Distributed Generation & Net Metering Policy Resources and Results

JANUARY 2015

Consumer Protection

Congress of the United States
Washington, DC 20515

November 19, 2014

The Honorable Richard Cordray
Director, Consumer Financial Protection Bureau
1700 G Street, N.W.
Washington, D.C. 20552

Director Cordray,

Over the next two years, hundreds of thousands of Americans will install rooftop solar panels on their homes, according to the U.S. Energy Information Administration's *Annual Energy Outlook 2014*. We are supportive of this trend because solar is a key component of America's energy future. However, as the industry rapidly expands, we must be vigilant in protecting consumers from any misleading sales practices.

While the cost of rooftop solar systems dropped 12-15 percent last year, the up-front cost of rooftop solar panels is beyond the financial means of most U.S. households. As a result, many Americans are drawn into the solar market by the promise of a zero-money-down solar lease. Industry analysts predict that 68 percent of rooftop solar installations will be financed through third-party leases in 2014, a growth of over 20 percent since 2011. A customer who signs a solar lease does not own the panels but contracts for the electricity produced by the system for 20 or more years. The initial attractiveness of a "no money down" long-term lease may incentivize the installation of rooftop solar. However, as was the case with the subprime mortgage crisis – easy initial financial terms, increased demand and a rapidly expanding industry can be high risk and ultimately harmful to consumers and the industry.

At the core of my concerns are reports that solar leasing companies may be overstating the economic benefits of signing a long-term solar lease while failing to disclose important information during the sales process. For example, customers are quoted savings each month on their utility bills. However, who calculates those estimations and are they accurate? Also, it is my understanding that early solar lease payments are teaser rates that make solar energy payments seem affordable. However, do these rates escalate over time and are consumers made aware of those potential increases?

Accordingly, I would appreciate your responses to the following questions:

1. What steps has the Consumer Financial Protection Bureau taken to investigate the possibility that misleading sales techniques are being employed in the rooftop solar industry?

2. What protections are in place to ensure that consumers who are considering entering into long-term solar leasing arrangements are made fully aware of the long-term implications of these transactions? For example, reports suggest that third-party leases may result in

escalating payments to home sellers in the event that subsequent buyers do not want the solar system or cannot assume the lease, thus complicating real estate transactions.

3. What has the Consumer Financial Protection Bureau done to investigate complaints that have arisen about the marketing techniques employed by some rooftop solar leasing operations?

4. Has the Consumer Financial Protection Bureau considered performing a staff review of third-party-leases in the rooftop solar industry and issuing recommendations on how we can better educate and protect consumers contemplating these transactions?

Given the rapid expansion of the rooftop solar industry underway and the importance of effective protections to the continued well-being of U.S. consumers, we look forward to your response to these questions within 30 days.

Sincerely,

Ann Kirkpatrick
Member of Congress

Ron Barber
Member of Congress

Kyrsten Sinema
Member of Congress

Gene Green
Member of Congress

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FOURTH DISTRICT, ARIZONA

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December 12, 2014

The Honorable Edith Ramirez
Chairwoman
U.S. Federal Trade Commission
600 Pennsylvania Avenue, NW
Washington, DC 20580

Dear Chairwoman Ramirez:

Given the rapid expansion of the rooftop solar industry, we wish to call your attention to the emergence of third-party leases for rooftop solar systems. Some of these companies that market leased solar systems to consumers as a way to leverage promoting solar leasing products are actually acting as sellers of financial products, leveraging the federal Investment Tax Credit (ITC) and applicable state renewable subsidies to obtain tax equity investment for the purposes of turning a profit. Under increasing pressure from Wall Street to sign up more leasing customers before the ITC expires, these companies are reported to be using potentially deceptive sales tactics - practices that, if true, merit investigation.

By way of background, the rooftop solar market has surged in recent years. This surge is, in part, due to regulatory subsidies and the increased use of third-party leasing arrangements in residential rooftop solar installations. Consumers are being enticed by solar leasing companies who offer zero-money-down leases, essentially teaser rates, for a 20 year lease agreement. Industry analysts predict that a vast majority of rooftop solar installations across the nation will be financed through long-term, third-party leases in 2014. One of the largest solar leasing companies, has a stated goal of committing one million customers to long-term contracts by 2018. As a very new industry with a limited track record and little regulatory oversight, the solar leasing market may pose a considerable risk to the increasingly large numbers of American consumers that commit to the leasing product without all of the relevant information (not to mention the American taxpayer, who heavily subsidizes each rooftop solar project).

Of particular concern, is the possibility that these third party leasing companies may be utilizing deceptive marketing strategies that overstate the savings the homeowner will receive, while understating the risks associated with agreeing to a decades-long lease that is often secured by a second deed of trust to the house – a financial commitment that will likely exceed both the life of the roof and duration of the lessor's home ownership. National solar leasing companies have aggressively marketed the zero-money-down leases to homeowners in select states. In fact, one of the largest solar leasing companies has partnered with a strategic sales company that sold large numbers of subprime mortgages to unsuspecting homeowners in the run up to the subprime mortgage crisis.[1] Class action lawsuits have been filed in

[1] http://www.nbcnews.com/id/27844894/ns/business-stocks_and_economy/t/fh#.VIIGuzHF9ul ; http://www.oregonlive.com/business/oregonian/index.ssf?/base/business/1216866352224170.xml; http://www.solarcity.com/newsroom/press/solarcity-acquire-paramount-solar-first-step-toward-million-customer-goal ; http://blog.seattlepi.com/realestatenews/2009/05/15/mortgage-company-settles-with-state/

California and Louisiana by homeowners alleging fraudulent marketing and overstating potential savings from zero-money-down leases.[2] In addition, numerous reports have found that homeowners who have signed these zero-money-down leases are struggling to sell their homes, indicating that they were not fully aware of the terms of their 20-30 year lease commitments.[3]

Consumer protection and fairness require a clear explanation of possible risks. Fairness also requires accurate factual assumptions when presenting the options to consumers. As it stands, solar consumers are likely not aware of these risks. A key concern is that if these leases are not offered in good faith or with accurate disclosures, the entire solar industry could be tainted.

Therefore, we ask that you respond to the following questions:

1. What options exist to ensure consumers are fully apprised of the costs and benefits of solar leasing arrangements, including potential financial risks? At a minimum there appears to exist a need for a resource center for consumers to weigh risks before making a financial commitment.

2. In the unlikely event of a company or market failure, what recourse exists for the end consumer to be held harmless for the remainder of the lease? After the recent housing crisis it seems only reasonable for consumers to know their recourse should they need one.

3. What level of coordination and information-sharing does the Commission have with state-level consumer protection offices with other similar type financial services?

4. What options exist to ensure that consumers are fully apprised of the costs and benefits of solar leasing arrangements, including potential financial risks?

5. Has the Commission received any complaints pertaining to solar lease contracts? Have any of these complaints involved the use of potentially erroneous information by marketing personnel to increase the attractiveness of solar leases?

Thank you for your attention to the issues raised by this letter; we look forward to your timely response. As always, we ask that this matter be handled in strict accordance with the existing agency rules, regulations, and ethical guidelines. Should you need have any questions please contact Jeff Small at Jeff.Small@mail.house.gov

Sincerely,

Paul A. Gosar, D.D.S.
Member of Congress

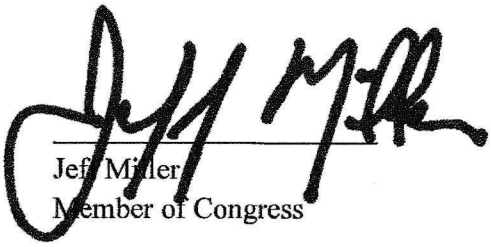
Matt Salmon
Member of Congress

Trent Franks
Member of Congress

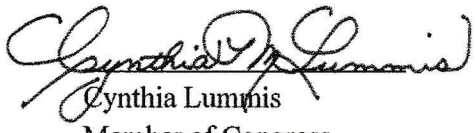
Lamar Smith
Member of Congress

[2] http://topclassactions.com/lawsuit-settlements/lawsuit-news/4404-sunrun-deceptive-marketing-class-action-moves-forward/; http://theadvocate.com/news/neworleans/neworleansnews/8349370-123/suit-filed-against-solar-company

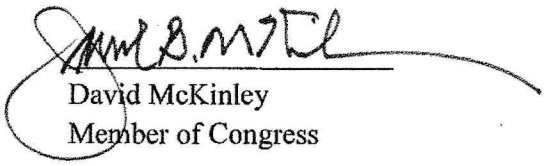
[3] http://www.npr.org/2014/07/15/330769382/leased-solar-panels-can-cast-a-shadow-over-a-homes-value ; http://www.bloomberg.com/news/2014-06-23/rooftop-solar-leases-scaring-buyers-when-homeowners-sell.html



Jeff Miller
Member of Congress



Cynthia Lummis
Member of Congress



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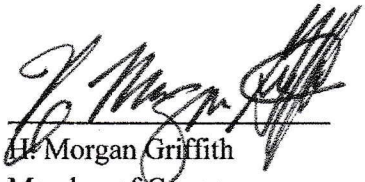
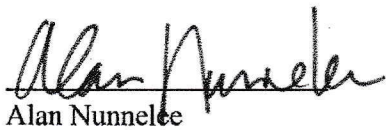


H. Morgan Griffith
Member of Congress

Ted Poe
Member of Congress



Alan Nunnelee
Member of Congress

Arizona Republic: Gosar, other lawmakers raise concerns with solar leases
Ryan Randazzo
December 16, 2014

U.S. Rep. Paul Gosar has joined a growing chorus of officials concerned with solar leases, and asked the Federal Trade Commission to look into the industry in a letter co-signed by several other Republicans.

Solar leases are a popular option for homeowners who do not want to pay upfront for rooftop solar panels, and for non-profits or government facilities that can't take advantage of federal tax credits when they install solar.

The leasing companies are able to capture those subsidies and offer solar for no money down or little upfront investment for customers.

Gosar's letter, also signed by Arizona Republicans Trent Franks, Matt Salmon and nine other congressmen from around the country, adds to comments from a growing number of elected officials and regulators concerned with the ethics of the solar-leasing industry.

"Of particular concern is the possibility that these third-party leasing companies may be utilizing deceptive marketing strategies that overstate the savings the homeowner will receive, while understating the risks associated with agreeing to a decades-long lease that is often secured by a second deed of trust to the house — a financial commitment that will likely exceed both the life of the roof and duration of the lessor's home ownership," Gosar wrote.

The leases commonly have terms of 20 years and require monthly payments. The tricky part for consumers is calculating whether those payments will be less than the amount of money they save by generating much of their own electricity with solar.

A solar lease only can guarantee the amount of electricity the solar panels will generate, and not what utility rates will be in the future.

Lyndon Rive, CEO of SolarCity Corp. of San Mateo, Calif., has said that the average leasing customers save about $5 to $10 a month by reducing their power bills, but taking on lease payments.

For example, a customer might lower the monthly power bill by $100 but pay $90 in lease payments.

Some leases have flat payments, while others increase as much as 2.9 percent a year, which might be more than utility rates increase annually over the next 20 years.

Gosar's concerns mirror those of Arizona's Democrats in Congress, who wrote a similar letter last month.

Reps. Ann Kirkpatrick, Kyrsten Sinema and Ron Barber, along with Gene Green of Texas, sent a letter to the U.S. Consumer Financial Protection Bureau with concerns that leasing companies "may be overstating the economic benefits of signing a long-term solar lease while failing to disclose important information" when making sales pitches.

SolarCity, which controls most of the solar-leasing market in Arizona and the country, responded to news of that letter by attacking Arizona Public Service Co., the biggest utility in the state.

Officials asserted that the utility has been lobbying Congress on the issue and spreading "misinformation" about solar leases.

In the past year, other officials voicing concerns with leases include Arizona Attorney General Tom Horne and Arizona Corporation Commission Chairman Bob Stump, as well as executives with utilities APS and Salt River Project.

Members of the Corporation Commission, which regulates utilities in Arizona, have asked their staff to open an investigation of consumer protections in the solar-leasing industry.

Arizona Republic: What's wrong with a second look at solar leases?
Editorial Board
November 29, 2014

http://www.azcentral.com/story/opinion/editorial/2014/11/29/rooftop-solar-power-arizona/19557291/

Our View: Long-term leases are complex. Why shouldn't a consumer-protection agency ensure that homeowners are getting a good deal?

Conscientious homeowners — and there are many in Arizona — seem to like rooftop solar systems. They want to do the right environmental thing.

But they also want their substantial investments to pencil out financially. And that is no longer a simple equation.

With the vast majority of rooftop systems now being leased, rather than sold — most of them through a single company, SolarCity of California — it seems reasonable to ask whether those leases really do pencil out.

Or at least it did to three Democratic members of the Arizona congressional delegation, who asked the new Consumer Financial Protection Bureau in Washington to have a look at rooftop solar leases. In a letter, Reps. Ann Kirkpatrick, Kyrsten Sinema and Ron Barber, as well as Rep. Gene Green of Texas, raised concerns about details that struck them as similar to what we saw during the subprime mortgage crisis:

"Customers are quoted savings each month on their utility bills. However, who calculates those estimations and are they accurate?"

The concerns do not seem unreasonable. Kirkpatrick's office reports having received "numerous" constituent complaints about the leases. Most of the tax breaks and other incentives to "go solar" go to the owner of the system, which, in a leasing arrangement, is not the homeowner.

A complex, long-term lease deal can be difficult for a layman to calculate accurately. Asking the consumer financial-protection bureau to help out would seem a natural thing for a member of Congress to do.

But don't tell that to the rooftop solar industry, which is striking back furiously at the representatives.

"Liberal lawmakers smear rooftop solar forgetting that Arizonans want to 'go green' AND 'save green,' " screamed the hyperbolic headline of a press release from an industry advocacy group.

A complaint that "liberal" lawmakers are opposed to anyone going "green" is a clear first for us. If there is anything certain about modern American politics, it is that Democrats, "liberal" or otherwise, are committed to environmentalism. And that emphatically includes solar.

They also are committed to institutions dedicated to consumer protection. Like the CFPB.

There is nothing wrong with examining the proliferation of expensive rooftop solar systems being leased to homeowners. If the leases pencil out, fine. If not, this heavy-handed industry attempt to keep us in the dark speaks volumes.

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

Resolution 2014-05

Urging Broad Consumer Protections for Distributed Generation Customers

Whereas, distributed generation (DG) can be defined as decentralized electricity generation, usually on a small scale, which is interconnected with the distribution system, located at or near the load (i.e., a customer's home, business or other facility) and includes energy sources such as solar panels, small wind, energy storage devices, fuel cells and microturbines; and

Whereas, in recent years, development of distributed generation has increased in many states which is attributable, in large part, to the adoption of public policies supporting the development of decentralized or small-scale renewable energy generation; and

Whereas, twenty-nine states plus the District of Columbia and two territories have promulgated statutory Renewable Portfolio Standards mandating the integration of renewable energy sources in their fuel mix; and

Whereas, forty-three states plus the District of Columbia and four territories have adopted net energy metering regulations for small-scale renewable generation; and

Whereas, the federal government and several states have codified tax incentives for renewable energy generation; and

Whereas, in many jurisdictions, wider commercial deployment of solar energy technologies, such as rooftop solar photovoltaics and solar thermal systems, has played a central role in the expansion of distributed generation; and

Whereas, within the past few years, the cost of rooftop solar energy systems has fallen significantly and there is growing consumer demand for solar energy in some regions; and

Whereas, the increasing affordability of DG for residential consumers is, in part, attributable to DG providers (third-party DG providers), such as solar companies, offering more financing options which allow customers to participate in DG without having to make large capital investments and owning and bearing the responsibility for maintaining the energy systems installed at their property; and

Whereas, these financing arrangements may include third-party ownership business models (third-party DG contracts) such as power purchase agreements and lease agreements which may require little or no upfront down payments; and

Whereas, although these third-party DG ownership models may provide benefits for consumers, entities such as the Better Business Bureau have received complaints regarding the business practices of certain third-party DG providers; and

Whereas, these complaints demonstrate that more oversight and consumer education is warranted because of the potentially significant risks for consumers engaging in DG contracts, including but not limited to:

1. Fraudulent and deceptive business practices by DG providers, such as misrepresentation of the potential energy output of the DG system, exaggeration of the value of the DG system, and withholding information or misleading customers regarding information related to property repairs or upgrades necessary for installation of the DG system;

2. Improperly installed DG systems, including poor workmanship or systems failing to meet interconnection requirements which can result in safety hazards;

3. Unfulfilled contract obligations, such as third-party DG providers' failure to maintain or repair the system pursuant to contract terms;

4. Limits on consumer legal remedies, such as mandatory arbitration clauses and unfair limits on damages that DG customers could be awarded in a legal dispute with third-party DG providers; and

5. Inadequate disclosure of contract terms, such as failure of third-party DG providers to engage the DG consumer in a true "arm's length" transaction where the consumer is fully aware of their obligations under the contract.

Now, therefore, be it resolved, NASUCA acknowledges the growing distributed generation market and supports efforts to establish measures that enhance protection of DG customers; and

Be it further resolved, that NASUCA encourages state legislatures, state public utility commissions, consumer advocates, state attorneys general and other consumer protection agencies to coordinate their respective activities in regard to this market in order to:

1. Ensure that the rights of DG customers are fully and fairly protected and enforced under existing, or if necessary, new statutes and regulations;

2. Educate consumers regarding their rights and obligations under third-party DG contracts either from a utility or third party program;

3. Establish and enforce standards for the DG marketplace which promote equitable treatment and safety of consumers; and

Be it further resolved, that state legislatures are encouraged to require that state public utility commissions, and other relevant consumer protection agencies, establish standards that require third-party DG providers to fully and accurately disclose and explain information related to the installation of DG systems on consumers' property including, but not limited to, the expected energy output and value of the DG system, the extent of property alterations necessary for the realization of the full benefit of the DG system and the terms and conditions in their contracts; and

Be it further resolved, that state legislatures are encouraged to review and delineate the jurisdiction of state public utility commissions over third-party DG providers and conduct reviews of complaint resolution processes and legal remedies available to consumers in third-party DG contracts in order to determine whether such remedies are sufficient, reasonable and fair; and

Be it further resolved, that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution. The Executive Committee shall advise the membership of any proposed action prior to taking such action, if possible, and shall notify the membership of any action taken pursuant to the resolution.

Submitted by the Distributed Energy Resources Committee
Approved: November 18, 2014
San Francisco, California
Abstained: Michigan

Solar Power for Your Home

A Consumer's Guide

Purpose Statement: The purpose of the upcoming publication is to provide consumers with a detailed, yet user-friendly and objective guide to enable them to make well-informed decisions when considering a photovoltaic (PV) solar energy system. It is designed in a question and answer format to help homeowners: (1) explore and weigh both technology and financial options, and (2) ask important questions for making a good choice for their circumstances, to avoid common problems and to enjoy the benefits they seek. Following is the content outline and the DRAFT *Questions to Ask* supplemental worksheet. The full document is now in peer review and revision to refine it.

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Louisiana State University Agricultural Center
Louisiana Cooperative Extension Service
LaHouse Resource Center
Issued in furtherance of Cooperative Extension work, Acts of Congress of May 8 and June 30, 1914, in cooperation with the United States Department of Agriculture. The Louisiana Cooperative Extension Service provides equal opportunities in programs and employment

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Author:
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Questions to Ask

When Considering a Solar Energy System for Your Home

1. What **energy efficiency improvements** should be made to my home before investing in solar energy?
1. What renewable energy alternatives are available such as community solar or utility renewable energy programs?
2. How much electricity did my home use last year? How much is it likely to use in the next year (considering energy efficiency and household changes)? What is my **average kWh usage per month** (estimate for next year)?
3. What is the current rate I pay for electricity (cents/kWh) from my utility company? What is my **average monthly electricity cost** (estimate for next year)?
4. What is the history of electricity price changes for my utility company? What **annual electricity inflation rate** trend is predicted by my utility company, state regulator, U.S. Dept. of Energy, local university or other reliable source?
5. Would my home be eligible for **net metering**? If so, are there system size limits to qualify? Could it change or expire for me in the future? How does the program treat energy that I produce in excess of my usage? If I'm not eligible, what is the rate (cents/kWh) the utility will credit or pay for surplus power I generate? Is the rate higher at peak load times (usually late afternoon)?
6. How much **solar energy (kWh/month)** would I like to generate with a PV system? Should my system be sized to avoid producing more power that I use (surplus)?
7. What **incentive tax credits, exclusions and rebates** are available that would reduce the cost of buying a home PV system? What are their limits and requirements? When does each expire?
8. What is my area's **solar resource** (average amount of sunshine per day)?
9. Does my community have any restrictions on placing solar panels? How much **unshaded roof area** facing S, SW or SE is available? How much faces W? What is the roof slope? Should my roofing be replaced before installing PV?
10. Would I prefer a thin film system that blends into my roofing, or a crystalline **type of PV technology** for higher efficiency in less area? Can it withstand hail and my area's wind risk? What is the expected service life? What are common problems with each type of system? What is the reputation of the manufacturer?
11. Does the system use one **inverter or micro-inverters** on each module? What is the inverter(s) expected life and what will it cost to replace it?
12. What **monitoring systems** are available? What information do they provide? What do they require and cost?
13. What **PV power capacity (kW)** will fit on my available roof area (of the type I want)?
14. How much electricity (kWh) is it expected to generate **(energy output)** in the first year? How was that determined? What is the expected annual **degradation rate** (reduction in electricity produced)?
15. What is the **total installed cost** of the PV systems I'm considering? What is the typical cost/Watt in my area? How much will the available tax credits, exclusions and rebate **solar incentives** reduce my cost?
16. Are there any low cost **solar loan programs** available to me? If not, do I qualify for a VA, FHA, or HUD home improvement loan? Or, could I qualify for a home equity or 2nd mortgage loan? What are the interest rate, down payment required, closing cost, terms and tax advantages?
17. What is the **monthly payment to finance** the net purchase cost (after incentives), with and without a down payment? How does that compare to predicted monthly utility bill savings – both initially and as electric rates rise?
18. How many years will it take to recoup my net purchase cost (**payback period**)? What will my annual utility bill savings be after payback? What is the equipment's expected service life? What is my estimated **total return on investment** (ROI)? (Use an online calculator.) Does the ROI factor in general inflation?
19. What effect will a rooftop solar system have on my home's **market value** in my location? How will it affect my homeowner's insurance premiums? Will my property taxes change?
20. Will the firm quoting on the system install it or hire installers? What are the **qualifications, certifications and licenses of the installers**? Are they bonded and

have liability and workmen's compensation insurance? How long have they been installing PV systems on homes? How long have they been in business?

21. Have any **complaints** been filed against the vendor, manufacturer or installer with the state licensing board, consumer protection agency, or the Better Business Bureau? Are their customers satisfied with their work quality and follow-up service?
22. What does the **warranty** cover (PV panels, inverter, mounting rack, labor) and how long? Who is responsible to make warranty repairs? What maintenance does the warranty require? Will a PV system void my roofing warranty?
23. Does the **contract detail** the system components, timeline for completion, payment schedule, a lien waiver, and who is responsible for any damages, injuries and permitting? What are my rights and remedies if my home is damaged, the installation is poor, or someone is hurt by the installation?

Additional Questions to Ask
When Considering a Solar Lease

When considering a solar lease, first ask the previous questions, then ask the following questions to help you compare the initial and long-term costs and benefits of buying vs. leasing for your home and needs.

24. Can I lease the **PV system type, capacity and installer** of my choice (Questions 10-11, 17-18)? If the leasing company chooses, why is the selected system recommended?
25. What is the **lease term** (years)? What happens at the end of the lease? Is it renewable? If I don't renew, who is responsible for removing the PV system and restoring my home?
26. Would I rather pay a set amount each month (rental-type **solar lease**) or pay only for the solar power my home uses (**purchase power agreement** or PPA)? Which method would likely result in a lower total cost over time?
27. What **incentives** will the leasing company receive? With a solar lease, am I eligible for any incentives such as property tax exclusions, or others that the leasing company cannot use?
28. What will be my **monthly payment or PPA rate** (cents/kWh) for the first year? How does that compare to my electric utility rate or average monthly bill? How does it compare to a loan payment amount (Question 16)?
29. What is the lease **annual escalation rate** (% the payment or PPA rate will rise each year)? What will my payment or rate become each year of the lease (payment escalation schedule)? When will it exceed a loan payment amount?
30. How does the lease escalation rate compare to my **utility company's historical and predicted inflation rate** (Question 4)? What are the basis and assumptions of the leasing company's projected utility inflation rate and **total predicted savings** over the entire lease term?
31. Do I have a legal **right to rescind** (back out) the lease after signing it? If so, how many days is the right in effect?
32. What are my **responsibilities in maintaining** and operating the PV system? What are the leasing company's responsibilities? What do I do if the system isn't working or is damaged? Will my monthly lease payment be reduced or suspended when the system is not operating?
33. When my **roofing needs replacement**, who is responsible for removing and reinstalling the PV panels?
34. Under what circumstances can the lease be **terminated** (ended) by me or the leasing company? What can I do if the company doesn't maintain the system, goes out of business, or uses illegal or deceptive practices?
35. What happens if I can't make payments and **default** on the lease? What if my payment is late?
36. If I want to **sell my home**, what does the lease require from the buyer and from me? What if the buyer doesn't want to assume the lease? How will a lease PV system affect my home's marketability and value in my location?
37. If I ever want to buy the leased system, how is the **fair market price** determined? Can I buy it at any time?

THE NATIONAL BLACK CAUCUS OF STATE LEGISLATORS

Committee on Energy, Transportation, and Environment

WHITE PAPER 2014

THE NEED TO DEVELOP & IMPLEMENT EQUITABLE **ENERGY** POLICIES

NBCSL

National Black Caucus of State Legislators

ACKNOWLEDGMENTS

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MISSION

NBCSL's mission is to develop, conduct, and promote educational, research, and training programs designed to enhance the effectiveness of our members as they consider legislation and issues of public policy which impact, either directly or indirectly, upon "the general welfare" of African American constituents within their respective jurisdictions. Over the past 37 years, NBCSL has grown from 14 members to a body of nearly 675 African-American state legislators. NBCSL's mission is to create more economic, political, and social equality. NBCSL's priority is to implement policies that will protect and benefit all Americans.

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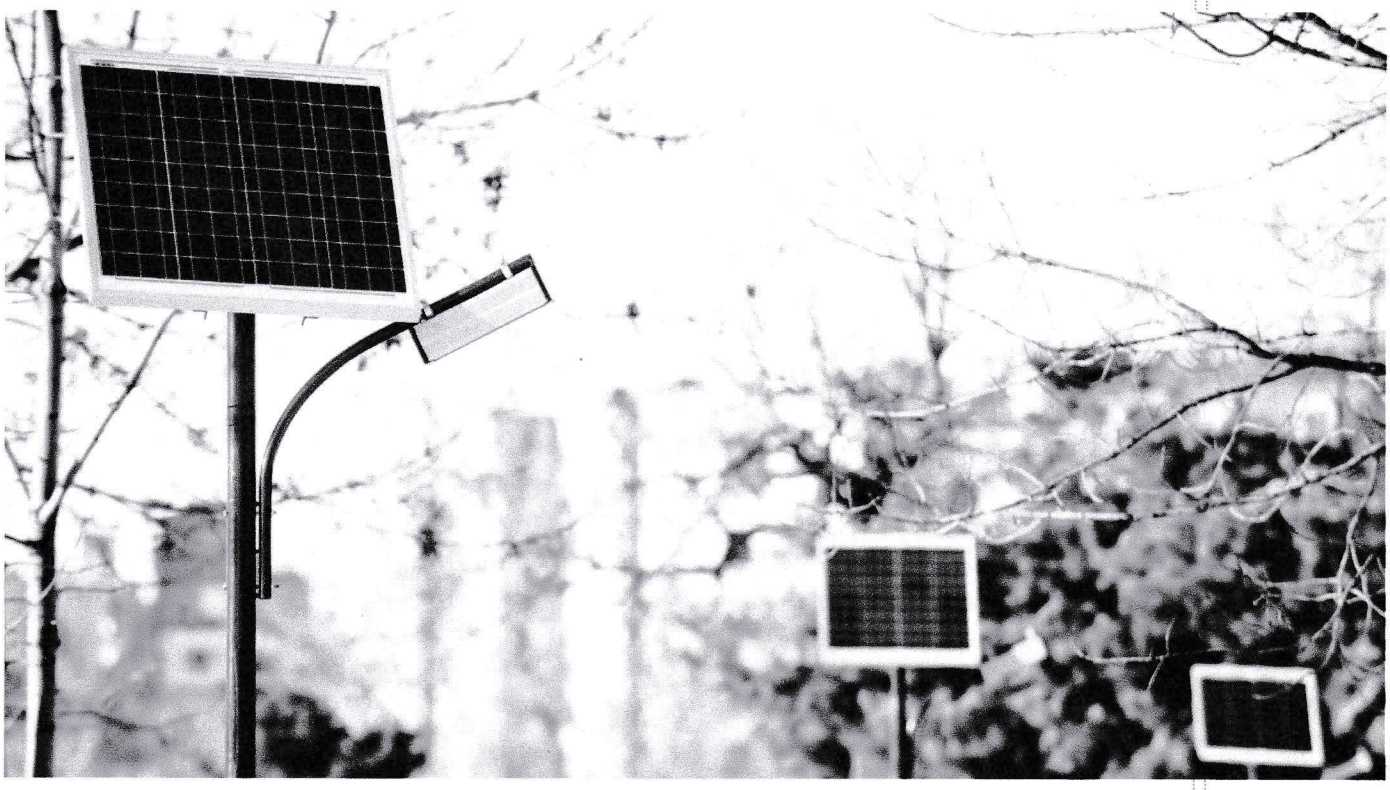


The National Black Caucus of State Legislators (NBCSL) is the nation's largest membership association of African-American state legislators.[1] With nearly 675 members from across the country representing more than 65,000,000 constituents, the primary mission of NBCSL is to educate its members on policies that advance the interests of African Americans, and vulnerable communities more broadly, in the United States. NBCSL's work is sparked by a desire to protect those at a disadvantage by enacting policies that embody core notions of social justice.[2]

Although our efforts are wide-ranging and span many sectors, those impacting essential services, like electricity, deserve urgent attention. Minority policymakers and policymaking bodies like NBCSL have worked for many years to assure universal, affordable, and reliable access to basic energy service. And with many new innovations and technologies coming online, we have great opportunities for our community – so long as policies adhere to the principle of fairness and do not benefit some at the expense of all.

Recent energy developments have led to the significant deployment of distributed generation

1. For more information, please visit http://www.nbcsl.org.
2. Over the years, NBCSL has adopted a number of policy resolutions drawing attention to these types of issues and put forward workable ideas for solving them. These resolutions can be found at http://www.nbcsl.org/public-policy/resolutions.html.

(DG) technologies that allow people to generate their own electricity on site. For those who can afford to invest in DG, they will benefit from lower electric bills and from the knowledge that they are directly supporting a form of cleaner energy. But, because many DG technologies rely on renewable energy to produce electricity, consumers will still want (and need) to be connected to the electric grid. Just think for a moment about the electricity needed to run your home – refrigerator, television, computer, wash machine – after the sun has gone down. If you weren't connected to the electric grid, all of those activities would have to wait until sunrise.

As an overview, energy generation has traditionally been centralized at large plants that burn, for example, coal or natural gas. The electricity generated at these plants is then delivered to consumers' homes via the electric grid – from the power plant, over transmission lines, then into our neighborhoods and eventually to our homes. It is always there at the ready. DG, on the other hand, decentralizes this process. It enables customers to generate electricity on-site by tapping into a variety of energy sources, even renewable sources like the sun. Roof-top solar panels installed on homes are one of the most widely-used DG systems. States have developed a number of policies and incentives to encourage the adoption of DG and have resulted in growing popularity of rooftop solar amongst many consumers.

NBCSL enthusiastically embraces the promise of cleaner and more affordable energy of all kinds, and supports the experimentation and innovation that is driving progress in the DG space. However, the prevailing approach to DG has created a fundamentally inequitable dynamic, which risks creating two separate and unequal classes of electric customers: those who can afford to install and participate in DG programs, and those who cannot. The unfortunate irony is that those who would benefit most immediately and most profoundly from these programs – minorities, low-income households, and those on fixed incomes, who already pay a greater percentage of their income for electricity service – are disproportionally picking up additional costs. The cost savings advertised to customers come in the form of buying less electricity from the utility and via "net metering," which measures any excess electricity produced by the DG system. The savings from buying less electricity is really no different than consumers being more efficient and effective stewards within their homes. The savings via "net metering," however, are a result of the way electric rates were originally designed and essentially provide a reading that does not fully account for the infrastructure used to transport electricity to and from homes with DG.

We are concerned about the regressive nature of the cost-shifting that results from the net metering policies used to make DG appear to be a more attractive financial proposition. The end result is that households not able to afford DG systems are inadvertently left to pay more for the electric grid. These costs will continue to escalate as DG providers continue to market to more affluent households. The last in line will continue to share an increasingly larger financial burden. Electric utilities have an array of statutory and regulatory, non-avoidable, obligations to maintain the electric grid. Under the current policy framework, as the number of DG customers increases, the greater the burden on non-DG customers to support grid maintenance and enhancements.

This paper emphasizes the importance of developing and implementing equitable policies impacting the vital service of electricity through solar distributed generation. Left unaddressed, policymakers risk the creation of an "energy divide" alongside the already established income gap where low and fixed income consumers and large swaths of minority consumers subsidize new distributed generation services for higher-income customers. To assure fairer and more inclusive outcomes, we are concluding this paper with five equitable, forward-looking, and consumer-oriented guiding principles for service, delivery, use, and pricing in the energy sector.

WHY WE NEED TO REMAIN VIGILANT AND CONTINUE WORKING ON BEHALF OF THE MOST VULNERABLE MEMBERS OF OUR COMMUNITIES

The work of organizations like NBCSL to promote equality across every sector of the economy has yielded many gains Yet, much remains to be done, particularly to protect our low-income, minority, and fixed-income communities. These communities are most vulnerable to the consequences of uncertain economic growth in the United States. These communities remain in a constant state of economic precariousness which leaves them vulnerable to sudden market shifts. The impacts of this economic instability on vulnerable populations are acutely evident in the energy utilities space. Minority, low-income households, and those on fixed incomes spend significantly more, as a percentage of their incomes, on electricity than any other group. In particular, those with annual pre-tax incomes below $50,000 devote more than double their share of income to pay for energy than those with incomes over that threshold.[3] Not surprisingly, that share increases sharply as annual income decreases: those earning between $10,000 and $30,000 a year devote about a quarter of their income to electricity, while those earning under $10,000 devote 75 percent. With more than 60 percent of African Americans and Hispanics earning less than $50,000 each year, poor minority communities are especially vulnerable to rising energy costs.[4]

In response to this dilemma, an array of state and federal government entities have developed programs to offset some of these costs. The Low Income Home Energy Assistance Program (LIHEAP) is the flagship federal program developed for these purposes. Administered by the U.S. Department of Health & Human Services (HHS), LIHEAP "helps keep families safe and healthy through initiatives that assist families with energy costs. [HHS] provides federally funded assistance in managing costs associated with home energy bills, energy crises, and weatherization and energy-related minor home repairs." Many states also have their own energy assistance programs.

Unfortunately, funding for these programs, including LIHEAP, has been cut deeply over the last few years. Funding cuts, coupled with rising energy costs, high unemployment, and non-existent wage growth, puts these families in a precarious situation. In its brief on the effects of rising energy costs, American Electric Power stated, "...many American families must make the difficult choice of either heating or eating. In response to this dilemma, many households reported going to such extreme measures as closing off parts of their homes, keeping temperatures at unsafe levels, and even using a kitchen stove as a source of heat."[5] The prospect of higher electric bills could prove disastrous to a large portion of low- and fixed-income consumers, and especially minorities in light of the 20-1 racial wealth gap that leaves them with few resources with which to meet unexpected costs.

