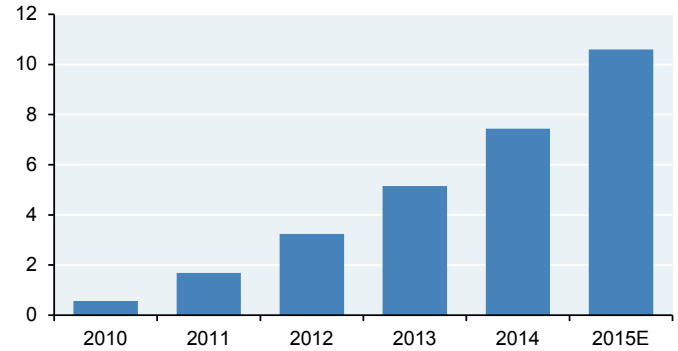
[IV] The Utility Empire Strikes Back: Distributed solar power and billing changes

Several factors have contributed to growth in US distributed residential and commercial solar capacity from less than 1 GW in 2010 to over 10 GW in 2015 (1st chart):

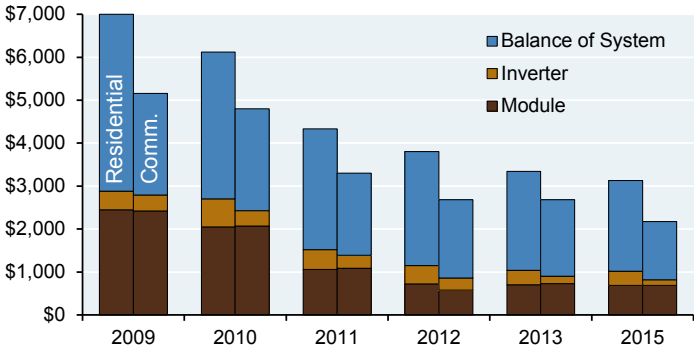
- Declining costs of distributed solar power (2nd chart), and the availability of third party ownership/ leasing which allows customers to put less money down upfront
- The prevalence (until very recently) of most utilities compensating solar PV owners for electricity sold back to the grid at the customer's retail rate, a practice known as "net metering"
- The practice by most utilities to recover the majority of costs through volumetric (per kWh) charges instead of fixed dollar charges, magnifying potential savings for PV customers and undercharging them for transmission infrastructure
- Attractive Federal and state subsidies for solar PV purchasers

Total installed distributed solar PV
GW of residential and commercial capacity



Source: Solar Energy Industries Association. 2015.

Upfront capital costs for distributed PV
USD per kW-DC, residential and commercial systems



Source: National Renewable Energy Laboratory. August 2015.

Growth in distributed solar does not come without complications: how will utilities deal with the portion of transmission and infrastructure costs that PV customers no longer pay for? If utilities simply raise prices per kWh on everyone, some believe it could make distributed solar more attractive, leading to greater solar adoption and continually collapsing utility revenues (the so-called "**death spiral**"). There are a lot of debates about how realistic a death spiral really is[21]. Nevertheless, there are several options utilities are considering to prevent such a spiral from ever happening:

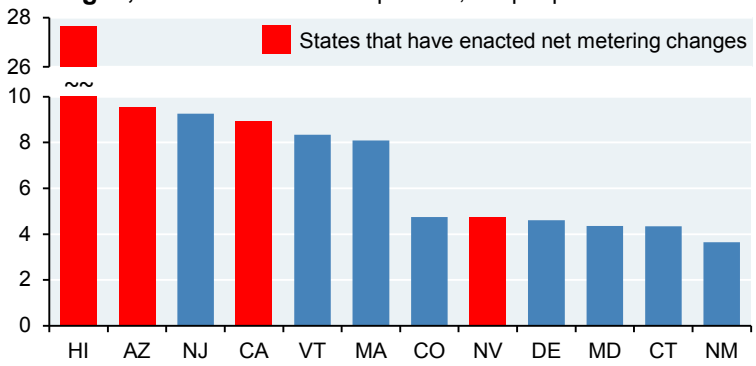
- Reallocating cost recovery from volumetric charges to **fixed dollar charges**
- **Time-varying** electricity rates, a system in which customers buy and sell electricity based on its instantaneous price at that point in the day. The implication: solar power sold in the middle of the day could be much less valuable since it would be more abundant
- **Partial net metering**: customers use what they produce, and sell their surplus electricity back *to* the grid at a price that's lower than the retail rate at which they buy electricity *from* the grid
- **Lower feed-in tariffs**: this system effectively assumes that PV users are in the distribution business. All the power they produce is sold to the grid (not just their surplus generation) at a lower rate. Then, they have to purchase all power they consume at a higher rate. As a result, lower feed-in tariffs are less rewarding for PV customers than partial net metering

