MOHAMMAD ANSARIN

The Economic Consequences of Electricity Pricing in the Renewable Energy Era

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De economische gevolgen van het beprijzen van elektriciteit in het tijdperk van hernieuwbare energie

Thesis

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Foreword

I first thank you, the reader, for choosing this thesis for your reading pleasure. Many hours were spent in article reading, data acquisition and cleaning, analysis, plotting, writing, deleting, and re-writing for this manuscript. Throughout this process, I have learned much about energy systems, management, economics, academia, storytelling, and writing. I hope this experience is reflected in the pages to come.

I thank my supervisors, Wolfgang Ketter, Yashar Ghiassi-Farrokhfal, and John Collins, for the help and attention they invested in my training and our mutual work. I thank my doctoral committee members, Eric van Heck, Ronald Huisman, and Zofia Lukszo for vetting this research and ensuring it meets a high bar of excellence. I also thank my family and friends for their support during the PhD trajectory.

Lastly, I thank the numerous others who have supported my thesis research throughout the years, including conference and seminar discussants, members of the wider Erasmus Research Institute of Management and Rotterdam School of Management communities, and the editors and reviewers of the journals and conferences receiving our manuscripts.

July 2021
Mohammad Ansarin

"*C'est par maniere de devis que je parle de tout, et de rien par maniere d'advis.* Nec me pudet, ut istos, fateri nescire quod nesciam. *Je ne serois pas si hardy à parler s'il m'appartenoit d'en estre creu.*"

Michel de Montaigne, Essais, vol. 3, p. 329

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Chapter 1

Introduction

As the anthropogenic climate change of approaching decades becomes further entrenched, societies seek to minimize their future impact on the environment. For most societies, the energy system is a primary contributor to greenhouse gas (GHG) emissions, one of the main drivers of climate change. Globally, this system demanded 14,400 million tons of oil equivalent (Mtoe) of energy in 2019 and emitted 33.3 Gt CO_2 (*World Energy Outlook 2020* 2020), equivalent to about 64% of overall annual GHG emissions (Olivier and Peters, 2020). The energy system's actors and stakeholders have thus prioritized reducing these emissions in recent times.

The electricity sector is particularly keen on reducing emissions. In 2019, this sector emitted 13.7 Gt CO_2 globally (*World Energy Outlook 2020* 2020). Most governments push to reduce the emissions and pollution effects from fossil fuel-based electricity generation, including those from the burning of coal, natural gas, and oils. However, regions differ in how quickly they decrease fossil fuel-based electricity generation, with Europe, North America, and Australia being front-runners, and other OECD countries lagging further behind (ibid). A common policy for driving this technological change is the promotion of electricity generation with non-exhaustible (e.g. wind, sunshine, the water cycle, earth core heat) or negligibly exhaustible (e.g. nuclear fuels, biomass) resources. The environmental impact of these generators are generally far smaller than their fossil fuel-based counterparts and they are commonly labeled as clean and/or renewable electricity generation.

Concerned about climate change and other environmental harms such as air pollution, policymakers search for optimal means of promoting the uptake of this form of electricity generation. Unlike traditional generation plants, some renewable sources can be installed at smaller scales at the distribution level of the electricity grid, and are labeled distributed renewable energy sources (D-RES). Here, policymakers promote the uptake of D-RES particularly for residential and small commercial users.

The promotion of D-RES is often economic. Many policymakers have created favorable pricing schemes or tax incentives for electricity generated by D-RES, with mixed success. So far, only 11.6% of global electricity demand is served by renewables (*World Energy Outlook 2020* 2020), with higher installation numbers being found in Germany (Winter and Schlesewsky, 2019), the US state of California (Borenstein, 2017), and Australia (Poruschi, Ambrey, and Smart, 2018). These D-RES-installing households are often labelled as "prosumers" to reflect the electricity consumer's new parallel role as a producer of electricity, both for themselves and other consumers.

The pricing schemes of these installations can create economic burdens for households, retailers, and governments. Electricity retailers have traditionally had an economic relationship with their customers in the form of tariffs. These tariffs are designed to adhere to a set of principles (Reneses and Ortega, 2014). By installing D-RES, households upset many of the assumptions inherent in a retailer's attempt to adhere to these principles.

Two principles vulnerable to D-RES growth are economic efficiency and equity. Economic efficiency refers to allocating resources to those who value it most, and equity refers to allocating resources equally to similar customers (i.e. no two equal customers are given unequal prices for the same good).

For equity, issues relate to the differing costs of electricity trade for different households. As D-RES is installed, the generated electricity distorts the assumptions made by retailers about electricity use by customers. Consequently, some households are charged more than what their electricity should cost, whereas others are charged less. Bound by competition or regulation, retailers often operate in a restricted monetary space and thus compensate revenue deficits with tariff increases. In such a scenario, the imbalance between costs and bills leads to some households subsidizing others, i.e. "cross-subsidization". This cross-subsidization can form both between consumers and prosumers, and also within each population.

For economic efficiency, concerns often pertain to two aspects of electricity trade in the residential sector. The first is when electricity is being consumed more or less than it should be. Traditionally, households have been inflexible in their electricity demand, primarily due to lack of suitable mechanisms for controlling their electricity use. In economics terms, the residential sector has had very low demand elasticity. However, the recent uptick of advanced metering infrastructure (AMI; smart meters) and internet-of-things devices is poised to significantly impact this assumption (Alahakoon and Yu, 2016). As households install smart meters and devices, they become capable of both being informed of and efficiently control their devices' electricity use. Consequently, household demand elasticity is expected to increase in the future, and likewise the importance of economic efficiency losses due to mis-pricing electricity.

The second economic efficiency issue relates to producing electricity more or less than is optimal. This is often a result of mis-pricing D-RES installation value for the electricity grid. D-RES is commonly subsidized (and rarely under-priced) leading to too many (too few) installations in a given region. The additional electricity generation from these sources thus cause welfare loss (i.e. wasted economic efficiency). As D-RES growth accelerates in many grids, this second source of inefficiency becomes particularly substantial and important for consideration in tariff design.

These two aspects of electricity tariffing, namely equity and economic efficiency, are the primary economic consequences of widespread growth in D-RES installations. As D-RES, primarily solar photo-voltaic panels, continue to decrease in price, their installations are expected to continuously grow in many regions around the world. Thus, these issues with electricity pricing are expected to become ever more prevalent. This thesis endeavors to answer the question:

"What are the economic consequences of residential electricity pricing in the new renewable energy era?"

To this end, the first task is to review past literature on electricity tariff design and its equity- and efficiency-related consequences. The research of equity (or distributional) effects in electricity pricing has been particularly active, with particular attention given to issues concerning the growth of D-RES. Thus, in Chapter 2, this thesis first reviews past research on equity in electricity tariff designs. By filtering a Web of Science search, the chapter reviews over 400 articles in the electricity tariff space, and separates those that focus on the specific subject. The chapter elaborates on three general sub-fields: a) normative discussions of equity, b) comparisons of equity for various policies, and c) transition management studies for equity. For each sub-field, the chapter describes current research gaps. The chapter also combines the methodological issues encountered in these papers and provides recommendations for studies that seek to quantify equity. Some policy implications in the chapter guide policymakers and businesses in the energy sector regarding the equity-related outcomes of D-RES installations.

The thesis continues in Chapter 3 with an investigation of the cross-subsidies due to choices in metering infrastructure. One development in the electricity grid somewhat simultaneous to D-RES growth has been the rapid availability and expansion of smart meters and AMI. Smart meters and their communication and control infrastructure has become continuously cheaper, reaching levels suitable for mass deployment to residential users. Consequently, the information flows provided for end-users has had significant impact on the electricity grid, especially in facilitating demand response. Likewise, this information flow can be used to price electricity in manners that were previously cumbersome for retailers and/or customers, with non-trivial impacts for equity. In this chapter, the thesis describes the analysis of two (metering setup) choices for retailers who credit D-RES generation; choices which can directly impact the tariffs and thus the equities experienced by end-users. These choices are: (a) whether to meter household consumption and D-RES generation separately or together, and (b) whether smart meters are used. The analysis uses high-resolution (per-minute) energy data from 2016 from Austin, TX, USA, to study how these choices impact equity in a household population. Results show that traditional tariffs using legacy metering create median annual cross-subsidy values from 38% to 100% of the real costs of electricity trade. However, AMI can reduce these values by 2 to 3 orders of magnitude when a tariff that utilizes AMI's options is used. In contrast, metering generation separately from consumption appears to have little impact on cross-subsidies. Assuming even high values of demand elasticity does not alter these comparative conclusions. The chapter elaborates on the causes for these results, and ends with a discussion of their policy implications, particularly for regions undergoing rapid expansion of D-RES generation.

The thesis next investigates how increases in D-RES may impact these results for both equity and economic efficiency. Chapter 4 details a study of the economic consequences of D-RES growth in a residential grid. The chapter considers a subset of the tariffs used in Chapter 3 and calculates the changes in economic equity (as changes in consumer surplus; cross-subsidization) and economic efficiency (as dead-weight loss) under growing rates of D-RES use. A similar dataset of 144 households is used to calculate per-household rates of cross-subsidy and dead-weight loss. Regarding equity, results show that traditional tariff designs allow for large wealth transfers, often to D-RES owners from non-owners, who may be paying on the median 22% more than their fair share for electricity trade. For economic efficiency, traditional tariffs again perform poorly, with dead-weight loss reaching a maximum of 8.6% of total electricity expenditure in a high D-RES setting. Newer time-based (time-of-use, or TOU, and real-time dynamic pricing) tariffs show few signs of cross-subsidization and better economic efficiency. Potential demand elasticity does not significantly alter conclusions for fairness, but significantly impacts those for economic efficiency. The chapter also ruminates on what these results imply for policy-makers intent on balancing efficiency and equity in a changing grid.

Chapter 5 complements the economic efficiency results of Chapter 4 with a study on the efficiency losses due to mis-pricing D-RES generation. Here, hypothetical installation sizes are found for multiple commonly-used tariffs for crediting D-RES electricity generation. The study compares these values to a hypothetical scenario where D-RES electricity generation was paid at exactly the long-run and short-run (marginal) value it provides for the retailer. These comparisons are used to find losses due to the over- or under-installation of D-RES generation. Results show that a flat-rate tariff shows low levels of loss that are mainly due to its not matching the temporal fluctuations of wholesale market prices. However, net metering tariffs show very high loss from their disadvantageous pricing for grid electricity injection, causing many households to avoid D-RES altogether. These losses are mostly mitigated by accumulation, i.e. netting consumption and generation over a time span. This practice drastically reduces losses for all households, with the highest setting (accumulating generation over a year) resulting in losses comparable to that of the flat tariff. The chapter also reports on the results' sensitivity to changes in D-RES installation costs and to the value provided to the grid for offsetting capacity costs (e.g. by deferring grid investments). As with prior chapters, this chapter ends with discussions for retailers and policy-makers, especially those seeking to price D-RES such that perverse incentives for D-RES installation (or non-installation) are minimized.

The conclusion (Chapter 6) collects insights from prior chapters, which are gathered as an answer for the research question. These insights aim to update stakeholders in the energy sector for the new renewable energy era. This chapter also lists limitations common to prior chapters and provides some directions for future research in electricity pricing.

This thesis is primarily written to contribute to current understanding of equity and economic efficiency in residential electricity pricing. For an academic audience, the thesis provides new insights with higher thresholds of rigor into the equity and economic efficiency effects of multiple common electricity tariffs. In addition, it clarifies how these effects change as D-RES expands across the grid. The rigorous treatment of these economic consequences of electricity tariffs provides a benchmark methodology for future investigations, which is discussed at length in Section 2.5.

This thesis may also prove valuable for audiences external to academia. A primary goal of the author was to be inform the (often political) debate surrounding tariff design in the real world. Hence, ensuring high practical applicability of the results drove most assumptions and choices in the methodology. Tariff design debates are now common across regions with high D-RES penetration, such as multiple US states, Australia, and Germany. Thus, the results herein provide insights for policymakers and legislators regarding the possible effects of policies designed to promote D-RES and/or regulate electricity trade. For electricity retailers, grid operators, and other businesses in the electricity sector, the thesis provides insights about how transactions with residential users may be impacted by high D-RES growth. These results also give households valuable information regarding the potential ramifications of D-RES installations. This information on the indirect public costs and benefits of D-RES may otherwise be hidden from households within the economic transactions of electricity consumption.

1.1 Declaration of Contribution

The chapters presented here represent work that was done in majority by the author of the thesis. However, multiple others have assisted with preparing and finalizing this manuscript. The contributions are primarily from the promotor (Wolfgang Ketter, WK), the supervisor (Yashar Ghiassi-Farrokhfal, YG), and Dr. John Collins (JC, University of Minnesota). The following list presents these contributions and other places in which the content has appeared.

Chapter 1 Written by the author, with feedback incorporated from the promotor and supervisors.

Chapter 2 The chapter's literature search was entirely conducted by the author. The commencing review of literature was also entirely conducted by the author. Some additional papers were suggested by the co-authors of the manuscript (WK, YG, and JC) and were incorporated in the review procedure. The writing format and organization of the manuscript were also changed in accordance with suggestions from the co-authors. At the time of publication, this chapter's content is under peer review for a first-quartile journal.

Chapter 3 The modeling and problem formulation was conducted in collaboration with YG. The literature review, analysis, and presentation of results were primarily conducted by the author, with suggestions incorporated from the co-authors (WK, YG, and JC). The conclusions and policy implications of the study were formulated in collaboration with all co-authors. Shmuel Oren, Olivier Rebenaque, Peter Volkmar, and participants of the 41st International Association for Energy Economics Conference (IAEE 2018) provided helpful comments on earlier versions of this manuscript. This manuscript was presented at IAEE 2018 and was published in Energy Policy (see Ansarin et al. (2020a)).

Chapter 4 The literature review, modeling, analysis, and presentation of results were entirely conducted by the author, with advice from the co-authors (YG, WK, and JC) incorporated in the final text. The conclusions and policy implications were written in collaboration with all co-authors. Laurens de Vries, Srinivasan Keshav, and Karen Pardos Olsen, along with participants of the 42nd International Association for Energy Economics Conference (IAEE 2019) and the 11th International Conference on Applied Energy (ICAE 2019) provided helpful comments on earlier versions of this manuscript. This manuscript was presented at IAEE 2019, ICAE 2019, and published in Applied Energy (see Ansarin et al. (2020c)).

Chapter 5 The literature review, modeling, analysis, results, and sensitivity analyses were entirely conducted by the author, with advice from the co-authors (YG, WK, and JC) incorporated in the final text. The conclusions and policy implications were written in collaboration with all co-authors. Participants of the 43rd International Association for Energy Economics Conference (IAEE 2021) and the 12th International Conference on Applied Energy (ICAE 2020) provided helpful comments on earlier versions of this manuscript. At the time of publication, this chapter's content is under peer review for a first-quartile journal.

Chapter 6 Written by the author, with feedback incorporated from the promotor and supervisors.

Chapter 2

Literature Review[1]

2.1 Introduction

Electricity is generally considered to be a public (pooled-resource) good, especially in the residential sector. Here, most electricity is traded via tariffs. These tariffs are designed to meet particular goals, which, due to the public-goods approach towards electricity, are both economic and political in nature. However, multiple disruptions in the energy industry, including generation from distributed renewable energy sources (D-RES), advanced metering infrastructure (AMI; "smart meters"; (Alahakoon and Yu, 2016)), and electric vehicles, are undermining the assumptions underlying electricity tariff design (Matisoff et al., 2020). Hence, conventional tariffs may no longer suitably reach their design goals.

Areas with high D-RES growth have witnessed heated debates about tariff design changes in the past few years (Klass, 2019). One goal of tariff design, "fairness" (or "equity"), is a recurring theme of debate. Different stakeholders in different regions understand fairness as different concepts (Lamb et al., 2020; Neuteleers, Mulder, and Hindriks, 2017; Burger et al., 2019). Here we use the common economic definition, i.e. as the subsidization of product by some consumers for other (similar) consumers; i.e. cross-subsidization. These distributional concerns have been previously well-researched for multiple tariffs under various assumptions. However, the D-RES debate has re-ignited the issue and added further complexity to this subject (Picciariello et al., 2015a; Chapman, McLellan, and Tezuka, 2016). Particularly, the

[1] At the time of publication, this chapter was in peer review for an academic journal.

residential sector is well-suited for D-RES installations, and has historically been the subject of the most scrutiny regarding pricing fairness.

The debate regarding tariff fairness in a high-D-RES grid is missing a comprehensive review of research on residential electricity pricing fairness. It is important to understand what elements of the effects of D-RES uptake on tariff fairness have been studied, and which remain. Here, we review fairness studies in electricity tariff design, focusing on the discussion surrounding the impact of D-RES. This paper consists of:

1. A description of the employed literature review method (Section 2.2).
2. Background information about electricity tariff design (Section 2.3).
3. A review of current state-of-the-art in electricity tariff design studies, placing the studies within the wider research field (Section 2.4).
4. An overview of possible future research in this field (Section 2.5), including a discussion on methodological concerns for future studies (Section 2.5.2).
5. A conclusions section (Section 2.6).

Our goal with this review is three-fold. First, we aim to provide a map for research on electricity tariff fairness, where we can find disparate and sometimes conflicting quantifications and policy recommendations. Second, by elaborating on varying definitions and methodological choices, we present a more accurate approach to measuring and understanding fairness, especially in high-D-RES scenarios. Third, we seek to inform policy-makers and retailers on the current understanding of residential electricity tariff fairness. The discussion presented here is particularly relevant to stakeholders facing high growth in D-RES within their networks.

2.2 Literature Review Method

We review literature to develop a comprehensive map of current research in electricity tariff fairness, particularly in the residential sector. The literature review method is inspired by Matisoff et al. (2020) and began with a systematic search on Clarivate Analytics' Web of Science.[2] The following search terms were used for finding articles relevant to this paper. We chose article subjects to be

- relevant to "energy" and/or "electricity", and

[2] Available at `http://www.webofknowledge.com/`

- relevant to “fairness”, “equity”, “distributional” concerns, and/or “cross-subsidies”, and
- relevant to “renewable”, “clean”, “solar” or “photovoltaic” generation, and/or “wind” generation
- published between 1900 and 2020.
- written in English.
- focused on the residential sector.[3]

These considerations were first tested in trial searches on WOS and were then grouped into the search term:

TS = ((electric OR energy) AND (rate OR tariff OR pric*) AND (fairness OR equity OR distributional OR distributive OR cross-subs*) AND (renewable OR clean OR solar OR wind OR photovoltaic)) AND PY = (1900-2020).*

This search returned 401 results in January 2021. All articles' metadata and abstract were reviewed for relevance, from which relevant (78) and marginally relevant (40) articles were filtered.[4] From this collection, each paper's full text was reviewed and its content used in this article where appropriate. 66 articles cited in these papers and from the authors' own knowledge were added to this collection, while 26 lacked adequate relevance and/or rigor and were discarded. The final collection consisted of 128 articles.

We first check the (relative) development of this research stream during the past years. To this end, we compare per-year publication counts in the reviewed articles group with those of WOS's Energy & Fuels category (Figure 2.1).[5] Since the 2000s, there has been a clear growth in the number of articles published about equity concerns due to renewable energy, focused specifically on tariffing. This trend shortly follows similar growth in solar photo-voltaic (PV) panel installations in some regions, such as southern Europe (Sakhrani and Parsons, 2010). Thus, more attention seems to be given to the equity concerns of D-RES in recent years. This trend can be expected to grow as more D-RES is installed in many grids.

[3]Most fairness studies focus on the residential sector. No search terms proved adequate to narrow down results based on their implementation in the residential sector. Hence, we used no related keywords for the search results and relied on individual article review to find papers with this focus.

[4]Marginal articles were those that were related to the subject of equity in energy systems, but addressed a different aspect in the system, e.g. carbon taxes or renewable portfolio standards. These articles were also separated for potential comparative mention but are excluded from the bibliometric analysis.

[5]Data for WOS's Energy and & Fuels category exists from 1990 onward. Hence, the comparison can only be done from this year onward.

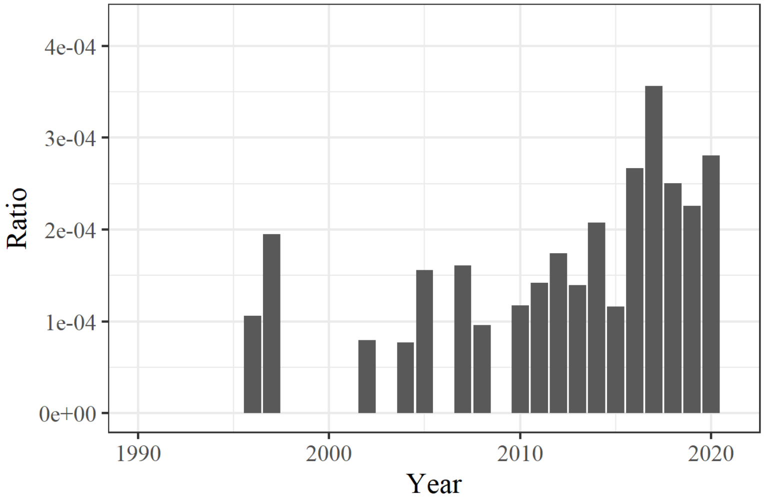


Figure 2.1: Papers in literature review as ratio of articles in Web of Science (WOS)'s "Energy and Fuels" category, sorted by publication year (post-1990). The ratio for the year 2020 may be under-estimated, as papers published in that year may not yet be indexed by Web of Science.

Before discussing this research field, we cover some background matters on tariff design in the residential electricity sector.

2.3 Tariff Design Background

Electricity retailers (or "utilities") trade electricity with end-users. Their costs consist of multiple components:

1. Energy costs for wholesale electricity purchases from generation markets, or for recovering per-kWh generation costs from own generation plants.

2. Generation capacity, for investments in ensuring future demand requirements are met.

3. Transmission grid system costs (including infrastructure, operation and maintenance, and losses).

4. Distribution grid system costs (including infrastructure and depreciation, operation and maintenance).

5. Other costs related to the retailer's operations, including sales, general, and administrative (SGA) costs, marketing costs, and taxes and other line items.

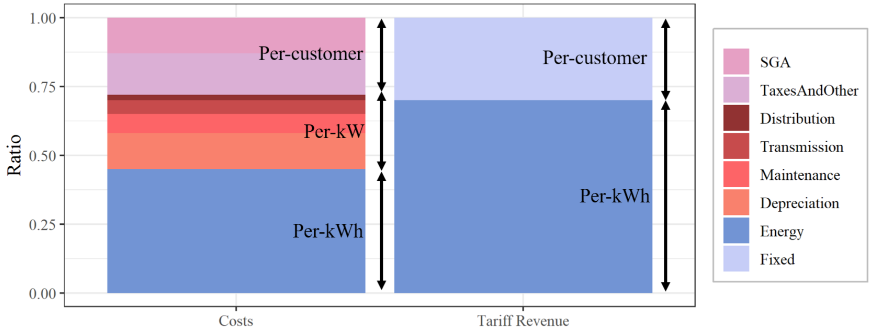


Figure 2.2: Costs of electricity provision (left) versus tariff revenue (right) for a sample customer. Colors indicate cost/revenue component. Data from Burger (2019)

These costs, displayed in Figure 2.2, can be divided into three groups based on dependency. First, some retailer costs (1, energy costs) depend mainly on kWh consumed by tariff subscribers at each instant. Second, the "fixed and sunk costs" of capacity and grid infrastructure are partially dependent on an individual household's peak demand over a long timespan, and partially dependent on the distribution grid's overall peak demand. Third, most other costs (5) depend on factors that are largely independent of the aforementioned consumption attributes, and depend mostly on the number of tariff subscribers.

Electricity retailers recover these costs via revenue from one or multiple tariffs. Tariffs are intended to meet multiple objectives, some of which cannot be met simultaneously (Rodríguez Ortega et al., 2008). Bonbright (1961) discusses matters of importance for rate design for public goods, which Reneses and Ortega (2014) qualify and modernize as electricity tariff design principles. These principles are:

P1. Sustainability or Sufficiency of revenue: The recovery of sufficient revenue for grid operation.

P2. Equity or non-discriminatory access: Ensuring equal charges for equal power consumption, irrespective of user characteristics.

P3. Economic efficiency: Allocating resources to those who value them most. In free market systems, this is often ensured through pricing at marginal costs. In nonmarket systems, such as monopolies, economic efficiency is often maintained by regulation.[6]

P4. Transparency: Clarity in the tariff design process and its outcome.
P5. Simplicity: Tariff designs are easy to understand and react to for subscribers.
P6. Stability: Less divergence of tariff design (tariff formulation) and tariff charges (the values within the formulation) across billing cycles.
P7. Consistency with larger regulatory framework: Ensuring that regulation of the electricity sector is not at odds with regulation in (other) public goods.
P8. Additivity of costs elements: Ensuring that the final charge equals the added sum of each tariff component.

These principles generally guide policy-makers and retailers in debates regarding distribution-level electricity pricing. No feasible tariff can simultaneously meet all requirements, and thus the tariff design process is one of compromise and balancing the social and private benefits and costs of one tariff versus another (Yakubovich, Granovetter, and Mcguire, 2005). Hence, finding a suitable answer to the tariff design question is complex. Consequently, tariff mechanisms may not match in function with the dependencies of the retailer's costs. Figure 2.2 illustrates this mismatch by comparing costs for an average USA utility and revenue for a two-part tariff.[7]

As electricity is considered a common-pool resource, decision-making on its pricing has often been a political issue (Yakubovich, Granovetter, and Mcguire, 2005). The common choice for electricity pricing, especially for residential consumers, has been a fixed volumetric fee (i.e. a per-kWh fee per units consumed over a time window). Some proposals, such as Coase's two-part tariff (Coase, 1946) have also been implemented to varying levels. However, despite the economic inefficiencies caused by volumetric pricing, its arguably favorable redistributional nature has made it the dominant pricing method in many regions. It can transfer costs from the poor to the wealthy, thus being considered socially progressive and favorable in residential settings. On the other hand, such pricing creates inertia against more cost-reflective and economically efficient tariff designs (Borenstein, 2016).

Despite this inertia, multiple retailers have developed tariff designs that are better able to fulfill design principles in the modern electricity grid. Alongside **Flat-rate** tariffs, where the price is a constant per-kWh rate, such tariffs include:

[6] Ensuring this principle also often ensures *a priori* that customers are sent the correct behavioral signals with regard to their consumption. An appropriate change in behavioral response is also dependent on P6.
[7] Note that a tariff's revenue might not necessarily equal the related costs of electricity trade.

- **Increasing-block pricing (IBP)**, where higher cumulative consumption during a billing period is billed at a higher price.

- **Ramsey pricing**, where a user's per-kWh prices are inversely related to the user's demand elasticity[8], i.e. users with higher demand elasticity receive lower prices.

- **Real-time Pricing (RTP)**, also called dynamic pricing, where retail price at each instance follows wholesale market prices.

- **Time-of-Use (TOU)** prices, where the rate is time-dependent, often changing by time of day and season. As TOU pricing is often intended to reflect some wholesale market deviations in retail markets, it can be considered a simpler version of RTP.[9]

- **Critical Peak Pricing (CPP)**; this tariff is similar to TOU pricing, with two main differences: only a few specific time windows are chosen in a long time window (e.g. 1 year), and prices during these time windows are far higher than usually seen in TOU.

- **Demand charges**, where (often the capacity costs of) electricity delivery is (are) priced based on the peak power drawn from the grid within a specific time window. These charges may depend on the peak power drawn by the user (non-coincident peak), or on the peak power drawn by a group of regionally proximate users (coincident peak).

Similarly, retailers and policy-makers have used divergent approaches for crediting the production of D-RES. These schemes include:

- **Net metering**, where the net demand (consumption less generation) of users are priced similarly, no matter whether electricity is drawn from or flows into the grid.

- **Net purchase and sale**, where the price of electricity drawn from the grid and flowing into the grid (from extra D-RES generation) is unequal. Such schemes may also have accumulation, where net demand is calculated over a period, such as a day, month, or year.

[8]Demand elasticity refers to the relationship between electricity's price and the consumers' demand.
[9]In some contexts, the TOU and RTP labels are used interchangeably.

- **Feed-in tariff (FiT)** (also called "buy-all sell-all" pricing in the United States), where a user's generation of electricity is measured and priced separately from its consumption. FiTs require separate meters for D-RES generation and household consumption.

For each scheme, various aforementioned tariffs (e.g. RTP, IBP) may be used for pricing the elements of electricity consumption and generation.

The advent of renewables has complicated tariff design decisions. One significant barrier to mass adoption of RES has been the high capital required for the initial purchase and installation of generation units. To motivate such installations, local and regional governments re-design payments for electricity producers to provide subsidies for RES generation, particularly those from smaller scale D-RES units. In many instances, new owners of D-RES generators are already subscribed to an electricity retailer's tariffs for their electricity consumption needs. Subsidies for D-RES can combine and possibly conflict with these tariffs, weakening their achievement of tariff design principles (Convery, Mohlin, and Spiller, 2017; Bento, 2013). For example, Poruschi, Ambrey, and Smart (2018) review FiT implementations for solar photo-voltaic D-RES across states in Australia, finding evidence of tariff principles, particularly equity, becoming less adhered to in some regions. Thus, the same tariff which was previously suitable for a consumer may no longer be suitable for a "prosumer" (i.e. a consumer who also produces electricity).

Additionally, D-RES is prone to changing the acceptability of previously-acceptable distributional effects from consumption tariffs. Installing D-RES has significantly altered the relationships between consumption patterns, wealth, and social costs, which were pre-supposed in historical tariff designs (Convery, Mohlin, and Spiller, 2017). For example, Borenstein (2017) shows how California's increased-block pricing leads to a large regressive subsidy scheme for solar PV owners, who often reside in high income brackets.

These impacts are not isolated to mechanisms involved in consumption pricing, and extend to pricing D-RES generation credits. Many D-RES installations have cost-of-capital rates (or rates-of-return) that are lower than the cross-subsidies prevalent in traditional electricity prices. In other words, a prosumer may be losing an amount via consumption comparable to what they gain via production of the same good. Consequently, many consumers may withhold on solar PV installations that would, cross-subsidies removed, be economically efficient and socially good decisions. For example, Ansarin et al. (2020c) show that flat-rate and increased-block pricing tariffs in Austin, Texas, USA, lead to cross-subsidies that can be higher than the median rate-of-return for a solar installation.

D-RES uptake is thus significantly related to the fairness principle in electricity tariff design. It is particularly prevalent in residential settings. In the following section, we discuss fairness and review the literature on this subject. We place a particular emphasis on D-RES and its impacts on fairness, and thus approach the literature from the renewables perspective.

2.4 Current Research

Subsidies occur when one group of consumers (or producers) pay more (or are paid less) than a product's value. When this value is limited by regulation and/or market concentration, these subsidies are confined to be transfers between consumer or producer groups. This "cross-subsidization" is a common issue in network industries, where a common network used for product manufacture or delivery (and its inherent costs), is shared between users. In such cases, the marginal cost of product delivery is higher than the average cost of its production (Feldstein, 1972). Telephone lines, air transportation, and utilities such as water (Schoengold and Zilberman, 2014) contain some cross-subsidization within their pricing schemes. Thus, highly cross-subsidized products are usually considered public goods and/or are regulated natural monopolies (Heald, 1997). Energy is one such good.

In the energy industry, equity concerns have been researched for many policies and cases, e.g. for carbon taxation (Maestre-Andres, Drews, and van den Bergh, 2019; Wang et al., 2016), generation assets (Ambec and Crampes, 2012), environmental pollution (Sovacool et al., 2016), and fuels for heating use (Roberts, 2008). The electricity sector likewise contains cross-subsidization, some of which is desirable (see discussion in Heald (1997)). For example, it has been traditionally accepted that rural electricity use is subsidized by urban users (Huanying, Kline, and Shenghong, 2007; Saddler, 1996).

Electricity cross-subsidization can be divided into that between different sectors and that within one sector of an economy. Between sectors of a national or regional economy, electricity may be cross-subsidized for political goals. For example, there are often significant cross-subsidies transferred from residential users, who are often captives to location, to industrial users, who can more readily switch both energy procurement and location (i.e. have higher demand elasticity; a form of Ramsey pricing; Burke and Abayasekara (2018)). There can also be cross-subsidization towards sectors considered socially important or vulnerable, e.g. agriculture (Chattopadhyay, 2004). RES installations can also cause cross-subsidies between sectors when costs and benefits are not equitably passed through by retailers. Evidence of this exists for wind energy's effects on wholesale electricity markets in Australia (2011-13; Cludius, Forrest, and MacGill (2014)), Portugal-Spain (2015; Prata, Carvalho, and Azevedo (2018)) and Germany (Cludius et al. (2014)), and likewise for solar energy in Germany (Tobben, 2017). Gambardella and Pahle (2018) models the German case and also calculates the welfare effects of RES growth and simultaneous tariff changes. Reguant (2019) presents a general model of the between-sector distributional impacts of RES support policies (carbon taxes, renewable portfolio standards, flat subsidies, and feed-in tariffs) using multiple pricing schemes with 2011-15 California data.

These inter-sector cross-subsidies are often on a larger scale than D-RES' immediate impact on a local grid. However, they are also impacted from increasing D-RES use. Roulot and Raineri (2018) and Percebois and Pommeret (2018) find cross-subsidies between industrial and residential users as D-RES installations increase, but in opposing directions. Johnson et al. (2017) also investigate the influence of increasing D-RES on electricity prices for residential, small commercial, and large commercial/industrial users, finding implicit cross-subsidies becoming larger as D-RES grows. Neetzow, Mendelevitch, and Siddiqui (2019) comment on the distributional effects of D-RES plus storage systems, between system owners and grid operators, under different policy schemes.

Our primary focus is on cross-subsidies within the residential sector. Unlike pricing for commercial or industrial users (Borenstein, 2007), residential electricity pricing is subject to a strong public-goods approach. Much previous literature has such an approach on discussion of residential tariffs under D-RES growth, which differs slightly from approaches to inter-sectoral cross-subsidies. This cross-subsidization corresponds to the "fairness" or "equity" principle from Section 2.3. In our literature review, we found three sub-fields of research in tariff equity. First, some studies look into the "due-ness" of cross-subsidies, i.e. normative discussions on whether a policy scheme's fairness consequences are acceptable to its stakeholders. Second, some studies focus on comparing policy choices (e.g. tariff designs) and their specific fairness consequences. Third, some equity studies discuss the transition management of policy changes or longer-term (multi-year) trends of policies discussed in the prior sub-field. We review each sub-field based on their discussion of D-RES growth, beginning with the subject of due versus undue cross-subsidization.

2.4.1 Due versus undue

Table 2.1: Articles discussing normative aspects of D-RES's impact on tariff fairness.

Topic	Jurisdiction	Article	Notes
Effect of D-RES on wealthy households	California, United States of America	Borenstein (2017)	
	United States of America	O'Shaughnessy et al. (2021)	
	Flanders, Belgium	De Groote, Pepermans, and Verboven (2016)	
	Australia	Macintosh and Wilkinson (2011)	
	United Kingdom	Grover and Daniels (2017)	
Desirability of D-RES cross-subidies	Western Australia	Simpson and Clifton (2016)	
	United States	Liang, Qiu, and Padmanabhan (2017)	
Normative aspects of renewable electricity surcharges	Germany	Winter and Schlesewsky (2019)	
	"	Gawel, Korte, and Tews (2015)	
Discussions of legal arguments about cross-subsidies from increased D-RES	US states of Nevada, New Mexico, and Minnesota	Klass (2019)	
	"	Rule (2015)	
	Tucson, Arizona, United States	Franklin and Osborne (2017)	
Theoretical discussions of equity in D-RES financing	N/A	Granqvist and Grover (2016)	

Public goods are privy to many normative discussions surrounding equity considerations. The desirability of cross-subsidization in residential electricity tariffing depends on multiple factors (Heald, 1997). Historically, stakeholder groups in the electricity tariffing debate have agreed that some forms of cross-subsidies, such as limited transfers from wealthy to poor users, are acceptable (or "due"). Disagreement is also quite common (see e.g. Martin and Rice (2018) for Queensland, Australia). For example, a regulated utility may be concerned about recovering costs, whereas regulators are more interested in ensuring some socially positive cross-subsidization (Martin and Rice, 2018). Burger et al. (2019) discuss these different and occasionally conflicting approaches to equity, which may lead to differing opinions on acceptable cross-subsidization for tariffs.

These disagreements may also exist within stakeholder groups, for example between households. Customer perceptions of fairness in pricing has garnered much research interest in behavioral economics (see e.g. the literature discussed in Gielissen, Dutilh, and Graafland (2008)), and here we focus on that concerned with electricity (briefly discussed in Hobman et al. (2016)). Normative judgements on the fairness of various tariffs are diverse. In a survey of Dutch households, RTP and flat-rate tariffs received polarized responses, whereas Ramsey pricing received a negative consensus (Neuteleers, Mulder, and Hindriks, 2017). Volumetric (e.g. flat-rate) tariffs were somewhat desired due to socially progressive inequities, which were reduced or negated in other tariffs. In addition, opponents of dynamic pricing view it as an attempt to "marketize" what is perceived to be a public good (and thus should be un-marketable; Alexander (2010)). Behavioral principles also drive some issues with dynamic pricing, and novel tariff designs in general (Hobman et al., 2016). Households may be ill-equipped to understand and respond to dynamic prices, and the trends followed by dynamic prices (i.e. wholesale market rates) are often regulated by institutions different from those regulating retail rates (Alexander, 2010). Faruqui (2010) and Procter (2013) also discuss the missing appeal of dynamic pricing for households and suggest some improvements. Hobman et al. (2016) generalizes the discussion and presents solutions from psychology and behavioral economics literature for the perceived unfairness of novel tariff designs.

These normative disagreements on equity are often related to various demographic attributes and political views (Yakubovich, Granovetter, and Mcguire, 2005). Following the United States' 1973 Energy Crisis, the political ideological leanings of electricity pricing regulators influenced redistribution decisions in electricity pricing (Ka and Teske, 2002). More recently, Fremeth, Holburn, and Spiller (2014) show that consumer advocacy groups impact welfare redistribution from electricity pricing, mainly by increasing benefits to residential consumers. Likewise, US jurisdictions with a Democrat-leaning voter base and higher income inequalities are more likely to support (progressive) cross-subsidization (Levinson and Silva, 2019). On an international level, there is evidence that distributional interests motivate democratic policymakers to favor feed-in tariffs (which promote D-RES) over other mechanisms of RES promotion (Bayer and Urpelainen, 2016).