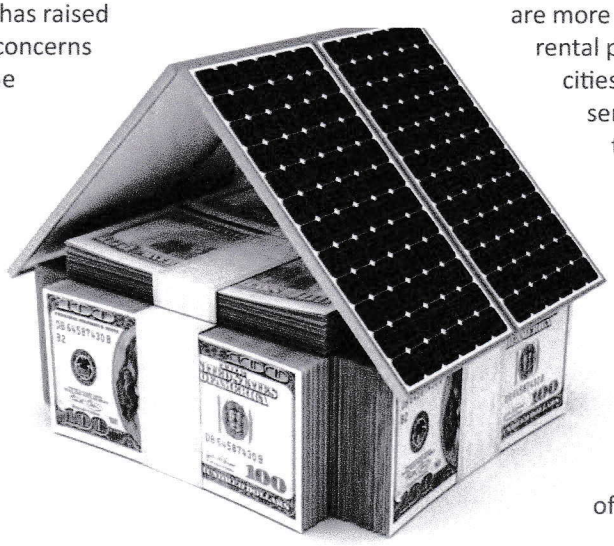
Stronger regulatory oversight and planning is critical to ensure that energy programs like net metering are inclusive, non-regressive, and equitably structured. DG has the ability to help deliver energy services efficiently and affordably

3. American Coalition for Clean Coal Electricity. February 2012. Report found on: http://www.americaspower.org/sites/default/files/Energy_Cost_Impacts_2012_FINAL.pdf
4. American Coalition for Clean Coal Electricity. (February 2012). Report found on: http://www.americaspower.org/sites/default/files/Energy_Cost_Impacts_2012_FINAL.pdf
5. American Electric Power. Brief found on: http://www.aep.com/about/IssuesAndPositions/Financial/docs/risingcostLow-Income.pdf

if it is properly implemented and widely adopted. For low-income, minority and fixed-income communities, initiatives around modernizing the traditional electric rate structure model hold particular promise, especially with regard to lowering rates and empowering these customers with more control over their already unwieldy monthly bill. But without oversight by regulators, the costs of these new services for low-income and minority and fixed-income communities could very well outweigh any benefits. As such, we as policymakers must ensure that innovation in this sector is as inclusive as possible and sustainable for years to come.

THE OPPORTUNITIES AND CHALLENGES ASSOCIATED WITH DISTRIBUTED GENERATION

Distributed generation entails the installation of small-scale generation technologies on customers' premises. Many of these involve the use of renewable energy resources like solar. Customers who can afford to install an array of photovoltaic solar cells on their roof are able to offset their energy use with the electricity generated by these alternative methods. In some cases, they can sell excess energy back to the utility, which could further reduce monthly bills. As such, this approach to modernizing the provision of energy services holds a great deal of promise for low-income, minority and fixed-income consumers who, in theory, would be able to use these new services to greatly decrease energy expenditures. However, the ways in which distributed generation programs have been rolled out across the country has raised serious concerns about the extent to which these benefits are accessible to low-income and minority customers.



For NBCSL, and those we represent, the primary concern stemming from DG programs revolves around how the costs and benefits of this new method are shared among utility customers. In most cases, individual customers are responsible for paying all the costs associated with the purchase and installation of DG systems. Even after taking into account generous tax subsidies for both the production and installation of solar panels, these costs can still be quite high, often leaving them far beyond the reach of low- and fixed-income customers. In addition, there is low awareness of and demand for these types of services among low-income, minority and fixed-income households because these consumers are more likely to live in apartment buildings, rental properties or in densely populated cities that are simply not amenable to DG services. The result is a widening gap in the demographic profile of households who are able to pursue distributed generation opportunities and reap the benefits, and those who are not.

But those with DG on their premises do more than capture all the benefits – *they also indirectly raise overall utility costs for non-participants*. This result stems from the current approach of compensating DG participants for

offsetting the electricity they use and occasionally the excess energy they generate and sell back to utilities. This is arrangement is called "net metering," which is defined under federal law as "[s]ervice to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to local distribution facilities may be used to offset electric energy provided by the electric utility to the consumer during the billing period."[6] In short, this refers to the ability of DG customers to offset their electricity use (slow their meter down) and sometimes sell excess energy back to the utility at rates that equal (or nearly equal) to the full retail rate. These customers are using the services of the electric grid, but they are not paying for it. In practice, this shifts many costs to non-DG customers.

Retail rates encompass a range of costs that are above and beyond those that are incurred by customers with DG systems. In particular, the retail rate is typically set to cover costs associated with the generation (e.g., fuel costs), transmission (e.g., line maintenance and construction), and distribution (e.g., maintenance of local above- and below-ground electric networks) of energy services. The traditional structure of the retail rate equitably distributes the many costs associated with electric power in the United States. Put more simply, everyone pays their fair share regardless of demographic profile or geographic location.

However, in the DG context, net metering creates situations where certain customers inadvertently are avoiding paying for the full range of services provided by the grid, leaving a smaller group of customers to pick up the slack. In this way, many DG programs make it possible for participants to avoid paying their fair share for maintaining the electric grid. As current trends make clear, there is a very high likelihood that this shrinking group of customers will be comprised of disproportionately large numbers of low-income, fixed-income, and minority households.

Generous subsidies, tax breaks, and incentive programs were vital to the early success of many DG systems, including solar at a time when equipment and installation costs were high. Such subsidies are no longer justified given current market conditions. Local, state, and federal policies provided – and continue to provide – solar owners and firms with tax credits, grants, and loans in addition to generous net metering policies. These policies were established to stimulate and maturate the solar market by reducing the costs of production, equipment and installations, and to aid consumers in recouping their investment. Solar policies were largely successful in lowering the cost of solar energy. In 1980, the cost of solar hovered near $25 per watt. By 2011, the cost declined to $6.13 per watt. The robust nature of the solar market coupled with the technology's relatively low cost no longer justify such generous subsidizations – especially given the regressive aspects of current policies.

Some states, via their legislatures and public utility commissions, are beginning to reevaluate relevant laws and policies, but many remain unaware of the regressive cost-shifting that is resulting from their net metering and DG policies. In addition, they are being pressured by some interests to maintain existing policies on the theory that rules dating from the infancy of solar power continue to be necessary to incubate their businesses. Many of these same interests currently operate free of the various consumer protection rules, service obligations, and rate-making processes that govern traditional electric utilities. This has given rise to several of the inequalities described above. As such, it is incumbent upon state policymakers, particularly those representing minority, low-income, and fixed-income consumers, to take the lead in forging fairer and more inclusive policies.

6. Pursuant to section 1251 of the federal Energy Policy Act of 2005, the full text of which is available at http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.

UTILITY POLICY GOING FORWARD

The National Black Caucus of State Legislators remains committed to developing polices that advance equality and fairness for all in the utility space. Indeed, NBCSL recently adopted a resolution "urging equitable distribution of electricity grid systems."[7] Our goal in this resolution was to assure fairer and more equitable pricing and ratemaking outcomes in the DG space. The resolution encourages policymakers to do the following:

- Update net metering policies in their states so that solar customers and other distributed generation customers who use the electric grid pay a fair and equitable fee to maintain the grid and to keep it operating reliably at all times;
- Develop policies for solar rooftop customers that distribute system costs equitably by creating mechanisms that recover grid costs from DG systems, enhance cost transparency, and determine if non-solar customers do, in fact, benefit sufficiently from the policy change; and
- Support programs that provide funding or utilize fair and equitable financing models to aid low-income households and communities to become more energy efficient, and to use solar panels or other forms of alternative energy.

As policymakers and regulators address these action steps, we respectfully offer the following five principles to guide their efforts:

1. **Ensure that utility policies reflect core notions of equity and social justice.**
   Policymakers at every level of government should strive to ensure that policies impacting the utility sector will promote equal opportunity and bolster core notions of social justice. Utility services are too essential to risk the development of policy regimes that result in the inequitable provision of electricity. NBCSL's recent resolution on DG, discussed above, offers a useful template for how these new approaches might be structured.

2. **Avoid regressive cost allocation in distributed generation programs.**
   The rate-setting process in the utility space has barely changed over the last few decades. As a result, very little has been done to develop approaches that reflect the technological and economic realities of the modern utility space. Low-income, minority and fixed-income consumers have been negatively impacted by this stagnation: they pay significantly more, as a percentage of their income, than most other demographic groups. Coupled with low levels of participation in DG programs, these groups are likely to remain subject to regressive cost allocations without some kind of policy intervention. Thus, policymakers should seize every opportunity to experiment with new ways of ensuring that cost allocation models do not remain regressive.

3. **New regulatory frameworks should strive to distribute the benefits and costs of innovative new utility services more evenly.**
   Continued deployment of innovative services like DG give us a unique opportunity to revisit rate-making policies. The collision of new services with existing regulatory and rate-making frameworks has resulted in the uneven distribution of the costs and benefits of these services. Even so, there are opportunities to implement revised net metering policies that can ensure low-income customers do not shoulder a disproportionate share of the costs of grid maintenance. Other options include

7. The full text of this resolution is available at http://www.nbcsl.org/public-policy/resolutions/item/1051-energy-transportation-and-environment-resolution-ete-14-32.html.

levying a fee, based on their grid use, to be paid by solar and other DG customers.

4. **Study these issues in more detail and inform new policies with data.**
   Effective regulation in the solar sector requires policymakers and regulators to examine new technologies and evolving business models. These efforts will inevitably yield useful data about the benefits and costs of policies like DG. This information can be used to craft effective policies that support the continued innovation of solar and encourage more widespread access and use by minority, low-income and fixed-income consumers. Policymakers and regulators should conduct a formal study on whether and how to bring solar firms and related DG entities under the same regulatory umbrella as traditional utilities. Data should guide whether formal regulatory oversight of these firms is necessary to achieve informed and impactful policymaking.

5. **Assure robust consumer protections.**
   Consumer protections and increased regulatory oversight must be a key component of future energy legislation. These protections and safeguards are vital to ensuring that every utility customer has equal opportunity to reap the benefits of new services, while also paying their fair share of the costs. Many existing consumer protection standards remain viable in this new era. Policymakers should extend these robust protections to solar customers. To this end, policymakers and regulators should work closely together to ensure core values are reflected in any consumer protection regimes that emerge.

CONCLUSION

The National Black Caucus of State Legislators recognizes renewable energy's potential. Current policies, however, exact an inequitable and unjust cost on minority, low income and fixed income consumers. If left unchecked, current policies like net metering will only increase the burden on these consumers. This outcome is not only unfair, it is unnecessary. We must not allow outdated policies to create a consumer caste system where some can utilize and benefit from solar policies at the expense of our most vulnerable of citizens. We at NBCSL urge our colleagues to reform laws and policies in a manner that reflects the foundational principles set forth above.

Economics of Rooftop Solar Subsidies

Bernstein Energy & Power: High Noon for Distributed Solar, or Are Regulated Utilities the Future of Solar Power?

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"Florida Power & Light (FPL) now believe we can bring forward three roughly 75-megawatt solar PV projects that can take advantage of the 2016 ITC window, leverage available land and transmission capacity, as well as prior permitting and development work, and that will prove cost effective for our customers... The way to think about cost-effectiveness for these projects is to think of them in the context of a constantly evolving integrated resource plan... In the IRP, we plug in different combinations of potential future generation and figure out, on a present value basis, which of those are cheaper for our customers...We think we now can introduce these three solar projects into the mix and drive the overall present value, as seen through the customers' eyes, lower. That's a good thing for our customers and something that we want to go ahead with."

Moray Dewhurst, CFO, NextEra Energy, on Florida Power & Light's plan to integrate solar PV as a low cost energy resource

High Noon for Distributed Solar?

By Hugh Wynne, Francois Broquin, CFA and Sam Shrank

Over the five years through 2013, U.S. distributed solar generation has grown at a compound annual rate of 56%. As can be seen in **Exhibit 1**, however, the growth of utility-scale solar—large (> 1MW) solar installations tied into the traditional grid system in the same manner as conventional power plants— has been even more rapid. We estimate that in 2014, utility scale solar generation will exceed that of distributed solar by over 50%.

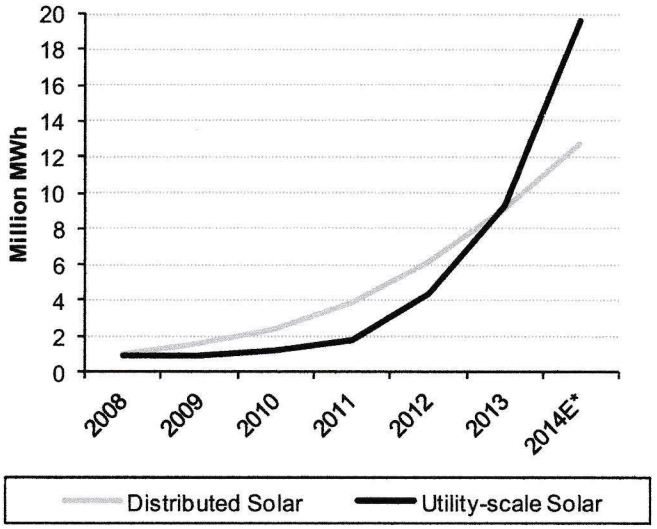
Distributed solar generation directly challenges the legacy grid system, reducing consumption of utility-supplied electricity (see our June 9, 2014 Research Call *The Long View: U.S. Utilities - Competitive Distributed Solar, Coming to a Utility Territory Near You*). Because U.S. electricity bills are based on kWh consumed, the loss of electricity sales to distributed solar erodes utility revenues -- undermining utilities' ability to recover capital invested in the grid.

Utility-scale solar presents no such threat to regulated utilities. When required to deploy it by state mandates, regulated utilities can recover its cost in retail electricity rates. Given recent cost declines, utility-scale solar may even save consumers money; FPL's plan to add three ~75 MW utility-scale solar farms to its grid does not respond to a state renewable mandate (the Sunshine State doesn't have one), but rather grew out of the utility's integrated resource planning, which identifies the lowest cost resources to supply power to the grid.

Going forward, we expect utility scale and distributed solar generation to enter into more direct competition for subsidy dollars and regulatory favor. The lower cost of utility-scale solar, combined with its compatibility with regulated utilities' business model, render it, in our view, a looming threat to the distributed solar industry.

Exhibit 1

Both utility-scale and distributed solar generation have grown rapidly – but utility solar generation now exceeds distributed by over 50%



*2014E extrapolated based on 2014 YTD generation compared to equivalent 2013 amount

Source: EIA, ABB Ventyx, SEIA, Bernstein analysis and estimates

The competition between distributed and utility-scale solar generation reflects the fact that they meet the same goals while relying on the same pots of money (taxpayers' and ratepayers') to do so. Both distributed and utility-scale solar are generously subsidized because they emit no CO2, SO2, NOx, mercury, particulate matter or other pollutants; require little environmentally disruptive mining or transportation; and, critically, offer long term price stability.

These benefits come at substantial cost, however. We estimate the unsubsidized lifetime cost of a residential distributed solar system at ~$230/MWh, or almost twice the average residential price for electricity in the United States (see **Exhibit 4**). We estimate the cost of utility scale solar generation at ~$91/MWh, or roughly twice the wholesale price of electricity. To sustain its growth, therefore, the solar industry relies upon (i) renewable portfolio standards and feed-in tariffs, which essentially require utility customers to purchase solar generation at an above-market price, and (ii) investment tax credits, which require taxpayers to cover 30% of the installed cost of solar power systems.

We calculate that renewable portfolio standards and feed-in tariffs add ~$2.1 billion annually to customers' electricity bills, in excess of the value of the electricity supplied by distributed solar, while the investment tax credit cost taxpayers ~$3.5 billion in 2013. **The combined cost of ratepayer and taxpayer subsidies for solar generation, at some $5.6 billion annually, is equivalent to ~$50 per U.S. household per year.**

The cost of these subsidies grows in direct proportion to the capital invested in solar generation. Annual investment in U.S. solar generation has increased at a compound annual rate of ~45% over the last five years. **As the industry continues to grow, we believe this rising cost will drive taxpayers and consumers (and through them, legislators and regulators) to focus increasingly on cost-effectiveness. And a focus on cost will inevitably benefit utility scale solar, which can deliver the environmental advantages of solar generation at a cost that is 50% to 60% below that of distributed solar.**

In the next section we discuss the major cost differences between utility-scale and distributed solar, and make the case that cost advantages of utility-scale are likely to persist in the long term.

Utility-scale solar:

Utility-scale solar enjoys five key cost advantages relative to distributed solar: (i) lower customer acquisition costs, (ii) economies of scale in installation, (iii) market power in equipment procurement, (iv) a significantly lower cost of capital, and (v) higher average capacity factors. These differences, in our view, are inherent in the two technologies, and therefore will be reflected in a permanent cost advantage for utility scale solar projects.

- *Lower customer acquisition costs*

Customer acquisition is perhaps the most challenging aspect of the distributed solar business. Contacting thousands of potential customers to discuss their interest in distributed solar is inherently a labor intensive and time consuming effort. The success rate is low. Many potential customers are not interested; some that are prove not to be creditworthy; and the properties of those that are both often prove unsuitable for distributed solar, due to shading from trees, the absence of a southern facing exposure, or the presence of dormers or gables that limit suitable roof space.

As monopoly suppliers of electricity in their service territories, utilities do not need to acquire customers or even consult them before installing solar generation. On the contrary, every utility customer, even apartment dwellers without rooftops (like the authors of this note), can be supplied from a utility scale facility.

- *Economies of scale for labor and installation*

The most obvious advantage utility-scale solar is its lower cost. The installation of a single 10 MW system, all else equal, costs less than the installation of 100 systems of 100kW (0.1MW). For the latter, installers must travel to 100 different locations, familiarize themselves with 100 different plans and unique circumstances, obtain 100 construction permits and secure 100 utility hookups. The costly repetition of these basic tasks is inherent to distributed solar generation and is avoided by utility scale projects.

Distributed solar installations can also be more complex than utility-scale systems. Installing roof mounted panels is inherently costlier and riskier than building ground mounted panels. And installing rooftop systems (especially on houses with pitched roofs, gables, dormers or chimneys) requires significant customization relative to uniform ground mounted arrays.

- *Oligopsony*

Regulated utilities are the monopoly suppliers of electric within very large service territories. Thus a handful of major utilities may supply the overwhelming majority of consumers in a state the size of Texas or California, and interstate utility holding companies such as Duke Energy or Southern may supply the bulk of the power needs of several states. In any given region, therefore, a limited number of utilities comprise the market for utility-scale systems; they consequently enjoy the pricing power associated with oligopsony (a market with few buyers).

Because of the scale and ongoing nature of their equipment purchases, moreover, utilities have dedicated procurement departments staffed with engineers and purchasing

managers. Through the competitive bidding process, these professionals are able to choose from an array of options each time they want to expand solar capacity, selecting the lowest cost solution and paying the cheapest price.

Contrast this with the distributed solar market, where customers are often unfamiliar with solar power before being approached by a developer, and may not have the technical expertise or even the time to aggressively seek the lowest price. As the distributed solar industry grows, we expect suppliers will be forced to compete more with each other (as opposed to simply beating the prevailing utility retail rate), and the potential to over-price distributed generation will be reduced. But the market power enjoyed by utilities in the procurement of utility scale systems will persist.

- *Lower cost of capital*

Similar considerations favor utilities in procuring capital. As the monopoly suppliers of an essential service, supported by cost-of-service based rate regulation, utilities command unrivaled access to the capital markets. The risks of housing related consumer credit, by contrast, are still a painful memory for banks and institutional investors.

- *Higher capacity factors*

In any given location, a MW of utility-scale solar will generate more electricity, on average, than an equivalent amount of distributed solar capacity (i.e. will have a higher capacity factor). This reflects the fact that utility-scale solar can be designed such that the panels are optimally positioned (facing south at a tilt equal to latitude) so as to maximize the solar energy they receive. The capacity factor of rooftop systems, by contrast, is often constrained by the direction and tilt of the roof (particularly for residential systems), and any nearby buildings or trees that block sunlight. As a result, distributed solar capacity factors average ~20% nationally, compared to 25% or higher for utility-scale systems.

Similarly, ground mounted utility scale systems allow for the deployment of heavier, more sophisticated technologies than are feasible for rooftop systems. An example is single-axis tracking, or panels that follow the sun's movement through the sky, a technology which, while more expensive, has consistently proved to be cost-effective for ground-mounted systems.

Favoring distributed solar:

Distributed solar also commands certain advantages, of course, the most important of which are transmission cost savings and, in certain cases, speed of permitting.

- *Lower transmission costs*

Distributed solar generation enjoys one major cost advantage relative to utility scale systems: it requires no investment in transmission infrastructure. Not only do distributed solar systems avoid the costs associated with building transmission lines to connect utility-scale installations to the grid, they can also put off the need for future investment in transmission systems by reducing the external electricity supply needed within a given area.

- *Lower transmission losses*

By generating electricity close to the point of consumption, distributed solar also avoids the power losses associated with sending electricity over transmission and distribution networks to the consumer (nationally averaging ~10%). The absence of transmission losses implies that each megawatt-hour generated by a distributed solar system can offset 1.1 MWh of utility generation.

- *Speed of Permitting*

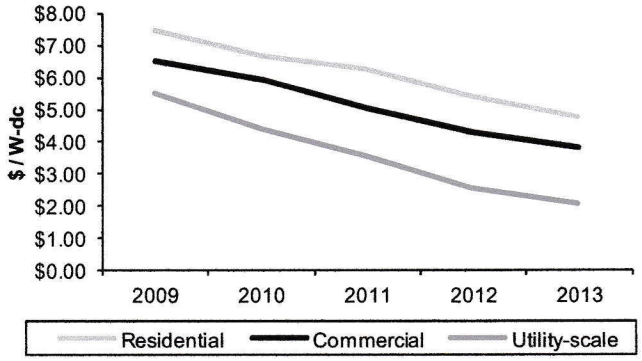
Getting utility-scale solar projects approved comes with the procedural and regulatory complications of any large-scale project. Many utility-scale solar projects in the Southwest are situated in sensitive desert habitats or on tribal lands; permitting of these projects has in certain cases been held up for years. The permitting of distributed solar systems is generally not subject to such delays. To the best of our knowledge, no distributed solar project has ever been held up due to its threat to the habitat of the desert tortoise.

Putting it all together: a cost advantage for utility-scale solar

Data on the installed cost of U.S. residential, commercial and utility-scale solar PV systems over time has been gathered and published by the Solar Energy Industries Association and the Lawrence Berkeley National Laboratory (see **Exhibit 2** and **Exhibit 3**, respectively). Both sets of data show a substantial and persistent cost advantage for utility scale systems.[1]

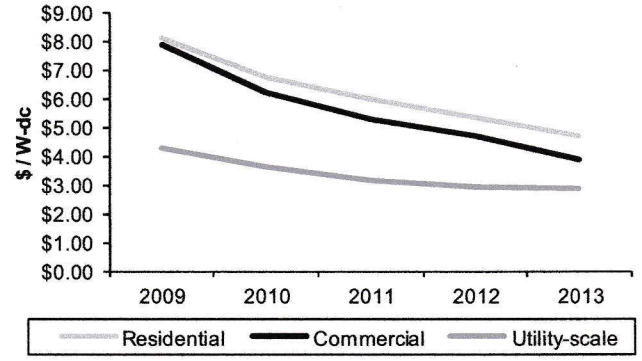
[1] We note that data on the installed cost of utility-scale and distributed solar systems do not capture fully the economic benefit of the former because they fail to account for the fact that a watt of utility-scale capacity generates more electricity, on average, than a watt of distributed capacity.

Exhibit 2
Installed cost of residential, commercial and utility-scale solar PV systems, 2009-2013 (reported prices, gathered by the Solar Energy Industries Association)



Source: Solar Energy Industries Association, Bernstein analysis

Exhibit 3
Installed cost of residential, commercial and utility-scale solar PV systems, 2009-2013 (reported prices, gathered by Lawrence Berkeley National Laboratory)



Source: Lawrence Berkeley National Laboratory, Bernstein analysis

It is possible that costs for distributed solar generation may decline more rapidly in future than those for utility scale systems, reflecting the potential for reductions in customer acquisition and installation costs as the distributed solar industry grows and becomes more competitive. But for the reasons outlined above, we believe utility scale solar is inherently more efficient. Particularly when compared to residential systems, it is unlikely that the cost advantage for utility scale systems will ever disappear.

A cost/benefit analysis of renewable generation

In most countries, the cost/benefit analysis of environmental of renewable generation has been muddled at best, with costly results in countries such as Germany and Spain and, we would argue, in the United States as well. In this section we will illustrate the relevance of cost/benefit analysis and demonstrate how it favors utility-scale solar.

Alternative sources of generation are frequently compared based upon their levelized cost of energy (LCOE), or the price per kWh of electricity that permits the recovery of all the costs of a generation system over its useful life. In **Exhibit 4** we show our estimates of the LCOEs for alternative power generation technologies. [2] Note that our LCOEs for solar and wind generation exclude the benefit of fiscal incentives such as the production tax credit for wind and investment tax credits for solar. We have used modeled costs for solar PV systems of $3.00/Watt-dc for residential and $1.65/Watt-dc for utility scale.

However, to properly assess the economic benefits of different generation technologies, it is important to take into account not just their cost, but also the value of the energy they produce. This is in large part a function of when they generate electricity. In the U.S. today, on-peak power prices can be 33% to 50% higher than off-peak prices. A technology that generates electricity during on-peak hours, such as solar, thus produces more valuable electricity than a technology whose output is skewed to off-peak hours, such as wind. This difference in the value of electricity produced is reflected in the Levelized Avoided Cost of Energy (LACE), which calculates the market value of the energy displaced by different generation technologies.

By comparing the Levelized Avoided Cost of Energy from a particular generation technology to its Levelized Cost of Energy it thus becomes possible to compare the value of power plant's output to its cost of production. The difference, if positive, represents the economic value-added of the generation technology; if negative, its economic cost.

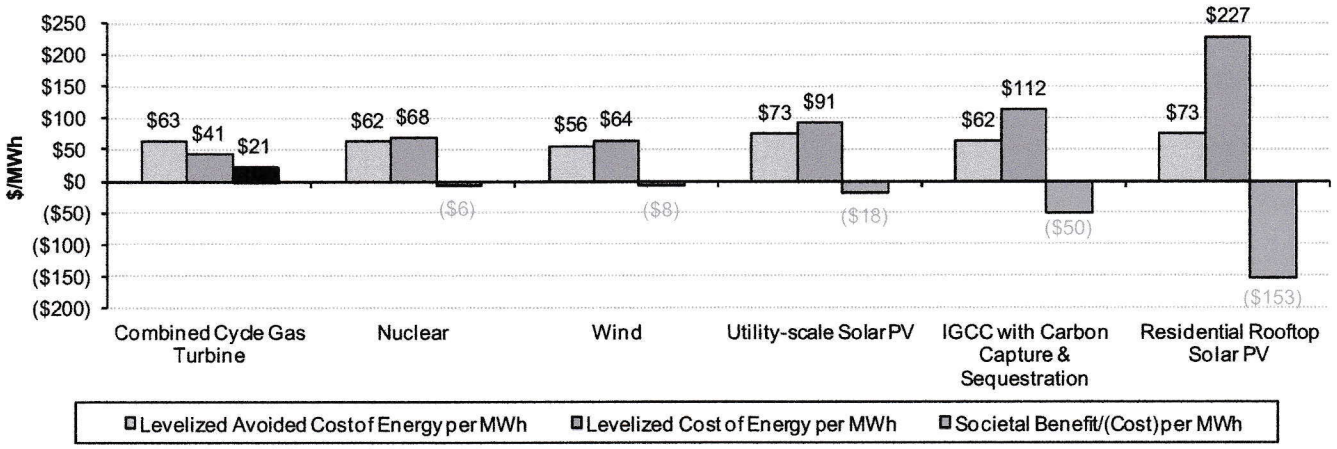
We compare the LACE and LCOE of the various generation technologies in **Exhibit 5**. As can be seen there, two renewable technologies, wind and utility-scale solar have a cost of generation (LCOE) that modestly exceeds the value of the electricity they produce (LACE). For rooftop solar, by contrast, the difference between the cost of generation and the value of output is huge, at an estimated $153/MWh.

Perhaps the single most important benefit of renewable generation is its ability to supply electricity with zero emissions of CO2 or other heat-trapping gases. In **Exhibit 5**, therefore, we compare the cost across the various

[2] Conventional coal fired plants are omitted from this analysis due to their failure to comply with the EPA's proposed New Source Performance Standards for CO2.

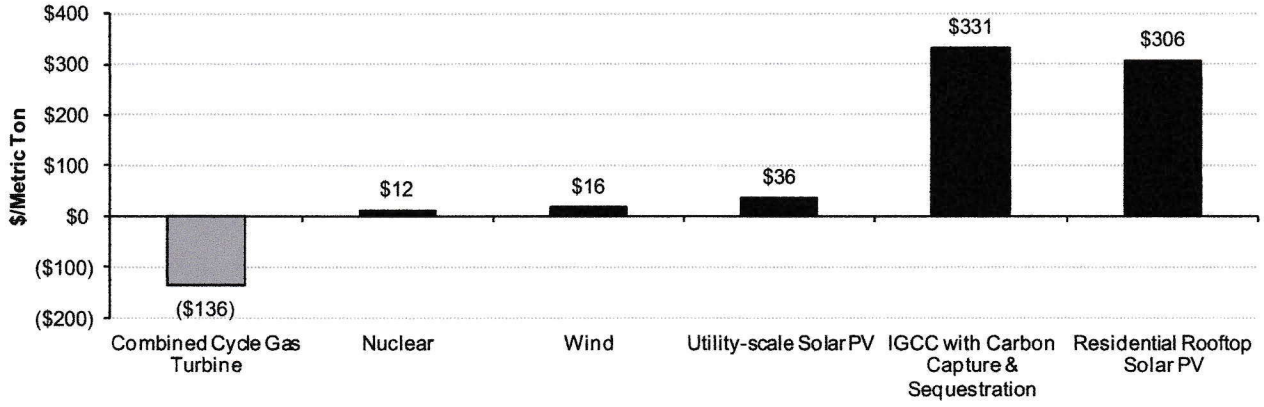
generation technologies of avoiding a ton of CO2 emissions. The columns in **Exhibit 5** represent the ratio of (i) the CO2 emissions avoided by the technology in question, relative to the average CO2 emissions rate of 0.5 metric tons per MWh for grid-supplied electricity, divided by (ii) the economic cost or benefit of the generation technology, calculated as its LACE less its LCOE. As can be seen there, wind and utility scale solar generation are capable of reducing CO2 emissions at a cost of $16 to $36 per metric ton. For distributed solar, the cost of this same environmental benefit is $306 per ton.

Exhibit 4
Levelized Cost of Energy (LCOE) compared to Levelized Avoided Cost of Energy (LACE) for feasible new sources of supply



Source: EIA, NREL, ABB Ventyx, Bernstein analysis and estimates

Exhibit 5
Cost of CO2 reduction for feasible new sources of supply, based on grid average carbon intensity of 0.5 tons of CO2/MWh



Source: EIA, NREL, ABB Ventyx, Bernstein analysis and estimates

Distributed solar offers a broader value proposition...

It can be argued that our analysis has focused too narrowly on the economic disadvantages of distributed solar, while ignoring the fact that distributed generation also offers other, partially unquantifiable, benefits to customers. These are critical to its appeal, and for truly competitive alternatives to distributed solar to be offered by utilities, they will need to be largely replicated.

- *Direct promotion of renewable generation*

Many distributed solar customers are heavily motivated by the satisfaction they feel from their personal installation – their solar rooftop – contributing to the larger good of environmentally benign electricity. This personal connection cannot be fully replicated by utility scale renewable generation.

- *Price certainty*

Lacking an ongoing fuel expense and with little required O&M, solar installations offer far more predictable costs over their lifetime than conventional power plants, whose fuel costs fluctuate with the prices of coal or gas, and whose operation and maintenance costs rise with inflation. Distributed solar providers are able to use this to their advantage in selling to customers who value price certainty, most notably retirees on fixed incomes, offering 20-year, fixed price leases for rooftop solar systems.

- *A sense of self-reliance*

Some distributed solar customers are motivated by a sense of self-reliance that comes from generating a portion of their own power needs. This is largely a state of mind; to take advantage of the net energy metering subsidy, distributed solar systems must remain connected to the grid and sell their power back to the utility.

...but it can be replicated

If utilities had marketing departments, they would have realized by now that some of these benefits, such as price certainty and the connection to particular solar installations, are well within utilities' ability to offer. It is possible, for example, for utilities to offer their customers a direct stake in utility-scale solar developments, allowing subscribers to see the direct impact of their spending. Such ownership stakes, moreover, can serve as a hedge against fluctuating power prices. Some states and utilities are already moving in this direction.

One example of this is Colorado's community solar gardens program, which has since been replicated in various other states. Under this program, subscribers—either households or businesses—purchase or lease shares in a solar project, whose output is sold to the local utility. In return, they receive a credit on their utility bill for their share of the solar garden's generation, valued at a rate that moves with the retail rate. Since 2012, Colorado's largest utility, Xcel (XEL, not covered) has approved 25 such community solar installations with a combined capacity of over 18MW. A quarter of this capacity is now operational.

In 2013, Minnesota adopted a law requiring utilities to administer a similar community solar garden program. Xcel, which also operates in Minnesota, has proposed a plan under which it would have the option to develop solar gardens itself, as well as contracting development out to third parties.

Conclusion

The combined cost of ratepayer and taxpayer subsidies for solar generation, at some $5.6 billion annually, is equivalent to ~$50 per U.S. household per year. The cost of these subsidies grows in direct proportion to the capital invested in solar generation. Annual investment in U.S. solar generation has increased at a compound annual rate of ~45% over the last five years.

As the industry continues to grow, we believe its cost will drive taxpayers and consumers (and through them, legislators and regulators) to focus increasingly on cost-effectiveness. A focus on cost will inevitably benefit utility scale solar, which can deliver the environmental advantages of solar generation at a cost that is 50% to 60% below that of distributed solar.

The cost advantage of utility scale solar, in our view, reflects differences inherent in centralized versus distributed generation systems. Utility-scale solar enjoys five key cost advantages relative to distributed solar: (i) lower customer acquisition costs, (ii) economies of scale in installation, (iii) market power in equipment procurement, (iv) a significantly lower cost of capital, and (v) higher average capacity factors. These advantages are permanent in nature.

The arc of the electricity industry is long, but it bends towards economics.

This Week's Reports

(Available on FirstCall/bernsteinresearch.com)

US Utilities

EXC: Exelon's Earnings Continue to Stagnate, but Several Long Term Upsides Are Getting Closer (10/30/2014)
While we believe Exelon is challenged to realize organic earnings growth at either its competitive or regulated utility segments, we nonetheless see the potential for material earnings upside from three external sources. EXC's agreed acquisition of Pepco Holding would add, by our estimate, $0.14 to $0.16 per share to EXC's 2017 EPS. Second, EXC stands to benefit from PJM's planned capacity market reforms; a $100/MW-day rise in the capacity price would add $0.50 to EPS. Most importantly, EXC's predominantly nuclear fleet is uniquely levered to EPA's plan to regulate power plant emissions of CO2. We calculate that these regulations could add $1.60 per share to long term earnings, equal to 60% of EXC's consensus 2016 EPS.

EIX: CEO Warns Investors to Curb Their Enthusiasm, Earnings Will Revert to Allowed Levels; Raising TP on Dividend Outlook *(10/29/2014)*
EIX yesterday raised its guidance range for 2014 core earnings to $4.25-$4.35 from $3.60-$3.80 previously. This dramatic increase primarily reflects further reductions in expected 2014 operation and maintenance expense and income taxes. However, EIX CEO Ted Craver repeatedly emphasized that both the O&M and tax savings are expected to fall away in 2015, as Edison's revenue requirement is re-set in its 2015 General Rate Case to reflect the savings realized in 2014. We expect core earnings to remain below 2014 levels until at least 2018. However, as Edison raises its dividend payout to its target range, we expect ~11% annual growth in dividends over 2014-2017. We are raising our year-end 2015 TP to $66 per share.

U.S. Utilities: PJM Market Monitor Expects New Capacity Market Architecture to Triple Capacity Prices (10/27/2014)
On Oct. 16, I interviewed Dr. Joseph Bowring, PJM's Independent Market Monitor, with respect to the radical changes to the architecture of the PJM capacity market currently under consideration by PJM. This note presents the transcript of our conversation. Bowring expects PJM's Capacity Performance Proposal, dated Oct. 7, to drive future capacity prices to Net CONE (ranging from $315 to$375/MW-day, depending on the region) compared to a clearing price of only $120/MW-day in the 2017/2018 capacity auction. In the note, we quantify the sensitivity of generators' earnings to a $100/MW-day increase in PJM capacity prices. NRG has the most earnings leverage to a PJM capacity price increase, followed by CPN, FE, EXC, DYN, PEG and PPL.

