Optimizing the Electricity Bill

Creating a two-part electricity tariffs to induce a targeted level of rooftop solar adoption while meeting utility operating expenses

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Abstract

Renewable energy technologies are a much needed, clean alternative to the conventional fossil fuel electricity power plants of the last century. The market for installing solar panels on rooftops is a highly promising avenue for expanding the use of these technologies, but its profitability depends significantly on the electricity prices offered by electric utilities. Investing in solar panels offset a percentage of the electricity purchased from the utility. This paper models the investment decision of electricity consumers and looks at what the optimal per unit price of electricity should be in order to make building solar panels a profitable decision for a target share of households. The model shows how this optimal rate decreases at lower prices of investing, when the share of utility-purchased electricity offset by the panels increases, and when the target level of solar adoption decreases. Finally, it looks at how this per unit rate impacts the utility's decision to set a fixed monthly charge for electricity in order to recover all of its operating expenses.

JEL Classifications: L94, Q42, Q48

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I. Introduction

Renewable electricity technologies are often presented as stepping-stones towards a cleaner, more sustainable future. Over the last decade, the production costs of wind turbines and solar panels have plummeted, spurring adoption of these "green" technologies to impressive levels and with shares of renewable electricity in national energy portfolios rising steadily. By 2015, global wind and solar electricity made up around 11% of the world's 550 Terawatts of installed generation capacity (IEA, 2014a). In many ways, this progress is a significant achievement of sustainability for economies historically reliant on environmentally destructive electricity industries.

This rapid adoption of renewable energy has not been without its growing pains though. While producing these technologies is now cost competitive even without subsidies, their integration into existing electricity systems has proved remarkably challenging (EIA, 2014). In many ways, this conflict can be summarized as a clash between the future and the past: on one side, groundbreaking technologies of tomorrow against aging electric utilities bogged down by laws and regulation from the last century. Regularly, integrating these renewable technologies causes many negative, unintended consequences. The International Energy Agency (IEA) estimated that a hypothetical system unprepared to integrate variable renewable resources could see prices increase by 40% if shares of these technologies reached the 45% target used in some 2050 long term plans (IEA, 2014c). As a result, the electricity industry has begun to fight back against pro-renewable policies.

Part of the difficulty can be attributed to the variability of renewable energies. Whereas conventional fossil fuel power plants (along with nuclear and hydro power plants) can be expected to run during regular intervals, wind and solar technologies only operate when the weather cooperates. Even more revolutionizing though has been modularity of renewable energy and its potential for decentralization. Solar and wind generation can easily be scaled up or down, giving the technologies an unrivaled installation flexibility. The same solar panels can be used in a large 20 MW solar farm that closely resembles a coal or gas plant in its relationship to the electricity grid, or they can be installed in small capacities on residential rooftops. This characteristic has allowed small, private electricity consumers the ability to purchase their own electricity generational device at a reasonable cost, most commonly in the form of a solar photovoltaic rooftop system (rooftop PV). In essence, this means that private households can have their own mini-power plants.

These two characteristics combined have proved to be a technical nightmare for electric utilities, sometimes resulting in significant cost savings, other times causing enormous revenue losses. This can primarily be attributed to the antiquated operating practices of most electric utilities for both rate setting and dispatching. Consumers also acting as decentralized power generators – but only during certain time periods of cloudless sunny weather – were not included in the operating and financing models that were in large part developed in the 50s and 60s.

Unfortunately, the industry has been slow to change these dated practices, partially because of the significant regulatory barriers still in place, partially because alternative options are still being debated. For most of the world's utilities, recuperating electricity generation costs is still done through a two-part tariff: a fixed monthly, weekly, or daily charge and a variable per kWh charge that is a function of how much electricity is consumed. Given that the cost of generating electricity is itself highly variable one minute to the next, this is understandably not the most accurate method for recovering operating expenses. But without easily implemented alternatives, the two-part tariff remains the most common pricing model in the short term and is the focus of this research. Tensions are exacerbated as government throughout the world, eager to combat the threat of global warming, are setting guidelines for renewable technology adoptions without too much consideration to additional costs incurred by electricity systems.

Much of the work done in recent years to make residential tariffs more suited to PV deployment has centered on creating new, more optimal “time of use” tariffs, which create different variable electricity charges for different times of the day. However, though these tariffs have proved much better at recouping utility operating costs while keeping rates low for consumers, they have primarily done so by creating closer links between rates and wholesale energy prices (Hledik, 2014). For most networks, these tariffs are not yet convenient since they require special “smart meters” for real-time pricing to be possible. For many state-regulated utilities, these new tariffs also require significant policy changes.

I am aiming to propose a tenable balance for utilities to recoup their costs while maintaining a more traditional two-part tariff. In this paper I first present a simple theoretical model where consumers decide whether to install solar panels based on cost considerations, while electric companies are tasked with setting rates to achieve a imposed level of solar adoption, presumably set by a utility commission. After outlying the theoretical model I then use real world data to choose key parameter values, such as the price elasticity of electricity demand and the discount factor, to illustrate the two part tariff scheme that is required to reach the electric company's solar adoption target. The values of some of these key parameters are then varied within reasonable bounds to see how the rate structure is affected.

This paper will include a Literature Review considering other works relating to the topic of electricity rate setting and residential PV deployment (II), a section detailing the Theoretical Framework behind the optimization model (III), a Specification of the model using real world data (IV), analyses of the model's Sensitivity to various variables (V), and a Conclusion discussing the general findings (VI).

II. Literature Review

Both scholars and policy makers have traditionally considered questions surrounding electricity rate setting and renewable power integration separately. Rate setting procedures are designed to apply to broad ranges of consumers on the grid, not just the tiny percentage with installed solar panels. Studies looking at improving the practices and methodologies of electric utilities therefore try to consider system-wide impact price changes. Studies looking at the integration of solar panels into the electricity grid are also limited by the small size of the population and choose instead to take as a given the electricity rates. However, with adoption of decentralized solar generation technologies increasing in the last few years, researchers have finally started to bridge the gap between the two.

