Net Energy Metering for Residences: Impacts of Tariff Design

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White Paper

Contents

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Overview of Distributed Generation

The traditional view of delivery of electrical energy services dates back to the very first electric utility, started by Thomas Edison at the Pearl Street Station in 1882 (Schewe, 2007). At that point in time, the only use of electricity was the electric light bulb (not coincidentally, invented and marketed by Thomas Edison) and the only customers lived in a densely populated and upscale neighborhood in New York City. The Pearl Street Station was, in principle, very similar to the large coal and natural gas power plants providing over 50% of our electricity today. Fuel was burned to make steam, which powered a mechanical engine that turned a generator, which energized the wires.

Even though the original grid of Edison Illuminating Co. was direct current (DC) (as opposed to today's grid with is alternating current(AC)), it shared many of the aspects of today's power grid. Most importantly, it had no inherent ability to store energy: every time someone on the system turned on or off a light switch, it either changed the voltage in the system (and hence the light intensity of all other customers), or the central generating plant had to change its output to compensate.

In this model, electric utilities, often large, investor-owned corporations, own the central generating plants, and much, if not all, of the wires that exist between the plants and the customers. They invest significant capital in the infrastructure and recoup their investment, and a return on that investment, one kilowatt hour at a time, and they do so under the scrutiny of the Public Utility Commissions in each state.

The rapid development and deployment of renewable energy systems, particularly wind and solar, are challenging that model. Instead of large centralized plants with capacities in the 100's of MegaWatts, solar and wind are often deployed in much smaller increments. Solar panels come in increments of 100's of Watts, and wind turbines run the gamut from 400 Watt DC battery chargers to 3 MW behemoth turbines. These contribute to generating capacity growing in smaller increments.

A benefit of smaller capacity increments is illustrated in Figure 1 (Masters, 2004). The figures shows changes in the load over time of a hypothetical electric utility (the continuous line) and how that load can be met with large, central generating resources (the dot-dash line) and, alternatively, how it could be met with smaller, incremental resources (dashed line). Keeping in mind that some idle capacity is inevitable in utility planning, it is important to note that capacity built in smaller increments (often known as Distributed Generation, or DG) has the potential of minimizing excess capacity and minimizing the chance that the utility will over-build capacity resources.

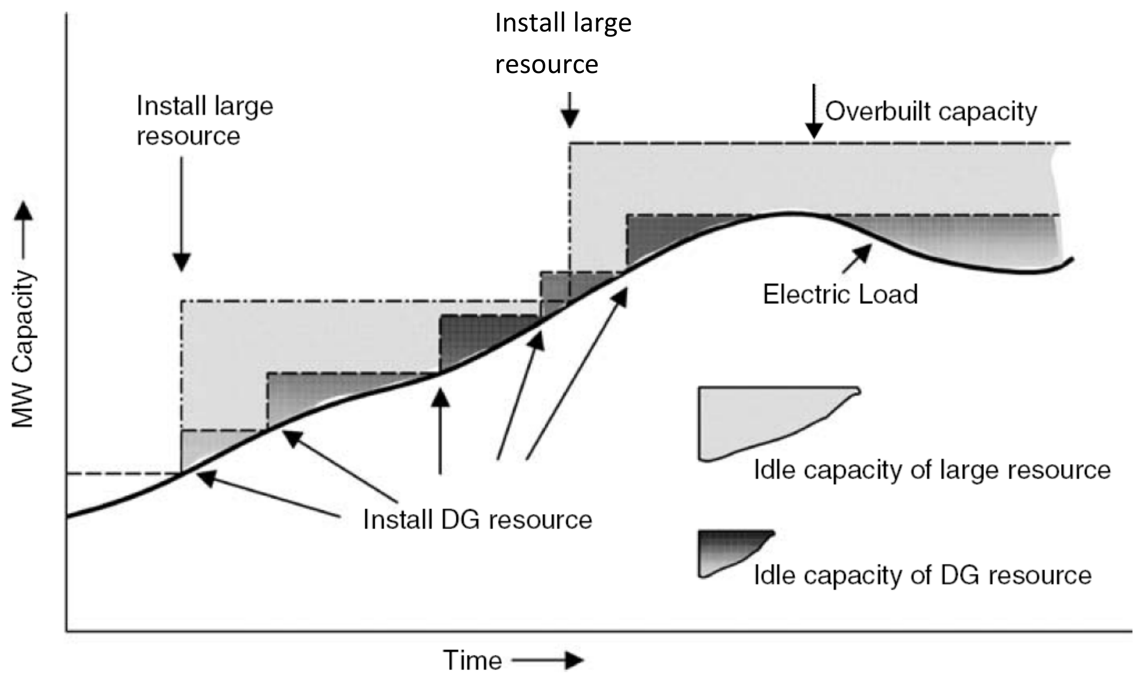

Figure 1: Hypothetical load and capacity histories for an electric utility. Note that building capacity in large increments results in significantly more idle capacity on the grid than building in smaller increments, typical of DG development. (Masters, 2004).

Distributed Generation (DG)

This new paradigm is widely known as "Distributed Generation" and is at the heart of much of the controversy around renewable energy, its price, its cost and the government policies that encourage or discourage its development. Features often attributed to Distributed Generation (also known as DG) are:

- They are geographically distributed throughout the grid and generally near the loads that will use the energy produced.
- They are operated and built in small increments, often 1-5 kW at a time
- They are often renewable energy sources, typically wind and solar
- They are not owned, operated or paid for by the utility that services that area
- They are owned by individual homeowners and business owners
- They are often installed "behind the meter" on private property not owned by the utility
- They primarily are used to generate electricity for the load to which they are connected, but they can export energy to the grid when the generation exceeds demand.

The fact that DG resources can provide generating capacity to the grid, beyond the load of the owners, and how to address the issues this creates, is the central theme of this report, and the motivation for a class of electricity pricing schedules (or tariffs) known as Net Energy Metering (NEM). Before we get to the NEM however, it would be appropriate to look at the basics of utility rate making.

Electric Rates: Fixed and Variable Costs

While the subject of electric rate structures could fill (and has) several volumes, the basic concepts are fairly simple. It costs money to build power plants, transmission infrastructure and to run the business. It also costs money to operate the plants including purchasing fuel to run coal and gas-fired power plants. The utility measures how much electricity customers use and the bill is based on that measurement.