North American Oil & Gas E&Ps

Bernstein E&Ps : What the Strong Dollar Did (and May Do) to Oil Prices (10/31/2014)
The strengthening of the dollar has been invoked as one of the causes of the decline in oil price. Indeed, the dollar index has risen 7% YTD corresponding to falling oil and commodity prices. The relation between Brent and the dollar is not simple. Over the long run, correlations do not persist but year to date, the beta of oil price to dollar is greater than 3. This requires that some other variable (macro fear is our hypothesis) is driving both, rather than either driving the other. If you believe that oil price returns, then investing in oil-linked equities is an obvious strategy. We recommend EOG, CIE, APA, and TLM (all outperform) as equities that will respond positively to a rising crude price.

Bernstein E&Ps: The Mystery of SWN and the West Virginia Marcellus - Horse Tracks or Unicorn Tracks? (10/28/2014)
On Oct 17, SWN announced the acquisition of SW Marcellus and Utica Assets from CHK. Purchase price was $5.375 billion with assets representing 413,000 net acres and 0.34 BCFED of production. Transaction comps suggest an overpayment of 95%. Equity markets rewarded CHK and punished SWN 17% and -10% respectively on day of announcement, erasing $1.3B of SWN market cap. We have always believed that SWN was one of the more returns-focused teams in our coverage space. This does not fit the mold. Alternatively, there is more to this deal than meets the eye and a patient shareholder (having seen the 'bear case' already reflected in the stock) should consider waiting a month or two to decide. We reiterate outperform.

Asia Pacific Oil & Gas

China Economic & Energy Indicators - September 2014: Signs of Stabilization in Energy Demand with the Fillings of SPR (10/30/2014)
Blended energy consumption growth in 3Q came in at 3.5% y-o-y, 2.8 percentage points lower than 2Q, consistent with the pullback in GDP growth. Despite weak readings in 3Q, China economic and energy indicators showed signs of stabilization in September. Oil demand increased strongly by 7.6% yoy to 10.5Mbpd in September. Low oil prices and elevated geopolitical risk have led to accelerated fill of SPR. Gas output increased 12% yoy to 9.9bcm in August 2014 while total gas demand was up 8% yoy to 14.6bcm. Crude steel production in September 2014 was ~67.5Mt, up 3.2% y-o-y and up 1.3% m-o-m. Primary aluminum production in came in at 2.04Mt in September, up 9.9% y-o-y and up 4.0% m-o-m. LME all-in price approaching ~US$2,500 per ton in US and Europe.

European Oil Services

Saipem: ...And Into the Fire - TP Cut by 30% on Major Write Down Threat. Underperform, TP €10
(10/30/2014)
Following disappointing Q3 results the key controversy on Saipem is about entry point: has the stock bottomed out? We think

not. In our experience this many cracks alert to a new problem, and we highlight the five key datapoints investors should focus on. Unbilled invoices are getting worse not better, increasing 15% to €1.5bn. Zero-profit contracts refuse to pass, increasing from 17% to 20% of 2015 backlog. 2014 net debt, EBIT and net income were guided down 8% with little substantial reason. Multiple warning signs make us fear non-collection of the €1.5bn of unbilled invoices will be larger than we thought. Hence we model a €350m write-down (20% of the total) into our forecast and accordingly cut our target price 30% to €10.00. Underperform.

European Utilities

Southern European Utilities: Have No Fear - Why Investors Should Not be Afraid of a Rise in Interest Rates (10/30/2014)
"What will happen to Southern European Utilities when interest rates rise?" We have investigated whether investors should fear a possible increase in interest rates and concluded that the perception of interest rate risk is largely overstated. Our 15-year analysis shows that no inverse relationship exists between rates & Utilities' prices. This is due to 3 key stabilizers: (a) networks' remuneration, (b) nuclear provisions, (c) shareholding structure skewed towards Gov't & strategic investors. We simulate 2 rising interest rate scenarios and show that the greater near term risk might stem from an insufficient rate increase, rather than the opposite. Hence, we reiterate our ratings and TP: EDF, GSZ, Enel, EGPW (OP), Snam, GAS (MP), and IBE (UP).

European Utilities: UK Capacity Market Auction - Updated analysis based on potential bidding strategies (10/30/2014)
We update our earlier capacity market analysis to take into account a revised demand curve, revised supply numbers and granularly analyse over 500 potential supply sources to predict potential bidding patterns based on economics of various sources. Our estimate for clearing prices remain unchanged at ~£38/KW per KW of derated capacity (2012 prices), as we still expect existing plants that are 'price-makers' or requiring refurbishments, depending on their bidding price, to set the price. Not all existing capacity will clear the auction - possibly only 2.6GW of old CCGT and old coal; EDF and RWE have highest amount of capacity that is most likely to clear auction at 7.5GW and 7.2GW respectively followed by SSE at ~5GW

UK Utilities: What To Expect from the CMA Investigation on Energy Retail ? - The Detailed Low-down (10/28/2014)
In today's note, we tease-out the potential solutions that the CMA can look at, based on responses of new entrants and analyses. The outcome is far from clear and depends on how tough a stand they will take to eliminate real / perceived barriers to entry. We view the remedies of (1) Divestment (2) Some measure to shake-up 'inactive' customers (Informational/ opt-in/ maximum mark-up) as being most controversial and holding the key to the impact of reforms on the profitabilty of the Big Six. For Centrica (MP), we find that a bleak post-CMA world has been priced into the stock. For SSE (UP), while domestic retail is ~12% of operating profits (vs 21% for Centrica), we find that very little of downsides from the investigation are priced in

RWE: Three reasons why the recent underperformance is unwarranted and represents a good entry point (10/27/2014)
In the last month, RWE is -13% vs DAX -6%; this has been attributed to (1) Challenges in sale of RWE DEA due the lack a comfort letter from the UK (2) A weaker German macro, declining coal prices (3) Discriminatory capacity markets. DEA sale has not been blocked by UK and UK assets can be ring-fenced; RWE still targets year end closure. There has been a structural decoupling of its share price and power prices; besides forward power prices declines have been modest in the last month. Discriminatory capacity markets are not favoured by the independent consultant reports commissioned by the Government; domestic and EU level political support is unlikely in our view. The recent performance is unwarranted and represents a good entry point

European Utilities: Seven Frequently Asked Questions on German Power Markets (10/27/2014)

While central to our thesis on RWE and E.ON is the diminishing relevance of the power generation business, we find that this area continues to be biggest area of investor focus and concern. In this note, we address 7 most FAQs and update our forecasts. Commodity prices account for ~80% of the drop in power prices; Capacity closures of 8-18GW needed for a ~10-25% increase in prices; Renewables impact on prices limited; Power dd not on a downward trajectory unless there is continued economic contraction. CO2 prices will unlikely provide support due to limited political support for radical interventions; Coal has likely bottomed-out and lignite will offer a floor for prices in Germany; a capacity market is preferable to a distorted energy only market

Disclosure Appendix

Ticker Table

Ticker	Rating	CUR	31 Oct 2014 Closing Price	Target Price	TTM Rel. Perf.	EPS 2013A	EPS 2014E	EPS 2015E	P/E 2013A	P/E 2014E	P/E 2015E	Yield
AEP	M	USD	58.34	58.00	9.7%	3.23	3.46	3.57	18.1	16.9	16.3	3.6%
D	M	USD	71.30	48.00	-3.1%	3.05	3.25	3.36	23.4	21.2	21.2	3.4%
DUK	M	USD	82.15	78.00	-0.4%	4.35	4.62	4.75	18.9	17.8	17.3	3.9%
EIX	O	USD	62.58	66.00	12.8%	3.80	4.30	3.55	16.5	14.6	17.6	2.3%
EXC	M	USD	36.59	34.00	13.3%	2.50	2.35	2.35	14.6	15.6	15.6	3.4%
FE	M	USD	37.34	38.00	-16.3%	3.04	2.54	3.00	12.3	14.7	12.4	3.9%
NEE	M	USD	100.22	100.00	3.4%	4.97	5.28	5.47	20.2	19.0	18.3	2.9%
PCG	O	USD	50.32	50.00	5.4%	2.72	2.94	3.15	18.5	17.1	16.0	3.6%
1251.HK (SPT)	O	HKD	2.45	4.70	-37.7%	0.25	0.27	0.41	9.8	9.1	6.0	2.5%
135.HK (Kunlun Energy)	U	HKD	10.28	10.00	17.6%	0.85	0.75	0.78	12.1	13.7	13.2	2.2%
1605.JP (Inpex)	O	JPY	1350.00	1605.00	19.7%	116.25	125.80	114.00	11.6	10.7	11.8	1.3%
1623.HK (Hilong)	O	HKD	2.59	4.70	-49.7%	0.26	0.35	0.45	9.9	7.4	5.8	3.8%
2883.HK (COSL)	M	HKD	18.16	20.00	-14.7%	1.88	2.17	2.27	9.7	8.4	8.0	3.0%
3337.HK (Anton)	M	HKD	1.69	2.70	-61.6%	0.22	0.13	0.19	7.5	13.0	8.9	3.7%
SNP	M	USD	87.09	96.70	9.0%	8.77	9.41	10.44	9.9	9.3	8.3	4.3%
386.HK (SinoPec)	M	HKD	6.79	7.50	12.5%	0.68	0.73	0.81	10.0	9.3	8.4	4.3%
PTR	M	USD	124.77	128.98	10.1%	11.48	11.74	13.29	10.9	10.6	9.4	4.2%
857.HK (PetroChina)	M	HKD	9.84	10.00	10.9%	0.89	0.91	1.03	11.1	10.8	9.6	4.1%
CEO	O	USD	162.42	206.29	-18.1%	20.50	21.15	24.50	7.9	7.7	6.6	4.5%
883.HK (CNOOC)	O	HKD	12.56	16.00	-17.9%	1.59	1.64	1.90	7.9	7.7	6.6	4.5%
IOC	O	USD	55.14	90.00	-31.6%	-0.83	6.99	-0.59	2.5	2.6	2.5	NA
ONGC.IN	M	INR	391.70	380.00	35.7%	30.60	35.27	40.50	12.8	11.1	9.7	2.3%
OSH.AU	O	AUD	8.49	11.00	1.4%	0.16	0.40	0.68	53.1	21.2	12.5	0.5%
PTTEP.TB	M	THB	143.50	185.00	-14.6%	14.20	16.90	17.30	10.1	8.5	8.3	3.5%
RIL.IN	O	INR	934.05	1050.00	6.6%	76.50	89.40	102.00	12.2	10.4	9.2	1.2%
RIGD.LI	O	USD	30.48	43.82	6.0%	3.19	3.73	4.26	9.5	8.2	7.2	1.6%
STO.AU	M	AUD	12.92	14.00	-13.2%	0.52	0.60	0.92	24.8	21.5	14.0	2.3%
WPL.AU	M	AUD	39.74	43.00	3.3%	2.14	2.93	3.08	18.6	13.6	12.9	6.8%
BG/.LN	O	GBp	1044.50	1650.00	-18.0%	83.96	70.93	89.88	12.4	14.7	11.6	1.7%
BP/.LN	M	GBp	445.30	500.00	-7.3%	45.28	43.86	53.95	9.8	10.2	8.3	5.5%
BP	M	USD	42.90	50.00	-19.0%	4.26	4.39	5.18	10.1	9.8	8.3	5.5%
CNE.LN	M	GBp	154.60	330.00	-41.2%	-57.00	-14.00	-13.00	NM	NM	NM	NA
ENI.IM	O	EUR	16.33	20.00	-5.2%	1.22	1.23	1.76	13.4	13.3	9.3	6.9%
E	O	USD	41.40	52.00	-21.9%	3.24	3.33	4.52	12.8	12.4	9.2	7.4%
TOT	O	USD	58.64	74.50	-11.5%	6.28	5.81	6.45	9.3	10.1	9.1	5.7%
FP.FP	O	EUR	46.40	58.00	5.6%	4.73	4.30	5.04	9.8	10.8	9.2	5.3%
GALP.PL	O	EUR	11.49	17.00	-2.1%	0.23	0.36	0.47	50.0	31.9	24.4	2.5%
OGZD.LI	O	USD	6.49	13.00	-23.1%	3.29	2.64	3.05	2.0	2.5	2.1	6.5%
GAZP.RM	O	RUB	138.50	230.00	0.8%	49.94	43.96	39.88	2.8	3.2	3.5	5.4%
LKOH.RM	M	RUB	2042.50	2030.00	1.1%	322.00	425.00	392.00	6.3	4.8	5.2	6.0%
LKOD.LI	M	USD	47.49	57.00	-22.9%	10.38	13.62	12.68	4.6	3.5	3.7	7.2%
NVTK.RM	M	RUB	427.97	362.97	8.1%	24.52	34.28	35.97	17.5	12.5	11.9	2.7%
NVTK.LI	M	USD	104.00	137.00	-23.0%	7.91	10.77	11.91	13.2	9.7	8.7	3.1%
PMO.LN	O	GBp	269.60	460.00	-13.0%	28.00	36.00	44.00	9.6	7.5	6.1	1.9%
RDS/B	O	USD	74.28	83.00	-8.4%	5.32	7.79	8.69	14.0	9.5	8.5	5.1%
RDSA.LN	O	GBp	2235.50	2600.00	4.8%	172.73	233.00	272.00	12.9	9.6	8.2	5.0%
RDSA.NA	O	EUR	28.22	32.50	10.4%	2.00	2.89	3.39	14.1	9.8	8.3	4.9%
RDSB.LN	O	GBp	2313.50	2600.00	2.9%	172.73	233.00	272.00	13.4	9.9	8.5	4.8%
RDSB.NA	O	EUR	29.44	32.50	9.3%	2.00	2.89	3.39	14.7	10.2	8.7	4.7%
RDS/A	O	USD	71.36	83.00	-7.1%	5.32	7.79	8.69	13.4	9.2	8.2	5.3%
REP.SM	M	EUR	17.48	21.00	1.8%	1.80	1.29	1.43	9.7	13.6	12.2	5.7%
ROSN.RM	M	RUB	233.45	350.00	-6.2%	40.32	36.56	37.16	5.8	6.4	6.3	3.7%
ROSN.LI	M	USD	5.45	9.90	-27.5%	1.30	1.21	1.23	4.2	4.5	4.4	4.5%
SGGD.LI	M	USD	6.36	8.00	-25.4%	1.49	1.77	1.71	4.3	3.6	3.7	3.0%
STO	O	USD	23.60	35.00	-9.4%	2.46	2.49	2.72	9.6	9.5	8.7	5.0%
STL.NO	O	NOK	158.70	210.00	9.4%	14.46	15.26	17.69	11.0	10.4	9.0	4.4%
TLW.LN	O	GBp	494.00	1300.00	-40.8%	12.00	32.00	40.00	41.2	15.4	12.4	1.2%
APA	O	USD	77.20	121.00	-28.0%	7.92	7.28	8.26	9.7	10.6	9.3	1.3%
APC	M	USD	91.78	106.00	-18.6%	4.45	5.88	6.16	20.6	15.6	14.9	1.2%

CHK	M	USD	22.18	26.00	-31.0%	2.55	1.95	1.73	8.7	11.4	12.8	1.6%
CIE	O	USD	11.71	27.00	-64.4%	-1.46	-1.71	-2.26	NM	NM	NM	NA
COG	O	USD	31.10	37.00	-26.8%	0.71	1.28	1.25	43.8	24.3	24.9	0.3%
DVN	M	USD	60.00	69.00	-20.0%	4.27	5.46	5.57	14.1	11.0	10.8	1.6%
ECA.CN	M	CAD	20.45	22.00	-2.5%	1.08	2.01	1.72	18.9	10.2	11.9	1.5%
ECA	M	USD	18.63	20.00	-10.9%	1.08	1.83	1.57	17.3	10.2	11.9	1.5%
EOG	O	USD	95.05	109.00	-8.3%	8.19	5.36	7.22	11.6	17.7	13.2	0.7%
NBL	M	USD	57.63	62.00	-38.0%	3.23	3.36	3.86	17.8	17.2	14.9	1.3%
RRC	O	USD	68.40	88.00	-24.5%	1.45	2.09	2.14	47.2	32.7	32.0	0.2%
SWN	O	USD	32.51	51.00	-27.5%	2.00	2.58	2.43	16.3	12.6	13.4	NA
TLM.CN	O	CAD	6.97	14.00	-59.6%	-0.24	0.05	0.09	NM	NM	79.8	4.2%
TLM	O	USD	6.38	13.00	-63.8%	-0.24	0.05	0.08	NM	NM	79.8	4.2%
AKSO.NO	M	NOK	45.20	100.00	0.3%	4.64	7.25	8.33	NA	NA	NA	9.1%
PFC.LN	O	GBp	1045.00	1400.00	-28.5%	1.91	1.66	2.13	6.7	6.7	5.0	0.1%
SBMO.NA	U	EUR	10.10	9.00	-35.6%	0.56	1.68	0.88	8.9	8.3	12.1	NA
SPM.IM	U	EUR	12.67	10.00	-25.4%	-0.36	0.63	0.44	8.1	7.6	6.9	NA
SUBC.NO	U	NOK	76.45	86.00	-38.4%	1.04	1.77	1.28	3.4	3.1	3.7	0.8%
TEC.FP	O	EUR	55.47	91.00	-36.7%	5.06	5.81	7.16	5.3	4.6	3.9	3.3%
TEN.IM	M	EUR	15.35	16.00	-12.7%	1.31	1.38	1.34	11.7	11.1	11.5	2.8%
VK.FP	O	EUR	29.74	43.00	-32.0%	2.10	1.78	2.33	14.1	16.7	12.8	2.7%
CNA.LN	M	GBp	292.70	300.00	-18.2%	25.90	19.89	24.14	11.3	14.7	12.1	6.0%
DRX.LN	U	GBp	589.50	550.00	-10.5%	35.00	22.50	25.00	16.8	26.2	23.6	2.1%
EOAN.GR	O	EUR	13.22	17.00	-1.9%	1.18	0.90	1.19	11.2	14.7	11.1	4.4%
NG/.LN	O	GBp	891.00	960.00	14.1%	54.00	59.00	63.00	16.5	15.1	14.1	4.7%
RWE.GR	O	EUR	27.24	37.00	1.0%	3.77	2.23	2.26	7.2	12.2	12.1	3.7%
SSE.LN	U	GBp	1536.00	1330.00	7.8%	123.40	124.47	100.22	12.4	12.3	15.3	5.8%
SVT.LN	M	GBp	1988.00	1914.00	6.6%	88.00	90.10	74.70	22.6	22.1	26.6	4.3%
UU/.LN	O	GBp	838.00	970.00	16.5%	44.71	45.87	36.32	18.7	18.3	23.1	4.5%
EDF.FP	O	EUR	22.95	32.70	-7.8%	2.17	1.86	2.20	10.6	12.3	10.4	5.5%
EGPW.IM	O	EUR	1.91	2.40	7.1%	0.11	0.10	0.12	18.1	18.8	15.6	1.7%
ENEL.IM	O	EUR	3.91	4.90	26.6%	0.34	0.31	0.34	11.4	12.6	11.5	3.3%
GAS.SM	M	EUR	22.55	21.00	23.4%	1.44	1.41	1.60	15.6	16.0	14.1	4.0%
GSZ.FP	O	EUR	18.93	22.00	13.2%	1.46	1.22	1.57	13.0	15.5	12.1	7.9%
IBE.SM	U	EUR	5.54	4.20	24.9%	0.41	0.36	0.34	13.4	15.3	16.3	5.7%
SRG.IM	M	EUR	4.18	4.10	5.5%	0.27	0.30	0.33	15.4	13.9	12.7	6.0%
SPX			2018.05			108.50	116.87	130.04	18.6	17.3	15.5	1.9%
MXAPJ			481.63			33.75	36.74	40.57	14.3	13.1	11.9	3.1%
MXJP			787.24			51.39	54.00	60.98	15.3	14.6	12.9	1.9%
MXEF			1007.54			81.77	85.54	95.64	12.3	11.8	10.5	2.8%
MSDLE15			1363.01			86.93	91.10	102.61	15.7	15.0	13.3	3.5%

O – Outperform, M – Market-Perform, U – Underperform, N – Not Rated

1605.JP, SGGD.LI estimates are 2012A/2013E/2014E; IOC metrics is P/B; AKSO.NO, PFC.LN, SBMO.NA, SPM.IM, SUBC.NO, TEC.FP metrics is EV/EBITDA

Valuation Methodology

European Oil Services & Equipment

We value our coverage using one-year ahead earnings forecasts (2015) applied to a target multiple. We use one-year ahead earnings to reflect the high degree of visibility typically afforded by orderbooks of work that is won but not yet delivered. We find that the market looks at EBITDA and net income (earnings per share) equally when assessing prospects for Oil Services, and so we calculate our target price on both of these measures and average the two.

To derive our target multiple, we use stock-specific multiples. We prefer this method to using a sector-average multiple +/- premium/discount, because the wide variety of business models at play in the sector lead to significant variation around the sector average. Whilst oil prices remain broadly flat we believe it is appropriate to base our target multiple on historical average multiples, selecting two-year averages rather than 10-year averages to reflect lower investor confidence since the oil price crash.

European Oil & Gas

Our target prices for the European Integrated Oils are calculated by applying our estimates for 2012 cashflow per share (CFPS) to a forward price-to-cashflow (P/CF) multiple. This P/CF multiple is generated through the relationship, and historically strong correlation, between 12 month forward P/CF multiples and Return on Average Capital Employed (ROACE) within the

Integrated Oils group. Our calculation utilizes this relationship and an estimated long term, through the cycle ROACE to generate the target P/CF multiple. The price calculations for the Integrated are summarized below. We use $90/bbl Brent and $3.75/mcf for US gas in 2012 and $115/bbl Brent and $4.25/mcf for US gas in 2013.

North American Oil & Gas Exploration/Production

Our valuation framework for our coverage of North American E&P oil & gas stocks is based on the correlation of P/CF multiple and the recycle ratio (cash flow per barrel divided by F&D costs). The recycle ratio-implied target multiples are supplemented by company-specific catalysts, which are valued independently under a full-life cycle NPV methodology and applied in the form of incremental (positive or negative) change. We adjust our target multiples to include the effects of growth, capitalization, capital efficiency, and risk.

Asia-Pacific Oil & Gas

We value large cap oil and gas companies by identifying the forward price to book multiples they should trade at based on returns on equity, long term earnings growth expectations, dividend payout ratio and cost of equity. Our starting point is that Fwd P/B = (ROE x PO) / (Ke – g), where ROE is our estimates of ROE for 2015, PO is the dividend payout ratio, Ke is the cost of equity, and g is the long term growth rates.

For Santos, Oil Search, Woodside and Inpex, we believe an NAV approach is appropriate given a significant portion of their values are attached to future LNG projects. In calculating the NAV, we have assumed a long term oil price of $100 (real).

We value RIL using a sum of the parts methodology.

We value COSL using a sum of the parts method.

We value Kunlun Energy using a sum of the parts method.

U.S. Utilities

Our target prices reflect the results of three alternative valuation methodologies: (i) a multiple-based valuation calculated by applying the median valuation multiples of a group of comparable companies to our estimates of a utility's future earnings, dividends and EBITDA; (ii) a discounted cash flow model over the forecast period of 2014-2017, and a terminal value in 2018 discounted back to present value at the weighted average cost of capital; and (iii) a discounted dividend model over the forecast period of 2014-2017, and a terminal value in 2018, discounted back to present value at the cost of equity.

UK and Northern European Utilities

We value our coverage (except DRX) based on an average of Sum of the Parts DCF and Dividend Discount model (50%/50%). We value DRX on a DCF basis only.

Southern European Utilities:

We use a blended (50%/50%) valuation methodology of discounted cash flow (DCF) and adjusted multiples (P/E, EV/EBITDA).

Risks

European Oil Services & Equipment

Our coverage group's trading multiples and after a lag, earnings, are highly sensitive to changes in the oil price. Oil price forecasts are heavily dependent on GDP expectations and global supply expectations, both of which could be materially different from our macro-economic assumptions. Supply disruptions in particular caused by weather, terrorism or political events remain a material upside risk to the oil price. Hence the greatest risk to our target prices is a significant decline in crude oil prices, as these stocks commonly trade in line with commodity prices.

For the Facilities Engineers in particular, project-specific complications in executing the scope of work are a common source of surprise to the market. Similarly the timing of profit recognition is significantly influenced by the status of a relatively small number of large construction projects. Accordingly a key risk to our target price is operational problems and delay to one or a number of these projects, as each can cause a material reduction in share price.

European Oil & Gas

For the European Majors, the greatest risk to our target prices is a significant decline in crude oil prices, as the Majors commonly trade in line with commodity prices. Additionally, downward revisions to production volume targets could adversely impact share prices.

North American Oil & Gas Exploration/Production

The primary risk to our target prices for the North American E&Ps is lower than expected commodity prices over the next few years. For instance, oil prices could be negatively affected by slower than expected economic growth, higher global supply, or faster switching to alternative fuel sources, which could depress product demand and drive oil prices below the marginal cost of supply. For natural gas, prices could be negatively affected by warm weather, continued healthy supply growth, lower coal-to-gas power switching, or higher LNG/pipeline net imports. Additionally, government policy and administration, including but not limited to the BOEM/BSEE's pace of permitting or leasing, or changes to various countries' tax rates/fiscal terms, have the potential to positively or negatively affect the commodities and companies.

U.S. Utilities

Our earnings and cash flow forecasts for the regulated utilities in our coverage (AEP, D, DUK, EIX, FE, NEE, and PCG) are driven primarily by our projections of volume sales and future rate relief and, in the long term, by the rate of growth in rate base and the return on equity allowed by the utilities' regulators. If our assumptions in these critical areas prove overly optimistic/(pessimistic), our earnings and cash flow forecasts may need to be cut/(raised) and with them our target prices.

Our earnings and cash flow forecasts for the competitive generators in our coverage (EXC), and for the competitive generation business of primarily regulated utilities, are predicated on currently prevailing forward price curves for power and generation fuels (coal, gas and nuclear fuel). Changes in these forward price curves can thus have a material impact on our forecasts of earnings and cash flow and consequently on our target prices for these stocks. Power prices can be quite sensitive to the price of natural gas, so that higher gas prices tend to be reflected in higher revenues, earnings and cash flow. However, higher prices for coal and nuclear fuel tend to depress generation margins.

Finally, our forecasts for both regulated utilities and competitive generators are sensitive to the estimated growth in property, plant and equipment, which drives depreciation and interest expense, as well as to the expected growth in operations and maintenance expense.

European Utilities

Adverse changes in commodity prices

Adverse changes in regulation/ policy

Adverse credit conditions limiting access to credit

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  Outperform: Stock will outpace the market index by more than 15 pp in the year ahead.

  Market-Perform: Stock will perform in line with the market index to within +/-15 pp in the year ahead.

  Underperform: Stock will trail the performance of the market index by more than 15 pp in the year ahead.

  Not Rated: The stock Rating, Target Price and estimates (if any) have been suspended temporarily.
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12-Month Rating History as of 11/02/2014

Ticker	Rating Changes		
1251.HK	O (IC) 05/13/14		
135.HK	U (RC) 10/07/14	M (RC) 03/27/14	M (DC) 01/28/13
1605.JP	O (RC) 02/18/14	M (IC) 06/13/13	
1623.HK	O (IC) 05/13/14		
2883.HK	M (RC) 01/08/13		
3337.HK	M (IC) 05/13/14		
386.HK	M (RC) 09/16/14	O (RC) 01/21/14	M (RC) 03/28/13
857.HK	M (RC) 11/01/13		
883.HK	O (RC) 10/07/14	M (RC) 01/21/14	O (RC) 12/01/11
AEP	M (IC) 01/15/03		
AKSO.NO	M (IC) 06/24/14		
APA	O (IC) 05/13/11		
APC	M (RC) 07/18/14	O (RC) 06/28/12	
BG/.LN	O (IC) 01/22/09		
BP	M (IC) 08/03/10		
BP/.LN	M (IC) 08/03/10		
CEO	O (RC) 10/07/14	M (RC) 01/21/14	O (RC) 12/01/11

CHK	M (RC) 06/13/12			
CIE	O (IC) 06/16/14			
CNA.LN	M (RC) 10/13/14	U (IC) 05/08/14		
CNE.LN	M (RC) 01/29/13			
COG	O (RC) 10/20/14	M (RC) 05/02/14	O (RC) 11/20/13	M (RC) 07/30/13
D	M (RC) 09/04/07			
DRX.LN	U (RC) 08/14/14	M (IC) 05/08/14		
DUK	M (RC) 08/05/04			
DVN	M (IC) 05/13/11			
E	O (RC) 06/14/13			
ECA	M (IC) 05/13/11			
ECA.CN	M (IC) 05/13/11			
EDF.FP	O (IC) 05/12/14			
EGPW.IM	O (IC) 05/12/14			
EIX	O (RC) 06/14/13			
ENEL.IM	O (IC) 05/12/14			
ENI.IM	O (RC) 06/14/13			
EOAN.GR	O (IC) 05/08/14			
EOG	O (RC) 10/13/14	M (RC) 07/18/14	O (RC) 11/02/11	
EXC	M (RC) 02/05/10			
FE	M (RC) 10/27/10			
FP.FP	O (IC) 08/03/10			
GALP.PL	O (RC) 05/26/10			
GAS.SM	M (IC) 05/12/14			
GAZP.RM	O (IC) 10/16/13			
GSZ.FP	O (IC) 05/12/14			
IBE.SM	U (IC) 05/12/14			
IOC	O (IC) 08/14/14			
LKOD.LI	M (RC) 06/28/12			
LKOH.RM	M (IC) 10/16/13			
NBL	M (RC) 01/08/13			
NEE	M (IC) 12/18/09			
NG/.LN	O (IC) 05/08/14			
NVTK.LI	M (RC) 10/16/13			
NVTK.RM	M (IC) 10/16/13			
OGZD.LI	O (RC) 07/16/09			
ONGC.IN	M (RC) 11/17/09			
OSH.AU	O (IC) 06/29/09			
PCG	O (RC) 03/27/13			
PFC.LN	O (IC) 06/24/14			
PMO.LN	O (RC) 06/28/12			
PTR	M (RC) 11/01/13			
PTTEP.TB	M (RC) 11/07/12			
RDS/A	O (RC) 09/30/14	M (RC) 03/09/12		
RDS/B	O (RC) 09/30/14	M (RC) 03/09/12		
RDSA.LN	O (RC) 09/30/14	M (RC) 03/09/12		
RDSA.NA	O (RC) 09/30/14	M (RC) 03/09/12		
RDSB.LN	O (RC) 09/30/14	M (RC) 03/09/12		
RDSB.NA	O (RC) 09/30/14	M (RC) 03/09/12		
REP.SM	M (RC) 12/03/13	O (IC) 03/19/12		
RIGD.LI	O (RC) 05/27/13			
RIL.IN	O (RC) 05/27/13			
ROSN.LI	M (RC) 01/29/13			
ROSN.RM	M (IC) 10/16/13			
RRC	O (RC) 02/26/14	M (RC) 02/20/14	O (IC) 09/11/12	
RWE.GR	O (IC) 05/08/14			
SBMO.NA	U (IC) 06/24/14			
SGGD.LI	M (RC) 06/28/12			
SNP	M (RC) 09/16/14	O (RC) 01/21/14	M (RC) 03/28/13	
SPM.IM	U (IC) 06/24/14			
SRG.IM	M (IC) 05/12/14			
SSE.LN	U (IC) 05/08/14			
STL.NO	O (RC) 12/03/13	M (RC) 06/28/12		
STO	O (RC) 12/03/13	M (RC) 06/28/12		

STO.AU	M (RC) 04/20/11	
SUBC.NO	U (IC) 06/24/14	
SVT.LN	M (IC) 05/08/14	
SWN	O (IC) 09/11/12	
TEC.FP	O (IC) 06/24/14	
TEN.IM	M (IC) 06/24/14	
TLM	O (RC) 06/28/12	
TLM.CN	O (RC) 06/28/12	
TLW.LN	O (IC) 01/22/09	
TOT	O (IC) 08/03/10	
UU/.LN	O (IC) 05/08/14	
VK.FP	O (IC) 06/24/14	
WPL.AU	M (RC) 05/29/14	O (RC) 01/08/13

Rating Guide: O - Outperform, M - Market-Perform, U - Underperform, N - Not Rated
Rating Actions: IC - Initiated Coverage, DC - Dropped Coverage, RC - Rating Change

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US Utilities

Regulatory Response Looks to Stay Ahead of the Distributed Generation Curve

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Summary

» **Distributed generation (DG) is a long-term threat to utilities operating under a traditional ratemaking structure, but the call of a "death spiral" is premature.** Technological developments are inherently uncertain and could be disruptive, but today, we don't see the utility structure being upset on the horizon. We discount the "death spiral" scenario, because the electric grid is a critical piece of infrastructure, and consequently, we believe utilities will continue to receive reasonable regulatory treatment.

» **Proactive regulatory response is credit positive.** Across the US, utilities are working with their regulators to refine their suite of recovery mechanisms to stay ahead of the potential industry transformation that a widespread adoption of DG would bring. A few states are going further in pursuing a brand new utility business model that embraces DG, but most are tackling rate design and policy issues first.

» **The near-term agenda is reforming net energy metering (net metering) to avoid "cost shifting"** between customers who have rooftop solar and those who don't. Rate design reforms that fix the issues that arise from net metering include decoupling, which reduces volume risk to revenues, and higher fixed charges, which better match the fixed costs of operating utility assets.

» **Lawmakers and regulators also use policies to manage DG's market adoption.** Utility markets that will see faster adoption tend to be those in states that are deregulated, feature high electricity prices and have policies that encourage DG, such as renewable portfolio standards and net metering.

» **DG poses a competitive threat to vertically integrated utilities with generation assets if a large number of their customers switch to DG**; transmission and distribution (T&D) utilities don't face that threat.

» **T&Ds could see their business position improve** from the increased investments in the electric grid. **DG could be a business opportunity** for vertically integrated utilities as well. Lessons learned from these early initiatives will set precedents for others in the sector.

Distributed generation poses a threat under traditional ratemaking but the call of a "death spiral" is premature

Distributed generation (DG) is energy produced on a utility customer's site, off the utility's electric grid. The most common form of DG is solar photovoltaic (PV) installations by residential customers. The falling cost of PV systems is driving a rapid growth in the residential market from a currently small base. Tariffs that promote DG, like net metering for residential customers, plus other state and federal incentives can significantly lower their utility bills. If enough customers install solar panels, utilities could see their revenues erode under the traditional rate design, in which most of the utility's rates are based on sales volume.[1]

Customers can not only pay less to the utility, but also conceivably disconnect ("defect") from the grid and not pay the utility at all, if they couple their solar panels with battery storage, which saves the energy that the panels produce during the day for use at night. We believe mass grid defection is unlikely in the foreseeable future because the cost of batteries is still an order of magnitude too high. While we do not rule out the potential for a large decline in battery cost, numerous behavioral or physical barriers make most people unwilling or unable to defect from their utilities.

Technological developments are inherently uncertain and could be disruptive, but today, we don't see the utility structure being upset on the horizon. We discount the "death spiral" scenario of a mass grid defection, leaving a dwindling number of customers to foot the utility's costs, because the electric grid is a critical piece of infrastructure that is a vehicle for policymakers to implement their energy policies. Consequently, we believe utilities will continue to receive reasonable regulatory treatment. In fact, the grid will become even more important as the platform for the more complex flows of power and information in the utility of the future.

Proactive regulatory response is credit positive

Across the US, utilities are working with their regulators to refine their suite of recovery mechanisms to stay ahead of the potential industry transformation that a widespread adoption of DG would bring. Many legislatures and regulatory commissions are assessing DG, including pre-emptively in states, such as Idaho and Oklahoma, where DG is still miniscule.[2] While solar overall accounts for less than 1%[3] of electric generating capacity in the US, the double-digit increases in residential solar installations (a 45% leap in capacity between Q2 2013 and Q2 2014[4]) are pushing lawmakers and regulators to act sooner rather than later. Hawaii has by far the highest market penetration, with 11% of Hawaiian Electric Company, Inc.'s (Baa1) residential customers with solar PV.[5] The rapid adoption has tested Hawaiian Electric's operations and strained relationships with regulators and customers, a situation utilities want to avoid.