The problem of charging traditional electricity rates to non-traditional consumers (i.e. consumers with solar generation installed) has become increasingly apparent in recent years, as both electricity prices and solar panel installations have increased. In studying the interconnection of these events in California markets, Cai, Adlakha, Low, Martini, and Chandy (2013) identified a feedback cycle between rising electricity costs and profitability of solar systems. As electricity rates increase, the consumption offset by self-generated solar production increasingly lowers the electricity bill. The feedback process happens because the utility must continue to maintain and expand the distribution and transmission networks for solar consumers since, due to the variability of solar energy, panel owners still require access to the grid. However, since these consumers are paying less to the utility, it must increase its electricity prices to make up for revenue shortfalls. This further increases the value of solar panels and leads to even greater market adoption.

In California for example, electricity rates are structured in such a way that the fixed network costs (considered demand costs) incurred by the utilities are hidden from consumers and entirely lumped into the per-kWh-consumed variable monthly tariff component. While this has the effect of encouraging energy conservation, it makes it more difficult for utilities to recoup their fixed operating costs in the event of sudden consumption decrease, as is the case for solar consumers. However, making these demand-related fixed costs of system operation more explicit on consumer bills and charging them as fixed monthly rates has the downside of decreasing the value of solar panels. Researchers at the National Renewable Energy Laboratory found that electricity tariffs that include explicit demand charges (i.e. fixed charges) have a significant adverse effect on the economic performance of photovoltaic (PV) systems compared to entirely variable tariffs, which increase the value of solar panels by 13%" (Ong, Campbell, & Clark, 2012; Ong, Denholm, & Doris, 2010). Glassmire, Komor, and Lilienthal (2012) confirm a similar conclusion when looking at the consumption of a large university. They obverse that, due to the variability of production, even a large solar panel installation is not able to consistently lower the load demand of the university to significantly decrease its demand-related bills.

Understanding these problems however requires a more general understanding of how demand charges are set for consumers. In a historical study of electricity pricing strategies, John Neufeld (1987) notes that, ironically, demand charges were developed between 1906 and 1915 as "an instrument of price discrimination designed to reduce the price of electricity for those for whom the self-generation of electricity in isolated plants was an alternative to the purchase of electricity from electric utilities." The practice beat out more cost-effective peak-load and cost of service pricing methods and has remained the norm until only recently. Oren, Smith, and Wilson (1985) explicitly model this practice and conclude that in its most basic application, a demand charge is a profit maximizing tool for a monopolist seller. As they point out though, their study does not take into account a consumer's ability to respond to monopolistic prices by shifting consumption to another time or simply decreasing consumption (Oren et al., 1985, p. 563).

With the introduction of solar panels and their decentralized, variable production, traditional methods of apportioning demand charges have begun to show their age. Utilities have gradually introduced new tariff formats to try to respond more effectively to these shifts in demand patterns, yet even in new rate structures they cling to the archaic demand-charge apportionment practices. Taylor and Schwarz (1990) show how even under time of use pricing rates[1], demand charges included in variable per kWh peak-price components have unexpected consequences on consumer behavior. Their analysis of electricity prices for Duke Energy consumers showed that demand charges rolled into the daily peak prices didn't have the intended effect of reducing a consumer's maximum demand but rather of shifting that maximum demand to another time. The resulting implications of this being that demand charges for solar consumers will most likely compound with solar consumption to have unintended shifts in consumption patterns. Given that the interaction of demand charges and PV consumption have unpredictable effects, this paper will instead look to simply optimizing the split of the demand charge into a variable rate and a fixed rate that are the same for both solar and non-solar consumers.

Having the demand charge be a standalone fixed component of the tariff has been proposed to deal with the issue and is not a novel idea, since it is already commonplace to do so for commercial and industrial consumers. However, implementing it for residential consumers

[1] Rates with charges that vary based on the time of day associated with the cost of generation at that time. They take various forms depending on the utility's intended economic reaction.

could provide an interesting alternative to the current model being employed. Studies have shown how demand charges can increase consumer response to peak pricing by consciously lowering consumption variability (Stokke, Doorman, & Ericson, 2010). In addition, as Hledik (2014) points out, inserting a demand charge to utility bills can avoid intra-consumer class subsidies and benefit lower income households. This could potentially resolve problems of regressive subsidization of solar panels by lower income consumers for higher income ones. However, these studies acknowledge that demand charges could have adverse effect on the profitability of solar panels, as mentioned earlier.

The aim of this study is to find a way to ensure that the utility recovers its full demand cost while continuing to encourage solar growth to a target level. Practices for allocating demand charges are old and not adapted to increasingly deregulated markets with decentralized consumers, but they are difficult to change due to the momentum of decades of legislation and business practices. Given that no ideal alternative to two-part tariffs has yet been feasibly implemented, the hope is to find a short to medium term balance to allow utilities to cover their costs through a two-part tariff that does not hamper solar adoption.

III. Theoretical Framework

Rate setting is often characterized as an art, rather than a science, since designs must invariably offer a tradeoff between ensuring that the utility meets its cost of operation and keeping electricity prices fair and affordable for consumers. The significant variability in operating costs and primary energy prices, along with unpredictable demand, can make it difficult to determine a tariff efficient for all parties. Further complicating the process are the significant levels of administrative and historical ingrained habits that make experimenting with new rate designs difficult.

Rate Structuring

In a simple two-part tariff, the utility first determines its cost of operation over a given time frame (usually a year or two) times a determined rate of return. This is the revenue requirement (RR) it needs to meet. The RR can be broken down into three primary cost types: energy (variable per kWh consumed), service and O&M costs (fixed), and demand (per kW). Once the variable, fixed, and demand costs are determined for each customer or customer class, they are crafted into the electricity tariffs that will be used to recover the utility's operating costs. Traditionally, vertically integrated utilities offer two-part tariffs, which include a fixed weekly or monthly charge and a variable per kWh consumed charge. The fixed portion paid by the consumer can roughly be equated to the fixed costs associated with connecting that consumer to the grid and the variable portion is the energy charge.

