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

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Overview

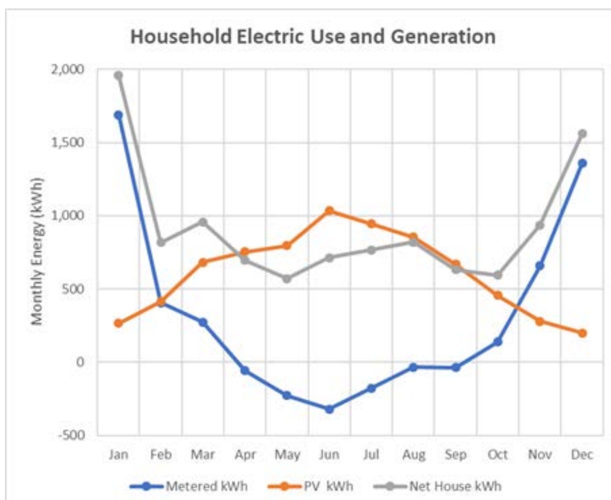
In the era of distributed generation (especially solar) at the residential level, it has become obvious that the legacy rate structures used by most utilities are no longer valid. The electricity rate typically has three components, generation, transmission and distribution, but all of these are typically based only on energy consumption for residential customers. A legacy utility would usually have a relatively low fixed monthly service charge and then balance revenue needs by charging a "per kWh" rate higher than what actual generation cost, often by a factor or two or more. This works 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 DG surcharges or demand charges, 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 a full year's worth of data from both the utility meter and from the solar array, so it is possible to back-calculate what the energy usage / bill would have been without the solar installed. This was used as the base-case for comparison with net metering and other potential rate structures. Each rate was 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).

Section 2: Structure of Study

This is a single household case study, using data from a residence in Germantown, MD. The household is an "interior" (i.e. non-end-unit) townhouse with two full floors and a walk-out basement, approx. 1500 sf). The system uses a standard heat pump for heating and cooling, has energy efficient windows and almost all lighting has been converted to LED. Hot water 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.



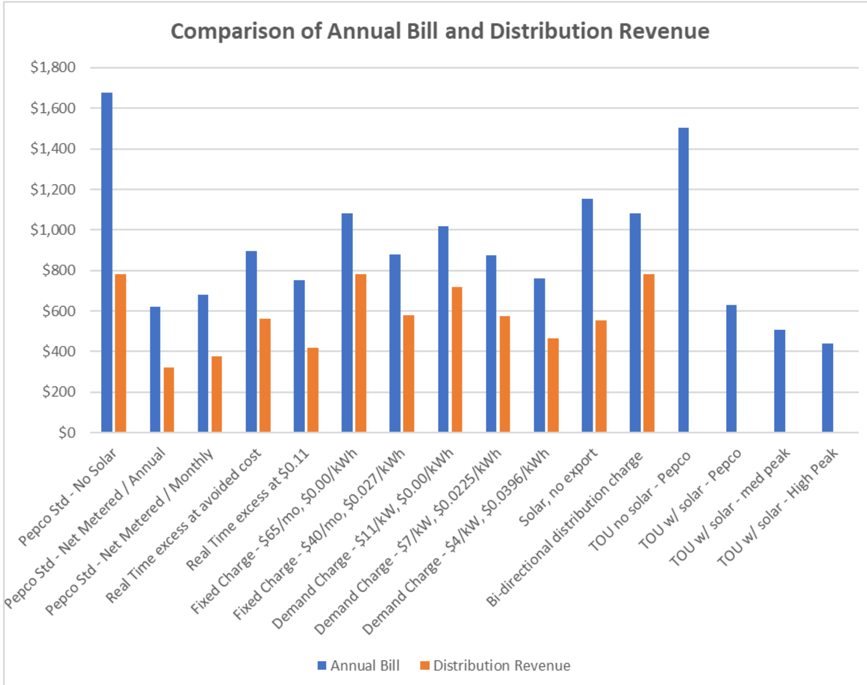
The solar data was gathered from the online SolarEdge monitoring portal in 15 minute intervals. The household use data was gathered from the Pepco "smart meter" in one hour intervals and converted to 15 minute data using simple linear interpolation.

The household used 11,020 kWh during the study year. The PV array generated 7,347 kWh so the net billed energy was 3,673 kWh, or approximately one third of the actual household usage.

Analysis was performed for seven variations on a resisdential rate structure: baseline/legacy, retail net metering, distributed energy buyback / value of solar, adjustment of fixed cost, demand charges, time-of-use rates, bi-directional distribution system usage charge, and "no export allowed" in response to targeted DG customer additional charges. The variables in each of the rates were set so that the the system without solar would be revenue neutral comparged to the baseline legacy rate..

Section 3: Rate Comparison Results

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, 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 charges to cover distribution expenses) came in with less than a 10% reduction in distribution revenue. Several other rates generated more than 70% of the base distribution revenue.

Section 4: Results and Conclusions

Although many of the rate options show the ability for utilities to continue to receive distribution revenues nearly equal to the non-solar case, they open up the opportunity for dramatic changes in customer behaviour. For example, if a utility charged a "DG Fee" only for solar customers, the consumer could set up their system to never export to the grid and use excess solar energy to charge a battery / EV or adjust load timing through automated home software now becoming widely avaiilable. Since they would never export energy to the grid (the system would automatically clip the array output to prevent this from happening), the customer could not be considered a "distributed generator" and could not be charged the DG fee. Similarly, adding a residential demand charge to a net metering rate could make it cost effective for residential customers to install a battery and charge/discharge it to optimize their own eceonomics, rather than to the benefit of the utility. Raising the fixed charge while lowering the kWh charge could be problematic on a legal basis unless it was done for all customers, but then it would lower incentives for energy conservation. This could lead to increased energy use causing a demand for more infrastructure which could only be paid for by raising the fixed charge even more. Rate makers must consider rates in the same way as a chess game – looking more than one move ahead.