The charge per unit of electric consumption (kilowatt-hour) is a combination of the variable costs (VC, the incremental cost, on average, to produce a kWh) and the 'share' of the fixed costs (FC) spread out over all kilowatt-hours generated, plus the profit approved by the regulating commission. It is important to realize that the per-kWh rate is based on an assumption of how many kWh will be sold in a given period. The regulatory regime commonly known as "decoupling" allows the utility to 'true up' the rates every year based on the difference between the actual kWh sold and the projected amount. This removes the disincentive that exists for energy efficiency measures when the return is not decoupled (otherwise a utility loses money when they sell less kWh). That adjustment is often presented as a separate line on the utility bill and is usually called the Fixed Cost Adjustment (FCA).

So, in its simplest form, the rate charged (Energy Charge or EC) on a per kWh basis is derived as shown:

$$EC = \frac{FC}{kWh_{total}} + VC$$

The amount charged for each kWh, EC, is the sum of the VC for each kWh plus the total fixed costs for one year allocated across the total number of kWh sold in that year.

In addition to the energy charge, two other charges are normally included in an electric utility bill. They can go by various names. The Demand Charge (DC) is a charge based on the largest demand, or rate of energy use during a billing period. This is computed on a per kilowatt basis and is common on industrial or large commercial loads. When the Demand Charge is assessed on the highest demand over the course of a year (as opposed to monthly) it is often called the Basic Load Capacity Charge (BLCC). A Demand Charge attempts to recover some of the incremental costs of a utility having reserve generating, transmission and distribution capacities in place to meet the highest customer demand times.

The last charge we consider is a Monthly Charge (MC), a simple flat rate on every bill intended to recoup costs that are not associated with energy production or delivery such as corporate overhead and customer service.

The monthly bill then might be computed as follows:

$$MonthlyBill = EC * (Total\ kWh\, used) + BLCC * (Highest\ demand) + MC$$

Clearly, this is a gross simplification and many other factors come into play, including tiered rates (where the first block of energy used each month is charged less than higher amounts) and time-of-use structures that charge more when energy is in more demand and more expensive to produce. Also, different classes of customers are charged differently (residential vs. industrial), but this captures the main points of utility ratemaking required for this discussion.

Net Metering

As mentioned previously, one feature of DG systems is that they are often installed on the customer's side of the meter and are largely used to directly power the customer's needs. It is only when the instantaneous generation exceeds the load that power can flow back to the grid. A class of tariffs known as Net Energy Metering are schemes in which the exported power 'turns the meter backward', generating a unit-for-unit credit for the customer. In other words, the utility essentially pays the DG owner the same retail rate as it charges.

But this explanation is an oversimplification. Even within this straightforward NEM tariff, this is room for subtle adjustments. For example, if there is a net export at the end of the billing cycle, is the customer issued a credit, or does it simply roll over to the next cycle? Can credits be accumulated indefinitely or are they swept (set to zero without compensation) at the end of the calendar year? If a payment is made at the end of the year, is it computed at the retail rate, or some other rate such as avoided costs (the cost the utility is avoiding by having the net metering customer provide the power)? There are 43 states that have mandatory NEM regulations and all of these variations are found within those regulations.

Two important observation to be made regarding NEM tariff are: A) When a utility purchases an excess kWh from a DG facility at the same rate they sell kWh to the load, the DG facility is being reimbursed at a rate that has nothing to do with the cost of owning and operating that DG facility, and B) The amount paid to the DG owner is similarly not based on an assessment of the value that kWh has to the utility.

Recent State Study: Vermont

In January of 2013, the Vermont Public Service Department published the results of a study of the costs and benefits of Net Energy Metering, created in response legislation passed in the 2012 session. At the time of the study, NEM was in place since 1999 and represented a cumulative nameplate capacity of 20,910 kW, 87.8% of which was solar photovoltaic PV. The most common installation size range was 3 to 4 kW. In all utilities operating in Vermont, none had NEM representing more than 4% of overall capacity and, on an energy basis, they produced less than 1% of the power Vermont uses each year (NEM generates about 35 GWh/year).

The study attempted to understand the extent to which “cross-subsidization” occurred between NEM and non-NEM ratepayers. “Cross-subsidization” refers to a situation in which some ratepayers are charged more than their share to make up for others who are being charged less. This is a criticism often levied against net metering customers. Included in the analysis was the Vermont solar Credit, which acts as a 10-year feed-in tariff for solar NEM customers. In essence, customers are paid 20¢/kWh for the solar energy they export to the grid (the retail rate in Vermont is 12-15¢/kWh). The tariff is implemented as a combination of NEM (with credits issued for each kWh exported) and an additional payment to make the effective rate of reimbursement 20¢/kWh. The additional payment comes from state funds. In addition to the rate subsidy, the study attempted to capture the benefits of avoided capacity costs, regional transmission costs, and in-state transmission costs that are realized with distributed generation.

The result of the study was an analysis of the costs and benefits (from the ratepayer perspective) of the current net metering program in Vermont and are summarized in Figure 2 and Table 1 below.

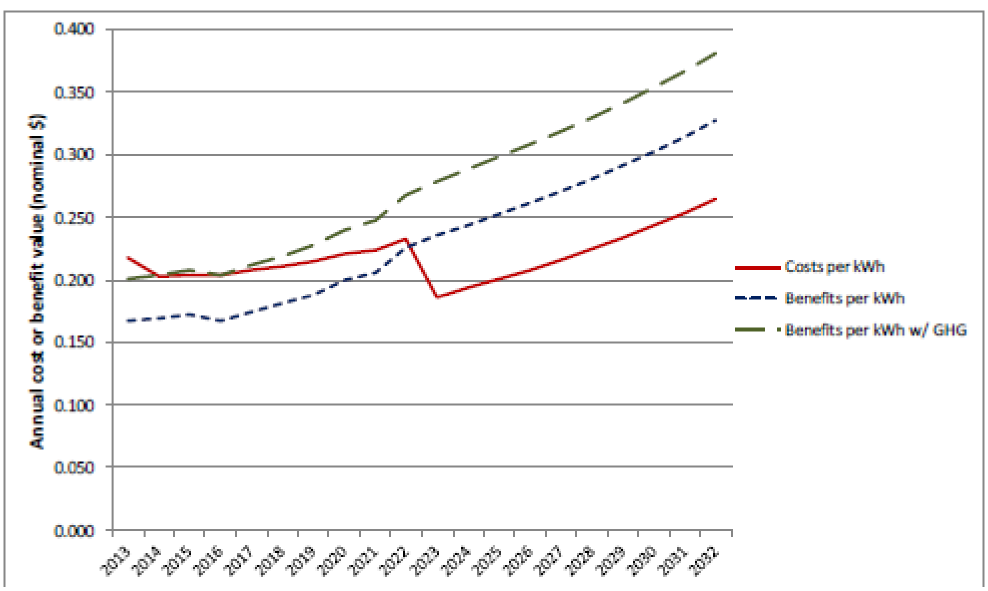

Figure 2: Annual costs and benefits (to non NEM ratepayers) for a 4 kw fixed solar PV residential system installed in 2013 (from Vermont Public Services Study, 2013).