The addition of D-RES can also impact normative beliefs about equity. Recent evidence from the USA (Borenstein, 2017; O'Shaughnessy et al., 2021), the Flanders region of Belgium (De Groote, Pepermans, and Verboven, 2016), Australia (Macintosh and Wilkinson, 2011), and the United Kingdom (Grover and Daniels, 2017) shows that distribution grids often witness a large growth of D-RES primarily added by wealthier households. Thus, subsidies supporting D-RES installations are usually regressive, as they are given to wealthy households, while being funded from the general or electricity-consuming public. Such policy instruments can be disfavored; Simpson and Clifton (2016) discuss mixed responses from Western Australian households on whether a socially regressive cross-subsidization of D-RES was desirable. Liang, Qiu, and Padmanabhan (2017) find similarly that demographic attributes correlate with attitudes towards the fairness of price increases and demand charges due to D-RES installations in a survey of the USA. However, debate continues about whether such calculations of regressivity are a suitable representation of equity for normative judgements. For example, Winter and Schlesewsky (2019) and Gawel, Korte, and Tews (2015) address the normative aspects of equity concerns from Germany's renewable electricity surcharge (EEG; in German: Erneuerbare-Energien-Gesetz). They argue (respectively) for and against labelling the EEG's regressivity as an equity concern. Using a moral-philosophical foundation, Granqvist and Grover (2016) describes a set of normative criteria for equitable cost recovery for financing D-RES and other clean energy policies.

Some scholars argue that such normative appeals may be made strategically. Klass (2019) discusses the differing legal arguments and approaches of the regulatory bodies of the US states of Nevada, New Mexico, and Minnesota regarding their utilities' concerns about cross-subsidization from increased D-RES. Rule (2015) further elaborates that such appeals to fairness by retailers are often strategically motivated to promote shareholder interests over ratepayer interests, and/or to maintain barriers to market entry by competing generation resources, rather than allow for objective discussions about the amount and nature of cross-subsidization. Franklin and Osborne (2017) discuss similar matters, and cover other energy justice concerns, namely procedural and recognition justice.

The studies listed in the previous paragraphs clarify various normative aspects of electricity pricing equity. However, this area remains weakly researched, both before and during the upsurge of renewable energy. In Section 2.5, we review such research gaps related to D-RES. Prior to this, the next subsection covers reviewed research on comparing tariff designs and other policies based on their impact on equity.

2.4.2 Policy comparisons

Most studies of fairness in electricity systems focus on comparing the equity effects of various policies. In residential retail, the most relevant policies for such study are the tariffs used for pricing electricity trade. We first discuss equity in residential electricity pricing in a wider historical context, then review literature focused on the recent uptick in D-RES.

Historically, electricity tariff design was inhibited by the metering infrastructure in place. For example, in the USA in the 1970s, multiple programs showed the effectiveness of novel tariff designs with fairer cost allocations. However, AMI was missing and expensive, and thus other matters were prioritized (Faruqui and Bourbonnais, 2020). Consequently, most tariff designs relied on volumetric metering and billing, a practice which has persisted until recently (Matisoff et al., 2020). Many studies of fairness focus on these volumetric tariffs, often designed to combine marginal costs with some of the other non-marginal costs elements of electricity delivery. Borenstein (2011) investigates equity effects from changing a flat-rate and IBP tariff to fixed charges in California, USA. He finds significant regressive wealth transfers from this change. On the other hand, switching from flat rates to IBP appears to create moderate but progressive redistribution (i.e. from the wealthy to the poor), but at the expense of economic efficiency Borenstein (2012). Ito (2014) reports on the differing economic inefficiencies from flat-rate and IBP tariffs for a subset of Californian households. For similar tariffs, Hancevic, Núñez, and Rosellón (2019) find implicit cross-subsidies between different consumption deciles in a country-wide study of Mexican households.

Alongside marginal pricing, some historic research has focused on the distributional and efficiency effects of fixed charges. These charges aligned well with the sunk and fixed costs of grid operators, and if set equal to these values, would optimize economic efficiency (Coase, 1946). However, this practice often resulted in implicit regressive taxation and was thus disfavored (Henderson, 1947). Feldstein (1972) analyzes both marginal prices and fixed charges for a two-part tariff, formulating an optimal tariff with a parameter that represents the normative beliefs regarding the balance between distributional and efficiency concerns. Batlle, Mastropietro, and Rodilla (2020) discuss inequities for recent Spanish tariffs, which combine multiple pricing mechanisms to recover network costs.

The more recent expansion of AMI has led to many newer tariff designs being considered for and used in many regions (Faruqui and Bourbonnais, 2020; Alahakoon and Yu, 2016). Many such tariff designs have been common in the commercial and industrial (C&I) sector and are now being applied in a residential setting. As these tariffs are more reflective of actual electricity costs, they often perform better in equity. For example, RTP tariffs have been shown in many studies to have lower cross-subsidies than flat-rate or other traditional tariffs (e.g. in the US states of Illinois (Burger et al., 2020; Horowitz and Lave, 2014) and California (Borenstein and Holland, 2005), and in Germany (Gambardella and Pahle, 2018)). Some research presents versions of the RTP tariff optimized for fairness and/or overall welfare under conditions of high demand elasticity (Steriotis et al., 2018). TOU tariffs are similarly popular in recent research. Simshauser and Downer (2016) compare equity for flat-rate and TOU tariffs in Victoria, Australia. They find that TOU tariffs are more equal, particularly for more vulnerable household populations.

Another example of tariff design common in the C&I sector applied to residential grids is demand charges. Hledik and Greenstein (2016) compare the equity of demand charges and flat-rate tariffs using 2014-2015 data from the US state of Vermont. Their comparison of low-income and regular households shows equity effects are similar for both cohorts when demand charges are used. Passey et al. (2017) study the design of these demand charges and how they reduce cross-subsidy with data from the Australian state of New South Wales. Blank and Gegax (2014) give a counter-example (with 2011 data from an Alaska, USA, utility), showing that demand charge costs are correlated with energy costs; thus, demand charges would recover similar costs and create similar equity as flat-rate charges for capacity costs. Demand charges continue to be intensely debated regarding their applicability to a residential setting (Borenstein, 2016).

Tariffs in differing regions may have positive or negative outcomes, as geographical and regulatory differences often limit the generalizability of tariff designs. Thus, researchers instead consider multiple tariffs for a single region, thus studying multiple policy choices under fixed geographical and regulatory assumptions. Azarova et al. (2018) investigate cross-subsidies in grid costs for a range of tariffs from demand charges to flat rates for a cohort of Austrian households. Burger et al. (2019) does a similar study of households in the US state of Illinois.

D-RES effects on policy fairness

The studies previously discussed in this subsection provide a methodological basis for investigating the effect of D-RES on equity. However, some of these effects are uniquely dependent on the inclusion of D-RES, and thus D-RES-agnostic studies have conclusions with limited applicability for high-D-RES grids. Thus, much research in recent years has focused on applying these methods to study high D-RES scenarios (Lamb et al., 2020). Studies considering the impact of D-RES on the equity of tariffs and other pricing policies are listed in Table 2.2.

Table 2.2: Prior research on the effects of D-RES on policy fairness.

Topic	Jurisdiction	Article	Notes
Effects of direct D-RES subsidies (e.g. tax incentives and cost rebates)	New South Wales, Australia	Nelson, Simshauser, and Kelley (2011)	
	Queensland, Australia	Nelson, Simshauser, and Nelson (2012)	
	United States of America	Vaishnav, Horner, and Azevedo (2017)	
	Belgium and Portugal	Bartiaux et al. (2016)	

Topic	Jurisdiction	Article	Notes
	Germany	Neuhoff et al. (2013), Grösche and Schröder (2014), Andor, Frondel, and Vance (2015), Frondel, Sommer, and Vance (2015), Tobben (2017), Winter and Schlesewsky (2019), and Cludius et al. (2014)	Focused on the EEG surcharge
	Republic of Ireland	Farrell and Lyons (2015)	Focused on the Public Service Obligation
	Italy	Verde and Pazienza (2016)	Focused on the A3 surcharge
	United Kingdom	Grover and Daniels (2017)	
	Japan	Nagata et al. (2018)	
	Canada	Mastropietro (2019)	
Effects of adjusting per-kWh volumetric prices, and/or energy costs	Austin, Texas, USA	Ansarin et al. (2020a)	Compares different metering setups and different tariffs (including RTP, TOU, demand charges, and IBP)
	Spain	Eid et al. (2014)	
	California, USA	Borenstein (2017)	Compares IBP and flat-rate tariff with up-front and other incentive schemes
	United Kingdom	Farrell (2018)	Uses economic inefficiency differences as a measure of inequity

Topic	Jurisdiction	Article	Notes
	New Mexico and Nevada, USA	Singh and Scheller-Wolf (2017)	Studies discriminatory pricing between D-RES owners and different customer classes
Theoretical studies of the aforementioned effects	N/A	Brown and Sappington (2017b) and Brown and Sappington (2017a)	
	N/A	Gautier, Jacqmin, and Poudou (2018) and Gautier, Jacqmin, and Poudou (2021)	
	N/A	Fikru and Canfield (2020)	
Effect from D-RES on capacity/network cost pricing fairness	Queensland, Australia	Simshauser (2016)	Compares demand charges with current default cost recovery method and other alternatives
	United Kingdom	Strielkowski, Štreimikienė, and Bilan (2017)	Similar method to Simshauser (2016)
	France	Clastres et al. (2019)	Compares cross-subsidy for different rates of D-RES self-consumption
	Portugal	Fontana (2016)	"
	United States of America	Picciariello et al. (2015b)	
	Netherlands	Nijhuis, Gibescu, and Cobben (2017)	

Topic	Jurisdiction	Article	Notes
	(generic data)	Schittekatte, Momber, and Meeus (2018) and Schittekatte and Meeus (2020)	Uses generic costs and pricing data to study model results for varying tariffs and scenarios; also includes storage
Studies with implicit cross-subsidies from policy/tariff designs for D-RES	Spain	Morell Dameto, Chaves-Avila, and Gomez San Roman (2020)	
	California, USA	Wolak (2018)	
	New Jersey, USA	Athawale and Felder (2016)	

We first review research on the fairness effects of direct D-RES subsidies, such as tax credits or cost rebates. Across many regions of the globe, including the Australian states of New South Wales and Queensland (Nelson, Simshauser, and Kelley, 2011; Nelson, Simshauser, and Nelson, 2012), most US states (Vaishnav, Horner, and Azevedo, 2017) and Belgium and Portugal (Bartiaux et al., 2016), high-income households are more likely to install and own PV panels, and their ownership is partially subsidized by low-income households. Likewise in Germany's case, Neuhoff et al. (2013), Grösche and Schröder (2014), Andor, Frondel, and Vance (2015), Frondel, Sommer, and Vance (2015), Tobben (2017), and Winter and Schlesewsky (2019) (the latter of which is the more rigorous and recent) study the EEG, which is used to fund the German solar feed-in tariff. All studies report that the surcharge disproportionately impacts lower-income households and offer different suggestions for alleviating these inequity effects. Cludius et al. (2014) propose and calculate another solution: wholesale market price decreases can be passed on to surcharge payers to somewhat dampen this effect. Other surcharges in Ireland (the Public Service Obligation; Farrell and Lyons (2015)), Italy (A3 surcharge; Verde and Pazienza (2016)), the United Kingdom (Grover and Daniels, 2017), Japan (Nagata et al., 2018), and Canada (Mastropietro, 2019) show similar regressive transfers of electricity costs.

The design of consumption and generation tariffs can have an impact comparable to or greater than that of direct tax credits or other subsidy incentives for D-RES (Borenstein, 2017; Lamb et al., 2020; Brugger and Henry, 2019). As such an impact is indirect, tariffs are particularly prone to creating unnoticed fairness issues. Lamb et al. (2020) reviews *ex post* literature on feed-in tariffs, finding that they are more consistently socially regressive than most other forms of D-RES support. For electricity tariffs, the energy and capacity cost portions create inequity in differing manners. Thus, most studies of equity in electricity tariffs focus on either the energy or capacity costs component.

Some studies focus on the equity effects of tariff designs in energy, or marginal, costs. Most such studies investigate the effects of separating the pricing, and thus metering, of D-RES generation from household consumption. Ansarin et al. (2020a) compares the inequities of multiple tariffs based on both legacy and smart meters. They find a large difference between time-dependent (e.g. RTP) and flat-rate tariffs, but a comparatively weaker effect from D-RES metering choices (i.e. metering and billing consumption and generation separately or together). Similarly, Eid et al. (2014) uses Spanish data to calculate cross-subsidies between prosumers and consumers under separate and net metering of consumption and generation. They find significant potential inequity, especially if under net metering generation credits are allowed to accumulate over longer time periods. Borenstein (2017) studies the net benefits of D-RES installations in the US state of California. He finds significant evidence for cross-subsidization due to implementations of IBP and net metering. Farrell (2018) compares differences in economic efficiency (deadweight loss) for different rates of D-RES adoption in the United Kingdom. He finds significant differences between the current default flat tariff and a flat tariff with marginal prices equal to marginal cost (i.e. Coasian pricing, Coase (1946)). Brown and Sappington (2017b) and Brown and Sappington (2017a) show that setting equal prices for consumption purchase and D-RES generation sale (i.e. net metering) can create cross-subsidies in different directions (between prosumers and consumers). Singh and Scheller-Wolf (2017) simulate the tariff fairness problem and consider different prices for separate customer classes and D-RES owners. Their numerical study is based on the different situations of the US states of New Mexico and Nevada (see Klass (2019) for details) and shows that separate pricing for D-RES owners is especially important for reducing inequities. Gautier, Jacqmin, and Poudou (2018) study various net metering and net purchasing tariffs for D-RES, finding that the former often transfer more cross-subsidies from consumers to prosumers. They also discuss different forms of discriminatory pricing (i.e. higher prices for prosumers) that alleviate these cross-subsidies. The authors later extend this model by considering full heterogeneity in households, rather than assuming two homogeneous groups of consumers and prosumers (Gautier, Jacqmin, and Poudou, 2021). Fikru and Canfield (2020) similarly use flat per-kWh pricing that differs per subscriber to minimize the cross-subsidies from prosumers installing solar PVs.

Many studies focus on the cross-subsidies specific to mispricings of capacity (i.e. network) costs. As discussed in Section 2.3, these costs often depend on the grid's peak demand over a long (multi-year) time period, but were often (partially) recovered by per-kWh charges. Borenstein (2016) describes the economic efficiency and equity considerations in recovering network costs through various tariff designs. Simshauser (2016) studies inequities between owners and non-owners of D-RES in the Australian state of Queensland. The author finds significant wealth transfers from PV non-owners to PV owners under a volumetric (per-kWh) rate, which is significantly reduced with a demand charge (per-kW) rate. Strielkowski, Štreimikienė, and Bilan (2017) use a similar methodology to find qualitatively similar but quantitatively lower wealth transfers among United Kingdom households. Clastres et al. (2019) predict the effect of increasing D-RES installations in France in 2021. They conclude that prosumers must be given a higher fixed charge to avoid receiving significant cross-subsidies from consumers. Nijhuis, Gibescu, and Cobben (2017) study the inequities in pricing network costs for various tariffs in a Dutch distribution grid. Their base results with negligible D-RES are compared with scenarios with high D-RES penetration, finding divergent results. Fontana (2016) focuses on cross-subsidies from grid capacity costs being integrated into per-kWh energy rates. He calculates total cross-subsidies over the lifetime of solar panels with a net present value analysis, finding significant cross-subsidies based on Portuguese data. Picciariello et al. (2015b) study inequities between prosumers and consumers in multiple US grids based on various rates of D-RES penetration. They find that metering D-RES generation separately leads to significant decreases in cross-subsidies. Building on a prior model (Schittekatte, Momber, and Meeus, 2018), Schittekatte and Meeus (2020) study the different options for pricing network costs (per-kWh flat rates, per-kW coincident peak pricing, and fixed charges) for simulated groups of prosumers and consumers, and investigate the trade-offs between efficiency and fairness for each tariff design under limited information.

Some studies also find implicit cross-subsidies. Wolak (2018) studies the increase of Californian residential retail rates, comparing the current state of increasing D-RES with one absent D-RES. He finds signs that increasing D-RES has caused increases in retail electricity prices, creating implicit cross-subsidies between prosumers and consumers. Morell Dameto, Chaves-Avila, and Gomez San Roman (2020) present a case study with some households installing D-RES, leading to implicit cross-subsidies under the Spanish network tariff (consisting of per-kWh volumetric and per-kW coincident peak charges) and an equivalent per-kWh rate. Athawale and Felder (2016) discuss the bill changes faced by low- and high-consuming customers of a New Jersey, USA, based utility due to D-RES installations.

In total, the methodological choices of these studies vary greatly, as does their area of applicability. We review some of these points in Subsection 2.5.2, where some recommendations for methods and study design are also covered. Other studies of tariff equity place their focus on long-term trends rather than more precise short-term calculations. In the following subsection, we review these papers and their discussion of electricity tariff fairness.

2.4.3 Transition management

Policy changes are not one-off events; they are rather often transitional. These socio-technical transitions are a common theme of study for socio-technical systems (Geels and Schot, 2007). In these studies, researchers investigate the effects of a policy change as it is being carried out, or it interacts with other system elements. Hence, time is a central actor in transition management studies, where policy effects are often discussed on longer time horizons.

For electricity tariffs and their fairness considerations, changes in tariff designs has been one line of inquiry in transition management. Procter (2013) and Faruqui (2010) discuss the equity considerations of such transitions and describe methods for mitigating its side effects. A common remedy for popular resistance to electricity tariff changes, particularly to dynamic pricing variants, is to provide new tariffs on a voluntary basis. However, such implementations are often prone to creating cross-subsidies between groups subscribed to different tariffs. Borenstein and Holland (2005) discuss the fairness consequences of transitioning from flat rates to real-time pricing. Using simulated and real-world electricity demand data from the US state of California, they show that the gains for some customers are higher than others. Gambardella and Pahle (2018) use similar methods to investigate the distributional effects of incomplete switching from flat-rate to RTP pricing under RES growth in

Table 2.3: Transition management literature related to the effects of D-RES on electricity pricing equity.

Topic	Jurisdiction	Article	Notes
Direct equity effects of D-RES increases	United States of America	Picciariello et al. (2015b)	
	Ansarin et al. (2020c)		
Equity effects of tariff instability caused by D-RES increase	Portugal	Prata and Carvalho (2018)	
	Queensland, Australia	Simshauser (2016)	
	Wallonia, Belgium	Villena et al. (2021a) and Villena et al. (2021b)	
	Columbia	Castaneda et al. (2017)	
	Switzerland	Kubli (2018)	Includes storage in model; considers volumetric pricing, net metering, and demand charges
	Germany	Jägemann, Hagspiel, and Lindenberger (2013)	Also reports on economic efficiency effects of D-RES increases

wholesale markets. They find evidence of both within-sector and between-sector cross-subsidies. Choi et al. (2019) model how cross-subsidies may arise between adopters and non-adopters of TOU tariffs. Their numerical results show that cross-subsidies would increase across most of the United States from a voluntary implementation of TOU tariffs, but would decrease if such a tariff transition was mandated.

More recently, the rapid uptake of D-RES generation has added more equity-related research topics in transition management studies (Table 2.3). With D-RES's strong relationship with environmental policy, the equity considerations of electricity tariffs in a transitory setting require further attention (Bento, 2013). Few studies focus on the direct equity effects of growth in D-RES, when tariff designs are held constant. One such study is Picciariello et al. (2015b), which simulates the fairness effects of transitioning from a low-D-RES grid to a high-D-RES grid. They find significant cross-subsidies forming between prosumers and consumers, with inequalities plateauing at specific rates of D-RES penetration for each simulated location. Ansarin et al. (2020c) find similar results for volumetric rates, but less pronounced cross-subsidies for time-dependent rates (i.e. TOU and RTP tariffs) in Austin, Texas, USA.

A more common strand of literature focuses on the tariff instability caused by multi-year increases in D-RES. In these situations, tariff rates change per billing period, possibly in an unstable diverging format termed a "death spiral" (Johnson et al., 2017). Many studies investigate the consequences for tariff equity in such unstable pricing scenarios. Prata and Carvalho (2018) investigate this instability due to D-RES installations for multiple tariff alternatives. Their Portuguese case study shows that transitioning grid costs from a per-kWh rate to a fixed charge significantly reduces future impacts on tariff fairness, based on network costs incurred on prosumers versus consumers. Simshauser (2016) estimate the consequences of increasing D-RES on grid capacity costs instability over a multi-year period in Australia. Using the model described in Villena et al. (2021a), Villena et al. (2021b) study the effect of distribution tariffs on PV installation growth in Wallonia (Belgium) and the growth's consequent effect on the tariffs. They find that the feedback loop between the two leads to an implicit cross-subsidy from consumers to prosumers (dependent on tariff used) which increases with D-RES. Castaneda et al. (2017) use a multi-year model to investigate the death spiral in Columbia's grid. Their results show significant tariff inequities in the long term, which can be partially solved through fixed charges, D-RES ownership fees, or more stringent net purchase agreements. Kubli

(2018) uses similar modeling and Swiss data to study grid costs increases from (and their recovery via various tariffs) D-RES and storage installation. She considers volumetric pricing, net metering, and demand charges to recover these costs, and finds varying growth rates in implicit cross-subsidy from consumers to prosumers (with demand charges performing best). Jägemann, Hagspiel, and Lindenberger (2013) reports on the long-term equity (and economic efficiency) effects of the German electricity tariff as D-RES continues to expand across its grid until 2050.

In following Section, we discuss the current gaps in the literature within these research sub-fields in the order in which they were reviewed.

2.5 Research Gaps

Prior to 2010, most research on the inequities of electricity tariffs has focused on settings with negligible D-RES generation. As D-RES grows, particularly by the uptake of small-scale solar and wind power generation units within residential grids, many new questions arise about the fairness of electricity tariffs. In the following subsections, we describe remaining research directions for each sub-field of electricity tariff fairness studies. Most research directions relate to multiple sub-fields. Thus, each study's focal point is categorized based on the sub-field to which it is closest.

2.5.1 Due versus undue

Much of the normative discussions surrounding electricity tariff inequities rely on its perception as a public good. This public goods approach has driven tariff design decisions for many regions and use cases (Bonbright, 1961; Heald, 1997). However, as discussed in the following paragraphs, scattered evidence in recent years indicates that D-RES has altered this perception. Hence, previously acceptable inequities may no longer be acceptable.

A household's decision to install D-RES is primarily motivated by economic reasons (Sagebiel, Müller, and Rommel, 2014). Consequently, it is expected that D-RES owners perceive electricity as more of a marketable good than D-RES non-owners. However, there is little quantitative evidence about the existence or magnitude of this change in perception. This perception of marketability can influence the acceptability of inequity, thus shedding light on the inequities themselves. More specifically, precise studies on how D-RES owners and non-owners differ in their normative judgements of tariff equity are missing. Other factors of D-RES, such as granting (some) independence to households regarding power generation, are also relevant here. D-RES's increasing availability and feasibility may impact not only the perception of D-RES *owners* but also D-RES *non-owners* about the public versus private nature of electricity as a product. In general, we need to place a spotlight on the differences in perceptions between D-RES owners and non-owners towards electricity and its trade.

It is generally believed that socially progressive cost transfers are desirable, but socially regressive transfers are not. There is evidence for the relative wealth of D-RES owners in many regions (e.g. in California, USA; Borenstein (2017)). Hence, it has been widely believed that D-RES subsidies may form regressive taxation (e.g. in Queensland, Australia; Nelson, Simshauser, and Nelson (2012)). On this basis, more progressive stakeholders disfavor subsidies for D-RES sources. However, a consistent counter-argument have been the positive (but often vague and difficult to quantify) externalities of offsetting pollutant generation with clean D-RES generation (Rule, 2015). Moreover, wealth differences between D-RES owners and non-owners may be decreasing, if not disappearing (Borenstein, 2017; Vaishnav, Horner, and Azevedo, 2017). Hence, a worthwhile research question would be to what extent (and where) are D-RES owners still wealthy, and whether such cost transfers are socially regressive policies (and whether a difference remains between stakeholder perceptions of and real accounts of this regressivity).

Other than wealth, characteristics of the receivers of cross-subsidies from D-RES may impact how acceptable such cross-subsidies are to the population. A neglected characteristic is the effect of population density on such normative concerns. Rural communities have both better spaces and more incentives for installing D-RES and have historically been cross-subsidized (especially in grid costs) by urban electricity users (Heald, 1997). Thus, an open question is whether such a cross-subsidy remains acceptable, given the recent propagation of affordable D-RES and storage systems more easily installed in rural settings. Other characteristics that may similarly influence inequity acceptability (in high D-RES scenarios) but are less discussed include political marginalization (e.g. due to ethnicity or religious conviction), electric vehicle (EV) ownership, home ownership, and household composition (e.g. number of children).

An additional normative concern ties to the liberalization of markets. Many past inquiries into this subject assumed that a singular tariff or policy was implemented. However, the electricity retail of many regions has liberalized and multiple tariffs may be available for household consumption and D-RES generation. More liberal market settings may offer differing normative beliefs about the inequities inherent in their pricing mechanisms.

2.5.2 Policy comparisons

Some research directions could focus more on the specific policies that impact electricity tariff fairness. It is important to understand the equity effects of the more debated tariffs, particularly RTP, CPP, and demand charges, in high-D-RES scenarios.

Electricity tariffing studies also must grapple with geographical limitations. There is a mismatch in scale between the global or regional problem addressed by D-RES (cleaner electricity generation) and the local influencers of D-RES generation, one being electricity tariffing regulations and designs. Consequently, academic studies are often molded based on data and assumptions from one region to be most applicable to that region (e.g. Borenstein (2017)). This is often intentional, as favoring a broader approach may reduce the utility of the study to practical irrelevance. Data availability is often another contributing factor, which is a primary reason for little research being previously conducted on a broader geographical scope. However, more recent years have witnessed an uptick in the availability of such data, leading to studies of tariff designs (and other policies) across larger geographic expanses. Examples of these include Nelson, Simshauser, and Nelson (2012) and Picciariello et al. (2015b), which benefit from the expansive geography and policy similarity of Australia and the United States to compare the equity effects of D-RES. Another example is per-kWh surcharges, which, as reviewed in Lamb et al. (2020) are commonly used across the world to fund D-RES subsidies (Tobben, 2017; Winter and Schlesewsky, 2019; Verde and Pazienza, 2016; Grover and Daniels, 2017; Nagata et al., 2018). A comparative study of their quantified equity outcomes or comparative analyses of the articles' proposed solutions would be supremely useful for other regions who have just begun using this policy mechanism.

Many studies of the equity effects of policies under high D-RES penetration compare household cohorts. Researchers categorize households based on income, consumption, D-RES ownership, or demographic characteristics and compare the cross-subsidies between such household groups. This is often a data limitation. However, missing is an understanding of the heterogeneity within such groups, and an understanding of the related equity concerns. The data barrier that made difficult a study of within-group inequities is now less prevalent, as multiple datasets contain the per-household consumption and D-RES generation traces of large areas. Hence, there are still open questions with regard to the inequities inherent in pricing D-RES and consumption under high D-RES within such groups, e.g. D-RES owners, single-family households, or apartment buildings.

Many prior studies have also focused on one or two tariffs being offered by an oligopolistic retailer, regulated by a governmental entity. However, many liberalized electricity markets include market-based electricity retail, with diverse tariffs offered simultaneously by various retailers (who are often distinct from the distribution system operators). Equity under such market conditions, especially under increasing D-RES penetration, remains poorly understood. Additional agency problems appear here, as multiple actors are considered, with the separation of the distribution system operator from the retailer being one important issue. Such studies would benefit excellently from studies within agent-based competitive benchmarking (Ketter et al., 2016b) approaches, such as the Power Trading Agent Competition (Ketter et al., 2016a).

Lastly, prior interest in tariff design has mostly focused on tariffs that vary based on time, volume or peak power consumed, and/or technology (e.g. specific rates for solar PV or EVs; Glick, Lehrman, and Smith (2014)). However, the abundance of data under AMI makes it possible to consider tariffs that vary (per subscriber) on a new and important dimension: location (Fikru and Canfield, 2020). In some transmission grid operation (e.g. in continental USA), such pricing practices are conducted already via locational price effects on wholesale market clearance prices (locational-marginal pricing). As similar data granularity becomes available for distribution grids, such pricing practices can be adopted in a retailer's pricing practices Glick, Lehrman, and Smith (2014). The equity effects of such pricing practices are an emerging topic of research, especially in regions with high D-RES growth (Fikru and Canfield, 2020).

Good practices for cross-subsidy studies

Many past studies of equities in electricity tariffs, particularly those involving D-RES, suffer from methodological or data concerns that limit their results and the

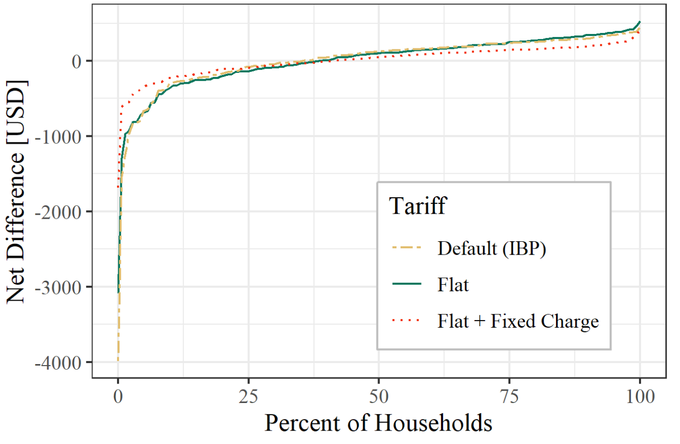


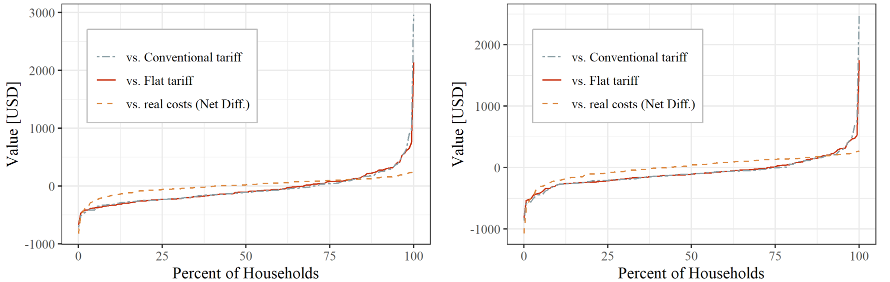
Figure 2.3: The effect of tariff design choices on cross-subsidy calculation (net difference; sorted by value). The Default tariff (Increasing-Block Pricing; yellow dashes) is compared with a flat-rate tariff (green line) and a flat-rate tariff where capacity costs are separately charged (red dots).

conclusions drawn from them. Some of these concerns and potential good practices follow:[10]

- **Tariff calibration and design:** There is much diversity in potential tariff choices for study. The most important factor in this choice is interest by stakeholders in the tariff design debate. Hence, this choice is somewhat politically motivated. For example, decreasing-block pricing was sometimes favored in the past, but is rarely offered nowadays (Borenstein, 2016), and is thus rarely studied.

  Often, research contributions rely on theoretical extensions of existing tariffs. These extensions can differ upon multiple dimensions with their real-world counterparts. The calibration of these tariffs must reflect real-world assumptions and possible extensions and be geographically applicable to the region for which the study is conducted. For example, for Austin, Texas, USA, for comparison with extensions, one could consider the current default residential rate. This IBP tariff (i.e. higher monthly rates for higher volumes of electricity consumption) was designed to trade a promotion of energy effi-

[10]Sample tariff designs, calculation formulas, and data sources are similar to those described in Ansarin et al. (2020c). Household consumption and D-RES generation data were obtained from Pecan Street Dataport (`https://www.pecanstreet.org/dataport/`). Energy price data were obtained from the Electricity Reliability Council of Texas (`http://www.ercot.com/`) and Austin Energy (`https://austinenergy.com/ae/rates/residential-rates/residential-electric-rates-and-line-items`).



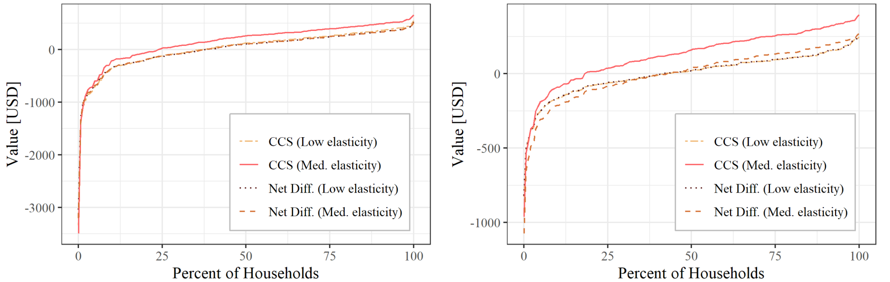
(a) Low elasticity **(b)** Medium elasticity

Figure 2.4: Cross-subsidy rates, sorted by value, when comparison is made to other tariff bills for RTP + DC tariff. Values are shown for low (left) and medium (right) elasticity scenarios.

ciency (via higher marginal rates at higher consumption volume) with creating some inequity (as households receive different average rates). Hence, the cross-subsidies in this design are inherently biased based on a policy choice. A flat-rate tariff design could be chosen instead based on the average price observed by all households (Borenstein, 2017). Similar to the IBP tariff, this tariff would include all capacity costs in a per-kWh rate, but would lack the energy-efficiency-for-cross-subsidy trade. Alternatively, the flat-rate tariff could separate such capacity costs and levy it as a fixed charge. Each of these tariffs would present a different set of cross-subsidies (Figure 2.3), but can all be labelled as "volumetric" and compared with time-dependent rates. Depending on which is chosen as a baseline, the rate of cross-subsidy for a novel tariff design can appear comparatively different. It is important these design choices result in an objective assessment of tariff inequity.

- **Cross-subsidy calculation:** The most common attribute of studies of electricity tariff pricing is that cross-subsidization is only implicitly found (e.g. in Athawale and Felder (2016)), rather than explicitly calculated (e.g. in Burger et al. (2019)). If a policy change, such as a tariff design change, is to be discussed and evaluated, its effects on equity require explicit calculation and comparison on the basis of one or more suitable metrics.

  Various metrics can be used to quantify the fairness of electricity tariffs. The ideal comparison would be between a tariff's bill and a bill that returns the exact costs imposed on the retailer by the household (see "cost causality" discussion in Picciariello et al. (2015b)). However, the latter costs are in reality

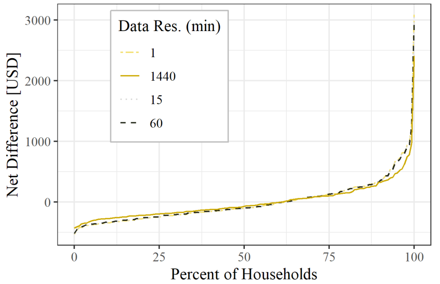


(a) Flat-rate tariff **(b)** RTP + Demand Charge tariff

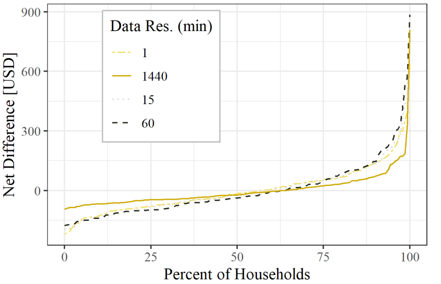
Figure 2.5: Rate of cross-subsidy, sorted by value, based on choice of cross-subsidy metric (change in consumer surplus (CCS) and net difference) for Flat-rate and RTP + Demand Charge tariffs. Values are shown for low and medium elasticity scenarios. Color and line type distinguish choice of cross-subsidy metric and elasticity rate.

difficult to obtain, as they depend on the financial information of often private firms. Hence, researchers often resort to comparing bills between one tariff and another. Yet both tariffs would contain cross-subsidies, as each tariff's bill would be different from the actual costs imposed on the retailer and grid. Hence, comparisons of tariffs in these scenarios are often fraught with bias. An example of this is displayed in Figure 2.4, where the bill of a chosen (RTP plus demand charge) tariff is compared with an IBP tariff (labelled "Conventional", default rate in region of dataset), a flat-rate designed to avoid some cross-subsidies inherent in the IBP rate (as calibrated in Borenstein (2017); discussed in previous bullet point), and the real costs of electricity trade. Although there are large differences between using real costs and the tariffs as a baseline, the differences between the tariffs (and the influence of elasticity, as the two subfigures compare) is relatively minimal. Such results on cross-subsidies are often representative of the *relative* equity effects of tariff design changes, rather than the *absolute* equity of one tariff or another. Consequently, policy designs based on these metrics are handicapped by the entrenched unfairness of the base rate.

Another common issue arises in cases where demand elasticity is non-zero. A change in demand due to a change in price requires that the marginal value of electricity for end-users is non-equal across values of consumption. In other words, the first few kWhs of electricity are more precious to a household than later kWhs, and this consideration should be represented in measures of fair-



(a) Flat-rate tariff



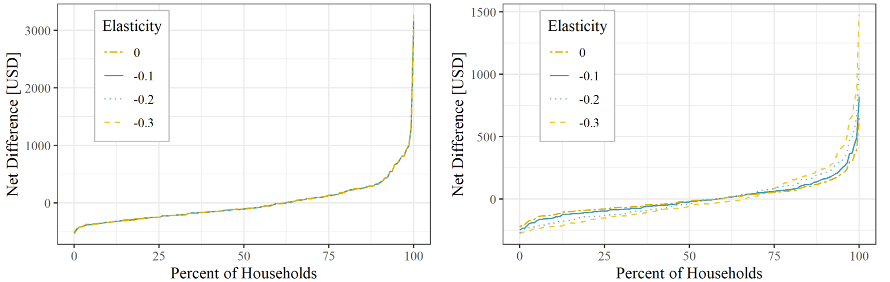
(b) RTP + Demand Charge tariff

Figure 2.6: The effect of data resolution (color and line type) on cross-subsidy (net difference) calculations for Flat-rate and RTP+DC tariffs (sorted by value).

ness. This is often done through calculating fairness as changes in *consumer surplus*, rather than as changes in *bills*. Burger et al. (2020) discuss the calculation of changes in consumer surplus as applicable to electricity tariffs. The difference between these two metrics are more pronounced at higher elasticity rates, as shown in Figure 2.5. The left subfigure shows a divergence between net difference (changes in bills) and changes in consumer surplus for a flat-rate tariff under two rates of (constant) demand elasticity. These differences are smaller than those seen in the right subfigure, which shows similar values for the RTP + Demand Charge tariff. As expected, tariffs designed to capitalize on more demand elasticity show a bigger divergence between these values. such differences are expected to increase as demand elasticity continues to increase in many grids.

