Case Study on Distributed Generation Rate Options:
From Both Sides of the Meter

by

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Abstract

In the era of distributed generation (especially solar) at the residential level, it has become obvious that the legacy rate structures used by most utilities are no longer viable. The electricity rate has three components: generation, transmission and distribution, but all of these are typically based only on kilowatt-hour (kWh) consumption for residential customers. A utility usually has a relatively low fixed monthly service charge (historically to cover the cost of meter reading and bill preparation) and with revenue needs (energy, maintenance, etc.) recovered by charging a "per kWh" rate higher than the actual generation costs, often by a factor or two or more. This worked as long as the utility supplies all of its customers' electricity. Once customers were able to implement dramatic energy efficiency methods or even generate their own electricity through rooftop PV systems, this balance was upset. As a result, many utilities are looking at changing residential rates by raising fixed charges, adding demand charges or distributed generation (DG) surcharges, or implementing time-of-use rates.

This paper uses a year's worth of data from a household with a solar array to evaluate the effects of different types of rate structures on both the customer's electric bill and on distribution revenues for the utility. The data set includes data from both the utility meter and the solar array, so it is possible to back-calculate what the energy usage / bill would have been without the solar installed. The non-solar bill is used as the baseline for comparison with net metering and other proposed rate structures. Each rate is evaluated both from the point of view of the customer (i.e., actual monthly bill) and the utility (i.e., distribution system revenue, assuming that generation costs were on a straight pass-through basis).

Rate Structures

The basic household energy use is calculated from the utility-meter data and the solar array data. The household is an "interior" (i.e. non-end-unit) townhouse with two full floors and a walk-out basement, approx. 1500 sf) in Germantown, Maryland. The house uses an air-source heat pump for heating and cooling, has energy efficient windows, and almost all lighting has been converted to LEDs. Water heating and cooking are both electric. It is currently being served by PEPCO.

The PV system is a 6.89 kWp array connected to the grid through a SolarEdge system (inverter/module optimizers). The array is on both the southeast-facing back roof and the northwest-facing front roof.

Baseline Bill Structure

The basic energy rate is an "energy only" net-metered rate. It has a fixed customer charge of $7.80. Because Maryland is unregulated, the distribution and "supply" charges are separate. Except for the small fixed cost, all other charges are based on "net" kWh used during the month. According to the base Pepco residential rate, Generation is $0.07263/kWh, Transmission is $0.00869/kWh, and Distribution is $0.06236/kWh. The net cost of energy to me is thus $7.80 plus $0.144 per kWh[1].

For the sake of easy analysis, it is assumed that other rates will be "revenue neutral" for distribution costs based on the original bill. This is one of the basic premises often used when considering new rate structures, although it is usually applied to a broad set of customers, rather than to a single user. However, the electricity consumption of my moderately sized, relatively energy efficient all-electric house happens to match the US average – my actual energy consumption over the study year was 11,200 kWh, while the average for the US in 2016 was 10,766 kWh[2].

Net Metering

Net metering (sometimes called "net energy metering" or NEM) is the most common rate structure currently used by utilities for distributed generation customers. "Net metering" requires that all energy not used by the house is credited back on a one-for-one basis. Essentially, the utility is buying back electricity at the full retail rate. Although net metering is mandated in 38 states and several others have voluntarily adopted net-metering policies, these rules do not necessarily apply to all utilities within the states (co-ops, public power districts and municipal utilities are sometimes exempted), and most states include a "cap" on the number of systems allowed under net metering.

Net metering was originally the only real metering option because traditional meters run "backwards" when power is being exported to the grid. Utilities had no way to distinguish how much actual energy flowed in either direction, so the bill was based on the actual "net" meter reading each month. By the time utilities realized this was going on, the solar lobby has convinced regulators that solar was valuable enough to justify the use of retail compensation, at least up to a certain point. Utilities figured that solar would never cost effective enough to ever cause problems. Thus was net metering born.

Most net metering rates include a periodic "true-up" to ensure that a customer does not export more energy to the grid than they use. Any excess energy is compensated at a reduced rate – typically the utility's "avoided cost." This study will look at net metering rates using an annual true-up (the most common) as well as monthly true-ups.

Distributed Energy Buyback / Value of Solar

Modern digital "smart" meters have the ability to measure power flow in both directions, so they can charge different prices for energy delivered to the house and energy received from the house. There are three different options for energy exported to the utility – retail rate (resulting in net metering as described above), avoided cost (the cost the utility would pay for other third-

[1] The actual Pepco rate contains seasonal variation and future costs adjustments, which will be ignored for the sake of simplicity.

