RATE DESIGN MATTERS

The Impact of Tariff Structure on Solar Project Economics in the U.S.

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GTM RESEARCH
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Contents

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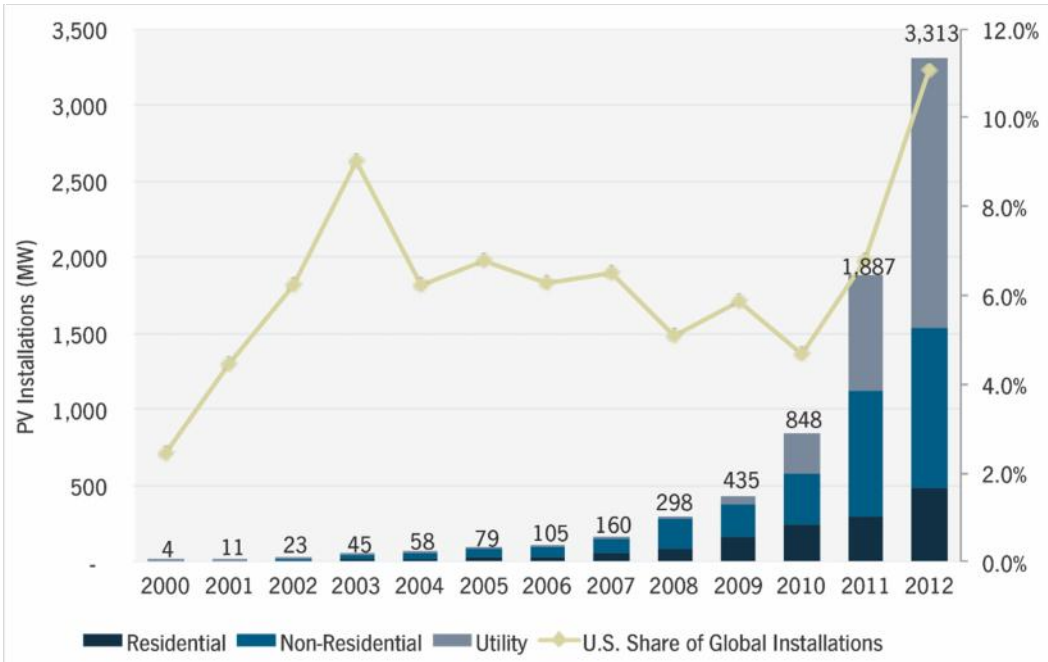
1. Introduction

With the 30 percent Federal Energy Investment Tax Credit (ITC) set to expire at the end of 2016 and many states approaching near-term compliance with their respective renewable portfolio standards (RPS), the U.S. solar market is headed for a dramatic transformation. Anticipating these changes, GTM Research has begun to assess the U.S. solar market on a more granular level. We're particularly interested in changes in project economics as the market transitions away from the incentive schemes that have bolstered demand to this point.

Figure 1.1 U.S. PV Installations and Global Market Share, 2000-2012



Source: GTM Research/SEIA U.S. Solar Market Insight Report, 2012 Year in Review

To assess the potential for solar deployment going forward, we are looking for a scenario where solar becomes cost-effective without state- and utility-level incentives (and, after 2016, without the 30% ITC). In the distributed generation market, we highlight an initial tipping point when developers can offer customers a power purchase agreement (PPA) at less than retail electricity prices.

In undertaking this comparison, we've come to recognize the considerable impact of rate design on project viability. We will continue to assess overall project economics through 2017, but in the meantime we wanted to provide an analysis showing that **tariff design can make or break solar project economics**. As any installer knows, solar often does not reduce a customer's bill by the full retail rate. There are fixed charges on most bills (particularly in the commercial sector), not to mention nuances such as time-of-use pricing and tiered rates, that drastically alter the competitiveness of a solar project.

In this paper, we'll take a closer look at how commercial solar stacks up under default and "solar-friendly" rate structures in California and seek to highlight the role of utility tariffs in the deployment of distributed solar going forward.

2. The Competitiveness of Distributed Solar

In assessing the potential for solar deployment, our core assumption has been that solar becomes economical when developers can offer customers PPAs in which electricity is priced at rates that are lower than retail rates. Further, if a PPA has an escalator, it should be less than historical increases in energy prices.