[21] **Death spiral?** LBNL notes that there have been no studies to-date conclusively showing death-spiral dynamics in motion. They believe a utility death spiral is unlikely, since feedback effects operate in opposing directions: higher costs per kWh improve solar PV economics for residential customers, but worsen them for commercial PV customers on time-varying rates since higher PV adoption by residential customers increases electricity supply. The former is found to increase PV adoption by 2050 by 8%, while the latter reduces deployment by 5%. These are national estimates; effects for individual utilities could vary greatly, depending on their customer mix.

This not an abstract discussion. **In California, Arizona, Nevada and Hawaii where 54% of US distributed solar capacity has been installed to-date, these changes are already happening:**

- ***Arizona***. In November 2013, the Arizona Corporation Commission (the regulatory body overseeing privately owned utilities in Arizona), voted to install a $5 monthly fixed charge on new residential solar PV users. Utilities governed by the ACC serve 2 million customers in Arizona (~1/3 of the population). Other smaller privately owned utilities in Arizona have sought regulatory approval to lower net metering rates from retail to wholesale rates, and to increase fixed charges.
- ***Arizona***. The net metering debate is not confined to privately owned utilities. The Salt River Project, a public utility serving 1 million customers in Arizona, changed pricing for new solar PV users to be based on time-varying rates, and began applying monthly fixed charges and demand surcharges (extra fees based on periods of maximum customer demand).
- ***California***. In January 2016, the California Public Utilities Commission (CPUC) voted to apply a one-time interconnection fee to all solar customers, to apply time-varying rates to all customers, and to accelerate them for solar PV customers. The three largest utilities in California who serve ~24 million customers had been arguing for a lower feed-in tariff instead, which would have been more negative for solar users. Our sense is that none of the newly adopted approaches are written in stone, and are subject to change; California has agreed to revisit the issue in 2019.
- ***Nevada***. In February 2016, the Nevada Public Utilities Commission finalized new rules on *all* solar PV customers (not just new adopters) that increase fixed monthly charges on net-metering customers by 2x - 3x over the next 12 years, decrease net metering credits for surplus generation by 60% - 70%, decrease volumetric charges by 10% - 30%, and give net-metering customers the option to move to time-varying rates. This is a very complex billing system; from our perspective, this new approach is the **most economically negative** for solar PV customers since they include both fixed charges and lower net metering rates. The NPUC regulates NV Energy which serves 1.3 million customers, or around half of the state's population.
- ***Hawaii***. Hawaii has the greatest amount of distributed solar per capita. In October 2015, the Hawaii Public Utility Commission lowered pricing on surplus PV generation to 15 - 28 cents per kWh vs. an average retail rate of 38 cents per kWh.