[2] https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

party generation) and "value of solar[3]" (a tariff which assumes that distributed generation has additional value beyond simple energy – reduction in need for addition generation, reduction in distribution / transmission losses, reduction in carbon emissions, etc.).

It is important to realize that if the "value of solar" is higher than the retail rate, it makes sense to put in a separate "production meter" and connect the solar array directly the grid on the utility side of the household meter. This is sometimes called "sell-all, buy-all."

Adjusting the Fixed Cost of Service

Since revenue needed for distribution system operation is based on kWh usage, a household with net metering is paying less for its service than a standard customer. One of the most obvious ways to recover revenue for residential self-generation/consumption is to change the ratio between the fixed service charge and the electricity price itself. Many small utilities[4] (and some not-so-small[5]) are looking at raising their fixed charges to cover "cost of service" and lowering electricity price to a basic pass-through charge.

This study will look at two options:

- raising the fixed charge to a value where it replaces the entire distribution cost of the baseline bill (effectively making the distribution system operator a "poles and wires" company), and
- Choosing a fixed cost which still includes variable distribution costs

Demand Charges

Another potential change is to implement demand charges, something that has not traditionally been part of residential rates[6]. (Note – a demand charge is a charge per kilowatt of power used during a certain period, as opposed to kilowatt-hours of energy used during that period.) This is being implemented in Arizona and Massachusetts, among other places. The general idea is that it is more expensive to supply electricity during peak periods due to less efficient generators and transmission congestion, so customers with a higher demand should pay more of the share of these costs.

There are many variations to this approach. The simplest is a "non-coincident" demand charge – the demand charge is based on the highest electricity used over a specific period (typically a month), regardless of whether that demand contributes to actual utility costs.

The second method is to charge demand only during utility peak periods such as a four to six hour period on weekday afternoons. There may be seasonal variations in both time and demand charge.

The third is to define specific peak periods when the actual costs to utilities will be high. Customers are typically notified in advance of these "critical peak periods."

This study will look at several demand charge options:

- A demand charge of $11/kW which, along with the fixed cost, completely replaces the energy-based distribution costs.

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[3] https://mn.gov/commerce/policy-data-reports/energy-data-reports/?id=17-81656

[4] http://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf

[5] http://midwestenergynews.com/2015/01/06/as-in-wisconsin-missouri-utilities-seek-to-raise-fixed-charges/

[6] https://www.greentechmedia.com/articles/read/new-aps-rate-case-seeks-mandatory-demand-charges#gs.RmJozYw

- A demand charge of $7/kW with an energy charge to provide equivalent distribution revenue, and
- A demand charge of $4/kW with an energy charge to provide equivalent distribution revenue.

Time-of-Use Rates

Time-of-use (TOU) rates are usually associated with commercial or industrial customers, and while some utilities have established residential TOU rates, there are very few users who take advantage of these rates. The basic idea of a TOU rate is to charge higher energy (kWh) prices during periods of higher demand when it is more expensive to generate and deliver power, and lower prices during periods of lower demand. Historically this has been a day/night tradeoff, with lower prices at night. However, with increased solar generation resulting in a "duck curve[7]", energy during the day may be less expensive than energy in the morning or evening. Once again, this may have seasonal variations.

This study will look at several variations of TOU models with peak, off-peak, and "shoulder" periods, from the existing Pepco tariff to variations with higher peak and lower off-peak costs.

PEPCO TIME-OF-USE RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period 12:00 noon to 8:00 p.m.
Intermediate Period 8:00 a.m. to 12:00 noon, and
8:00 p.m. to 12:00 midnight
Off-Peak Period 12:00 midnight to 8:00 a.m.

Saturdays, Sundays and Holidays - Off-Peak Period All Hours

Holidays include New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving

Distribution System Charges

In some states, utility rates are unbundled, which means that generation/transmission charges and distribution charges are separate items in the bill. This study will look at the effect of allowing net metering for the energy related charges (generation and transmission) but charging for the distribution system in both directions – import and export.

Surcharges on DG Customers

Some utilities have proposed fees specifically on customers with distributed generation[8], since they are the ones who have "broken the model" that utilities have relied on for the past

[7] https://www.greentechmedia.com/articles/read/the-california-duck-curve-is-real-and-bigger-than-expected#gs.MgwpNDE

[8] http://midwestenergynews.com/2017/06/06/minnesota-ends-regulatory-oversight-of-fixed-fees-for-small-rural-utilities/

hundred years. A slight variation on this approach is a "non-export" or "self-supply[9]" rate where customers are not allowed to export energy to the grid.

This study will look at the effect of such a charge on a traditional "net metered" PV system, along with the results of a "non-export" rate.