The demand charge can be split between the variable and fixed portion in a number of different ways according to the intended goal of the utility and regulator, providing some leeway in setting electricity prices. This is where the "artistic" component of rate setting primarily comes into play. Putting the entirety of the demand charge into the fixed cost component can ensure that the utility recoups its entire cost of operation, but it can also increase a price signal to the consumer that each marginal unit of electricity consumed is cheaper. This would then encourage customers to over-consume. On the other hand, putting the entirety of demand costs into the variable component encourages consumers to lower their demand and relieve stress on the grid. If consumption is decreased too much however, this might mean that there is not enough revenue generated for the utility to recover its operating costs. This creates a tradeoff between high marginal prices that send signals to decrease consumption and high fixed costs that ensure the utility recovers its expenses.

If the utility is at the same time trying to encourage a mandated percentage of its consumers to install PV systems, it must then also factor into the equation how the variable electricity rate impacts the profitability – and therefore desirability – of the solar system. A consumer will only invest in solar PV if the lifetime total value saved from consuming electricity produced by the panel rather than bought from the utility is equal to or greater than the price of installing it. If the variable rate is too high, more people than anticipated will install solar PV. If it is too low, too few will choose to invest in the technology. If the utility is mandated to have a given quantity of its consumers using solar panels, it must find the optimal variable rate that will achieve that goal while still recovering its production costs.

Model Specification

My model will solve for an optimal distribution of operating costs into a variable per kWh charge (r) and a fixed charge (f) in order to encourage a target share of consumers to install solar panels ($\hat{s}$). To simplify the model, the utility's production costs (variable, fixed, and demand) are all lumped together so as to use the Department of Energy's national average cost of producing one kWh of electricity. This means that there is no range boundary for the variable and fixed values since the demand cost is not itemized. I am therefore solving for an optimal two-part tariff rather than an optimal allocation of the demand charge.

To model a population of consumers with preferences for different levels of electricity consumption, we assume that households are uniformly distributed over $a \sim unif(1,2)$.

Consumers with the lowest demand for electricity will have a value $a = 1$ while those with the highest demand will have $a = 2$. We also assume that all consumers are linked to the grid and therefore pay the fixed cost every billing cycle, regardless of electricity consumption.

Demand is modeled as having a constant elasticity, in accordance with Department of Energy findings (Berstein & Griffin, 2006):

$$D_a(r) = \beta a r^{\varepsilon} \tag{1}$$

Where a is the consumer preference, r is the variable rate, ε is the elasticity, and β is a coefficient that scales the range of demand to the average American annual kWh of electricity consumption at today's prices.

Because of limitations with the model, it was impossible to explicitly model electricity produced by the solar PV system. Instead, I assumed that installing a PV system only offset a percentage (λ) of normal electricity demand. This in effect means that the model represents an electricity market in which there is no remuneration for solar electricity not immediately consumed by the consumer, which is not very realistic for the US since utilities generally do have such solar buy-back programs. λ is therefore the percentage of total electricity consumption that comes from electricity produced by the PV system. Demand for consumers with solar panels installed is:

$$\hat{D}_a(r) = (1 - \lambda) D_a(r) \tag{2}$$

The cost of investing in a solar panel system is a function of the number of panels installed and the cost per panel. Panels are rated by kilowatt (kW) of capacity, usually sized at 1 kW.[2] Costs for solar panels are given as \$/kW, so the total investment cost is a fixed sum and I

[2] To obtain the annual quantity of electricity in kWh produced by a PV system, you multiply its kW size by the hours of sunlight in a year, usually around 1000 hours out of 8760.

assume labor costs for installing the solar panels to be included in that variable. Note that investment is exogenous to the model and that consumers are deciding whether to install solar rather than how much solar to install.

$$Investment = panels \cdot cost \tag{3}$$

The lifetime (and payback period) for a solar panel is generally 20 years. Consumers will choose to install solar PV if the cost of installation is less than the savings obtained from consuming at the reduced demand over the system lifetime. This is represented by the following inequality of total electricity costs over 20 years, using a discount factor (δ) at interest rate (i):

$$\sum_{1}^{20} \delta^{20}[D_a(r) \cdot r + f] \geq \sum_{1}^{20} \delta^{20}[\hat{D}_a(r) \cdot r + f] + Investment \tag{4}$$

Solving the above for a^* gives the function of r at which consumers decide to invest in a solar PV array. It is a downward sloping function that indicates that, as r increases, more and more consumers will find it profitable to invest in solar panels. Since $a \sim unif(1,2)$, the target share of consumers the utility needs to encourage to adopt solar panels s is a fraction of that area, with $[1, a^*]$ being the subset of consumers that don't invest and $[a^*, 2]$ being the set s that does. The set of all consumers can be rewritten as:

$$a^* + s = 2 \tag{5}$$

After setting s, we can solve for an optimal r^* from the function $a^* = 2 - s$. This is the variable rate the utility needs to set to encourage enough consumers to switch over to the more profitable use of solar panels. Note that this optimal r^* does not depend on the utility's generation costs but is rather solely a result of trying to encourage a set percentage of solar PV installation. The utility still needs to set the fixed charge to finish recovering its operating costs.

This is done first by finding out how much total electricity in kWh is consumed at that optimal r^*. The total electricity consumed in a year is the sum of all the electricity consumed by consumers without solar panels and with solar panels at that variable rate:

$$totalD = \int_1^{a^*} D_a(r^*)\ da + \int_{a^*}^{2} \hat{D}_a(r^*)\ da \tag{6}$$

To find the total cost of operation, I multiply this total demand for electricity by the average costs of producing one kWh of electricity for US utilities. This number is calculated by dividing the total costs of operation of electric utilities over the total amount of electricity consumed. This product is the revenue requirement (RR) of the utility.

$$RR = prodcost \cdot totalD \tag{7}$$

To find the fixed charge the utility needs to charge to consumers to meet this requirement, we calculate the total income from the variable rate r^* and solve for f:

$$RR = \int_1^{a^*} [D_a(r^*) \cdot r^* + f]\ da + \int_{a^*}^{2} [\hat{D}_a(r^*) \cdot r^* + f]\ da \tag{8}$$

The resulting r and f give us the optimal two-part tariff that ensures this hypothetical US electric utility is able to recover its operating costs while still encouraging a target level of solar PV adoption.