For our analysis, we'll assume that the benchmark for a good deal—the tipping point where solar becomes competitive with traditional generation—is 10% day-one savings to the end-customer with a 2% annual PPA escalator. When looking at project economics, there can be many different "tipping points", (i.e., varying initial savings vs. escalators), but we've set this particular benchmark based on a multitude of discussions with industry participants.

This point can be determined by comparing levelized cost of energy for a solar system to retail electricity charges. In looking at energy cost, as opposed to capital cost, we are able to assess the competitiveness of solar versus traditional generation.

2.1. Model Assumptions

The levelized cost of energy (LCOE) is a measure of total generation cost in dollars per kilowatt-hour (kWh) over the lifetime of a PV system. An LCOE calculation consists of four main components: capital cost, fixed O&M cost, variable O&M cost, and fuel cost.

For our analysis of the distributed generation market in California, a 500-kilowatt commercial system was modeled in two utility territories: Southern California Edison (SCE) & San Diego Gas & Electric (SDG&E). Model assumptions are set forth in the following table.

Figure 2.1 Commercial LCOE Model Assumptions, 2013

Commercial		
General		
City	Long Beach	San Diego
Utility	SCE	SDG&E
Capacity Factor	18.7%	19.4%
DC-to-AC Derate Factor	80%	
Site Type	For-profit commercial rooftop	
DC System Capacity (kW)	500	
System Lifetime (years)	25	
Output Degradation (starting in year 2)	0.50%	
Financing		
Federal Tax Rate	35%	
Equity Financing	30%	
Debt Financing	70%	
Equity Required Return	11%	
Debt Required Return	7.0%	
Weighted Average Cost of Capital	8.2%	
Inflation	2.0%	
Discount Rate	6.2%	
Costs		
Installed Cost - 2013 ($/W)	$3.85	$3.75
System Cost	$1,922,974	$1,876,525
Fixed O&M Cost ($/kW/year)	$25	
Variable O&M Cost ($/MWh)	$1.10	
Sales Tax Assessment (% of project costs)	100%	
Effective Sales Tax	8.13%	
Incentives		
Federal Tax Credit (% of Expenditures)	30%	

Source: GTM Research

Our analysis uses a real LCOE in order to account for the impacts of inflation over the 25-year life of the system. By incorporating a 2% inflation rate, the nominal discount rate is adjusted down to get a real discount rate. This is essentially the same as incorporating a 2% escalation rate into the PPA.

GTM's LCOE model includes no incentives or subsidies apart from the 30% ITC and the Modified Accelerated Cost Recovery System (MACRS). In 2017, the ITC is stepped down to 10% for commercial systems in accordance with Section 48 of the Internal Revenue Code.

Installed cost assumptions are derived from California Solar Initiative data for the various utility territories and are shown in the following chart.

Figure 2.2 Commercial Installed Cost Assumptions, 2013E-2020E

$/W	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
SCE	$3.85	$3.75	$3.51	$3.36	$3.21	$3.07	$2.94	$2.82
SDG&E	$3.75	$3.66	$3.42	$3.27	$3.13	$3.00	$2.87	$2.75

Source: GTM Research

Note that there is significant room for debate on where installed prices will go—and significant variability among systems in any given year (e.g., in 2013, we might have some residential systems at $3.00/W and others at $5.50), but regardless, *the impact of rate design remains the same*. These assumptions for system price reductions are also intentionally conservative – system prices in later years may be significantly lower than we model here. Again, the primary focus in this paper is on the impact of varying rate structures, not the individual project assumptions.

2.2. Avoided Cost Calculations

In undertaking a cost comparison between solar and traditional generation, **we cannot simply look at average retail rates**, as this typically overestimates the savings derived from installing solar. This is a common error contained within well-intentioned solar "grid parity" analyses. **Though solar can offset a portion of the rate paid to a utility, not all segments of a bill can be avoided.** Therefore, the viability of solar is driven almost entirely by rate design.