Household Data

The meter collected was collected from my Pepco "smart" meter in one-hour intervals and then downloaded from the Pepco customer "energy usage" section of their website. The solar data was collected and downloaded in 15-minute intervals via the SolarEdge monitoring system. The meter data was put through an algorithm to interpolate 15-minute values between the measured points. (Note – the system was commissioned in mid-January 2017, so data from January 2018 were used to complete an annual dataset.) The "actual" household load was calculated by adding the solar production to the meters energy use[10].

Summary of the full year's data:

- Net Metered usage 3,673 kWh
- PV generation 7,347 kWh, of which 3,686 kWh was exported to the grid.
- Net energy usage 11,020 kWh
- PV contribution 67% of annual household load

Figure 1 shows the monthly energy balance of the system.

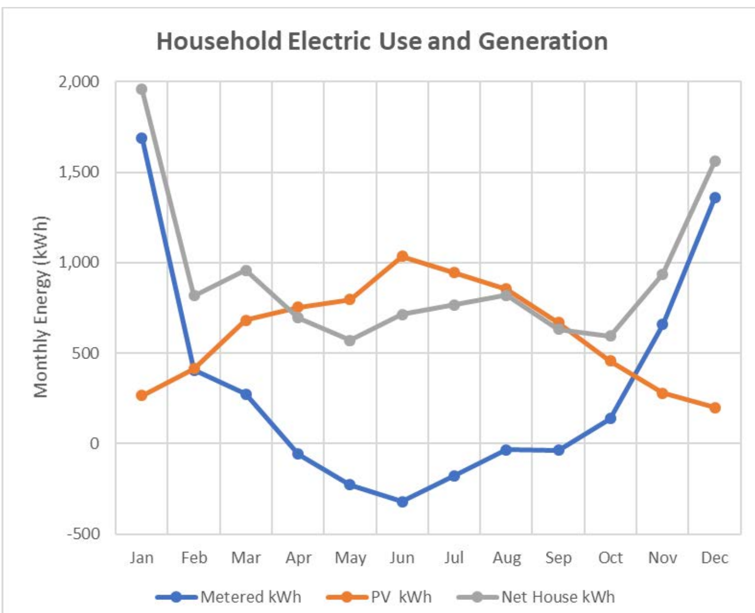

Figure 1 - Annual household energy generation and usage

Note that there is a net monthly export of energy from April through September. This graph also clearly illustrates that heating load is a much larger load than air-conditioning for my house, since we tend to keep the windows open and the AC off if possible. It is also interesting to note

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[9] https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-renewable-programs

[10] Note: This occasionally resulted in small negative "real house loads" for specific 15-minute periods since the actual intra-hour house loads varied in a non-linear fashion. However, the overall energy balance calculations are correct.

that the solar output is nearly five times as much in June as it is in December. This is due to the relatively shallow tilt of our roof and the fact that half the array faces northwest, so it receives relatively little sun in the winter. Other household will have different load patterns and different array outputs, but this is probably not an exceptional situation.

Although there was a net monthly export in only six months of the year, the system exported energy to the grid at some point during all months except February. Figure 2 shows the average daily export for each month.

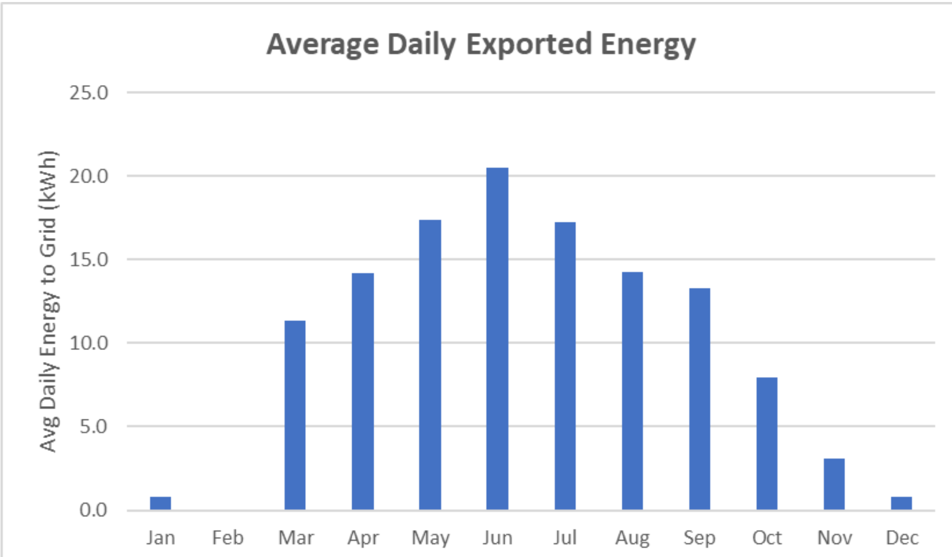

Figure 2 - Average Daily Exported Energy by Month

Figure 3 shows the exported energy for each day in June – the month with the highest export. Note that there are five days with exports totaling more than 30 kWh, sixteen days greater than 20 kWh and twenty-six days greater than 10 kWh.