It is also important to consider that changes in consumer surplus can also reflect homogeneous consumer welfare gains (or losses); in the case of electricity tariffs, a suitably designed tariff may induce all users to reduce demand peaks, causing an increase in overall surplus, as can be seen in Figure 2.5 (and is larger for higher demand elasticity). However, assuming revenue neutrality, overall changes in bills within the household cohort are masked. Hence, unlike consumer surplus, bill changes can only represent differences between households.

- **Data resolution:** Many studies of tariff equity have used aggregated energy and billing data from annual or monthly accounting cycles. As discussed in Section 2.3, the costs and value of electricity delivery often depend on the



(a) Flat-rate tariff **(b)** RTP + Demand Charge tariff

Figure 2.7: The effect of demand elasticity (color and line type) on cross-subsidy (net difference; sorted by value) calculations for Flat-rate and RTP+DC tariffs.

values of electricity at each time. Recent expansions of AMI has made data with higher resolution available, some at a per-second basis, allowing more precise measurement of value and costs associated to electricity consumption and generation (Ketter et al., 2018). This precision can impact the revenue and costs of electricity trade, and thus cross-subsidy rates.

In reality, equity calculations for different tariffs are impacted differently by data resolution. Traditional volumetric tariffs, such as flat per-kWh rates, are less dependent on minute-by-minute changes in price. Hence, low data granularity is able to capture such tariff's cross-subsidies accurately (Figure 2.6a). The same does not hold for newer tariffs with higher time granularity. For example, a RTP plus demand charge rate is strongly impacted by reductions in data resolution (Figure 2.6b). Consequently, the cross-subsidy rates for this and similar tariffs are strongly dependent on data resolution: poor data resolution may result in deceptively low inequities. Time resolution is a significant factor in calculating cross-subsidies for tariffs with time-dependent or power-dependent rates. As the popularity of such tariff designs continues to grow, analyses and datasets with higher time granularity are required for equity studies.

- **Demand elasticity:** Studies of tariff fairness differ greatly in their demand (consumption) elasticity assumptions. Some studies model per-device load shifting and make simple assumptions about consumer behavior. The assumptions of consumer behavior in these studies are often difficult to empirically measure and verify. Hence, the approach of simulating total demand elasticity with a linear (Faruqui and Sergici, 2013) or exponential (constant rate) (Burger et al., 2020) demand function is often preferred.

Many studies do not consider demand elasticity fully, as its effect on tariff equity is not self-evident. For some tariffs, elasticity may cause cross-subsidies to appear larger or smaller than they realistically are. For others, it may have little influence on the final cross-subsidies. Figure 2.7 shows cross-subsidies for a Flat-rate and a RTP + Demand Charge tariff, where the rate of (constant rate) demand elasticity is varied from zero to a high (-0.3) value. The results show how for the less granular tariff, elasticity has little effect in the differences between real and tariffed costs, whereas for the more granular (RTP + DC) tariff, the differences are significant. Including a suitable measure of demand elasticity improves the numerical accuracy of a study's results, although such differences are less pronounced for less granular tariffs.

- **Other important assumptions:** Each study of tariff policies require multiple influential assumptions. For studying equity, probably the most significant assumption is ensuring that any changes to the overall revenue, and thus any equal changes to user bills, is separated from the calculated rate of cross-subsidies. In other words, inequity should reflect the differences between users, rather than their similarities, as they are billed. For this purpose, it is important to assume revenue-neutrality, namely that any change in price would lead to a similar overall revenue. This ensures that changes in bills per user are isolated to other households, and thus represent cross-subsidies, rather than a general increase or decrease in the cost of electricity trade between the retailer and households (which may represent subsidies or taxes from or to an entity external to the household cohort). The revenue neutrality constraint only holds within the retailer's accounting period. That is, of retailers with annual accounting, many transfer year-on-year deviations in their overall costs to tariff prices. Hence, each year's tariff, and thus its total revenue, may be based on a differing amount of overall costs.

  It is likewise important that all elements of electricity costs are included in the revenue and costs comparisons. For example, Gawel, Korte, and Tews (2015) describes how subsidies and externalities of conventional generation are not adequately reflected in distributional studies of the German renewable energy surcharge (EEG), as calculated in Neuhoff et al. (2013) and Frondel, Sommer, and Vance (2015). In past research, data limitations made it common that inequity was studied for mispricing only one cost creator, e.g. energy or capacity costs. However, changing pricing for one cost component can affect another. For example, demand charges induce reduced peaks, but also reduced overall demand, and thus cause a reduction of energy costs, which may impact cross-subsidy distribution. As more granular data becomes available, it becomes possible to consider a holistic approach, with all costs components considered in equity calculations (Ansarin et al., 2020c).

Lastly, calculating each cost component of electricity trade requires multiple assumptions. Differences in assumptions regard network (distribution and transmission grid operation and maintenance) costs are far larger than such differences for energy or other cost components. Studies vary in network costs calculations, from assuming a fixed percentage amount of bills (Simshauser, 2016) to calculating costs based on a reference network model (Picciariello et al., 2015b). This diversity in method is mainly due to poor availability of network costs information. These costs are often private and/or difficult to connect directly to tariff prices. The accurate measurement of tariff cross-subsidies, especially in high D-RES scenarios significantly impacted by network costs changes, can benefit greatly from more precise and granular information from distribution grid operators and retailers.

The aforementioned methodological concerns ensure that policy results are accurate, precise, and realistic. Some of these methodological concerns also apply to studies of transition management for electricity tariff equity. In the following subsection, we review research gaps in this sub-field.

2.5.3 Transition management

In this sub-field, most past research on tariff fairness has discussed the effects of tariff changes. Their results and thus conclusions were often agnostic to D-RES uptake. In this regard, there are two areas of inquiry that remain.

The first is the transition from low D-RES uptake to high D-RES uptake, and its effects on inequities from electricity pricing. The increase of D-RES is expected to have myriad effects on the costs of electricity provision for a retailer. Retailers experiencing this change have continuously adjusted their tariff prices to meet consequent costs changes. This practice often results in tariff instability that create uncertainty-based problems for end-users. In addition, they also change the inequities inherent in tariff designs. For example, many flat-rate tariffs proven suitable for low D-RES settings have been adjusted such that their inequities may no longer be acceptable in a high D-RES setting. Although some prior studies have investigated this matter (Castaneda et al., 2017; Kubli, 2018; Villena et al., 2021b), we miss an explicit and comprehensive calculation of these equity effects. Thus, an important area of inquiry would be the long-term change in tariff equity, resulting from the changing retailer costs due to D-RES increase.

The second area of inquiry is the potential effect of D-RES on the transitory (equity) effects of tariff changes. In this case, the transitioning instrument is the tariff itself, rather than D-RES, as in the previous paragraph. For example, transitioning from fixed volumetric rates to RTP has been the focus of many papers (see review in Matisoff et al. (2020)). However, this transition would be markedly different with a high number of D-RES units in the grid. D-RES significantly impacts a retailer's costs, and including this influence would indirectly also impact household bills. Thus, equity changes would differ based on the amount of high-D-RES penetration. Such studies, namely the transitory effects of tariff changes in high-D-RES grids, are an opportunity for future research.

As in the two other sub-fields, transition management studies have also put very little focus on liberalized forms of electricity retail. Most articles assume transitions from one tariff to another, or from low to high D-RES scenarios under a single tariff. Thus, they rarely account for multi-actor systems with multiple possible tariffs. This sub-field is also missing much research on similar topics, but studied within competitive market scenarios.

2.6 Conclusions

In 1961, Bonbright (1961) reviewed the equity considerations of tariff design for public goods. Heald (1997) further elaborated on these equity considerations, particularly of network goods, and/or goods provisioned in concentrated or monopolized markets. In more recent times, electricity produced from renewable energy sources has grown rapidly across many distribution grids; the economics of electricity provision have similarly changed. Hence, revisiting their equity concerns for end-users, particularly at the local distribution grid scale, appears necessary.

This paper reviewed the current state of research on residential tariff equity. We placed focus on studies including distribution renewable energy sources (D-RES) and more common and debated tariff designs. Study subjects fall closer to one of three focal points, each containing multiple avenues for future study. The first concerns the acceptability of inevitable tariff inequities. Broadly speaking, two points of research remain to be understood here. First, the differences in perceptions of D-RES owners and non-owners towards electricity trade and its economic effects (in this case, equity) are a poorly-understood matter. Second, it is also not clearly understood if the social regressivity (or progressivity) of D-RES reimbursements match the perceptions of the general public. Prior evidence points to both under-estimation and over-estimation of such parameters in various regions.

The second focus is the quantified effects of pricing policies, particularly tariff designs, on equity. In this regard, multiple avenues of research have been proposed. Additionally, we offered some suggestions for improving the quality of studies on policies influencing the subsidizing and uptake of D-RES. These include rigor in cross-subsidy calculation metrics, data resolution, demand elasticity, tariff calibration and design, and simplifying assumptions. Moreover, more studies concerning multiple regions and jurisdictions and comparing the consequences of their policy choices can be conducted.

The third group of studies add time as an element and investigate the transitional effects of policies on equity. Two lines of research stand out here. The first line involves understanding the long-term consequences of D-RES increases in tariff equity. The second investigates the (possibly moderating) effect of D-RES on the transitory effects of tariff changes. As D-RES uptake continues to grow, such transitional studies increase significantly in importance and influence.

In general, most past studies were limited by the details of their datasets. However, given the rapid integration of smart meters (AMI), these limitations are less applicable for future studies of tariff design and its economic consequences. In addition, much of past research has focused on monopolistic scenarios. Equity considerations in more liberalized retail markets appear to have been weakly researched. Thus, much remains to be understood about equity concerns when competition (more strongly) defines the economic relationships between actors in residential electricity retail.

We must also note the emphasis on geography in this article. The concept and calculation of equity relies heavily on technical, economic, socio-political, and environmental factors. Hence, a persistent theme throughout almost every reviewed paper was the limits to its applicability to other regions and cases. Many of the assumptions chosen to simplify or quantify factors of an electricity network or its supporting economic system are inherently present in one or few regions. Moreover, normative aspects of equity also appear to be regionally dependent (e.g. see Levinson and Silva (2019)). Consequently, although many studies attempt to generalize, they are often only remotely applicable to jurisdictions outside of the study's focus. In light of this finding, we have emphasized the locations for which each study applied throughout the manuscript, and hope that readers can assess the generalizability of each study of interest upon a deeper inspection.

As renewables grow across many distribution grids, their economic consequences still remain weakly understood. The consequences for equity are especially affected by D-RES and retail tariffs. As the financial case for some renewables continues to benefit from declining manufacturing costs and climate change mitigation policies, the equity effects of renewables expansion is expected to remain an important subject for years to come.

Chapter 3

Metering Choices and Tariff Fairness[1]

3.1 Introduction

The electricity supply chain is undergoing significant upheaval. As renewable energy sources (RES, renewables) are favored over fossil fuels for electricity generation, they are rapidly displacing conventional plants in many regions. Some of this displacement is happening within distribution grids, where distributed RES (D-RES, e.g. solar photovoltaic panels) are installed. Electricity production thus becomes cleaner and less centralized.

Owners of D-RES typically purchase electricity from a distribution grid retailer. Such retailers purchase electricity wholesale, transfer it via a distribution grid to end-users, and recover costs via tariff subscriptions. These tariffs are designed to meet specific objectives based on specific assumptions (Reneses and Ortega, 2014). However, the increase in D-RES is swiftly upending many of these assumptions, particularly for smaller residential users. In the past, these users were often assumed to be passive consumers. Installing D-RES quickly changes these consumers into active producer-consumers, or "prosumers". Consequently, the tariffs they are based on fail in multiple ways to suitably price electricity (Picciariello et al., 2015a). In particular, D-RES can impact tariff fairness considerations, i.e. ensuring equal cus-

[1] This chapter was published in Energy Policy (see Ansarin et al. (2020a)). Parts of this chapter were also presented at the Workshop on Information Technology and Systems in 2016 and 2017, and the International Association for Energy Economics 2018 conference.

tomers pay equal prices for the same good. Past research has shown D-RES can worsen “cross-subsidies”, where one consumer subsidizes the product for another (Simshauser, 2016). Thus, tariff design must be revisited to properly account for the impact of D-RES growth.

Tariff design is by nature dependent on how electricity is measured. As D-RES increases, jurisdictions have approached the issue of metering generation from two directions: metering generation and consumption separately (FiT[2] metering) or together (net metering). While the former allows for more versatility in tariff design, the latter is simpler (and thus cheaper) to bill and account and requires a smaller up-front investment in infrastructure. However, the cross-subsidies of most FiT metering tariffs have not been directly compared with net metering tariffs. In particular, there is little prior research on these tariffs regarding a distribution grid with high levels of D-RES (Picciariello et al., 2015a).

Tariff design also depends on the measurement capabilities of grid infrastructure. Advanced metering infrastructure, also known as “smart meters”, have many benefits and are rapidly being adopted across many regions (Alahakoon and Yu, 2016). Smart meters measure and communicate (and sometimes control) electricity flow with far more time granularity than legacy metering infrastructure. This finer time granularity is particularly important for measuring D-RES generation, which can vary over short time spans. High-resolution measurements are important for electricity pricing, particularly for grid infrastructure costs (Hu et al., 2015). Thus, AMI’s influence in tariff design has become a common focus of study, for example in dynamic pricing (Feuerriegel, Bodenbenner, and Neumann, 2016).

Despite these developments, existing literature lacks a comprehensive assessment of how these matters affect fairness within a high D-RES grid. We take a data-driven approach with high-resolution electricity consumption, generation, and pricing data from Austin, TX, USA, for 2016, to understand the influence of tariff and metering choices on this matter. We implement commonly-used and -debated tariff designs that differ in their dependence on a) FiT versus net metering, and b) legacy versus smart meters (AMI). These tariffs include flat-rate volumetric prices, two-tier Time-of-Use rates, real-time pricing, and demand charges. Our metric of fairness is cross-subsidization, or cost transfers between households subscribed to a common utility.

[2]Stands for “Feed-in Tariff”. There are multiple tariffs possible when generation and consumption are metered separately, and FiTs are one such tariff type. FiT tariffs are the most common in dual-meter setups, so for simplicity we refer to dual-metering tariffs as FiT.

Our methods and data differ from most past work in two important ways: first, we use high-resolution per-minute consumption and generation data, which can significantly impact cost calculations (Hu et al., 2015). Less granular cross-subsidies rates may mask some cross-subsidies from being calculated, e.g. in Picciariello et al. (2015b). Second, most past work calculates cross-subsidy by comparing revenues from two tariffs. Our work separates the real costs of electricity delivery from tariff revenue, thus creating a common reference for comparing cross-subsidies between all tariffs.

Our results show significant variation in cross-subsidies. Key insights from our work include (details in Section 3.6):

1. Using AMI instead of legacy infrastructure appears to significantly impact cross-subsidies. Non-AMI based tariffs exhibit cross-subsidies two or three orders of magnitude higher on the median (dependent on tariff) than AMI-based tariffs.

2. Metering consumption and generation separately (under FiT metering) or together (under net metering) has a far smaller effect on cross-subsidies.

3. Aside from metering choices, tariff design can significantly impact cross-subsidy. Order-of-magnitude differences are observed between real-time pricing, time-of-use, and demand charge tariffs.

4. Price elasticity of consumption does not significantly alter our results.

Thus, metering and tariff choices have varying effects on cross-subsidies within a distribution grid. We discuss the overlaps and divergences in the effects of these choices and form recommendations for a high-renewables distribution grid. In particular, the common discussion focus of net versus FiT metering appears less consequential in terms of fairness than AMI versus no AMI. Elasticity may marginally impact cross-subsidy and should be considered; however, its effects on cross-subsidy are far weaker than installing AMI.

In the following section (3.2), we review previous research related to cross-subsidies in electricity tariffs. Section 3.3 provides details on calculating costs, cross-subsidies, and demand elasticity. We describe the datasets used in this analysis in Section 3.4 and their numerical results in Section 3.5. Section 3.6 discusses policy implications, and includes some limitations of work and further study options.

3.2 Background and Literature Review

Historically, retail electricity tariffs have been influenced by both politics and economics (Yakubovich, Granovetter, and Mcguire, 2005). An interested reader can refer to Simshauser (2016, Section 3) for a concise historical review. Based on Bonbright's original principles (Bonbright, 1961), Reneses and Ortega (2014) list the following principles for electricity tariff design:

P1. Sustainability or Sufficiency of revenue: Recovering sufficient revenue for grid operation from tariffed consumers.

P2. Equity or non-discriminatory access: Ensuring equal charges for equal power consumption, irrespective of user characteristics.

P3. Economic efficiency: Allocating resources to those who value them most.

P4. Transparency: Clarity in tariff design process and outcome.

P5. Simplicity: Tariff designs being easy to understand and react to for subscribers.

P6. Stability: Controlling the variation of tariff design (tariff formulation) and tariff charges (the values within the formulation) over long time periods.

P7. Consistency with larger regulatory framework: Ensuring that regulation of the electricity sector is not at odds with regulation in (other) public goods.

P8. Additivity of costs elements: Ensuring that the final charge is equal to the added sum of each tariff component.

Realistically, it is impossible to simultaneously adhere to all principles. Hence, tariff design has been a (often political) process of compromise, prioritizing some principles over others (Reneses and Ortega, 2014). Practical difficulties in measuring product consumption have directly impacted tariff design possibilities. The most common metering approach for residential users, based on volume of energy consumed over a long time horizon (volumetric metering), has limited the diversity of possible tariffs (Borenstein, 2016). Recent increases in D-RES ownership by prosumers can make these tariffs no longer suitable for recovering the costs of electricity generation and transport (Borenstein, 2016; Picciariello et al., 2015a). For these smaller users, retailers and regulators struggle with simultaneously meeting P1 (sufficiency of revenue), P2 (equity), and P6 (stability) (Sakhrani and Parsons (2010) detail some examples from tariffs used in Spain and Portugal).

These challenges can be partially addressed by advances in metering infrastructure. Advanced metering infrastructure (AMI) can provide instantaneous power measurement and bi-directional information and (in some cases) control signals. These capabilities create many more options for tariff design (Alahakoon and Yu, 2016). Designing tariffs based on hourly pricing has drawn much attention recently

(Eid et al., 2014; Fridgen et al., 2018; Sakhrani and Parsons, 2010). AMI can also significantly increase demand elasticity for end-users, making elasticity potentially more important for tariff design.

We focus here on P2, the equity (or fairness) principle, constrained by the principles of revenue neutrality (P1) and tariff stability (P6). One measure of equity in tariffs is cross-subsidy, which occurs when one population of tariff subscribers pays more than they should for a product, while another population pays less (Heald, 1997). High cross-subsidies exist within many distribution grids, mainly because of other tariff design principles taking precedence over equity. Many studies use consumption-based data to calculate cross-subsidies and discuss their implications for various stakeholders (Faruqui, 2010; Borenstein, 2007; Simshauser and Downer, 2016; Passey et al., 2017; Blank and Gegax, 2014; Azarova et al., 2018; Burger et al., 2020). Although informative, results from these consumption-based studies may not be applicable to high D-RES grids. Increasing D-RES has myriad effects on the distribution grid and on retailers, which cannot be captured by studies based on consumption patterns alone (Picciariello et al., 2015b).

Some past studies of high D-RES scenarios detail these effects for cross-subsidy and equity in general. Johnson et al. (2017) show some between-sector cross-subsidies caused by renewables. We focus here on residential within-sector cross-subsidies, i.e. transfers from households to households. Using Australian data, Simshauser (2016) investigated the effect of capacity costs on wealth transfer in a solar-heavy distribution grid. With a similar model, Strielkowski, Štreimikienė, and Bilan (2017) study wealth transfers between customer groups in the UK. Borenstein (2017) compares wealth transfers resulting from various economic instruments (direct payments, tax incentives, and tariff-based transfers) on the cost distribution of solar PV panels in the US state of California. Picciariello et al. (2015b) simulated various US-based distribution grids and calculated the effects of solar PV panels on tariff-based cross-subsidies. Clastres et al. (2019) similarly simulate French distribution grids and focus on the cross-subsidies formed by the self-consumption of D-RES generation. Fontana (2016) also study a case of cross-subsidies in a simulation of a Portuguese grid. These past studies do not consider all cost components of electricity trade and/or do not use a representative range of tariffs. The former may mask the actual cross-subsidies of a tariff (Burger et al., 2019), while the latter would allow us to separate the effects of metering infrastructure and tariff design. Thus, our goal is to conduct such a comprehensive analysis and separate the effects of metering and tariffs on cross-subsidy in a high D-RES grid.

3.3 Methods

3.3.1 Choice of tariffs

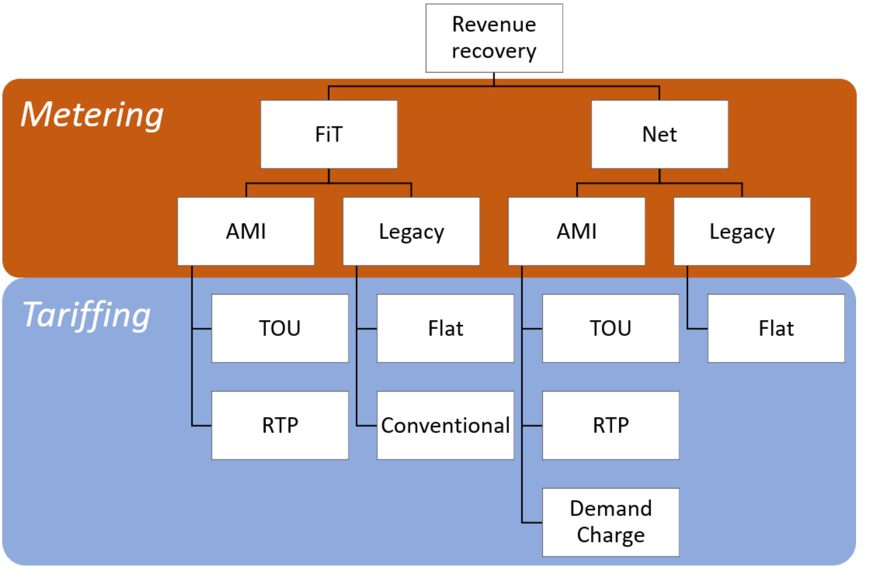


Figure 3.1: Tariffs used in this study and their dependence on metering infrastructure.

Tariff design is constrained by its dependence on metering infrastructure (Figure 3.1). In a distribution grid with high counts of D-RES generation, the metering of electricity requires two important choices. The first choice is whether to meter generation and consumption separately or together. Some jurisdictions (e.g. Austin, TX, USA) choose separate (FiT) metering, while others (e.g. US state of California) opt for metering the two together as net demand (indicated by "Net" in Figure 3.1). This choice usually follows D-RES growth policies and how each jurisdiction chooses to compensate D-RES generation.

There is a second choice with regards to the devices used in the metering arrangement. Traditional (or legacy) meters allow for tariff designs dependent on monthly accounting and billing, such as flat-rate and volumetric tariffs. However, an upgrade to AMI is required for metering and billing with high time resolution, a prerequisite for tariffs that intend to match time resolution or measure separated capacity costs. Across these metering choices, we choose and formulate tariffs based

Table 3.1: Tariffs used in this study

Tariff	AMI Required	FiT/Net	Notes	Past Studies / Relevance
Conventional	No	FiT	Status quo	Current tariff in use
Flat-rate	No	FiT/Net	Most common tariff design	Borenstein (2007), Borenstein (2017), Borenstein (2016), and Picciariello et al. (2015b)
Two-Tier Time-Of-Use	Yes	FiT/Net	Intended as middle-ground between simpler Flat-rate and accurate RTP pricing	similar to pilot tariffs in Texas and Netherlands
Real-Time Pricing	Yes	FiT/Net	Sacrifices simplicity and predictability for accurate pricing	Azarova et al. (2018) and Horowitz and Lave (2014)
Demand Charge	Yes	Net	encourages households to flatten demand	Passey et al. (2017), Simshauser (2016), and Borenstein (2016)

on common use by utilities, discussion between utilities and regulators, and prior academic studies (Figure 3.1). These tariffs are summarized in Table 3.1.

The tariffs are designed to recover the retailer's costs for electricity supply (and provide its credits for purchase). These costs typically consist of three elements. The first, *energy costs*, relates to the provision of electricity from the transmission grid or from the utility's local generation units. These costs are usually a function of how much energy is demanded by the grid at each time. The second element, *capacity costs*, consists of the sunk and fixed costs of maintaining network infrastructure. These costs typically reflect returns on investment or maintenance costs, which depend on how much power (i.e. energy flow) the grid can support with specific reliability constraints (Simshauser, 2016). Finally, other costs, such as billing, accounting, and other overhead costs, depend mainly on how many subscribers the retailer has. Similar to most past studies, we assume this final group of costs do not contribute to cross-subsidies and ignore them here.

Crediting D-RES generation of subscribers can also be considered an "energy cost" source. These credits are akin to negative energy costs and are often treated in the same way. In some rate designs, bonuses for D-RES are included in the scheme as a subsidy for (or an "internalization" of) the positive externalities of clean renewable generation. Based on Rábago et al. (2012), we assume the positive externalities of this generation can be best represented and compensated for by a per-kWh bonus.

3.3.2 Tariff design and cross-subsidy calculations

Table 3.2: Nomenclature

Label	Unit	Description
x	kWh	Consumption
g	kWh	Generation (always > 0)
d	kWh	Net Demand
$p_{max}(\tau)$	kW	Maximum Net Power over period τ
E	$/kWh	Consumption price
G	$/kWh	Generation price
D	$/kWh	Net Demand price
C	$/kW	Capacity price
P_g	$/kWh	Green Certificate reimbursement price
α	$	Green Certificate reimbursement cost
δ_p	$	Capacity surcharge per unit of power
δ	$	Capacity surcharge
θ	$	Total costs
L	$	Lump sum payment (extra fixed cost)
i	-	House index
j	-	Tariff index
r	-	Real costs index
t	min	Time unit (1 minute)
T	-	Billing period
τ	-	Time horizon
λ	-	Cross-subsidy Ratio
ν	$	(Cross-subsidy) Net Difference

We first explain our study's assumptions and formulation and then detail the calibration methods for each tariff. All prices are from the perspective of households, i.e. negative prices are a funds transfer from utility to household. Nomenclature is listed in Table 3.2.

For this study, our main assumptions are:

1. Household metering infrastructure is homogeneous: all households either have or lack AMI, and all households measure generation and consumption either together or separately.

2. All households in the study population are subscribed to the same tariff.

3. The retailer, who trades electricity on behalf of the households with the external grid, operates on a revenue-neutral basis. In other words, its revenues match costs.

To model tariffing prices and cross-subsidies, we first need to define the billing period T. This is the period within which we take the tariff design and subscription to be constant. Like most past studies (e.g. Burger et al., 2019) and most utility tariff update cycles, we assume billing is done yearly, i.e. T = 1 year. Let M and N represent the household set and the tariff set, with index i and j referring to household $i \in M$ and tariff $j \in N$, respectively. x_i, g_i, and d_i are energy consumption, generation, and net demand of household $i \in M$ at every time interval $t \in T$, where $d_i = x_i - g_i$.[3] Take $p_{max,i}(\tau)$ as peak net power (capacity) use of household i within given time horizon τ; the price per energy unit of consumption (E_j), generation (G_j), and net demand (D_j) are specified based on tariff $j \in N$; and $\alpha_{j,i}$ is any extra credit reimbursed for D-RES generation, for household i and tariff j, aside from regular tariff reimbursements (e.g. reimbursements from the sale of Renewable Energy Certificates). Finally, C_j represents the per power unit capacity price of tariff j, i.e. revenue for all costs related to long term capacity-related investments and maintenance. These prices and values can be a function of time, energy volume over a time horizon, and/or power flow.

With this notation, for each household $i \in M$ and tariff $j \in N$, the total tariffed costs of electricity supply, $\theta_{j,i}$, is

$$\theta_{j,i} = \sum_{t \in T} E_j x_i(t) + \sum_{t \in T} G_j g_i(t) + \sum_{t \in T} D_j d_i(t) + \sum_{\tau \in T} C_j p_{max,i}(\tau) + \alpha_{j,i}. \tag{3.1}$$

The total costs for the entire population M for tariff j is $\theta_j = \sum_{i \in M} \theta_{j,i}$.

Our study assumes revenue neutrality, i.e. all tariffs return the same revenue to the electricity provider, and this revenue is equal to the real costs of electricity delivery (denoted by index r):

$$\forall j \in N : \theta_j = \theta_r. \tag{3.2}$$

Some tariff calibrations require an additional degree of freedom to ensure this constraint is met. For these, we add a lump sum L_j to each household's bill. This extra charge is distributed equally across households so as not to mask the cross-subsidies inherent in each tariff.

[3] Net demand is separately defined here as it is separately measured in net metering scenarios. This simplifies later comparisons between net and FiT metering.

We first detail the makeup of the real costs of electricity trade, then explain each tariff's calibration.

Real costs

As discussed in 3.3.1, the real costs of electricity trade depend on energy costs and credits and capacity costs, plus any additional D-RES reimbursements. For consumed energy E_r, the real price at each instant is assumed to be equal to real-time locational-marginal prices (RTLMP). These prices are real-time wholesale market clearing prices at each instance in a region, biased by network conditions (e.g. congestion, losses) at each location (or node). The generation credit G_r is set to E_r, plus the bonus $\alpha_{r,i}$, which is based on a per-kWh credit P_g. To simplify, we integrate both as $G_r = E_r + P_g$.

Capacity costs of the utility's distribution grid mainly depend on the maximum net power demand over a time horizon (Simshauser, 2016). Thus, C_r is taken to be a constant per-kW price, which is multiplied by the net power demand of the utility that remunerates these costs. Since the real costs of consumption and generation are calculated separately, $D_r = 0$.

We next discuss how different tariffs are calibrated with respect to real costs.

FiT metering tariffs

The FiT Metering tariffs consist of tariffs under conventional metering, i.e. the Conventional tariff and the flat-rate tariff; and tariffs under AMI, namely the Time-of-Use and the Real-Time Pricing tariffs (see Figure 3.1). Since generation and consumption are metered separately, net demand is not used to price electricity and $D_j = 0$.

(1) Conventional tariff:[4] This refers to the tariff currently used in the area under study. In our case, our dataset is from households in a Austin, TX, USA, neighborhood, currently subscribed to Austin Energy's residential tariff. This tariff consists of tiered volumetric consumption prices and a flat-rate generation credit. The consumption price $E_{1,i}$ for household i depends on the total monthly consumption of the household and the month of the year ($T_m, m \in \{1..12\}$). Hence, each household gets a different price per month, $E_{1,i}(\sum_{t \in T_m} x_i(t), T_m)$. The generation price G_1 is set to Austin Energy's Value of Solar rate for 2016 (11.3 c/kWh, details in Rábago et al.

[4] To refer to the formulations, we index tariffs $j \in \{1..8\}$. Within the results, however, the tariffs are only referenced by name.

(2012)). Since all values are known, $\theta_{1,i}$ is known. Note that this is the only tariff where consumption prices $E_{1,i}$ differ among households.

As all tariff elements are calibrated by Austin Energy, a lump sum L_1 is added to households as a fixed charge to ensure revenue neutrality (Equation (3.2)) is met. This additional cost is levied equally across all households so that it does not contribute to cross-subsidies:

$$\theta_r = \theta_1 = \sum_{i \in M} (\theta_{1,i} + L_1). \tag{3.3}$$

(2) Flat-rate FiT tariff:

The previous volumetric tariff was designed to promote energy efficiency, at the expense of equal prices. To compare this tariff with one designed for equal prices, we include a flat-rate tariff, i.e. E_2 and G_2 are constant values:

$$\theta_2 = \sum_{i \in M} \theta_{2,i} = \sum_{i \in M} \sum_{t \in T} [E_2 x_i(t) + G_2 g_i(t)] \tag{3.4}$$

G_2 is set based on a fixed rate calculated as the value of D-RES (e.g. in Rábago et al. (2012)), including additional subsidies (i.e. $\alpha_{2,i} = 0$). In addition, capacity is not separately priced ($C_2 = 0$), and the related costs are included in the flat rate for consumption E_2. The only unknown is E_2 and can be calculated by the revenue neutrality constraint, i.e. setting $\theta_2 = \theta_r$.

(3) TOU FiT tariff:

The Time-of-Use tariff depends on AMI, and hence can have differing prices for consumption (E_3) according to the hour of day. We investigate a two-tier TOU which prices electricity during daytime (T_d) and nighttime hours (T_n) separately:

$$E_3 = \begin{cases} E_{3,d} & \text{when } t \in T_d \\ E_{3,n} & \text{when } t \in T_n \end{cases}. \tag{3.5}$$

We set G_3 to the real-time value of solar generation detailed in the Real-time Pricing tariff. Similarly, for a tariff under AMI, p_{max} is known at each instance, and thus capacity costs can be recovered separately. Hence, the price for these costs is set similar to C_r. In total, we have:

$$\theta_3 = \sum_{i \in M} \sum_{t \in T_d} [E_{3,d} x_i(t) - G_3 g_i(t)] + \sum_{i \in M} \sum_{t \in T_n} [E_{3,n} x_i(t) - G_3 g_i(t)] + C_2 p_{max} \tag{3.6}$$

By setting this equal to real costs θ_r, we have one equation with two unknowns ($E_{3,n}$ and $E_{3,d}$), i.e. one degree of freedom. To solve this equation, we require another constraint. We assume that $E_{3,d}$ and $E_{3,n}$ are proportionally scaled (with scaling factor r_3) based on average RTLMP prices during daytime (P_d) and nighttime (P_n):

$$\begin{cases} E_{3,d} = r_3 P_d \\ E_{3,n} = r_3 P_n \end{cases} \tag{3.7}$$

With this additional constraint, Equation (3.6) can be solved for r_3.

(4) RTP FiT tariff:

For the Real-time Pricing tariff (RTP), consumption prices are taken to be equal to average RTLMP prices per hour. Thus, each hour has its own price, $E_4(t)$. The generation remuneration price G_4 is taken to be E_4 with a known bonus element for reimbursements, $G_4 = E_4 + P_g$. Capacity prices C_4 are set equal to C_r. Hence, θ_4 is defined, but may not meet the revenue neutrality constraint (Equation (3.2)). To this end, an equally shared lump sum (L_4) is added:

$$\theta_4 = \sum_{i \in M} (\theta_{4,i} + L_4) = \theta_r, \tag{3.8}$$

and Equation (3.8) is solved for L_4.

Net metering tariffs

The net demand tariffs, as the name suggests, assume a net metering scenario. Hence, $E_i = G_i = 0$, while $D_i \neq 0$. To allow for a comparison of costs with FiT metering tariffs, we assume prices for net metering tariffs, $D_i(t)$, are independent of net demand, $d_{i,j}(t)$.

In all net metering tariffs, D-RES bonuses are accounted for as $\alpha_{j,i}$, separate from the metering of net demand. We assume here that the kWh generated by each solar panel can be accurately calculated based on panel characteristics and weather data. Thus, a lump bonus of $\alpha_{j,i}$ can be calculated based on a fixed per-kWh credit, P_g. This ensures that any cross-subsidies due to choosing net versus FiT metering relate to tariff design itself, rather than how D-RES subsidies are distributed among producers. The following tariffs fall into the Net Metering category (Figure 3.1).

(5) Flat-rate net tariff:

This tariff is defined based on a fixed price for net demand at any instance, i.e. D_5 is a constant. Similar to the flat-rate FiT tariff, capacity costs are included in the flat rate, $C_5 = 0$. For θ_5 we have:

$$\theta_5 = \sum_{i \in M} \theta_{5,i} = \sum_{i \in M} \left[\sum_{t \in T} D_5 d_i(t) + \alpha_{5,i} \right] = D_5 \sum_{i \in M} \sum_{t \in T} d_i(t) + \alpha_5 \tag{3.9}$$

By setting $\theta_5 = \theta_r$, Equation (3.9) can be solved for D_5.

(6) TOU net tariff:

The TOU net tariff is defined as a TOU tariff similar to the TOU FiT tariff, where the consumption price formulation is used instead for the net demand price D_6. $D_{6,d}$ and $D_{6,n}$ are defined according to RTLMP daytime and nighttime prices with a ratio r_6. Capacity costs are calculated similar to the TOU FiT tariff.

(7) RTP net tariff:

Likewise, the RTP Net Demand Tariff is defined to be similar to the RTP FiT metering tariff. D_7 is defined according to average hourly RTLMP prices and a lump sum is added to ensure revenue neutrality. Capacity costs are similarly calculated.

(8) Demand Charge tariff:

The Demand Charge tariff combines real-time pricing of energy costs with a monthly demand charge for capacity costs. The price for net demand at each instance is set similar to the RTP net tariff, or $D_8 = D_7$. To recover capacity costs, for each household i, there is a price (C_8) per kilowatt of maximum power demand during each month T_m, $p_{max,i}(T_m)$. The cost for household i over T equals $C_8 \sum_{T_m \in T} p_{max,i}(T_m)$.

The per-kilowatt capacity price C_8 is set to ensure capacity costs are equal to real capacity costs:

$$C_r p_{max}(T) = C_8 \sum_{T_m \in T} p_{max,i}(T_m). \tag{3.10}$$

The equation can be solved for C_8.