Electricity tariffs generally consist of three types of charges:

1. **Fixed charges**, which do not change with energy consumption; these charges typically involve a single customer charge allocated per meter and per day.
2. **Demand charges** calculated on a per-kW basis for customer's maximum registered power demand during each billing cycle; generally recorded over a 15-minute period.
3. **Consumption charges** based on kWh of energy used; this is the piece of a customer's monthly bill that can be avoided with solar; includes generation charges, transmission charges, and distribution charges.

Additionally, these charges may be varied by season or time-of-use (TOU) tier. Rates with seasonal and TOU adjustments generally have a higher avoided cost with installed PV, as the load profile of a solar system matches the increased rate tiers associated with these adjustments fairly well.

Particular aspects of tariff design can be more or less friendly for customers with installed PV. For instance, rates with the majority of charges from consumption and very little from demand generally provide a high potential for avoided cost, and thus better solar economics.

For our analysis, we calculate avoided cost as follows:

(ANNUAL UTILITY BILL PRE-SOLAR – ANNUAL UTILITY BILL POST-SOLAR)/ANNUAL PV PRODUCTION

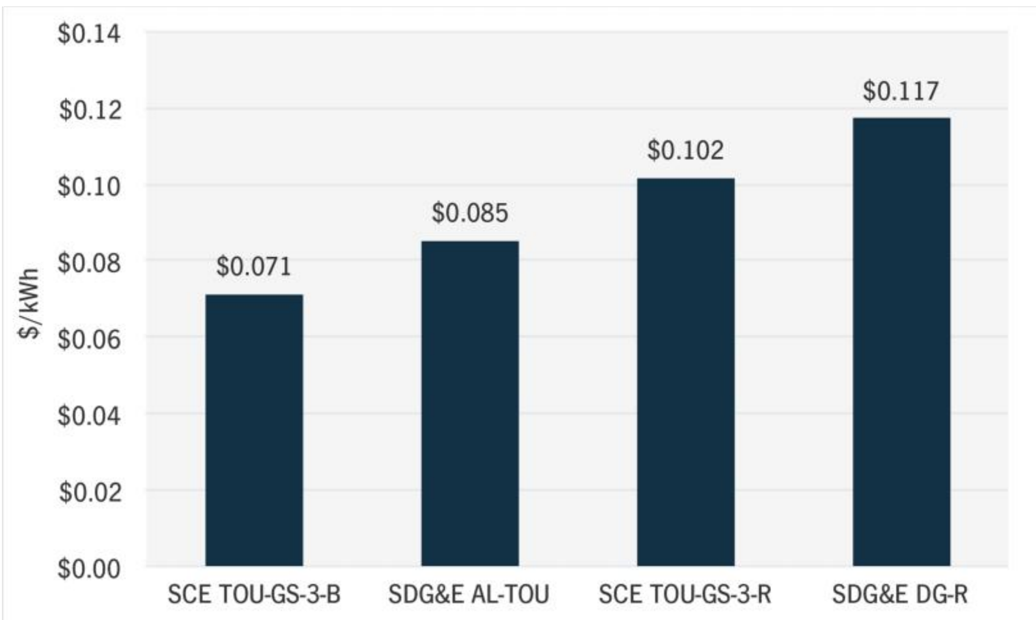
We use Genability's Explorer tool to reproduce an example of a customer's utility bill with and without solar in SCE and SDG&E territories. Customer load profiles were modeled for the two investor-owned utilities, based on the assumption that the 500 kW installations would offset approximately 75% of the customer's annual electricity use.

Figure 2.3 Assumed Commercial Customer Load Profiles

	SCE	SDG&E
Annual Usage (kWh)	994,291	1,051,057
Annual PV Production (kWh)	745,460	787,435
Usage Reduction (%)	75%	75%

Source: Genability Explorer

Figure 2.4 Avoided Cost of Commercial Solar, 2013



Source: GTM Research

Figure 2.4 illustrates the variation in avoided costs across four commercial tariffs:

- SCE's General Time-of-Use, Demand Metered, Option B (TOU-GS-3-B)
- SCE's General Time-of-Use, Option R (TOU-GS-3-R)
- SDG&E's General Time Metered (AL-TOU)
- SDG&E's Distributed Generation Renewable Time Metered (DG-R)

Of these four rates, two are renewable-specific and see the highest avoided cost:

SCE's TOU-GS-3-R is for customers who install, own, or operate eligible on-site renewable energy generation systems with a net capacity of 15% or more of their annual peak demand. Typically, this tariff generates 30% more savings than a traditional rate with no on-peak or mid-peak demand charges, a reduced Facilities-Related Demand Charge, and higher on-peak and mid-peak energy charges than Option B.