While energy storage is too expensive and impractical for homeowners now, technology will advance to make storage more common in the next decade. By starting to address the potential impact now, utilities and regulators will have more time to prepare by improving their rate designs and planning

[1] For more information on our views on DG and rate design issues, please refer to the Special Comments *Rooftop Solar, Distributed Generation Not Expected to Pose Threat to Utilities*, published in November 2013, and *Regulatory Framework Holds Key to Risks and Rewards Associated With Distributed Generation*, April 2014, and Credit Focus *Arizona Public Service: Getting a Jump on Rooftop Solar Distributed Generation*, published in May 2014.

[2] Oklahoma has only 350 DG customers, according to *Oklahoma Executive Order 2014-07*, Oklahoma Senate Bill 1456, 21 April 2014. That number would account for 0.02% of the state's utility customers, according to data from the US Energy Information Administration.

[3] Federal Energy Regulatory Commission, Office of Energy Projects, *Energy Infrastructure Update*, July 2014

[4] Solar Energy Industries Association and GTM Research, *US Solar Market Insight Report*, Q2 2014

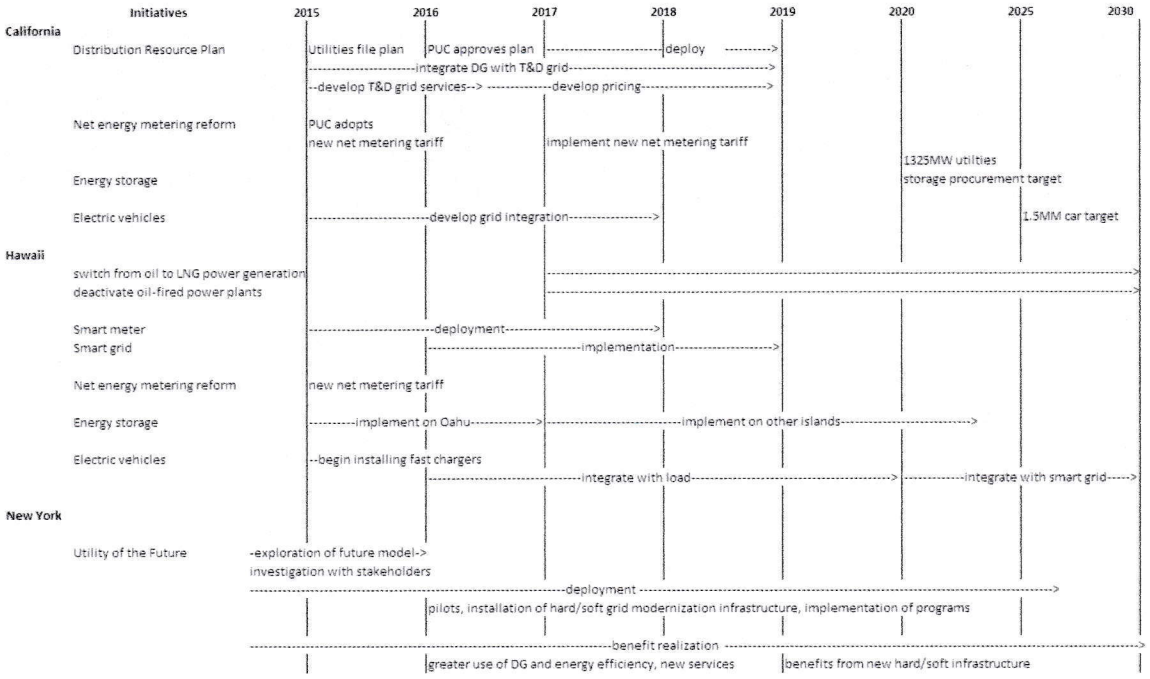
[5] Hawaiian Electric Industries, Inc. *Second Quarter 2014 Financial Results and Outlook* slides, 11 August 2014

longer term for infrastructure that will integrate more DG into the electric grid. Consequently, stakeholders (lawmakers, regulators, the utilities, their customers and the solar industry) are tackling rate design and policy issues first.

Across the country, utilities and their stakeholders are studying what "Utility 2.0,"[6] the next generation utility, should be. In fact, California, Hawaii and New York have already begun initiatives to transform their utility models (see *Appendix B – State visions of "Utility 2.0" for 2020+* for details on each of those states). As shown in Exhibit 1, we expect these plans will be evolutions extending well into the next decade, in time for when energy storage and electric vehicles are expected to be more commonplace.

EXHIBIT 1

Illustrative Road Maps to "Utility 2.0" Extend Into the Next Decade



Source: Moody's Investors Service, regulatory filings

[6] A name coined by the Energy Future Coalition's report to Maryland Governor Martin O'Malley, *Utility 2.0: Piloting the Future for Maryland's Electric Utilities and their Customers,* 15 March 2013.

Near-term agenda is reforming net metering to avoid "cost shifting"

The first order of business for policymakers is net metering, which principally applies to residential rooftop solar. Most residential solar customers subscribe to a net metering tariff, which allows them to offset the cost of the power they buy from the grid with the price of the power they sell to the grid. Available in 43 states, net metering has been around for 30 years as an incentive to promote clean energy, but numerous utilities are calling to reform this incentive, now that it has worked to make rooftop solar more commonplace.

Rooftop solar and net metering raise the issue of cost shifting. First, residential solar customers will need less power from the utility, and thus pay less under the traditional volumetric rate design. Utilities with decoupling mechanisms may be made whole for these lost revenues, but the cost of doing so will shift to other customers. Second, net metering allows solar customers to credit their bills at a retail rate (the same rate at which they buy electricity), lowering the amount they pay to the utility. Here, too, the lost contributions to the utility will shift from the net metered customers to others.

As shown in Exhibit 2, regulators in numerous states are responding to this cost-shifting issue. A common approach reduces the volumetric component of rates, by assessing a fixed customer charge on everyone. All else being equal, the customer's total bill (and the utility's revenue requirement) is the same, but more of it is fixed, which makes revenues more predictable, a credit positive for the utility. Another approach is imposing additional charges only on rooftop solar customers, but such proposals by Central Maine Power Company (A3) and PacifiCorp (A3) in Utah did not prevail this year. With regard to the retail price on the excess energy from net metering customers, regulators in Hawaii and California are considering proposals to lower the rate of compensation.

EXHIBIT 2

Recent Regulatory Responses to Reform Net Metering

Issue	Fix	Regulatory Responses	
Fewer customers without rooftop solar have to pay more of the fixed costs to maintain the utility's facilities	Assess a fixed customer charge on all customers to pay for the utility's fixed costs	Maine	Central Maine Power increased fixed charges by $3/month
		California	2013 legislation enabled net metering reform, including the implementation of a fixed charge of up to $10/month beginning in 2017
		Connecticut	Connecticut Light & Power has proposed to increase fixed charges by $9.50/month
	Impose an additional demand charge on rooftop solar customers to pay for the capacity utility has to maintain for them	Arizona	Arizona Public Service increased fixed charges by about $5/month
		Hawaii	Hawaiian Electric has proposed upfront interconnection fee and fixed standby or demand charges for DG customers
		Oklahoma	Enabling legislation passed in 2014 to consider fixed customer charges as well as time-of-use rates, minimum bills, and demand charges
		Maine	Central Maine Power's proposal to impose $25 standby charge dropped
		Utah	PacifiCorp's request for $4.65/month facilities charge denied
		Colorado	Public Service Co. of Colorado has proposed a demand charge
		Wisconsin	We Energies has proposed to implement a demand charge of $3.79/KW
Rooftop solar customers sell power to the grid at a higher retail rate that is credited to their bills, resulting in lower revenues that must be made up by other customers in order to meet the utility's revenue requirement	Reform net metering to change the compensation that the rooftop solar customers receive to some lower avoided cost rate that reflects the price of power the utility would have paid in the market	Hawaii	Hawaiian Electric has proposed compensation at wholesale rates
		California	Under consideration as part of net metering reform mentioned above
Rates for power generated by rooftop solar do not sufficiently capture the value solar energy brings to the grid	Replace net metering with a Value of Solar tariff that incorporates the value that solar energy brings (capital cost savings, environmental benefits) netted against the additional costs it requires (voltage controls)	Austin, Texas	Austin Energy implemented Value of Solar tariffs in 2013
		Minnesota	Value of Solar enabling law passed in 2014; yet to be implemented

Sources: Moody's, SNL

Some regulators are considering whether to replace net metering with another new rate scheme that recognizes not only the additional costs, but also the benefits of rooftop solar, including operational (e.g., avoided costs of fuel, maintenance, generation, transmission and distribution) and environmental (e.g., avoided compliance costs, cleaner air, less water used). Austin Energy and the Minnesota Public Utilities Commission have approved such Value of Solar rate methodology as an alternative to net metering, though this scheme has a very limited track record at this stage.[7]

Lawmakers and regulators use policies to manage DG's market adoption

Aside from changing utility rate design, policymakers can use rules and regulations to manage the pace of DG adoption. Policy is important, because emerging DG technologies need government incentives to promote them (see Exhibit 3). In fact, some recent regulatory activity was a result of incentives nearing expiration. Lawmakers and regulators will enact policies that reflect what their voters (who also happen to be utility customers) want, whether it be lower electricity prices or more access to clean energy.

EXHIBIT 3

Factors That Promote or Constrain DG (Principally Focused on Rooftop Solar)

	Promote	Constrain
Policy	Net Metering High RPS 3rd Party Solar Financing Allowed Tax Credits, Renewable Energy Credits, Rebates	No Net Metering Low RPS 3rd Party Solar Financing Restricted No Incentives
Economic Factors	High Electricity Price Low PV System Costs Home Ownership	Low Electricity Price High PV System Costs Rental Housing
Regulatory Scheme	T&D Utilities Volumetric Utility Rates Decoupling	Vertically Integrated Utilities Fixed Utility Charges No Decoupling
Behavior	"Cool Factor" Technology Saavy Clean Energy Bias	"Hassle Factor" Technology Geek Fossil Energy Bias
Natural Environment	Sun Open Sky	Clouds Shade Trees

Sources: Moody's, IEA[8]

[7] The US Internal Revenue Service (IRS) is currently reviewing the tax deductibility of income that a distributed solar owner receives for selling power to Austin Energy (A1) under its value of solar tariff. The IRS ruling will determine whether other jurisdictions adopt the tariff.

[8] Adapted from *Residential Prosumers – Drivers and Policy Options (RE-Prosumers)*, page 38, International Energy Agency – Renewable Energy Technology Deployment, June 2014

To promote solar energy adoption, net metering is a central policy tool that reduces utility bills for the residential customer. Another tool is the renewable portfolio standard (RPS) which, in 29 states, requires utilities to derive a certain percentage of their energy from renewables. A rooftop solar owner can generate valuable renewable energy credits and sell them to the utility, which will use that credit towards its RPS requirement. In addition, numerous federal, state and local tax exemptions, subsidized loans, and rebates are available that could significantly cut solar installation costs and turn a costly investment into an economic one for the owner. On the other hand, policymakers can slow down the spread of DG, for example, by setting caps on net metered capacity, setting expiration dates, and reducing government funding for an incentive program.

T&D utilities could see their business position improve

California and New York, where new utility models embracing DG are actively being pursued, are jurisdictions where utilities divested generation assets during the electricity deregulation in the 1990s. These utilities, which are mostly T&D,[9] do not face the competitive threat that vertically integrated utilities with generation assets do, if a large number of their customers switch to DG to generate their own power supply. The lack of this competitive threat to a T&D contributes to distributed solar business flourishing in certain markets.

Other factors can promote or constrain the market adoption of rooftop solar and other forms of DG. Exhibit 4 shows the top 10 states favorable to DG adoption. These are the states that need to deal with DG, rate design and policy issues earlier, if they aren't already. These states have the policies and circumstances that promote DG (shown in green): high electricity prices and policy matters such as renewable portfolio standards (a reflection of customer priorities and the political will), net metering and third-party solar financing. In addition, utilities that don't own generation and have decoupled rates are more likely to promote DG in their service territories. These policy and regulatory factors trump natural factors (most top 10 states are in the less sunny Northeast) as important to the market adoption of DG.[10]

[9] Utilities in California own some generation but purchase the majority of their energy from independent power producers. Consolidated Edison Company of New York owns some steam generation.

[10] For more information on how incentives can offset low insolation, please refer to the Special Comment *Cloudy Skies and Low Rates Shield Washington State Electric Utilities from Unfettered Rooftop Solar Growth*, published in August 2014.

EXHIBIT 4

Top 10 States Favorable to DG Adoption Have Mostly Decoupled T&D Utilities

	Economics	Policies				Nature	Regulatory Scheme	
States	Above/Below US Avg Res Price ($/kWh)	RPS	Net Metering	% of Net Metered to Ttl Customers	3rd Party Solar PV PPAs authorized	Annual Avg Solar Resource (kWh/m²/Day)	Electric Decoupling	Electricity Deregulated / T&Ds
California	$3.46	33% by 2020	Yes	1.06%	Yes	6	Yes	Yes
Hawaii	$25.46	40% by 2030	Yes	4.63%	Yes	6	Yes	No
Connecticut	$5.46	27% by 2020	Yes	0.19%	Yes	4	Yes	Yes
Oregon	-$2.08	25% by 2025	Yes	0.33%	Yes	5	Yes	Yes
Delaware	$1.70	25% by 2026	Yes	0.28%	Yes	5	No	Yes
Arizona	-$0.59	15% by 2025	Yes	0.84%	Yes	6	Yes	No
Massachusetts	$3.03	22.1% by 2020	Yes	0.20%	Yes	4	Yes	Yes
New York	$5.74	29% by 2015	Yes	0.13%	Yes	4	Yes	Yes
New Jersey	$3.90	20.38% by 2021	Yes	0.49%	Yes	5	No	Yes
Maryland	$0.96	20% by 2020	Yes	0.17%	Yes	5	Yes	Yes

Key: Constrains DG <-----> Promotes DG

Sources: Moody's, EIA, Natural Resource Defense Council, Database of State Incentives for Renewables & Efficiency, National Renewable Energy Laboratory

For the full list of states, see Appendix A – *State ranking by factors favorable to DG.*

In fact, DG would be positive for utilities as a rate base growth opportunity, because the T&D grid will need substantial investments in order to accommodate more DG,[11] making the grid even more essential. For example, more distributed energy resources (not only power from DG, but also energy storage in the future) will necessitate an upgrade to the grid to accommodate two-way power flows rather than just one way and to control greater and more frequent voltage fluctuations. On the other hand, DG can reduce the need for the utility sector to invest in new generation and transmission, resulting in cost savings to ratepayers.

Hawaiian Electric's DG Interconnection Plan, referenced in Exhibit 5, suggests new technologies can provide utilities with better information to manage their loads and achieve greater energy efficiency, while giving customers more options, such as the ability to monitor and control their usage to manage their bills.

[11] California utilities currently spend $6 billion a year in distribution investments, while preparing to integrate over 15 gigawatts of DG to the grid, according to the California Public Utilities Commission. New York estimates average capital spending of $3 billion a year over the next decade; for more, see the Appendix.

EXHIBIT 5

Investments in the T&D Grid to Lower Costs, Increase Energy Efficiency and Reliability

Benefits	Applications	Description
Lower Electricity Bills	Volt Optimization	Allows utilities to more accurately control the level of power delivered to the end-consumer
Expanded Customer Choices	Customer Energy Portal	Allows customers to monitor their bills and usage patterns to reduce energy consumption
Increased Reliability	Advanced Metering Infrastructure Outage Management	Enables automated billing for customers, reducing meter reading costs, as well as acts as a sensor for outage detection and many other applications
	Fault Circuit Indicator	Helps utilities find outages on the grid to restore power to customers more quickly
	Remote Switching	Enables devices in the field to be remotely controlled to get an outage fixed more quickly
Optimal Integration of DG	Direct Load Control	Shapes energy demand to ensure the grid can safely manage variable energy sources such as renewable wind or solar
Reduced CO_2 Emissions	Electric Vehicle Charging	Enables the scheduling of electric vehicle charging

Source: Hawaiian Electric [12]

DG poses a competitive threat to vertically integrated utilities with generation assets

DG poses a competitive threat to vertically integrated utilities with generation assets if a large number of their customers switch to DG, but DG tends to have less penetration in their markets. As shown in Exhibit 6, utilities in the states most likely to lag in DG adoption are all vertically integrated and do not have decoupling.

[12] Source: *Distributed Generation Interconnection Plan, page 4-4*, filed with the Hawai'i Public Utilities Commission, 26 August 2014

EXHIBIT 6

Bottom 10 States Favorable to DG Adoption All Under Traditional Vertically Integrated Regulation

	Economics	Policies				Nature	Regulatory Scheme	
States	Above/Below US Avg Res Price ($/kWh)	RPS	Net Metering	% of Net Metered to Ttl Customers	3rd Party Solar PV PPAs authorized	Annual Avg Solar Resource (kWh/m²/Day)	Electric Decoupling	Electricity Deregulated / T&Ds
Louisiana	-$2.03	No	Yes	0.07%	No	6	No	No
Nebraska	-$1.84	No	Yes	0.01%	No	5	No	No
Virginia	-$1.81	10% by 2015	No	0.00%	No	5	No	No
Iowa	-$1.06	already met	Yes	0.01%	No	4	No	No
Indiana	-$1.35	No	Yes	0.01%	No	4	No	No
South Carolina	-$0.41	No	No	0.00%	No	5	No	No
Kentucky	-$2.45	No	Yes	0.01%	No	4	No	No
Alabama	-$0.48	No	No	0.00%	No	5	No	No
Mississippi	-$1.62	No	No	0.00%	No	5	No	No
Tennessee	-$1.78	No	No	0.00%	No	5	No	No

Key: Constrains DG <-----> Promotes DG

Sources: Moody's, EIA, Natural Resource Defense Council, Database of State Incentives for Renewables & Efficiency, National Renewable Energy Laboratory, National Renewable Energy Laboratory

We note that five of the above states are served by the Tennessee Valley Authority (TVA, Aaa), an agency of the US, which has electric rates well below the US average. The bottom 10 states, generally in the South and the Midwest, all have below-average electric rates, usually due to low-cost coal-fired power generation and lack the incentives to switch to DG as another source. Although TVA has initiated a study on DG, the competitive threat appears distant in these states.

DG could be a business opportunity for vertically integrated utilities as well, as seen by a number of projects across the country. For example, Florida Power & Light Company (A1) recently announced a utility-scale solar project as a cost-effective option that could satisfy some customers who want clean energy. Another option is a community solar project, such as those Xcel Energy Inc. (A3) is rolling out in Colorado and Minnesota, where residential and commercial customers can own an interest in a centralized solar facility. Additionally, Arizona Public Service Company (A3) has proposed installing and rate-basing solar panels on customers' rooftops and giving those customers a monthly credit for the use of their roofs. Lessons learned from these projects and the "Utility 2.0" initiatives in other states will set precedents for others in the sector.

Appendix A – State ranking by factors favorable to DG

The table below ranks states in order from the most to least favorable towards DG under eight factors.

EXHIBIT 7

State Ranking by Factors Favorable to DG Adoption

	Economics	Policies				Nature	Regulatory Scheme	
States	Above/Below US Avg Res Price ($/kWh)	RPS	Net Metering	% of Net Metered to Ttl Customers	3rd Party Solar PV PPAs authorized	Annual Avg Solar Resource (kWh/m²/Day)	Electric Decoupling	Electricity Deregulated / T&Ds
California	$3.46	33% by 2020	Yes	1.06%	Yes	6	Yes	Yes
Hawaii	$25.46	40% by 2030	Yes	4.63%	Yes	6	Yes	No
Connecticut	$5.46	27% by 2020	Yes	0.19%	Yes	4	Yes	Yes
Oregon	-$2.08	25% by 2025	Yes	0.33%	Yes	5	Yes	Yes
Delaware	$1.70	25% by 2026	Yes	0.28%	Yes	5	No	Yes
Arizona	-$0.59	15% by 2025	Yes	0.84%	Yes	6	Yes	No
Massachusetts	$3.03	22.1% by 2020	Yes	0.20%	Yes	4	Yes	Yes
New York	$5.74	29% by 2015	Yes	0.13%	Yes	4	Yes	Yes
New Jersey	$3.90	20.38% by 2021	Yes	0.49%	Yes	5	No	Yes
Maryland	$0.96	20% by 2020	Yes	0.17%	Yes	5	Yes	Yes
Colorado	-$0.42	30% by 2020	Yes	0.65%	Yes	6	No	No
Michigan	$2.25	10% by 2015	Yes	0.02%	Yes	4	Yes	Yes
Rhode Island	$2.52	16% by 2019	Yes	0.04%	Yes	4	Yes	Yes
Vermont	$5.13	20% by 2017	Yes	0.64%	Yes	4	Yes	No
New Hampshire	$4.19	24.8% by 2025	Yes	0.11%	Yes	4	No	Yes
New Mexico	-$0.51	20% Solar by 2020	Yes	0.43%	Yes	6	No	No
Nevada	-$0.05	25% by 2025	Yes	0.18%	Yes	6	No	No
Ohio	-$0.12	12.5% by 2024	Yes	0.02%	Yes	4	Yes	Yes
Illinois	-$0.50	25% by 2026	Yes	0.01%	Yes	4	No	Yes
Texas	-$0.90	12% by 2015	No	0.00%	Yes	5	No	Partial
Maine	$2.78	40% by 2017	Yes	0.12%	No	4	No	Yes
Pennsylvania	$0.87	18% by 2020	Yes	0.13%	Yes	4	No	Yes
Utah	-$1.95	20% of adjusted retail sales by 2025	Yes	0.15%	Yes	6	No	No
Minnesota	-$0.53	25-32% by 2025	Yes	0.04%	No	4	Yes	No
Wisconsin	$1.31	10% by 2015	Yes	0.04%	No	4	Yes	No
Montana	-$1.80	15% by 2015	Yes	0.17%	No	5	No	No
Arkansas	-$2.58	No	Yes	0.02%	No	5	Yes	No
North Carolina	-$0.97	12.5% by 2021	Yes	0.01%	No	5	No	No
Kansas	-$0.64	20% of each peak demand capacity by 2020	Yes	0.01%	No	5	No	No
Washington	-$3.35	15% by 2020	Yes	0.10%	No	4	Yes	No
Florida	-$0.46	No	Yes	0.05%	No	5	No	No
Alaska	$6.00	No	Yes	0.02%	No	4	No	No

EXHIBIT 7

State Ranking by Factors Favorable to DG Adoption

	Economics	Policies				Nature	Regulatory Scheme	
States	Above/Below US Avg Res Price ($/kWh)	RPS	Net Metering	% of Net Metered to Ttl Customers	3rd Party Solar PV PPAs authorized	Annual Avg Solar Resource (kWh/m²/Day)	Electric Decoupling	Electricity Deregulated / T&Ds
Georgia	-$0.71	No	Yes	0.01%	No	5	No	No
Missouri	-$1.71	15% by 2021	Yes	0.04%	No	5	No	No
West Virginia	-$2.03	25% by 2025	Yes	0.02%	No	4	No	No
Louisiana	-$3.51	No	Yes	0.17%	No	5	No	No
Virginia	-$0.80	No	Yes	0.04%	No	5	No	No
Idaho	-$3.21	No	No	0.00%	No	5	Yes	No
North Dakota	-$2.82	10% by 2015	Yes	0.00%	No	5	No	No
Oklahoma	-$2.37	15% by 2015	Yes	0.01%	No	5	No	No
Wyoming	-$2.03	No	Yes	0.07%	No	6	No	No
Nebraska	-$1.84	No	Yes	0.01%	No	5	No	No
South Dakota	-$1.81	10% by 2015	No	0.00%	No	5	No	No
Iowa	-$1.06	already met	Yes	0.01%	No	4	No	No
Indiana	-$1.35	No	Yes	0.01%	No	4	No	No
South Carolina	-$0.41	No	No	0.00%	No	5	No	No
Kentucky	-$2.45	No	Yes	0.01%	No	4	No	No
Alabama	-$0.48	No	No	0.00%	No	5	No	No
Mississippi	-$1.62	No	No	0.00%	No	5	No	No
Tennessee	-$1.78	No	No	0.00%	No	5	No	No

Key: Constrains DG <-----> Promotes DG

Sources: Moody's, EIA, Natural Resource Defense Council, Database of State Incentives for Renewables & Efficiency National Renewable Energy Laboratory

Appendix B – State visions of "Utility 2.0" for 2020+

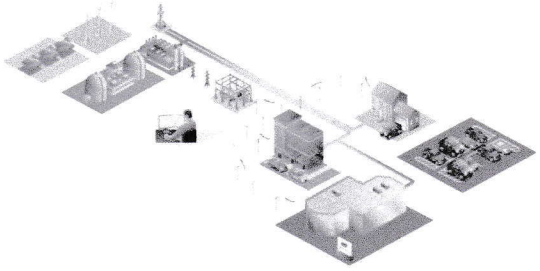
The Utility 2.0 envisioned in the plans in California, Hawaii and New York are similar. The plans all integrate power from a utility as well as DG, energy storage and electric vehicles onto the grid. They transition from a century-old centralized utility model, in which power flowed one way from the utility to its customers to a two-way transactive model (see Exhibit 7). The two-way flow of customer and load data will allow the utility to provide a wider menu of services, so that customers have a la carte options, such as standby service for rooftop solar, special tariffs for electric vehicle owners and time-of-use rates.

Of these three states, California is closest to this model, because it already has not only rooftop solar, but also initiatives underway for energy storage and electric vehicles. California is also the only one that has deployed smart meters, which are essential for the two-way communications required for this future model.

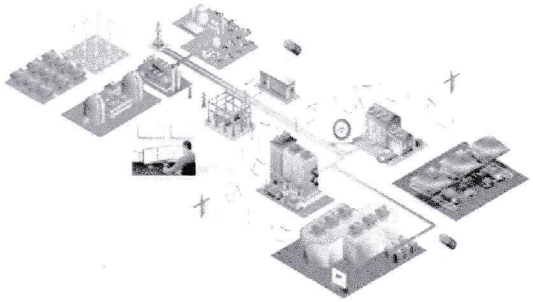
EXHIBIT 8

Future Utility Model Integrates Two-Way Power Flows From Diverse Power Sources

Today: A Centralized One-Way Model



Future: A Distributed Transactive[14] Model



Source: San Diego Gas & Electric's presentation to the Arizona Corporation Commission, 20 June 2014 [13]

California

For California, the future is already here. A leader in adopting clean energy and technological innovation, California has been promoting distributed energy generation for over a decade. California continues to move ahead with numerous rulemakings that envision an electric grid that will work very differently by 2020. These initiatives involve distributed resource planning to add more distributed energy generation to their systems and the integration of energy storage and electric vehicles. The state is still in the development phase of its "smart grid" modernization project. Having substantially completed the rollout of "smart meters," the utilities are just beginning to activate the two-way communications functionality of those meters, through which the utility can provide demand response and pricing signals to the customer. Parallel with these efforts, the California Public Utilities Commission is doing a comprehensive study of the utilities' residential rate structures and rates that vary by the time of day (time-of-use rates) and load conditions.

[13] http://www.azcc.gov/Divisions/Utilities/Electric/Value&Cost_default.asp. Accessed 29 September 2014.

[14] Managing the power grid and consumption with dynamic, interactive market signals. For more, click here. http://www.gridwiseac.org/about/transactive_energy.aspx. Accessed 30 September 2014.

Promoted by the policies and incentives that have long been in place, the state leads the US in the number of net metered customers, plug-in electric vehicles and battery energy storage projects. The need to modernize the grid is all the more acute in California, where the increase in DG and electric cars is quickly changing how the grid operates. The California Independent System Operator projects unusually wide fluctuations in California's daily electric load, the so-called "duck curve," in which solar PV causes an oversupply of power in midday, while requiring a rapid ramp-up in demand as the sun sets.

Time-of-use rates are not common yet among retail customers, but a pilot by San Diego Gas & Electric Company (A1) has demonstrated that this mechanism can motivate owners of electric vehicles to charge them in the wee hours when power demand is low and prices are cheaper.[15]

Like New York, California's electric utilities own limited generation; therefore, they are more agnostic to a competitive threat from distributed generation than a typical vertically integrated utility. New York and California also each have an independent system operator (ISO) that operates in a single state, which will make it easier to integrate the wholesale markets that the ISO coordinates with the retail markets at the utilities' level.

Hawaii

Among the three states cited in the Appendix, Hawaii faces the most urgent change in its utility model. Unlike utilities in California and New York, Hawaiian Electric, the largest utility in the state, owns a significant amount of generation, most of it fueled by very expensive fuel oil. This reliance on oil has led to the highest electricity costs in the country by far and, as a result, the highest penetration of rooftop solar in the US. These conditions have strained Hawaiian Electric's relationship with both its customers and regulators.

Hawaiian Electric has proposed plans[16] that involve a "clean slate" approach, remaking its business model over the 15 years from 2015 to 2030. The plans propose to retire all of Hawaiian Electric's oil-fired generating units and replace them with liquefied natural gas in 2017. At the same time, the utility plans to triple rooftop solar on its system and enter into purchase power agreements to procure wind and solar, raising renewables to 67% of its energy, which would exceed the state's 40% renewable portfolio standard target by 2030.

This overhaul will be costly with a price tag of $6 billion estimated for the island of Oahu alone, half of which will be spent over the 2015-20 timeframe. It will be a large capital program for Hawaiian Electric relative to its balance sheet ($5 billion in total assets reported as of 30 June 2014) spread across a small customer base on three disconnected islands.[17] These customers are mostly on the island of Oahu, but most of the renewable resources are on other islands without any transmission connecting them. Nevertheless, Hawaiian Electric forecasts a 23%-28% reduction in customers' bills by lowering the fuel costs from lower priced liquefied natural gas and purchased power agreements and reducing operating expenses with new, more efficient infrastructure.

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[15] Ibid, slide 13.

[16] Hawaiian Electric's *Distributed Generation Interconnection Plan and Power Supply Improvement Plans*, filed with the Hawai'i Public Utilities Commission, 26 August 2014.

[17] In terms of state population, Hawaii ranked as 40th in the US with one million residents, while California ranked first with 38 million and New York ranked third with 20 million. http://www.census.gov/popest/data/national/totals/2013/index.html, accessed 3 October 2014.

New York

In 2014, New York began a process of transforming the utility business model in what it calls a Reforming the Energy Vision (REV) initiative, with the goal of determining generic policies by early 2015. The call for utility reform did not arise from net metering, although New York ranks in the top 10 by number of rooftop solar installations. Rather, the catalysts that put energy issues on Governor Andrew Cuomo's agenda were arguably climate change events, such as Superstorm Sandy in 2012, which highlighted the weaknesses in the state's power infrastructure, and the Polar Vortex in the winter of 2013-14, when customers' bills soared. REV is still in an early exploratory phase as numerous stakeholders[18] are providing input into formulating the final plan.

The utilities' century-old legacy transmission and distribution systems are aging and need to be upgraded at a cost of $30 billion over the next 10 years, roughly double the $17 billion spent over the past decade.[19] Policymakers want to grow distributed energy resources to accomplish a number of goals, including (1) promoting more diverse, cleaner sources of power; and (2) providing the information and tools needed to empower customers to effectively manage their total energy bill.

RIIO – A Model for the Utility of the Future

RIIO (an acronym for Revenue = Incentives + Innovation + Outputs) is a utility rate scheme that was introduced in the UK in 2010. Utilities are incentivized on certain performance measures and can be rewarded with higher returns if they outperform their peers. Conversely, underperformers will face penalties or lower returns. A long period of price controls (eight years) and ex-ante formula rates provide transparency in a multi-year capital program.

According to the REV proposal, a distributed system platform (DSP), most likely the incumbent utility, will coordinate demand and supply at the distribution level. The DSP will have two-way communications and power flows among retail customers (which could be generating their own power) and other sources of generation. Likewise, the DSP will have two-way power flows with the New York Independent System Operator (NYISO), which will coordinate demand and supply at the bulk wholesale level.

In addition to the huge cost of modernizing the grid, New York faces numerous structural and cultural challenges in implementing REV. First, the state has not rolled out smart meters that would enable the two-way communications envisioned in the plan. Without the smart meters, the state lacks the customer data that can be used to formulate new energy services and products, and the tariffs to provide them. Many New Yorkers are wary of smart meters because of concerns over privacy and data security. These concerns are particularly pertinent in New York, where consumers can choose to buy their power from a host of unregulated energy service companies.

Another challenge is changing customer behavior. Historically, customers in New York have been disengaged with their energy use and underutilized the state's DG and energy efficiency programs.[20] This disinterest stems from many New Yorkers living in rented apartments and, therefore, having little control or incentive to conserve energy or invest in DG, in contrast to a long-term homeowner.

[18] Currently, some 260 parties are collaborating in the REV process. Re-examining Smart Power: How Electric Utilities Can Respond to Climate Change Challenges, Energy Security Initiative Conference, Brookings Institution, 1 October 2014.

[19] Shaping the Future of Energy, New York State Energy Plan, Volume 1, New York State Energy Planning Board, January 2014, page 2.

[20] REV Working Group I: Customer Engagement, New York Public Service Commission Staff Report on the Work of the Customer Engagement Committee, 8 July 2014, pages 6-14.

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U.S. Utilities v. Distributed Solar: How Are Utility Management Teams Responding? Lesson from EEI

Ticker	Rating	CUR	14 Nov 2014 Closing Price	Target Price	TTM Rel. Perf.	EPS 2013A	EPS 2014E	EPS 2015E	P/E 2013A	P/E 2014E	P/E 2015E	Yield
EIX	O	USD	61.76	66.00	13.2%	3.80	4.30	3.55	16.3	14.4	17.4	2.3%
NEE	M	USD	101.85	92.00	2.5%	4.97	5.28	5.47	20.5	19.3	18.6	2.9%
PCG	O	USD	49.65	50.00	7.2%	2.72	2.94	3.15	18.3	16.9	15.8	3.7%
SPX			2039.82			108.50	116.87	130.04	18.8	17.5	15.7	1.9%

O – Outperform, M – Market-Perform, U – Underperform, N – Not Rated

Highlights

This year's Edison Electric Institute conference afforded us the opportunity to meet with utilities from the three states – Hawaii, Arizona and California – that to date have seen the most rapid growth of distributed solar generation. In this note, we summarize the diverse strategies being deployed by utility managements in these and other states to address erosion of utility revenues caused by the growth of distributed solar.

- Utilities' strategies seem to fall into three principal categories:
  - (i) the reform of rate design so as to limit the economic incentives for customers to deploy distributed solar generation;
  - (ii) the roll-out of utility-owned solar generation as an alternative to distributed solar, and
  - (iii) facilitating the growth of distributed solar generation as part of a new vision of the utility business and regulatory model.

Reforming Rate Design

- Utilities have had very limited success in introducing fixed monthly charges for grid access, so as to ensure that customers with distributed solar make an equitable contribution to the cost of the grid.
  - California's AB 327 sets a cap of $10 per month on the fixed charge that utilities may levy on their residential customers. This compares with an average residential bill in the state of some $88 per month and thus would translate into a fixed charge only 11% of the average customer's bill – and a much lower percentage of higher volume customers' bill.
  - Similarly, the Arizona Corporation Commission (ACC) last year allowed the introduction of a fixed charge of $0.70/kW on all distributed solar systems installed after 2013. Arizona Public Service (APS) estimates that this will translate into an average fixed charge for its residential customers of $4.90/month – equivalent to ~4% of the average residential bill of $120 per month (see **Exhibit 4**).
- Unsuccessful in their efforts to introduce a substantial fixed charge for grid access, utilities in both California and Arizona are re-directing their efforts to reducing the per kWh rates paid by their residential customers. Thus Southern California Edison, which today charges its highest volume residential customers $0.32/kWh, proposes by 2018 to reduce its maximum retail rate to only $0.20/kWh, materially reducing, if not eliminating, the economic incentive for large volume residential customers to install distributed solar systems (see **Exhibit 6**).

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- APS is attempting to push through a similar reform. In Arizona, residential customers are billed on a time-of-use basis, with retail electricity rates rising during peak demand hours to reflect the cost of electricity on the grid at that time. APS management, however, contends that Arizona's time-of-use rates, having been set prior to the collapse in the natural gas price in 2009, are now outdated, and over-charge customers for on-peak consumption. Thus time-of-use rates can be twice as high during peak hours as during off-peak hours, yet the currently prevailing difference between on- and off-peak power prices at the Palo Verde Hub is only 25%. Retail electricity rates that more accurately reflected the economic value of peak electricity supplies would render distributed solar generation far less attractive.
- Ironically, as both utility scale and distributed solar generation rise in importance in Arizona and California, on-peak power prices may decline further. **Exhibit 7** presents a chart prepared by the California Independent System Operator (CAISO) forecasting the level of net power demand on the California grid over each hour of a typical spring for fall day for the years 2014 through 2020. CAISO expects the growth of renewable generation to drive the daytime requirement for conventional (non-renewable) generation down from ~19 GW in 2013 to only 12 GW by 2020 – a level equivalent to only two thirds of current *nighttime* loads. Power prices during hours of peak electricity demand could thus fall to levels even lower than the off-peak prices prevailing today during the hours of lowest demand.