Similar again to the RTP net tariff, the overall energy costs θ_8 are defined as equal to real energy costs θ_r, with a lump sum L_8 required (based on Equation (3.2)) to ensure the equality:

$$\theta_r = \theta_8 = \sum_{i \in M} \left[\sum_{t \in T} D_8 d_i(t) + \sum_{T_m \in T} C_8 p_{max,i}(T_m) + \alpha_{8,i} + L_8 \right] \tag{3.11}$$

Cross-subsidies

Cross-subsidy is the ratio of the difference in real versus tariffed costs, divided by the absolute value of the real cost of electricity supply, or

$$\forall i \in M; j \in N : \lambda_{j,i} = \frac{\theta_{j,i} - \theta_{r,i}}{|\theta_{r,i}|}. \tag{3.12}$$

This ratio is used in most prior literature to calculate and compare cross-subsidies.[5] However, these studies mostly do not consider generation, and/or use a denominator that depends on a tariff's revenue. Thus, their per-household cross-subsidy ratios all include denominators that are well above zero. In our study, some households' real costs are offset by generation credits and the total costs of electricity transfer become close to zero. This leads to the denominator of Equation (3.12) being very small, leading to exaggerated cross-subsidy ratios. We include these ratios to allow for a comparison of our results to past studies. However, we rely on the numerator of Equation (3.12) instead to compare our tariffs, which represents the "Net Difference" between the real costs and tariffed costs of electricity trade:

$$\forall i \in M; j \in N : \nu_{j,i} = \theta_{j,i} - \theta_{r,i}. \tag{3.13}$$

3.3.3 Demand elasticity

Electricity for residential households generally has very low demand elasticity. Similar to past research (Borenstein, 2012; Horowitz and Lave, 2014; Burger et al., 2020), we assume that each household i is demand-elastic in each timeslot t according to a constant elasticity rate ϵ, i.e. $x = AE^{\epsilon}$ (black curve in Figure 3.2). The constant A depends on initial consumption and initial price values, i.e. $A_{i,t} = x_{i,conv,t}/(E^{\epsilon}_{i,conv,t})$.

We make the following assumptions to ensure a change in prices at each instance induces an appropriate change in consumption:

1. We choose elasticity values at the low ($\epsilon = -0.1$) and high ($\epsilon = -0.3$) ends of past empirical results, similar to past research (Burger et al., 2020; Borenstein, 2012; Borenstein, 2007). These are close to estimates of short- and long-term elasticity (respectively) for residential households (Labandeira, Labeaga, and López-Otero, 2017).

[5] Examples of such studies include Azarova et al. (2018), Borenstein (2017), Borenstein (2007), Simshauser and Downer (2016), Strielkowski, Štreimikienė, and Bilan (2017), Passey et al. (2017), and Johnson et al. (2017).

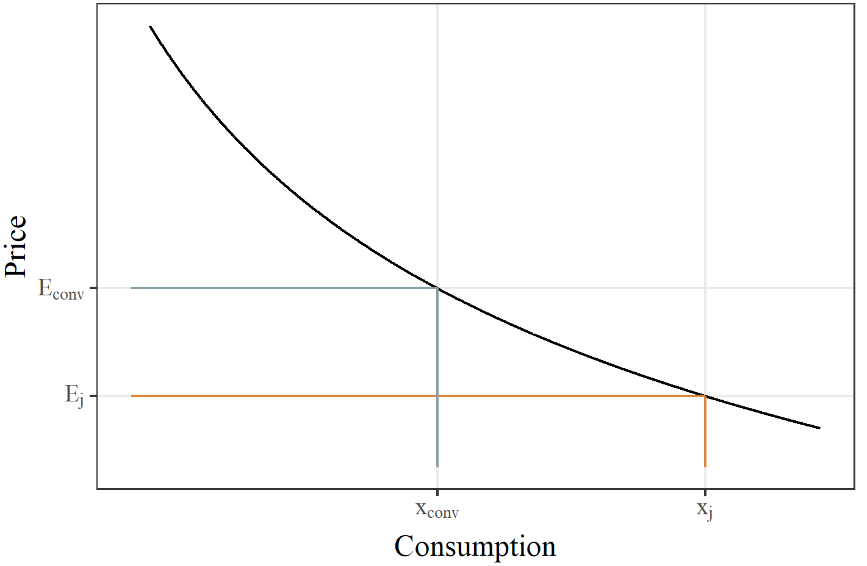


Figure 3.2: The Demand Curve (black) shows the relationship between prices and (consumption) quantities.

2. The initial observed price $E_{i,conv,t}$ is chosen as the conventional tariff's average prices. For our dataset, this consists of increasing-block prices, where the marginal price increases as monthly consumption increases. However, following Ito (2014), we take the household's average price in each month to be its initial observed price.

3. Demand elasticity functions are applicable to positive prices. However, some timeslots may have negative or zero prices. In these cases, we choose the consumer's observed price to be 0.1 c/kWh, which, when compared to a new price of 10 c/kWh (and $\epsilon = -0.1$), creates a consumption increase of 58%. This happens most for the RTP tariff, for 1.5% of instances overall.

4. For tariffs that separate capacity costs, we assume these costs are discounted from price estimates of the average conventional price, i.e. $E_{i,conv,t}$ is reduced to reflect that it also contained capacity costs. This follows from past evidence that consumers discount (i.e. do not respond to) fixed charges (Burger et al., 2020).

The Demand Charge tariff is designed to also induce demand elasticity based on the demand charge for capacity costs. Using a similar model, we assume "acceptable" peak demand over a month is dependent on the change in price of capacity costs per kW of peak demand. Thus, all timeslots are checked versus new acceptable peak demand. If lower, all timeslots with higher consumption are lowered to the new peak; if higher, consumption is increased to its original value or to the new acceptable peak demand (whichever is lower). This accounts for the demand charge signal of flattening demand, while allowing for deviations due to exceptionally low (or high) energy prices.

We use these elasticity approaches to calculate a new consumption profile per household per tariff. Much of tariff price calibration depends on real costs, which depend on consumption profiles, which depend on tariff prices. This requires iteration until an equilibrium is reached. Our algorithm iterated on costs until the sum of absolute changes in household bills was less that 0.1% of all bills combined. The final household bills were used to calculate net differences and cross-subsidy ratios.

3.4 Data

Table 3.3: Tariff values (all values in c/kWh, except C_j in \$/kW)

#	Tariff Name	Consumption (E_j)	Generation (G_j)	Net Demand (D_j)	Capacity (C_j)	REC Credit (P_g)
1	Conventional	E_1	-11.3	0	0	0
2	Flat-rate FiT	E_2	-11.3	0	0	0
3	TOU FiT	$E_{3,d}$, $E_{3,n}$	-(E_4 + 2.5)	0	8.3	0
4	RTP FiT	RTP hourly (E_4)	-(E_4 + 2.5)	0	8.3	0
5	Flat-rate net	0	0	D_5	0	-2.5
6	TOU net	0	0	D_6	8.3	-2.5
7	RTP net	0	0	D_7	8.3	-2.5
8	Demand Charge [net]	0	0	D_8	C_8	-2.5
-	*Real costs*	*ERCOT RTLMP* (E_r)	-(E_r + 2.5)	*0*	8.3	*0*

One could quantitatively compare cross-subsidies for various tariffs and metering setups with suitable high-resolution real-world data from a distribution grid and its consumer population. We were able to obtain such data containing all necessary elements for a grid in Austin, TX, USA. These datasets consist of two parts:

1. **Energy consumption and generation data**. This data was obtained with an academic license from the Pecan Street Dataport.[6] The dataset was narrowed down based on multiple criteria:

   (a) Per-minute data available for entire year of 2016. Tariff design and utility costs calculations are done annually, so a duration of one year was chosen as a representative period. 2016 was chosen due to higher data availability.

   (b) Household contains solar photo-voltaic panels.

   (c) Consumption and generation data contained less than 5% missing or erroneous data points.

   144 households' energy data met all criteria and was included.

2. **Electricity pricing data for calibrating tariffs.** This data was collected from two sources local to the energy data. We gathered real-time locational-marginal clearing prices (RTLMP) at the Austin load zone from the transmission grid (and wholesale market) operator, Electric Reliability Council of Texas (ERCOT).[7] These nodal prices are cleared in quarter-hourly intervals. The dataset obtained from ERCOT contained no missing values. Tariff rates from Austin Energy, a local public utility, were also obtained to calibrate tariff values. [8] These two data sources were used for tariff calibration in the following ways:

   (a) ERCOT's RTLMP values were used as real energy costs (E_r) at each time.[9]

   (b) Real capacity price (C_r) was set equal to the capacity price of a similarly-sized commercial or industrial entity on the Austin Energy grid.[10]

   (c) Austin Energy's 2016 Value of Solar rate (11.3 c/kWh) was used for the flat FiT tariff's generation price, G_2, based on calculations from Rábago et al. (2012).

[6] More information at `https://www.pecanstreet.org/dataport/`

[7] ERCOT RTLMP details and values can be found at `http://ercot.com`

[8] Dataset and more information at `https://austinenergy.com/ae/`

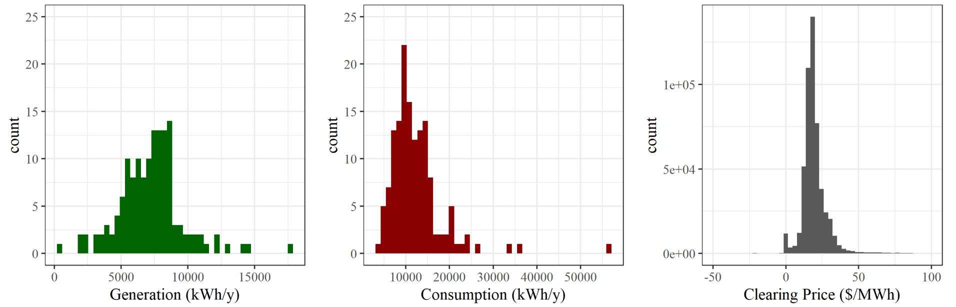
[9] Our data has assumed energy costs equal to the ERCOT RTLMP prices at each instance. While this is commonly used a proxy for the value of energy at each instance (Burger et al., 2020; Fridgen et al., 2018; Rábago et al., 2012), energy is often procured through multiple other sources, which differ in price compared to real-time market prices, in this case ERCOT RTLMP prices. These deviations are assumed to be relatively small and have been shown to have a negligible effect on cross-subsidies (Borenstein, 2007).

[10] Prices can be found at `https://austinenergy.com/ae/commercial/rates/commercial-electric-rates-and-line-items`

(d) Texas includes a market for solar Renewable Portfolio Standards (also known as Renewable Energy Certificates), which returns about 2.5 c/kWh for each unit of solar generation (Rábago et al., 2012). We took this value as P_g, i.e. the bonus for D-RES generation.

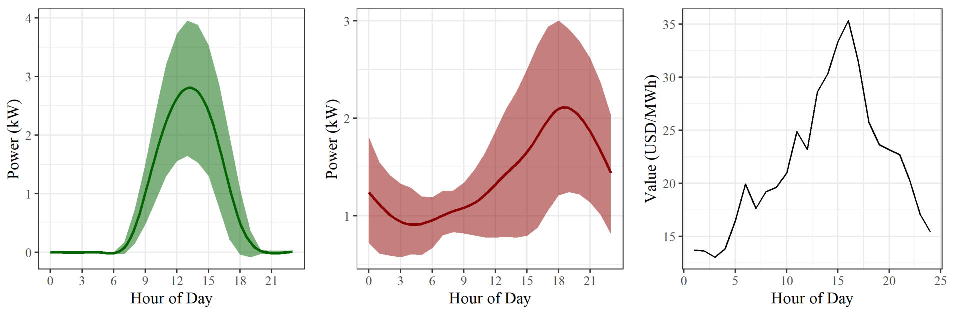
(e) The Time-of-Use tariff's high- and low-price hours were chosen similar to pilot tariff schemes from Austin Energy and other local utilities as 6:00-22:00 for daytime and 22:00-6:00 for nighttime.

The final tariff set is summarized in Table 3.3.



(a) (b) (c)

Figure 3.3: Total annual per-household generation (a) and consumption (b) distributions and ERCOT RTLMP clearing price distribution for 2016 (c). 0.86% of clearing prices are not displayed in the ercot histogram, as they represented extreme values in the range of {100,1511} $/MWh.



(a) (b) (c)

Figure 3.4: Generation (a) and consumption (b) of households and average ERCOT RTLMP (c) per hour-of-day. Shaded areas indicate one standard deviation (Except for (c), whose standard deviations were too large to display with averages).

Figures 3.3 and 3.4 show summary statistics of the two datasets. A histogram of annual household consumption (Figure 3.3b) matches the log-normal distribution expected of a distribution grid with residential end users in the Austin, TX, area. These households generally experience peak consumption in the early evening hours, mainly due to use of HVAC units (Figure 3.4b). Annual household generation (Figure 3.3a) is also distributed as expected, with values close to the 7289 kWh/y average value. A histogram of hourly ERCOT RTLMP values for the Austin load zone for the year of 2016 are plotted in Figure 3.3c. On rare occasions, prices rise above 1000$/MWh. On average, however, these prices fluctuate strongly during the day, with very high prices at high demand moments during the early evening hours (Figure 3.4c).

3.5 Results and Discussion

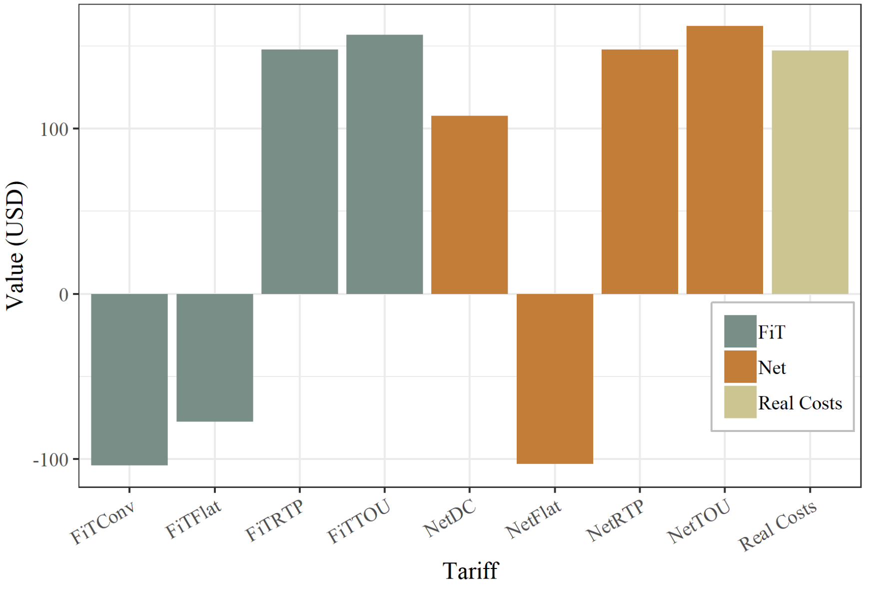


Figure 3.5: Sample household costs per tariff and real costs.

For each household, we first calculate the real costs of electricity trade and each tariff's revenues. We then compare these values based on net difference and cross-subsidy ratio. To illustrate this, Figure 3.5 shows tariffed revenue and real costs for one sample household from the population. The differing tariff revenues are compared with real costs (Figure 3.5, blue) to find the net difference, which is compared within and across tariffs. All net difference values reported here are on a per annum basis.

3.5.1 Comparison of tariffs based on legacy metering

Table 3.4: Numerical comparison of tariff cross-subsidies.

Tariff	Prosumers w/ negative Cross-subsidy, NegRatio (% of population)	Median negative cross-subsidy, MedNegCross	Median positive cross-subsidy, MedPosCross	Median household negative costs transfer, MedNegTransfer (USD)	Median household positive costs transfer, MedPosTransfer (USD)
Conventional	64	-0.7234	0.3807	-164.59	157.12
Flat-rate FiT	62	-0.8886	0.4815	-212.53	229.50
TOU FiT	72	-0.05072	0.04877	-7.26	7.75
RTP FiT	45	-0.002041	0.001803	-0.53	0.55
Flat-Rate Net	63	-1.008	0.5391	-232.64	259.07
TOU Net	48	-0.01953	0.02399	-6.60	6.90
RTP Net	47	-0.002270	0.001954	-0.61	0.55
DC Net	63	-0.302	0.209	-65.8	91.8

The residential tariff currently employed by Austin Energy, albeit flat-rate, consists of a volumetric increasing price for consumption. That is, each month a high energy user would pay more per kWh than a low energy user. This policy choice, while sacrificing some welfare transfer, intends to motivate energy efficiency by residential users (Borenstein, 2017). Thus, comparing such a tariff with other tariffs would not only consider cross-subsidies from flattening the temporal dynamics of energy prices, but also from this intentional policy choice. To balance this out, another conventional tariff, a flat-rate fee, was designed and calibrated to match this volumetric tariff without the added volumetrically increasing prices, and thus without cross-subsidy from the policy instrument (ibid). This Flat-rate tariff is designed in two ways, with one based on Net metering and the other based on FiT metering (Table 3.3).

Figure 3.6 shows the cross-subsidy spread from the three non-AMI tariffs, per household, sorted based on value. While some households observe fairer costs under a flat-rate tariff (i.e. closer to the horizontal axis), others are put into a less fair position (further to the extremes). However, at the medians, results are marginally

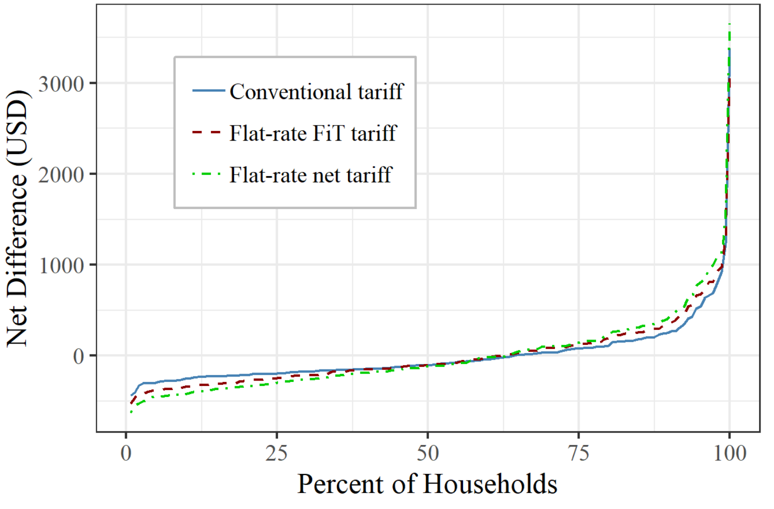


Figure 3.6: Net difference (sorted) for the conventional Austin Energy tariff and the flat-rate tariffs under FiT and Net metering per household.

different. The median values of positive and negative cross-subsidies (i.e. the median of all positive and all negative cross-subsidy ratios) from the flat-rate tariffs are worse than the conventional tariff (Table 3.4). In terms of net differences, the flat-rate tariffs see median positive "transfers" of $229.50 (FiT) and $259.07 (Net) and median negative transfers of -$212.53 (FiT) and -$232.64 (Net), while the conventional tariff's median transfers are $157.12 and -$164.59, respectively. Thus, the flat-rate tariffs are marginally worse overall at ensuring cost-causality. The flat fee added for calibration to the conventional tariff reduces some cross-subsidies that are due to capacity costs. These cross-subsidies are larger than the cross-subsidies inherent in the volumetric design of the energy portion of the Conventional tariff. As a result, this tariff maintains lower overall cross-subsidies than the flat-rate tariffs.

3.5.2 Comparison of tariffs based on AMI

Our AMI tariffs consisted of two sets of tariffs (TOU and RTP) dependent on two different metering setups (FiT and net metering). These 4 tariffs are compared with each other and the corresponding flat-rate tariffs in Figures 3.7 and 3.8. Both TOU and RTP tariffs produce far less cross-subsidy than the flat-rate tariffs. In FiT metering (Figure 3.7) for example, median net differences for the flat-rate tariff are $229.50 (positive transfers) and -$212.53 (negative transfers). Compare this with me-

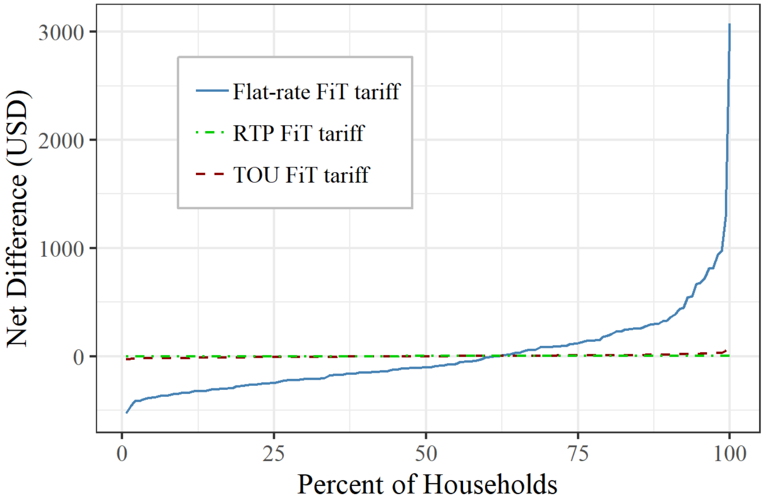


Figure 3.7: Net difference for FiT metering tariffs per household.

dian positive and negative transfers of $7.75 and -$7.26 for TOU and $0.55 and -$0.53 for the RTP tariff. This 2-order-of-magnitude difference is due to two matters. First, tariffs based on AMI (TOU and RTP) capture the capacity costs of the distribution grid and can recover those separately from the per kWh energy charge. Second, they are able to reflect the temporal dynamics of wholesale energy prices. These both contribute to a significantly reduced cross-subsidy spread, which is reflected in the median values of positive and negative net differences.

The TOU tariff performs similarly to the RTP tariff in most cases (Figure 3.9, Table 3.4). While the cross-subsidies spread between the TOU tariffs and the RTP tariffs are quite different, they are very small compared to the flat-rate tariffs. For example, the TOU net tariff's median positive and negative cross-subsidy ratios amount to 2.4% and -1.9%, respectively, while those of the RTP tariff are one order of magnitude less (namely 0.2% and -0.2%, respectively).

The TOU tariff is designed to reflect some of the temporal dynamics of energy price fluctuations, while remaining relatively simple in design. That is, it provides a suitable economic signal while reducing some of the cross-subsidies from energy prices. In previous research, simulations have shown that new peaks can form due to consumers reacting to the new price signal (Valogianni and Ketter, 2016). Energy prices are from wholesale market locational-marginal rates for electricity supply at the transmission level, a market in which the utility is assumed to be a price-taker

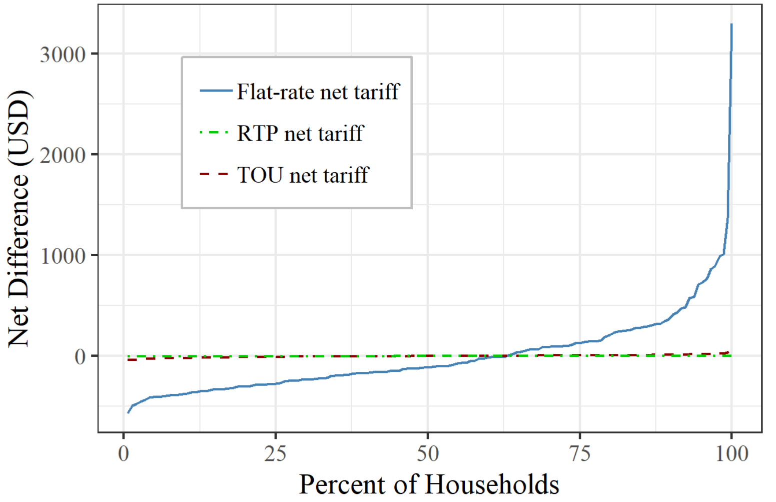


Figure 3.8: Net difference for net metering tariffs per household.

(i.e. its demand changes do not significantly impact market prices). Hence, the formation of these new peaks in a distribution grid is not expected to increase energy prices, and thus energy costs, at peak demand moments. Yet they may cause higher peak demand, thus increasing capacity costs (ibid). A time-of-use tariff's prices are not reactive to such peak demand changes and thus do not provide a suitable economic signal for peak demand reductions in the long term. A possible solution for passing on such an incentive would be the Demand Charge tariff, which is discussed in the next subsection.

The RTP tariff is designed to be the least cross subsidy-inducing tariff as cross-subsidies from both energy and capacity costs are mostly removed. However, this tariff's pricing mechanism is difficult for households to act on. Even with the presence of a suitably accurate prediction algorithm, such a tariff often requires that a household installs automatic control and monitoring of switchable devices (i.e automated demand response) in order to act on the economic signal. In other words, the economic signal is both "difficult to decode" and "difficult to react to". Moreover, these devices need to be able to elicit and/or represent consumer preferences in a way that is simultaneously effective in demand response and accurate in its elicitations/representations (Bichler, Gupta, and Ketter, 2010). Hence, we see that the tariff indeed performs best in cost causality, at least by an order of magnitude compared

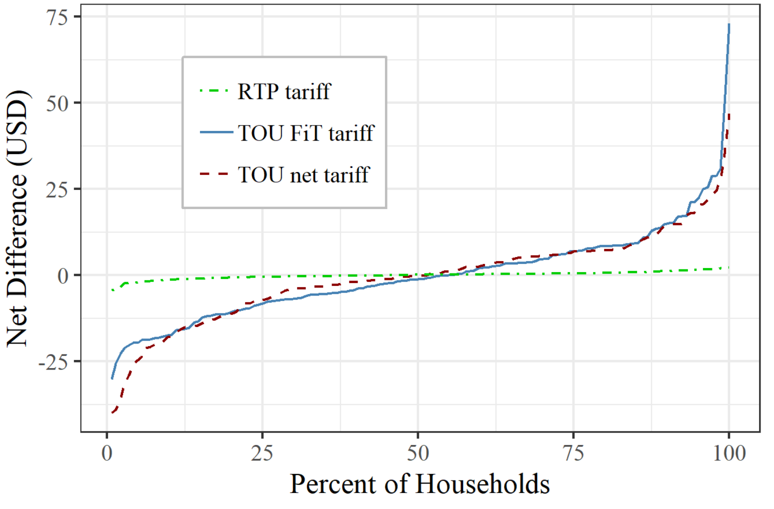


Figure 3.9: Net difference for tariffs based on advanced metering infrastructure (AMI) per household. RTP tariff results under net metering and FiT metering are very similar, so only one line is plotted.

to the TOU tariff. However, it lags behind the TOU tariff and others in simplicity and providing suitable economic signals.

3.5.3 Evaluating the Demand Charge tariff

The Demand Charge tariff is designed to recover energy costs based on the RTP tariff while offering a net demand flattening signal to households. Despite sacrificing some cross-subsidy, this pricing ensures that suitable economic signals are given to households for stabilizing net demand. The cross-subsidies for this tariff, with median costs transfers of -\$65.8 and \$91.8, are less than that of the Flat-rate Net tariff (medians -\$232.64 and \$259.07) and more than that of the RTP Net tariff (medians -\$0.61 and \$0.55, Figure 3.10).

Implementing this tariff can significantly increase demand elasticity for the capacity portion of electricity costs. These costs typically account for about 60% of a distribution grid's costs, (Simshauser, 2016) with percentage being generally lower for higher-density grids. In this study's case, these costs were about 55% of total costs (excluding generation credits). Most residential households experience demand peaks at similar times. However, there are differences between individual demand peaks and the distribution grid's demand peak. Consequently, there is cross-

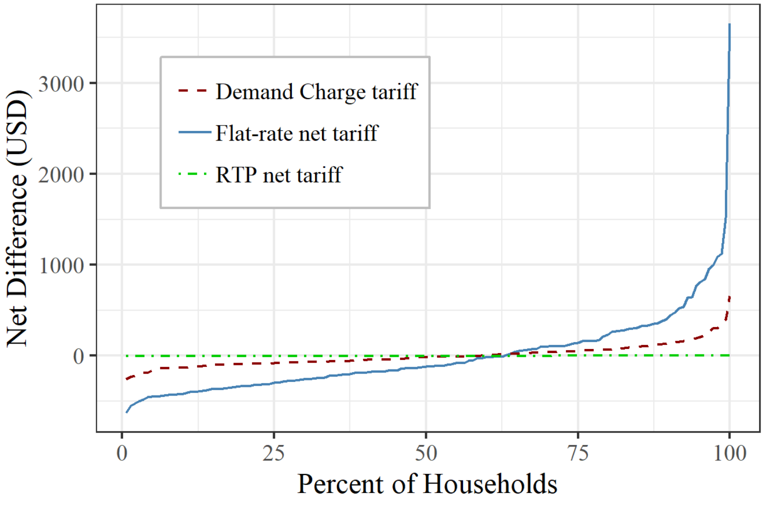


Figure 3.10: Net difference for Flat-rate, Demand Charge, and RTP tariffs, all under net metering, per household.

subsidy when households are charged based on individual peaks (as in the Demand Charge tariff) whereas costs depend on the utility's peak demand (as is priced in the RTP tariff). Given that the charge depends on maximum kilowatts used per month, there is a direct incentive for households to flatten (or reduce) their demand, rather than shift it to a period where electricity use is "cheaper", as in the TOU and RTP tariffs. As this demand flattens, updates of capacity costs would reduce the DC tariff's demand charge, leading to an equilibrium of all elastic demand flattened, without direct increases in other (energy) costs. Hence, this tariff can be expected to consistently motivate a reduction in overall peak demand, and thus capacity costs, in the long run.

3.5.4 Comparing FiT metering and net metering

The FiT and Net metering tariffs perform relatively similarly in cross-subsidy (Figures 3.6 and 3.9). The primary costs of electricity trade depend on energy and capacity for the utility. Both these costs components depend on the net demand of the entire grid as a function of time. Hence, the choice of metering generation and consumption separately or together cannot be expected to significantly influence costs of electricity supply.

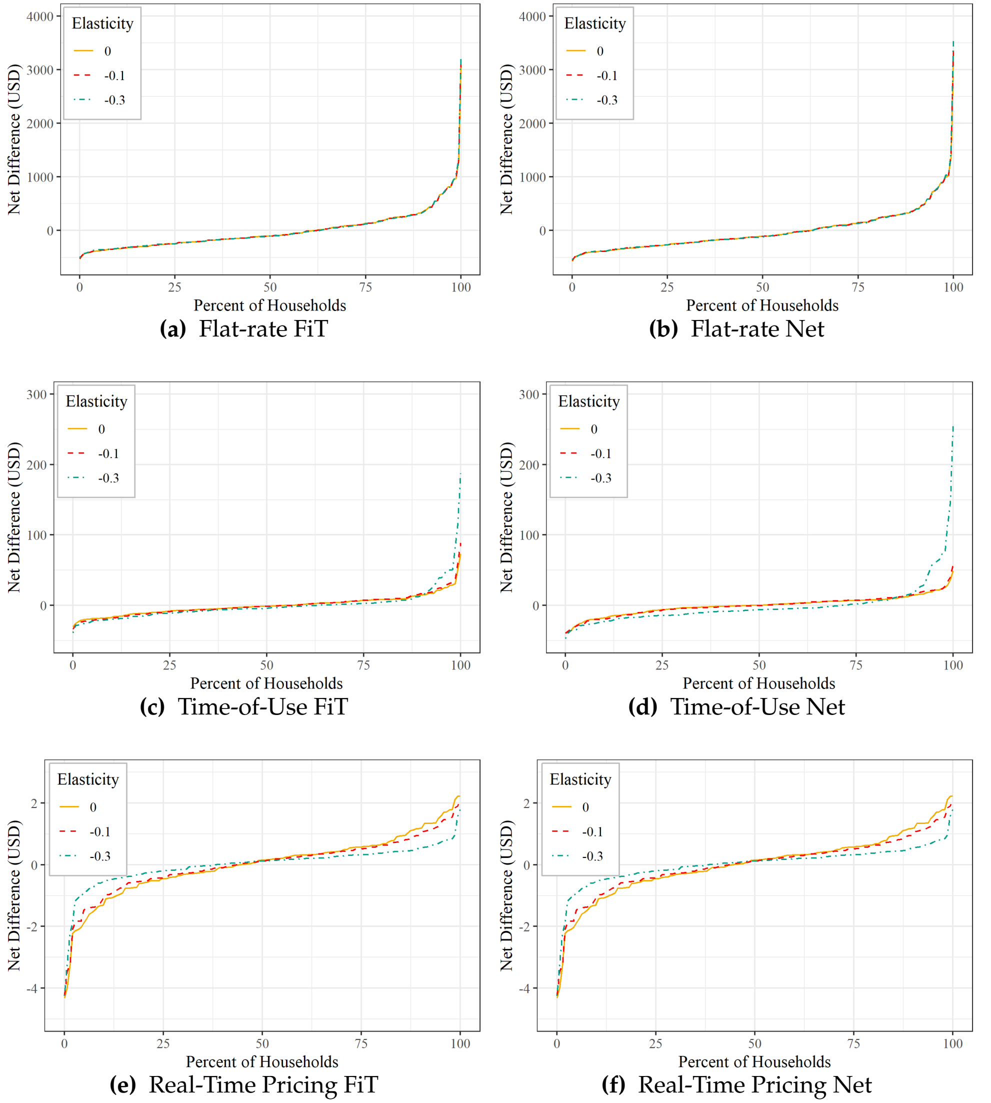
The same cannot be said for the credits given for generation resources. These credits often are energy prices over time, plus any subsidies given by local, national, or international governments or institutions. The energy prices, similar to electricity supply, depends on net demand per time. The subsidies, however, often depends on the D-RES unit itself; sometimes the nature of the resource (e.g. whether it is a wind-based or solar-based unit), often also the total electricity produced by the unit. In the case of our dataset, in Austin, TX, USA, these additional credits take the form of the Renewable Energy Certificate reimbursement, calculated as 2.5 c/kWh (Rábago et al., 2012). Without separate measurement of generation via a feed-in tariff, this reimbursement cannot be accurately credited. Thus, the policy goal of promoting renewable energy uptake depends on this metering choice. On the other hand, there are multiple ways this promotion can happen without incentives that depend on precise generation metering. Examples of these can be found in Germany (Yildiz et al., 2015) and the US state of California (Borenstein, 2017). In this article, we separately account for these costs, and thus they do not contribute to the cross-subsidies matter. The study of which form of subsidies best promote an uptake of renewables is a good topic for future analysis.

As real costs between FiT and net metering cannot be expected to differ, we turn our attention to tariff revenue. We find that our (generalized) tariff setups do not create significant differences between net metering and FiT metering. For the flat-rate tariffs, the differences between FiT and net metering can be summarized into choosing two different flat rates, or just one flat rate. Aligning with intuition, we find that using two flat rates does create a fairer scenario with cross-subsidies curves closer to the horizontal axis in Figure 3.6. However, this difference is far smaller than the difference between non-AMI and AMI-based tariffs. For TOU and RTP tariffs, we find similar results, mainly due to similar differences between using two rates versus one. Consequently, we find that measuring generation and consumption separately (under FiT metering) or together (under Net metering) does not affect cross-subsidies as strongly as implementing AMI.

3.5.5 Demand elasticity effects

Lastly, we look at the effects of demand elasticity on the comparison between net and FiT metering, and between AMI and non-AMI tariffs.

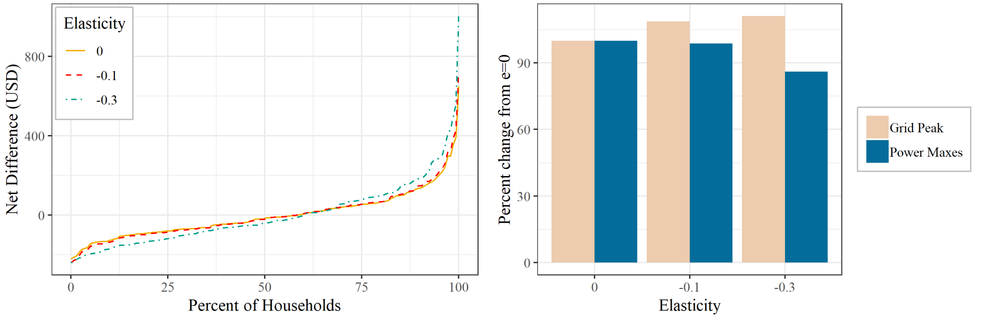
Elasticity affects the cross-subsidy rates of each tariff in differing ways, shown in Figures 3.11 and 3.12. For the flat-rate tariffs in both net and FiT metering, elasticity has a minimally increasing effect on cross-subsidies (Subfigures 3.11a and 3.11b).



(a) Flat-rate FiT **(b)** Flat-rate Net **(c)** Time-of-Use FiT **(d)** Time-of-Use Net **(e)** Real-Time Pricing FiT **(f)** Real-Time Pricing Net

Figure 3.11: Net difference sorted per household per elasticity rate (colors).

This is mainly because the flat-rate tariffs have prices close to the initial price at consumption, which also includes capacity costs. Hence, a user has little incentive at each instance to reduce or increase consumption. Tariffs based on legacy metering show the same cross-subsidy rates, with little dependence on elasticity.



(a) Demand Charge Net **(b)** Grid peak versus household peaks

Figure 3.12: Net difference sorted per household for Demand Charge Net tariff (3.12a) and overall population peak versus sum of individual household peaks, per elasticity ratio, as percentage of zero-elasticity case (3.12b).

The case for AMI-based tariffs is more nuanced. For the TOU tariff in both metering setups, we also find that elasticity increases cross-subsidies (Subfigures 3.11c and 3.11d). However, the effect is stronger than for the legacy tariffs. Compared to the flat-rate tariffs, the price signals for TOU tariffs are more divergent from initial prices. Thus, consumers react with stronger changes in demand, causing further cross-subsidy. For the RTP tariff, the results are reversed (Subfigures 3.11e and 3.11f). As elasticity increases, both net and FiT metering-based RTP tariffs show significant decreases in cross-subsidy, with net difference curves closer to the horizontal axis. The RTP tariff is designed to signal the most cost-reflective price to end-users. Consequently, any change in consumption would lead to tariff revenue being closer to real costs, i.e. reduced cross-subsidies.

We witness increasing cross-subsidies for the DC tariff as well (Subfigure 3.12a). The demand charge misprices capacity costs, which encourages households to change their monthly peak. Indeed, the sum total of all household monthly demand peaks decreases if there is elasticity (with larger decreases with more elasticity, Subfigure 3.12b). However, demand charges signal for reductions in a household's peak, not on the grid peak. Thus, users often change demand at times different from the grid peak hour, with little benefit for grid costs. Surprisingly, we find that the grid peak instead is higher for high elasticity scenarios (Subfigure 3.12b). This indicates that the demand charge indeed gives poor signals for reducing grid costs, with worse results in high elasticity scenarios. This mirrors predictions by Borenstein (2016), which appear extensible to a high-D-RES grid.