IV. Model Specification and Baseline

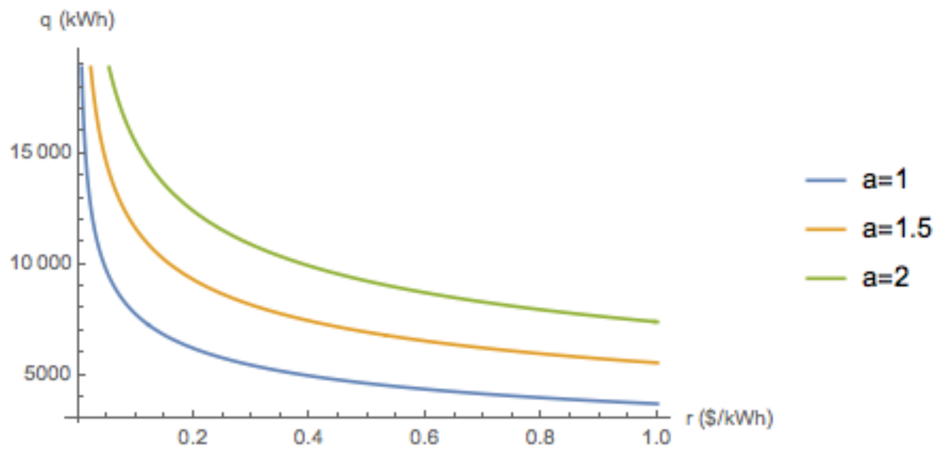
Before testing for the sensitivity of the model, some of the above parameters can be set using real world data. These will set the basic real world constraint of the model and will primarily be drawn from data looking at averages for the US. The most important parameters to specify are demand price elasticity of electricity (ε), the scaling coefficient (β), the percentage of grid electricity demand offset by PV (λ), and the discount rate (δ). The price of solar panels (*cost*), the size of the installed solar panel array (*panel*), the target level of PV adoption (s), and the utility's price of generating electricity (*prodcost*) are all variables that will be tested in a sensitivity analysis.

First, the demand curve is derived using the electricity demand-price elasticity of residential consumers found by the National Renewable Energy Lab in a report to the Department of Energy about the elasticity of energy demand in the US. The report found that the long-run elasticity for residential electricity consumption in the continental US was $\varepsilon = -0.32$ (Berstein & Griffin, 2006). The report specified that, since the elasticity of electricity had begun to be measured in the 1980s, this value has not changed much. This value also indicates a relatively inelastic demand.

The scaling coefficient β is set using the average electricity consumption for an American household in 2014 and the average variable rate of a kWh of electricity charged to residential consumers. The Energy Information Administration reports that average annual consumption for the country was 10,908 kWh, and the average rate was \$0.1212/kWh (EIA, 2013). Solving the demand function for β at $a = 1.5$ (the average consumer) and $r = .1212$ gives the value 3701.47. This gives the following demand curves, illustrated in Figure 1:

$$D_a(r) = \frac{(3701.57a)}{r^{0.32}} \tag{9}$$

Figure 1. Demand curves for low, average and high Consumers



The cost of PV systems has been declining at an incredible rate over the last decade. The 2013 price of a typical PV system in the US was $4.9/Watt, or $4900/kW. This is on the higher end of international prices though: in China, the same system costs $1.5/W, while in Germany, it costs $2.4/W (IEA, 2014e). A common size of system installation is between 1kW and 5kW. The energy company EDF found in a survey of electricity consumers that a 3kW system installed on the rooftop of a house that consumed around 10,000kWh of electricity each year could supply the house with about 30% of its power. I therefore set the baseline number of panels installed at 3kW and the percentage offset (λ) at 30%.[3]

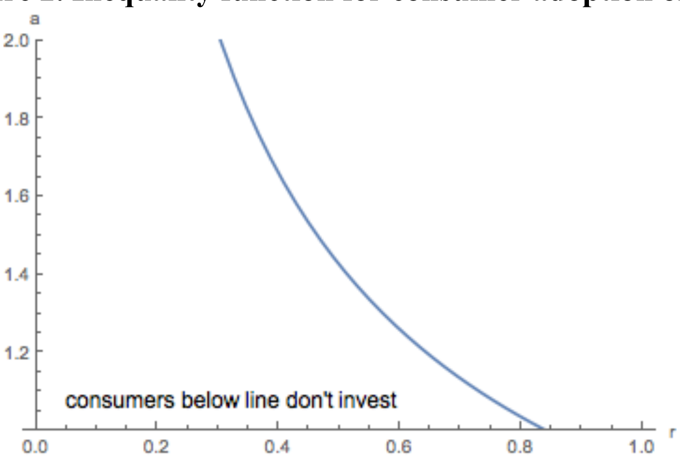
Inputting these values into the demand equations (1) and (2) and calculating the investment to be a one time sum of $\$14700 = 3kW \cdot \$4900 / kW$ allows us to solve the inequality (4) for a. I use a real interest rate of 3% to discount the electricity rates paid to the utility over the 20-year lifetime of the PV system:

$$a^* = \frac{0.8898}{r^{0.68}} \tag{10}$$

[3] This is not a very realistic approach to modeling self-consumption of solar PV electricity, but because of time constraints, I was unable to get the investment function and the offset variable to change dynamically with the consumer's electricity demand.