States with high distributed solar PV and net-metering changes, Distributed solar MW per 100,000 people

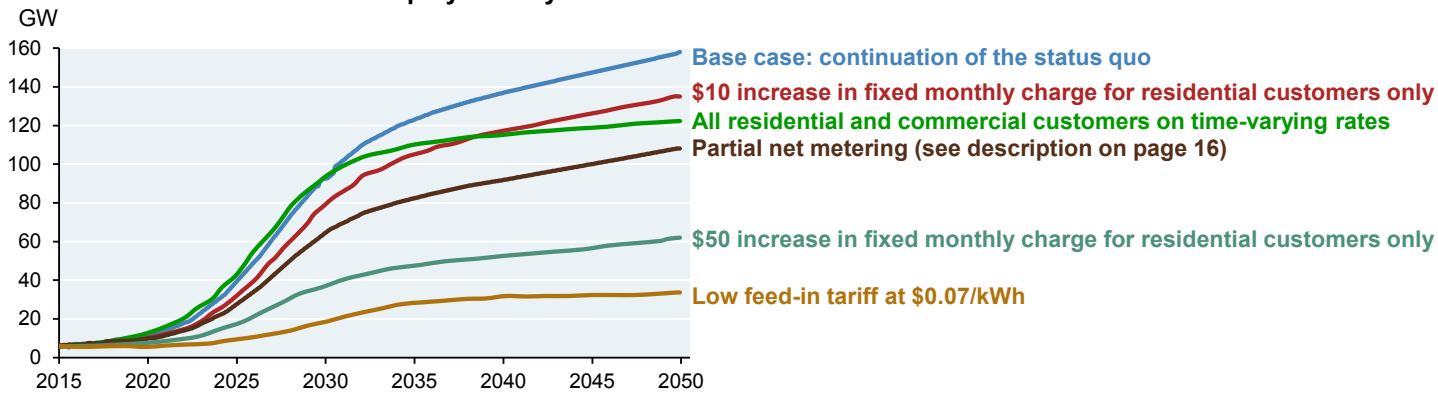


Source: EIA, US Census Bureau. January 2016. States shown are those with more than 3 MW per 100,000 people.

How might such utility responses affect the rate of solar PV adoption? To answer that question, we turn to a 2015 analysis from Lawrence Berkeley National Laboratory on distributed solar power growth[22]. The chart below shows their results, which we interpret as follows:

- If "death spiral" utility responses are confined to small monthly fixed charges or a shift to time-varying rates, the projected impact on overall PV adoption is not radically different from a status-quo base case. Note that the time-varying adoption curve flattens out, since the greater the abundance of solar PV, the lower mid-day electricity rates would be for PV customers selling back to the grid.
- However, if more fundamental changes to customer billing were to take place (larger fixed monthly charges and lower feed-in tariffs), distributed solar adoption rates could be materially affected.
- **What are the early signs? Mixed.** In California, while time-varying rates adopted by the CPUC should only have a modest impact, ongoing utility counter-proposals would dampen solar PV incentives further. In Arizona, the outcome is modest so far with a $5 charge, while in Nevada, the outcome was much more negative for solar PV economics, leading to large solar industry layoffs in the state.

National distributed solar PV deployment by scenario



Source: Lawrence Berkeley National Laboratory. July 2015.

Below, we show each scenario in 2040: distributed solar capacity, its electricity generation assuming a 15% capacity factor[23] and its share of all electricity generation. **Even in the base case, distributed solar's 2040 share would be less than what wind already contributes today**.

Implied 2040 distributed solar PV under various scenarios

	Implied 2040 Capacity (GW)	Implied 2040 Generation (GWh)	Share of 2040 projected electricity generation
Base case	139	182,560	3.7%
$10 fixed charge	118	155,208	3.1%
Time-varying rates	115	150,925	3.0%
Partial net-metering	93	122,585	2.5%
$50 fixed charge	52	68,937	1.4%
Low feed-in tariff	32	41,850	0.8%

Source: Lawrence Berkeley National Laboratory, EIA, JPMAM. July 2015.
Note: assumes 15% capacity factor.

[22] LBNL expanded on an NREL model that simulates customer adoption of distributed PV. The model uses a bottoms-up approach where customer adoption depends on a comparison of PV system costs with reductions in customer electricity bills, using data from 216 solar resource regions and more than 2,000 electric utilities.

[23] **Current national weighted average rooftop solar capacity factors are 15%**, using NREL data. While there have been large declines in the *price* of solar modules, *capacity factor* improvements have been more limited.