SDG&E's DG-R is a voluntary rate for metered non-residential customers with operational distributed generation equal to or greater than 10% of peak annual load. The tariff has reduced demand charges and higher TOU rates relative to a default commercial rate.

Figure 2.5 Rate Structure Comparison: Charge Type as a Portion of Total Bill

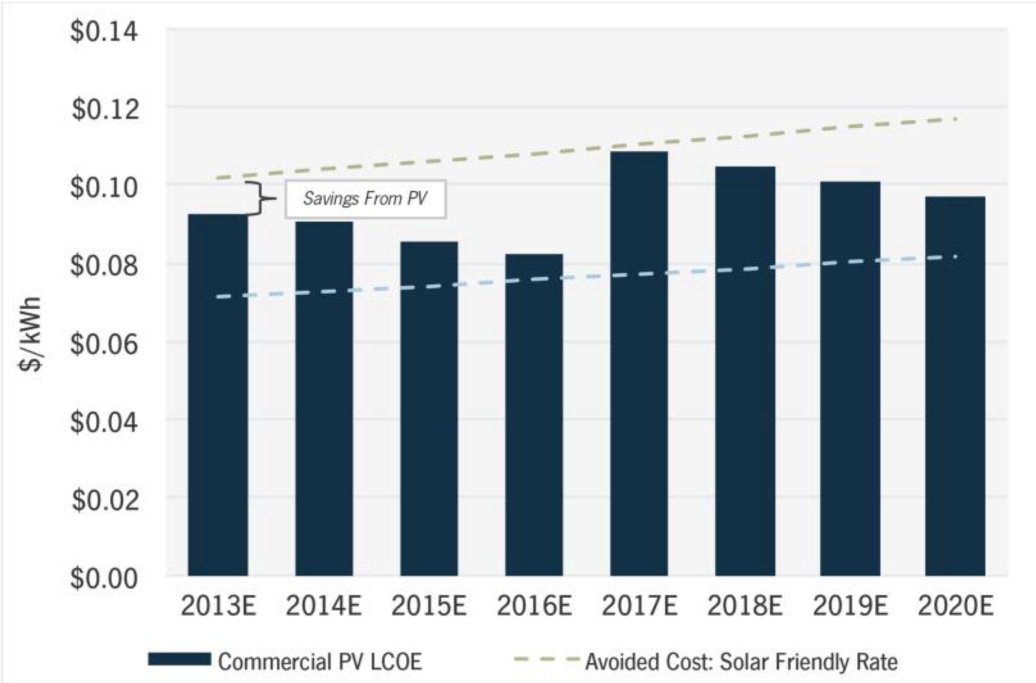
	SCE TOU-GS-3-B	SCE TOU-GS-3-R	SDG&E AL-TOU	SDG&E DG-R
Rate Type	Default	Renewable	Default	Renewable
Fixed Charges	9%	14%	1%	2%
Demand Charges	69%	37%	73%	41%
Consumption Charges	22%	49%	26%	57%

Source: Genability Explorer

2.3. The Impact of Rate Design on Project Economics

Comparing LCOE and avoided cost, we can estimate the point in time when developers can offer a PPA to customers at less than retail prices, with an escalator equal to inflation, and assess the potential for commercial solar deployment in California.