Table 1: 20-year Levelized costs and benefits of NEM (Vermont Public Services, 2013)

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	Benefit	Net Benefit	Benefit	Net Benefit
Ratepayer	0.221	0.215	($0.006)	$0.257	$0.036
Statewide	0.222	0.222	$0.000	$0.264	$0.043

These data, taken directly from the Vermont report, show the results of the study for a typical 4 kW fixed solar PV residential system. The red line shows the costs to the ratepayers (note the feed-in tariff ending after 10 years) while the blue dotted line shows the benefit accruing to ratepayers. The table shows the net cost levelized over the 20 year life of the analysis[1]. Note that, for the case when no GHG value is included, the statewide net benefit/cost of the net metering program is zero. The study further suggests significant benefit to both the ratepayer and the system if regulation comes to pass which creates a cost associated with GHG emissions.

Utility Perspective: Austin Energy

Much of the literature dealing with costs and values of net metering refer to the work commissioned by Austin Energy, the municipal utility of Austin, TX, in 2006 (Hoff, 2006). The study, carried out by Clean Power Research, LLC, was commissioned in an effort to inform the utility's policies to achieve the goal of 15 MW of solar by the end of 2007 and 100 MW of solar by 2020. That goal has since increased to 200 MW by 2020.

The main purpose of this study was to develop a methodology for assessing the value of distributed solar installations so that the incentives, which are in the form of both installation rebates (on a per kW capacity basis) and energy payments (per kWh) can be re-adjusted based on the changing landscape of the utility and the regulations that govern its operation.

The study looked at several types of PV installation including horizontal, 3 different 30° tilt (south-facing, SW-facing and west-facing) and one west-facing at an angel of 45°. The study considered benefits to the system including avoided energy costs, avoided capacity, avoided losses and avoided transmission and distribution investment. Other factors such as environmental impacts and possible reactive power support were considered in the course of the study, but did not contribute to the reported value of the PV systems.

The result of this study, summarized in Table 2, was an estimate of the value of the distributed generation resource to the utility system on both a per kW capacity basis and a per kWh energy basis.

[1] The study used two different discount rates in the levelized cost analysis. The "ratepayer" discount rate was 8.03% while the statewide rate was 5.52%

As shown in the table, the value to Austin Energy of a 1 kW solar installation (south-facing, tilted at latitude) is $2,299 and the resultant energy is worth 11.3¢/kWh.

Table 2: Value of 15 MW of distributed PV for the Austin Energy System (Hoff, 2006)

Value of 15 MW of PV	Present Value ($/kW)	Levelized ($/kWh)
Fixed Systems		
Horizontal	$2,154	$0.111
South 30°	$2,299	$0.108
SW 30°	$2,312	$0.113
West 30°	$2,127	$0.117
West 45°	$1,983	$0.118
Tracking Systems		
1-Axis	$2,813	$0.110
1-Axis 30°	$2,938	$0.109

This methodology has been applied periodically by Austin Energy to re-assess its rebate and energy buy-back program. The installation rebate has been reducing steadily since 2004. Most recently it dropped from $2,500/kW capacity in 2012 to its current level of $1,500 as of May of 2013. The energy price has been less volatile and currently the price that Austin Energy credits customers for every kWh of solar generated is 12.8 ¢/kWh.

Note that Austin Energy does not implement a traditional net metering system. Instead, residents pay for all electrical consumption (whether it was generated by the PV or the utility) according to standard residential rates, while the utility credits the homeowner for every kWh generated by the PV array at a flat rate of 12.8 ¢/kWh. Standard residential rates are tiered (5 tiers at 500 kWh increments) at summer-peak rates. The lowest rate (0 to 500 kWh, non-summer) is 1.8¢/kWh while the highest is 11.4 ¢/kWh. This approach to distributed generation is distinct from net metering and is often referred to as "net purchase and sale" (Yamamoto, 2012).

A very interesting aspect of the Austin Energy study was the analysis of the generating capacity of the DG solar. The study authors used the Effective Load Carrying Capacity (ELCC) method (Garver, 1966). In this method, the generating capacity of a new generator is considered equivalent to the new incremental load that could be supported by that generator while maintaining the same system reliability. This approach accounts for the variability which is inherent in the solar resource. By looking at average weather patterns and correlating them to average usage patterns, and applying sophisticates statistical modeling (which is typical of utility load planning), engineers can estimate the amount to which the grid can depend on a new solar generator to meet increased load. Using this methodology, the generating capacity added by a 1kW south-facing, 30° tilt system is 0.51 kW. This number assumes 10% system-wide solar penetration. The number is higher at more modest levels of penetration (e.g. 0.58 kW at 2% penetration).

Modeling NEM tariffs

Most of the literature surrounding residential PV, net metering and distributed generation focuses on the value these system offer the serving utility and methodology to assess that value. However, there is also need to better understand the value from the perspective of the homeowner under various existing and proposed tariffs.

To understand homeowners experience under various net metering scenarios, a model was developed which utilized PVWatts[2], the DOE program that predicts PV array performance at specific locations around the world. PVWatts will predict hourly PV array outputs (downstream of the inverter) for a given PV array capacity and installation. While PVWatts uses actual weather history, in the form of the Typical Meteorological Year (TMY) for each vicinity, it does not model shading or size effects, so the hourly results for a 1 kW array can be scaled for any sized array, with the caveat that the estimate of performance is likely to be worse as the array size increases as larger arrays are more likely to encounter shading or degraded cells. Two 1 kW arrays are modeled, one in Boise, the other in Pocatello. Both are south-facing with a tilt equal to the latitude.