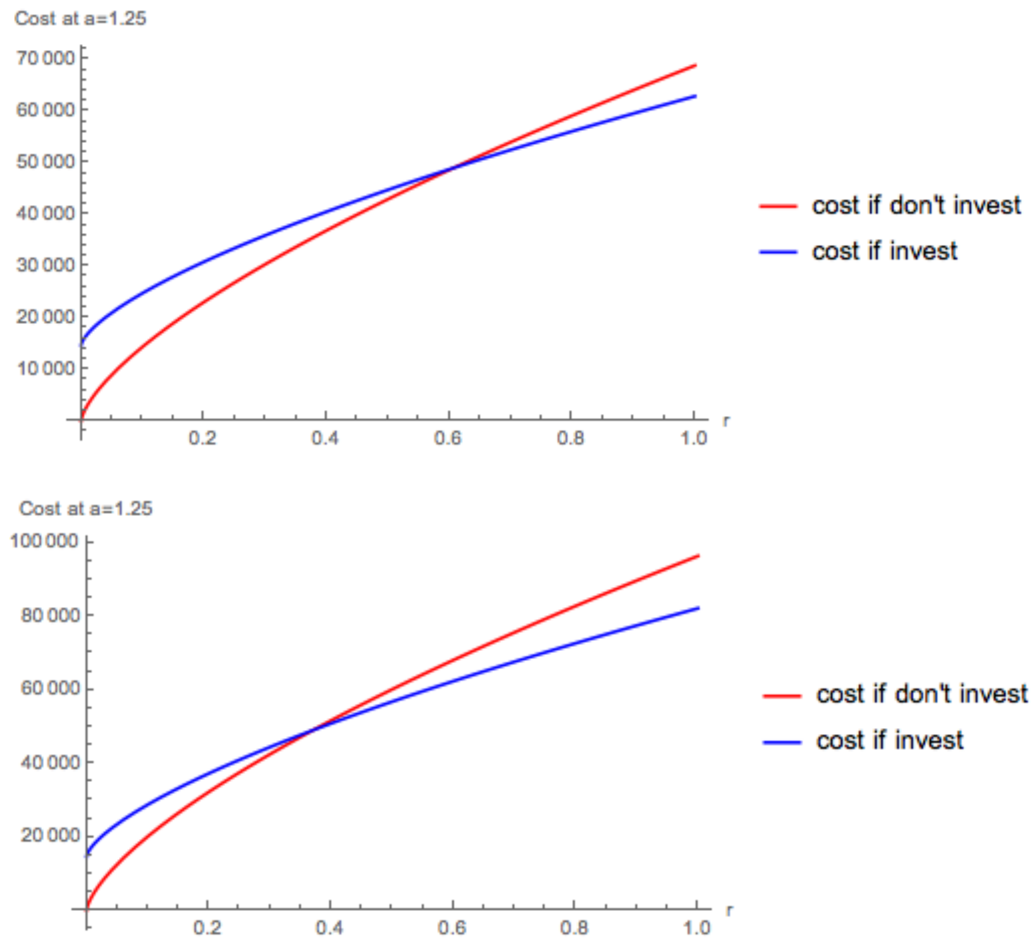
This function is illustrated in Figure 2. Consumers above the curve choose to invest in solar PV. As the value of r increases, an increasingly larger share of the consumers decide to install a system. With these parameters set, the minimum r needed to encourage adoption is \$0.304/kWh while everybody invests at $r \geq$ \$0.842/kWh.

Figure 2. Inequality function for consumer adoption of PV



We can also flip the equation around and look at how each consumer decides to invest by comparing the 20-year payments to the utility with or without a solar system installed. Figure 3 shows the cost curves for consumers with consumption levels at $a = 1.25$ and $a = 1.75$. In both cases, the cost curve with solar panels installed crosses the cost curve without. Those values of r where the lines intersect are used to create Figure 2.

Figure 3. 20-year cost of electricity with and without solar PV



The next step is finding the optimal r^* at which a set percentage of the system consumers will invest in PV. Currently, California leads the country in terms of installed systems, with about 250,000 of its 6.5 million households (about 3.8%) having a PV system ("California Solar Statistics," 2015). Since this model is looking at a hypothetical system based on average American electric systems, I use this as the target value for $\hat{s}$, suggesting that the rest of the country catch up to the Golden State. Plugging this value into equation (5) and solving for r gives the optimal r^* of $0.313/kWh. For comparison, California's current average electricity price is \$0.162/kWh, though a rate twice as large still makes senses since this model does not account for remuneration schemes, which California does have.

At that high of an r^*, most consumers have significantly lowered their electricity consumption. Still, the utility must recover its cost of generating. We find the total consumption of the system by plugging into equation (6). Average cost of production from equation (7) is set at \$0.10/kWh, the average price of generation in the US given its mix of power plants (EIA, 2014). Multiplying that value by the total electric demand gives the utility's revenue requirement. Integrating equation (8) gives us the total revenue obtained from consumers paying the variable rate for each kWh of electricity consumed. The revenue requirement minus the revenue from the variable rate is what the utility much charge to recover its cost.

Interestingly, what happens in this model is that the utility needs to charge a fixed price of \$-140.56/month. This means that the utility is forced to pay consumers a fixed amount each month if it does not want to exceed its revenue requirement. I discuss this negative result in more detail in the conclusion section. The following sensitivity analysis will look demonstrate how a number of the parameters above impact this fixed charge.