Utility-owned Solar Generation as an Alternative to Distributed Solar

- Utilities are seeking to compete directly with distributed solar generation. Thus APS has proposed to the ACC that it be allowed to deploy 20 MW of distributed solar generation directly on customer rooftops. APS proposes to compensate participating customers through a credit against their monthly utility bills. The utility would own the distributed solar system as well as their power output.
  - APS cites two advantages to the program. First, APS would seek to optimize the location of the solar arrays it installs, maximizing the use of western facing rooftops to offset peak hour demand and deploying the panels at locations where they would tend to enhance, rather than detract from, the stability of the distribution grid. Second, APS is prepared to install solar rooftops on the homes of customers who cannot afford the cost of a distributed solar system and would not quality for the lease financing offered by distribution solar installation companies.
- A variation on this concept is being developed by Xcel, whose utility subsidiaries in Colorado and Minnesota now offer customers the opportunity to invest directly in ground mounted, utility-scale solar farms. Xcel's programs allow consumers that cannot deploy distributed solar generation to purchase interests in community scale solar projects. These projects allow the consumers to contribute directly to renewable generation, and to enjoy some of the economic benefits of distributed solar.
- Xcel's programs, like Arizona Public Service' rent-a-rooftop scheme, have the benefit of ensuring that the output of the solar capacity deployed is marketed by the utility, thus avoiding the loss of kWh sales, and consequent erosion of revenues, precipitated by consumer deployment of distributed solar generation.
- Finally, NextEra Energy's Florida Power & Light (FPL) is rolling out utility scale solar generation not because it is required by state renewable mandates but because these solar projects offer cost-competitive sources of peak hour power and can be situated at advantageous locations on the utility's distribution network. Specifically, FPL is proposing to build three ~75 MW solar projects at sites already owned by FPL, and with access to existing transmission capacity. These advantages are reflected in an estimated cost of $1.50 to $1.80 per Watt.

A New Vision of the Utility Business and Regulatory Model

- Some U.S. electric utilities in states that have decoupled utility revenues from electric deliveries are already embracing a future in which their role will encompass both (i) operating the power grid in

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manner that ensures high levels of system reliability while (ii) facilitating the growth of distributed solar generation as well as utility scale renewable generation .

- Hawaii Electric is perhaps the most telling example. Hawaiian Electric's reliance on high cost imported fuel oil to power its fossil generation fleet renders both utility scale and distributed solar generation economically attractive sources of power supply.
- On the mainland, renewable generation remains, as a general matter, a more expensive source of power that conventional resources, but widespread political support for renewables render their growth inevitable in states such as California, whose state renewable mandate requires utilities to procure a third of the power they supply their customers from renewable resources by 2020. Edison International subsidiary Southern California Edison sees its future following this model (**Exhibit 13**).

Investment Conclusion

Electric utilities enjoy several powerful economic advantages in their struggle with distributed solar generation, and in time these advantages may present a material risk to the growth of the distributed generation industry.

We estimate the unsubsidized lifetime cost of a residential distributed solar system at ~$230/MWh, or almost twice the average residential price for electricity in the United States. We estimate the cost of utility scale solar generation at ~$91/MWh, or roughly twice the wholesale price of electricity. The solar industry therefore relies upon (i) renewable portfolio standards, which essentially require utility customers to purchase solar generation at an above-market price, and (ii) investment tax credits, which require taxpayers to cover 30% of the installed cost of solar power systems. We calculate that renewable portfolio standards add ~$2.1 billion annually to customers' electricity bills, in excess of the value of the electricity supplied, while the investment tax credit cost taxpayers ~$3.5 billion in 2013. The combined cost of ratepayer and taxpayer subsidies for solar generation, at some $5.6 billion annually, is equivalent to ~$50 per U.S. household per year. An industry reliant on subsidies of this scale is inherently vulnerable.

Second, we expect utility scale solar generation, along the lines of the projects being developed by NextEra and Xcel, to offer a competitive alternative to distributed solar generation. Utility scale systems have over time demonstrated a substantial and persistent cost advantage relative to distributed solar generation (see **Exhibit 11**). As the industry continues to grow, its rising cost to taxpayers and consumers will force legislators and regulators to focus increasingly on cost-effectiveness. And a focus on cost will inevitably benefit utility scale solar, which can deliver the environmental advantages of solar generation at a cost that is 50% to 60% below that of distributed solar.

Third, the current system of volumetric billing of electricity, combined with utilities' obligation to credit distributed generation at the full retail electricity rate (net energy metering), fails to impose on distributed generation customers a proper charge for their use of the grid. To correct this, utilities argue, the credit for distributed solar generation should only reflect the value of the electricity supplied. If this is the defined as the avoided cost to the utility of supplying the electricity itself, the proper credit against customers' bills for distributed solar generation would be only a third or so of the retail electricity rate – rendering distributed solar systems prohibitively expensive relative to grid supplied electricity.

Finally, as solar resources are added to the grid, the price of on-peak power could fall dramatically. The California Independent System Operator expects the growth of solar in California to drive the daytime requirement for conventional (non-renewable) generation down from ~19 GW in 2013 to only 12 GW by 2020 – a level equivalent to only two thirds of current *nighttime* loads. The implication is that power prices during hours of peak electricity demand can be expected fall to levels even lower than the off-peak prices prevailing today during the hours of lowest demand. As the economic value added of solar generation falls, the growth of solar capacity will asymptotically approach its limit.

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Details

This year's Edison Electric Institute conference afforded us the opportunity to meet with utilities from the three states – Hawaii, Arizona and California – that to date have seen the most rapid growth of distributed solar generation. In this note, we summarize the diverse strategies deployed by utility managements in these and other states to address the risk of revenue loss to distributed solar generation.

The strategies that utility managements presented to us seem to fall into three principal categories:

(i) the reform of rate design to reduce the subsidy implicit in net energy metering,

(ii) the deployment of utility-owned solar generation as an alternative to distributed solar, and

(iii) facilitating the growth of distributed solar generation as part of a new vision of the utility business and regulatory model.

Reform of Rate Design to Reduce the Subsidy Implicit in Net Energy Metering

Utilities in California, Arizona, and other states across the country are actively seeking to reform the design of their retail electricity rates so as to reduce the subsidy implicit in net energy metering.

Net energy metering, which is mandatory in the vast majority of states, is the practice of requiring utilities to credit their customers for the electricity produced by their rooftop solar installations at the retail electricity rate. Because utilities commonly bill residential and commercial customers based on the volume of the electricity consumed, i.e., on a cents per kilowatt-hour basis, net energy metering has the effect of reducing a retail customer's bill in direct proportion to the output of their rooftop solar system. Utility customers living in detached, single family homes, whose rooftop solar systems can typically supply between a half and three quarters of their total electricity needs, are thus in a position to reduce their electric utility bills by a similar percentage.

Utilities argue that net energy metering, combined with the practice of billing for electricity based on kilowatt-hours consumed, fails to recognize the fixed costs that utilities incur to provide grid access to their customers – including those with distributed solar systems. The utilities point out that customers with distributed solar generation continue to draw electricity from the grid – at night, obviously, but also during the day when their demand for power exceeds the output of their distributed solar system (as occurs when the electric motors used for air conditioning or pool pumps begin operation). Customers with distributed solar generation also rely on the grid to export the electricity they generate in excess of their needs during the sunniest hours of the day (see **Exhibit 1**). Furthermore, the utilities point out that the fixed costs of providing access to the grid – e.g., the depreciation and interest expense associated with utilities' investment in their generation, transmission and distribution assets, and the fixed operation and maintenance expense associated with their upkeep and operation – account for approximately two thirds of the total cost of retail electricity supply, with the variable cost of fuel and purchased power making up the remainder (see **Exhibit 2**). Thus by requiring utilities to credit their customers for distributed solar generation at the full retail price of electricity, net metering fails to impose on these customers a proper charge for their use of the grid. To correct this, utilities argue, the credit for distributed solar generation should only reflect the value of the electricity supplied. If this is the defined as the avoided cost to the utility of supplying the electricity itself, the proper credit against customers' bills for distributed solar generation would be only a third or so of the retail electricity rate.

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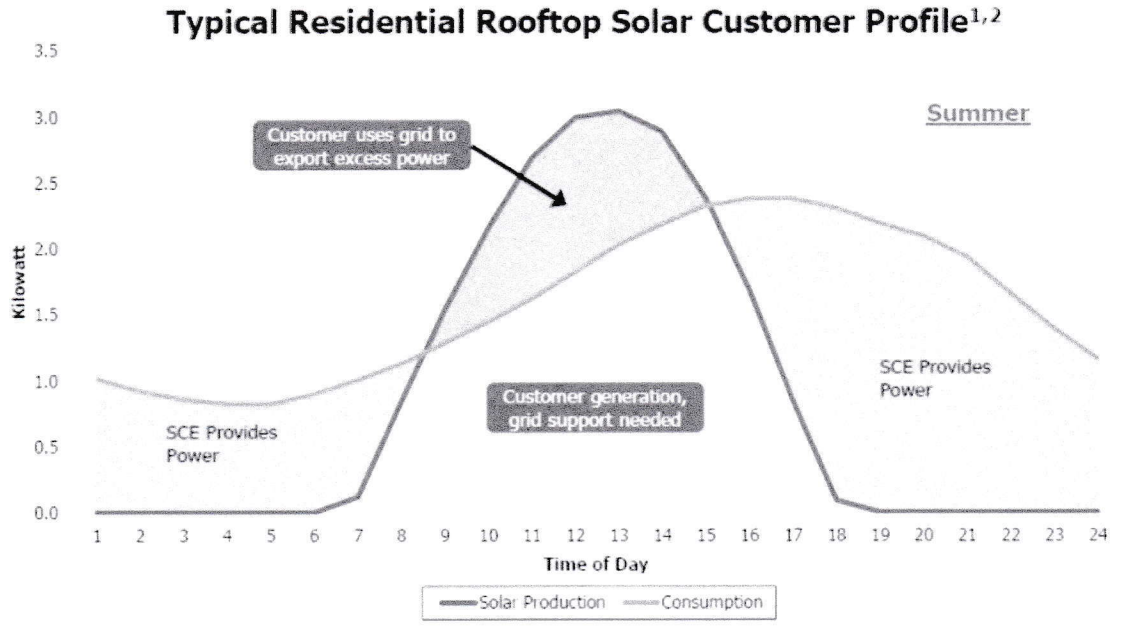
Exhibit 1

Consumers with distributed solar systems continue to draw power from the grid -- not only at night, but also during the day when their needs exceed their production. They also feed the excess electricity they produce into the grid.



Solar customers benefit from the flexibility provided by the SCE grid

1 Solar production shape based on a 4.8 kW system expected summer performance (source: https://sam.nrel.gov/). Sizing to eliminate Tier 3 and 4 usage.
2 Residential consumption shape based on summer average for a high user (1,150 kWh/month) (source: SCE load research)

Source: : Edison International

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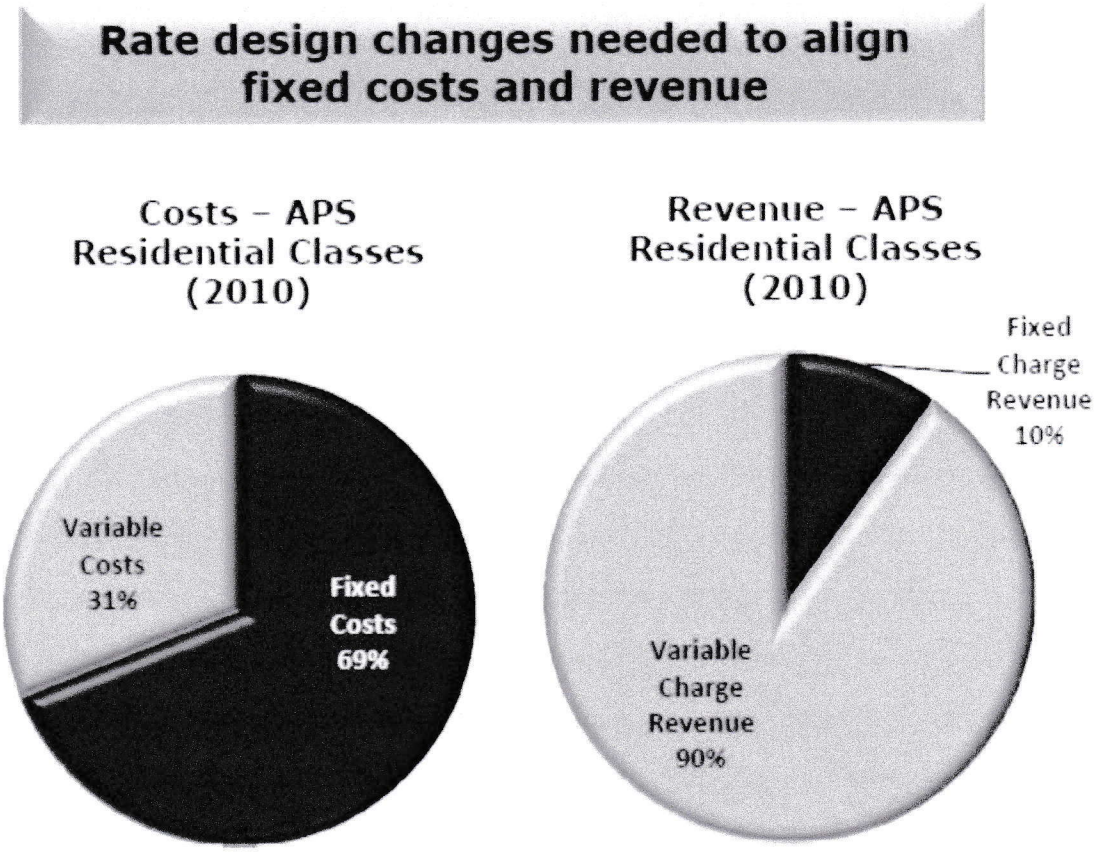
Exhibit 2
The current practice billing for retail electricity sales based on the volume of electricity consumed fails to reflect the fact that variable costs are a small share of the cost of grid supplied electricity, the bulk of whose cost is fixed



Source: Pinnacle West

Ideally, therefore, utilities would like to reform their retail electricity rates so that the variable cost of supplying electricity would be reflected in a variable charge to cover the cost of fuel and purchased power, while the fixed cost of providing access to the grid would be covered by a fixed monthly charge on each customer's bill. An illustration of how this might work is presented in **Exhibit 3**, which uses California's residential electricity rate as an example. The average residential rate for electricity in California is ~$0.15/kWh. Of this, ~$0.09/kWh represents the recovery of the fixed costs of the utility's transmission and distribution network and power generating fleet. Only the remaining $0.06/kWh reflects the variable cost of supplying round-the-clock, full requirements power (primarily the cost of fuel and purchased power). Were the variable component of residential customers' rates to reflect only the variable cost of supplying electricity, and the utility's fixed costs to be recovered through a fixed monthly charge, it would be very difficult for distributed solar to compete. Today, even with the benefit of the 30% investment tax credit, the all-in cost of electricity from a residential solar rooftop system is California exceeds $0.20/kWh.

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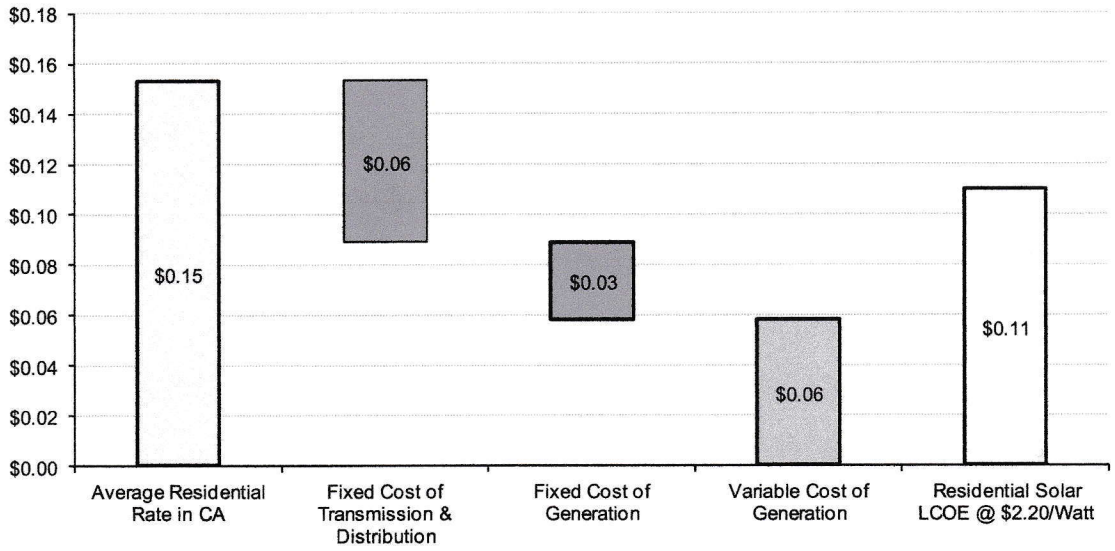
Even if the installed costs of distributed solar systems in the U.S. to fall to German levels, which are approximately half those in the United States today, the all-in cost of distributed solar would still, by our estimate, be ~$0.11/MWh. Faced with the prospect of incurring an $0.11/MWh cost to offset a variable charge for grid supplied electricity of only $0.06/kWh, no residential customer would switch for economic reasons alone.

Exhibit 3
Were utilities to recover the fixed cost of providing grid access through a fixed monthly charge, the advantage of solar would be undermine – even if the cost of distributed generation were to fall by half



Source: ABB Ventyx, SEIA, EIA, NREL, Edison Electric Institute, Bernstein analysis and estimates

Electric utilities have had very limited success, however, in moving the structure of their retail electric rates away from volumetric billing towards a mix of fixed and variable charges. Thus California passed legislation in October of last year (AB 327) that set in motion a restructuring of the state's retail electricity rates and required the California Public Utility Commission to re-examine the net energy metering tariff. Yet AB 327 sets a cap of $10 per month on the fixed charge that utilities may levy on their residential customers. This compares with an average residential bill in the state of some $88 per month and thus would translate into a fixed charge only 11% of the average customer's bill – and a much lower percentage of higher volume customers' bill.

Similarly, Arizona Public Service Company (APS) last year asked its regulator, the Arizona Corporation Commission (ACC), either to (i) create a fixed charge on distributed solar systems or (ii) allow the state's utilities to purchase distributed solar generation not at the full retail rate, but at the lower generation rate. After a heated debate among the state's utilities, consumer advocates, and the distributed solar generation industry, the ACC decided to implement a fixed charge of $0.70/kW on all systems installed after 2013, but to leave net metering reimbursement unchanged, at least until APS next files a rate case in 2015. APS estimates that this will translate into an average fixed charge for its residential customers of only $4.90/month – or ~4% of the average residential bill in the state of some $120 per month (see **Exhibit 4**).

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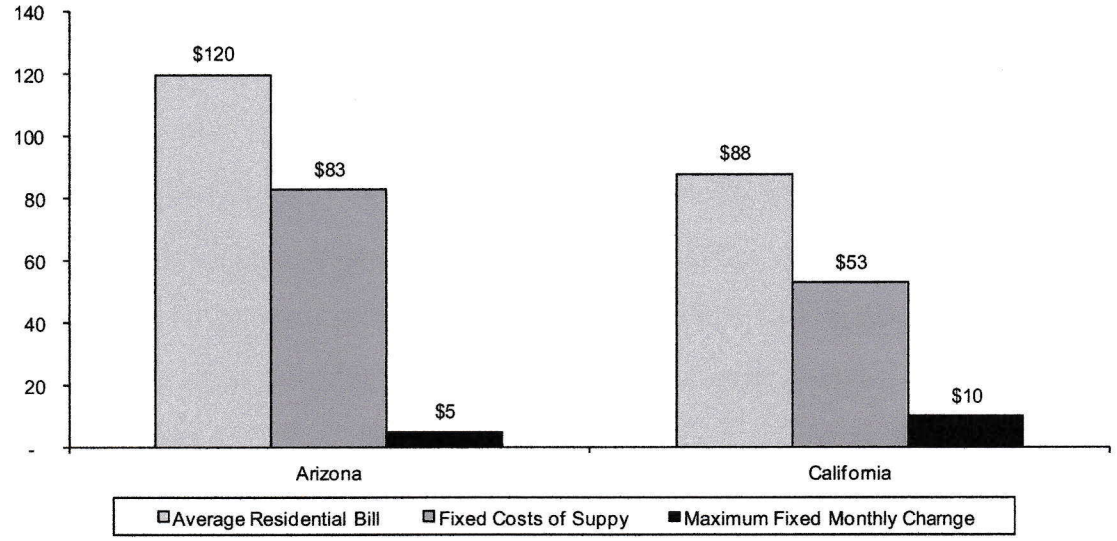
Exhibit 4
Arizona & California: Average monthly bill for residential customers compared to the estimated fixed cost of providing grid access (in blue) and the maximum fixed monthly charge currently permitted (in black)



Source: Energy Information Administration, SNL and Bernstein analysis and estimates

Unsuccessful in their efforts to introduce a substantial fixed charge for grid access, utilities in both states are re-directing their efforts to reducing the per kWh rates paid by their residential customers. In California, for example, the residential customers with the highest volumes of electricity consumption pay retail rates that are twice the residential average (~$0.32/kWh v. an average rate of ~$0.15 per kWh), rendering distributed solar generation, even at an all-in cost in excess of $0.20/kWh, highly attractive. This disparity in residential rates stems from legislation passed following California's energy crisis of 2000-2001, which introduced a system of tiered electricity rates, with low rates per kWh for low volume electricity customers and progressively higher rates per kWh for higher volume customers. Critically, the lowest, Tier 1 rates were frozen, and over the following decade all increases in the utilities' cost of supplying electricity were borne only by the Tier 2 through 4 customers, tending to further polarize electricity rates over time. AB 327 allows the state's utilities gradually to eliminate this tiered rate structure and by 2018 to replace the current four tier system with one comprising only two tiers. Thus Southern California Edison, which today charges its highest volume residential customers $0.32/kWh, proposes by 2018 to reduce its maximum retail rate to only $0.20/kWh, materially reducing, if not eliminating, the economic incentive for large volume customers to install distributed solar systems (see **Exhibit 6**).

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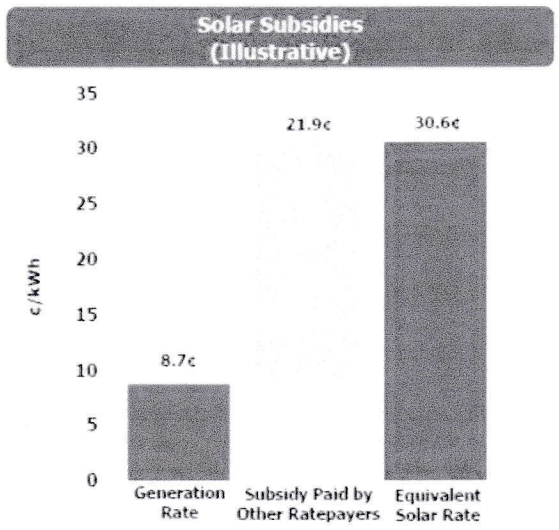
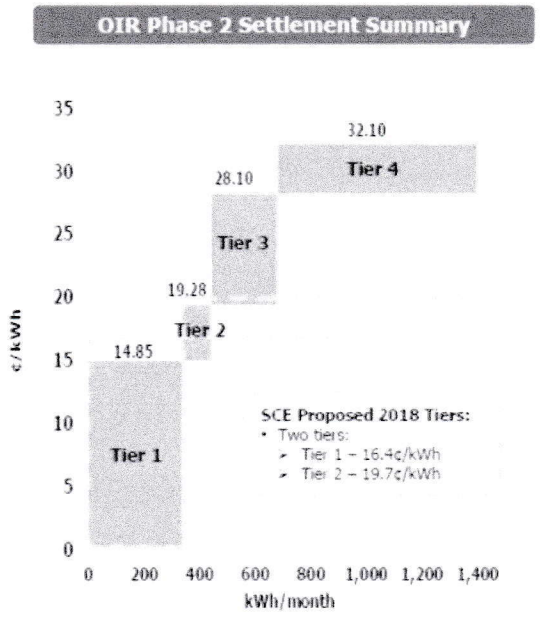
Exhibit 5
Southern California Edison: Net Energy Metering at Maximum Residential Retail Rate (Historical)



Source: Edison International

Exhibit 6
Southern California Edison: 2014 and Proposed 2018 Residential Rate Structures



Source: Edison International

Arizona Public Service is attempting to push through a similar reform. In Arizona, residential customers are billed on a time-of-use basis, with retail electricity rates rising during peak demand hours to reflect the cost of electricity on the grid at that time. APS management, however, contends that Arizona's time-of-use rates, having been set prior to the collapse in the natural gas price in 2009, are now outdated, and over-charge customers for on-peak consumption. APS points out that time-of-use rates can be twice as high during peak hours as during off-peak hours, yet the currently prevailing difference between on- and off-peak power prices at the Palo Verde Hub is now only 25%. Retail electricity rates that more accurately reflected the economic value of peak electricity supplies would render distributed solar generation far less attractive.

Ironically, as both utility scale and distributed solar generation rise in importance in Arizona and California, on-peak power prices may decline further. **Exhibit 7** presents a chart prepared by the California Independent System Operator (CAISO) forecasting the level of net power demand on the California grid over each hour of a typical day in spring or fall for the years 2014 through 2020. CAISO expects the growth of renewable generation capacity in response to California's aggressive renewable mandate, which requires the state's utilities to procure 33% of their electricity supplies from renewable resources by 2020, to result in materially higher levels of solar generation over the course of the decade. CAISO forecasts this growth to drive the daytime requirement for conventional (non-renewable) generation down from ~19 GW in 2013 to only 12 GW by 2020 – a level equivalent to only two thirds of current nighttime loads. The implication could be that power prices during hours of peak electricity demand will fall to levels even lower than the off-peak prices prevailing today during the hours of lowest demand. In this scenario, time-of-use pricing would discourage rather than encourage retail customers from installing distributed solar systems.

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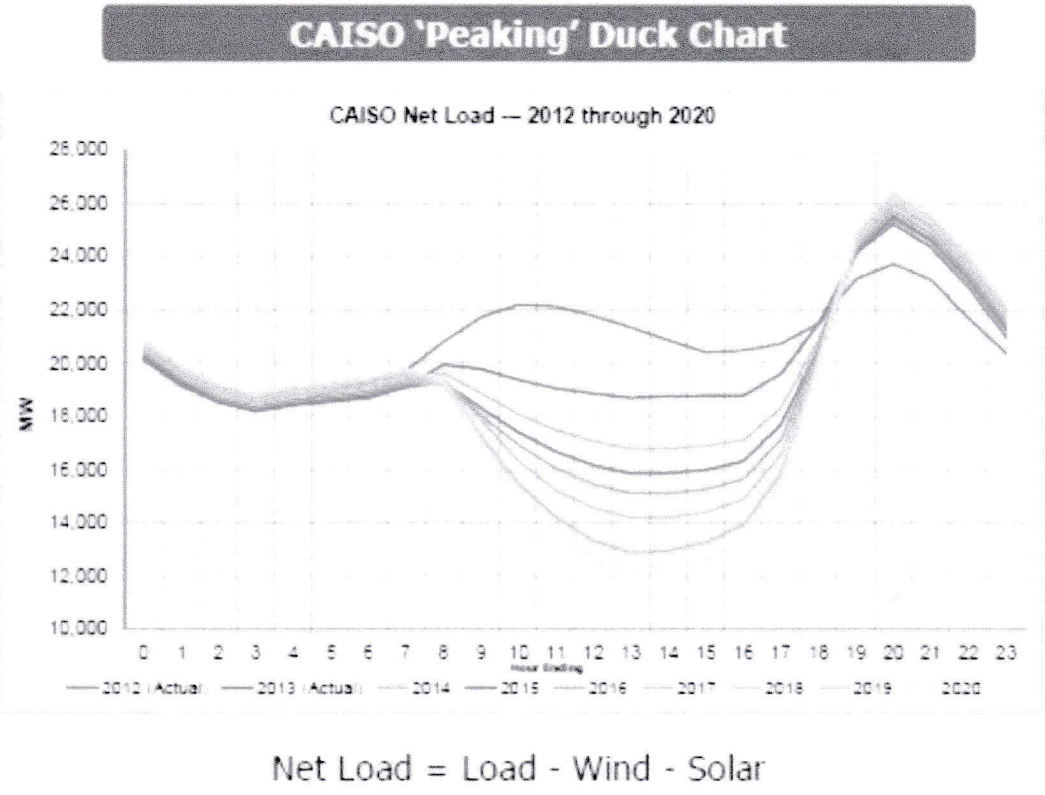
Exhibit 7
CAISO "Peaking" Duck Chart



Source: Edison International

Utility-owned Solar Generation as an Alternative to Distributed Solar

Not only are utilities attempting to render utility supplied power more competitive with distributed generation, they are also seeking to compete directly with distributed solar generation. Thus Arizona Public Service has proposed to the Arizona Corporations Commission that it be allowed to deploy 20 MW of distributed solar generation directly on customer rooftops. APS proposes to compensate participating customers through a credit against their monthly utility bills. The utility would own the distributed solar system as well as their power output.

APS cites two advantages to the program. First, APS would seek to optimize the location of the solar arrays it installs, maximizing the use of western facing rooftops to offset peak hour demand and deploying the panels at locations where they would tend to enhance, rather than detract from, the stability of the distribution grid. Second, APS is prepared to install solar rooftops on the homes of customers who cannot afford the cost of a distributed solar system and would not quality for the lease financing offered by distribution solar installation companies.

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Exhibit 8
Arizona Public Service is offering to deploy solar panels on the homes of customers who would otherwise not be able to afford them, offering to lease these customers' rooftops for a credit against their monthly electricity bills

- APS proposed an option to the ACC to convert 20 MW of AZ Sun into APS-owned residential rooftop solar, equates to approximately 3,000 customers
- Estimated cost of $57-70 million
- Benefits:
  - Provides an alternative for those who cannot afford solar or do not want a lease
  - Participating customers receive monthly credit on their bill through the 20-year life
  - Support and partner with Arizona solar installers
- APS has track record through the Flagstaff Community Power Project
  - Launched in 2010
  - 1.5 MW of distributed energy from solar panels owned by APS, spread across:
    - 125 residential rooftops
    - Schools
    - Neighborhood-scale solar power plant

Source: Pinnacle West

A variation on this concept is being developed by Xcel Energy, whose utility subsidiaries in Colorado and Minnesota are offering customers the opportunity to invest directly in ground mounted, utility-scale solar farms. Xcel's programs allow consumers who might otherwise not be eligible for distributed solar generation to purchase interests in community scale solar projects. These projects allow the consumers to contribute directly to renewable generation, and to enjoy some of the economic benefits of distributed solar.

In Colorado, for example, Xcel's utility subsidiary, Public Service Company of Colorado, offers a community solar gardens program. Under this program, subscribers—either households or businesses—purchase or lease shares in a solar project, whose output is sold to the utility. In return, they receive a credit on their utility bill for their share of the solar garden's generation, valued at a rate that moves with the retail rate. Since 2012, Public Service of Colorado has approved 25 such community solar installations with a combined capacity of over 18MW. A quarter of this capacity is now operational.

In 2013, Minnesota adopted a law requiring utilities to administer a similar community solar garden program. Xcel, which also operates in Minnesota, has proposed a plan under which it would have the option to develop solar gardens itself, as well as contracting development out to third parties.

From Xcel's perspective, these programs, like Arizona Public Service' rent-a-rooftop scheme, have the benefit of ensuring that the output of the solar capacity deployed is marketed by the utility, thus avoiding the loss of kWh sales, and consequent erosion of revenues, precipitated by consumer deployment of distributed solar generation.

Finally, some utilities, such as NextEra Energy's Florida Power & Light (FPL), are rolling out utility scale solar generation not because it is required by state renewable mandates (the Sunshine State doesn't have one) but because these solar projects offer cost-competitive sources of peak hour power and can be situated at advantageous locations on the utility's distribution network. Specifically, FPL is proposing to build three

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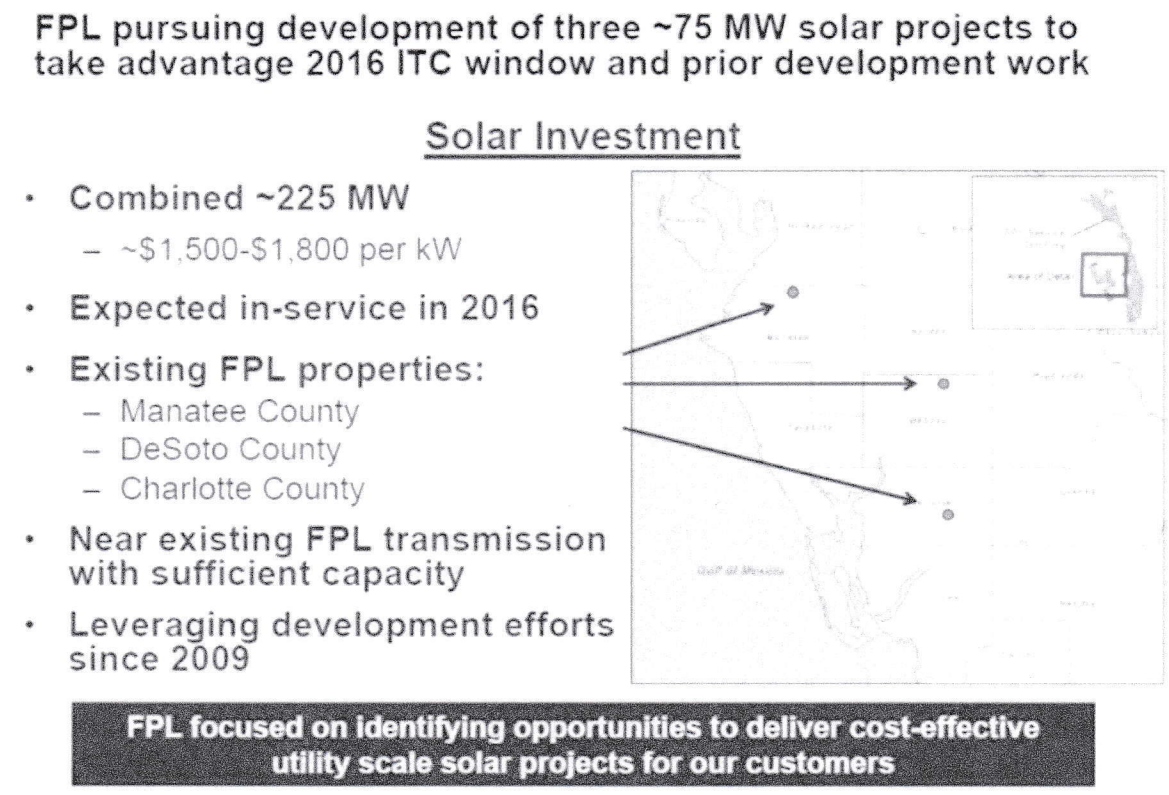
~75 MW solar projects built at sites already owned by FPL, and with access to existing transmission capacity. These advantages are reflected in an estimated cost a $1,500 to $1,800 per kW or $1.50 to $1.80 per Watt (see **Exhibit 9**). In the words on NextEra Energy CFO Moray Dewhurst, these projects:

> will prove cost effective for our customers… The way to think about cost-effectiveness for these projects is to think of them in the context of a constantly evolving integrated resource plan… In the IRP, we plug in different combinations of potential future generation and figure out, on a present value basis, which of those are cheaper for our customers…We think we now can introduce these three solar projects into the mix and drive the overall present value, as seen through the customers' eyes, lower. That's a good thing for our customers and something that we want to go ahead with."