We can compare the effects of elasticity to those of AMI and net-versus-FiT metering. From this relative perspective, elasticity's effects are weak. The ratio between median net difference for the flat-rate FiT and TOU FiT tariffs (absent elasticity) is 29.21 on the positive (losing) side and 29.09 on the negative (winning) side. We can compare this with a similar ratio for high- and zero-elasticity results for the tariffs most influenced by elasticity (the RTP FiT or Net tariffs). This ratio is 1.98 (positive side) and 1.57 (negative side), far lower than differences between AMI and non-AMI based tariffs. Hence, elasticity's effects are far weaker than AMI, but similar to or stronger than net-versus-FiT metering choices.

3.6 Conclusion and Policy Implications

Electricity has historically been thought of as a public good and its supply (and consequent pricing) has been as much subject to politics as to economics (Yakubovich, Granovetter, and Mcguire, 2005; Reneses and Ortega, 2014). As a result, tariff design has sometimes followed economically suboptimal but politically viable paths. With an increasing share of D-RES, a distribution grid subject to democratic decision-making can be politically bound to pursue tariffs that do not cause widespread resentment. Some (socially progressive) tariffs have been designed to transfer costs from the vulnerable to the privileged; despite their higher cross-subsidies, they have been considered acceptable (Heald, 1997). For a distribution utility organized as a highly regulated and non-profit entity, we can expect two metrics to influence decision-making; 1) the ratio of subscribers negatively impacted, and 2) how strongly they are affected. For our study, the ratio of prosumers paying less than their real costs (NegRatio) is above 50% for tariffs based on legacy metering (Table 3.4). This is often the equilibrium for current tariffs (Borenstein, 2007; Simshauser and Downer, 2016). However, a NegRatio above 50% implies that in a high D-RES grid using conventional tariffs, a tariff change would *negatively impact most subscribers* and would be unpopular. The value of the cost transfer (the median negative transfer, MedNegTransfer, and the median positive transfer, MedPosTransfer) define the pressure to support new tariff designs. In simpler terms, while NegRatio shows how much of a subscriber group would support tariff design change, MedPosTransfer and MedNegTransfer indicate how strong that support would be.

While there is a big benefit overall in switching from a traditional tariff to a less cross-subsidizing tariff, the initial unpopularity makes such a change difficult. This has been documented for industrial and commercial users with only consumption;

Borenstein (2007) has recommended a payback mechanism for reducing the significance of the initial overall cost increase for the majority of negatively affected users. However, for such a payback mechanism to lead to a long-term (closer to) optimal solution, end-user demand must become (more) elastic (ibid). Historically, industrial and commercial consumers have had higher demand elasticity than residential users. This may still hold, but the advent of AMI may significantly boost residential demand elasticity (Alahakoon and Yu, 2016). Hence, such a payback mechanism may work for residential users in the future.

There is also a separate question of how the costs of AMI compare to the benefits. The costs of AMI have been well documented, both in utility reports and in academic articles (for example see Feuerriegel, Bodenbenner, and Neumann (2016)'s cost-benefit analysis of AMI for demand response). Some studies have investigated the benefits of tariffs dependent on AMI (citations towards end of Section 3.2). We are not aware of any prior analysis focused solely on AMI's impact on cross-subsidies in a high-D-RES grid. However, a cost-benefit analysis of AMI requires weighting the benefits of cross-subsidy against other benefits and costs. It is not clear what these weights would be: e.g. how the difference between median cost transfers for the Flat-rate FiT and the TOU FiT tariffs (a difference of $157.33) translate into a value stream for AMI. Determining these weights enters the territory of what can be considered "due" and "undue" discrimination. Heald (1997) and Yakubovich, Granovetter, and Mcguire (2005) describe these considerations and clarify that they do not respond well to attempts to be quantified. They, and tariff design in general, are often matters of public debate. Hence, we focused our study on quantifying cross-subsidies and leave such value judgments to policymakers.

In this study, we used two datasets: one of energy (consumption and generation values over time) and one of prices (market prices, tariff calibrations, etc.). Both datasets are strongly region-dependent. Energy consumption is a slave to weather and household habits and generation depends on weather and location. Additionally, prices depend on many factors, including regulations, weather, demand, and regional geography. This implies that the quantitative results can be expected to change per region and this analysis mainly holds for Austin, TX. However, our methods can be applied for any region, should the aforementioned data be available. The main influencers in our analysis are weather and electricity wholesale market prices, so similar results can be expected for regions similar to Austin, TX, in these two matters. However, a qualitative discussion of the results would hold across regions as well. For example, while the difference in cross-subsidy between the Flat-rate tariff and RTP tariff might be smaller in a region with fewer sunlight hours per year, the RTP tariff would still perform far better. From this point onward, a more qualitative discussion follows and is intended to be generally applicable to other regions.

Table 3.5: Qualitative comparison of tariffs

Tariff	AMI required	Short-term Economic Signaling	Long-term Economic Signaling	Energy Costs Cross-subsidies	Capacity Costs Cross-subsidies	Precise transfer of D-RES subsidies
Conventional	no	poor	average	high	high	yes
Flat-rate FiT	no	poor	poor	high	high	yes
TOU FiT	yes	good	poor	low	low	yes
RTP FiT	yes	average	average	low	low	yes
Flat-Rate Net	no	poor	poor	high	high	no
TOU Net	yes	good	poor	low	low	no
RTP Net	yes	average	average	low	low	no
DC Net	yes	poor	poor	low	medium	no

Our study shows that the differences between FiT and net metering are dwarfed by differences in pricing with non-AMI metering and AMI. Net metering is well-known to create distortionary effects by pricing generation and consumption together, leading to many problems including cross-subsidies (Borenstein, 2017). However, in the hypothetical scenario of a grid with rapidly expanding D-RES generation, policy-makers concerned with cross-subsidies should prioritize AMI implementation over installing extra meters for generation sources.

Our conclusions appear to be relatively agnostic to household demand elasticity. Even with high elasticity, AMI-based tariffs strongly outperform non-AMI-based tariffs whereas differences between FiT and net metering are minor. The effect of elasticity itself is also comparatively small. Elasticity appears to be a weaker concern when considering the effects of metering setup on cross-subsidies.

Reducing cross-subsidies is often considered good. However, its importance is sometimes diminished by more pressing concerns, such as sending proper economic signals to end-users. We summarize these conclusions in Table 3.5. The economic signaling aspects of various tariffs have been discussed extensively in and follow from past literature, e.g. Azarova et al. (2018). The cross-subsidy values for energy and capacity costs are higher for flat rate tariffs than for the TOU, RTP, and DC tariffs. On the other hand, precise transfer of D-RES subsidies depends on their being measured separately (see e.g. Verbruggen and Lauber (2012)). In this respect, FiT tariffs are better than Net tariffs. Overall, we can formulate a suitable tariff design in a high-prosumer grid. A Time-of-Use tariff for energy prices may offer the best middle ground between simplicity and cost causality. A peak-coincident capacity charge for capacity costs may provide poor signals for reducing the grid peak, but minimizes cross-subsidies. For generation credits, a separate feed-in tariff designed with a premium over energy rates may be the optimal design.

Our analysis of cross-subsidy in a high-DRES distribution grid has two main conclusions: There is little difference between FiT and net metering, and there is a large difference between using and avoiding AMI. In addition, these conclusions appear unaltered by demand elasticity. Our results are based on a numerical analysis of household, market, and retailer data from 2016 from Austin, TX, USA. Insofar as electricity consumption and generation and trade costs are similar to Austin, TX, the quantitative results may be valid for other locales as well.

3.6.1 Future work

With regards to tariff design, this analysis was not intended to explore the full design space. Instead, we picked some common tariffs within that space and used them to describe the various dimensions along which tariffs can differ, leading to various political and economic consequences. These consequences are often not only a function of quantitative metrics, but also the regional and local infrastructure and politics within which the tariffs are implemented. One tariff may work very well in Austin, TX, but perform poorly in other regions. In addition, all tariff design changes require transition management, e.g. paybacks to losing households that will compensate for the higher (but fairer) costs they face.

Elements of this transition management are suitable for future research in this area. One such topic can be the payback mechanisms that most suitably compensate losers from tariff changes. In addition, Picciariello et al. (2015b)'s simulations notwithstanding, there is little written previously about how increases in D-RES affect cross-subsidies. We intend to continue this research with such an investigation.

Chapter 4

Renewables, Tariff Design, and Social Welfare[1]

4.1 Introduction

Climate change is a global coordination problem. While most of the world population experiences the consequences of climate change, they are not equally responsible for its cause, i.e. greenhouse gas emissions. Thus, the burden of negative externalities from extracting and consuming fossil fuels has fallen on some who do not partake (or partake less) in its benefits and subsidize other energy consumers.

This "cross-subsidization" of some consumers by others can also be seen in local parts of the energy system, such as electricity distribution grids. Most households subscribe to a constant "flat-rate" tariff based on measured consumption volume over a long time period (e.g. monthly, seasonal, yearly). However, the costs of electricity delivery depend on multiple factors that may not align with this constant price. For example, electricity generation prices, particularly in liberalized wholesale markets, often change dramatically from hour to hour (Joskow, 2008). Due to this mismatch between costs and prices, some subscribers may pay less than their fair share for electricity while others pay more. As retailers are often regulated to meet specific financial criteria, such cost transfers are imposed as cross-subsidies

[1]This chapter was published in Energy Policy (see Ansarin et al. (2020c)). Parts of this chapter were also presented at the International Association for Energy Economics 2019 conference and the International Conference of Applied Energy 2019.

on the consumer population. This fairness issue is a common theme of debate in distribution grid pricing.

Some amount of cross-subsidies, a form of inequity (or fairness), has been typical in distribution grids for over a century. It was lightly considered in design decisions due to its possibly socially progressive nature (i.e. transferring welfare from the wealthy to the poor) (Yakubovich, Granovetter, and Mcguire, 2005; Heald, 1997), despite its economic inefficiencies (Borenstein, 2016). However, the advent of D-RES can create socially regressive cost transfers, as seen in the US State of California (Borenstein, 2017). Hence, equity concerns play a more prominent role in tariff design as D-RES units increase.

Economic efficiency is also a significant consideration for distribution grid pricing. This matter, namely ensuring that each product is purchased by the consumer who values it most, was previously less important in electricity tariff design compared to other more pressing matters. However, D-RES growth can influence who observes economic inefficiencies, and by how much; thus, its importance has now increased (Borenstein, 2016). Consequently, research now also focuses on the economic efficiencies of electricity tariffs.

Many studies have focused on the fairness and economic efficiency considerations of electricity tariffs (detailed in Section 4.2). More specifically, many studies focus on the impact of D-RES on these matters. However, we are not aware of a study that uses a comprehensive set of tariffs, based on all components of electricity costs. We analyze this matter using per-minute generation and consumption and pricing data from a residential population in Austin, TX, USA. Our contributions include:

- Absent D-RES, traditional electricity tariffs (namely increasing-block pricing and flat rates) create very large cross-subsidies. As D-RES grows, these cross-subsidies peak when roughly half to two-thirds of households own D-RES. More importantly, these cross-subsidies are mainly to the benefit of D-RES owners, reaching a peak of over one-fifth of their overall electricity costs. These cost transfers are likely to be socially regressive, i.e. taxing the poor more than the wealthy (Borenstein, 2017).

- Some residential tariffs are proposed to change to time-dependent and/or demand charge pricing (i.e. pricing household peak demand). For these tariffs, we find lower cross-subsidies by two to three orders of magnitude at the median compared to traditional tariffs. These cross-subsidies are not as strongly dependent on D-RES amount.

- Social welfare is worse for the traditional tariffs and better for time-dependent and demand charge pricing. As D-RES grows, social welfare worsens, but at a faster pace for the traditional tariffs, reaching values of over 20% of total household bills.

- Cross-subsidies are higher in regions with higher household demand elasticity. More importantly, demand elasticity affects different tariffs differently. For example, underestimating demand elasticity would underestimate the cross-subsidies of demand charge pricing.

In the following pages, we first review background literature on tariff design, cross-subsidization, and economic efficiency. We next cover details on methodology and data in Section 4.3. Our study results follow, with results for the zero elasticity case in Section 4.5 and the non-zero elasticity case in Section 4.6. Economic efficiency results are discussed separately in Section 4.7. The paper concludes in Section 4.8 with notes on policy implications and potential future research.

4.2 Background and Literature Review

Electricity is often considered to be a public good for households. Pricing this product has thus been influenced by both politics and economics (Yakubovich, Granovetter, and Mcguire, 2005). For most households, these prices appear as tariff rates from regional retailers. These tariff rates are often designed with specific principles in mind. These include (1) sufficiency of revenue, (2) equity, (3) economic efficiency, (4) transparency, (5) simplicity, (6) stability, (7) consistency with larger regulatory framework, and (8) cost additivity (Reneses and Ortega, 2014). It is often to simultaneously adhere to all principles; hence, tariff design has been a process of compromise over how well to meet each principle.

Choosing an optimal tariff often requires weighting each principle's importance versus others. These weights often depend on assumptions about the location in which the tariff is applied, e.g. the customer population and the distribution grid. For example, residential consumers have historically been assumed to be demand-inelastic passive price-takers of electricity. Hence, fixed rates charged on a per-kWh basis have been the most common format for pricing electricity (Woo et al., 2014). These tariffs are designed to be simple and sufficient in revenue. However, they perform poorly on equity and economic efficiency (Borenstein and Bushnell, 2018; Simshauser and Downer, 2016; Horowitz and Lave, 2014; Borenstein, 2016), which are unlikely to be significant for households with inelastic demand. Hence, most residential electricity pricing in many regions is based on such non-changing per-kWh charges.

D-RES significantly impacts many of the considerations regarding the principles of electricity tariff design (Fridgen et al., 2018; Rieger et al., 2016). Consumers are no longer passive price-takers of electricity; rather, D-RES transforms these users into active and calculating producer-consumers, or "prosumers". For these users, the rates of cross-subsidization within flat-rate tariffs are often comparable to their D-RES return on investment. The economic feasibility of D-RES depends on this value, so it is unlikely these values would be acceptable for regulators or customers.

D-RES affects another aspect of the acceptability of flat-rate pricing. Flat rates often disfavor high consumers for low consumers of electricity. Consumption was thought to correlate with wealth, so this was believed to be an implicit transfer of wealth from the wealthy to the poor. D-RES drastically reduces household consumption, while it is often owned by the wealthy (Borenstein, 2017). Thus, there is evidence of socially regressive wealth transfers forming in many high D-RES grids, such as in the US State of California (Borenstein, 2017) and the Australian States of Queensland (Simshauser, 2016) and New South Wales (Nelson, Simshauser, and Kelley, 2011).

Given these considerations, the cross-subsidies inherent in traditional tariff designs may no longer be acceptable when D-RES is added. However, D-RES affects not only the acceptability of a certain amount of cross-subsidization, but also the amount itself. A retailer's costs are described in Subsection 4.3.1; in summary, these costs consist of 1) energy-related costs, dependent on consumption volume at each time, 2) capacity-related costs, dependent on maximum power flow over a long timespan, and 3) other costs unrelated to volume or power flow. The latter costs group rarely affect cross-subsidization, whereas the former two groups do. Clastres et al. (2019) describe how D-RES can lead to cross-subsidization from energy costs, and quantify these rates for a hypothetical French grid. For capacity-related costs, results from the Australian state of Queensland (Simshauser, 2016) and United Kingdom (Strielkowski, Štreimikienė, and Bilan, 2017) show that D-RES significantly increases cross-subsidies. Picciariello et al. (2015a) simulate multiple grids across the US and investigate cross-subsidies between prosumers and consumers. Fontana (2016) similarly simulate this for a Portuguese case.

There are few studies however which include all components of cross-subsidization, when D-RES is considered. Athawale and Felder (2016) included both energy and capacity-related costs for New Jersey's volumetric tariffs, finding cross-subsidization between customer groups. However, we miss a study with a comprehensive set of tariffs, focused on the effect of D-RES on tariff fairness.

We likewise miss an explicit study of how D-RES affects economic efficiency for various tariffs. Economic efficiency is generally used to understand how well resources are distributed among consumers. Consumers differ in how much they value a product, thus consuming more or less at any given price. Mispricing, for example due to subsidies or differential pricing, leads to divergences in how much these consumers would consume. Consequently, they would consume more or less than optimal, leading to "deadweight loss". For example, fuel subsidies are known to create massive deadweight losses due to elevated consumption on a global scale (Davis, 2017). In electricity distribution pricing, Borenstein (2016) describes the importance of D-RES for economic efficiency considerations, particularly for grid capacity costs. Wolak (2018) uses 1990-2016 data from Californian utilities to measure the effects of residential solar panel installations on electricity prices, which implies some economic inefficiencies from network cost misallocation. Regarding energy costs, Borenstein and Bushnell (2018) compare retailer prices across the United States, finding significant deadweight loss within many regions. These studies clarify aspects of economic efficiency in distribution grid pricing. However, similar to fairness (or equity), no prior study uses real-world data to compare the effects of D-RES on economic efficiency for various tariffs. Hence, we focus on the fairness and economic efficiency aspects of tariffs, and how they are influenced by increases in D-RES.

4.3 Methods

4.3.1 Electricity trade: costs and tariffs

A retailer's cost for electricity consists of multiple components. First, the retailer must obtain energy at every instant to meet demand requirements, either from its own generation assets or the wholesale market. Thus, a retailer's observed prices are typically anchored by wholesale market prices and depend on the per-kWh marginal market cost, along with the transmission system operator's costs for electricity transport. The latter costs are generally distributed equally across subscribers and are ignored here. Second, the retailer must distribute this energy to end-users through a distribution grid, owned by itself or another business. The cost of this grid mostly depends on the maximum total power flow the grid is designed to support (Abdelmotteleb et al., 2018). Here, we assume these capacity costs are similar to an equally sized commercial and/or industrial customer in the same region. Third, the retailer's overhead costs, such as administration, billing, and marketing, often depend on its number of subscribers in a specific subscriber class. As these costs do not depend on subscriber usage, they can be expected to not contribute to cross-subsidies and are ignored here. Finally, the retailer must also credit the generation of any D-RES owned by its subscribers. This D-RES electricity generation offsets energy requirements and power flow for the retailer and thus interacts in complex ways with energy and capacity costs. This added value depends on multiple factors, including governmental D-RES subsidy schemes, overall deferred investments in capacity expansion, hourly energy requirements and prices, and avoided costs for transport over the transmission grid (Rábago et al., 2012). For simplicity, we assume that similar to (Rábago et al., 2012) these costs can be accurately accounted for in a flat per-kWh bonus to energy cost. As these cost components are the basis for cross-subsidization within a retailer's subscriber population, D-RES generation can significantly alter the acceptability of a tariff's cross-subsidies.

Cost components do not necessarily align with the variables used in the design of a tariff that recovers those costs (Table 4.1). We investigate cross-subsidies in 5 tariffs. These tariffs were chosen based on prior analysis and how commonly they are used or discussed for use by electricity retailers around the world:

1. Flat-rate tariff: Consists of a fixed fee per kWh of electricity consumption. We likewise assume a flat-rate credit per kWh of electricity generation. This tariff is similar to those used in Borenstein (2017), Borenstein (2007), Borenstein (2016), Simshauser and Downer (2016), and Picciariello et al. (2015b).

2. Time-of-Use tariff: These tariffs are intended as a middle ground between the simplicity of flat-rate tariffs and real-time pricing. This tariff was designed to be similar to pilot tariffs in the US state of Texas and the Netherlands. As such, we assume higher daytime (6:00-22:00) prices and lower nighttime (22:00-6:00) prices, with hourly pricing for generation credits.

3. Real-Time Pricing: This tariff's pricing depends on hourly wholesale market prices for both generation and consumption prices, similar to Azarova et al. (2018), Horowitz and Lave (2014), and Burger et al. (2020).

4. Demand Charge tariff: A real-time pricing scheme with monthly demand charges to recover capacity costs. These demand charges, which depend on a house-

hold's monthly peak demand, have been proposed (and contested, e.g. see Borenstein (2016)) for recovering fixed grid costs while sending suitable signals for demand response. Examples of past studies of this tariff include Passey et al. (2017) and Simshauser (2016).

5. Conventional tariff: We include this as a comparison with the status quo, i.e. what the dataset's population is currently paying. Our Austin, TX, USA, households were subscribed to Austin Energy's residential rates, which is an increasing-block rate tariff for energy consumption with a flat-rate Value of Solar credit for D-RES generation (Rábago et al., 2012). More information about the data follows in 4.4

These tariffs are calibrated to be cost-sufficient, i.e. recover overall revenue equal to the overall real costs of electricity trade (for an individual household, however, the real costs of electricity trade can differ from its tariff bill).

4.3.2 Tariff and costs formulas

Each tariff's details and calibration methods are described in the coming subsections. Prior to these, we describe the general formulation of costs and cross-subsidization (nomenclature is listed in Table 4.2). For the billing period T, similar to most past studies, e.g. Burger et al. (2020) and Azarova et al. (2018), we choose a period of 1 year. For each household i in set M and tariff j in set N (which includes real costs and prices as a "tariff" denoted by r), we have

$$\theta_{j,i} = \sum_{t \in T} E_j q_i(t) + \sum_{t \in T} G_j g_i(t) + \sum_{\tau \in T} C_j p(\tau) \tag{4.1}$$

where E_j is the electricity purchase price for amount $q_i(t)$, G_j is the sale price for D-RES generation of $g_i(t)$, C_j is the price for capacity per unit of power flow p over a time horizon $\tau \in T$, and $\theta_{j,i}$ is the overall costs of tariff j for household i. The total costs for the household population M for tariff j is $\theta_j = \sum_{i \in M} \theta_{j,i}$. All prices are from the perspective of households, i.e. negative prices are a funds transfer from utility to household.

Our study assumes cost sufficiency, i.e. all tariffs return enough revenue to meet the real costs of electricity delivery (θ_r):

$$\forall j \in N : \theta_j = \theta_r. \tag{4.2}$$

Table 4.1: Tariffs used in this study

#	Tariff	Consumption	Generation	Capacity	Notes
1	Conventional	Increased-block pricing	Flat rate	N/A (in consumption prices)	Reference tariff currently in use
2	Flat-rate	Flat rate			Most common
3	2-Tier Time-of-Use (TOU)	High daytime prices, low nighttime prices	Hourly market prices (plus subsidy markup)	Separate fixed charge	Middle-ground between simplicity (Flat-rate) and time variation (RTP)
4	Real-Time Pricing (RTP)	Hourly market prices			-
5	Demand Charge (DC)			Monthly demand charge of household peak	Similar to Simshauser (2016) and Passey et al. (2017)
-	*real costs*	*Real-time market prices*	*Real-time market prices (plus subsidy markup)*	*Fixed charge (at overall demand peak time)*	

Given this constraint, cross-subsidies can be defined as the “Net Difference” ratio in individual households, between real and tariffed costs:

$$\forall j \in N; i \in M : \nu_{j,i} = \theta_{r,i} - \theta_{j,i}. \tag{4.3}$$

To compute the cross-subsidy $\nu_{j,i}$ in Equation (4.3), we find the bill of any household i per tariff j ($\theta_{j,i}$) as well as the real costs for electricity delivery ($\theta_{j,i}$) based on Equation 4.1. We next describe how each of these terms are computed.

Table 4.2: Nomenclature

Label	Unit	Description
q	kWh	Consumption
g	kWh	Generation (always > 0)
p	kW	Net power flow. First time differential of (q-g)
E	$/kWh	Consumption price
G	$/kWh	Generation price
C	$/kW	Capacity price
P_g	$/kWh	Green Certificate reimbursement price
α	$	Green Certificate reimbursement cost
θ	$	Total costs
i	-	House index
j	-	Tariff index
t	min	Time unit (1 minute)
T	-	Time horizon
ν	$	(Cross-subsidization) Net Difference
λ	-	Cross-subsidization Ratio
ϵ	-	Elasticity constant
A	-	Demand elasticity formula constant
C.S.	$	Consumer Surplus
D.W.L.	$	Deadweight Loss

Real costs

For consumed energy, the real price at each instance E_r is assumed to be equal to real-time locational-marginal prices (RTLMP). These are real-time wholesale market clearing prices at each instance in a location (node), biased by network conditions (e.g. congestion, losses) in the grid. The generation credit G_r is set to E_r, plus a bonus $\alpha_{r,i}$ for internalizing any potential benefits of D-RES, which is based on a per-kWh credit P_g. To simplify, we integrate both as $G_r = E_r + P_g$. Capacity costs of the utility's distribution grid mainly depend on the maximum net power demand over a time horizon (Simshauser, 2016). Thus, C_r is taken to be a constant per-kW price per household, which is multiplied by the maximum net power demand of the entire household group M over the time horizon T, $p_{max,M,T}$. These costs are distributed to each household based on Equation 4.1.

Conventional tariff

This tariff consists of tiered volumetric consumption prices and a flat-rate "Value of Solar" generation credit. The consumption price $E_{conv,i}$ for household i depends on the total monthly consumption of the household and the month of the year ($T_m, m \in \{1..12\}$). Hence, each household gets a different price per month, $E_{conv,i}(\sum_{t \in T_m} q_i(t), T_m)$, based on Austin Energy's 2016 residential rates (note: this is the only tariff where consumption prices $E_{conv,i}$ differ among households). The generation price G_{conv} is set to Austin Energy's Value of Solar rate for 2016 (11.3 c/kWh, details in Rábago et al. (2012)). Since all values are known, $\theta_{conv,i}$ is known. As all tariff elements are calibrated by Austin Energy, a lump sum L_{conv} is added to households as a fixed charge to ensure cost sufficiency (Equation (4.2)) is met. This additional cost is levied equally across all households so that it does not bias the tariff's original cross-subsidization:

$$\theta_r = \theta_{conv} = \sum_{i \in M} (\theta_{conv,i} + L_{conv}). \tag{4.4}$$

Flat-rate tariff

The conventional tariff is designed by Austin Energy to promote energy efficiency at the expense of equal prices. A flat-rate tariff, which retains the time-ignorance of the conventional tariff but removes the energy efficiency design choices, would be a fairer comparison to other tariffs that are also not biased by such design choices. In this tariff, E_{flat} and G_{flat} are constant values. Capacity costs are embedded into the flat energy rate E_{flat} (and $C_{flat} = 0$):

$$\theta_{flat} = \sum_{i \in M} \theta_{flat,i} = \sum_{i \in M} \sum_{t \in T} [E_{flat} q_i(t) + G_{flat} g_i(t)] \tag{4.5}$$

G_{flat} is set based on a fixed rate calculated as the value of D-RES (e.g. in Rábago et al. (2012)), including additional subsidies. Thus, the only unknown is E_{flat} and can be calculated by the revenue neutrality constraint, i.e. setting $\theta_{flat} = \theta_r$.

TOU tariff

The Time-of-Use tariff has differing prices for consumption (E_{tou}) according to the hour of day. We investigate a two-tier TOU with separate daytime (T_d) and night-time (T_n) pricing. With two tiers:

$$E_{tou} = \begin{cases} E_{tou,d} & \text{when } t \in T_d \\ E_{tou,n} & \text{when } t \in T_n \end{cases}. \tag{4.6}$$

There is no benefit from simpler pricing for generation credits, so G_{tou} is set to the real-time value of solar generation detailed in the Real-time Pricing tariff. We also separate capacity costs here based on p_{max}, similar to C_r. In total, we have:

$$\theta_{tou} = \sum_{i \in M} \sum_{t \in T_d} [E_{tou,d} q_i(t) - G_{tou} g_i(t)] + \sum_{i \in M} \sum_{t \in T_n} [E_{tou,n} q_i(t) - G_{tou} g_i(t)] + C_r p_{max}. \tag{4.7}$$

By setting this equal to real costs θ_r, we have one equation with two unknowns ($E_{tou,n}$ and $E_{tou,d}$), i.e. one degree of freedom. To solve this equation, we add another constraint. We assume that $E_{tou,d}$ and $E_{tou,n}$ are proportionally scaled (with scaling factor r_{tou}) based on average RTLMP prices during daytime (P_d) and nighttime (P_n):

$$\begin{cases} E_{tou,d} = r_{tou} P_d \\ E_{tou,n} = r_{tou} P_n \end{cases} . \tag{4.8}$$

Equation (4.7) can then be solved for r_{tou}.

With this additional constraint, the two time-of-use tiers mainly differ based on r_{tou} which depends on the difference in the average RTLMP prices in daytime and nighttime.

RTP tariff

In this tariff, consumption prices $E_{rtp}(t)$ are taken to be equal to average RTLMP prices per hour. The generation remuneration price G_{rtp} is taken to be E_{rtp} with a bonus element for reimbursements, $G_{rtp} = E_{rtp} + P_g$. Capacity prices C_{rtp} are set equal to C_r. Hence, θ_{rtp} is defined. An extra lump sum (L_{rtp}) is added equally to to ensure cost sufficiency (Equation (4.2)):

$$\theta_r = \theta_{rtp} = \sum_{i \in M} (\theta_{rtp,i} + L_{rtp}) \tag{4.9}$$

which is solved for L_{rtp}.

Demand Charge tariff

This tariff combines a real-time pricing of energy costs with a monthly demand charge for capacity costs. Consumption and generation prices are similar to the RTP tariff, $E_{dc} = E_{rtp}$ and $G_{dc} = G_{rtp}$. However, capacity prices differ: for each household $i \in M$, a price (C_{dc}) is assigned per kilowatt of maximum power demand during each month T_m, $p_{max,i}(T_m)$. Total capacity costs for household i over T equals $C_{dc} \sum_{T_m \in T} p_{max,i}(T_m)$.

The per-kilowatt capacity price C_{dc} is set to equal capacity costs with real capacity costs:

$$C_r p_{max}(T) = C_{dc} \sum_{T_m \in T} p_{max,i}(T_m). \tag{4.10}$$

which is solved for C_{dc}.

The overall costs θ_{dc} are defined as equal to real costs θ_r, with a lump sum L_{dc} calibrated to ensure cost sufficiency (Equation 4.2):

$$\theta_r = \theta_{dc} = \sum_{i \in M} \left[\sum_{t \in T} E_{dc} q_i(t) + \sum_{t \in T} G_{dc} g_i(t) + \sum_{T_m \in T} C_{dc} p_{max,i}(T_m) + L_{dc} \right] \tag{4.11}$$

4.3.3 Calculating elasticity, consumer surplus, and deadweight loss

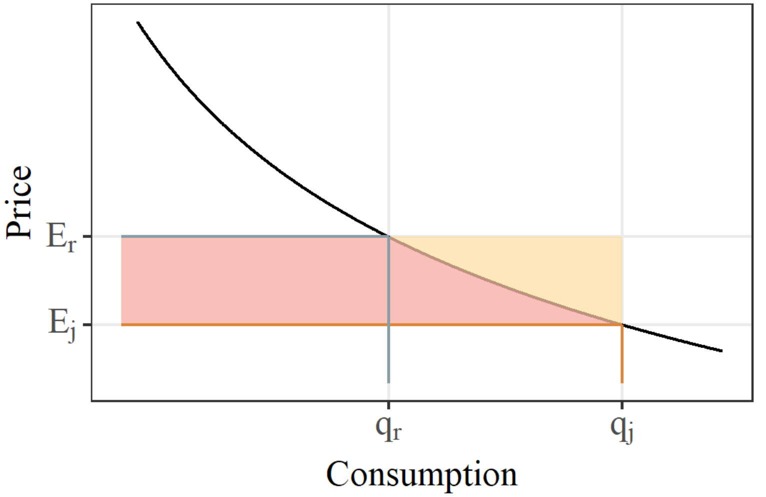


Figure 4.1: The Demand Curve (black) shows the relationship between prices and (consumption) quantities. The difference in area between real price and quantity (blue lines) and tariff price and quantity (orange lines) is the difference in consumer surplus between consumption under real and tariff prices (pink area). Deadweight Loss (yellow area) shows the overall welfare loss caused by the difference in price.

Electricity as a product for residential households is generally perceived as a public good and has very low demand elasticity. Similar to Borenstein (2012), Horowitz and Lave (2014), and Burger et al. (2020), we assume that each household i is demand-elastic according to a constant elasticity rate ϵ and a constant multiplier A, i.e. $q = AE^{\epsilon}$ (black curve in Figure 4.1), where q is the consumption at price E. We find A by using initial consumption and price values; in our case, the households are initially subscribed to the Conventional tariff, i.e. $A_{i,t} = q_{i,conv,t} / E^{\epsilon}_{i,conv,t}$.

We make the following assumptions to ensure a change in prices at each instance returns an appropriate change in consumption:

1. We choose elasticity values at the low ($\epsilon = -0.1$) and high ($\epsilon = -0.3$) ends of past empirical results, similar to past research (Burger et al., 2020; Borenstein, 2012; Borenstein, 2007). These are close to estimates of short- and long-term elasticity (respectively) for residential households (Labandeira, Labeaga, and López-Otero, 2017).

2. The Conventional tariff consists of increasing-block prices, where the marginal price increases as monthly consumption increases. Following from Ito (2014), we assume the household's average price per month (rather than its marginal price) to be its initial observed price.

3. In some situations, prices may become negative. If so, we choose the observed price to be 0.1 c/kWh, which, when compared to a new price of 10 c/kWh (and $\epsilon = -0.1$), creates a consumption increase of 58%. This happens most for the RTP tariff, for 1.5% of instances overall.

4. For tariffs that separate capacity costs, we assume these costs are discounted from price estimates of the average conventional price, i.e. $E_{i,conv,t}$ is reduced to reflect that it also contained capacity costs. This follows from past evidence that consumers do not respond to fixed charges (Burger et al., 2020).

The Demand Charge tariff is designed to also induce demand elasticity based on the demand charge for capacity costs. Using a similar model, we assume maximum "acceptable" demand over a month is dependent on the change in price of capacity costs per kW of maximum demand. For this scenario, all time slots are checked versus new demand. If lower, all time slots with higher consumption are lowered to the new low, and if higher, consumption is increased to its original value or to the new maximum acceptable demand (whichever is lower). This accounts for the demand charge signal of flattening demand, while allowing for deviations due to exceptionally low (or high) energy prices.

We use these elasticity approaches to calculate a new demand profile per household per tariff. Much of tariff price calibration depends on real costs, which depend on demand profiles, which depend on tariff prices. This requires iteration until an equilibrium is reached. Our algorithm iterated on costs until the sum of absolute changes in household bills was less that 0.1% of all bills combined.

Our consumer surplus calculations follow from prior economic studies of energy prices. Borenstein (2016) contains a general explanation, while Burger et al. (2020) and Davis (2017) describe this approach for two different (albeit energy-related) empirical cases. At each time interval $t \in T$, a household $i \in M$ consumes a specific amount of electricity $q_{i,j,t}$ considering the instance price $E_{i,j,t}$ of tariff j. Consumer surplus can be considered as the area under the demand curve from the maximum allowable price $E_{i,max,t}$ up to $\{E_{i,j,t}, q_{i,j,t}\}$ (in Figure 4.1, the area between the demand curve and the orange horizontal line), summed with any credits or costs otherwise added or imposed (Burger et al., 2020):

$$C.S._{i,j} = \sum_{t \in T} \int_{E_{i,j,t}}^{E_{i,max,t}} q_{i,j,t} dE + Gen.Cred_{i,j} - Cap.Costs_{i,j} \tag{4.12}$$

where $Gen.Cred_{i,j}$ and $Cap.Costs_{i,j}$ represent the generation credits and capacity costs for the tariff-household pair. We are most interested in the difference in consumer surplus based on the current tariff and the consumer surplus based on the real costs of electricity trade (in Figure 4.1, this is equal to the pink area). This difference for the first term on the right side of Equation 4.12 for one timeslot $t \in T$, is:

$$\begin{aligned} C.S._{i,j,t} - C.S._{i,r,t} = \Delta C.S._{cons,i,j,r,t} &= \int_{E_{i,j,t}}^{E_{i,max,t}} q_{i,j,t} dE - \int_{E_{i,r,t}}^{E_{i,max,t}} q_{i,j,t} dE \\ &= \int_{E_{i,j,t}}^{E_{i,r,t}} q_{i,j,t} dE \end{aligned} \tag{4.13}$$

where $E_{i,r,t}$ is the real price (or value) of electricity at that moment t. Using the elasticity formula $q = AE^{\epsilon}$ where $A_{i,t} = q_{i,conv,t} / E^{\epsilon}_{i,conv,t}$, we have

$$\Delta C.S._{cons,i,j,r,t} = \int_{E_{i,j,t}}^{E_{i,r,t}} q_{i,j,t} dE = \frac{A_{i,t}}{1+\epsilon} (E_{i,r,t}^{\epsilon+1} - E_{i,j,t}^{\epsilon+1}). \tag{4.14}$$

Adding in the generation credits and capacity costs portion and summing over all timeslots in T, we can find the difference in consumer surplus for tariff j and

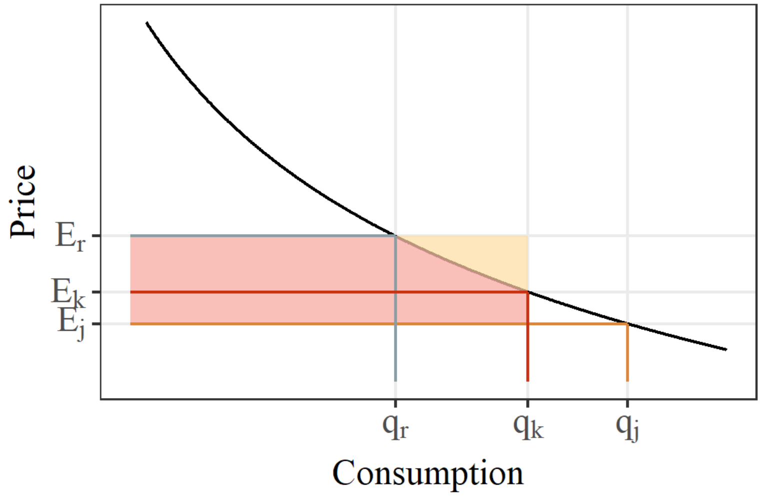


Figure 4.2: Similar to Figure 4.1; consumer surplus change (pink area) and deadweight loss (yellow area) in scenario where actual consumption and price (q_k and E_j) is not on demand curve.

household i as

$$\Delta C.S._{\cdot i,j} = \sum_{t \in T} \frac{A_{i,t}}{1+\epsilon}(E_{i,r,t}^{\epsilon+1} - E_{i,j,t}^{\epsilon+1}) + \Delta Gen.Cred_{i,j} - \Delta Cap.Costs_{i,j} \tag{4.15}$$

where the two latter terms of the right side are differences in generation credit and capacity costs (plus any other lump sum additions) between real and tariffed costs. Note that the change in consumer surplus formula collapses to Net Difference when $\epsilon = 0$.