Two representative residential load patterns are used in this study. These are files with hourly kWh consumption influenced by the seasonal weather variations as well as random fluctuations that are typically seen in actual use patterns. Two different files are used, one typical of homes that are heated by natural gas and requiring significant air conditioning in the summer. Homes in Southwest Idaho meet this description. The other load pattern is typical of homes in the south-central and Eastern Idaho where natural gas is not as widely available and winters are more severe. We refer to the first usage patterns as the summer-peaking pattern, the latter is the winter-peaking pattern. Like the PV Watts results, these load files are easily scaled to achieve an arbitrary average load value.

For each location, a PVWatts and load file are used as the starting point. For Boise-area homes we use the Boise PVWatts file and the summer-peaking load profile. For Eastern and South-Central homes, we use the Pocatello PVWatts file and the winter-peaking load profile.

Then for each hour of the year, the difference between the load and the PV production is computed. If that number is positive, that value is considered a "grid purchase", if negative, than that value is consider a "grid sales".

The hourly data is sorted by month and for each month in a calendar year, the total load kWh, the total Grid Sales and the total Grid Purchases are computed. The model also identifies the highest hourly net grid purchase for each month. This will be used to determine the Basic Load Capacity for each case.

[2] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/

After the monthly totals are computed, the various tariff scenarios are applied and the annual cost associated with each tariff is computed. Costs are limited to three categories: Energy cost (per kWh with allowances for tiered structure and seasonally varying rates), Fixed charges (those charges that are invariant relative to energy use), Demand or Basic Load Capacity charges (those charges based on peak demand over a time period). In addition, the model allows for various means of dealing with excess generation including payments to customers or monthly carry-over credits with checks issued on balances at the end of the year, or balances swept by the utilities at the end of the year.

Two tariffs, designated A and B, are considered in this study. Each has a different energy rate, set in tiers and seasonal differentials and each has a different monthly charge. Tariff B additionally has a Basic Load Capacity charge while Tariff A does not. Finally, under tariff A, a customer would be paid at the end of the calendar year if a generation credit exists (at the retail rate) while tariff B simply eliminates the credit at the end of the year. Details of the tariffs are shown in Table 3.

Table 3: Details of the two tariffs studied

Tariff A			**Tariff B**		
Energy Charge			Energy Charge		
Tier	Non-Summer	Summer	Tier	Winter	Summer
0-800 kWh	$0.072355	$0.078428	0-800 kWh	$0.048512	$0.052583
801-2000	$0.080519	$0.095788	801-2000	$0.053985	$0.064223
Above 2000	$0.089960	$0.115166	Above 2000	$0.060315	$0.077215
Monthly Charge	$5.00		Monthly Charge	$20.02	
BLC Charge	None		BLC Charge	$1.48	Per kW BLC
12-month credit	Paid at retail rate		12-month credit	swept	

For each case considered, the following results were tabulated:

- Baseline Costs: The annual costs under Tariff A with no PV production
- Annual Costs Under Tariff A
- Annual Costs Under Tariff B
- Basic Load Capacity (BLC). The BLC is the average of the two monthly peak demands over the course of the year. Some proposed tariffs include a per kW BLC charge, as is the case for most commercial and industrial customers. Note that the model presented here can only compute the highest average hourly demand while, in most cases, the BLC is set by the highest 15-minute demands. It is clear that the 15-minute BLC will be higher than the hourly, but it is not clear how much. Very limited research indicates that the 15-minute BLC is likely to be about 50% higher than the hourly one. Therefore, a factor of 1.5 is used in computed the BLC-related charges, but the tables show the hourly BLC.

- Net-Zero Ratio (NZR). The NZR is the ratio of total PV production over the year divided by the total load requirement. NZR = 1.0 indicates a net-zero home. Greater than 1 indicates a net producer of electricity.
- 12-month credit. The 12-month production credit assumes that monthly excess production is credited against the next month's bill until the end of the year. This is the production that is not compensated under Tariff B.

Examples

Using this model, we look at the costs incurred by a typical residential load (summer peaking, 1.4 kW average consumption) with a 5 kW installation. The results are summarized in Table 4.

Table 4: Tariff Model results for a 1.4 $kW_{(avg)}$ home with 5 kW capacity PV array in Boise, ID

	Value	Units
Total Consumption	12,264	kWh
Total PV Production	6,824	kWh
Total Grid Purchases	7,936	kWh
Total Grid Sales	2,496	kWh
Baseline Costs	$1,003.90	
Tariff A Costs	$ 463.28	
Tariff B Costs	$ 574.56	
BLC (hourly)	2.4	kW
NZR	0.56	
12-month credit	0	kWh

The table reveals the following results for an average home with an average PV installation. The 5 kW array generates 56% of the homeowner's needs and under the straight-forward net metering tariff, she would save $540.62 per year compared to the same home without PV. The proposed net metering tariff would also save the homeowner money, but somewhat less: $429.34. There are no credits remaining at the end of December under either Tariff A or B.

Further analysis shows that to achieve net-zero using PV, a home with an average load of 1.4 kW in Boise would need a 9 kW array. This case is shown in Table 5.

Table 5: Tariff Model results for a 1.4 $kW_{(avg)}$ home with 9 kW capacity PV array in Boise, ID

	Value	Units
Total Consumption	12,264	kWh
Total PV Production	12,283	kWh
Total Grid Purchases	7,346	kWh
Total Grid Sales	7,365	kWh
Baseline Costs	$1,003.90	
Tariff A Costs	$ 57.90	
Tariff B Costs	$ 327.95	
BLC (hourly)	2.4	kW
NZR	1.00	
12-month credit (paid only under Tariff A)	508.9	kWh

Table 5 shows a subtle implication of the practice of sweeping the excess production after 12 months. The salient point is that the alignment of the 12-month period affects the value of the credit at the end of the period. In this case, consumption exceeds PV production in January and February, resulting in a net credit at the end of December, even though the total consumption and total PV production are nearly the same. If the 12-month period started in March, the net credit at the end of 12 months would be much closer to zero.

Tariff Analysis: Boise Region

To better understand how the situations compare under a range of loads and PV installations, the model was run for 6 different values of average load (from 0.8 to 3 kW) and for 9 different values of installed PV Capacity (from 0.16 to 25 kW) for a total of 54 separate cases, summarized in Table 6.

Table 6: Parameter values for cases analyzed. All combinations of the 6 average loads and 9 PV capacities were used for a total of 54 cases.