V. Sensitivity Analysis

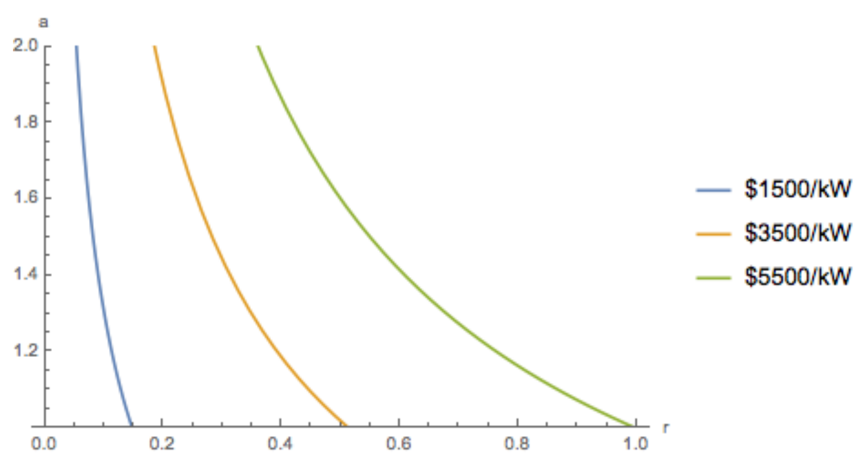
This analysis will modify the cost of solar panels ($cost$), the utility's generating costs ($prodcost$), and the target share of adoption (s). The baseline model relies heavily on average statistics of the US market. In a lot of ways, these are not entirely representative of the conditions utilities and consumers face when making decisions to set rates and install solar PV systems.

Consumers might choose to install larger or smaller systems,[4] the cost per kW can vary, the interest rate might vary, or the utility's cost of generating electricity might increase. Most of those are interconnected however and will produce similar effects based on how they relate to each other. Below are the results of running the model with ranges for the selected independent variables.

System Costs

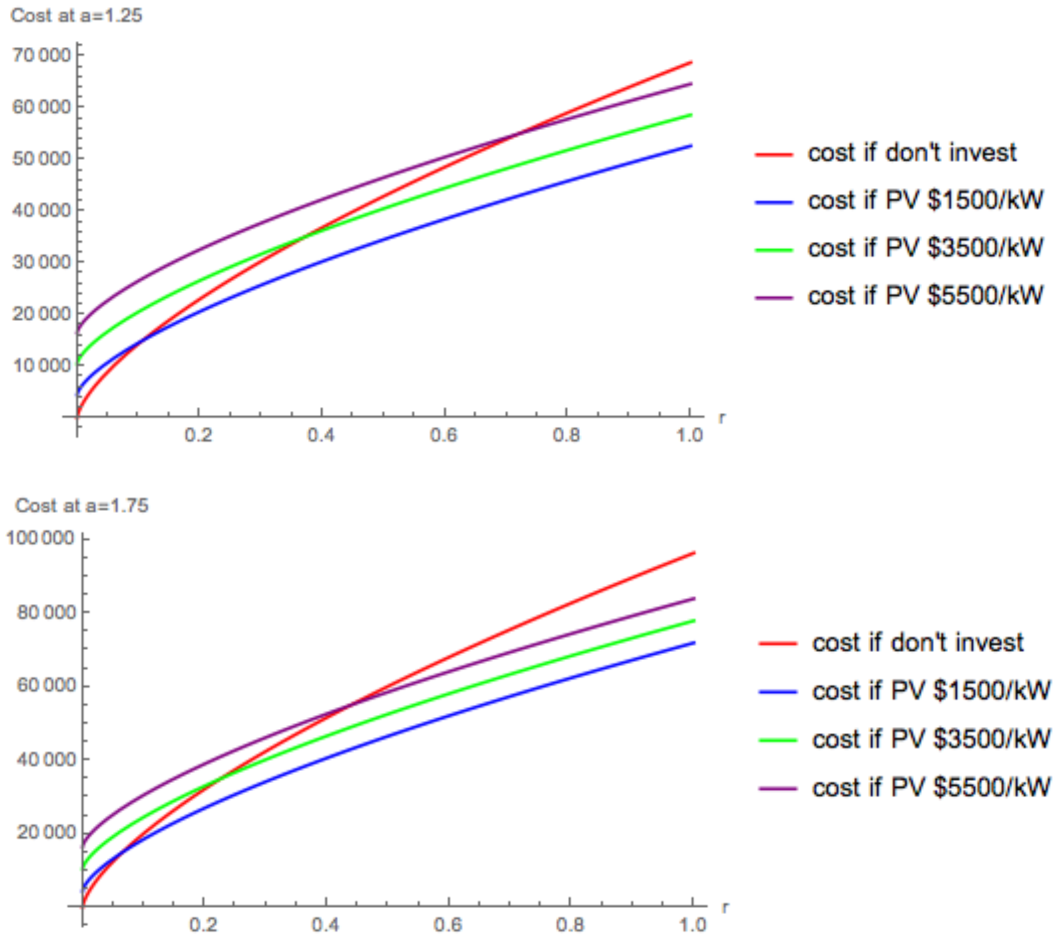
As mentioned earlier, prices for solar panels have generally gone down significantly over the last decade. They also range quite a bit from country to country, with lows of $1.5/W, or $1500/kW in China. Since the cost of investing in solar is the consumer's biggest deciding factor in whether or not to install a system, lower costs should therefore result in adoption at lower r values. Figure 4 shows the investment threshold curves for 3kW systems priced at $1500/kW, $3500/kW, and $5500/kW. Figure 5 shows the investment decisions for the same two $a = 1.25$ and $a = 1.75$ of the baseline.

Figure 4. Inequality function for consumer adoption of PV



[4] I keep the 30% offset electricity constant for practical purposes. The model behaves strangely otherwise. Changing the panel size therefore represents consumers installing systems large enough to allow them to reach that level of solar consumption.

Figure 5. 20-year cost of electricity with and without solar PV



The effect of solar panel prices on the optimal variable rate r is shown in Figure 6. As the price of panels increases, the utility needs to charge a higher and higher variable rate to keep the systems desirable enough. Figure 7 shows that same effect on the eventual monthly fixed cost the utility needs to charge consumers in order to recover its operating costs.