The deadweight loss per household-tariff-instance triple $\{i, j, t\}$ can be considered as the (almost) triangular yellow area in Figure 4.1. This represents the entire system's total loss (overall welfare loss) due to inaccurate pricing of electricity (Borenstein, 2016). We can find this value at each instance by subtracting the pink area (equal to $\Delta C.S._{\cdot cons,i,j,r,t}$ from Equation 4.14) from the rectangle consisting of pink and yellow areas in Figure 4.1 (see Burger et al. (2020) for details). Summing over all timeslots, we find the total deadweight loss as

$$D.W.L._{\cdot i,j} = \sum_{t \in T} \left[(E_{i,r,t} - E_{i,j,t}) q_{i,j,t} - \frac{A_{i,t}}{1+\epsilon}(E_{i,r,t}^{\epsilon+1} - E_{i,j,t}^{\epsilon+1}) \right]. \tag{4.16}$$

Sometimes, particularly for the flat-rate and demand charge tariffs, the quantity of electricity consumed can be distorted by an additional factor: the misrepresentation of capacity costs in the tariff. This may cause a household's consumed energy to be higher or lower than they would otherwise choose based on the energy price signal. In mathematical terms, at price $E_{i,j,t}$ the household i consumes quantity $q_{i,k,t}$ rather than $q_{i,j,t}$ (red and orange lines in Figure 4.2, respectively). To compute deadweight loss for these scenarios, we find $E_{i,k,t}$ based on the demand function and replace the j-index values for k-index values in the relevant formulas (see Figure 4.2 for a visual representation). The change in consumer surplus is adjusted in a similar way. However, there is an additional change, as the consumer also pays a different price ($E_{i,j,t}$) compared to what they would pay at quantity $q_{i,k,t}$, i.e. $E_{i,k,t}$. This difference in costs (red rectangular area in Figure 4.2) is also subtracted from the consumer surplus at each instance. In mathematical terms, Equation 4.14 becomes

$$\Delta C.S._{cons,i,k,r,t} = \frac{A_{i,t}}{1+\epsilon}(E_{i,r,t}^{\epsilon+1} - E_{i,k,t}^{\epsilon+1}) + (E_{i,k,t} - E_{i,j,t})q_{i,k,t}. \tag{4.17}$$

All other calculation details remain unchanged.

4.4 Data

To quantify cross-subsidies in a household population, we require pricing and energy data from a distribution grid and its end-users. We gathered per-minute household generation and consumption data from the Pecan Street Dataport with an academic license.[2] We used the following criteria to clean this dataset:

1. Household contains solar photo-voltaic panels (335 households)
2. Location is Austin, TX, US (282 of 335 households)
3. Household registered for data collection for entire year of 2016. Tariff design and utility costs calculations are conducted on an annual basis, so a duration of one year was chosen as a representative period. 2016 was chosen due to higher data availability (216 of 282 households).
4. Consumption and generation data contained less than 5% missing or erroneous data points, after data cleaning operations (144 of 216 households). These operations included

[2]More details at `https://www.pecanstreet.org/dataport/`

(a) Identifying and relabelling mislabelled time stamps,

(b) Identifying and fixing implausible but recoverable values (e.g. generation traces that are negative), and

(c) Identifying and removing implausible and unrecoverable values (e.g. consumption values equal to very low numbers over long time periods, which indicate a recording failure or an empty household).

After cleaning operations, this dataset consisted of 144 households in Austin, TX, USA, for the year of 2016. Each household consisted of 527,040 data points for consumption and solar photo-voltaic panel generation.

We use pricing data from the same locale and time period to calibrate the tariffs. This data consisted of tariff rates of Austin Energy, a local publicly-owned retailer,[3] and real-time locational-marginal prices from the transmission grid and wholesale market operator (Electricity Reliability Council of Texas) for the Austin load zone.[4] This data for 2016 contained no missing values. The data was narrowed down for the Austin load zone and timestamps were added based on the day, hour, and minute columns.

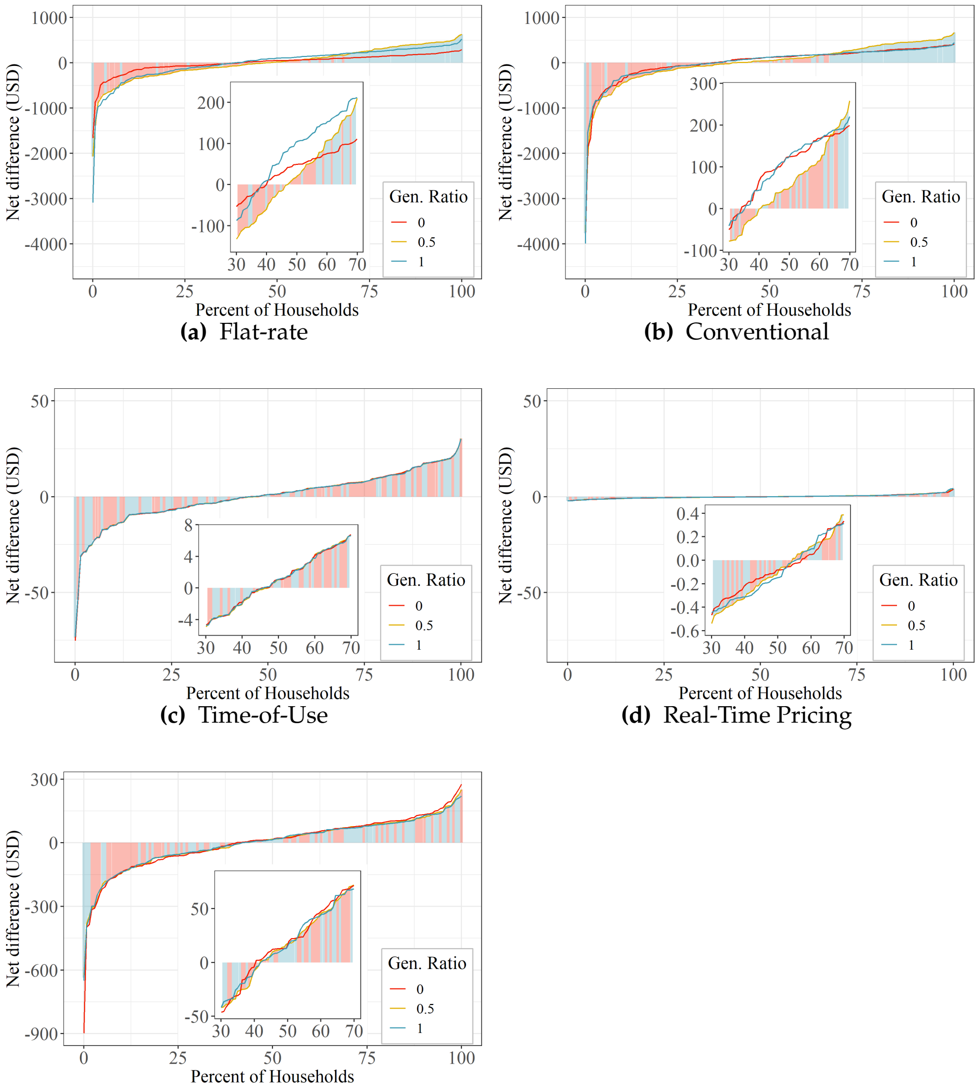
4.5 Cross-subsidization and Increased Renewables

We first look at the effects of increasing D-RES on the cross-subsidies of each tariff, absent demand elasticity. To do this, we increase D-RES by randomly assigning solar PV panels to consumer households in a stepwise fashion, from 0 to 100% of households owning solar panels. This process is repeated 10 times to separate the effect of randomness from trends related to increasing D-RES penetration.

With zero elasticity, cross-subsidization can be considered as the "net difference" between the real costs for each household's electricity trade and its tariffed revenue. Figure 4.3 shows the disparity in net difference between households, sorted per tariff (note the difference in vertical axes). All tariffs show extreme cases with households having very high or very low cross-subsidization relative to other households. For the Flat-rate and Conventional tariffs (Subfigures 4.3a and 4.3b), cross-subsidization is more pronounced when households are more heterogeneous in D-RES ownership. For a population split equally between consumers and prosumers (generation ratio = 0.5), there are worse cross-subsidies than with solely prosumers

[3]More details at `https://austinenergy.com/ae/rates`

[4]More details at `http://www.ercot.com/`



(a) Flat-rate **(b)** Conventional **(c)** Time-of-Use **(d)** Real-Time Pricing **(e)** Demand Charge

Figure 4.3: Cross-subsidization per household for Flat-rate (a), Conventional (b), Time-of-Use (c), Real-time Pricing (d), and Demand Charge (e) tariffs. Bar colors show (for Generation Ratio = 0.5) whether a household owns solar PV panels (blue) or not (red). Plots for Generation Ratio = 0.5 are for one sample run.

(generation ratio = 1) or consumers (generation ratio = 0). In particular, these cross-subsidies form between the group of prosumers and consumers. Most D-RES own-

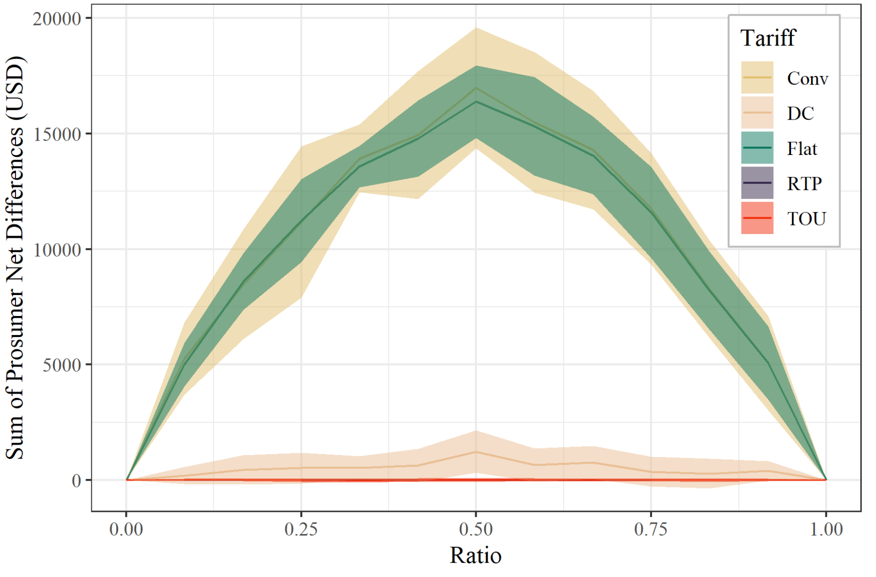


Figure 4.4: Sum of prosumer net differences per ratio per tariff (colors). Lines show average value and ribbons show one standard deviation. Note that RTP and TOU results coincide.

ers (colored blue in Figure 4.3) are shifted to the "winning side" of the cross-subsidization curve, where they pay less than their fair share of costs, while consumers (colored red) are shifted to the losing side. However, as generation ratio continues to increase and all households implement D-RES generation, cross-subsidization rates decrease again. This is explicitly shown in Figure 4.4, which indicates that the sum of prosumer net differences are significantly high, but only for the Conventional and Flat-rate tariffs. There are extra discriminatory cost transfers between owners and non-owners of D-RES, particularly when consumers and prosumers are roughly balanced. In such a scenario, these benefits for prosumers are about $16k, or 22-23% of the household population's overall costs for electricity. From the perspective of D-RES, over one-fourth (28-29%) of the credits earned by prosumers for their D-RES generation comes from non-prosumer households. Since solar D-RES owners are often high-income households (Borenstein, 2017; Nelson, Simshauser, and Kelley, 2011), these tariff designs can produce socially regressive wealth transfers during the renewable energy transition.

These observations do not apply to the TOU, RTP, and DC tariffs. While the DC tariff also shows high cross-subsidies, these tariffing schemes do not significantly favor prosumers or consumers (Figure 4.4). Thus, there is little change in the distribution of cross-subsides as generation ratio increases. The main reason for this difference between tariffs is capacity costs. The Conventional and Flat-rate tariffs integrate these costs into the per-kWh charge. Prosumers own generation units and purchase fewer kWhs of electricity from the retailer. Consequently, they cover less of the fixed capacity costs compared to non-owners of D-RES. The TOU, RTP, and DC tariffs separately account for capacity costs. Thus, their prosumers do not contribute less towards capacity costs simply due to owning D-RES units.

The cross-subsidies from the Demand Charge tariff warrant extra explanation. This tariff is designed as an extension of the RTP tariff, with a monthly demand charge per kilowatt of household peak demand for capacity cost recovery. However, overall grid costs depend on overall peak demand, rather than each household's individual peak demand. Thus, this scheme creates some cross-subsidization to send a "suitable" economic signal for end-users to flatten their demand curves. Consequently, cross-subsidies from the DC tariff are far higher than the RTP tariff. A median subscriber to the DC tariff on the winning side pays \$76.26 less while the median loser pays \$70.82 more. The same values for the median subscriber to the RTP tariff are \$0.57 and \$0.47. Compared to the Flat-rate tariff, which has medians of \$183.52 and \$229.57, respectively, the DC tariff's cross-subsidization remains low. In the next section, we will discuss per-tariff differences in detail.

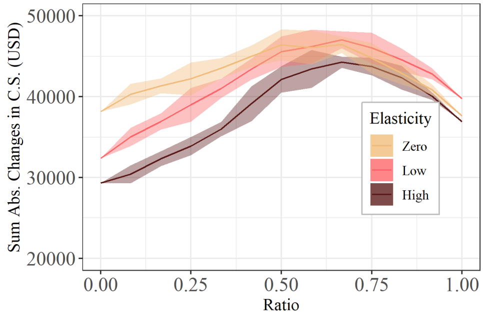
In short, a zero demand elasticity scenario shows that cross-subsidies for the Flat-rate and Conventional tariffs are significantly altered by increased D-RES installations. In addition, prosumers appear to be usual beneficiaries of these cross-subsidies, at the detriment of consumers. To avoid socially regressive cost transfers (Borenstein, 2017) during the renewable energy transition, we need tariffs that do not disproportionately favor D-RES owners. Separating capacity costs appears particularly important in this respect. Time-based pricing for energy costs a la the RTP tariff appears less consequential here.

4.6 Elasticity Effects

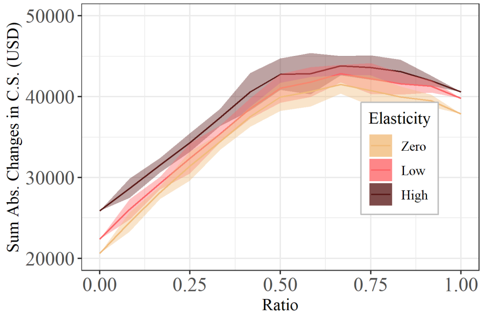
We next relax our zero-demand-elasticity assumption in investigating the effects of D-RES on tariff cross-subsidies. Our dataset's households have adjusted their initial consumption values to their current subscription, the Conventional tariff. A change to the Flat-rate, TOU, RTP, or DC tariff would create a change in demand, which would affect cross-subsidization. Similar to Burger et al. (2020) and Borenstein (2007), we model demand elasticity with an exponential demand curve based on two elasticity values at the low and high ends of prior estimates for residential electricity consumption, $\epsilon = -0.1$ and $\epsilon = -0.3$ (details in Section 4.3). Short-term elasticity is often closer to the former (Burke and Abayasekara, 2018) and long-term elasticity appears close to the latter (Burger et al., 2020). The former mostly represents behavioral choices (e.g. using devices during low-price periods) while the latter primarily reflects investment choices (e.g. energy efficiency or appliance investments).

To understand the effects of cross-subsidies for these households, we consider the changes in consumer surplus. Put simply, this is the difference between the benefit a consumer receives from consuming electricity at one price, versus the benefit he/she would receive at another price. We here compare the consumer surplus based on real prices versus the surplus from tariff prices. Since consumption profiles change, the population's total costs and thus the retailer's revenue needs may change. Hence, each tariff may find a different total sum of consumer surplus over all households. To focus on the differences between households, we rescale the values of consumer surplus to be zero-sum (over all households) by removing averages. The sum of the absolute values of rescaled consumer surplus changes gives a measure of overall cross-subsidization. For a zero-elasticity scenario, this value corresponds to the area between the horizontal axis and the Net Difference curves in the subfigures of Figure 4.3.

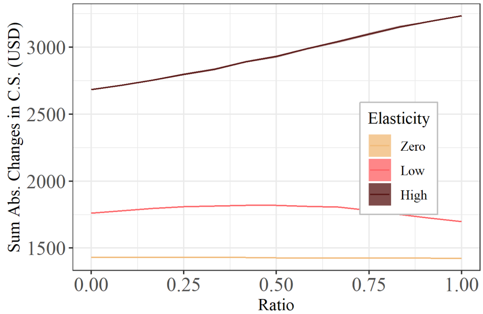
We first focus on cross-subsidization rates per tariff separately, as shown in Figure 4.5. Each tariff creates very different total absolute consumer surplus changes in the household group, based on elasticity and generation ratio. The Conventional and Flat-rate tariffs both show relatively high cross-subsidization at low D-RES rates. These values grow significantly as the ratio of prosumers to consumers increases. Cross-subsidies peak when prosumers become a two-thirds majority of households (i.e. generation ratio near 66%, Figure 4.5). This is mainly from wealth transfers due to capacity costs from D-RES non-owners (consumers) to D-RES owners (prosumers), as discussed in the prior section. Cross-subsidies then decrease as the household population becomes less different in their ownership of D-RES (i.e. Ratio approaches 1). However, irrespective of elasticity, the values continue to stay high for a high D-RES population (i.e. Ratio = 1). On the median, the loser in this cost transfer would see a loss of \$183 per year based on the Flat-rate tariff. A median Austin, TX, household's annual income of \$63,717 (Bureau, 2018) is far larger than this amount. However, these values are significant when compared against D-RES



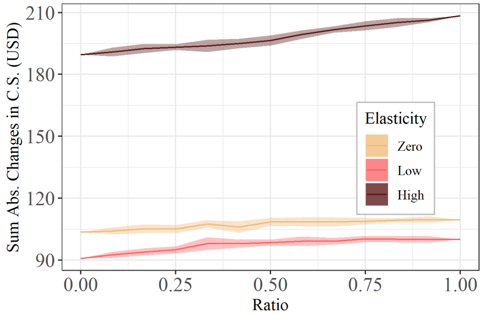
(a) Conventional tariff



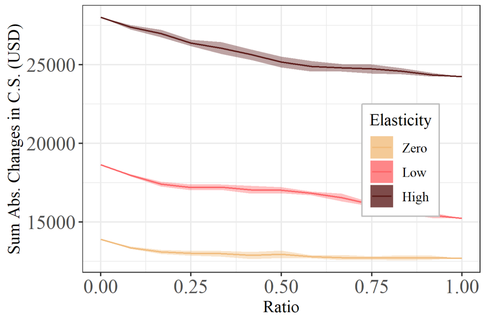
(b) Flat-rate tariff



(c) TOU tariff



(d) RTP tariff



(e) DC tariff

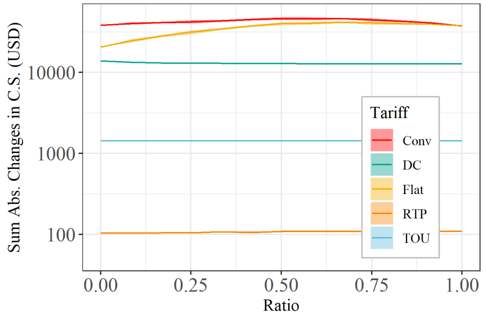
Figure 4.5: Sum of absolute changes in consumer surplus per household for Conventional (a), Flat-rate (b) Time-of-Use (c), Real-time Pricing (d), and Demand Charge (e) tariffs per generation ratio (prosumer ratio). Colors show elasticity rate. Ribbons indicate one standard deviation.

generation remunerations for an average household in our study population ($819 based on their actual tariff subscription, Austin Energy's Value of Solar rate). Hence, losing 22% of potential earnings to cross-subsidization may not be acceptable to the median household in such a high-D-RES scenario.

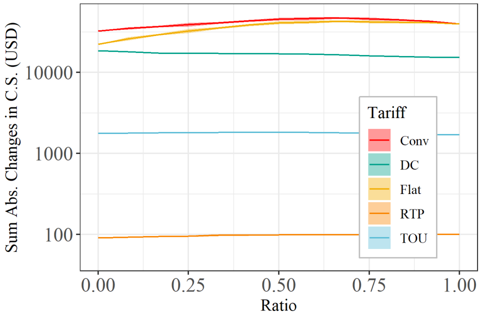
The TOU and RTP tariffs show cross-subsidies which are comparatively stable (i.e. do not change versus D-RES increases) in low-elasticity situations (Figures 4.5c and 4.5d). In high elasticity, the TOU and RTP tariffs show increasing cross-subsidies at high D-RES ratios, mainly due to the time-dependence of energy costs. In addition, a median loser subscribed to the TOU or RTP tariff sees far lower losses of potential earnings, at 0.9% (TOU) or 0.06% (RTP) of the average D-RES generation remuneration. Hence, switching to a TOU or RTP tariff appears to largely fix the two primary cross-subsidization issues inherent in the Conventional and Flat-rate tariffs.

For the DC tariff, we find decreasing cross-subsidies as generation ratio increases (Figure 4.5e). The cross-subsidies of the DC tariff are mainly due to the demand charge, which is in quantity dependent on overall capacity costs. As D-RES generation increases, the household population's peak demand slightly decreases. The consequent decrease in capacity costs leads to less influential cross-subsidies from demand charges. Hence, irrespective of elasticity, we find decreasing cross-subsidies for the DC tariff.

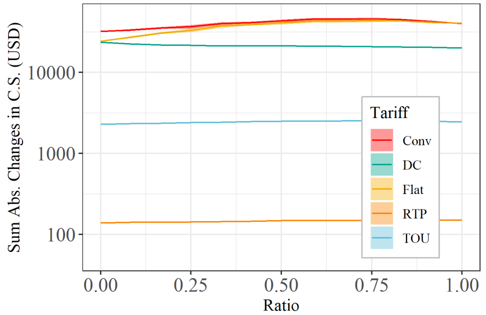
Similar to Burger et al. (2020), we also find that elasticity appears to have differing effects on cross-subsidization, depending on tariff. The Conventional and Flat-rate tariff's cross-subsidization shows relatively similar trends and similar values per elasticity rate (Figure 4.5b). The TOU and RTP tariffs, however, show increasing cross-subsidies in a high-elasticity scenario, but lower and stable cross-subsidies in low-elasticity and zero-elasticity scenarios (Subfigures 4.5c and 4.5d). The DC tariff's cross-subsidies are, in value, strongly dependent on elasticity. However, trends do not differ: cross-subsidies for this tariff decrease as D-RES increases. For the TOU and RTP tariffs, the higher price volatility (compared to the Flat-rate and Conventional tariffs) creates larger opportunities for consumption changes. Responses to changing energy prices are dependent on a household's prior use, with larger changes in consumption coming from high-consuming households, and thus also larger changes in final bills. Hence, elasticity increases the divergence in costs between high- and low-consuming households, leading to more cross-subsidization. As mentioned in the prior paragraph, capacity costs decrease as D-RES increases. As energy costs make a larger portion of the population's bills, their influence on cross-subsidies also increases. These portions are larger in a high-elasticity scenario, leading to the increasing cross-subsidies seen in Subfigures 4.5c and 4.5d.



(a) Zero elasticity ($\epsilon = 0$)



(b) Low elasticity ($\epsilon = -0.1$)



(c) High elasticity ($\epsilon = -0.3$)

Figure 4.6: Sum of absolute values of change in consumer surplus over all households (y axes), per generation ratio (x axes) and per tariff (colors), for zero (a), low (b), and high (c) elasticity cases. Ribbons indicate one standard deviation.

We next compare overall cross-subsidization changes per D-RES generation ratio between tariffs (Figure 4.6). There are large differences in the sums of absolute consumer surplus changes between the various tariffs with any measure of household elasticity. We witness an order-of-magnitude difference between the RTP tariff and the TOU tariff, and between the TOU tariff and other tariffs. For example, the low elasticity scenario's (Figure 4.6b) averages are \$97.4, \$1780, \$36500, \$41500, and \$16800 for the RTP, TOU, Flat-rate, Conventional, and DC tariffs respectively.

Comparisons of cross-subsidization between tariffs appear to depend very little on elasticity; all three subfigures in Figure 4.6 appear somewhat similar in shape. The DC tariff is an exception; its cross-subsidies are far lower than the Flat-rate and Conventional tariffs in a zero-elasticity scenario (Figure 4.6a). However, when higher elasticity is considered (e.g. Figure 4.6c), the former tariff's curve increases to those of the latter two tariffs. Since the DC tariff is an extension of the RTP tariff with a demand charge for capacity costs, these cross-subsidization effects (compared to the RTP tariff's lines) are entirely due to the demand charge. The distortion in observed price created by the demand charge can make the DC tariff very close to the traditional tariff designs. Hence, not considering elasticity can mask the potentially higher cross-subsidization of a DC tariff and make it appear more acceptable as a new tariff design.

To summarize, we find that each tariff shows different rates of cross-subsidization based on elasticity. The Conventional and Flat-rate tariffs generally have the highest cross-subsidization, followed by the DC, TOU, and RTP tariffs. All cross-subsidization rates appear to depend on how much D-RES is in the household population. In addition, the DC tariff is particularly sensitive to changes in elasticity.

4.7 Economic Efficiency

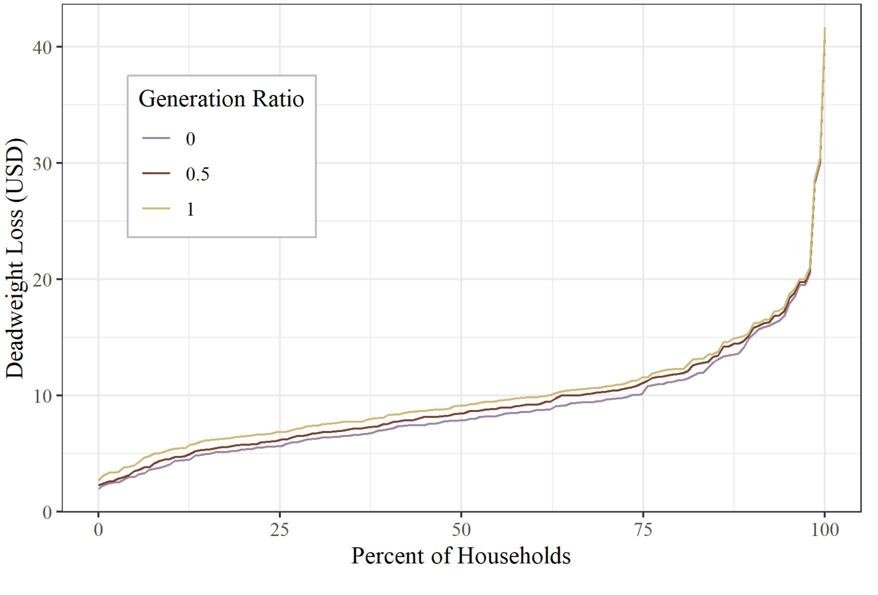
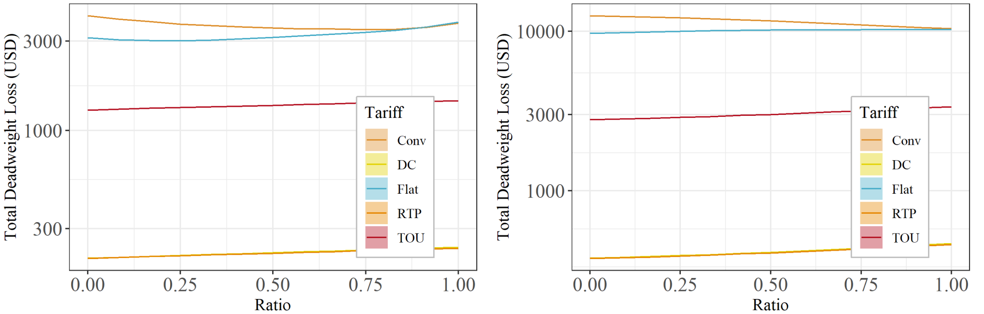


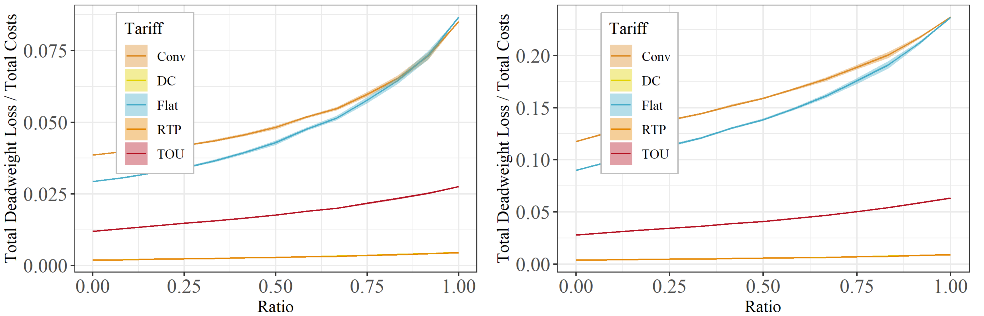
Figure 4.7: Deadweight loss sorted per household (x) for 3 generation ratios (colors) for TOU tariff in low elasticity scenario ($\epsilon = -0.1$).

Economic efficiency is an important consideration in tariff design. The most efficient allocation of resources is when each marginal amount of the resource is allocated to the consumer who values it most. For a public good such as electricity, this is often ensured through having consumers pay exactly the costs of the delivered



(a) Low elasticity ($\epsilon = -0.1$) **(b)** High elasticity ($\epsilon = -0.3$)

Figure 4.8: Total deadweight loss as a ratio of total costs, per generation ratio (x) and per tariff (color). Ribbons show one standard deviation.



(a) Low elasticity ($\epsilon = -0.1$) **(b)** High elasticity ($\epsilon = -0.3$)

Figure 4.9: Total deadweight loss as a ratio of total costs, per generation ratio (x) and per tariff (color). Ribbons show one standard deviation.

product. To summarize Borenstein (2016), any deviation from this pricing creates higher use for those who have little value for the resource, or lower use for those who have high value for it. The economic loss of welfare from these deviations can be measured as dead-weight loss (detailed in Section 4.3). An example of deadweight loss for the TOU tariff is plotted in Figure 4.7. For all tariffs, deadweight loss per household is relatively stable around median values, with some extreme cases at the high end.

Deadweight loss is strongly dependent on elasticity (Borenstein, 2012). Hence, we check total deadweight loss rates for the low elasticity and high elasticity cases separately. We can add the deadweight loss of individual households together to find a measure of total economic efficiency losses for the entire population. This is akin to the area under the curves of Figure 4.7, per generation ratio and per tariff. With low elasticity (Subfigure 4.8a), we see similar and low numbers for the RTP and DC tariffs, and similar and high numbers for the Flat-rate and Conventional tariffs. The TOU tariff reaches a middle-ground between the two extremes. The demand charge tariff's capacity pricing does not appear to create significant deadweight loss, compared to the RTP tariff. This implies that most deadweight loss is a consequence of energy pricing, rather than capacity pricing.

Comparing total deadweight loss to total household bills paints a different picture (Figure 4.9). In our low-elasticity scenario, all tariffs show an increase in deadweight loss relative to total bills. These changes are particularly drastic for the Conventional and Flat-rate tariffs. While the total deadweight loss stays the same (Subfigure 4.8a), the total bill decreases significantly as D-RES generation increases. Consequently, deadweight loss becomes relatively larger, reaching a maximum of about 8.6%.

These trends are relatively similar in a high elasticity scenario (Subfigure 4.8b). The Conventional tariff's losses decrease with prosumer ratio. For the Flat-rate tariff, however, it remains comparatively similar. The TOU, RTP, and DC tariffs experience increases in deadweight loss, mainly due to the deviations in consumption patterns between high- and low-consumption households, discussed previously in Section 4.6. When compared to total bills, in a high-elasticity scenario we witness more significant deadweight loss (Subfigure 4.9b). For the Conventional and Flat-rate tariffs, deadweight loss is near 10% without any D-RES. This value more than doubles as prosumers dominate the population. For the RTP and DC tariffs, changes are near zero, as in the low-elasticity scenario. The TOU tariff once again reaches a middle-ground between the two extremes.

In total, we find that the deadweight loss of the tariffs differ, some by two orders of magnitude. With low D-RES, these numbers appear low when compared against the total bills of the household population. However, we find that D-RES can significantly increase relative deadweight loss, for some tariffs by a factor of 2 or more. For higher-elasticity scenarios, deadweight loss increases significantly. Total deadweight loss is exponentially related to elasticity rate (Borenstein, 2012), but total household bills does not similarly increase. Hence, relative deadweight loss is far higher in a high-elasticity scenario. When high elasticity is considered, economic inefficiencies are far more prominent in tariff design; they appear particularly important for tariffs do not match costs with prices. More importantly, the importance appears significantly increased due to D-RES increases. Currently, household demand elasticity is believed to be low (Borenstein, 2016). As AMI proliferates and increases demand elasticity, we can expect to see a gradual transition from lower elasticity rates to higher ones. Thus, the future holds results more similar to the high-elasticity plots rather than the low-elasticity ones.

4.8 Conclusions

The advent of D-RES has raised concerns about the fairness (or equity) and economic efficiency of distribution grid tariffs. Here we quantify the former as cross-subsidization and the latter as deadweight loss. Each end-user's cross-subsidies and deadweight loss depend on costs and prices, which are both dependent on two volatile factors: household consumption and D-RES generation. Time resolution for these variables significantly affects the outcomes of policy design analyses, and low resolution in data can inhibit accurate policy-making (see e.g. Hu et al. (2015)). However, smart meter pilot programs in many regions have recently made high resolution (per-minute per-household) data, especially of D-RES generation, available. Our study uses such data to quantify cross-subsidization under high D-RES to a degree that was previously rare. Measuring equity accurately in this manner can lead to more accurate policy designs and pricing choices in the distribution grid, especially those with a rapid growth of D-RES.

Our analysis uses data on household consumption, D-RES generation, and pricing from Austin, TX, USA, for the year of 2016. Our choice of tariffs included the status quo (Conventional tariff, based on increasing-block pricing), the most common option (Flat-rate tariff), a common simple alternative piloted in the same region and popular in Europe (a 2-tier Time-of-Use tariff), and two common (and strongly debated) proposals for change (real-time dynamic pricing, and peak demand charges). Given data availability, our methods can be similarly applied to other regions and tariffs.

4.8.1 Policy implications

In our study, the flat-rate and increasing-block pricing (Conventional) tariffs show significant cross-subsidization between prosumers and consumers. These cross-subsidies are especially high when the two groups are evenly divided. Absent demand elasticity, the median loser in this trade, often a D-RES non-owner, may pay $183 per year over its fair share of costs. These funds are often transferred to solar PV owners, who tend to have higher wealth (Borenstein, 2017); this hints at a socially regressive cost transfer. However, these effects disappear when time-of-use pricing or real-time pricing is used. An additional demand charge significantly increases cross-subsidization, but the inequity does not disproportionately favor consumers or prosumers.

Our analysis also considers scenarios where households respond to price changes with consumption changes. A population with more elasticity usually has more overall cross-subsidization, irrespective of D-RES generation amount. However, the observations from a zero-elasticity case also appear in low and high elasticity scenarios. Elasticity mostly does not change the fairness comparisons between tariffs. The notable exception is the demand charge tariff, whose cross-subsidization significantly increases in a high elasticity scenario. An analysis of fairness which ignores elasticity may misplace this tariff as a middle ground between time-invariant (e.g. flat-rate) and time-based (e.g. real-time pricing) tariffs. However, if elasticity is high, this tariff can show similar cross-subsidization values to time-invariant tariffs.

Economic efficiency also appears to differ greatly between tariffs and D-RES amounts. D-RES growth appears to worsen relative inefficiencies, especially for the Flat-rate and Conventional tariffs. Hence, tariff designers may become more concerned with economic efficiency as D-RES expands across its intended subscriber population. This concern is particularly sensitive to elasticity, as higher-elasticity regions are expected to show far higher economic inefficiencies. As theorized in Borenstein (2016), D-RES indeed appears to significantly alter the economic efficiency of distribution network tariffs.

4.8.2 Limitations and future work

Our results are highly sensitive to consumption and generation patterns and electricity prices. Both datasets depend strongly on weather, household behavioral patterns, and geography. Hence, similar results can be found in regions with similar weather, households, and geography, to Austin, TX, USA. An in-depth study of cross-subsidization rates in a region with high D-RES generation but differing geographical patterns and tariffs, such as Germany, would make for excellent follow-up research. The economic inefficiencies from D-RES installations due to clean energy subsidy schemes have been hinted at in past research (Borenstein, 2017; Nelson, Simshauser, and Kelley, 2011). An explicit analysis of these economic inefficiencies would make a suitable complement to the economic efficiency analysis conducted here.

Chapter 5

Economic Inefficiencies of Distributed Generation under Novel Tariff Designs[1]

5.1 Introduction

Pricing a product more or less than it costs leads to consumption above or below what it ought to be (Davis, 2017). If prices are too low, consumers who benefit too little from the product will use it. If prices are too high, consumers who would have otherwise gained utility from the product would no longer make a purchase. These *economic efficiency* losses are a common side-effect of inaccurate pricing of goods.

In electricity, economic efficiency has been a significant factor in wholesale purchases and sales (Borenstein, 2007), but less so in small-scale retail trades (Borenstein, 2016). Many households buy electricity at rates different from the costs of generating and transporting the electricity, leading to consumption above or below the optimal level. Hence, high economic inefficiencies exist in electricity consumption at the retail level (Borenstein, 2016; Borenstein and Bushnell, 2018; Farrell, 2018; Burger et al., 2020; Ito, 2014; Borenstein, 2012; Hancevic, Núñez, and Rosellón, 2019).

Aside from pricing consumption, retail electricity trade also requires pricing of distributed generation (DG). Similar to consumption, the sale of electricity from

[1] At the time of publication, this chapter was in peer review for an academic journal. Parts of this chapter were also presented at the International Conference of Applied Energy 2020 and International Association for Energy Economics 2021 online conference.