Average Load (kW)		PV Capacity (kW)
0.8		0.16
1		1
1.4		2
2.0		5
2.5		7
3.0		10
		15
		20
		25

Figure 3 shows the baseline costs (assuming no PV production) for the six different loads analyzed, computed using Tariff A. Annual costs vary from about $600/year for an average load of 800 Watts to about $2300/year for a 3 kW_a load.

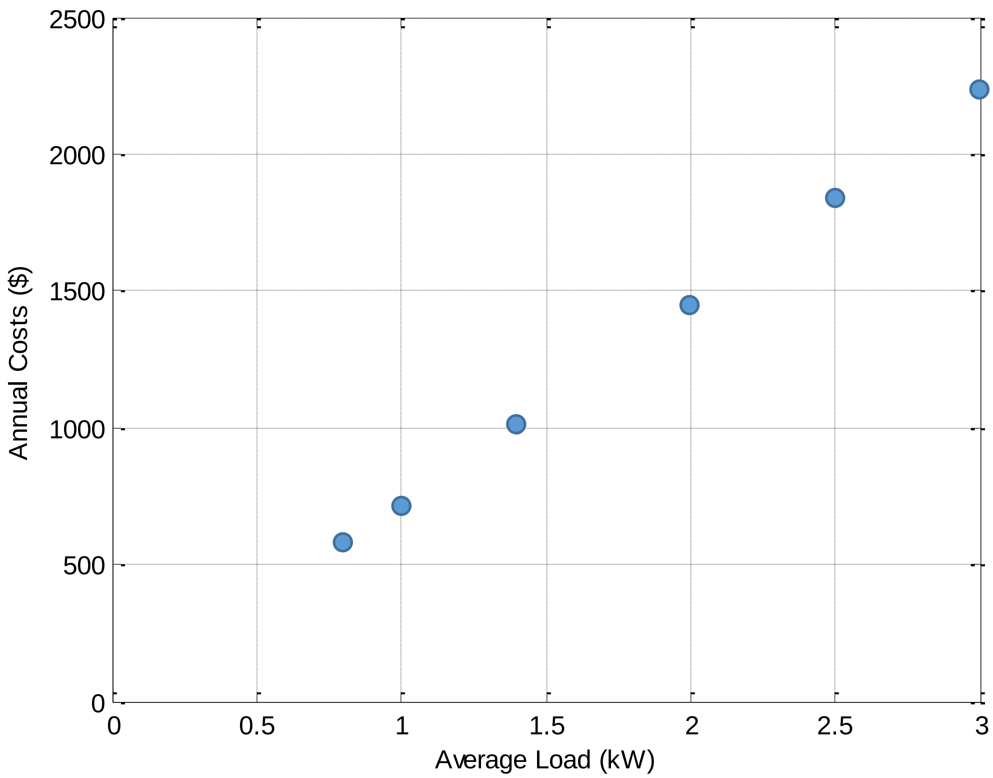

Figure 3: Annual costs (energy + customer charge) for various average loads with no PV under Tariff A.

In the following figures, the costs and other variables are plotted as a series of lines against the average load of the residence. Each line represents a different PV capacity as summarized in Table 6. In general, the lines indicating higher annual costs correspond to the lowest PV capacity. Note that since the smallest PV capacity is 0.16 kW, that line is generally indistinguishable to the baseline costs (shown in Figure 3) in each case.

Figure 4 shows the annual costs computed for all cases under Tariff A.

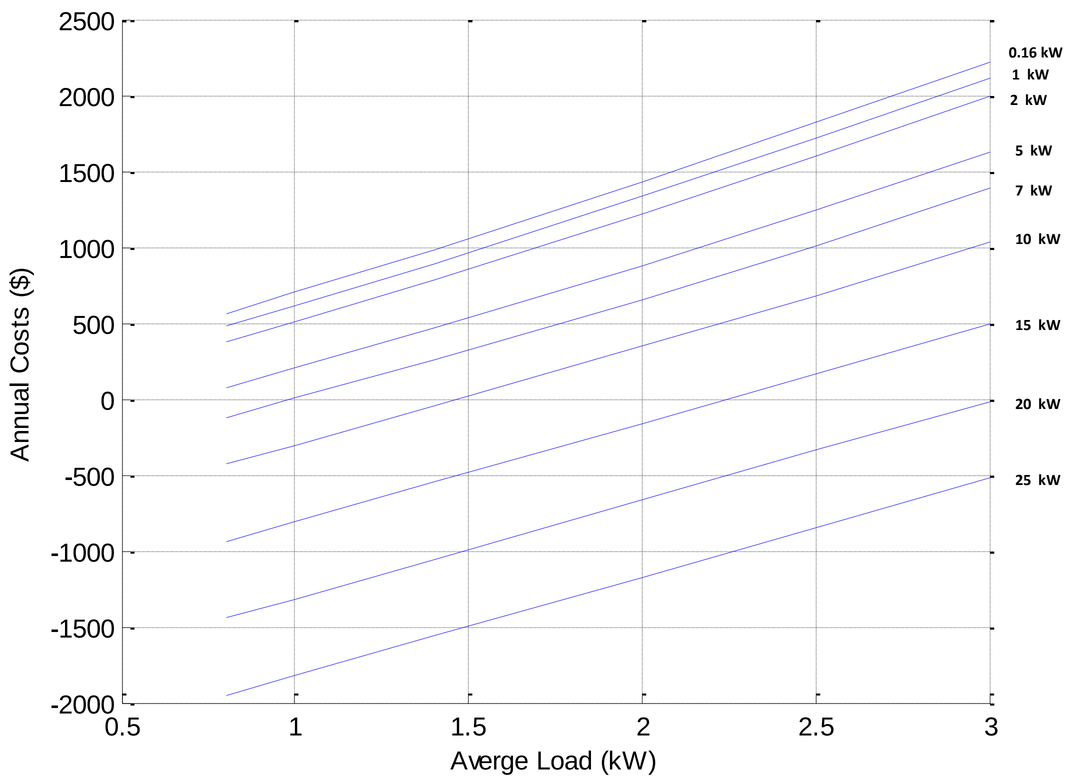

Figure 4: Costs vs. average load for Tariff A. PV capacity varies from 0.16 kW (top line) to 25 kW (bottom line)

Figure 4 shows that for a 1.5 kW average load, any PV installation above 10 kW under Tariff A results in a net payment to the customer at the end of the year. The extreme case shows an 800 Watt customer with a 25 kW array receiving nearly $2000/year payment from the utility.