Figure 6. Effect of panel price on optimal variable rate

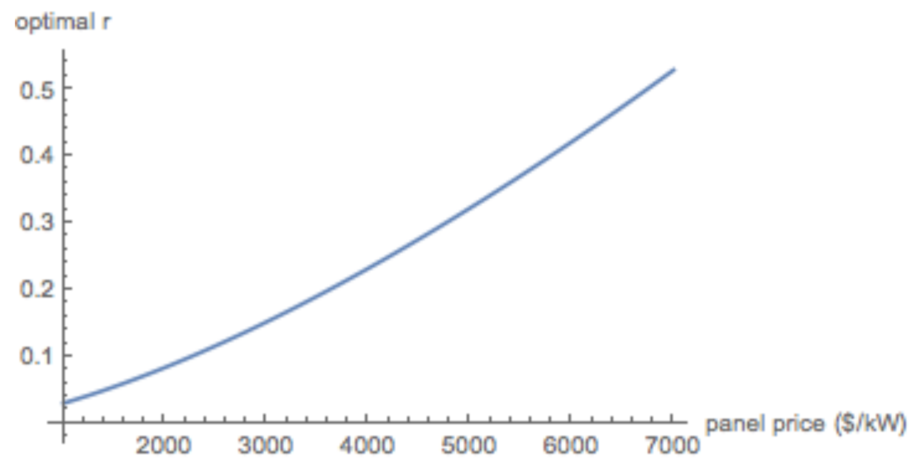
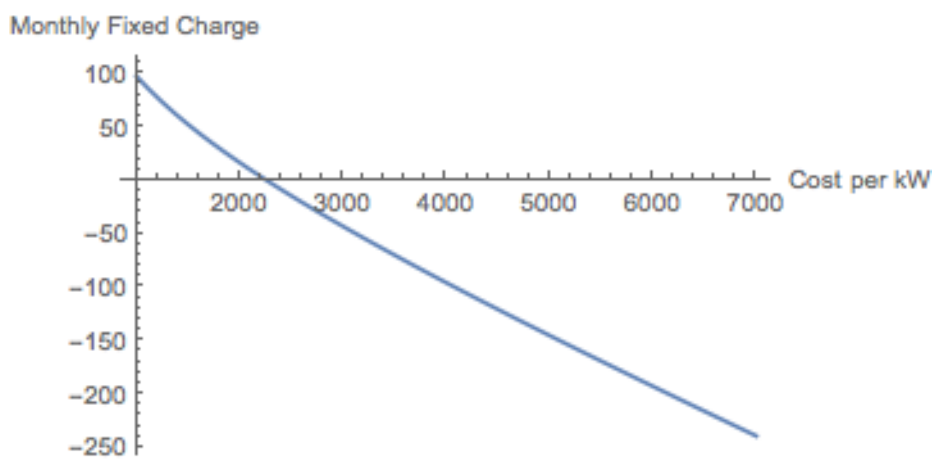


Figure 7. Effect of panel price on fixed charge



Here as well, the fixed charge the utility must set becomes negative fairly quickly. The price of solar panels is clearly a key contributor to the variable rate the utility needs to set. If panel costs in the US were to drop to Chinese levels for example, the utility would have no trouble at all encouraging consumers to invest.

Decreasing the interest rate produces the same effect as decreasing the price of solar PV since it increases the discounted value of total payment to the utility for electricity over the 20-

year lifetime of the system. Likewise, decreasing the needed system size (by improving the technology's efficiency) reduces the investment cost.

Target Adoption Share

The target level of PV adoption (s) is a variable meant to represent the renewable energy targets set by policy makers. Usually, governments will pass a mandate saying that a certain percentage of the country's electricity must come from clean sources. That value translates into a yearly kWh value, which utilities can then use to make investment decisions when building new generating capacity. In this model, the kWh consumption is not considered. Rather, I take the slightly less realistic decision to encourage a percentage of households to adopt. In the baseline, that share was set at 3.8%, the current number of households in California with installed solar. Figure 8 shows how the optimal variable rate would need to change if we changed the targets to be higher or lower than California. Figure 9 shows how the fixed rate must change in response to this optimal variable rate so the utility still recovers its operating costs.

Figure 8. Relationship between adoption target and optimal variable rate

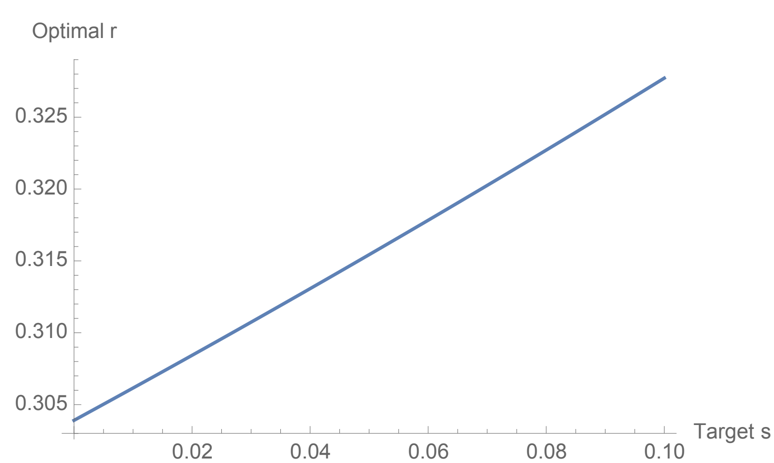
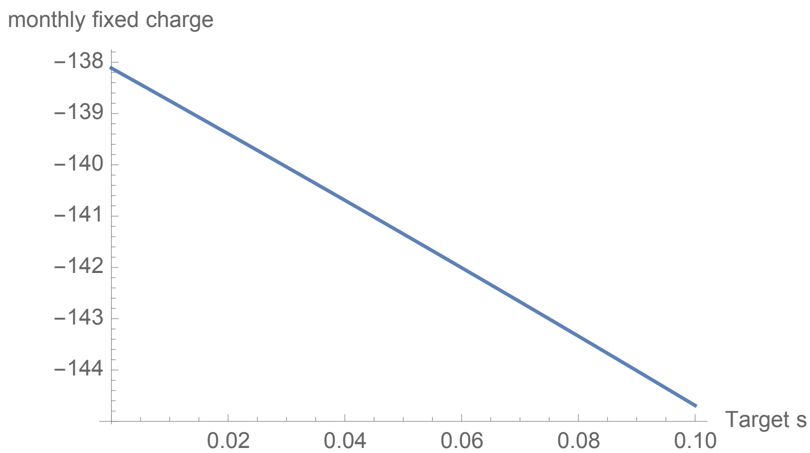