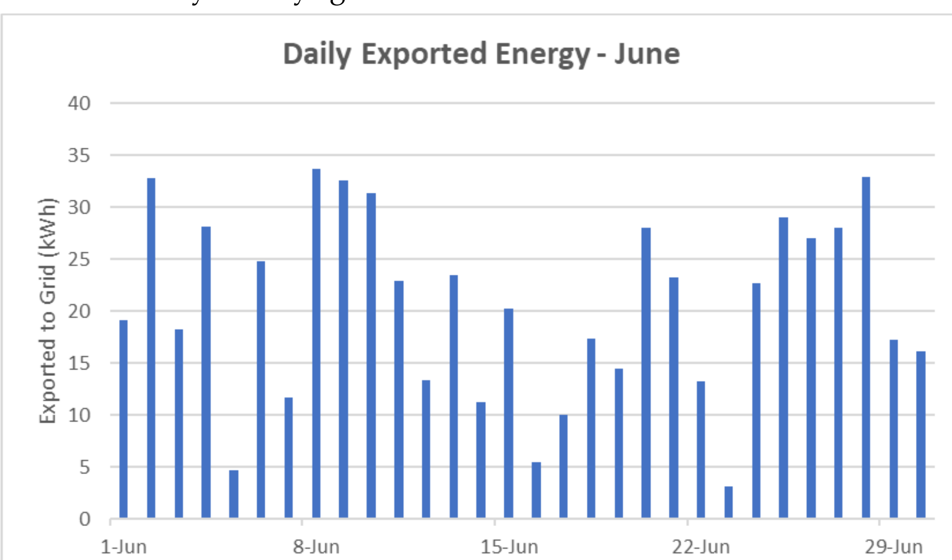

Figure 3 - Energy exported to grid each day in June

Figure 4 shows a typical summer day where the system is exporting energy.

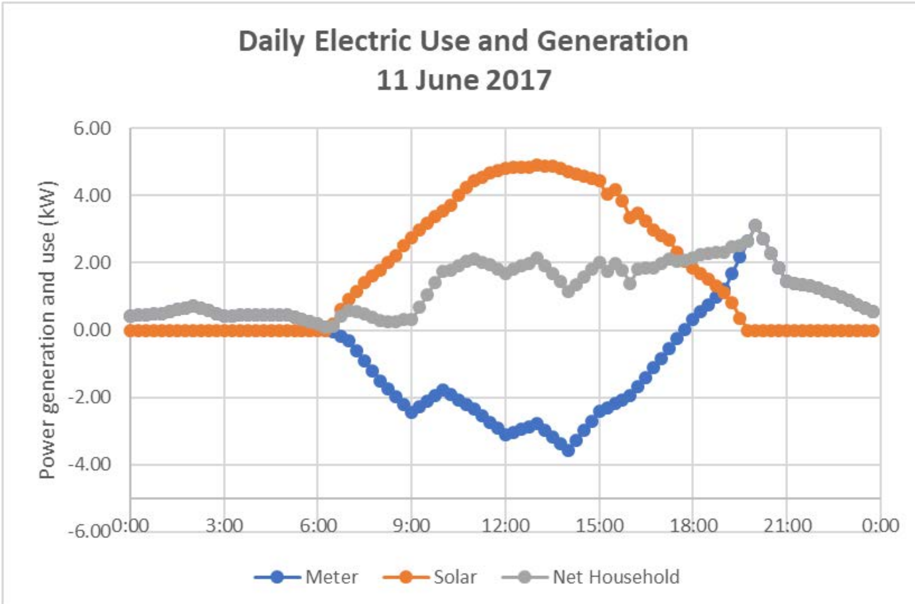

Figure 4 - Summer day energy generation and use

The rise in the household use was due to air conditioning – the high that day was 93°F. The evening peak was probably cooking on the electric range. This was a Sunday. The day was mostly clear, so there was a lot of solar energy and the system exported energy from about 7:30 in the morning until almost six in the evening.

The PV system generated 42 kWh that day, while the house load was only 30 kWh, so the metered load was -12 kWh. However, because of the low, flat load profile, the system actually exported nearly 23 kWh to the grid. These numbers will become important in the rate analyses. For example, if the energy sent to the grid is trued-up annually, the bill will reflect true retail net metering since the system only produces about 75% of the annual load. If the bill is trued-up on a daily basis, then 12 kWh would have been compensated at avoided cost. If the energy was metered in real time, then 23 kWh would have been accounted for at the lower cost.