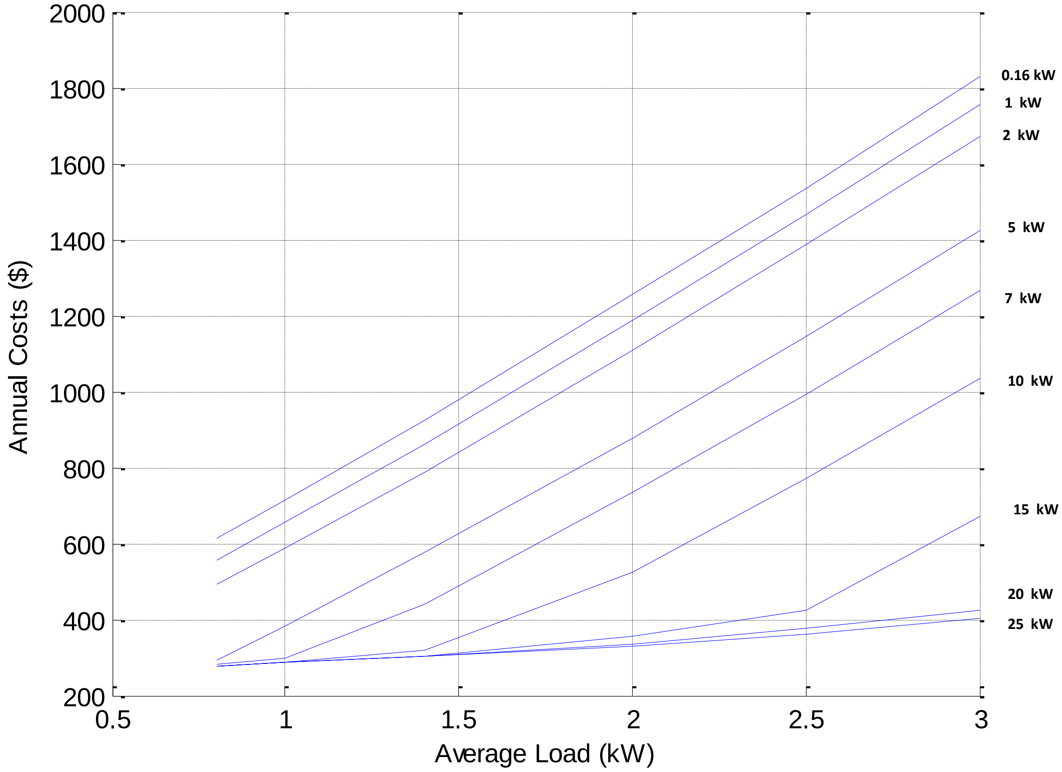

Figure 5: Costs vs. average load for Tariff B. PV capacity varies from 0.16 kW (top line) to 25 kW (bottom line)

Figure 5 shows the effect of Tariff B on payment for PV generation. The combination of sweeping the 12-month credit and a 4-fold increase in the monthly charge results in a floor of about $275 annual charge regardless of how much excess production the PV array generates. A 1.5 kW load with a 10 kW array (just over net zero) will pay about $350/year under Tariff B, as opposed to just a few dollars per year under Tariff A. In both cases, the amount of energy produced is very close to the amount generated.

In Figures 6 and 7, showing the annual credit and then the Net Zero Ratio on the y-axis, the higher PV capacities become the upper lines. Figure 6 shows the calendar year credit of production. The case that we have been tracking, 1.5 kW average load, 10 kW PV array, results in an end-of-year credit of about 1500 kWh of electric production. Note that a 5 kW array with the smallest analyzed load produces a negligible excess credit. Lower capacities produce no end-of-year credit.

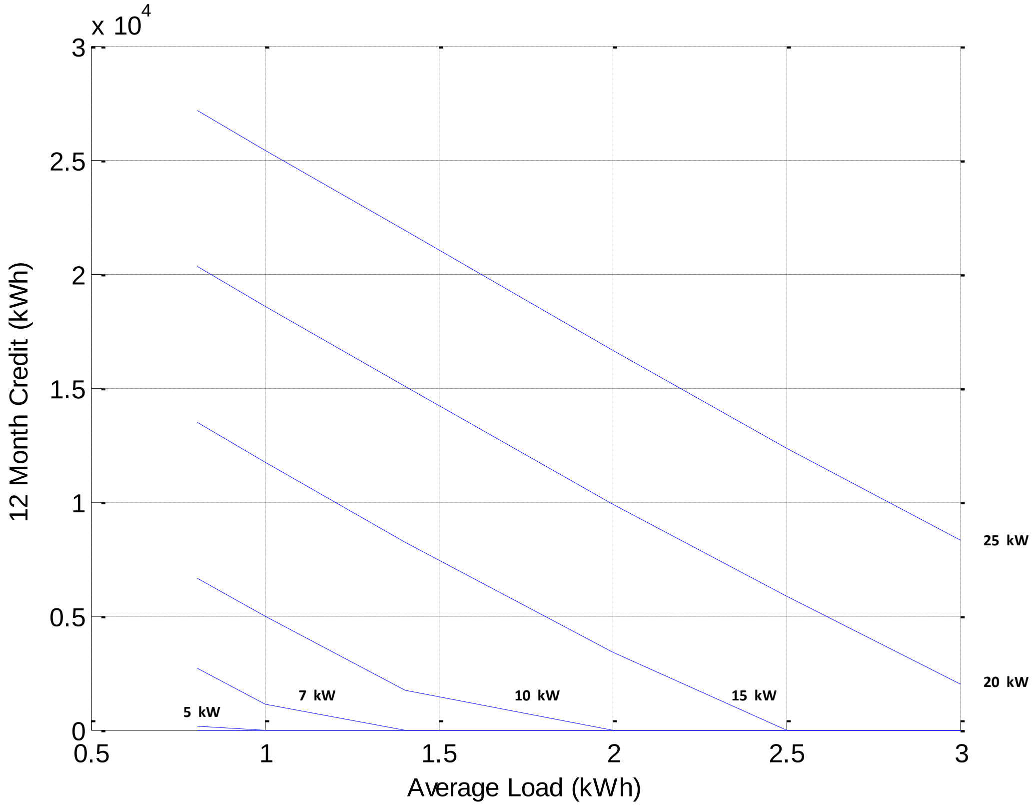

Figure 6: 12-month production credit based on the calendar year. Lines represent installed PV Capacity from 25 kW (top line) to 5 kW (lowest visible line)

Figure 7 is a plot that can be useful for finding the PV capacity to yield a net-zero home. The horizontal line at NZR=1.0 contains those combinations that result in net-zero energy (electric). Again, looking at 1.5 kW load, we see that a 10kW array yields an NZR of just over 1.0.

