NEM with 33% RE compared to RTP + NEM base case	[VALUE] 33% RE penetration leads to PV customers receiving 16% less value in bill savings
Dargouth (2014)	Flat rate, energy only market (no price cap), volumetric cost cover	[RATE] 33% RE penetration increases flat rate to \$0.192, compared to \$0.179 in a base scenario, an increase of 7.2%
Dargouth (2014)	TOU rate, energy only market (no price cap), volumetric cost cover	[RATE] 33% RE penetration increases high-priced season's peak TOU period by 16% due to a smaller peak period and higher volumetric adder
Dargouth (2014)	RTP rate, energy only market (no price cap), volumetric cost cover	[RATE] 33% RE penetration increases median RTP rate by 7%, and increases volumetric adder by 10% due to the additional cost of RE purchases, higher residential load and whole sale price coincidence, and reduced net sales for covering costs
Dargouth (2016)	Mix of flat and TOU pricing, examines effect of other rate structures on PV penetration	[PV PEN] Considers conflicting effects of 2 feedback effects: flat-rate pricing requires higher retail rates as PV customers increase, pushing up solar value, and encouraging deployment, while increased deployment of PV shifts peak-period pricing, reducing PV value to TOU customers. Compared to reference scenario of current mix of flat and TOU pricing, a flat, time-invariant rate would increase national deployment by 5%, while under a time-varying rate deployment would be 22% lower, 14% lower with \$10 fixed customer charge, 61% lower with \$50 customer charge, and 31% lower with partial net-metering (reduced rate for export)
Cai et al (2013)	Block pricing, 2-part tariff (fixed + variable)	[PV PEN] Feedback accelerates the time taken to reach 15% PV penetration by less than 2 months (1.3%); increases net-metering costs by 9.3% (driven by both PV uptake and increased rates)
Cai et al (2013)	Block pricing, 2-part tariff (fixed + variable)	[PV PEN] Feedback accelerates the time taken to reach 30% PV penetration by 0.9%; increases net-metering costs by 9.9% (driven by both PV uptake and increased rates)
Eid et al (2014)	Flat rate + NEM (unclear)	[RATE] At 20% PV penetration, using an hourly, daily, or monthly rolling credit alternative to net-metering results in potential cross-subsidy of 7.8%, 16.2%, and 17.2% respectively. For seasonal, ½ yearly, or yearly, cross subsidies are estimated at 17.5%, 19.9%, and 20%, respectively. This is not a direct rate impact, but indicates the amount of revenue lost to utilities, which will need to be recovered.
Janko et al (2016)	Seasonal TOU+NEM, 2-part tariff with fixed connection fee - Chicago	[RATE] 20% of homes with PV led to 16% rate increase, 40% PV led to 38% rate increase, 60% PV led to 72% rate increase, 80% PV led to 120% increase, 100% PV led to 192% increase

Janko et al (2016)	Seasonal TOU+NEM, 2-part tariff with fixed connection fee - Phoenix	[RATE] 20% of homes with PV led to 24% rate increase, 40% PV led to 63% rate increase, 60% PV led to 135% rate increase, 80% PV led to 268% rate increase, 100% PV led to 466% rate increase; high increases due to high NEM costs
Janko et al (2016)	Seasonal TOU+NEM, 2-part tariff with fixed connection fee - Seattle	[RATE] 20% homes with PV led to 8% rate increase, 40% PV led to 19% rate increase, 60% PV led to 32% rate increase, 80% PV led to 47% rate increase, 100% PV led to 66% rate increase low increases due to low NEM costs
Satchwell et al (2015a)	Flat rate pricing +NEM, 2 part tariff (variable energy and demand charge, fixed customer charge)	[RATE] Increasing rooftop PV from zero to 10% of utility sales led to a 3% increase in retail rates; sensitivity range indicated a range of 0-4% change possible
Satchwell et al (2015b)	Flat rate pricing +NEM, 2 part tariff (variable energy and demand charge, fixed customer charge)	[RATE] For a NE utility (wires-only + default service supplier), moving from 0 to 10% PV caused an average rate increase of 0.23 c/kWh over 10 years, moving to a high demand charge caused a rate increase of 0.01 c/kWh over 10 years, and adding a high fixed charge decreased average rate by 0.02 c/kWh
Satchwell et al (2015b)	Flat rate pricing +NEM, 2 part tariff (variable energy and demand charge, fixed customer charge)	[RATE] For a SW utility (vertically integrated), moving from 0-10% PV caused an average rate increase of 0.23 c/kWh over 10 years, adding a high demand charge added an increase of 0.07 c/kWh and moving to a high fixed charge increase average rate by 0.29 c/kWh
Johnson et al (2017)	Flat rate pricing with seasonal rate variation + day/night rates	[RATE] For a PV penetration of 5% of total electricity by 2030 (33% of which from residential), rates for non-PV customers increase by 1% compared to 2015.
Johnson et al (2017)	Flat rate pricing with seasonal rate variation + day/night rates	[RATE] For a PV penetration of 15% of total electricity by 2030 (33% of which from residential), rates for non-PV customers increase by 12% compared to 2015.
Johnson et al (2017)	Flat rate pricing with seasonal rate variation + day/night rates	[RATE] For a PV penetration of 15% of total electricity by 2030 (67% of which from residential), rates for non-PV customers increase by 14% compared to 2015.