Figure 5 shows four variations of the monthly system demand. The first is the actual demand measured by the meter. The second is a calculation of what the actual house load was without reduction from solar. The third bar is the metered demand during peak period – defined in this case at 3pm to 7pm on a weekday. The fourth bar is the actual household demand during the peak period.

Comparing the first two bars, it is clear that the solar array reduces the metered demand during all except for three months, with the largest reductions coming during June, July and August. The peak period calculations show a similar reduction in demand during all except December and January. (Note – the December and January peaks were due to the heat coming on in the morning after a very cool night. January in particular was very cold, and the heat pump almost certainly activated "emergency" mode / resistance heat during some periods.)

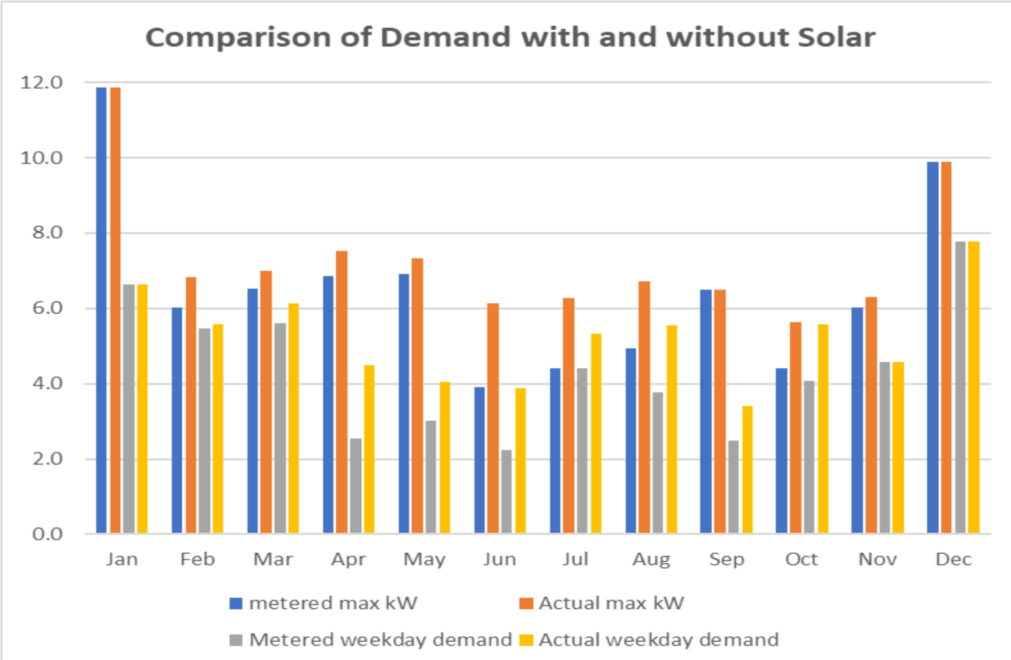

Figure 5 -- Comparison of demand peaks

Note that the peak-period demand was lower than the non-coincident demand for all months. In my house, this is almost certainly a result of cooking more on weekends. The solar array lowered the metered peak demand by up to 44% during nine months of the year.

Comparative Bills

Baseline Utility Rate

Utility bills can be extremely complicated, even for "standard offer service" such as those for Pepco Maryland. For instance, the PEPCO-MD "R" rate include generation, distribution and transmission charges as well as a fixed fee and various administrative charges and credits. Generation and distribution vary by season, although the seasons do not align.

For this study, I will assume that the base electric rate will not vary by season, and I will ignore the various state and local taxes and credits.

<u>Bill Components</u>

- **Distribution Service Charge $7.80 / month**
- Generation $0.07263 / kWh
- Transmission $0.00869 / kWh
- Distribution $0.06236 / kWh
- **Total Variable (G+T+D) $0.14368 / kWh**

Baseline Annual Bill

The baseline bill for the 12 months of the study would have been $1,677 if there was no solar on the house. Of this amount, $781 would have been collected in the fixed charge and in the kWh distribution charge.

For the monitored household, the highest bills were in the winter months (averaging $220 for Nov/Dec/Jan) followed by summer (Jun/Jul/Aug) at $118 average. This also reflects the fact that my family likes to minimize air conditioning except on very hot days, but it is difficult to avoid heating the house, especially on frigid days like we had in late December and early January.

Net Metering

The PV array produced 7,347 kWh over the year, about two thirds of the total household energy consumption. Almost 70% of that energy was produced in the spring and summer months.