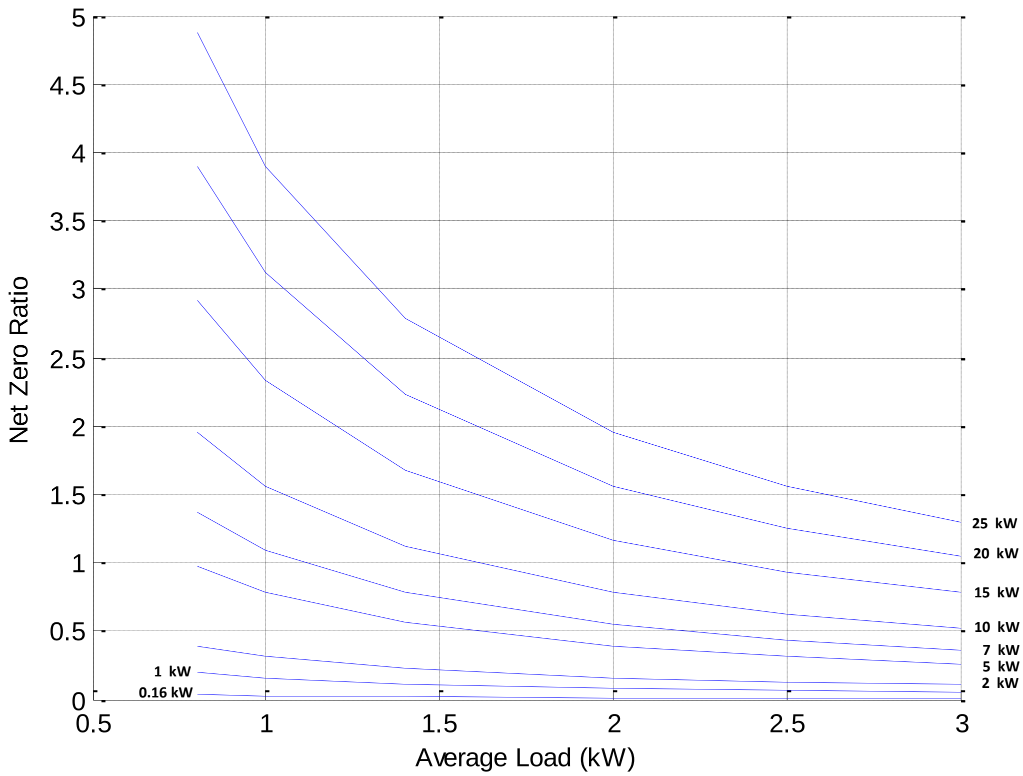

Figure 7: Net Zero Ratio (NZR) for PV installations in Boise. Lines represent installed PV Capacity from 25 kW (upper line) to 0.16 kW (bottom line).

The previous figures represent a large amount of data and can be difficult to interpret. One method of collapsing complex data sets is to find dimensionless parameters, or ratios of like variables, to graph the results against. In this case the ratio of the installed PV capacity to the annual average of the load it serves is a likely candidate. For example, if a residence with an annual load of 1 kW installed a 5 kW PV array, the ratio of PV capacity to load would be 5:1, or simply, 5.

Against this ratio, we plot the difference of the annual energy costs imposed by the two tariffs. Figure 8 shows this composite graph in which each data point represents a separate case that was considered. The x-axis is the PV-to-Average Load ratio, the y-axis is the annual cost under tariff B minus the annual cost under tariff A. Positive numbers indicate higher costs under tariff B.

The vertical line indicates a PV to load ratio of 6.5 that will generally result in a net-zero home in the Boise region.

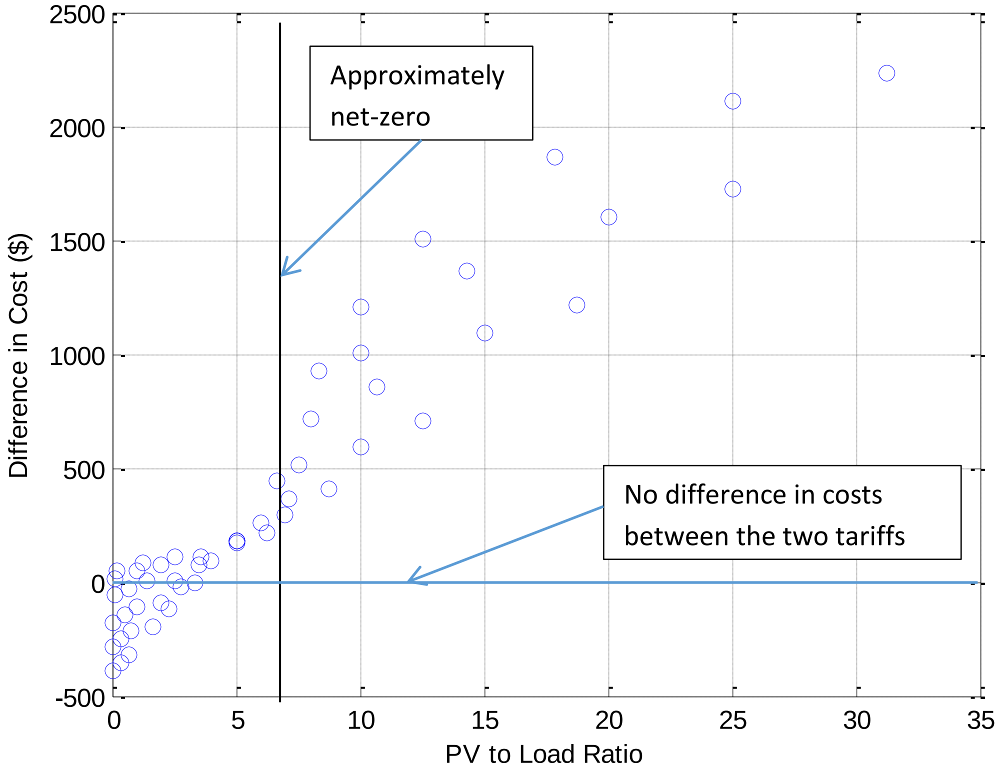

Figure 8: Difference in annual costs of Tariff B over to Tariff A vs. the ratio of PV capacity to average load.