Exhibit 9
[Enter the exhibit title]



Source: NextEra Energy

As we explain in our note of November 3rd, *Bernstein Energy & Power: High Noon for Distributed Solar, or Are Regulated Utilities the Future of Solar Power?*, we expect utility scale solar generation, along the lines of the projects being developed by NextEra and Xcel, to offer a competitive alternative to distributed solar generation. Over the five years through 2013, U.S. distributed solar generation has grown at a compound annual rate of 56%. As can be seen in **Exhibit 10**, however, the growth of utility-scale solar—large (> 1MW) solar installations tied into the traditional grid system in the same manner as conventional

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power plants— has been even more rapid. We estimate that in 2014, utility scale solar generation will exceed that of distributed solar by over 50%. In part this success reflects the fact that utility scale systems have over time demonstrated a substantial and persistent cost advantage relative to distributed solar generation (see **Exhibit 11**). The lower cost of utility-scale solar, combined with its compatibility with regulated utilities' business model, render it, in our view, a looming threat to the distributed solar industry.

The competition between distributed and utility-scale solar generation reflects the fact that they meet the same goals while relying on the same pots of money (taxpayers' and ratepayers') to do so. Both distributed and utility-scale solar are generously subsidized because they emit no CO2, SO2, NOx, mercury, particulate matter or other pollutants; require little environmentally disruptive mining or transportation; and, critically, offer long term price stability.

These benefits come at substantial cost, however. We estimate the unsubsidized lifetime cost of a residential distributed solar system at ~$230/MWh, or almost twice the average residential price for electricity in the United States. We estimate the cost of utility scale solar generation at ~$91/MWh, or roughly twice the wholesale price of electricity. To sustain its growth, therefore, the solar industry relies upon (i) renewable portfolio standards and feed-in tariffs, which essentially require utility customers to purchase solar generation at an above-market price, and (ii) investment tax credits, which require taxpayers to cover 30% of the installed cost of solar power systems.

We calculate that renewable portfolio standards and feed-in tariffs add ~$2.1 billion annually to customers' electricity bills, in excess of the value of the electricity supplied, while the investment tax credit cost taxpayers ~$3.5 billion in 2013. The combined cost of ratepayer and taxpayer subsidies for solar generation, at some $5.6 billion annually, is equivalent to ~$50 per U.S. household per year.

The cost of these subsidies grows in direct proportion to the capital invested in solar generation. Annual investment in U.S. solar generation has increased at a compound annual rate of ~45% over the last five years. As the industry continues to grow, we believe this rising cost will drive taxpayers and consumers (and through them, legislators and regulators) to focus increasingly on cost-effectiveness. And a focus on cost will inevitably benefit utility scale solar, which can deliver the environmental advantages of solar generation at a cost that is 50% to 60% below that of distributed solar.

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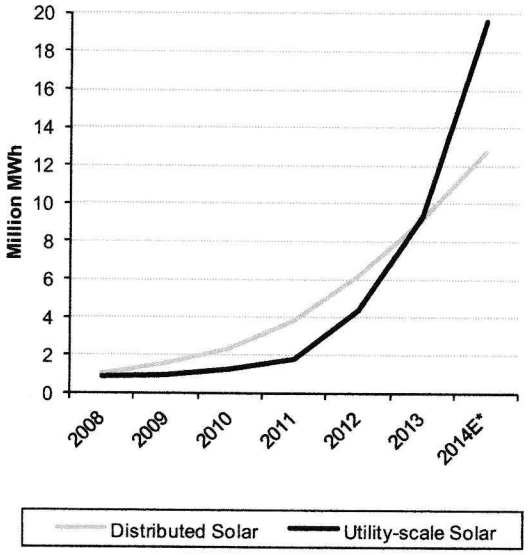
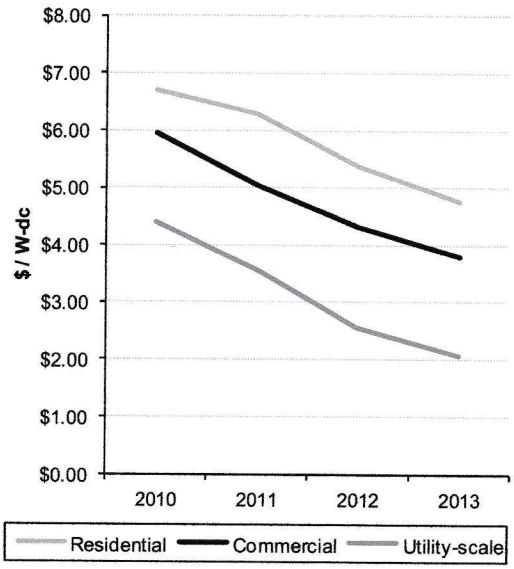
Exhibit 10
Both utility-scale and distributed solar generation have grown rapidly – but utility solar generation now exceeds distributed by over 50% (1)



1. 2014E extrapolated based on 2014 YTD generation compared to equivalent 2013 amount

Source: EIA, ABB Ventyx, SEIA, Bernstein analysis and estimates

Exhibit 11
Installed cost of residential, commercial and utility-scale solar PV systems, 2009-2013 (reported prices, gathered by the Solar Energy Industries Association)



Source: Solar Energy Industries Association, Bernstein analysis

Utility-scale solar enjoys five key cost advantages relative to distributed solar: (i) lower customer acquisition costs, (ii) economies of scale in installation, (iii) market power in equipment procurement, (iv) a significantly lower cost of capital, and (v) higher average capacity factors. These differences, in our view, are inherent in the two technologies, and therefore will be reflected in a permanent cost advantage for utility scale solar projects.

- *Lower customer acquisition costs*

Customer acquisition is perhaps the most challenging aspect of the distributed solar business. Contacting thousands of potential customers to discuss their interest in distributed solar is inherently a labor intensive and time consuming effort. The success rate is low. Many potential customers are not interested; some that are prove not to be creditworthy; and the properties of those that are both often prove unsuitable for distributed solar, due to shading from trees, the absence of a southern facing exposure, or the presence of dormers or gables that limit suitable roof space.

As monopoly suppliers of electricity in their service territories, utilities do not need to acquire customers or even consult them before installing solar generation. On the contrary, every utility customer, even apartment dwellers without rooftops (like the authors of this note), can be supplied from a utility scale facility.

- *Economies of scale for labor and installation*

The most obvious advantage of utility-scale solar is its lower cost. The installation of a single 10 MW system, all else equal, costs less than the installation of 100 systems of 100kW (0.1MW). For the latter,

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installers must travel to 100 different locations, familiarize themselves with 100 different plans and unique circumstances, obtain 100 construction permits and secure 100 utility hookups. The costly repetition of these basic tasks is inherent to distributed solar generation and is avoided by utility scale projects.

Distributed solar installations can also be more complex than utility-scale systems. Installing roof mounted panels is inherently costlier and riskier than building ground mounted panels. And installing rooftop systems (especially on houses with pitched roofs, gables, dormers or chimneys) requires significant customization relative to uniform ground mounted arrays.

- *Oligopsony*

Regulated utilities are the monopoly suppliers of electricity within very large service territories. Thus a handful of major utilities may supply the overwhelming majority of consumers in a state the size of Texas or California, and interstate utility holding companies such as Duke Energy or Southern may supply the bulk of the power needs of several states. In any given region, therefore, a limited number of utilities comprise the market for utility-scale systems; they consequently enjoy the pricing power associated with oligopsony (a market with few buyers).

Because of the scale and ongoing nature of their equipment purchases, moreover, utilities have dedicated procurement departments staffed with engineers and purchasing managers. Through the competitive bidding process, these professionals are able to choose from an array of options each time they want to expand solar capacity, selecting the lowest cost solution and paying the cheapest price.

Contrast this with the distributed solar market, where customers are often unfamiliar with solar power before being approached by a developer, and may not have the technical expertise or even the time to aggressively seek the lowest price. As the distributed solar industry grows, we expect suppliers will be forced to compete more with each other (as opposed to simply beating the prevailing utility retail rate), and the potential to over-price distributed generation will be reduced. But the market power enjoyed by utilities in the procurement of utility scale systems will persist.

- *Lower cost of capital*

Similar considerations favor utilities in procuring capital. As the monopoly suppliers of an essential service, supported by cost-of-service based rate regulation, utilities command unrivaled access to the capital markets. The risks of housing related consumer credit, by contrast, are still a painful memory for banks and institutional investors.

- *Higher capacity factors*

In any given location, a MW of utility-scale solar will generate more electricity, on average, than an equivalent amount of distributed solar capacity (i.e. will have a higher capacity factor). This reflects the fact that utility-scale solar can be designed such that the panels are optimally positioned (facing south at a tilt equal to latitude) so as to maximize the solar energy they receive. The capacity factor of rooftop systems, by contrast, is often constrained by the direction and tilt of the roof (particularly for residential systems), and any nearby buildings or trees that block sunlight. As a result, distributed solar capacity factors average ~20% nationally, compared to 25% or higher for utility-scale systems.

Similarly, ground mounted utility scale systems allow for the deployment of heavier, more sophisticated technologies than are feasible for rooftop systems. An example is single-axis tracking, or panels that follow the sun's movement through the sky, a technology which, while more expensive, has consistently proved to be cost-effective for ground-mounted systems.

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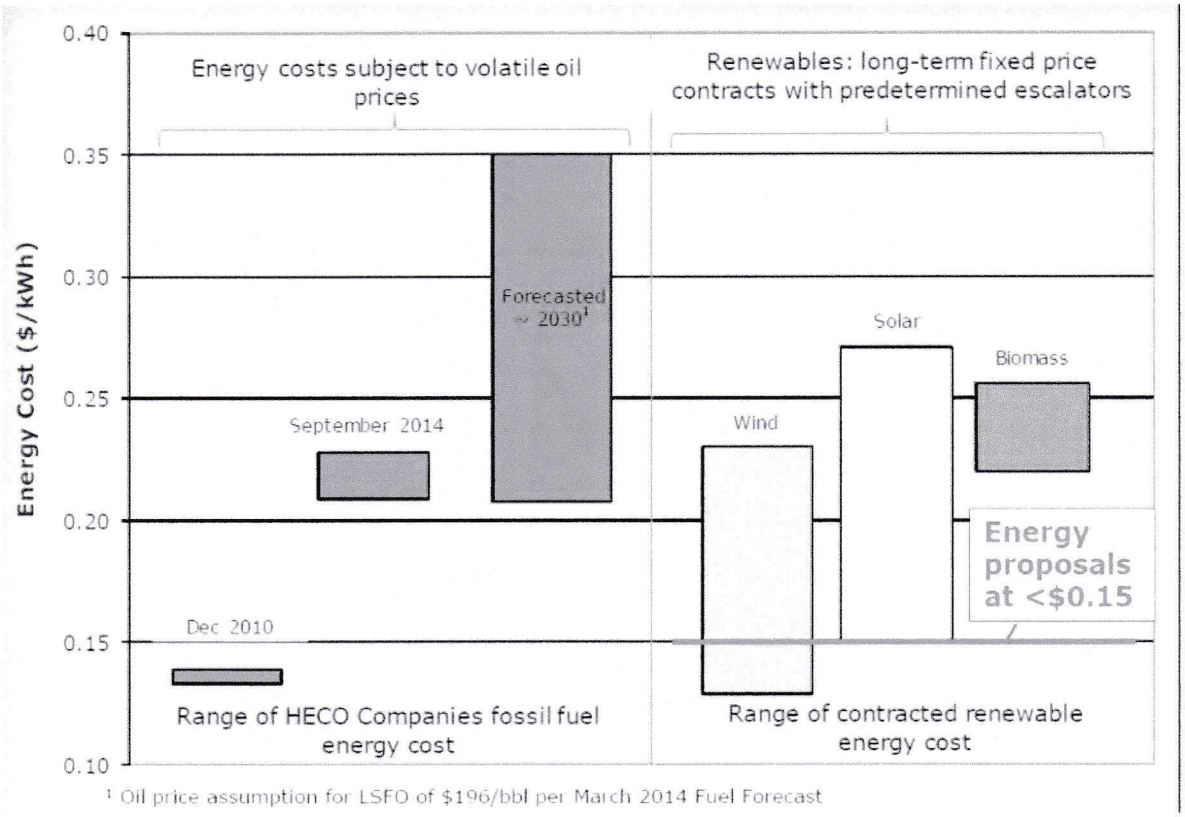
A New Vision of the Utility Business and Regulatory Model

Some U.S. electric utilities, particularly those operating in states that have decoupled utility revenues from the volume of electric deliveries, are already embracing a future in which their role will encompass both (i) operating the power grid in manner that ensures high levels of system reliability while (ii) facilitating the growth of distributed solar generation as well as renewable generation procured by the utility on behalf of its customers. Hawaii Electric is perhaps the most telling example. Hawaiian Electric's reliance on high cost imported fuel oil to power its fossil generation fleet renders both utility scale and distributed solar generation economically attractive sources of power supply (see the cost comparison provided by Hawaiian Electric in **Exhibit 12**). On the mainland, renewable generation remains, as a general matter, a more expensive source of power that conventional resources, but widespread political support for renewables render their growth inevitable in states such as California, whose state renewable mandate requires utilities to procure a third of the power the supply their customers from renewable resources by 2020.

Exhibit 12
Hawaii's reliance on high cost imported fuel oil to power its fossil generation fleet renders both utility scale and distributed solar generation an economically attractive source of power supply



Source: Hawaiian Electric Industries

Edison International CEO Ted Craver offers in our view the clearest vision of the role of the incumbent electric utility in these circumstances. Craver sees the utility's roles as (i) ensuring reliable supplies of power at the constant voltage required to operate household, commercial, industrial and transportation

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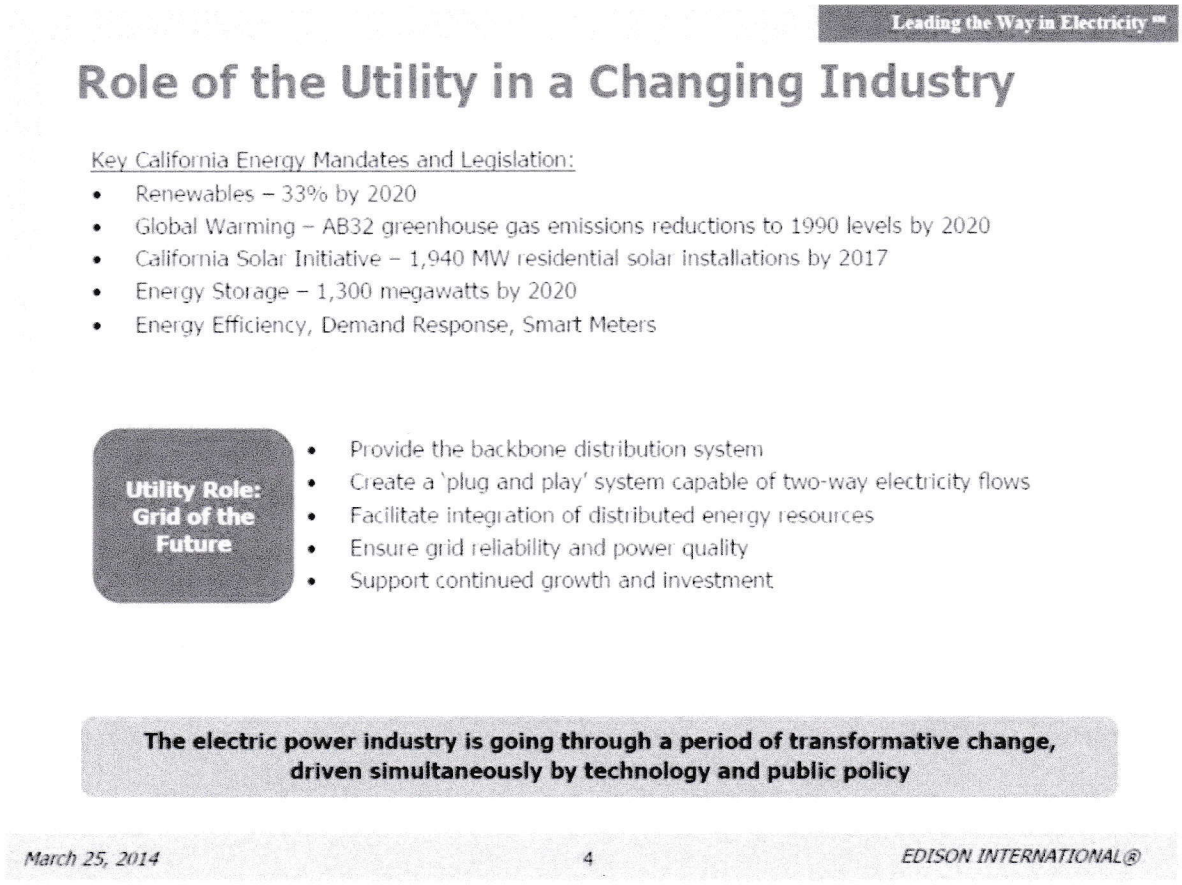
equipment (including electric vehicles) while (ii) allowing the roll-out of distributed solar generation by consumers as well as the integration of utility scale renewable resources onto the grid (see **Exhibit 10.**) Viewed holistically, the integration of high volumes of intermittent wind and solar generation is feasible only due to the offsetting flexibility of the power grid's rapid dispatch gas turbine and hydroelectric capacity. Distributed solar generation in particular is attractive only because of the back-up supply of conventional generation that is available from the grid at night, as well as the grid's ability to absorb the output of distributed solar generation during the day. Without the back up of the grid, very few consumers would find distributed solar generation attractive, nor would they be likely to in the foreseeable future. (see our note *Bernstein Energy & Power: Solar Power & the Utility Death Spiral, or How I Learned to Stop Worrying and Love the Grid).*

Exhibit 13
Role of the Utility in a Changing Industry



Source: Edison International

Craver goes further, arguing that the growth of renewable resources will require additional investment in the grid to render it more robust. Most of this investment will be associated with the need to accommodate

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high volumes of intermittent renewable generation. As is illustrated in **Exhibit 9**, the integration of large volumes of intermittent wind and solar generation can cause a high degree of volatility in the power supplied to the grid, requiring an equal volume of dispatchable conventional generation to be held in reserve to offset the loss of solar at sunset or the loss of wind at any point during the day. **Exhibit 9** illustrates this issue by charting the progression of power demand (load) net of wind and solar generation (net load) on the California grid over 24 hours during a typical day in the spring or fall. Historical levels of net load for 2012 and 2013 are illustrated in blue and red, respectively; the other lines represent forecasts out to 2020 incorporating the estimated growth in renewable generation required to meet California's 33% by 2020 renewable generation mandate. The chart illustrates how full compliance with this mandate is expect to cause net load between noon and 1 PM to fall from ~19 GW in 2013 to only12 GW by 2020. In California in the spring and summer months, however, peak load occurs between 7:00 and 8:00 PM, when the sun is down, lights are on and folks are eating dinner. The implication is that the conventional generation fleet must more than double its supply of power to the grid from its midday low of 12 GW to a peak of 26 GW. Approximately 10 GW of this 14 GW ramp in output is necessary to offset the drop in renewable (primarily solar) energy supplied to the grid. Historically, California's power system was designed to allow ramps in output of half this scale in the morning or evening hours (see the shape of the blue line in **Exhibit 7**). Going forward, much greater quick response capability will be required and it will supplied by utility owned or utility contracted conventional generation assets, supplying power along utility owned high voltage transmission lines.

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Valuation Methodology

Our target prices reflect the results of three alternative valuation methodologies: (i) a multiple-based valuation calculated by applying the median valuation multiples of a group of comparable companies to our estimates of a utility's future earnings, dividends and EBITDA; (ii) a discounted cash flow model over the forecast period of 2014-2017, and a terminal value in 2018 discounted back to present value at the weighted average cost of capital; and (iii) a discounted dividend model over the forecast period of 2014-2017, and a terminal value in 2018, discounted back to present value at the cost of equity.

Risks

Our earnings and cash flow forecasts for the regulated utilities in our coverage (AEP, D, DUK, EIX, FE, NEE, and PCG) are driven primarily by our projections of volume sales and future rate relief and, in the long term, by the rate of growth in rate base and the return on equity allowed by the utilities' regulators. If our assumptions in these critical areas prove overly optimistic/(pessimistic), our earnings and cash flow forecasts may need to be cut/(raised) and with them our target prices.

Our earnings and cash flow forecasts for the competitive generators in our coverage (EXC), and for the competitive generation business of primarily regulated utilities, are predicated on currently prevailing forward price curves for power and generation fuels (coal, gas and nuclear fuel). Changes in these forward price curves can thus have a material impact on our forecasts of earnings and cash flow and consequently on our target prices for these stocks. Power prices can be quite sensitive to the price of natural gas, so that higher gas prices tend to be reflected in higher revenues, earnings and cash flow. However, higher prices for coal and nuclear fuel tend to depress generation margins.

Finally, our forecasts for both regulated utilities and competitive generators are sensitive to the estimated growth in property, plant and equipment, which drives depreciation and interest expense, as well as to the expected growth in operations and maintenance expense.

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- Bernstein rates stocks based on forecasts of relative performance for the next 6-12 months versus the S&P 500 for stocks listed on the U.S. and Canadian exchanges, versus the MSCI Pan Europe Index for stocks listed on the European exchanges (except for Russian companies), versus the MSCI Emerging Markets Index for Russian companies and stocks listed on emerging markets exchanges outside of the Asia Pacific region, and versus the MSCI Asia Pacific ex-Japan Index for stocks listed on the Asian (ex-Japan) exchanges - unless otherwise specified. We have three categories of ratings:

  Outperform: Stock will outpace the market index by more than 15 pp in the year ahead.

  Market-Perform: Stock will perform in line with the market index to within +/-15 pp in the year ahead.

  Underperform: Stock will trail the performance of the market index by more than 15 pp in the year ahead.

  Not Rated: The stock Rating, Target Price and estimates (if any) have been suspended temporarily.
- As of 11/14/2014, Bernstein's ratings were distributed as follows: Outperform - 46.3% (2.2% banking clients) ; Market-Perform - 41.8% (0.8% banking clients); Underperform - 11.9% (0.0% banking clients); Not Rated - 0.0% (0.0% banking clients). The numbers in parentheses represent the percentage of companies in each category to whom Bernstein provided investment banking services within the last twelve (12) months.
- Hugh Wynne maintains a long position in Duke Energy Corp. (DUK).

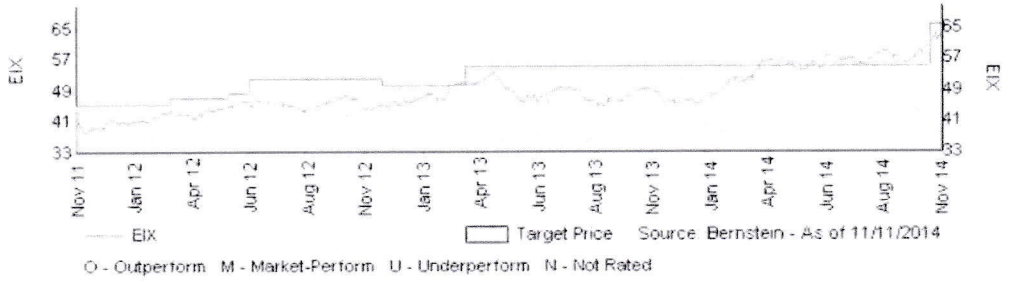
12-Month Rating History as of 11/16/2014

Ticker	Rating Changes
EIX	O (RC) 06/14/13
NEE	M (IC) 12/18/09
PCG	O (RC) 03/27/13

Rating Guide: O - Outperform, M - Market-Perform, U - Underperform, N - Not Rated
Rating Actions: IC - Initiated Coverage, DC - Dropped Coverage, RC - Rating Change

EIX / Edison International

Date	Rating	Target(USD)
11/10/11	O	45.00
03/09/12	O	47.00
05/22/12	O	48.00
06/18/12	O	52.00
12/03/12	M	50.00
03/19/13	M	55.00
06/14/13	O	55.00
10/29/14	O	66.00



NEE / NextEra Energy Inc

Date	Rating	Target(USD)
11/07/11	M	51.00
01/30/12	M	59.00
04/26/12	M	65.00
10/25/12	M	70.00
01/30/13	M	74.00
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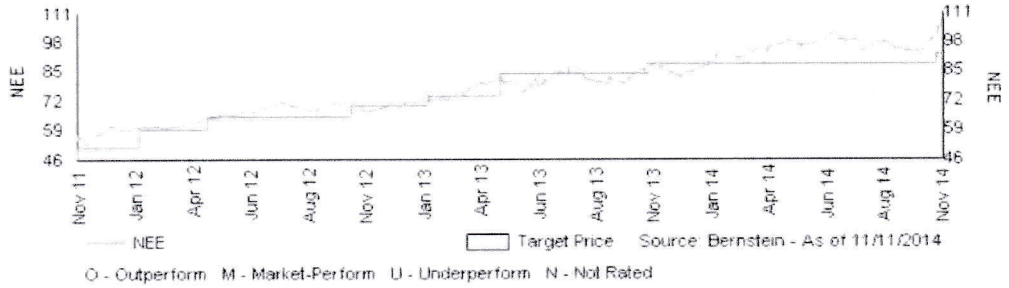
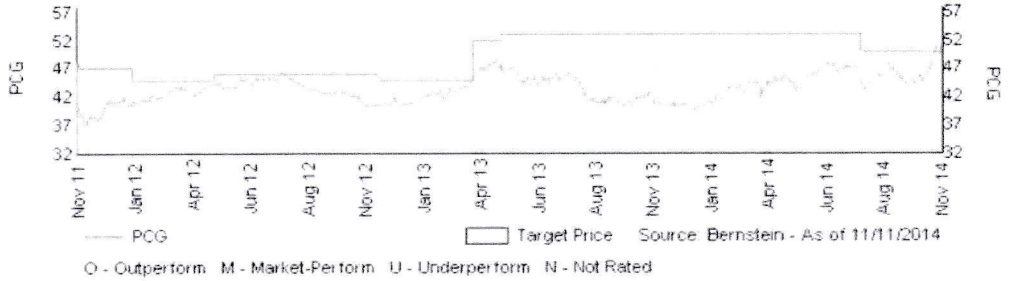
11/04/13	M	88.00
11/03/14	M	92.00



PCG / PG&E Corp

Date	Rating	Target(USD)
11/10/11	O	48.00
11/15/11	O	47.00
01/20/12	M	45.00
05/03/12	M	46.00
11/29/12	M	45.00
03/27/13	O	52.00
05/03/13	O	53.00
05/07/13	O	53.00
05/13/13	O	53.00
08/01/14	O	50.00



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Approved By: CDK

Seeking Alpha α

Utility Rate Changes An Ominous Sign For SolarCity

Dec. 12, 2014 2:47 PM ET
by: Casual Analyst

Summary

- We expect utility rate structures to fundamentally break the residential solar lease company business model.
- The risks for SolarCity are outsized and we see mostly negative catalysts going forward.
- We are revising our view of SolarCity from Avoid to Sell.

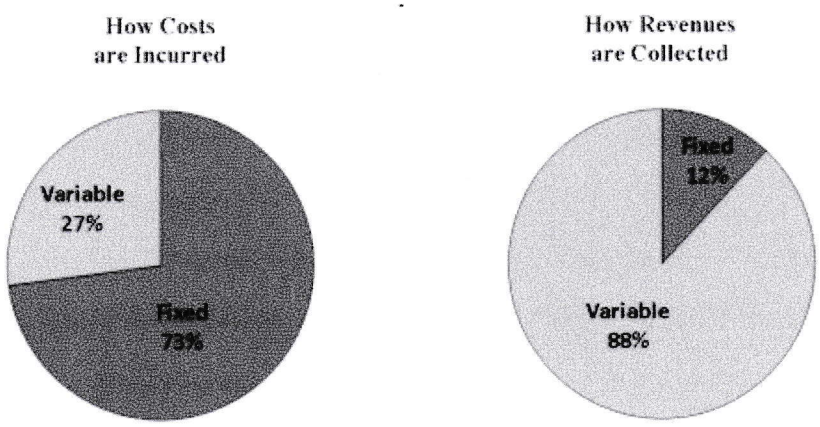
In this article, we discuss the rationale for the rate changes in the utility industry and how they are going to impact the residential solar market and SolarCity (NASDAQ:SCTY) specifically.

We believe that the SRP rate change proposal, following closely a similar change in Wisconsin, has implications far beyond what investors may realize. As a sign of things to come, Public Service Company of New Mexico, on Thursday, indicated that it is proposing a rate revision.

The talk of utility death spirals, the bond downgrades, the loss of market share to customer generated solar power and third-party systems, and the fear of survival has caused the utility companies across much of the developing world to get out of their slumber. Utilities across the US and rest of the world are waking up to the impact solar can have on their business models and are starting to reevaluate their long-term service and business models.

A fundamental reality with most utilities is that typical energy pricing models are based on simple per KWH charges. These decades' old KWH models worked well during monopolistic times but no longer work in today's competitive landscape.

The root of the problem can be traced to utilities' cost structure. Most utilities tend to have large asset bases and high fixed cost structures. Some of the larger utility fixed costs include power plants, transmission and distribution infrastructure. These fixed costs tend to be a large percentage of utilities' total costs (about 73% in the case of SRP as can be seen from the picture below).



While the fixed costs dominate the cost structure, the utility revenue model is dominated by variable per KWH charges (see picture above).

As customers move to rooftop or other distributed solar, the variable revenues decline but the fixed cost structure does not change. If energy sales are less than expected, the fixed costs simply are not recovered. What this means is that the utilities cannot recover their costs with the variable cost pricing structure.

Increasing KWH charges to make up for the shortfall reduces the utility competitiveness and increases customer defections. Misinformed pundits, taking this dynamic to the extremes, have pontificated about the utility death spiral.

Utilities realize the fallacy of this revenue model and are starting to align their rate plans to be more consistent with the fixed cost base. What this means is that utilities will start moving to a model where the customers' electric bills will more closely reflect the utility cost structure and more accurately reflect the incremental value of delivered energy.

This rate realignment leads to the following changes:

- Fixed charges will start increasing and will end up becoming a large part of the customers' bills. At the extreme, a case can be made that since about 70% of utilities costs are fixed, about 70% of the customers' bills also should be fixed. As the fixed component increases, solar becomes increasingly unattractive unless customers completely disassociate from the grid. For most customers, it will be uneconomical to disassociate from the grid for years to come.

- Per KWH charges will start declining across the US. In some cases the declines are likely to be steep - maybe as much as 50% from the current KWH levels. This change will immediately make PPA-type pricing models that SolarCity, Vivint Solar (NYSE:VSLR) and other residential installers use highly unattractive.

- New changes based on peak demand may start appearing to pay for the natural gas or other peaker plants. This charge once again works to the detriment of the solar lease model. (However, these demand charges could encourage battery deployment).

- Utilities will increasingly reduce customer compensation for customer power generation. Net metering will be increasingly effective at or below wholesale rates. Again, a substantial setback to solar deployment and SolarCity's business model.

Rate realignment efforts have become a top priority for utilities in geographies with high current or potential solar penetration. In spite of resistance from the solar industry, utilities are indicating they intend to move to new rate plan proposals.

In this environment, utilities in deregulated markets and utilities in markets that are not subject to rate reviews are set to move quickly with new rate structures. What we saw in the case of the SRP utility in Arizona was a community entity that moved quickly to adjust the rate structures.

As the reality of rapid solar deployment sets in, utility rate changes and other business model changes are happening faster than expected. With a Republican Congress, we expect this trend will further accelerate starting 2015. We expect to see a flood of utility rate changes in 2015 and 2016. By 2017, we estimate that most, if not all, of the major utilities in impacted markets will move to new rate structures. By 2020, as solar installation costs continue to go down, and as new markets become economical, we expect substantially all utilities across the US to move to new rate models.

As these rate changes are adopted, the market dynamics of solar installations will change dramatically. Utility rate changes will lead to the following consequences:

- These changes will essentially push out the economics of many new solar installations by three to five years. In other words, the oft-misused "grid parity" will get pushed out in each rate change market by 3 to 5 years. In particular, the economics of small residential solar systems will be impacted significantly. In other words, growth prospects for the residential solar industry and the likes of SolarCity are set to collapse.

- The rate changes will make solar leases and PPAs unattractive and reduce the overall residential market TAM in any given year. This does not mean solar will not be uneconomical in all cases in these markets. However, it does mean that the number of customers who can benefit with solar will decline substantially. Smaller residential scale system TAM will be particularly hard hit.

- In pursuit of growth, solar installers like SolarCity will increasingly chase the declining number of markets with favorable rate regimes. This will intensify competition in these markets and reduce PPA rates and margins.

- The rate changes, depending on the grandfathering aspects, will create an angry pool of customers whose existing installations and leases may no longer be economical. We expect to see a considerable increase in negative customer sentiment as the new rate plans take hold.

Because of these dynamics, we expect the residential solar market to slow down starting in 2015 and dramatically slow down when ITC benefits expire at the end of 2016. This slowdown will create yet another outsized risk for SolarCity in particular. By the time SolarCity ramps its new fab, there is a high risk that there will not be enough business for SolarCity to fill the fab. Given the highly leveraged balance sheet, the fab could create significant headwinds.

Our Take:

In summary, with the emerging reality of utility rate structures, SolarCity now faces several significant risks:

- Shrinking TAM

- Lower PPA rates and margins

- Customer backlash from underwater leases

- Uncertainty if there will be sufficient demand to fill the New York fab.

We have always felt that SolarCity stock should be avoided given the frothy valuation levels. However, the residential solar boom and the Musk factor have largely kept the stock from facing the realities on the ground. Given these dynamics, especially the Musk factor, in spite of the poor fundamentals, there was always a risk that momentum players would push the stock further into the stratosphere.

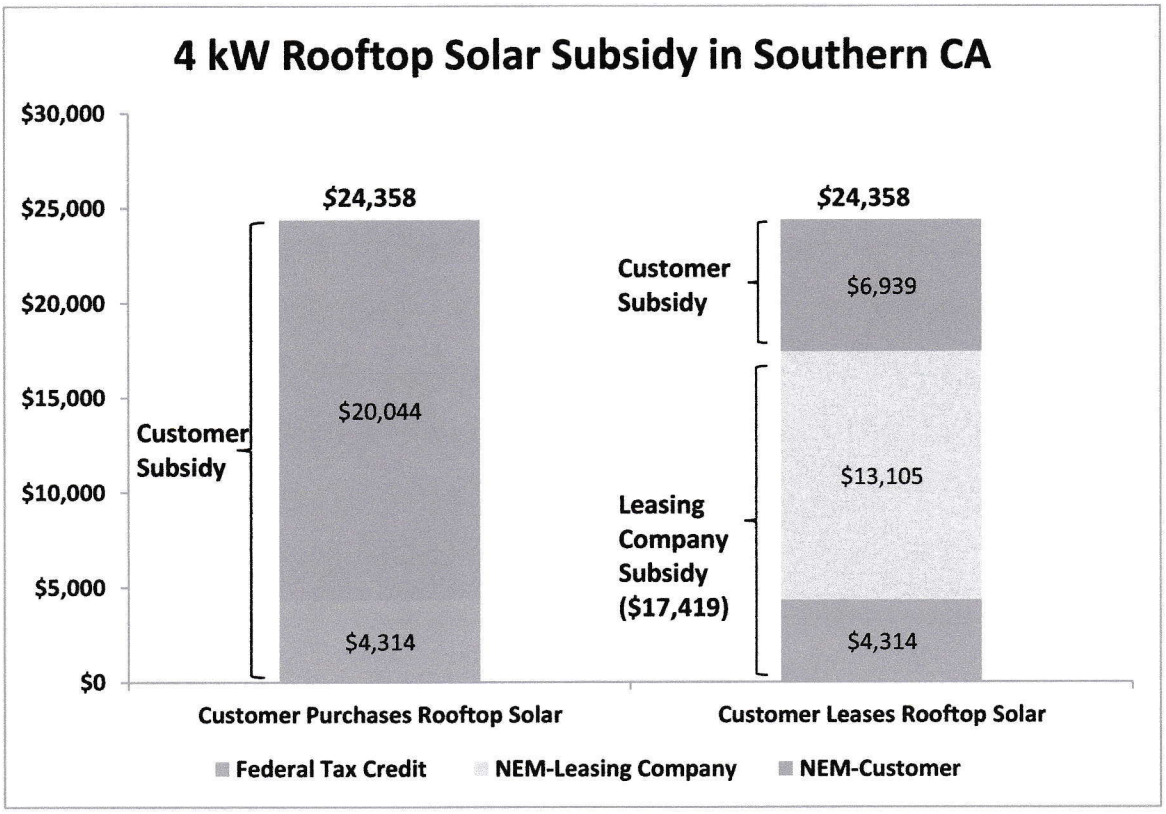
However, with the onset of new utility rate structures, we believe the residential solar PPA sector is now fundamentally broken. We do not see a significant risk of momentum building behind this name. As such, we see increasingly negative news and no positive catalysts for the company on the horizon.