Using net metering at full retail rate, the annual expenditure was $621, with $323 collected for distribution. This rate includes an annual "true-up," with excess energy paid at the generation cost (per the PEPCO net metering rate). Since there was no excess energy on an annual basis, this has no effect on the system economics.

Net metering with monthly "true-up" raised the annual bill to $682, with the utility collecting $376 in distribution charges and fixed costs.

Distributed Energy Buyback / Value of Solar

Assuming that all energy returned to the system is compensated at the generation cost rather than the retail rate, the annual bill would be $896, with $563 going towards distribution costs.

Adjusting the Fixed Cost of Service

One option for raising the fixed cost is to do a cost-of-service study for the distribution system and raised the fixed cost for all consumers so that it covers these costs. To achieve non-solar equivalence for distribution expenses, the fixed cost would have to be raised to $65 per month. For the solar case, this would result in an annual bill of $1,080, with all $781 recovered in distribution costs. For an interim fixed charge of $40 per month, the distribution charge would need to be $0.027/kWh to achieve equivalence. The net-metered bill would then be $878, with $579 recovered in distribution charges.

Demand Charges

For this case, it is assumed that the fixed charge remains at $7.80 and that all excess energy is net metered at full retail rate.

To achieve bill equivalence (Distribution Revenue = $781), three options were considered:

1. Demand charge = $11.00/kW DistrEnergy= $0.00/kWh Demand$= $689
2. Demand charge = $7.00/kW DistrEnergy= $0.0225/kWh Demand$= $439
3. Demand charge = $4.00/kW DistrEnergy= $0.0388/kWh Demand$= $251

The calculated bills with net metering are listed as "Bill", which is the total bill, "Distr", which is the portion of the bill allocated to distribution revenue, and "Demand" which is the part of distribution revenues allocated towards demand charges.

1. Rate: $11.00 / $0.0000 Bill: $1,017 Distr: $719 Demand: $625
2. Rate: $7.00 / $0.0225 Bill: $873 Distr: $574 Demand: $398
3. Rate: $4.00 / $0.0388 Bill: $762 Distr: $463 Demand: $227

Time-of-Use Rates

TOU rates were calculated on a 15-minute basis using three different rate structures, the published Pepco residential TOU rate with a fairly narrow spread, a rate with a high peak and lower off peak, and a medium rate in between the two. The values for the second and third rates were chosen to make the rate revenue neutral compared with the standard non-solar bill. The solar charges were calculated assuming full net metering at whatever rate was applicable. True up by separate rate class was not considered.

	Pepco	High Peak	Medium Peak
Peak $/kWh	$0.122	$0.260	$0.225
Shoulder$/kWh	$0.118	$0.120	$0.130
off-peak $/kWh	$0.117	$0.090	$0.100

TOU fixed charge is $16.77 per month based on the published Pepco rate. In this analysis, it was not possible to separate distribution, transmission, and generation charges, so only the full monthly bill is compared.

When the published Pepco residential TOU rate was applied to the non-solar usage, the annual bill would have been $1,505, or more than $150 less than the standard rate. With the current PEPCO rates, the solar bill would have been about 10% less than the net metering bill using the standard rate. Customer savings would have been even higher if the variance between peak and off-peak periods were larger, primarily because the peak period is during the daytime when the PV array is producing the most solar energy.

- Case 1 – Pepco TOU with solar: $628
- Case 2 – High peak with solar: $438
- Case 1 – Medium peak with solar: $509

Bidirectional Distribution System Charges

For this calculation, excess generation was compensated at the generation rate, transmission was charged on incoming energy only, and a distribution charge was applied to energy flowing both into and out of the household (essentially a “service” rate for using the poles and wires).

- Total bill with solar: $1,083
- Distribution component: $784

Surcharges on DG Customers

To make up for distribution system revenue difference between the solar and non-solar usage of the reference household, the utility would have to add a $38.18 per month surcharge ($4.90/kWp/month). This would bring the annual bill to $1,080, with distribution revenue at $781.

If a solar customer simply set the system to never export energy, they would no longer be subject to a DG surcharge. Since they would not export energy, they would waste a good deal of energy, raising their annual bill to $1,153 but the utility distribution revenue component would fall to $553.

Summary and Analysis

Figure 6 shows the modeled annual electric bill for each rate option, along with the amount received towards distribution expenses. (Note that it was not possible to break out distribution revenue for the three time-of-use rates.)