The analysis indicates that homeowners attempting to achieve net zero would be paying an additional $250 to $500 per year under tariff B.

Those that benefit the most under tariff B, saving nearly $500/year on their bill relative to tariff A, are homes with relatively large loads and the smallest PV installation analyzed (160 W).[3]

Data points on the horizontal zero cost line represent those cases for with the annual costs would be same for the two tariffs. Note those cases are all for relatively low values of PV capacity to load.

[3] 160W was chosen because that is the typical capacity of a single PV panel available for residential installation and hence, the smallest possible PV installation.

Tariff Analysis: Pocatello Region

Our analysis shows only subtle differences between cases in summer-peaking Boise and winter-peaking Pocatello. Similarly to Figure 8, Figure 9 shows all the cases run using the winter-peaking profile and the PVWatts results for Pocatello. The results are substantially the same as Boise with minor exceptions. For example, there are fewer points that lie below zero cost difference of Pocatello, suggesting that Tariff B will be more costly for Pocatello than for homeowners in Boise. These results suggest that tariff B is somewhat less beneficial to residences with winter peaking patterns than those with summer peaking patterns.

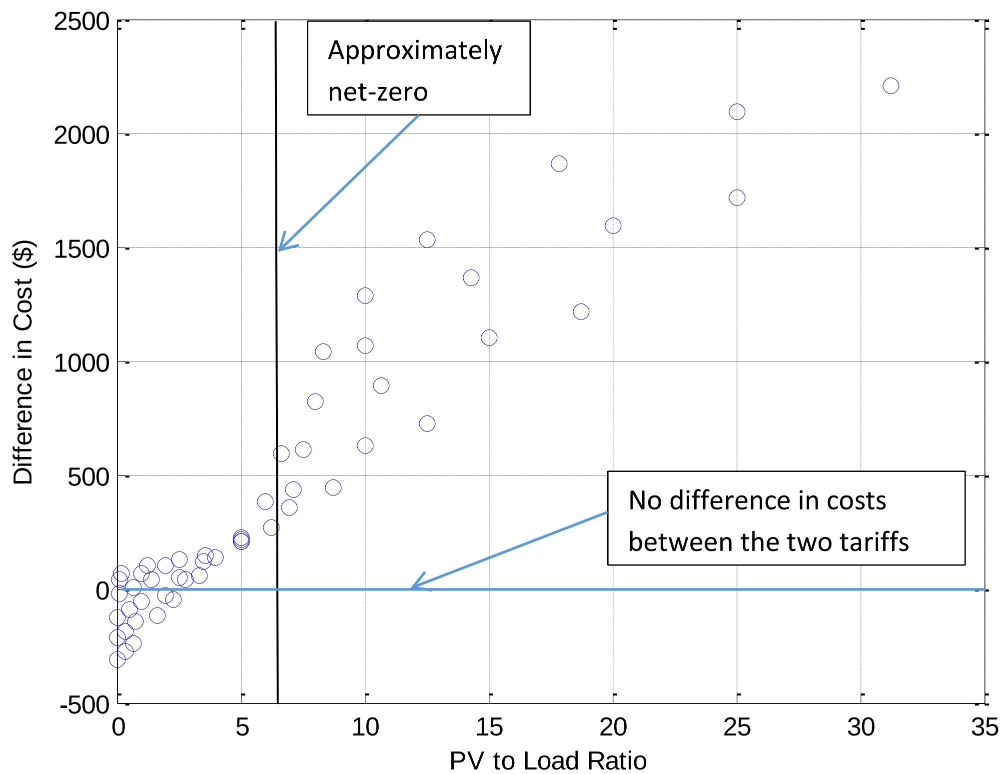

Figure 9: Cost Difference under Tariff B relative to Tariff A for winter-peaking load in Pocatello

Discussion

Tariff design to accommodate distributed generation is a rapidly evolving field and new approaches are suggested on a regular basis. Questions of value, cost and cross-subsidization are central to the discussion. It is clear that the questions of which approach is best will not be settled any time soon. Nevertheless some consensus is emerging.

Both the academic literature (Prinia et al., 2011)(Burns and Kang, 2012) and the careful studies by state energy offices and utilities strongly agree that the value of residential photovoltaic systems to the utility system are both real and significant(Hoff et al, 2006)(Vermont, 2013)(Beach et al, 2012) . The value derives from both intrinsic and extrinsic benefits. Intrinsic benefits include those traditionally measured by utility operators and include deferred investment in new generation due to the added generation capacity, decreased likelihood of over-capacity and deferred transmission and distribution investments. Extrinsic befits, including those referred as societal benefits include reduced greenhouse gas emissions, reduction in other air pollutions that result from coal or gas-fired power plants, and reduced water withdrawal and consumption.

Importantly, the success and customer experience in net metering environments are strongly dependent upon the underlying (non-DG) rate design. In particular, (Darghouth, 2011) found that inclining block rates (tiered rate structures such as Tariff A and Tariff B in this paper) "provide differentially greater support for PV adoption among high use customers." The author further found that the steeper the tiers, the bigger the effect.

Conclusion

The current state of electric utility rate design is a complex and highly specialized field. As opposed to other energy commodities such as gasoline and natural gas, electricity costs have multiple elements that are difficult for the typical customer to grasp and even more difficult to interpret in light of their behavior. When the variable performance of a home PV system is layered on top of that, it compounds the issues. Finally, when complex modifications to straightforward net metering tariffs are suggested, interpreting the impact of proposed tariffs becomes next to impossible for all but the most trained and patient customer.

However, the widespread deployment of Advanced Metering Infrastructures (aka "smart meters") enable the development of new analytical and predictive tools that may allow customers to make better informed decisions based on their actual usage patterns. Combining high resolution usage data with rapidly evolving PV modeling tools such as PVWatts, can provide a power tool that can not only help inform the consumer, but can also be an important part of the actual rate design process. To the extent that the utility staff make these tools and their results available to the general public, the transparency of the process can be dramatically improved.

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