Figure 2.6 Economics of Commercial Solar vs. Grid Electricity, California (SCE)



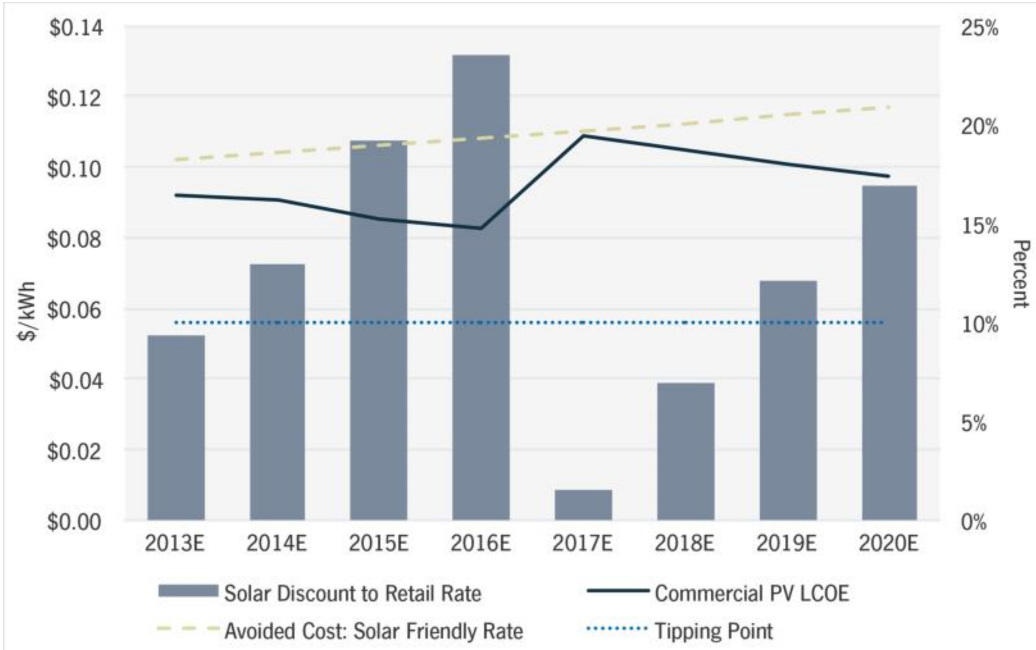
Source: GTM Research

Figure 2.6 illustrates the comparison for a commercial customer in SCE territory. In this scenario, customers installing PV at SCE's solar-friendly rate (TOU-GS-3-R) have the ability to capture monetary savings this year. Solar will remain cheaper that traditional generation under the solar-friendly rate even with the step-down of the ITC to 10% in 2017, though at that point the savings are negligible.

For customers on SCE's default commercial rate (TOU-GS-3-B), installing solar in an incentive-free market is not cost-effective. As evidenced by Figure 2.6, solar generation remains more expensive than retail electricity for the foreseeable future given our system price reduction assumptions.

Looking more closely at the avoided cost potential for a commercial customer with installed PV, savings can be calculated as solar's discount to traditional generation. As discussed, we assume that the benchmark for a good deal is 10% savings to the end-customer with a 2% escalator—the tipping point where solar becomes competitive with traditional generation.

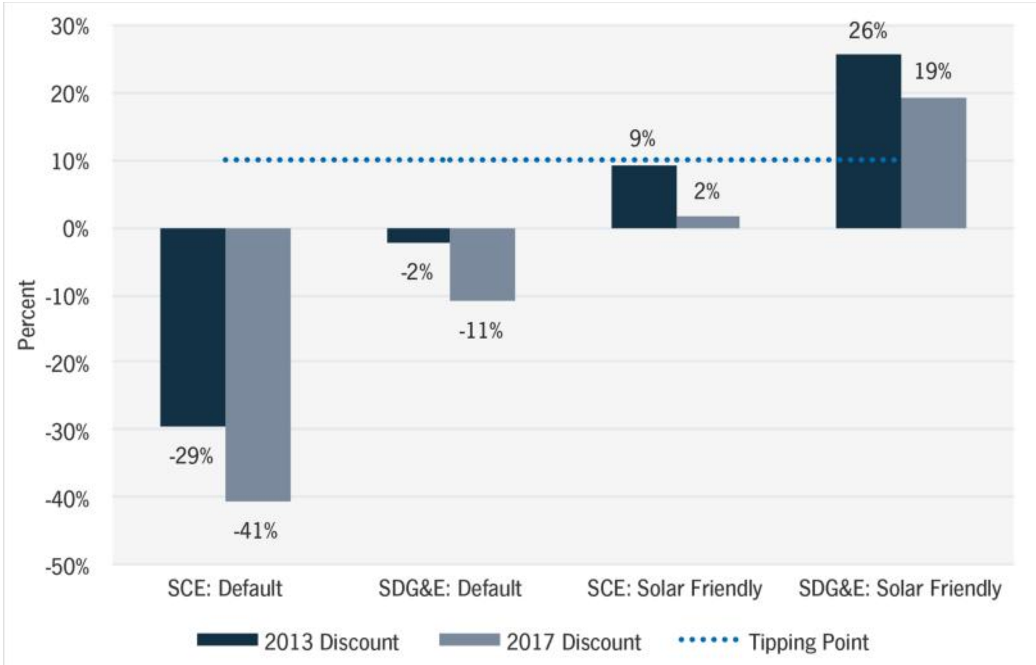
Figure 2.7 Economics of Commercial Solar: Solar-Friendly Tariff, California (SCE)