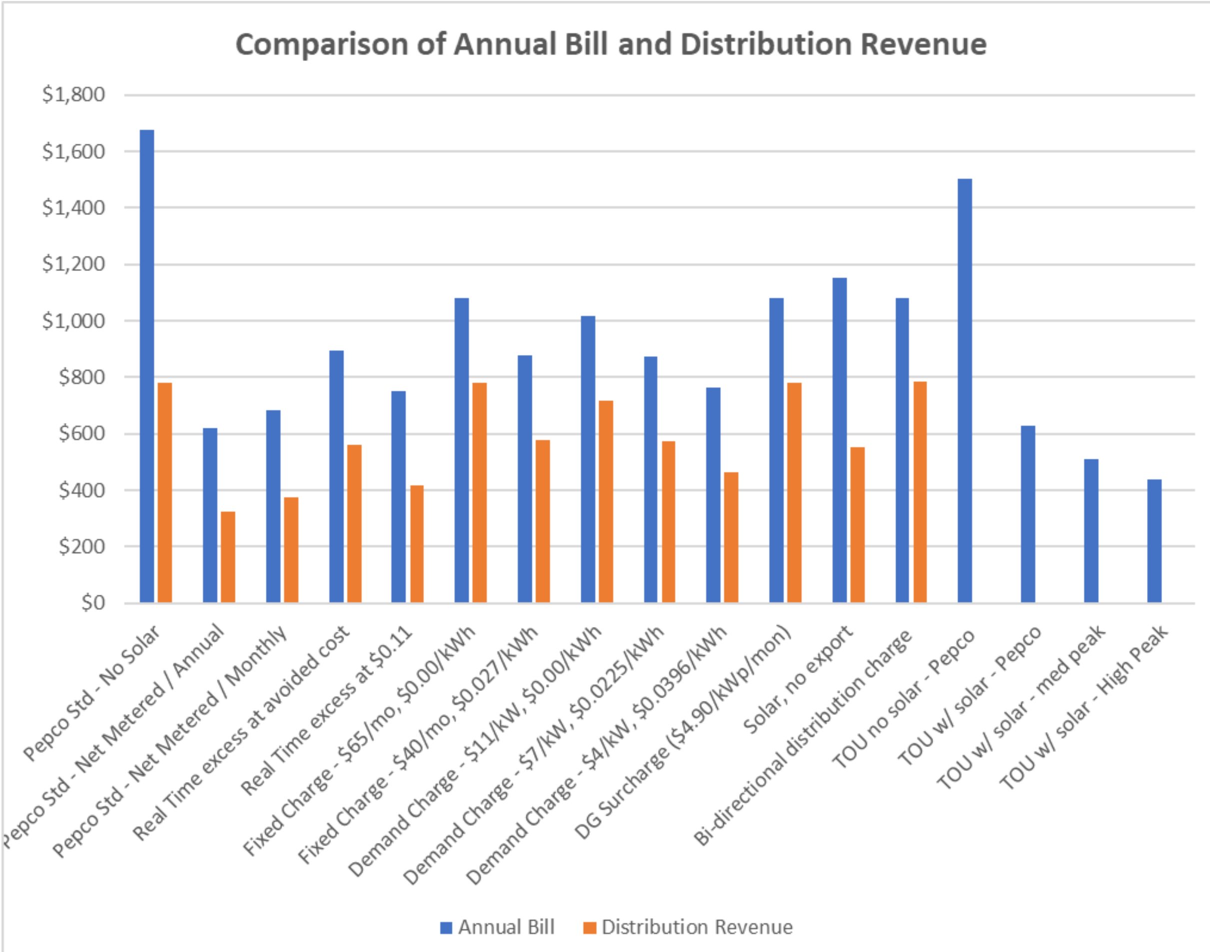

Figure 6 -- Annual Bill and Distribution Revenue for Rate Options

The net-metered case with 67% of the annual energy delivered by solar results in a 63% reduction in the annual bill to the customer and a 59% reduction in distribution revenue for the utility. All the other rates result in higher customer bills compared to net metering, except the three net-metered TOU rates. Monthly true-up with retail net metering results in a 10% increase over the base net-metering case, with real-time excess energy at $0.11/kWh (typical "value of solar" case) adding another 11%. From the utility perspective, these three rates would generate only 41%, 48% and 72% of the revenue of the non-solar revenue.

On the utility side of the spectrum, only the highest fixed charge rate (with no kWh-based distribution charge) and the bi-directional "pay-for-use" distribution charge rate (both with retail net metering) recovered as much revenue as the base non-solar case. The highest demand charge (with no kWh-based distribution charges) came in with less than a 10% reduction in distribution revenue and a selection rates generated more than 70% of the base revenue.