DG can also cause efficiency losses. For installation, DG pricing is often based on competitive market dynamics. However, the sale of DG electricity generation can be mis-priced similar to retail consumption (Ansarin et al., 2020c). Consequently, many households recover a different value for their DG installation's output than what it is truly worth (Convery, Mohlin, and Spiller, 2017). These households install larger or smaller DG sources than would be justified by their risk-adjusted discount rates, causing high efficiency losses. These efficiency losses are a significant concern for DG, especially for solar panel installations. For these resources, decreasing costs have led to grid parity in more regions, while their value is often not accurately reflected in returns to installers (Jägemann, Hagspiel, and Lindenberger, 2013). These concerns have been implicitly discussed in the context of current DG policies in Australia (Nelson, Simshauser, and Kelley, 2011; Nelson, Simshauser, and Nelson, 2012; Poruschi, Ambrey, and Smart, 2018), the US state of California (Borenstein, 2017), and Ireland (La Monaca and Ryan, 2017). However, no prior study has focused on explicitly calculating and comparing the efficiency losses from these tariffs for crediting DG based on real-world data.

In this research, we focus on the economic inefficiency caused by the generation part of retail electricity trade. Here, our DGs of choice are solar photo-voltaic panels; although the methods can be applied to other potential forms of DG with non-zero per-unit and fixed system costs. We calculate the returns on DG investment for a multitude of common tariff setups based on real-world data from Austin, TX, USA. We then use these values to calculate potential DG installation sizes, and thus efficiency losses due to DG installations that are larger or smaller than socially optimal. We next report on sensitivity analyses into important parameters of the study, finding that the results are generally agnostic to these changes. These conclusions clarify the implicit welfare losses resulting from simple pricing of residential electricity generation.

Our results are novel compared to past work on this subject in two ways. The first relates to our inclusion of the entire value chain of electricity. Much of past research focused on either the effects of DG on network grid costs or on the temporal aspect of marginal cost changes, but rarely both. In addition, most past work has not directly included the positive social externalities of renewable DG (e.g. Jägemann, Hagspiel, and Lindenberger (2013)). Our data collection includes quantifications of all three aspects of DG value (energy costs, network costs, and environmental externalities) and thus provides a more comprehensive picture of economic efficiency under novel tariff designs.

Our second point of departure from past research is our closed-form formulation of the efficiency loss. This is achieved by formulating a cost function for DG installation, whose parameters are determined from real-world data on DG installation sizes. Hence, unlike other studies, our results require no prior assumptions of the internal rate of return and years of use of DG. These values are subject to disagreement in the literature, and the former is strongly dependent on multiple factors that differ per household and per region (Steffen, 2020; De Groote and Verboven, 2019). Instead, we use real-world data to find an empirical (*ex post*) measure of the long-run value of DG for each household in this population. Thus, our results are less likely to be affected by averaged or median assumptions in this regard, which can hide true efficiency loss (see e.g. (Borenstein, 2012)).

In the following section, we provide some background on economic efficiency in electricity retail (Section 5.2). We then detail our methods (Section 5.3) and datasets (Section 5.4). In the results section (Section 5.5), we first describe the changes in generation size and then discuss the changes in efficiency loss between tariffs. Section 5.6 provides details on the sensitivity analysis, and Section 5.7 concludes.

5.2 Background

Economic efficiency is a particularly important topic of focus for energy systems. Most attention in this domain has been given to the economic inefficiencies of fossil fuel taxes and subsidies (Davis, 2017). For electricity, some research on economic efficiency has focused on the retail space. These studies generally focus on the consumption side of trade, i.e. efficiency losses attributable to consumer pricing. For example, some studies focus on increasing-block pricing, where consumers pay higher prices for higher monthly consumption volume (Borenstein, 2012; Ito, 2014; Hancevic, Núñez, and Rosellón, 2019). Borenstein and Bushnell (2018) calculates deadweight loss for multiple regions and tariffs across the US, de-composing these effects into those applicable to differences between average costs and average price, and those related to temporal deviations in marginal cost compared to average cost. Many studies also investigate the trade-offs between distributional (equity) and efficiency concerns in electricity retail (Feldstein, 1972).

A few studies investigate the effect of DG installations on consumer-side efficiency losses. Most retailers operate tariffs in a revenue-neutral fashion, imposed either via regulation on monopoly or competitive market forces. As DG is installed, retailer costs and bills for some households change (Gautier, Jacqmin, and Poudou, 2018). The mis-alignment of these two quantities causes welfare loss (Borenstein, 2016). Farrell (2018) uses UK data to find changes in welfare loss due to installations of DG on a two-part tariff (i.e. a tariff consisting of a per-kWh rate and a fixed charge). Schittekatte, Momber, and Meeus (2018) compare retailer costs as a proxy for inefficiency for peak demand charges. Ansarin et al. (2020c) compare the effects of increasing DG installations on deadweight loss in multiple tariffs.

Another recent source of inefficiency in electricity retail is the mispricing of credits for DG generation (Convery, Mohlin, and Spiller, 2017). Consumers install DG assets, thus becoming "prosumers" (producer-consumers). In many settings, especially for renewable and/or clean DG, these prosumers receive beneficial pricing for their DG's electricity production. The consequent over-installation of DG units results in two forms of efficiency loss. The first form is in the recovery of these credits from other electricity users or via taxes. Past research has studied these welfare effects for tariffs in Australia (Nelson, Simshauser, and Kelley, 2011; Nelson, Simshauser, and Nelson, 2012), Germany (Jägemann, Hagspiel, and Lindenberger, 2013), and Ireland (Farrell, 2018).

The second form of efficiency loss from DG over- (or under-) installation is directly from the over- (or under-) investment in DG. This paper studies this subject, where some prior research exists. One such study is Jägemann, Hagspiel, and Lindenberger (2013), where 2011 German tariffs were found to create €116b (in 2011) in social losses by 2050. Another is Gilbraith (2015, Chapter 4), which calculates over-installations of DG due to over-payments of solar credits in Portugal. Brown and Sappington (2017b) and Brown and Sappington (2017a) model the welfare effects of different compensation settings for DG generation for owners and non-owners. Our research here considers the efficiency losses from DG over- (or under-) installation caused by over- or (under-) pricing of DG generation for multiple other tariffs using real-world data.

Our study also relates to studies of the relationship between D-RES installations, electricity pricing, and subsidies/taxes. A common concern in this space is the difference in outcomes between up-front incentives (e.g. rebates and tax breaks) and production-based subsidies (e.g. net metering and feed-in tariffs). La Monaca and Ryan (2017) compares payback periods for DG installations under both up-front and DG generation-based incentives in Ireland. Poruschi, Ambrey, and Smart (2018) reviews the effect of feed-in tariffs on increasing solar DG installations in various Australian states. Matisoff and Johnson (2017) finds that unlike direct cash incentives, net metering policies had little effect on increasing DG in the United States.

De Groote and Verboven (2019) provides an explanation for this, by showing that households significantly under-value future returns on DG investment (e.g. via advantageous tariffs) over up-front incentives (e.g. direct cash payments). Villena et al. (2021b) calculates growth rates for DG installations and electricity bills for customers of various DG tariffs, based on a case study of Wallonia, Belgium. Gautier and Jacqmin (2020) use data from the same region to find that, under a net metering scheme, increasing a flat-rate tariff by 1 c€/kWh leads to 8% more installation of solar DG. Likewise, Hughes and Podolefsky (2015) find that Californian up-front incentives for solar DG resulted in a 10% increase in installations for each extra 100 $/kW-installed. We here calculate the different rates of DG installation under different tariffs, including flat-rate feed-in tariffs and net metering schemes, including different forms of volumetric accumulation (i.e. self-consumption over differing time periods).

5.3 Methods

This section consists of two parts. We first describe how we calculate efficiency loss for each household under each tariff. Next, we detail each tariff's design and calibration.

5.3.1 Calculating efficiency loss

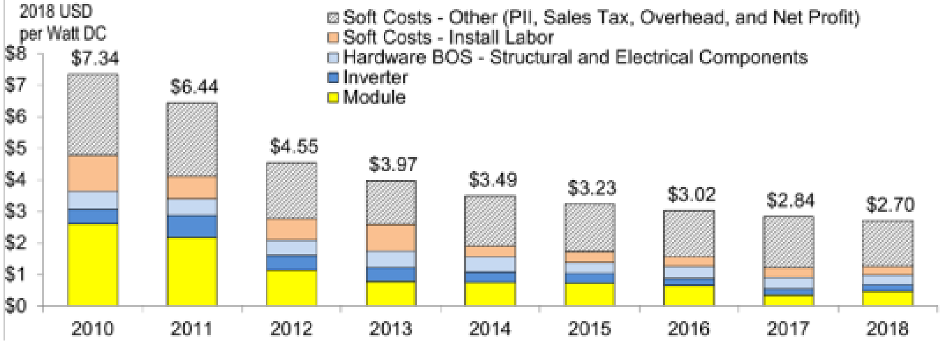


Figure 5.1: Residential solar panel costs 2010-2018 per cost component. Source: (Fu, Feldman, and Margolis, 2018)

Table 5.1: Nomenclature.

Label	Unit	Description
i	-	Household index
M	-	Household population
C	\$	Total DG system costs
C_g	\$/kW	DG system marginal cost per kilowatt
C_0	\$	DG system base costs
G	kW	Size/capacity of installed DG
n	-	DG installation lifetime
R	\$	Net present value of DG earnings
θ	\$	Annual DG earnings
r	-	DG system internal rate of return
α	-	Household earnings factor
P	\$/kWh	DG electricity credit price
t	min	Time unit (1 minute)
T	-	Time horizon
g	kWh	DG generated electricity
β	-	DG size increase factor
E.L.	\$	Efficiency loss
c	kWh	Household electricity consumption

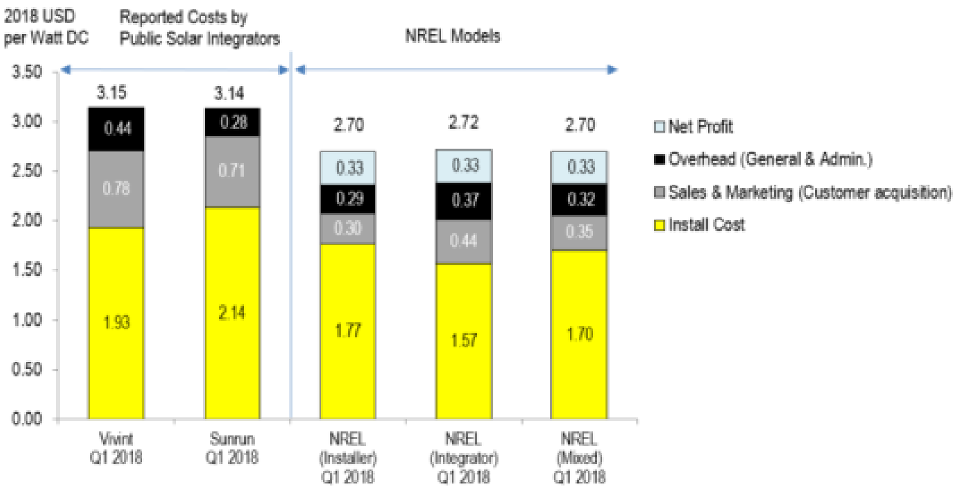


Figure 5.2: Residential solar panel costs in NREL analysis versus company reports. Source: (Fu, Feldman, and Margolis, 2018)

Solar panel costs consist of a) system hardware costs (modules, inverter, balance-of-system components), b) direct and indirect labor, c) permit, inspection, and interconnection (PII) costs, and d) overhead, sales, and marketing costs (Figure 5.1) (Fu, Feldman, and Margolis, 2018).[2] We can split these costs into those that depend on installation size, and those that do not. In terms of cost components, most hardware and labor costs ((a) and (b)) are size-dependent whereas most PII and overhead and marketing costs ((c) and (d)) are not. Hence, costs become a relationship as (household $i \in M$)

$$C_i = C_0 + C_g G_i, \tag{5.1}$$

where C_i is total system costs, C_0 is size-independent costs, C_g is size-dependency factor, and G_i is size of solar panel installation in kilowatts. Each household chooses their installation size based on the net present value of overall earnings based on their tariff. Over an assumed period of n years, these returns are equal to

$$R_i = \sum_{k=1}^{n} (\frac{1}{1+r_i})^k \theta_i(k), \tag{5.2}$$

[2]Note that the authors of Fu, Feldman, and Margolis (2018) believe these costs are probably slightly underestimated. Their values differ from company reports, which list higher financing and overhead costs per customer (Figure 5.2).

where R_i is the net present value of overall DG earnings, $\theta_i(k)$ is earnings for year k, and r_i is the household's acceptable internal rate of return on investment. This internal rate of return depends on multiple factors, primarily how much the necessary capital will cost the household. It would also be biased by interest in green and/or clean energy, local generation, self-sufficiency, and et cetera (Sagebiel, Müller, and Rommel, 2014). The net present value of DG earnings R_i per household i is equal to the present total system costs C_i. We also assume that yearly earnings are equal every year on average ($\theta_i(k) = \theta_i$) and summarize the second part of the sum (which depends on r_i and n) as α_i:

$$\sum_{k=1}^{n} (\frac{1}{1+r_i})^k \theta_i(k) = \theta_i \alpha_i. \tag{5.3}$$

At equilibrium, total cost for the solar panel installation is equal to the net present value of the generated electricity less costs. The equilibrium point is set by the values of electricity price ($P(t)$) and installed generation capacity (G_i):

$$\theta_i \alpha_i = C_0 + C_g G_i. \tag{5.4}$$

With a new tariff, a new equilibrium would exist with $P_{new}(t)$ and $G_{i,new}$:

$$\theta_{i,new} \alpha_i = C_0 + C_g G_{i,new}. \tag{5.5}$$

If the size of the generation installation G_i is increased, the generated electricity output would also increase. Here, we assume both these values increase at the same proportion β_i, or

$$G_{i,new} = \beta_i G_i \tag{5.6}$$

and

$$g_{i,new}(t) = \beta_i g_i(t). \tag{5.7}$$

Placing these into Equation 5.5 yields

$$\alpha_i \beta_i \sum_t P_{new}(t) g_i(t) = C_0 + C_g \beta_i G_i. \tag{5.8}$$

Solving for β_i, we find:

$$\beta_i = \frac{C_0}{\alpha_i \sum_t P_{new}(t) g_i(t) - C_g G_i} \tag{5.9}$$

With β_i, we can find $G_{i,new}$, i.e. the potential installed DG capacity for each new tariff.

Efficiency loss here can be considered as the excess investment in generation units by each household. This is equal to the difference in costs based on the real value of solar energy (denoted by $_{real}$), minus those based on the tariff price of solar energy, or

$$E.L._i = |C_i - C_{i,real}| = |G_i - G_{i,real}|C_g = |\beta_i - 1|G_i C_g \tag{5.10}$$

To find this efficiency loss per household i, we need to first find C_0 and C_g. This can be obtained from solar pricing information from manufacturers and installers of solar DG. We also need to calculate α_i. This depends on the household's characteristics and preferences and is calculated based on Equation 5.4, which can be simplified to

$$\alpha_i = \frac{C_0 + C_g G_i}{\theta_i} \tag{5.11}$$

θ_i , G_i, and $g_i(t)$ are calculated based on tariffs and generation and consumption data and all vary per household. Thus, all unknowns in Equation 5.10 are calculable per household.

5.3.2 Tariffs

Households can be subject to different tariffs for their DG generation and household consumption. These tariffs would impact α_i in the equations described before. We first describe the real costs of electricity trade, and then describe calculations for the costs of each tariff (which deviates from the real costs in different manners).

Real value

The real value of electricity generation is based on the Value of Solar analysis (Energy Resources, 2014), which we summarize as follows:[3]

[3]Grid hysteresis and distribution losses are found to be minimally impacted by D-RES and are thus ignored here. See Rábago et al. (2012).

1. The real value of electricity at any given time. This is based on the real-time wholesale market price at any given time. Hence, real-time locational-marginal market prices (RTLMP) are used for this purpose.[4]

2. The value of offsetting (or worsening) peak electricity demand in the distribution grid. In most regions, peak electricity demand is impacted by DG. As users install DG, they may use less electricity during peak demand moments, or DG may increase until its peak generation is higher than the previous grid peak capacity use.

3. The value of clean electricity generation. Multiple methods are used to internalize the benefits of clean electricity. In this case, we consider a fixed payment to users for each kWh of clean electricity generation.

We refer to this scheme for crediting DG electricity production as "real-time pricing".

Flat rate

A fixed per-kWh credit is often used to remunerate D-RES generation. This "Flat" rate is taken here as well, and is the default rate for solar credits in the area pertaining to the data used in this study. Hence, the flat rate is set equal to this default rate (see Rábago et al. (2012) for calculation details and components).

Net metering rate

We first consider a net metering rate which does not accumulate volume over a timespan. More specifically, the tariff gives a worse price per electricity injected into the grid than the retail rate of electricity absorbed from the grid. In many regions, only the first and third cost components are considered included in the injection credit. Hence, the returns for every unit of generation would be:

- Regular flat-rate pricing (including value component 2) when net demand is positive.

[4]Many retailers also have power purchase agreements or generation units, leading to deviations between the value of energy for the and the market price of electricity at each time. These deviations are often private information; consequently, most prior work has used real-time or day-ahead market prices as a proxy for the temporal value of electricity (Burger et al., 2020; Fridgen et al., 2018; Rábago et al., 2012). Some prior work has also shown that these deviations have little effect on measures of welfare (Borenstein, 2007).

- Real-time pricing (excluding value component 2) when net demand is negative.

In mathematical terms:

$$\theta_{i,net} = \sum_{t \in T} [max\{0, g_i(t) - c_i(t)\} P_{credit}(t) + min\{g_i(t), c_i(t)\} P_{retail}(t)]. \tag{5.12}$$

where $g_i(t)$ and $c_i(t)$ are generation and consumption at each timeslot, and $P_{credit}(t)$ and $P_{retail}(t)$ are injection and absorption prices, respectively, and T is time horizon of the billing period.

Net metering plus volumetric accumulation

This rate is similar to the former rate; however, the DG generation is accumulated over a specific period (T). The portion of the generated electricity that is used for the customer's self-consumption is credited at the retail rate, whereas the remainder is priced at the credit rate. This scheme is formulated as

$$\theta_{i,netvol} = min\{\sum_{t \in T} g_i(t), \sum_{t \in T} c_i(t)\} P_{retail}(t) + max\{\sum_{t \in T} g_i(t) - \sum_{t \in T} c_i(t), 0\} P_{credit}(t). \tag{5.13}$$

The accumulation period for this rate defines what kind of generation volatility is masked from credits. We consider three accumulation periods here:

- One day, labelled by $_{netaccumdaily}$, which covers the daily generation volatility (e.g. generation at daytime but not during nighttime).
- One week, labelled by $_{netaccumweekly}$, which covers daily volatility, plus some potential volatility due to short-term weather changes (e.g. high generation during sunny days, low generation during cloudy days)
- One month, labelled by $_{netaccummonthly}$, which covers all prior volatilities, and also some seasonal volatility (e.g. higher generation due to higher solar irradiance in spring versus winter)
- One year, labelled by $_{netaccumyearly}$, which covers all prior volatilities, and also seasonal volatility. Many regions, such as Wallonia, Belgium, use this tariff (Gautier and Jacqmin, 2020).

The retail price P_{retail} is set as the flat rate from the flat rate pricing scheme. The credit price P_{credit} is set as the average real-time pricing for the location (excluding value component 2).

5.4 Data

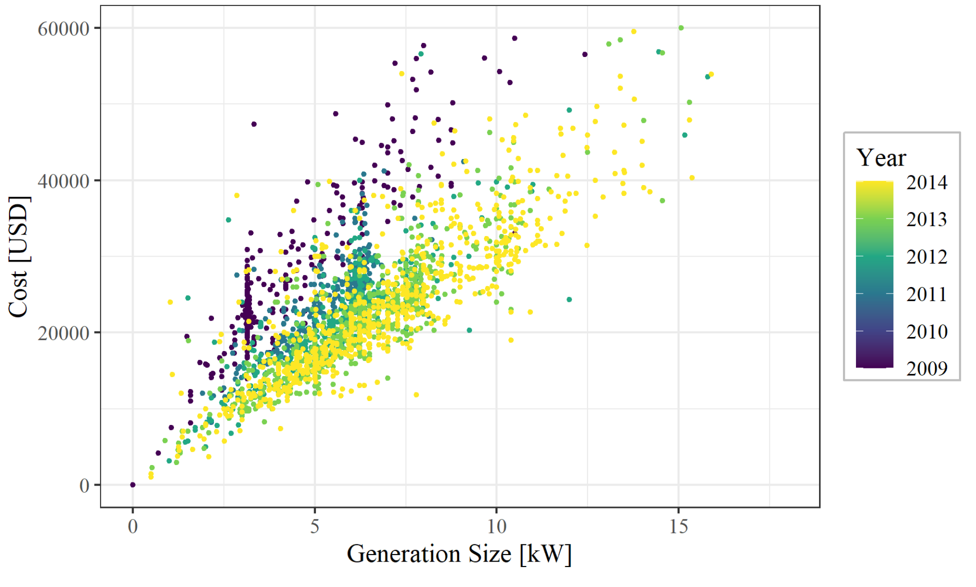


Figure 5.3: Solar panel installation costs per size of panel installation. Colors indicate year of installation. Data points with sizes above 18kW and costs above \$60000 (1.1% of dataset) are considered outliers and not shown here. Data courtesy of Austin Energy.

The primary generation and consumption data used for this study comes from the Pecan Street Dataport.[5] This data was obtained under an academic use license and consists of per-minute generation and consumption data for hundreds of households. We chose data from this set based on the following criteria:

- Households are in Austin, TX, USA. (282 households)
- Households contain generation and consumption values for the entire year of 2016. (216 of 282 households)

[5]More information at `www.pecanstreet.org`

- Consumption and generation data contained less than 5% missing or erroneous data points, after data cleaning operations (144 of 216 house-holds).
- Meta-data contained information about size of installed DG (125 of 144 households).

In total, 125 households were found to have suitable data for this analysis.

For the real value of DG, we use calculations and pricing data from the same locale as our energy data:

1. For real value of electricity: RTLMP data from the Electricity Reliability Council of Texas, the dataset region's independent system operator, at the Austin load zone. This consists of per-15 minute data for the entire year.[6]
2. For value of changing peak demand: The calculated difference between weighted-average market prices and currently-used feed-in tariffs from Austin Energy, a local publicly-owned electricity retailer, as a measure of the generation assets' benefit for the grid.[7] Austin Energy's VoS rate ensures that costs equal value in total. Hence, the second point ensures that the real value of electricity is (over all households) set as equal to the revenue of the flat tariff.
3. For the value of clean electricity generation: The returns per kWh of generation for selling renewable energy certificates on the Texan Renewable Portfolio Standards market. This is equal to 2.5 c/kWh as calculated by Rábago et al. (2012).

To find C_0 and C_G, we use a dataset from Austin Energy's Residential Solar Incentive Program, which contains solar installation information for households installing solar panels in Austin Energy's area of operations from 2004 to 2019. This dataset contains cost and size data for each installation. Outliers (i.e. installations above the 99th percentile, i.e. 18kW or more, and outlying results for 2010 and 2015) and missing data points for this dataset were cleaned, leading to 2686 cost and size combinations for the most likely period of installation (2009-2015). These data is used to regress Equation 1 and thus estimate C_0 and C_G, which were calculated as \$3019 and 3495 \$/kW, respectively. These values align with those reported by Fu, Feldman, and Margolis (2018) for the years in which the installations were made.

Some real-world constraints are required to make the model's output realistic. These include:

[6]More information at `www.ercot.com`
[7]More information at `austinenergy.com/ae/rates/`

- The potential installed solar panel sizes in each household are limited. First and foremost, they are limited by the physical space available for installations. Second, most subsidy schemes have upper bounds on the allowed system size, where most larger system sizes are economically unfeasible. On this basis, we limit the upper bound of each household's solar installation based on the distribution of solar panel sizes in Austin Energy's Residential Solar Incentive Program. Only 1% of the program's recipients had panel size above 18kW, and thus it was expected that all residential households would be smaller than this upper bound. Solar panel installations larger than this size were assumed to be unfeasible. The maximum solar panel capacity in households from the Pecan Street dataset was 15.3kW.

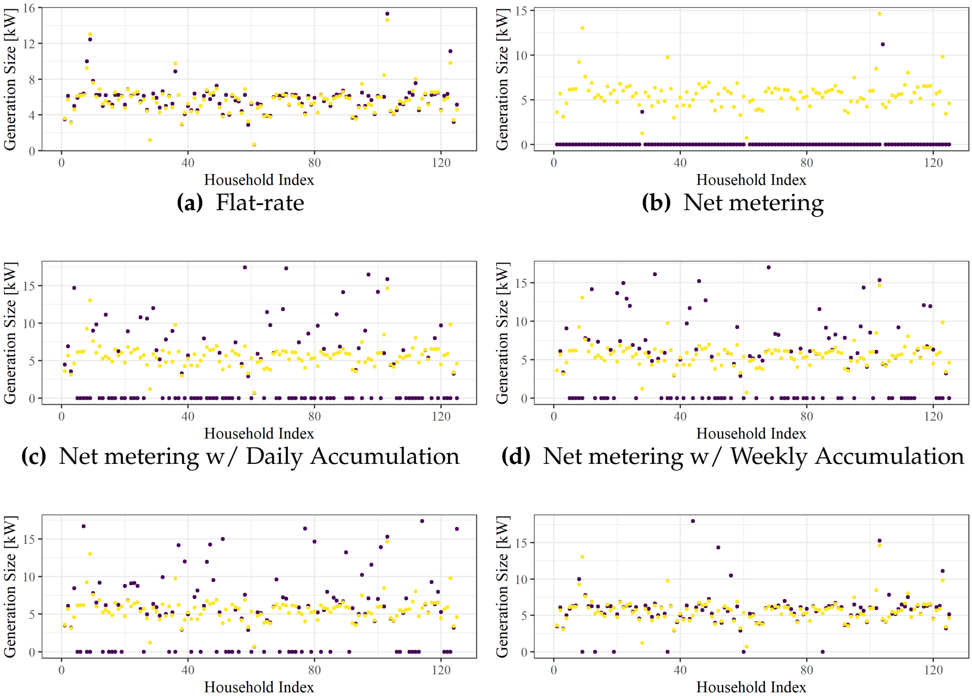
5.5 Results

5.5.1 Changes in DG size

Table 5.2: Numerical results of calculations.

Tariff	Average DG generation size change [kW]	Total DG installation costs [USD]	Total efficiency loss [USD]	Total efficiency loss as ratio of total installation costs
Flat	0.0643	2859748	128949	0.0451
Net	-5.49	431771	2816981	6.524
Net Accum. Daily	-2.02	1947322	2176758	1.12
Net Accum. Weekly	-1.13	2336322	1762152	0.754
Net Accum. Monthly	-0.486	2619216	1557088	0.594
Net Accum. Yearly	-0.0247	2820856	391102	0.139

We focus here on efficiency losses within prosumer households that are due to mispricing generation credits. These pricing practices can result in households installing larger or smaller DG units than appropriate. For each tariff-household pair, households would install a different amount of DG if they are credited based on the real value of their generation, rather than the value given to them by their tariff (Table 5.2). For the flat-rate tariff, on average, a household changes their generation capacity by 0.064 kW compared to its optimal size. This is due to the differences in returns between a real-time pricing and a flat-rate pricing scheme. These pricing



(a) Flat-rate
(b) Net metering
(c) Net metering w/ Daily Accumulation
(d) Net metering w/ Weekly Accumulation
(e) Net metering w/ Monthly Accumulation
(f) Net metering w/ Yearly Accumulation

Figure 5.4: DG installed size change per tariff. Colors indicate generation size when real value is credited for DG generation (yellow) versus when tariffed revenue is credited (dark blue). Data from Pecan Street Dataport.

differences are mainly a consequence of the time-dependent nature of electricity's value in the external (high voltage) grid, which are masked from prosumers in a flat per-kWh rate. Although some DG generation may align better with market price fluctuations(Jägemann, Hagspiel, and Lindenberger, 2013; Rábago et al., 2012), these differences are ignored when a flat-rate price is used.

Other tariffs show a larger change in generation size changes. We find that under a net metering scenario, wherein injecting electricity into the grid is given a less favorable price than self-consumption, very few households choose to install solar panels. This is mainly due to net metering's unfavorable injection prices, which worsens the financial case for DG. Consequently, average DG generation size change is -5.49kW under net metering with no volumetric accumulation.

In theory, the financial case for DG would be expected to improve as DG generated electricity is allowed to accumulate for self-consumption over a longer time span. Accumulation allows households to ignore the temporal differences of consumption and generation, leading to a higher amount of DG generation being consumed (theoretically; from the perspective of accounting) by the household.[8] As the pricing for injection into the grid is usually less advantageous than self-consumption, households thus receive more credits for their DG generation. Consequently, as more accumulation is allowed, further DG production intermittencies are ignored. The results reflect this expectation, with more DG installations becoming favorable as the time window increases. In the yearly setting, intermittencies due to hourly, daily, weekly, monthly, and seasonal variation for solar panel generation are ignored. Thus, average generation asset sizes decrease by 0.025 kW and many households find generation sizes closer to that of a flat-rate tariff (Table 5.2). Most of the decrease in this case is due to a few households that opt to not install solar panels, counterbalanced by few who install more solar panels. Comparatively, in total there is little difference between a flat-rate feed-in tariff and a net metering setup that accumulates on a yearly basis.

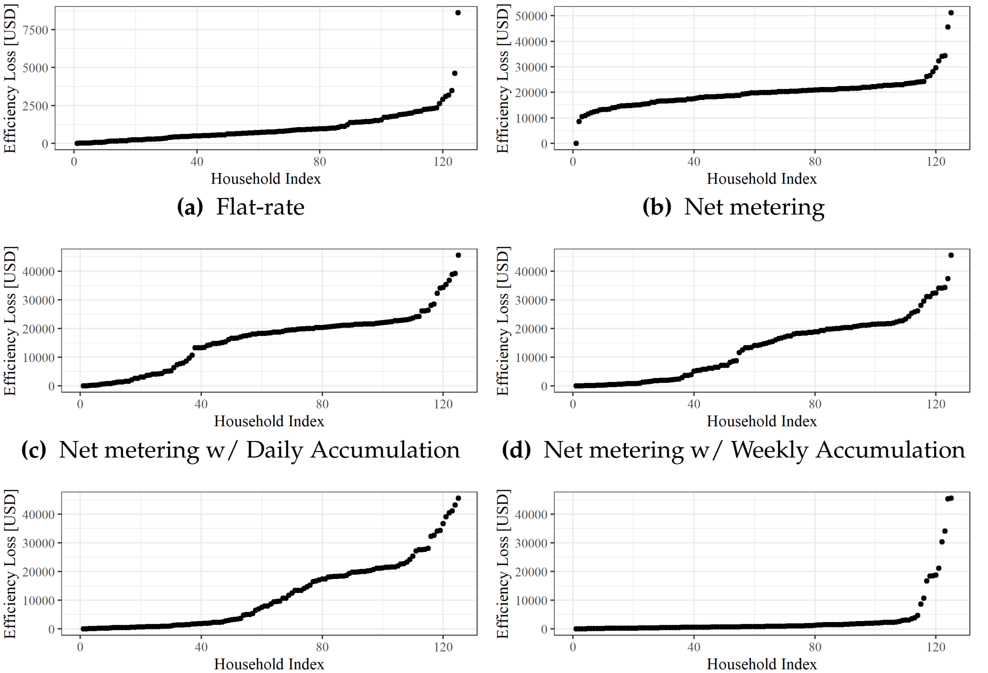
5.5.2 Efficiency losses

As households do not receive the real value of their solar generation under more simple tariffs, they are disadvantaged and thus install DG of an inappropriate size (or do not install DG at all). There is a welfare (or efficiency) loss due to this pricing difference. This efficiency loss is calculated per household and sorted in increasing order in Figure 5.5. We first review the results for each tariff, and then compare tariffs with each other.

For the flat-rate tariff (Figure 5.5a), a generally low amount of deadweight loss is present, with very high values for a few households. The losses here best represent the differences due to flattening the real-time value of electricity within the specific region. Households with higher kW of solar generation are more exposed to these differences and thus cause larger welfare losses. In total, these 125 households experience \$129,000 of efficiency loss; an average of \$1032 per household, or about 4.5% of the average DG installation costs.

The net metering tariff shows a similar trend (Figure 5.5b). Households find relatively similar rates of welfare loss, with a few households facing exceptionally large losses. However the net metering with accumulation tariffs each show a large

[8] In reality, and from a power-systems perspective, electricity must be balanced at all times, and electricity is indeed injected into the grid at times of high generation and low demand. This causes a difference in value for the retailer and the household. Thus, this can be considered as an indirect subsidy and may reduce overall efficiency.



(a) Flat-rate

(b) Net metering

(c) Net metering w/ Daily Accumulation

(d) Net metering w/ Weekly Accumulation

(e) Net metering w/ Monthly Accumulation

(f) Net metering w/ Yearly Accumulation

Figure 5.5: Total Efficiency loss per household from flat-rate tariff as compared to real-time pricing (sorted by amount). Data from Pecan Street Dataport.

jump at a specific household percentile. This generally indicates the percentile after which households choose to forego solar panels due to being economically unfeasible based on their required internal rate of return. Hence, their losses equal the entire installation costs. As accumulation window grows, fewer households make such a decision, leading to lower overall efficiency losses. For the net metering with yearly accumulation tariff, a few households are left without installations, while most install solar panels. These few (6 of 125) households cause a disproportionately high amount of welfare loss, accounting for 42% of this tariff's total welfare loss of $391,102 (Table 5.2). As explained in the prior subsection, most of these households no longer install solar panels due to economic feasibility, while a few install larger solar panel installations than before.

We next draw comparisons between the different loss rates per tariff, overall and between households. Comparing the different values for different curves in Figure 5.5, the flat-rate tariff presents lower losses than other tariffs. The biggest difference is between the flat-rate and the net metering tariff (totals appear in Table 5.2). In net metering, very few households choose to install solar panels due to a far less advantageous pricing structure. Although these losses are not entirely internalized (i.e. welfare losses are split between public and private loss), we can use Gini coefficients to compare the divergence of loss per household for these different curves. The flat-rate tariff's loss has a Gini coefficient of 0.47, while the net metering tariff is 0.15. Thus, although losses in the net metering scenario are higher, they are distributed more evenly.

The large difference between flat-rate and net metering tariffs' efficiency losses is mitigated by accumulation. This accounting practice gradually decreases these losses to levels comparable with the flat-rate tariff (save for a few households) in the yearly accumulation setting (Figure 5.5f). In this case, a few (6) households create a large part (42%) of the losses. However, on the median, losses between the flat-rate tariff and this tariff are similar ($748 and $816, respectively). Thus, in terms of overall efficiency loss, flat-rate and net metering with yearly accumulation perform somewhat similarly.

5.6 Sensitivity Analysis

5.6.1 Value of offsetting grid costs

One of the primary differences between the flat-rate tariff and other tariffs is how the second value factor (offsetting grid costs) is credited. For net metering, this additional "subsidy" is removed from any electricity injected into the grid, whereas for the flat-rate tariff this value is included in the tariff's price. Consequently, one of the main sources of difference in total household credits, and thus installed generation size and welfare loss, between these tariffs is this value factor.

To understand the effect of this factor on our results, we consider a 10% decrease to 10% increase of these factors. This corresponds to a likewise decrease or increase in the benefit of DG generation to a distribution system operator's grid management costs. Originally, grid costs reductions resulted in 5.9 c/kWh of benefits being credited for solar DG owners. Thus, this analysis considers the range of values [5.31,6.49] c/kWh. Based on these different costs, we calculate the DG size changes and welfare loss for each tariff.