We do not believe this stock should be valued above its hard asset valuation. For a detailed review on a good way to value this company, see our earlier article: A Fresh Look At SolarCity Valuation.

At this point, we believe the stock is worthy of consideration for shorts.

Our sentiment: Sell.

Figure 1. NEM and Federal Tax Credit Subsidies Shift from Customer to Leasing Company when Customer Leases Rooftop Solar (results based on 4 kW rooftop solar system in southern California that costs about $14,500).

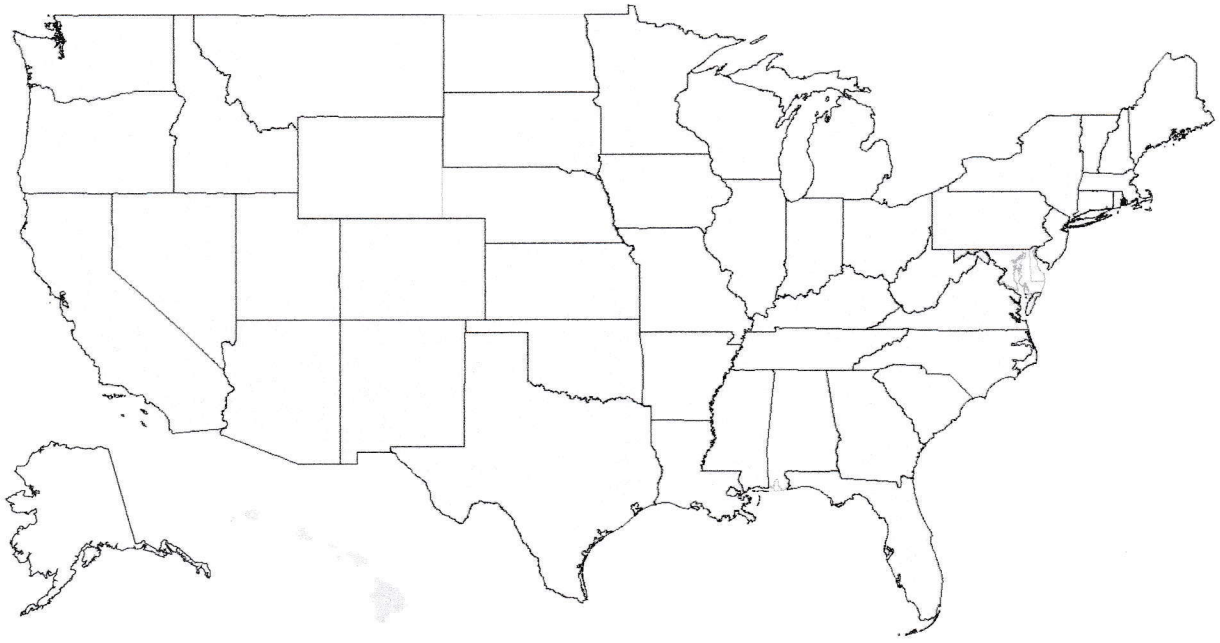


Source: *Net Energy Metering: Subsidy Issues and Regulatory Solutions.* Institute for Electric Innovation Issue Brief. September 2014. www.edisonfoundation.net

State Updates

States with Key Activities on NEM/DG Issues

December 15, 2014



Summary of Key State Activities on NEM and Related DG Issues: 43 States and D.C.

AR	Legislative debate on NEM compensation
AZ	ACC: Value of DG/grid, rate design, utility-owned DG, DG carve-out rules ▪ Tax & consumer issues
CA	CPUC: Rate reform, successor NEM tariff, shared solar, distribution resource planning, demand management, storage, interconnection ▪ Further RES expansion via rulemaking
CO	Regulators consider NEM issues, solar incentive levels ▪ Debate on centralized vs. distributed solar
CT	Expanded VNM ▪ Rate case w/higher fixed charges ▪ Recurring efforts on shared solar legislation
DC	Implementation of shared renewables law
FL	Potential NEM rulemaking, legislation; debate may conflate NEM w/ choice issues ▪ PSC reform bill
GA	Petitions to PSC on VOS, competitive procurement of DG
HI	Proceedings on DER policy including rate design, power supply, interconnection
IA	Regulatory NOI on DG ▪ Impact of state high court ruling allowing 3rd party rooftop solar financing
ID	Solar integration charges for QFs ▪ Solar advocates poised to defend against fixed charges, push VOS
IL	Rulemakings on NEM changes, interconnection ▪ Expected legislation on DG/NEM including VNM ▪ *Litigation of rate case outcome including SFV rate design*
IN	Regulatory proceeding to extend/modify NIPSCO feed-in tariff ▪ Energy strategy rollout
KS	Implementation of law allowing lower NEM credit, special charges ▪ RES repeal legislation
KY	Utility rate cases including higher customer charges

LA	PSC study of NEM costs/benefits ▪ NEM caps ▪ Rooftop solar tax, 3rd party financing, consumer issues
ME	NOI/report to legislature on distributed VOS ▪ Regulatory consideration of residential demand charge
MA	Implementation of NEM law raising caps, creating task force ▪ Longer-term program design to meet governor's goal of 1600 MW by 2020 ▪ NEM for small hydro
MI	Bills on NEM, community solar ▪ Rate design & community solar dockets ▪ Rate case w/higher fixed charges
MN	Utility solar garden program ▪ Rulemaking on NEM changes ▪ Possible proceeding on standby rates
MS	PUC weighs next steps, e.g., VOS structure, following study of NEM economic impact
MT	Review of rooftop solar subsidy via Universal System Benefits charge ▪ NEM legislation
MO	Debate on rooftop solar incentives/VOS ▪ Rate cases w/higher fixed charges ▪ State energy strategy
NV	PUC weighs separate rate class for DG ▪ Legislature considers PUC report on NEM costs/benefits
NH	Implementation of group NEM ▪ New state energy strategy w/DG provides legislative fodder
NJ	Rulemaking on aggregated NEM ▪ Updates of renewables rules w/NEM ▪ Legislation on NEM caps, RES
NM	Community renewables development ▪ Utility rate case w/rate design proposals
NY	Governor-PSC 'Reforming the Energy Vision' initiative-regulatory/ratemaking reform ▪ Rate cases w/higher fixed charges, community solar ▪ Other utility dockets w/DG, NEM issues ▪ NEM legislation
NC	Value of DG - PURPA avoided cost proceeding ▪ Possible proceeding on NEM changes ▪ Recurring legislative efforts on shared renewables, 3rd party solar financing
OH	NEM rule changes ▪ Impact of RES freeze law ▪ PUC seeks SFV rate design proposals
OK	Implementation of law addressing NEM cost shift; utility proposals in 2015
OR	PUC to consider resource VOS, NEM cost shift ▪ Legislature weighs PUC report on solar incentives
PA	PUC NOPR on NEM rule changes ▪ Rate cases w/higher fixed charges
RI	Implementation of law replacing contract DG w/tariff-based program, eliminating NEM caps
SC	Implementation of law creating statewide DER program including new NEM methodology, VOS
SD	Recurring legislation to institute NEM ▪ Potential legislation on fixed cost recovery
TN	Advocacy for expanded TVA green power program; TVA considers VOS study
TX	No statewide NEM but recurring efforts to institute to promote solar role in competitive market & as aid for compliance w/EPA carbon limits ▪ Austin VOS tariff studied as model
UT	Implementation of law requiring NEM cost/benefit study, authorizing special charges
VT	Redesign of NEM program under new law ▪ Persistent solar growth challenges new NEM caps
VA	Legislative consideration of administration NEM cost/benefit study, updated energy strategy w/DG
WA	UTC investigates DG, seeks to regulate 3rd party providers ▪ Governor exec. order on carbon/clean energy; seeks more rooftop solar ▪ Compromise legislation on 3rd party leasing
WI	Debate on 3rd party solar financing, community solar ▪ Possible legal challenge of utility rate case outcome including higher fixed charges
WV	Utility rate case including higher fixed charges ▪ Debate on RES repeal

State Activity on DG & Residential Fixed Charges

December 15, 2014

Special Charges to DG Customers

- Approved special charges for DG customers: **AL, AZ, CO, VA, WI**
- Special charges for DG customers under consideration: **HI, NM**
- Separate DG rate class under consideration: **CO, NV**

State	Company	Docket/Date	Type of Charge	Summary	Status
AL	AL Power	Case: U-4226 Decided: 1/10/13	Capacity reservation charge	$5/kW /mo.	APPROVED
AZ	APS	Case: E-01345A-13-0248 Decided: 12/3/13	Interim lost fixed cost recovery DG adjustment	$0.70/kW/mo.	APPROVED
CO	BHE	Case: 12AL-1052E Decided: 6/28/13	Customer charge for NEM customers w/solar	$5/mo. (plus $16.50 customer charge to all customers for total $21.50)	APPROVED
CO	Generic	Case: 14M-0235E Case opened: 3/18/14	Separate rate class for DG customers	PUC asked for legal briefs as part of investigation of DG issues; trial staff said PUC has authority to create separate rate class & impose higher fixed charges on DG customers	Pending
HI	HECO	Case: 2014-0192 Filed: 8/26/14	Fixed charge for standby generation & capacity requirements	$16/mo. (total $71 for DG customers incl. proposed $55/mo. minimum charge for all customers)	Proposed
NM	PNM	Case: 14-00332-UT Filed: 12/11/14 Decision expected by 3/15/16	DG interconnection fee	$6/kW/mo. (residential) for new customers as of 12/31/15; varies by rate class	Proposed
NV	Generic	Case: 13-07010 (orig. 14-03026) Filed: 4/3/14	Separate rate class for DG customers	Petition for investigation by AG Bureau of Consumer Protection	Pending
VA	Dominion	Case: PUE-2011-00088 Decided: 11/23/11	Standby charge for residential > 10 kW up to 20 kW of installed capacity	$4.19/kW = $2.79 for distribution & $1.40 for transmission	APPROVED
VA	APCo	Case: PUE-2014-00026 Decided: 11/26/14	Standby charge for residential > 10 kW up to 20 kW of installed capacity	$3.77/kW = $1.94 for distribution & $1.83 for transmission Note: Final numbers pending compliance filing incorporating approved modification of transmission component	APPROVED
WI	We Energies	Case: 05-UR-107 Decided: 11/14/14	Demand charge for DG customers w/< 300 kW of installed capacity to recover gen & dist standby costs; applies to customers on new COGS-NM & COGS-NP tariffs*	$3.79/KW/mo. for COGS-NM & COGS-NP customers using intermittent technology, e.g., solar & wind	APPROVED**

*COGS-NM = customer owned generation service-net metering; COGS-NP = customer owned generation service-non-purchase.

**The results are preliminary pending issuance of a final written order.

Fixed Charges to All Residential Customers

- Approved increase in customer charges: **FL, MS, NJ, NV, WA, WI**
- Customer charge increases under consideration: **CA, CT, HI, KY, MI, MN, MO, NM, NY, OK, PA, SD, VA, WA, WV**
- Residential demand charge under consideration or development: **CT, ME**
- Straight fixed variable rate design acted on but unresolved: **IL, OH**

State	Company	Docket/Date	Type of Charge	Summary	Status
CA	PG&E, SCE, SDG&E	Case: R12-06-013 Filed: 2/28/14 Decision expected in March 2015	Customer charge (called fixed charge by SCE, monthly service fee by PG&E and SDG&E)	Gradual increases thru 2018 for non-low income: PG&E: From zero to $10.42/mo. SCE: From $0.94 to $10/mo. SDG&E: From zero to $10/mo.	Proposed
CT	CL&P	Case: 14-05-06 Filed: 6/6/14 Decision expected by 12/17/14	Customer charge	Increase from $16 to $25.50/mo.	Proposed
FL	FPU	Case: 140025-EI Decided: 9/29/14	Customer charge (called customer facilities charge)	Increased from $12 to $14/mo. per settlement	APPROVED
HI	HECO	Case: 2014-0192 Filed: 8/26/14	Customer charge	New-$55/mo.	Proposed
IL	ComEd	Case: 13-0387 Decided: 12/18/13	Modified straight fixed variable (SFV) rate design	ICC reversed its 2011 approval of modified SFV and adopted rate design for 2 residential classes (single family homes w/ & w/o electric space heat) that increases fixed customer charge & decreases volumetric charge	Appealed by REACT to IL Appellate Court, 2nd District, Case 2-14-0202 (REACT = Coalition to Request Equitable Allocation of Costs Together)
KY	KU	Case: 2014-00371 Filed: 11/26/14 Decision expected by 6/26/15	Customer charge (called basic service charge)	Increase from $10.75 to $18/mo.	Proposed
KY	LG&E	Case: 2014-00372 Filed: 11/26/14 Decision expected by 6/26/15	Customer charge (called basic service charge)	Increase from $10.75 to $18/mo.	Proposed
ME	CMP	Case: 2013-00168 Decided: 8/25/14	Demand charge	PUC directed CMP to develop optional residential demand charge; proposal not yet filed	APPROVED (development of option, not actual proposal)
MI	CE	Case: U-17735 Filed: 12/5/14	Customer charge (called system access charge)	Increase from $7 to $7.50/mo.	Proposed
MI	WPS	Case: U-17669 Filed: 10/17/14	Customer charge	Increase from $9 to $12/mo.	Proposed
MN	Xcel	Case: 13-868 Filed: 11/4/13 Decision expected by 3/26/15	Customer charge	Increase from $8 to $9.25/mo. (overhead) Increase from $10 to $11.25/mo. (underground)	Proposed
MO	EDE	Case: ER-2014-0351 Filed: 8/29/14	Customer charge	Increase from $12.52 to $18.75/mo.	Proposed

		Decision expected by 7/26/15			
MO	KCP&L	Case: ER-2014-0370 Filed: 10/30/14 Decision expected by 8/31/15	Customer charge	Increase from $9 to $25/mo.	Proposed
MO	Ameren	Case: ER-2014-0258 Filed: 7/3/14 Decision expected by 5/30/15	Customer charge	Increase from $8 to $8.77/mo.	Proposed
MS	Entergy	Case: 2014-UN-132 Decided: 12/11/14; written order pending	Customer charge	Increased from $4.57 to $6.75/mo.	APPROVED**
NJ	ACE	Case: ER1403025 Decided: 8/20/14	Customer charge	Increased from $3 to $4/mo. per settlement	APPROVED
NM	PNM	Case: 14-00332-UT Filed: 12/11/14 Decision expected by 3/15/16	Customer charge	Increase from $5 to $12.80/mo.	Proposed
NV	NV Power	Case: 14-05004 Decided: 10/15/14	Customer charge (called basic service charge)	Increased from $10 to $12.75/mo.	APPROVED
NY	CHG&E	Case: 14-E-0318 Filed: 7/25/14 Decision expected by 6/30/15	Customer charge	Increase from $24 to $30/mo.	Proposed
NY	ORU	Case: 14-E-0493 Filed: 11/14/14	Customer charge	Increase from $20 to $25/mo.	Proposed
OH	Generic	Case: 12-2050-EL-ORD Decided: 8/21/13	Straight fixed variable rate design	The PUC found SFV may best accomplish energy efficiency, DG, other policy goals & encouraged utilities to file SFV proposal in next rate case; if utilities do not file, staff is directed to do so.	APPROVED (PUC request for utility proposals, not actual rate designs)
OK	PSO	Case: PUD 201300217 Filed: 1/17/14 Decision expected by 12/31/14	Customer charge (called base service charge)	Increase from $16.16 to $20/mo.	Proposed
PA	West Penn	Case: R-2014-2428742 Filed: 8/4/14 Decision expected by 4/30/15	Customer charge	Increase from $5 to $7.35/mo.	Proposed
PA	Penelec	Case: R-2014-2428743 Filed: 8/4/14 Decision expected by 4/30/15	Customer charge	Increase from $7.98 to $11.92/mo.	Proposed
PA	Penn Power	Case: R-2014-2428744 Filed: 8/4/14 Decision expected by 4/30/15	Customer charge	Increase from $8.89 to $12.71/mo.	Proposed
PA	MetEd	Case: R-2014-2428745	Customer charge	Increase from $8.11 to $13.29/mo.	Proposed

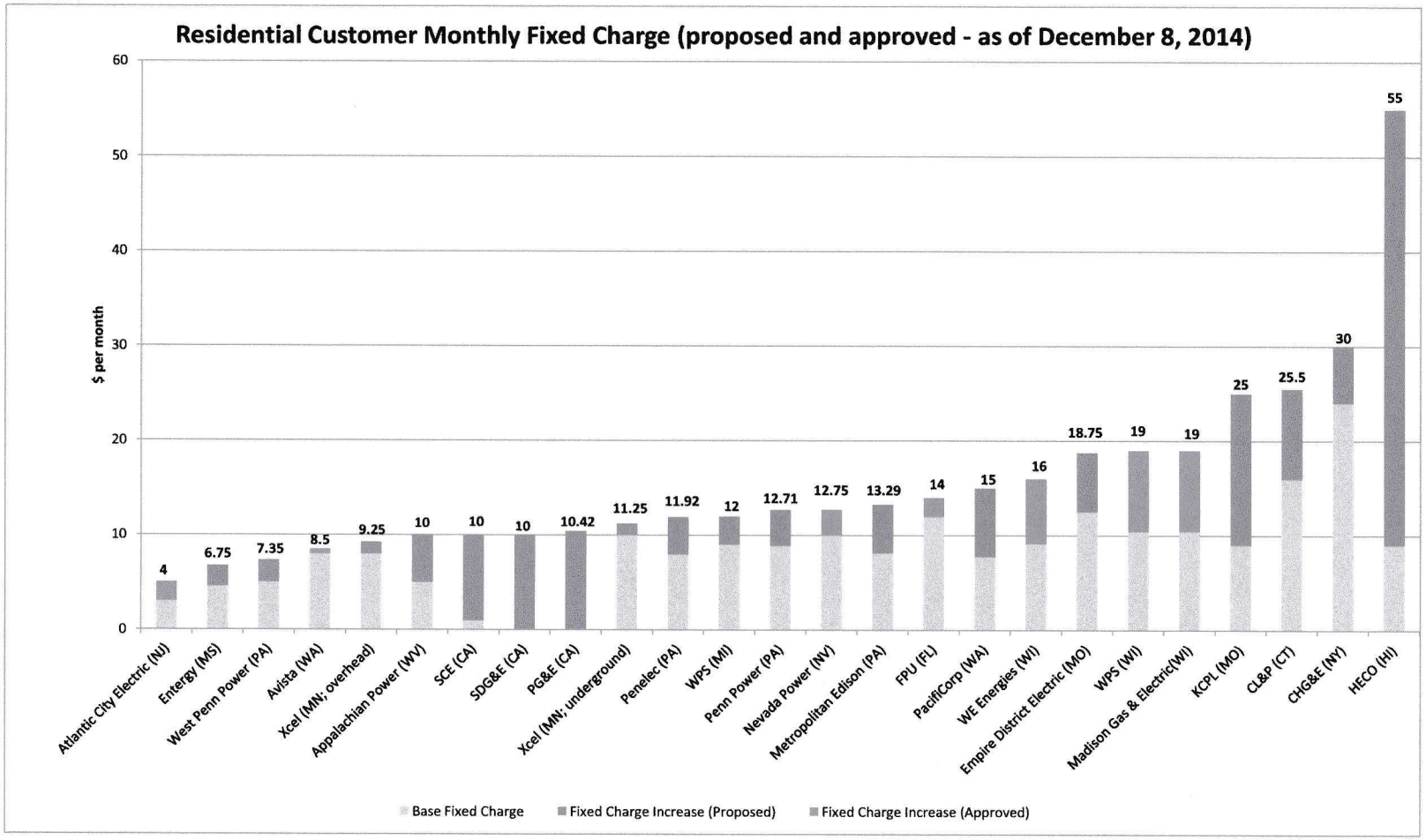
		Filed: 8/4/14 Decision expected by 4/30/15			
SD	Xcel	Case: EL14-058 Decision expected by 1/1/15	Customer charge	Increase from $8.25 to $9.25 (overhead); from $10.25 to $11.25 (underground)	Proposed
VA	APCo	Case: PUE-2014-00026 Decided: 11/26/14	Customer charge	~~Increase from $8.35 to $16/mo.~~	INCREASE REJECTED
WA	Avista	Case: UE-140188 Decided: 11/25/14	Customer charge (called basic charge)	Increased from $8 to $8.50/mo. per settlement	APPROVED
WA	PacifiCorp	Case: UE-140762 Filed: 5/1/14 Decision expected by 3/31/15	Customer charge	Increase from $7.75 to $14/mo.	Proposed
WI	MG&E	Case: 3270-UR-120 Decided: 11/26/14	Customer charge & grid connection charge	Increased customer charge from $10.44 to $14.97/mo. + $4.03/mo. grid connection charge = total $19/mo.	APPROVED**
WI	We Energies	Case: 05-UR-107 Decided: 11/14/14	Customer charge (called facilities charge)	Increased from $9.13 to $16/mo.	APPROVED**
WI	WPS	Case: 6690-UR-123 Decided: 11/6/14	Customer charge	Increased from $10.40 to $19/mo.	APPROVED**
WV	APCo	Case: 14-1152-E-42T Filed: 6/30/14 Decision expected by 4/26/15	Customer charge (called basic service charge)	Increase from $5 to $10/mo.	Proposed

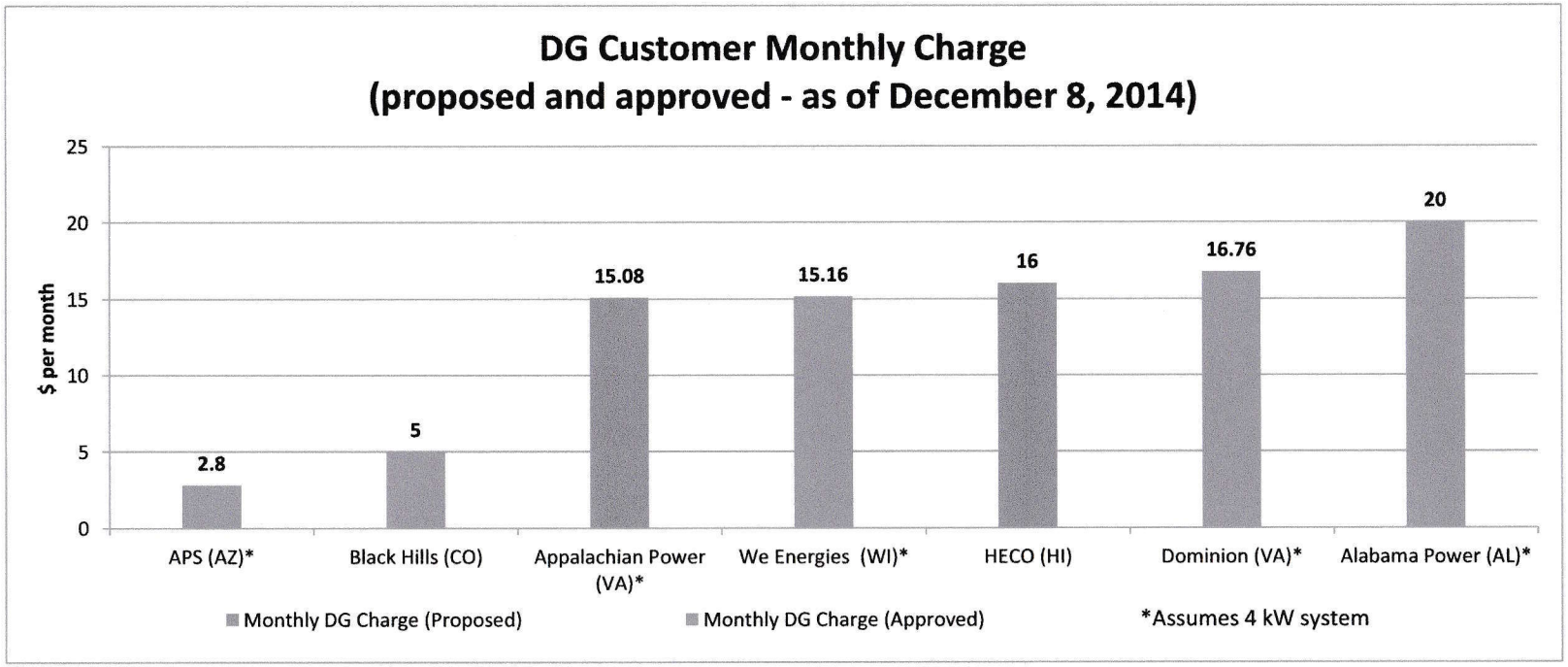
**The results are preliminary pending issuance of a final written order.

Legislation

State	Docket No.	Summary	Status
AR	HB 2019	Authorizes PSC to allow utilities to assess DG customers a greater fee or charge	Enacted 2013; a proposal has not been filed at the PSC
CA	AB 327	Provides for residential rate reform including customer charges up to $10/mo.	Enacted 2013; CPUC has generic proceeding underway
KS	HB 2101	Utilities may propose a minimum bill, TOU rate, or other rate structure for DG customers	Enacted 2014; a proposal has not been filed with the KCC
OK	SB 1456	Authorizes utility recovery of full costs of serving DG customers & imposition of higher fixed costs; prohibits subsidy of DG customers by non-DG customers,	Enacted 2014; the OCC has begun discussing how to implement
SC	SB 1189	Establishes statewide DER program; allows utility investment & DG cost recovery related to serving DG customers	Enacted; the PSC has opened a generic docket
UT	SB 208	Requires the PSC to study NEM costs & benefits & authorizes it to determine a charge, credit or ratemaking structure in light of study results	Enacted 2014; the PUC has opened a generic docket
VA	HB 1983	Provides that residential customers with capacity greater than 10 kW and up to 20 kW must pay a monthly standby charge	Enacted 2011; the SCC approved a standby charge for Dominion & is considering one for APCo

EEI Contact: Martha Rowley, mrowley@eei.org, 202-508-5251


Residential Customer Monthly Fixed Charge (proposed and approved - as of December 8, 2014)
$ per month
60
50
40
30
20
10
0
4
6.75
7.35
8.5
9.25
10
10
10
10.42
11.25
11.92
12
12.71
12.75
13.29
14
15
16
18.75
19
19
25
25.5
30
55
Atlantic City Electric (NJ)
Entergy (MS)
West Penn Power (PA)
Avista (WA)
Xcel (MN; overhead)
Appalachian Power (WV)
SCE (CA)
SDG&E (CA)
PG&E (CA)
Xcel (MN; underground)
Penelec (PA)
WPS (MI)
Penn Power (PA)
Nevada Power (NV)
Metropolitan Edison (PA)
FPU (FL)
PacifiCorp (WA)
WE Energies (WI)
Empire District Electric (MO)
WPS (WI)
Madison Gas & Electric(WI)
KCPL (MO)
CL&P (CT)
CHG&E (NY)
HECO (HI)
Base Fixed Charge
Fixed Charge Increase (Proposed)
Fixed Charge Increase (Approved)


DG Customer Monthly Charge
(proposed and approved - as of December 8, 2014)
$ per month
25
20
15
10
5
0
2.8
5
15.08
15.16
16
16.76
20
APS (AZ)*
Black Hills (CO)
Appalachian Power (VA)*
We Energies (WI)*
HECO (HI)
Dominion (VA)*
Alabama Power (AL)*
Monthly DG Charge (Proposed)
Monthly DG Charge (Approved)
*Assumes 4 kW system

Key News Clips

Key News Clips 2014

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May 11, 2014

The New York Times [LTE]
Ashley Brown
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The Wall Street Journal: No Solar Subsidies for the Well-Off [LTE]
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Journal Sentinel: Learn from German mistakes [Op-Ed]
Eric Bott
December 11, 2014

http://m.jsonline.com/opinion/wisconsin-should-learn-from-germanys-energy-mistakes-b99406312z1-285435051.html

It was surprising that the German experience was recently held up as an example of successful energy policy-making ("On energy, Germany is ahead of Wisconsin," Crossroads, Nov. 23). Germany's energy transformation or energiewende calls for a nuclear-free and carbon-reduced economy through the vast deployment of renewable technologies, but its results thus far have been higher prices, greater carbon intensity and a less reliable electric delivery network.

While that column pointed to Germany as a potential model, Wisconsin Manufacturers & Commerce views Germany as providing valuable lessons on missteps that the state of Wisconsin should avoid. Indeed, policy-makers in Germany now are reversing course on the large cost of renewable subsidies and the impact of those subsidies on residential and industrial electric rates and carbon dioxide emissions.

German consumers already pay the highest electricity prices in Europe and about double what most Americans pay. On average, German households pay an extra $355 a year just to subsidize renewables.

Costs also are going up for German employers, making them less competitive than rivals from America. Average electricity prices for German businesses and manufacturers have jumped 60% over the past five years because of costs passed along as part of government subsidies of renewable energy developments.

Germany's transformational energy policies have put the country's future economic competitiveness at risk. GDP growth shrank in the second quarter and industrial output and exports are plunging. The biggest concern is that German industry, the mainstay of its economy, is becoming less competitive. According to a recent survey by PricewaterhouseCoopers and the Federation of German Industry, nearly 75% of Germany's small- and medium-sized industrial businesses are most concerned with risks associated with rising energy costs.

Moreover, Germany is highly dependent on the success of its manufacturing sector, and high energy costs are leading to industrial investment losses, as German companies are being forced to invest abroad to stay competitive.

Renewable energy subsidies also are having a regressive effect on wealth distribution as poor and middle-class families pay higher rates to subsidize solar panels for the more affluent. Should Wisconsin go down this same path, forcing someone living in a small rental apartment, for instance, to subsidize a wealthy homeowner's roof-mounted solar panels through that renter's electricity bill? Simple fairness dictates no.

In addition to increasing energy costs for families and businesses and contributing to the loss of domestic investment, energiewende has recently had the perverse effect of increasing carbon dioxide emissions in Germany. The combination of a nuclear phase-out, dependence on high-priced Russian natural gas and the tremendous inefficiencies of renewables have combined to force Germany to burn more lignite and hard coal, which boosts greenhouse gas emissions.

Germany is a classic example of the severe consequences of adding extensive amounts of distributed generation without an integrated approach. Policy-makers are increasingly realizing that they must reform the energiewende to maintain the vitality of the German economy. The lessons learned in Europe prove that the large-scale integration of renewable power will result in increased costs to consumers and other stakeholders, and may not actually achieve well-intended environmental goals.

Wisconsin should heed the lessons learned in Germany and not repeat the same mistakes.

Eric Bott is environmental policy director of Wisconsin Manufacturers & Commerce, the state's largest business group.

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Forbes: Net Energy Metering -- Are We Capitalists Or What
Jim Conca
November 28, 2014

http://www.forbes.com/sites/jamesconca/2014/11/28/net-energy-metering-are-we-capitalists-or-what/

The public thinks that electricity is all about what generates it. Coal, natural gas, nuclear, hydro, wind, solar or biomass, heated discussions have focused on costs, carbon and reliability.

Few know or care about the grid that delivers the electricity. It's as important. But net metering just doesn't sound like a hot issue. Nevertheless, it could become a major problem in the future if we don't get it right.

Net metering, or net energy metering (NEM), is a billing system that credits small customers at the full retail electric price for any excess electricity they generate and sell to their local electric company via the grid from on-site small sources such as residential rooftop solar arrays.

Currently in place in 43 states and the District of Columbia, net metering is becoming another unnecessarily controversial issue.

This graph shows the typical energy production and consumption for a small source owner, or distributed generation (DG) customer with a rooftop PV solar array. When the customer produces more power than is being consumed, during peak sunlight hours, they can sell it back to the utility company at the full retail price. This is called net energy metering (NEM) or net metering. In 43 States and the District of Columbia, the utilities are forced to pay the full retail price even though it usually costs those utilities much less to produce that electricity themselves, or even to buy it on the wholesale market, and the utilities pay over half of that price in infrastructure support. These small users are still connected to the grid, a requirement for net metering, and also to power their homes at night or when their solar systems don't produce enough power. Source: Edison Foundation Institute for Electric Innovation.

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Rooftop solar owners say net metering is necessary to encourage solar installations and help reduce fossil fuel use. Utilities say it gives rooftop owners a free pass on paying their fair share of maintaining the electric grid like everyone else does.

These small generation sources are referred to as distributed generation (DG) and someone owning or leasing a rooftop solar array is a DG customer. Rooftop solar is the major small distributed energy source (>95%). Wind and other renewables like biomass are very small contributors.

Under most net metering policies, utilities are required to buy a DG customer's excess power at full retail price even though it costs those utilities much less to produce that electricity themselves, or buy it on the wholesale market.

The point of these policies is to encourage the adoption of distributed solar on residential and business rooftops, parking garages and other buildings, to take advantage of existing surfaces, to

generate the energy right where it's needed, and to reduce the total electric load during peak hours of the day. Along with increased efficiency and conservation, distributed generation can reduce the need to build new large power plants even as the population grows.

Small DG users are still connected to the grid, which is necessary to have net metering, and also to power their homes at night or when their solar arrays don't produce enough power (see figure).

This is not an academic matter. When – not if – DG customers expand to a significant number, say 5% or 10% of total capacity in the next ten years, the utilities will lose significant power sales. But the utilities are still required to maintain the electric grid from which everyone, including DG customers, must obtain their electricity. So the burden of maintaining the grid, and providing these services, falls on fewer and fewer non-DG customers, and their cost grows.

Isn't the obvious solution to adjust this practice so it's equitable to everyone?

Grid-connected solar PV systems effectively use the grid as a big battery, absorbing excess power without having to purchase actual batteries or back-up generation. At the same time, it is essential to appreciate the value of distributed solar to the grid itself, by reducing peak demand, lowering fuel costs and reducing the demand for fossil fuel generation.

This is all part of the global electricity revolution. According to Charlie Ebinger, Director of the Energy Security Initiative at the Brookings Institution, "distributed generation represents the most recent trend in a decades-old evolution of a changing electric power industry."

We do have a few years to hammer out a real solution. Distributed solar only makes up 0.2% of the U.S. electricity supply. Even in states that have pushed it hard with solar-friendly policies, it's still less the 2%. This gives us a bit of time to work out the best system to employ it before adverse economic and infrastructure effects are felt on the electric grid.

The adverse effects are becoming visible, however. A report issued last yearby the California Public Utilities Commission found that non-solar customers in the state face over $1 billion annually in higher costs because of net metering. In a state with a GDP of over a trillion dollars, that may not seem like a lot, and the pain is quite distributed over the other 30 million people.

While I dislike unfettered Capitalism, we do generally have to pay for what we use. This is America. If something doesn't make money, no one will do it. And if someone starts losing money, they generally stop doing it.

If homeowners don't make money on rooftop arrays, they won't install them. If the utilities don't make money on grid services, they will stop providing them.

As Lisa Wood of the Edison Foundation puts it, "[We need] to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using them." When normal consumers pay their electric bill, part of the bill is for the electricity they actually used, but the other part goes to maintaining the grid, referred to as grid services.

Consider an average residential monthly electricity bill (EIA) of $110 paid for 1,000 kWhs (11¢/kWhr). That $110 provides:

- $10 for transmission systems

- $30 for distribution services

- $19 for generation capacity

- $1 for ancillary/balancing services, and

- $50 for the generation of the electricity.

So $60 of this $110, more than half, goes to support these grid activities while only $50 goes to producing the electricity in the first place. Since small source owners, or DG customers, are not ever "off the grid", even if they're making more energy than they consume, a 55% gratuity is not a trivial gift given to them by net metering.

Unfortunately, net metering shifts these grid costs from the generally high-income homeowners, that can afford rooftop solar, to non-DG-customers through higher electricity bills. These are often low-income families that can least afford an increase in their monthly bill.

Utilities are not anti-solar. The utilities are the ones that have to maintain and use the grid. In fact, utilities are leading the way in our transition to a cleaner energy economy through the grid itself (Xcel Energy, Tucson Electric Power, Consolidated Edison, Duke Energy).

Using the grid smartly allows more renewable energy, more load following, more demand response, more efficiency and conservation, and provides greater grid stability. None of this could happen without the grid and it provides a good deal of benefit to solar owners as well.

In the end, we need to adopt a billing practice that supports both installation and distribution. As geologist and energy consultant Dr. Judith Wright says, "We need a real shift in our energy meme. Perhaps grandfathering in older DG customers at full retail price since they broke this ground, and giving later customers a more equitable wholesale value. Or maybe the DG customer receives the full retail price until the capital investment is paid off. We cannot thrive without a healthy grid. And we should not support income inequality."