Figure 9. Relationship between adoption target and fixed charge

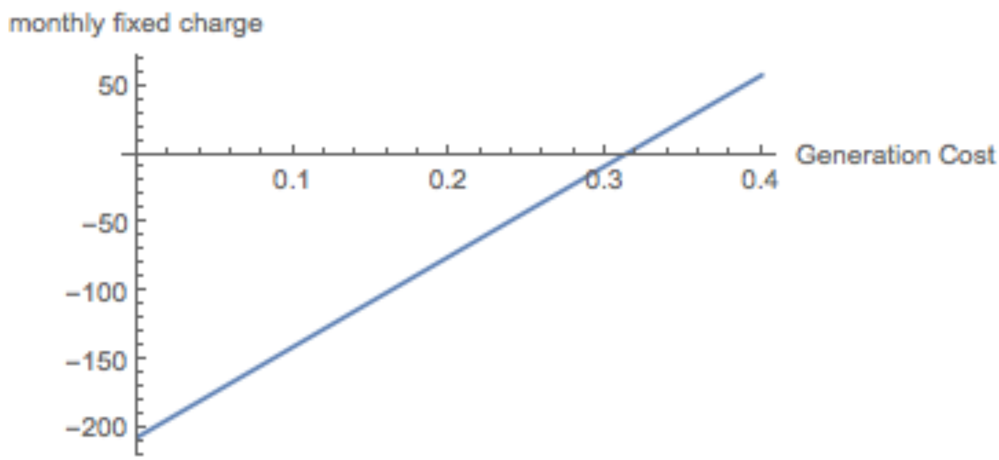


These graph clearly show how increasing the target share of adoption requires the utility to set the variable rate higher and higher to make solar PV profitable for more consumers. However, the interesting aspect to note is that the rate does not increase that rapidly as the target is set higher. The variable rate needed to encourage 10% of households to adopt rather than 1% of households is only $0.0215/kWh higher. This means that, once solar panels is profitable for one consumer, it is very close to being profitable for all consumers. This is the concept of grid parity, where solar electricity reaches the same low price as conventional electricity and becomes a desirable substitute.

<u>Generation Costs</u>

Another parameter that can be varied and that does not simply impact inequality (4) is the utility's cost of generating a kWh of electricity. While this does not impact the optimal r^* needed to encourage the solar consumers, it does alter the calculation of the fixed charge based on a new revenue requirement. Figure 10 shows how the fixed charge is linearly dependent on the utility's generation costs.

Figure 10. Relationship between fixed charged and generation costs



The peculiarity of this model is of course that the fixed charge the utility will set is not actually related to the fixed costs incurred by the utility. It only serves to make up the difference between the total revenue from the variable rate and the utility's revenue requirement. This implies that the utility does not ever try to turn a profit from the sale of electricity and limits itself to recovering the cost of generation, a realistic assumption since most publically regulated utilities are mandated to receive no more than a set rate of return. If it recovers too much from the variable charge, it needs to pay the difference back, hence the negative fixed charge. In all likelihood though, a utility in deregulated market like Texas or California would set the fixed charge to 0 and pocket the excess revenue as profit.

VI. Conclusion

The goal of this paper was to look at how an electric utility can meet its cost of operation without stifling the growth small-scale residential renewable energy. Especially over the last decade, growing interest in rooftop solar photovoltaic systems as a means to offset grid electricity consumption has caused tension between utilities and consumers over tariff setting practices. This model attempted to optimize the utility's cost-recovering prices while meeting a mandate to promote a target level of PV adoption.

Key input variables in the model were the cost of installing a system (based both on the number of panels installed and the price per 1kW panel), the percent reduction in electricity purchased from the utility that the PV system allowed, the target share of households that needed to install a PV system, and the utility's cost of generating electricity. The baseline model filled those variables using US averages reported by various governmental surveys and the various sensitivity tests looked at how much impact each had on the consumer's and the utility's decision-making.

The model showed that, as predicted, the investment cost of solar was a huge deciding factor in whether or not consumers invested in the technology. Anything that brought the price tag down – smaller system size, lower panel price, lower interest rate, higher panel efficiency – prompted consumers to install PV panels even at low variable prices for grid electricity. Thinking of this another way, the cheaper the system, the lower the variable rate r the utility would need to set in order to meet the PV adoption target.

On the utility side of the equation, the key input variable was the average cost of generating electricity. This was used to determine total operating costs of meeting consumer demand. Since r was solved for independently of the utility's revenue requirement, this variable only served to figure out the unrecovered costs left over after taking in the revenue from consumers paying the variable rate. Testing the sensitivity of this generation cost variable showed that, intuitively, as it increased, so did the fixed charge the utility would need to recover from consumers.

The peculiar result for most of the model's iterations was that in most cases, a high r value resulted in a negative fixed charge f. This would mean that the utility, in order to not recover more than its cost of generation, would need to pay consumers a fixed monthly sum. If it disregarded this payment, the utility would profit significantly from the relatively inelastic consumer demand for electricity. For publically owned utilities with government-mandated caps on returns, this would not be possible. However, paying consumers would also not be very practical. In general, what this indicates is that, as long as the electricity produced by solar PV is more expensive than the electricity produced by conventional power plants, the utility will have to set unrealistic prices for electricity in order to induce consumer adoption.

While this conclusion is intuitively realistic, the model's biggest failing in showing this is how the investment function is set up. Future work on this topic should aim to develop a dynamic investment function that changes with consumer preference for different system sizes. Right now, system size is an input variable, rather than a consumer decision. It is very likely that this decision is what is causing strange behavior like very negative fixed charges. Beyond that, the model is very simple and has much room to be improved to be more realistic. This might be the focus of future graduate-level work.

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