Figure 5.6 presents the main outcome of this sensitivity analysis. All tariffs show a mostly decreasing efficiency loss in response to higher grid cost reductions. This

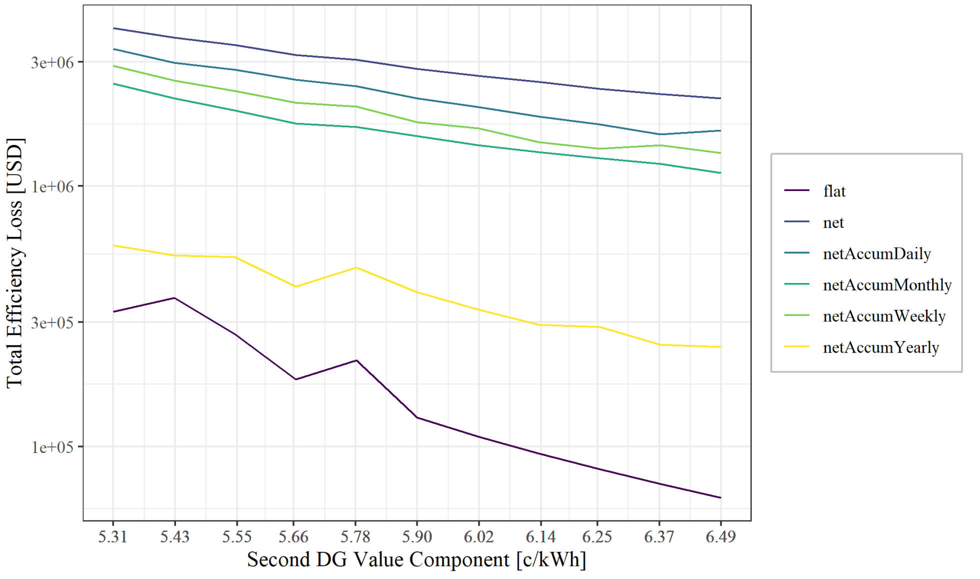
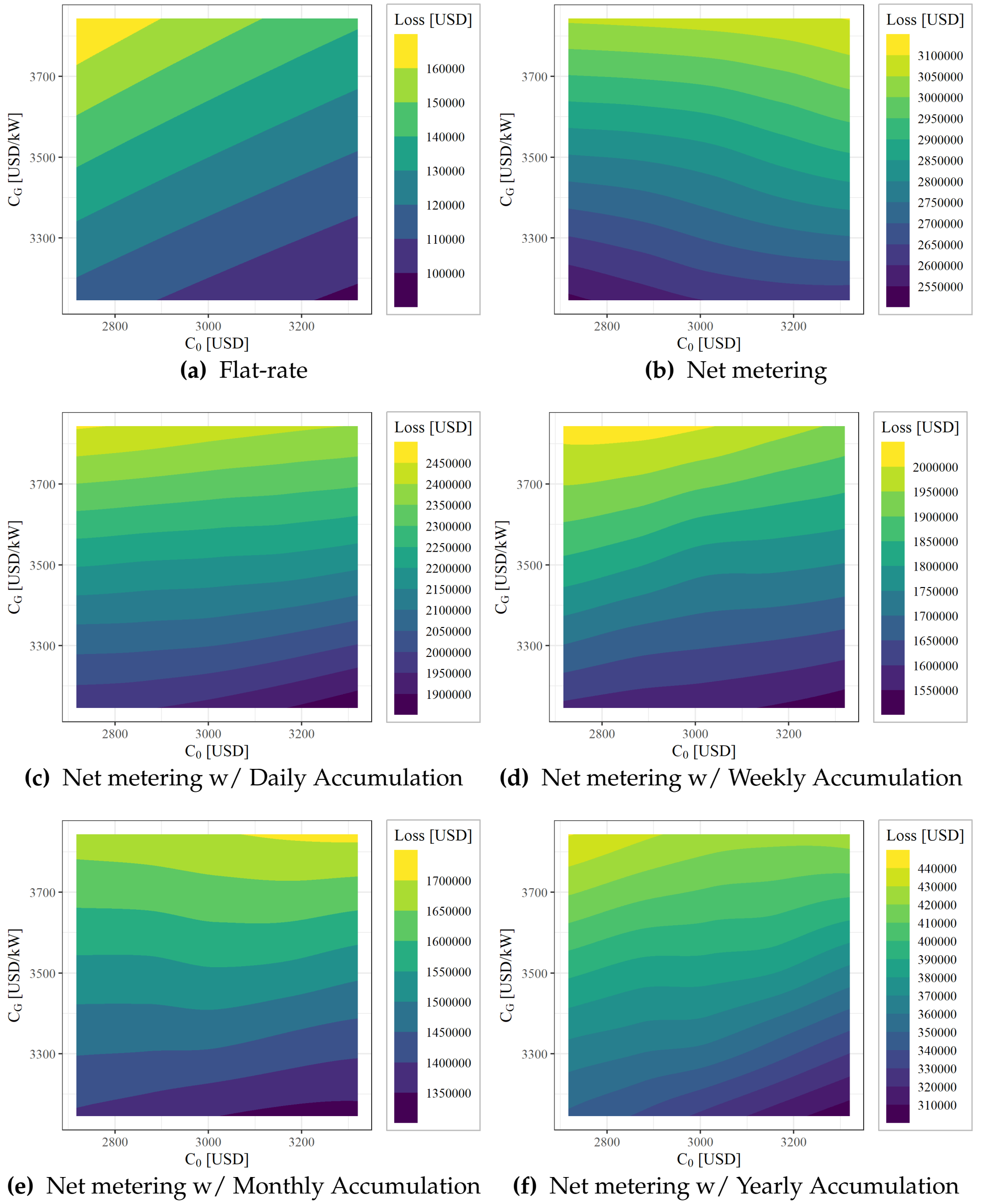


Figure 5.6: Sum of efficiency loss over household group per different rates of second value component of DG. Colors indicate different tariffs. Note that the Y-axis is logarithmic. Data from Pecan Street Dataport.

due to three interrelated causes. First, as this extra credit decreases, households must install larger DG installations for feasible solar panel installations. Second, as the extra credit decreases, it can happen that a few households find it economically and physically feasible to install solar panels when they are credited the real value of their generation, whereas they would not if credited according to a tariff. Both these effects create the general trend of increasing inefficiency. On the other hand, a third countervailing force may reduce inefficiency. Fewer households can achieve a feasible DG installation both when they are credited the real value of their generation and when credited by the tariffed value. In these cases, inefficiency losses are reduced. The former two effects generally dominate the trend; however, in a few instances, they are superseded by the latter effect. These instances are generally when one or two households responsible for much inefficiency are no longer installing solar panels, and thus no longer cause inefficiency. An example of this can be seen when the second value component changes from 5.66 to 5.78 c/kWh under a flat-rate tariff (Figure 5.6). Generally speaking, lower overall welfare losses are found for all tariffs when this value component is higher.



(a) Flat-rate

(b) Net metering

(c) Net metering w/ Daily Accumulation

(d) Net metering w/ Weekly Accumulation

(e) Net metering w/ Monthly Accumulation

(f) Net metering w/ Yearly Accumulation

Figure 5.7: Total Efficiency loss (color) per fixed installation costs (C_0, x axis) and variable installation costs (C_G, y axis). Data from Pecan Street Dataport.

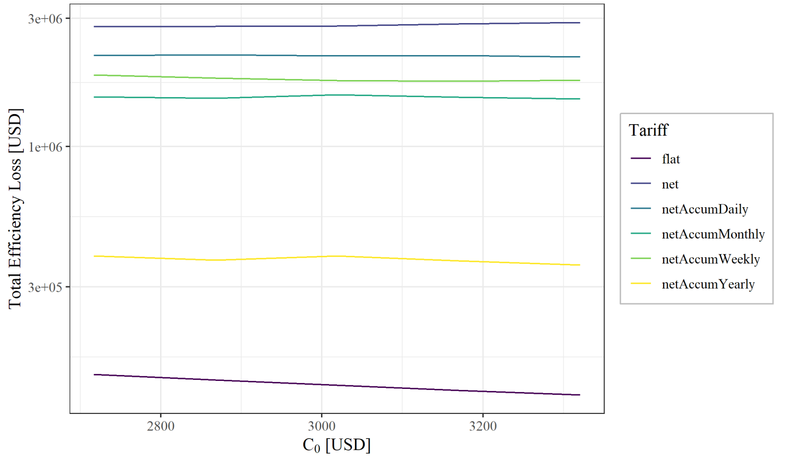


Figure 5.8: Sum of efficiency loss over household group per different fixed costs (C_0). Colors indicate different tariffs. Note that the Y-axis is logarithmic. Data from Pecan Street Dataport.

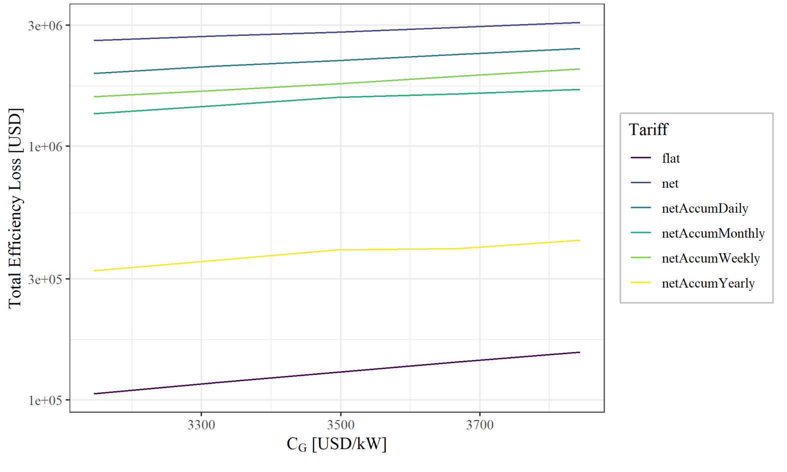


Figure 5.9: Sum of efficiency loss over household group per different variable costs (C_G). Colors indicate different tariffs. Note that the Y-axis is logarithmic. Data from Pecan Street Dataport.

5.6.2 Solar panel installation costs

In our study, we assumed that the costs of a household's solar panel installation can be decomposed into fixed and variable (per-kW) components, similar to literature on residential solar panel costs (Fu, Feldman, and Margolis, 2018). We found the values of these numbers based on a dataset of solar panel installation costs from the same region as the household population of our energy data. However, despite efforts at cleaning the dataset, it is possible that the values for the fixed (C_0) and variable (C_G) costs of DG are over- or under-estimated. Thus, we investigate the sensitivity of our primary conclusions to these two values.

We vary C_0 and C_G separately from a 10% decrease to a 10% increase compared to their original values (namely \$3019 and 3495 \$/kW, respectively). We then recalculate results based on these values. Figure 5.7 represents the results of this sensitivity analysis, with subfigures showing results per tariff. It can be seen that increases in C_G have a uniformly increasing effect on total efficiency losses for all tariffs. However, results for C_0 changes are more varied. For the flat-rate, net metering with yearly accumulation, and net metering with weekly accumulation, C_0 increase decreases total efficiency loss. For the other tariffs, however, C_0 and loss do not appear related.

We can also consider the differences between tariffs as C_0 and C_G change, which are shown in Figures 5.8 and 5.9 respectively. Similar to the prior sensitivity analysis, we find that neither C_0 nor C_G changes the qualitative differences between the tariffs; i.e. the differences in losses between tariffs remain relatively stable irrespective of fixed or variable cost changes.

5.7 Conclusions

In this study, we investigated the potential efficiency losses due to pricing (renewable) distributed generation at rates not matched by the real value they provide to the grid and to households. We calculated the potential DG installation sizes for when the real value is credited to households, and also for other possible pricing options. These pricing options include flat-rate tariffs and net metering both without and with multiple time windows for volumetric accumulation (i.e. self-consumption). Each of these tariffs were compared in installed DG sizes against the default (flat-rate feed-in) rate, and were then used to find efficiency losses per household. Our results demonstrate both heterogeneity between households and between tariffs in the losses attributable to mispricing DG electricity.

We find that there are relatively small efficiency losses due to the pricing of electricity based on a flat rate rather than a real-time pricing tariff. However, a change to net metering without volumetric accumulation significantly increases the efficiency loss, as far fewer households opt to install DG. As volumetric accumulation is added with larger time windows, the number of households opting to install solar panels increases, resulting in lower efficiency loss. For the most favorable setup, i.e. net metering with yearly volumetric accumulation, both DG sizes and efficiency losses are relatively similar between flat-rate and net metering tariff structures.

Our results are also support by two sensitivity analyses. First, we investigated the effect of changing the benefits of solar panel installations for the distribution grid, finding that these costs significantly impact the quantity of the results. More specifically, all tariffs show higher efficiency loss when these costs reductions are lower (i.e. households are given fewer credits for this). However, the differences between tariffs remains prevalent irrespective of this attribute's value, with the flat-rate tariff showing the lowest efficiency losses and the net metering without accumulation showing the highest efficiency losses. Second, we considered the sensitivity of results to the fixed and variable costs of DG installation. We find that increases in variable costs invariably increases efficiency loss. However, increases in fixed costs may decrease efficiency loss (for the flat-rate and net metering with weekly or yearly accumulation) or not have a clear impact on it (for other tariffs). Once again, comparing the various tariffs shows that the differences between tariffs are not impacted by these two variables.

A few limitations exist within our analysis. First, and foremost, our numerical results depend on the region of our dataset and assumptions. On the economic side, solar panel costs, market prices, grid operation costs, and environmental benefits are strongly region-dependent. On the power systems side, solar panel generation and household consumption profiles are strongly geography-dependent. Hence, our results can be expected to best be applicable to locations similar to Austin, TX, USA, in economic and geographical characteristics. Particularly the second value component, i.e. the effects of DG on network costs, can vary significantly per region (e.g. see Picciariello et al. (2015b)). Our sensitivity analysis, however, hints that these results may be applicable to a wider range of regions that may diverge from Austin in economic matters.

Another limitation of our study is our use of costs data from 2016 and earlier. This was primarily due to data availability, and results may be different for a more recent dataset. Solar panel costs have steadily decreased per year (Fu, Feldman, and Margolis, 2018), and thus different results may be expected should this analysis be replicated with more recent data.

Chapter 6

Conclusion

As climate change and pollution concerns continue to push a switch from fossil fuel-based to renewables-based electricity generation, more and more D-RES is installed in local grids. The incentive schemes designed to promote these installations create issues for the economic system underlying electricity trade. Specifically, the prior assumptions held by retailers and policymakers for households and other consumers may no longer hold. Hence, many of the pricing mechanisms may no longer be as adequate as they were in earlier times. As more regions begin a rapid growth phase of D-RES, debates regarding suitable tariff design intensify and engage the electricity sector.

Thus, what are the distributional (equity) and economic efficiency consequences of tariff designs in the renewable energy era? The prior chapters attempt to answer this research question with nuance and depth. In summary, this thesis reports that there are already high inequities in place in traditional tariffs (e.g. increasing-block and flat-rate pricing). Similar is the case for economic inefficiencies. As D-RES continues to grow, these inequities and inefficiencies will continue to worsen and become particularly extreme between different households groups (namely consumers and prosumers). Settings with high demand elasticity will find even harsher amounts of inequity and inefficiency. A clear solution to this is a) measuring electricity generation more precisely, and b) using these more precise measurements for tariff designs that better match revenue with costs. These tariff designs (e.g. demand charges and real-time pricing) show far lower rates of cross-subsidy and inefficiency, allowing for a more equitable and more efficient system of residential electricity trade.

The results of this thesis also present multiple insights and policy implications. These are:

- The study of equity in electricity tariffs has rapidly expanded in the prior years. As more and more D-RES is installed, two effects drive an increase in academic attention to this research topic.s First, the increasing attention given to D-RES as a clean and affordable alternative to fossil fuel-based electricity generation piques further interest in understanding its social effects. Second, with more D-RES uptake, more and more data becomes available for gleaning the equity effects of various D-RES policies. Quantifications of equity effects continue to increase, although comparisons of tariffs between regions are hindered by unwelcome diversity in methods. The main insight for policymakers and businesses is to be mindful of these divergences when drawing conclusions from research (detailed in Chapter 2).

- An important question regarding metering infrastructure in a future high-D-RES world is whether electricity generation from D-RES should be metered separately from the household's consumption. The alternative is to meter the two together at the grid connection, as net demand. Chapters 3 and 5 have elaborated on this question, and results show that both for equity and economic efficiency, the differences are small. This result is comparative; namely, we find that the intricacies of tariff design, e.g. whether network capacity costs are separately charged or whether D-RES generation is allowed to be self-consumed over a long time period, have a far larger influence on the equity and efficiency of the tariff scheme.

  The value of AMI (smart meters) is also often questioned. Considering their infrastructure costs, is it valuable for equity and efficiency concerns to use smart meters in a high D-RES grid? The answer to this question contrasts with that of the prior question; namely, smart meters are highly effective at improving outcomes for equity and economic efficiency in high D-RES grids. The primary caveat is that these benefits depend on use of suitable tariff designs that reflect the temporal changes in electricity's marginal price, and can suitably bill the measured use of network capacity.

  Together with the prior conclusion, we can develop an important policy implication for metering infrastructure and tariffing. Insofar as equity and efficiency are considered, the use of AMI and the correct design of tariffs trumps concerns regarding whether to install a separate meter for new D-RES installations. It is more essential to install a smart meter at the house (and use its informational advantages for pricing) than to install an extra (legacy) meter at the D-RES connection. In addition, the informational value of using smart meters is very high. Economics theory predicts that pricing the same good in an ambiguous manner leads to poor decisions by economic actors. Electricity trade proves no exception to this rule, and we witness high efficiency losses when household return on D-RES is priced inaccurately (Chapter 5). Thus, AMI must play an important role alongside the growth of D-RES in coming years.

- The increasing rate of D-RES leads to questions regarding the transition from a low D-RES to a high D-RES grid. This thesis also investigated the effects of D-RES increases in a residential grid on a tariff's economic outcomes. Results show that D-RES increases are very influential on the equity and economic efficiency of more traditional tariffs (e.g. flat-rate pricing, increasing-block pricing). However, the economics of novel tariff designs (e.g. real-time pricing, demand charges) are impervious to D-RES; as D-RES expands, these tariffs show similar fairness and efficiency (details in Chapter 4). A notable pre-requisite for using such tariffs is the implementation of smart meters. Hence, policy-makers must ensure that next to installations of smart meters, tariffs are installed which make use of the high-resolution information flows of these meters.

- Two trends are expected to drastically increase economic efficiency losses in retail electricity consumption in the coming years: increase in D-RES uptake and higher demand elasticity. Nonetheless, these values remain limited; in the worst-case scenario, one could expect losses equal to about 25% of costs (see calculations for Flat tariff under high elasticity in Section 4.7). Hence, the consumption side of efficiency losses is expected to remain comparatively small.

- For the D-RES generation side of efficiency losses, potentially very high losses can be expected (see calculations in Chapter 5). When the value of D-RES to the grid is misplaced, households can be expected to create some additional efficiency loss due to mis-sizing their D-RES installations. We find that these efficiency losses are very high for some implementations of net purchase and sale pricing. These efficiency losses are also inequal between households. Hence, policy decisions regarding how to credit D-RES can be highly influential in its welfare effects. Moreover, the focus of policy decisions should be on the efficiency losses of D-RES installations (i.e. for electricity generation), rather than on the effect of D-RES installations on existing efficiency losses in electricity consumption.

- Energy communities may create new means of electricity provision, by aggregating consumption for trade with a retailer, gathering financing for co-owned generation assets, and/or by facilitating trade within the community. Similar problems for equity and economic efficiency persist within single communities under legacy tariff designs. However, these problems may be of less importance here, as households in such communities often have homogeneous characteristics such as income and size. Likewise, the homogeneity of characteristics and electricity usage diminishes concerns due to D-RES installations. Nonetheless, large differences will exist between households who choose to install and those who do not install D-RES. As the installation of D-RES cannot be economically separated from electricity consumption, energy community administrators and managers must ensure that D-RES installations are conducted in a manner that maintains or improves the equity and efficiency existing in the community. As with other forms of electricity provision, this is best ensured via installing AMI and using its granular information for novel and more precise tariff designs.

6.1 Limitations and Future Research

Each chapter reviews some limitations of each study in its conclusions section. There are some common limitations to the quantitative results, which are listed below:

1. The quantification of equity and economic efficiency of electricity tariffs is strongly region-dependent. Consumption of households, D-RES generation, electricity marginal prices, grid maintenance and investment costs, clean energy subsidy policies, and demand and generation elasticity are some of the factors that vary between regions and strongly impact the economics of electricity trade. We have guided our study design to be conducive to application to many regions; however, our numerical results are informed by data from Austin, TX, USA. Thus, many of the insights gleaned from the quantitative results are primarily applicable to the city of Austin and other regions similar to Austin in the aforementioned factors. Nonetheless, given data availability, the

methods described here can be re-applied to other regions, possibly providing insights directly usable in that setting.

Similar to location, time also impacts the quantitative results of this study. We obtained the most suitable datasets for the year of 2016 in our location of choice. Between years, multiple trends may impact the electricity trade costs and tariff revenue, thus causing differences in calculated equity and economic efficiency metrics. These trends include multi-year weather fluctuations, developments upstream in the wholesale electricity markets, changes in transmission system grid topography, and change in household electricity consumption profiles (e.g. from electric vehicle use). Given the complex and extensive impact of these factors on the quantifications, it is difficult to extrapolate accurately from this thesis's results to future scenarios. However, it is expected that minor changes for future scenarios would not greatly alter the qualitative results.

2. We chose tariff and policy designs based on how commonly they were used or debated for use in electricity grids around the world. These included feed-in tariffs, real-time (dynamic) pricing, time-of-use pricing, net metering (or net purchase and sale), self-consumption, and demand charges. Thus, our analysis was limited to the tariff set described in each chapter. The design of tariffs and policies for electricity pricing under high D-RES is very expansive, and other tariffs may find interest in the future.

3. The quantitative results of this dissertation assume no effect on other parts of the electricity system from the use of D-RES. However, this is generally not the case in the real world. For example, it is well-known that D-RES significantly impacts wholesale electricity markets (Winter and Schlesewsky, 2019). These markets are constantly undergoing change due to the impact of increasing RES, similar to retail markets. Hence, the evolution of these markets can impact the effect of D-RES on these markets, and their likewise effect on the economics of the retail market. However, this evolution is influenced by other policies and designs, which are outside the scope of this study. Thus, we have assumed these parts of the electricity system are exogenous, insofar as they input data used in this analysis.

The studies of this thesis lead to multiple possible new directions for future research. These new directions include the following:

1. The transition from one tariff to another has been a subject of prior study (Castaneda et al., 2017; Kubli, 2018; Villena et al., 2021b). However, few papers have investigated how tariff changes may impact equity or economic efficiency, while a transition to high D-RES usage is underway. Such studies of transition management within this area is a potent area for future research.

2. Geography is a strong limiter for extrapolating the numerical results of this thesis. Much of the analysis in this thesis must be repeated for other regions, especially for those different from Austin, TX, USA, in the manners mentioned in the limitations list. It is particularly worth studying how such results would compare for a high-D-RES region with differing weather patterns (e.g. lower solar irradiation, Germany) and with differing electricity uses (e.g. lower use of air conditioning, European countries, or higher EV use, Norway).

3. The methods used in this thesis can be readily applied to multiple potential new tariff designs. Tariffs can differ in many different dimensions, thus leading to many options possible in different regional contexts. Other tariffs most applicable or interesting for a region can be studied for equity and economic efficiency concerns.

4. In future work, multiple core assumptions to the analysis can be relaxed. One core assumption was that the increasing use of D-RES does not impact other parts of the electricity system. Future research can study equity and economic efficiency of tariffs while electricity market prices are decreased (Winter and Schlesewsky, 2019). The impact of these price changes on equity and efficiency is not expected to be trivial.

5. In this thesis, we used a simple constant rate of elasticity for demand. However, recent evidence suggest that demand elasticity for electricity is more complex, and a model with such complexity may find differing results for the economic consequences of electricity tariffs in grids with high penetration of D-RES (Burke and Abayasekara, 2018; Ito, 2014).

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Summary

The first renewable energy era saw biomass (wood), wind energy (windmills), and hydropower as energy resources. Following the industrial revolution, the pollution and climate change effects of fossil fuel-based energy use has fostered interest in cleaner alternatives. One such alternative in the electricity grid, renewable energy sources, have also significantly reduced in price during the past years. Consequently, many stakeholders of electricity systems seek to replace fossil fuel-based electricity generation with generation from renewable sources, paving the way to a second renewable energy era.

Some renewable energy sources can be installed in smaller scales, potentially in residential settings. Policymakers and retailers thus promote renewable energy uptake by households in many regions around the world. Many promotions happen within retail pricing, for example by granting advantageous prices for electricity generated from renewable sources. These incentives have led to rapid growth of renewable resources in many regions of the world, including Germany, the US state of California, and Australia.

In electricity retail, multiple principles govern the economic relationship between retailers and customers. Two important principles represent economic efficiency and equity. Achieving both principles within a residential grid is commonly distorted by the increase of distributed renewable energy sources (D-RES). As this trend continues in many regions of the world, we can only expect such distortions to grow.

This thesis focuses on this matter and discusses, in quantitative terms, the consequences of (mis-) pricing electricity in this second renewable energy era. The thesis's contents begin in Chapter 1, the introduction. Here, the thesis presents some background for energy and electricity systems and its supporting economic system. On this basis, the thesis then details the motivation for the studies. The chapter ends

with a short overview of each chapter's study and co-author contributions for each chapter.

Chapter 2 reviews past research on equity in electricity tariff designs. After sieving over 400 articles from a Web of Science search, the chapter reviews each and find a set that focuses on equity for electricity tariffs for renewable energy. Three general sub-fields exist: a) normative discussions of equity, b) comparisons of equity for various policies, and c) transition management studies for equity. For each sub-field, the chapter describes current research gaps. The chapter also combines the methodological issues encountered in these papers and provide some recommendations for studies that seek to quantify equity. The chapter also contains some policy discussions based on the literature review.

In Chapter 3, the thesis investigates the cross-subsidies due to choices in metering infrastructure in a high D-RES grid. Two particular choices stand out for retailers who must credit D-RES generation in a modern electricity grid: (a) whether to meter household consumption and D-RES generation separately or together, and (b) whether advanced metering infrastructure should be used. The chapter uses high-resolution energy data from 2016 from Austin, TX, USA, to study the impact of these choices for equity in a household population. Results show that traditional tariffs using legacy metering create median annual cross-subsidy values from 38% to 100% of real costs. However, AMI can reduce these values by 2 to 3 orders of magnitude when a tariff that utilizes AMI's options is used. In contrast, metering generation separately from consumption appears to have little impact on cross-subsidies. Assuming even high values of demand elasticity does not alter these comparative conclusions. The thesis also discusses the policy implications of these results, particularly for regions undergoing rapid expansion of D-RES generation, especially solar panels.

In Chapter 4, the thesis investigates the economic consequences of D-RES growth in a residential grid. The chapter consider a subset of the tariffs used in Chapter 3 and calculate the changes in equity (as changes in consumer surplus) and economic efficiency (as dead-weight loss) for these tariffs under growing rates of D-RES. The chapter also uses a similar dataset of 144 households in Austin, TX, USA, and calculate per-household rates of cross-subsidy and dead-weight loss. Results show that traditional tariff designs allow for large wealth transfers, often to D-RES owners from non-owners, who may be paying on the median 22% more than their fair share. For economic efficiency, traditional tariffs again perform poorly, with dead-weight loss reaching a maximum of 8.6% of total electricity expenditure in a high D-RES setting. Newer time-based (time-of-use, or TOU, and real-time dynamic pricing) tariffs show few signs of cross-subsidization and better economic efficiency. Potential demand elasticity does not significantly alter conclusions for fairness, but significantly impacts those for economic efficiency. The chapter also discusses what our results imply for policy-makers intent on balancing efficiency and equity in a changing grid.

Chapter 5 complements the economic efficiency results of Chapter 4 with a study on the efficiency losses due to mis-pricing D-RES generation. Here, the thesis finds hypothetical installation sizes for multiple commonly-used tariffs for crediting D-RES electricity generation. The chapter compares these values to a hypothetical scenario where D-RES electricity generation was paid at exactly the long-run and short-run (marginal) value it provides for the retailer. These comparisons are used to find losses due to the over- or under-installation of D-RES generation. Results show that a flat-rate tariff shows low levels of loss that are mainly due to its not matching the temporal fluctuations of wholesale market prices. However, net metering tariffs show very high loss from their disadvantageous pricing for grid electricity injection, causing many households to avoid D-RES altogether. These losses are mostly mitigated by accumulation, i.e. netting consumption and generation over a time span, which drastically reduces losses for all households. The highest setting, i.e. accumulating generation over a year, results in losses comparable to that of the flat tariff. The chapter also reports on the results' sensitivity to changes in D-RES installation costs and to the value provided to the grid for offsetting capacity costs (e.g. by deferring grid investments). These results inform retailers and policy-makers interested in pricing D-RES such that perverse incentives for households that can install D-RES are minimized.

The conclusion (Chapter 6) collects the insights from prior chapters. These insights aim to update stakeholders in the energy sector for the new renewable energy era. This chapter also lists limitations common to prior chapters and provides some directions for future research in electricity pricing.

Nederlandse Samenvatting (Summary in Dutch)

In het eerste tijdperk van hernieuwbare energie werden biomassa (hout), windenergie (windmolens) en waterkracht als energiebronnen ingezet. Toen na de industriële revolutie het gebruik van fossiele brandstoffen bleek te leiden tot milieuverontreiniging en klimaatverandering, ontstond er belangstelling voor schonere alternatieven. Het alternatief van hernieuwbare energiebronnen voor het elektriciteitsnet is de afgelopen jaren ook aanzienlijk in prijs gedaald. Veel belanghebbenden in het elektriciteitssysteem streven dan ook naar de vervanging van fossiele brandstoffen door hernieuwbare elektriciteitsbronnen, waarmee de weg wordt vrijgemaakt voor een tweede tijdperk van hernieuwbare energie.

Sommige hernieuwbare energiebronnen kunnen op kleinere schaal worden geïnstalleerd, zoals in woonomgevingen. Beleidsmakers en energieleveranciers bevorderen daarmee het gebruik van hernieuwbare energie door huishoudens in vele regio's over de hele wereld. Veel stimulansen grijpen aan op de prijzen voor kleinverbruikers, bijvoorbeeld door gunstige prijzen te rekenen voor elektriciteit opgewekt uit hernieuwbare bronnen. Dergelijke stimuleringsmaatregelen hebben geleid tot een snelle groei van hernieuwbare energiebronnen in verschillende regio's in de wereld, zoals Duitsland, de Amerikaanse staat Californië en Australië.

In de elektriciteitsmarkt voor kleinverbruikers wordt de economische relatie tussen energiebedrijven en hun afnemers beheerst door verschillende beginselen, met economische efficiëntie en rechtvaardigheid als twee van de belangrijkste. Het voldoen aan deze beide beginselen binnen een elektriciteitsnet voor huishoudens wordt echter bemoeilijkt door de toename van gedistribueerde hernieuwbare energiebronnen (Distributed Renewable Energy Sources, oftewel D-RES). Naarmate deze trend in vele regio's doorzet, kunnen we alleen maar verwachten dat dit probleem zal toenemen.

Dit proefschrift focust op deze materie en bespreekt, in kwantitatieve termen, de gevolgen van het (verkeerd) beprijzen van elektriciteit in dit tweede tijdperk van hernieuwbare energie. Het proefschrift begint met de inleiding in hoofdstuk 1. Hierin is geschetst de achtergrond waartegen energie- en elektriciteitssystemen en het ondersteunende economische systeem kunnen worden beschouwd. Op basis hiervan motiveerd dit hoofdstuk welke deelstudies zijn uitgevoerd. Het hoofdstuk eindigt met een kort overzicht van de deelstudies en bijdragen van mede-auteurs in de volgende hoofdstukken.

Hoofdstuk 2 ziet eerder onderzoek naar rechtvaardigheid in de opbouw van elektriciteitstarieven voor. Na met een zoekactie in Web of Science meer dan 400 artikelen te hebben gevonden, dit hoofdstuk heeft ze allemaal doorgenomen en die artikelen behoudt die zich specifiek richten op rechtvaardigheid in elektriciteitstarieven voor hernieuwbare energie. Dit hoofdstuk heeft daarin drie deelgebieden geïdentificeerd: a) normatieve besprekingen van rechtvaardigheid, b) vergelijkingen van de invulling van het begrip binnen verschillende beleidsgebieden, c) studies naar rechtvaardigheid binnen transitiemanagement. Voor elk deelgebied beschrijft dit hoofdstuk de huidige leemten in het onderzoek. Het hoofdstuk combineert ook de methodologische kwesties die in de betreffende artikelen naar voren komen en geeft enkele aanbevelingen voor studies die rechtvaardigheid willen kwantificeren. Het hoofdstuk bevat tevens enige besprekingen van beleidsaspecten op basis van de literatuurstudie.

In hoofdstuk 3 onderzoekt dit proefschrift de kruissubsidies die het gevolg zijn van keuzes inzake meetinfrastructuur in een netwerk met veel D-RES. Twee specifieke keuzes springen in het oog voor energiebedrijven die de met D-RES opgewekte energie moeten crediteren in een modern elektriciteitsnet: a) de vraag of het huishoudelijk verbruik en de D-RES-productie afzonderlijk of samen moeten worden gemeten, en b) de vraag of er een geavanceerde meetinfrastructuur (AMI) moeten worden gebruikt. Dit hoofdstuk gebruikt energiedata met hoge resolutie uit 2016 uit de Amerikaanse stad Austin (Texas) om de impact van deze keuzes op rechtvaardigheid voor een groep huishoudens te bestuderen. Resultaten laten zien dat traditionele tarifering met traditionele meters op jaarbasis een kruissubsidie creëert die 38% tot 100% van de reële kosten bedraagt (mediaanwaarde). Deze waarden kunnen echter met 2 tot 3 ordes van grootte worden gereduceerd wanneer een tariefstelling wordt gehanteerd die gebruikmaakt van de mogelijkheden die AMI's bieden. aarentegen lijkt het apart meten van energieopwekking en -verbruik weinig effect te hebben op kruissubsidies. Zelfs wanneer wordt uitgegaan van hoge waarden voor de vraagelasticiteit verandert dit niet. Dit proefschrift bespreekt ook de beleidsimplicaties van deze resultaten, met name voor regio's waar de opwekking van elektriciteit uit gedistribueerde hernieuwbare energiebronnen, vooral zonnepanelen, snel toeneemt.

In hoofdstuk 4 onderzoekt dit proefschrift de economische gevolgen van de groei van D-RES in een elektriciteitsnet voor huishoudens. Het hoofdstuk beschouwt een subset van de in hoofdstuk 3 gebruikte tarieven en berekenen de veranderingen in rechtvaardigheid (als veranderingen in het consumentensurplus) en de economische efficiëntie (als welvaartsverlies, deadweight loss) voor deze tarieven bij toenemende D-RES-productie. Dit hoofdstuk heeft ook een soortgelijke dataset van 144 huishoudens in Austin gebruikt en heeft per huishouden de kruissubsidie en het welvaartsverlies berekend. Uit resultaten blijkt dat bij traditionele tariefstellingen vaak een grote overdracht van welvaart optreedt, veelal van mensen zonder naar mensen met D-RES, waarbij de eerstgenoemden dan gemiddeld (mediaanwaarde) 22% meer betalen dan billijk kan worden geacht. Ook wat economische efficiëntie betreft doen traditionele tariefstellingen het slecht, met een welvaartsverlies tot wel 8,6% van de totale elektriciteitsuitgaven in een scenario met veel D-RES. Nieuwere op tijd gebaseerde tarieven (time-of-use (TOU) en realtime dynamische prijsstellingen) vertonen weinig tekenen van kruissubsidiëring en een betere economische efficiëntie. Potentiële vraagelasticiteit verandert de conclusies voor billijkheid niet significant, maar heeft wel een significante invloed op die voor economische efficiëntie. De hoofdstuk bespreekt ook wat de resultaten impliceren voor beleidsmakers die een evenwicht willen vinden tussen efficiëntie en rechtvaardigheid in een veranderend elektriciteitsnet.

Hoofdstuk 5 vult de bevindingen inzake economische efficiëntie uit hoofdstuk 4 aan met een onderzoek naar de efficiëntieverliezen ten gevolge van verkeerde prijsstellingen voor D-RES-productie. Hier vindt het proefschrift hypothetische installatiegroottes voor verschillende veelgebruikte tarieven voor de creditering van D-RES-elektriciteitsproductie. Het hoofdstuk vergelijkt deze waarden met een hypothetisch scenario waarin D-RES-elektriciteitsproductie wordt vergoed tegen exact de (marginale) waarde op lange en korte termijn die zij voor het energiebedrijf oplevert. Deze vergelijkingen worden gebruikt om verliezen op te sporen die te wijten zijn aan te veel dan wel te weinig geïnstalleerde D-RES. Uit deze resultaten blijkt dat een uniform tarief een laag verlies te zien geeft, dat hoofdzakelijk te wijten is aan het feit dat het niet is afgestemd op de kortstondige schommelingen in de groothandelsmarktprijzen. Bij salderingstarieven blijken echter zeer hoge verliezen te ontstaan als gevolg van de ongunstige prijsstelling voor levering van elektriciteit aan het net, waardoor veel huishoudens D-RES helemaal links laten liggen. Deze verliezen worden grotendeels gecompenseerd door accumulatie, d.w.z. het netto met elkaar verrekenen van verbruikte en opgewekte energie over een bepaalde tijdspanne, waardoor de verliezen voor alle huishoudens drastisch worden beperkt. De hoogste instelling (accumulatie van opwekking gedurende een jaar) resulteert in verliezen die vergelijkbaar zijn met die bij het uniforme tarief. Dit hoofdstuk geeft ook inzicht in de gevoeligheid van deze resultaten voor veranderingen in de installatiekosten van D-RES en voor de waarde die aan het net wordt verleend voor het verlagen van capaciteitskosten (bv. door uitstel van investeringen in het net). Deze resultaten zijn informatief voor energiebedrijven en beleidsmakers die willen weten wat voor prijsstelling voor D-RES leidt tot een minimum aan perverse prikkels voor huishoudens die D-RES kunnen installeren.

In de conclusie (hoofdstuk 6) worden de inzichten uit de voorgaande hoofdstukken samengebracht. Deze inzichten zijn bedoeld om de belanghebbenden ervan op de hoogte te brengen en voor te bereiden op het nieuwe tijdperk van hernieuwbare energie. Dit hoofdstuk wordt enkele algemene beperkingen van dit proefschrift op een rijtje gezet en geeft enkele aanwijzingen voor toekomstig onderzoek naar de prijsstelling van elektriciteit.

About the Author

Mohammad Ansarin studies economics in the energy system. His research spans many categories, including equity and efficiency in retail electricity pricing, agent-based modeling of electricity systems, matching of solar generation and electric vehicle charging, competitive retail electricity market dynamics, energy storage systems, and sustainable urban heating systems. His research is inspired by practice, and he places great emphasis on applying empirical reasoning in real-world settings. His research has been presented and published at numerous conferences, seminars, and journals. He is currently a post-doctoral researcher at the Rotterdam School of Management, Erasmus University (Netherlands).

Mohammad has taught classes across a diverse set of courses and programs, supervised masters theses, presented and lectured for different audiences, and co-wrote business case studies. He has also represented PhD candidates in RSM's Faculty Council for 4 years and assumed vice-chair duties for 2 years. Since 2013, he has served as a reviewer for various academic conferences and journals.

Mohammad previously completed a BSc degree in mechanical engineering from Sharif University of Technology (Tehran, Iran) and an MSc degree in biomedical sciences and engineering from Koc University (Istanbul, Turkey).

Author's Portfolio

Research

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- Ulrich Fretzen, Mohammad Ansarin, and Tobias Brandt (Jan. 15, 2021). "Temporal City-Scale Matching of Solar Photovoltaic Generation and Electric Vehicle Charging". In: *Applied Energy* 282, p. 116160. ISSN: 0306-2619. DOI: `10.1016/j.apenergy.2020.116160`. URL: `http://www.sciencedirect.com/science/article/pii/S0306261920315658` (visited on 11/19/2020)
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Teaching

- Lecturer for Designing Business Applications course, part of Rotterdam School of Management's Business Information Management MSc program (BIM)
  2017 - 2020 (4 editions)
- Lecturer for Next Generation Business Applications course, part of BIM
  2016 - 2017 (2 editions)
- Teaching assistant for Energy Analytics and Sustainability course, part of Rotterdam School of Management's Masters in Business Administration program
  2015
- Master Thesis supervision for BIM and other MSc programs
  Academic years (AY) 2015 - 2021

Service

- Rotterdam School of Management Faculty Council
  AYs 2017-19: Member
  AYs 2019-21: Vice-chair
- Peer reviewer
  2015 - present: Journal publications include Energy Policy, Utilities Policy, The Energy Journal, Business and Information Systems Engineering, and Energy Efficiency. Conferences include AAMAS, ICIS, HICSS, IEEE ISGT, ECIS, ICAE, and ACM e-Energy.

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