Charlie Ebinger is hopeful. "There have been several notable attempts to fine tune or alter existing policy to address these [net metering] issues. For example, Austin Energy and the State of Minnesota have developed a value of solar tariff as a mechanism to better incorporate all the costs and benefits of solar rooftop PV."

This Thanksgiving, I'm thankful there's still time to evolve a robust energy system that rewards reliability and distribution, self-reliance and environmental sustainability.

And that saves the grid!

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CNBC.com: Solar firms, power companies battle over 'net metering'
Javier David
October 12, 2014

http://www.cnbc.com/id/102075665#.

As solar power expands its reach into greater residential use, can solar companies and utilities find common ground?

The flashpoint is over net-metering—a process where consumers use renewable energy to generate their own electricity, then cut their bills by sending excess power back to the grid at retail rates.
The system, which saves consumers money on utility bills, is gaining popularity yet remains the subject of fierce debate. At least 43 states have laws making it easy for residents to save via the sun; still, utilities are pushing back against solar's rapid encroachment on the retail market.

The U.S. is consuming more electricity than ever, costing consumers a pretty penny and encouraging them to turn to solar energy, which can save them money. The Energy Information Administration notes that retail electricity is up nearly 3 percent per kilowatt hour in 2014 versus a year ago, with costs rising for 20 consecutive months. This, despite the United States being in the midst of a massive domestic energy boom.

Power companies acknowledge that rooftop panels are forcing them to modernize the grid and rethink their business models. Additionally, residential units can help reduce strains on power systems during peak times and seasons.

"The good news from the net metering perspective is it reduces net demand" on utility companies, said Dan Bedell, senior director of their Principal Solar Institute. "But the downside is that not only are you taking away their revenue, they also have to pay for the excess power at a retail rate."

The rise of solar means utilities "have to price [their] products differently," said David Owens, executive vice president of business operations and regulatory policy at Edison Electric Institute, the association of publicly-traded electric companies.

"Rooftop solar panels are recognition that technology, public policy and customer preferences are requiring the utilities to look at this differently," Owens said in an interview.

However, he argued that net-metering was creating a classic "free-rider" economic conundrum, where non-rooftop clients are ultimately paying more for electricity than net-metering clients. Certain costs, such as infrastructure and grid usage, are not being captured in what net-metering customers are charged, Owens said.

For that reason, he thinks power companies—as well as other parties—are justified in challenging some of the presumptions behind solar panel use.

Consumers "want choice, but we want to make sure customers at the upper-income bracket are not being subsidized by non-rooftop customers," Owens said. "Utilities are not afraid of competition, but if you're using the grid, you need to pay for it."

Lynn Jurich, CEO of residential solar company Sunrun, said in a recent interview that solar power accounted for at least 50 percent of new electric capacity, helped in large part by a 10 percent year-over-year drop in solar costs.

The breakneck penetration of solar power is making utilities nervous while draining their coffers, Jurich said. She rejected the idea that net metering acted as some sort of wealth transfer.

"Utilities say solar is OK as long as they are the only ones building it," Jurich said.

"We welcome utilities competing in open and competitive solar markets, [but] we are opposed to utilities getting guaranteed profits from ratepayers for installing rooftop solar," she added.

To be certain, utilities are waging a ground war in multiple states to get governments to reconsider subsidies and pass more costs on to net-metering clients.

However, observers say developments are likely to ramp up in solar's favor. In consumption-heavy places like Texas—the 2nd largest energy consuming state and one of the biggest markets for renewable energy—soaring demand and shuttered carbon-based plants all but guarantee solar will partly fill the void.

"What you're going to see across next 2-10 years is a big increase in solar, but not a big decrease in base load generation," said Principal Solar's Bedell. "Fossil fuel will continue to carry the torch until [solar] batteries become really big and really cheap."

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The Wall Street Journal: Germany's Coal Binge [Editorial]
Green energy mandates have achieved the opposite of their intent.
September 25, 2014

http://online.wsj.com/articles/germanys-coal-binge-1411599265

Berlin's "energy revolution" is going great—if you own a coal mine. The German shift to renewable power sources that started in 2000 has brought the green share of German electricity up to around 25%. But the rest of the energy mix has become more heavily concentrated on coal, which now accounts for some 45% of power generation and growing. Embarrassingly for such an eco-conscious country, Germany is on track to miss its carbon emissions reduction goal by 2020.

Greens profess horror at this result, but no one who knows anything about economics will be surprised. It's the result of ChancellorAngela Merkel's Energiewende, or energy revolution, a

drive to thwart market forces and especially price signals, that might otherwise allocate energy resources. Now the market is striking back.

Take the so-called feed-in tariff, which requires distributors to buy electricity from green generators at fixed prices before buying power from other sources. Greens tout the measure because it has encouraged renewable generation to the point that Germany now sometimes experiences electricity gluts if the weather is particularly sunny or windy.

Yet by diverting demand to renewables, the tariff deprives traditional generators of revenue and makes it harder for them to forecast demand for thermal power plants that require millions of euros of investment and years to build. No wonder utilities favor cheaper coal plants to pick up the slack whenever renewables don't deliver as promised.

Mrs. Merkel's accelerated phase-out of nuclear power after the 2011 Fukushima disaster in Japan has had a similar effect. Shutting profitable nuclear plants deprives utilities of revenue and saddles them with steep decommissioning costs, which makes cheaper coal more appealing.

To top it off, Berlin has imposed a moratorium on fracking. By preventing exploitation of ample shale-gas reserves, the ban leaves Germany more exposed to strategic pressure from gas exporters (read: Russia) and raises the cost of gas relative to coal. This is another reason cheap, local coal is back in favor.

Ordinary Germans foot the bill for these market distortions, having ponied up an estimated €100 billion ($129 billion) extra on their electricity bills since 2000 to fund the renewable drive. The government estimates this revolution could cost a total of €1 trillion by 2040.

Berlin is scaling back some taxpayer subsidies for green power. But Germans still also pay for the energy revolution when job-creating investment goes to countries with lower power costs, as happened earlier this year when chemical company BASF said it would cut its investments in Germany to one-quarter of its global total from one-third, and when bad incentives skew generation toward dirtier coal instead of cleaner natural gas.

None of this is what environmentalists promise voters when they plug the virtues of a low-carbon future. Germany's coal renaissance is a cautionary tale in what happens when you try to substitute green dreams for economic realities.

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FoxNews.com: The sunshine of other people's money: The truth about 'net metering' [Op-Ed]
Benjamin Zycher
September 24, 2014

http://www.foxnews.com/opinion/2014/09/24/sunshine-other-peoples-money-truth-about-net-metering/

Politics is the art of wealth redistribution, an eternal truth illustrated well by the various machinations employed by bureaucrats and politicians to force goods and services uncompetitive but favored politically upon the market, despite adverse economic pressures.

One central recipient of this largesse is expensive electricity---wind and solar power in particular---the costs of which are far higher than those of such conventional electricity sources as coal and natural gas.

This political interference results in a large array of policies used by government to support energy technologies that cannot survive market competition. A prominent example is "net metering," an important system of shifting the costs of photovoltaic solar systems onto the consumers of electricity generally, with deeply adverse implications for costs and for the future reliability of the electric grid.

Over the long run---not necessarily a long period of time---the higher costs and prices mean that investment in maintenance and new generating capital will fall, and with it reliability and the economic benefits of inexpensive power.
How does net metering work?

Power consumers who install solar panels--again, large subsidies are paid for such installations---receive a credit for the power that they produce but do not consume. The excess electricity is transferred into the power grid for use by other consumers, and the owners of the solar systems receive a credit for the excess power, paying only for their "net" electricity consumption.

So: What problems are created by net metering? First, in most jurisdictions, the credit paid for the excess solar power is far higher than the cost of alternative electricity sources, usually from utilities or from the spot power market.

Consumers without such solar installations have to finance that credit, that is, the excessively expensive electricity, so that overall power prices are forced above the level that would prevail in the absence of the net metering system.

This problem is exacerbated by the tax and other incentives to install solar systems: The combination of the installation subsidies and the excessive prices paid for the power fed into the grid means that more solar capacity is installed than otherwise would be the case, more expensive power is fed into the grid, and prices are forced up, in principle in a sort of upward spiral process.

There is the further matter that reliability is a hugely valuable attribute of power systems; no one likes blackouts. Electricity bills reflect the cost of that reliability in the form of "capacity" charges, that is, the part of the bill covering the cost of the physical system and its spare capacity, before fuel expenses and other such generation costs.

People who install solar systems benefit from the reliability provided by the grid---they consume conventional power at night and at other times that the sun fails to shine---but because they pay only for their "net" power consumption, they get a free ride on the cost of the generation

equipment and other capital that yield the reliability upon which they depend. Except the free ride is not free: Other consumers have to pay for it.

Over the long run--not necessarily a long period of time--the higher costs and prices mean that investment in maintenance and new generating capital will fall, and with it reliability and the economic benefits of inexpensive power. Only costs will rise, not a salutary outcome.

Net metering receives strong political support in substantial part because it is useful politically. All subsidies--direct, indirect, explicit, or hidden--must be financed by someone, be it taxpayers, ratepayers, or the beneficiaries of other government programs.

Political incentives to hide the costs of such policies are powerful--it is better for bureaucrats and politicians that the losers not know that they are losing--and net metering serves that end beautifully.

A recent study of net metering in California found that the median income of households installing such systems is $91,210, while the comparable figure for all households in the relevant geographic areas is $67,821, a difference of over a third. Some part of the subsidies must be captured by the producers of the solar systems, whether in the U.S. or overseas, but it is difficult to avoid the conclusion that net metering forces those with relatively lower incomes to subsidize those with incomes relatively higher.

Is a regressive wealth transfer an appropriate outcome for public policy?

As with most other goods and services, those consuming them should pay the attendant costs. Hiding those costs and shifting them onto others is deeply perverse, and corrosive of the competitive resource productivity---in this context, lower costs and greater system reliability---that yields higher living standards for all.

Benjamin Zycher is the John G. Searle scholar at the American Enterprise Institute.

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TIME: Wall Street Goes Green
Michael Grunwald
August 28, 2014

http://time.com/3204258/wall-street-goes-green/

Why is solar booming? Finance

I've often heard the wind and solar industries mocked as "hippie energy" or "Obama power." Mitt Romney once dissed them as "imaginary." But at this summer's Renewable Energy Finance Forum (REFF) Wall Street, clean-tech venture capitalist Christian Zabbal offered a new jibe: "bulge brackets." Zabbal complained that the wind and solar space has become so safe–and so overcrowded with giants like Bank of America, Citigroup and Goldman Sachs–that it's no longer

attractive to cutting-edge investors. The cool kids don't want to play in bulge brackets. They prefer wide-open spaces that the big guys won't touch.

"We're getting out of solar," said Zabbal, managing director of Black Coral Capital. "It's gotten too mainstream."

In other words, the clean-power revolution is for real. The bulge brackets are bulging because wind and solar have gotten much cheaper, less novel and more predictable. Renewable projects are producing steady returns, so vast pools of risk-averse institutional capital are seeking new ones. Green electricity is no longer avant-garde; it has produced more than half of new U.S. generating capacity this year. Wind has tripled since 2008, while solar is up 1,200%. This is terrific news–for homeowners who reduce their electric bills by going solar, ratepayers whose utilities save them money by buying wind power, and the planet.

But there's a deeper message in the bulge brackets. People assume the future of clean energy depends on gee-whiz technological innovations: better solar panels and wind turbines, cheaper batteries and biofuels. And we will need those advances in the long term to cut carbon emissions 80% by 2050. But the biggest advances in the near term are likely to be boring financial innovations. The direct costs of deploying renewables are dropping fast, but the capital costs are still too high. The future builders who bring clean power to scale probably won't be scientists but financial wizards like the suits at REFF Wall Street.

This is already happening in the solar industry, where gradual improvements in photovoltaic panels–by the ill-fated manufacturer Solyndra, among others–have not been the key to making them cost-competitive. The innovation that launched the sunshine revolution was the solar lease, which has helped homeowners and businesses install rooftop systems without having to plunk down tens of thousands of dollars up front. Now they can sign 20-year contracts with no money down to lease panels from installers like SolarCity or Sunrun, then make payments out of the savings on their electric bills.

Now we're moving into the next phase of the renewable revolution. Those 20-year leases look a lot like mortgages, auto loans or other financial instruments that Wall Street routinely packages into securities. The financial crisis made securitization a dirty word, but it's a powerful tool that can convert a dribble of investment into a cascade and slash capital costs. And Wall Street has begun to package solar contracts into securities. The market for commercial solar securities has grown from less than $1 billion to $15 billion since 2008.

The buzz at REFF Wall Street was about MLPs, yieldcos and other obscure financial arrangements designed to sluice rivers of cash into clean energy. The market in green bonds has exploded from $2 billion in 2012 to $16.7 billion in the first half of 2014. At a panel moderated by Kyung-Ah Park, a Goldman Sachs managing director, solar developer Jeff Weiss summed up the industry's challenge. "You can't ask Kyung-Ah for a million dollars," said Weiss, co-chairman of Distributed Sun. "You can only ask her for a billion dollars." Goldman isn't interested in your roof, but it might get interested in thousands of roofs.

Distributed Sun's new product, truSolar, typifies today's green innovation. It's an investment platform that makes solar contracts much easier to evaluate, breaking down more than 600 potential risk factors for investors. The goal is to make solar deals as dull as any other financial instrument so the Kyung-Ahs of the world will feel even more comfortable throwing billions of dollars at them. "You've got this in every other asset class," Weiss said. "Why not ours?"

This is how the bulge brackets will get bulgier. As it gets cheaper to finance green projects, more will be deployed, so they'll get even cheaper to finance. Green finance isn't cool, but it can help cut emissions now. And it can free up the cool venture capitalists to focus on geniuses in garages so their inventions can cut emissions even more down the road.

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The Huffington Post: Support Solar, But Not at the Cost of the Working Poor [Op-Ed]
Jeff Johnson
July 16, 2014

http://www.huffingtonpost.com/jeff-johnson/solar-working-poor_b_5593050.html

Recently, many people throughout the country celebrated the first day of summer and the longest day of the year by urging consumers and businesses to "Put Solar on It." I also support "Putting Solar on It," because renewable energy sources of all types have many benefits for our country, helping to reduce carbon emissions, diversify our energy supply, and create jobs.

But as we all work to reap the benefits of the spread of renewable energy sources, we need to make sure to look carefully at the policies in place around "Putting Solar on It," because one of these might end up hurting those who don't have the option of using rooftop solar panels.

In fact, a policy called "net metering" is causing costs to increase for lower-income and minority groups that cannot afford such systems or do not have access to them in their current living situation. So, I am in support of putting solar on it, but not at an unfair cost to the working poor.

Let's first examine what net metering actually is. Net metering is allowed in many states, stemming from policymakers' desire to spur on the growth of renewable energy sources such as solar power. Net metering customers are allowed to sell back the extra electricity they generate to their electric company at the retail rate of electricity, which essentially allows them to avoid covering their fair share of the grid. This might not sound like a big deal -- but the problems with this policy become apparent once you look at how electricity bills work.

One part of your electricity bill is for the power you use, and the other part covers the costs of the electric grid. If some customers avoid paying that latter portion of their electricity bill, guess what? Someone else is stuck with the difference.

Because of old net metering requirements, customers without rooftop solar panels are the ones who end up shouldering those avoided costs. This goes beyond not being fair. We all use the electric system, whether we have solar panels on our roofs or not. And actually, the grid plays a helpful role in facilitating the selling of excess electricity for rooftop solar customers. Without

the grid, these customers also wouldn't be able to power their homes when their rooftop solar systems can't provide enough electricity to meet their needs (at night, for example).

This situation becomes even more unfair when you consider that homeowners who have solar panels are, for the most part, wealthier than those who do not. That's not surprising, because installing solar panels can be expensive, sometimes costing more than $50,000. But even when the cost of installation is lower, families on a budget have a difficult time seeing the benefit. Something I think we need to address. Wealthy families and home owners are taking advantage of not just the positive aspects of solar (something more of us should do), but a flawed policy that sticks someone else with part of the cost. A May 2014 Wall Street Journal story notes how some customers with rooftop solar have houses that are valued at $1.75 million dollars! What's more, those who live in apartments or rent -- including many low-income families -- don't even have the option of "putting solar on it" as these solar voices advocate.

Low income households that are already spending a significant portion of their income on household energy costs shouldn't be saddled with additional financial burdens because of their wealthier neighbors' decision to install rooftop solar systems. Switching to clean energy sources is something we should all be working towards -- but we can do without shifting energy costs from the affluent to the poor. In any discussion about "putting solar on it," we should find a way to balance our environmental goals with economic equality. Let's change net metering policies to make sure we don't hurt those who are most in need.

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NPR: Leased Solar Panels Can Cast A Shadow Over a Home's Value
Jeff Brady
July 15, 2014

http://www.npr.org/2014/07/15/330769382/leased-solar-panels-can-cast-a-shadow-over-a-homes-value

Installing solar panels on a house to generate electricity often costs $20,000 or more, and many homeowners have turned to leasing programs to avoid those upfront costs. But most leases are for 20 years, and that can present problems if someone wants to sell the house before the lease is completed.

Peter Auditore of El Granada, Calif., was happy with the leased solar panels he installed a few years back. When he decided to sell, he found a buyer who also appreciated the environmental benefits of solar panels. But then there was a hitch just as the sale was about to go through.

"The buyers all the sudden disclosed that they hadn't looked at the solar lease and that the lease was going to go out for another 15, 16 years," Auditore says. In last-minute negotiations, he and his real estate agent agreed to credit the buyer $10,000 in exchange for assuming the rest of the lease.

In this case, you could argue that those leased solar panels on the roof reduced the value of his home.

Real estate appraisers are grappling with this issue now. Sandra Adomatis, an appraiser in Punta Gorda, Fla., wrote a book for the Appraisal Institute on how to value homes with energy efficient features.
"If you're in a market where the market participants — the buyers in the market — don't understand solar leases and they're fearful of it, they may totally steer away from homes with a leased system," she says.

Today, it's difficult to determine whether a particular house with leased solar panels is worth less, Adomatis says. There just isn't a long history of sales involving such houses.

That is changing, though. Soon appraisers will have more data, because the number of houses with solar panels has increased tenfold in just the past seven years, according to the Solar Energy Industries Association. And much of that growth is due to the popularity of leased panels.

Exact Solar is a small company in Yardley, Pa., that both sells and leases solar systems. Owner Mark Bortman says transferring a lease does add an extra step during a house sale.

"Typically what most people would do is just have the new buyer assume the lease," Bortman says. "It's a relatively straightforward process. The finance company wants to be sure the new buyer is creditworthy."

And at big companies like Solar City in San Mateo, Calif., transferring leases is a regular part of doing business now.

"We have a team of 12 who work on this all day long to make sure that it's as smooth a process as possible for both the solar customer who's selling their home as well as the new Solar City customer," says William Craven, the company's director of public affairs. He says Solar City transferred more than 200 leases in June. And he estimates 95 percent of them were completed without any complications.

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Smart Energy Universe: Innovations in the Utility Industry [Op-Ed]
Lisa Wood
June 23, 2014

[No link available]

Op-Ed by Lisa Wood, Executive Director of the Institute for Electric Innovation, The Edison Foundation

Electric utilities are driving technological innovations that are changing the way electricity is generated, delivered, stored, and used across the nation. By partnering with a range of unique companies and stakeholders, from Apple to the U.S. Army, electric utilities are providing electricity to consumers reliably and in better and faster ways than ever before. Components that were once separate – such as power, information, and telecommunications systems – are increasingly operating as one intelligent and modern grid that has two-way data communication and control capabilities across physical power assets, sensor technologies, and business systems -- all fueled by new technology and innovation.

Despite this momentum, awareness is lacking about all of the exciting changes that are taking place behind the light switch. I would like to highlight a few of the cutting-edge projects that utilities across the country are engaging in today.

The U.S. Army Goes Solar

The U.S. Army announced that it will develop three 30 megawatt (MW), solar photovoltaic arrays on Forts Stewart, Gordon, and Benning, a great example of the kinds of public private partnerships that are happening in the electric power industry. Thanks to a range of partners who are collaborating on the project, including the U.S. Army Energy Initiatives Task Force; Forts Stewart, Gordon, and Benning; the General Services Administration; and Georgia Power, the U.S. Army will be able to increase its energy security and sustainability with these arrays. Once operational, an impressive 18 percent of the energy the U.S. Army consumes in Georgia will be generated on-site by renewable sources. Georgia Power, an operating utility of Southern Company, will finance, design, build, own, and operate the projects, which are expected to be complete by the end of 2016.

That's not all, though. In Arizona, another large solar array is being built by the U.S. Department of Defense. The 18 MW array at Fort Huachuca will provide the base with clean and cost-effective electricity, courtesy of a partnership between Tucson Electric Power (TEP) and the U.S. Army. Of note, the system will offset more than 58,000 tons of carbon dioxide per year.

Meeting Consumers Where They Are

Increasingly, electric utilities are putting information and technologies at the fingertips of consumers, for easy access and convenience on smartphones and other mobile devices. In New York, Consolidated Edison's "coolNYC" program helps customers lower their energy consumption by managing their air conditioning usage more efficiently. Participants receive a free smartAC "modlet" which allows them to control their room air conditioning unit remotely – with a smartphone – and set temperature schedules. The modlets are essentially plug-level meters with load control capabilities. This is especially exciting in a city with over 6 million room air-conditioning units.

DTE is in the process of developing an "Energy Awareness" mobile application. The platform engages users around discovering and improving their personal energy consumption, while providing DTE Energy with a next generation self-service channel that is rooted in positive

customer touch points. With a unique blend of coaching, gamification, and social elements, it enables DTE customers to engage with their personal energy consumption and ultimately reduce their energy use. Customers receive rewards for performance, including online and retail goods and virtual avatar upgrades. The application is being developed alongside Vectorform.

A Bite at the Apple

Another great example of innovation that's happening in conjunction with one of today's most exciting companies is NV Energy's partnership with Apple. Working with Apple's Reno Data Center, NV Energy is developing a 137-acre project that will host 18-20 MW of new solar capacity next to NV Energy's existing natural gas-fueled Fort Churchill Generating Station in Nevada. The unique partnership will generate more than 43 million kilowatt-hours of clean energy per year - equivalent to taking 6,400 passenger vehicles off the road per year - allowing customers to have a greater proportion of their energy generated by renewables.

It's Blowing in the Wind

Incredibly, electric utilities are also making headway in the prediction of wind patterns for electric generation. Advanced wind forecasting is being used to smartly integrate wind energy into the power grid. In its fifth year of use by Xcel Energy, the WindWX forecast technology has saved Xcel's customers more than $30 million by reducing wind power forecasting errors. Real-time, turbine-level operating data provide the input and WindWX's sophisticated algorithms forecast the amount of wind power that will be produced for a full week, every 15 minutes across the entire Xcel Energy service territory covering eight Western and Midwestern states.

Smart Meters Everywhere

With almost 50 million smart meters deployed across the U.S., utilities all across the country are demonstrating the value of digitizing the power grid. Information provided by smart meters and other investments in the grid improve the efficiency and reliability of the electric system.

Florida Power and Light (FPL), together with GE, Honeywell, and Silver Spring Networks has deployed 4.5 million smart meters, installed more than 10,000 intelligent devices on the electric grid, and added enhanced digital technology to nearly 600 substations. Investing in advanced technologies has resulted in a more reliable and efficient grid, outage prevention, and faster outage restoration. This is just one example of how investments in new technologies are changing the power sector.

More Smart Technology

PG&E has partnered with Opower and Honeywell to deliver a Smart Thermostat Solution pilot program in California.. The program provides customers with mobile access to their heating and cooling systems via a Honeywell Wi-Fi Thermostat platform and Opower thermostat management software. The solution coaches customers to create optimal thermostat schedules that fit their lifestyles.

The Opower/Honeywell pilot is helping to provide answers about energy efficiency potential. The Opower-designed mobile and web applications control Honeywell's thermostat, and provide real-time energy efficient feedback to customers for reducing heating and cooling costs by improving their thermostat settings. Also, the thermostat is programmed for energy savings (via the Opower solution) using efficient default set points before installation, which helps guide customers on the right path to efficiency from the onset.

As all of these technology stories illustrate that our electricity grid is evolving into a broader platform for new energy services and technology. And, a more integrated grid platform improves performance benefitting everyone – utilities and consumers alike. The power grid is the ultimate plug-and-play platform!

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SmartGridNews: The net metering debate: Solar power unfair to the poor says former regulator
Jesse Berst
June 18, 2014

http://www.smartgridnews.com/artman/publish/Technologies_DG_Renewables/The-net-metering-debate-Solar-power-unfair-to-the-poor-says-former-regulator-6587.html/?fpt#.U8PzJPldX5M

Quick Take: I've alerted you before that utilities may have an unlikely ally in the form of advocates for the rights of low-income families. Those groups are often opposed to utilities, or at least to utility rate hikes. In this case, however, they agree with those utilities who feel that the current net metering structure subsidizes high-income families that can afford rooftop solar, while penalizing apartment dwellers and the poor who cannot.

And now here comes a former utility commissioner who agrees. To date, utilities have often been stymied in their attempts to have net metering amended to be more fair. But if regulators are catching on, perhaps the tide will change. – Jesse Berst

"The poor shouldn't have to bear the cost of solar power!" trumpets former utility commissioner Monica Martinez in a recent guest post for the Forbes blog.

Martinez agrees that the country needs to move to cleaner energy sources. But not at the cost of putting low-income and middle-income families in worse economic shape. She argues that the net metering policies set many years ago in 42 states and the District of Columbia are unfair to those groups.

Net metering allows those with rooftop solar to sell excess power back to the local power company at the full retail rate. As a result, they do not pay their share of the cost of running the very grid that makes it possible for them to get paid for that excess power. This shifts the burden to those who cannot participate in net metering. "Did I mention that you have to have a high

credit score or your own cash to get the solar panels?" she asks. "I'm pretty sure a solar user isn't the family in rental housing – not to mention, families living in apartments it can't get solar systems – or the one out of every two families who live from paycheck to paycheck."

The California State Public Utilities Commission estimates that the state's non-solar customers will pay an extra $1 billion annually by 2020 if current policies stay in place. "As our nation moves to greater adoption of solar power, and as policy battles heat up in various states on this issue, I urge policymakers and all stakeholders involved to keep the very real consequences of net metering in mind and to ensure economic fairness for all," Martinez concludes.

Jesse Berst is the founder and Chief Analyst of SGN and Chairman of the Smart Cities Council, an industry coalition.

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Forbes.com: The Poor Shouldn't Have To Bear The Cost Of Solar Power [Op-Ed]
Monica Martinez
June 13, 2014

http://www.forbes.com/sites/realspin/2014/06/13/the-poor-shouldnt-have-to-bear-the-cost-of-solar-power/

Ms. Martinez is a former Michigan Public Service Commissioner and founder and CEO of Ruben Strategy Group LLC.

Energy policy. Income inequality. Economic vitality. Why aren't we talking about these concepts all together? Just last month I saw the articles with photos of solar panels at a Walmart in California, and once again heard how – according to the Obama Administration – solar power will be an important part of our nation's future energy supply. I wholeheartedly agree that we have to diversify our energy resources and find ways to move to cleaner supply sources. And, if the result is less pollution, who would be opposed? I believe, however, that we must be both smart and holistic in our approach. I also think that we can't bemoan income inequality while at the same time adopting energy policies that put low-income and middle-income families in worse economic shape.

Rooftop solar has a bright future and can benefit consumers. However, net metering policies – adopted in 42 states and the District of Columbia many years ago – are now having a detrimental impact on groups who can't afford solar and are faced with higher electricity bills as a result of these policies. If you are not familiar with net metering, it is a billing system that allows those with rooftop solar systems on their homes to sell excess power that they generate back to their local power company.

Under most state net metering provisions, electric companies are required to buy this excess power at the full retail rate or higher of electricity. No big deal, right? Wrong. What happens is

that the cost to serve net-metered customers is shifted to the non-solar customers. The California State Public Utilities Commission estimated the cost to non-solar customers will be more than $1 billion annually by 2020 if current policies stay in place. This is a cost shift and it is happening all around the country. Did I mention that you have to have a high credit score or your own cash to get the solar panels? I'm pretty sure a solar user isn't the family in rental housing – not to mention, families living in apartments that can't get solar systems – or the one out of every two families who live from paycheck to paycheck.

For a typical low income household, the cost for basic household energy can represent roughly 37% of a family's income. Add in added costs to supplement net metering customers, and you've just increased their energy cost burden. This is why I believe we must have a transparent and fruitful discussion on energy policy and the economic impact on families. We can't complain our country's income inequality is growing at the same time promoting policies that place added costs onto low-income and middle-class families we claim we are trying to figure out how to lift up. The growth of renewables must benefit all consumers and ensure long-term sustainability.

We all depend on affordable electricity to heat or cool our homes and small businesses. In our energy policy discussions, we can't forget those families who can't afford an increase in costs due to an outdated policy that incentivizes high-income homeowners to install rooftop solar systems. In an effort to end this unfair cost shift, many state utility commissions are in the process of re-examining their net metering policies to determine how best to integrate new technologies like rooftop solar onto the electricity grid properly and fairly. In Arizona, California and Colorado, regulators are all recognizing the need to enact reforms to end the cost shift which is placing an added burden on low-and middle-income families.

As our nation moves to greater adoption of solar power, and as policy battles heat up in various states on this issue, I urge policymakers and all stakeholders involved to keep the very real consequences of net metering in mind and to ensure economic fairness for all.

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The Wall Street Journal: Throwing Light on Value at SolarCity
Liam Denning
May 11, 2014

http://online.wsj.com/news/articles/SB10001424052702304655304579552234060157484

Think of a number. Then double it. Maybe triple it if you are having a good day.

Valuing SolarCity isn't quite that arbitrary. But the assumptions underlying how much the solar-leasing firm is worth are so open to debate that the exact stock price looks about as solid as sunlight.

The result is the stock's wild ride this year, rising 55% to a peak in February, only to drop by almost half by last Wednesday, before first-quarter results gave it a 12% boost the next day. Overlooking continued losses, investors cheered sales growth and raised targets.

SolarCity is essentially a financing business. Customers lease, rather than buy, panels, signing long-term contracts to buy electricity at a cheaper rate than their traditional utility bill. Typically, SolarCity utilizes tax incentives to raise financing from third-party investors to cover the installation costs. Once this is paid off in the early years of a project's life, SolarCity should then reap the profits from the remaining years.

That model means big losses up front as revenue goes to pay financiers. In the absence of profits to put multiples to, SolarCity publishes its own metric used by analysts and others to set valuations: "retained value."

This is an estimate of the value of future income from the electricity that customers buy far into the future, net of costs. A discount rate is applied to those cash flows to take into account the risks involved and effect of inflation to calculate a value in today's money.

That fairly straightforward premise is actually a black box of assumptions. SolarCity's latest estimate of retained value is $1.56 per watt of solar capacity installed already or in backlog, adding up to $1.29 billion. The company's market capitalization is $4.8 billion, or 3.7 times retained value. At its February peak, that multiple was north of seven times.

Clearly, the market expects rapid growth. And SolarCity has expanded rapidly. It aims to have installed more than 2,000 megawatts of panels by the end of 2015, up from less than 200 at the end of 2011. Pavel Molchanov at Raymond James estimates the potential market for residential solar at about 76,000 megawatts, 33 times the level installed now.

The problem is SolarCity's retained value figure already implies blue-sky thinking. For example, it assumes 90% of customers extend their typical 20-year leases for another decade. Those 10 years matter: SolarCity estimates the resulting cash flows equate to 29% of a project's retained value.

That may understate their importance. Using a model for a typical 6.4 kilowatt installation costing about $21,000—and assuming SolarCity's pricing, discount rate and renewals scenario—that last decade generates nearly 40% of the project's value. Indeed, upfront costs mean the project's value doesn't turn positive until the 10th year. The mismatch likely reflects differences in other assumptions in the models.

Moreover, the idea that 90% of customers renew leases is questionable. SolarCity's existence—all eight years of it—reflects the enormous strides solar power has made in the past decade. Who is to say what will happen in the next 20 years in terms of technology, the backlash from traditional utilities and how electricity is priced to consumers?

Say renewal rate wasn't 90%, but two-thirds. In our model, that cuts the project's value by 10%. That might not sound too bad. But this also prices in a discount rate, used to value those future cash flows, of just 6%.

Of all the inputs, SolarCity's discount rate looks the most aggressive. The company can point to recent, small securitized-debt issues priced at yields of less than 5% and, over time, the risks of this business should reduce as it becomes more established.

At 6%, though, the discount rate is only about 2.5 percentage points above the yield on 30-year Treasurys, a thin risk premium for a business that aims to revolutionize power consumption and depends, at least for now, on solar-friendly regulations and subsidies. And while SolarCity leads on market share, its leasing model is relatively new and has low barriers to entry, making competition a real risk.

A discount rate of 10% looks more realistic for shareholders. This would better reflect the mix of operating and competitive risks and time horizon involved. Financiers of installation costs, who get paid off earlier, can demand a return of 9% or more. Plug 10% into our model, though, and it cuts the project's net present value by more than half. SolarCity's market value, therefore, may imply a far higher multiple of retained value than 3.7 times.

Using the more conservative inputs above gives a value of 92 cents per watt for a typical residential project. SolarCity's estimate covers a portfolio of projects with various characteristics, so the numbers aren't directly comparable. Still, applying our lower value across the base and backlog of capacity would imply SolarCity's multiple leaping to more than six times; the true figure likely lies somewhere in between.

At today's share price, investors are baking in a lot of spectacular weather and no false dawns.

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The New York Times [LTE]
Ashley Brown
May 4, 2014

http://www.nytimes.com/2014/05/04/opinion/sunday/energy-incentives.html?_r=0

To the Editor: "The Koch Attack on Solar Energy" (editorial, April 27) does not address the true impact of net metering. By its nature net metering — running the meter backward when energy produced at the customer's location is exported into the distribution network — serves as a socially regressive subsidy largely for rooftop solar leasing companies.

As a recent study commissioned by regulators in California and performed by E3 Consulting, a highly reputable firm, pointed out, net metering in that state increases electricity costs disproportionately for those who can least afford it. The study forecasts that net metering will cost non-rooftop solar owners more than $1 billion a year in 2020. Essentially, net metering

redistributes the cost burden of the integrated electric system from more affluent to less affluent customers.

What was proposed in Arizona and elsewhere is not a tax, but rather a fairer, less socially regressive distribution of network costs. It is also consistent with the long-term viability of cost-effective renewable energy, as well as energy efficiency. Rooftop solar needs the electric grid as much as everyone else, and solar customers should pay a fair share of the cost rather than seeking a subsidy from lower income consumers.

Sustainable renewable energy is vital. Inefficient, unfair cross-subsidies endanger the viability of that vital resource.

ASHLEY BROWN
Belmont, Mass., April 28, 2014

The writer, a former commissioner of the Public Utilities Commission of Ohio, is executive director of the Harvard Electricity Policy Group at the John F. Kennedy School of Government.

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The Wall Street Journal: No Solar Subsidies for the Well-Off [LTE]
Rep. Joseph Gibbons
May 2, 2014

http://online.wsj.com/news/articles/SB10001424052702304518704579523781577296824

In states like California, customers subsidized by net metering represent costs shifted to customers who can least afford it.

Perhaps more upsetting than preferential tax treatment for SpaceX ("Elon Musk's Sacramento Pay Pals," Review & Outlook, April 21) are state net-metering policies that subsidize Mr. Musk's SolarCity and other rooftop solar leasing companies. Because of the way the net-metering rate structure is set up, it is essentially a massive subsidy for solar-panel owners, usually high-income homeowners. This massive subsidy is resulting in increased electricity costs for fixed-income individuals and working-class families.

In states like California, customers subsidized by net metering are avoiding paying for the costs to maintain the electric grid, which is essential to all communities. Those costs are shifted to customers who cannot afford to lease a system from Mr. Musk's SolarCity, including low-income and minority households, ultimately resulting in higher electricity bills for those who can least afford it.

Naturally, Mr. Musk and other millionaire owners of rooftop solar companies continue to push for overly generous net-metering policies to add to their bottom line at the expense of low-income communities.

The fact of the matter is that unfair government policies that benefit the 1%, and in this case take from those less fortunate, must be reformed.

Rep. Joseph Gibbons

Florida House of Representatives

Tallahassee, Fla.

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