Source: GTM Research

Figure 2.7 shows installed PV's discount relative to retail electricity for a SCE commercial customer on a solar-friendly tariff scheme. Though the LCOE of solar is lower than traditional generation from 2013 to 2020, it will not hit the tipping point until 2014, when PV generation costs are more than 10% less than retail electricity rates. In the meantime, California Solar Initiative incentives will carry the market. With the step-down of the ITC in 2017, the discount dips below the assumed tipping point, recovering to economical levels by 2019.

Figure 2.8 Commercial Solar Discount to Retail Rates, 2013 & 2017



Source: GTM Research

Assessing the solar discount across rates illustrates the ability of renewable-specific tariffs to make or break PV project economics. In these markets, solar is often not economical for commercial customers under a default rate—fixed and demand charges tend to make up a significant portion of traditional commercial rates, and savings related to these charges cannot be guaranteed through a PV installation. However, under a solar-friendly tariff structure, with reduced demand charges and higher-priced TOU tiers, installed PV becomes more attractive. Commercial customers on SDG&E's DG-R tariff can generate solar at more than a 25% discount relative to retail electricity in 2013 and a 19% discount in 2017. Under SCE's TOU-GS-3-R rate, commercial customers surpass the 10% tipping point by 2014.

3. Conclusion

In assessing the potential for solar deployment, it is difficult to apply broad conclusions, as project economics are installation-specific. However, **the influence of tariff design on project economics permeates the U.S. solar market**. The good news for the solar industry is that there are places in the U.S. right now where solar is cheaper than retail power. The bad news is that the existence of this cost advantage depends entirely on a given customer's electricity rate structure.

We draw a few key conclusions from this analysis:

- Rate design is one of the most important factors in determining the competitiveness of distributed solar. Factors such as fixed/demand charges, time-of-use pricing, and tiered rates can make or break entire PV markets.
- Project economics are customer-specific—various factors (including load size, installation size, percent of energy offset, location, roof orientation, and utility territory) affect a particular customer's value proposition.
- Where available, renewable-specific tariffs can create solar demand where it would not be otherwise.

We have already seen a push for solar-friendly tariff design in California. In the settlement of SCE's and SDG&E's 2012 General Rate Case Phase 2 proceedings, the utilities agreed to continue Option R and DG-R rates based on a cost/benefit analysis. PG&E is currently assessing the potential of adding a renewable option to commercial rates E-19 and E-20, attempting to determine whether shifting some portion of generation and distribution charges to TOU charges may more appropriately recover capacity-related costs from customers with distributed generation solar.

While our analysis here has focused on positive (i.e. solar-friendly) tariff design, it can go both ways. Some markets (most notably Texas) have been severely constrained by rate structures that allocate a larger portion of the bill to demand charges, while other markets (most notably commercial PV in Arizona) face a potential cliff as a combined result of falling incentives and relatively unfriendly rate structures. Given the full assault being directed at net metering by the IOUs, it will take substantial stakeholder pressure to ensure that rate structures become more favorable to solar, outside of what is legally mandated.

It remains to be seen how utilities will embrace rate design going forward. Regardless, rate design is just as important as net metering in determining the long-term viability of distributed generation, particularly as the U.S. transitions to a post-subsidy reality.

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