The demand-charge rates are interesting, since with a relatively modest reduction of 2 kW during peak periods each month, the customer would save $96 to $264, all of it coming out of the utility distribution revenue "bucket." With a recent surge of "smart-home" and other home automation technologies, it is reasonable to think that a home in the near future would be able to reduce peak demand charges to a bare minimum at a reasonable cost. Reduction in demand would have some benefit to the utility, but it is unlikely that customer demand charges are completely aligned with utility demand costs, so the net loss of revenue from customer-initiated demand reduction could pose further cost pressures on the utility. If demand response programs would allow credit for "negative demand," discharging a battery during peak periods could generate additional value, further reducing a customer's bills, as well as utility distribution revenue.

The time-of-use analysis deserves further study. The surprise was that the non-solar energy use case would have resulted in a 10% reduction in the annual bill compared to the "standard offer." One question is whether 10% would be enough to convince someone to go with a more complex rate. There are obvious opportunities to reduce these costs even further by automated load shifting[11] or installing residential energy storage. With net metering, the published Pepco rate would have no advantage over standard retail net metering, but if the spread was a little higher, the annual bill could be reduced by an additional $180. Clearly, this analysis is very sensitive to the TOU rate structure. Traditionally, peaks are during the day, with shoulder periods in morning and afternoon and off-peak at night. However, in the case illustrated by the famous California "duck curve[12]," peak periods occur during the morning and evening "shoulders," off-peak during maximum solar contribution and the "intermediate" period occurring during overnight hours. Utilities would have to be very careful of setting up TOU rates and then having power consumption patterns change dramatically, necessitating a complete change in rate design.

The "DG surcharge" is one of the most interesting rates. If implemented, the annual bill for a solar customer would be reduced to $1,080, which is nearly a $600 savings over the non-solar bill but is still $460 per year higher than the net metered rate. If the customer set up the system to never export (a controller would read the household load and take the array off of its maximum power point to control total energy generation). The customer would not be subject to the DG surcharge since they were never "generating," but their bill would rise an additional $73 per year so this does not make sense on its own. (Note – the utility distribution revenue in the non-export case is $553, a 30% drop from the non-solar case, due to reduced internal energy usage.)

However, they have an excess of 3,700 kWh of energy available to them. If they could adjust their load usage to take advantage of this excess energy using means such as pre-cooking the house during the day, running laundry or dishwasher when solar was available, etc., every kWh would result in full retail savings (and reduce utility distribution revenue accordingly). In Europe, this is called "*self-consumption*." If a customer could make full use of their solar energy, their bill would be the same as the net metered rate, but the utility distribution revenue would be even less than in under retail net metering. As a result, the utility would have implemented what is likely to be perceived as a "hostile" rate structure and ended up with even less revenue than if they had simply "left well enough alone."

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[11] "Alexa – minimize my energy usage during peak billing times."

[12] https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf

Conclusions

Ratemaking has always been a complex task – balancing the desire to serve customers via low rates with the need to generate sufficient revenue to ensure proper system operation and maintenance. This task has become more complex with the advent of distributed customer owned generation, especially rooftop PV. With costs continuing to fall, it is likely that adoption of behind-the-meter solar will increase across many areas of the country both at the residential and at the commercial / industrial level. As utilities adjust their rates to compensate for this behavior, customers will use increasingly new home automation technologies to adjust their load profiles to optimize their bills, likely reducing revenue to the utility even more.

This paper studies a single household over a single year, but the data now exists for utilities to start doing these types of analyses on broad classes of customers under various scenarios.

Despite the limited nature of the case study, some interesting points rose out of the simplified analysis:

- Increased fixed charges, with corresponding reductions in energy cost per kWh, will disincentivize energy efficiency, possibly causing problems with regulated efficiency targets. Reduced kWh cost could also lead to more consumption, which could lead to the need for upgraded infrastructure and associated maintenance. Since the fixed charge is based on the legacy system / consumption, this could necessitate a further rise in the fixed charge.
- Rate structures which include demand charges will be subject to home automation / load scheduling as well as behind-the-meter energy storage. This can have economic benefits for both parties so long as the demand rates are truly transparent, but often this is not the case.
- Time-of-use rates designed to limit usage during utility peaks and incentivize use during off-peak periods must be flexible enough to account for the changes in the utility's load shape with high penetration of solar (both customer-owned and utility owned/managed).
- "DG surcharges" are likely to be viewed as anti-environmental as well as antagonistic towards customers who choose to install solar. This can lead to further load defection[13] and even potential grid-defection if the cost of solar and storage continues to fall.

Utilities who are considering changes in legacy rates need to look beyond just "solving a problem" and treat it more as a chess game where they look "a few moves ahead" to see how customers might react to proposed rate changes. Of course, this analogy cannot be taken too far, since utilities are not really trying to outsmart their customers and "win the game." Or are they?

[13] https://rmi.org/insight/economics-load-defection/