COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC CONSIDERATION OF THE	**) Case No. 2019-00256**
IMPLEMENTATION OF THE NET METERING ACT	**)**

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PRELIMINARY COMMENTS OF THE KENTUCKY RESOURCES COUNCIL

The Kentucky Resources Council ("Council") appreciates this opportunity to submit these comments in response to the Commission's Order dated July 30, 2019,[1] requesting comments from interested stakeholders to develop a record which the Commission can look to in its consideration of the implementation of the 2019 Net Metering Act ("Act") as it applies to individual utilities. Because data specific to each utility will be necessary to fully assess the questions before the Commission, these comments focus on several overarching themes the Council believes will be at issue in these proceedings and should be applied across all net metering rate cases brought before the Commission after January 1, 2020.

[1] The Commission's Order dated September 13, 2019, extended the deadline to submit comments to October 15, 2019. Pursuant to 807 KAR 5:001, Section 8(12)(a), this electronic filing will be followed by filing hard copies of these comments within two (2) business days.

As a preliminary matter, while the Council applauds the Commission for seeking comments from all interested stakeholders on the implementation of the 2019 Act in advance of the filing of a specific case pursuant to the Act, this opportunity to provide comment should not and cannot be considered as a surrogate or substitute for allowing those individuals, organizations, or businesses that seek intervention and satisfy the standards in the Commission regulations for intervention, from being made parties to individual rate cases brought pursuant to the Act. As noted by the Commission in a February 18, 2019 Letter to Senator Brandon Smith, Chair of the Senate Natural Resources and Energy Committee, regarding a proposed (and ultimately rejected) floor amendment to Senate Bill 100, the rate cases are the processes by which jurisdictional utilities could propose, and the Commission could evaluate, a change in the valuation of the electricity fed into the grid by an eligible customer-generator:

> The original provisions of Senate Bill 100 create a transparent process that would have allowed broad participation among all stakeholder interests with the ability of the Commission to fulfill its statutory directive to establish rates that are fair, just and reasonable to all ratepayers.

February 18, 2019 Letter to Senator Brandon Smith, annexed as Attachment 1.

The Council concurs with the Commission that *broad participation among all stakeholder interests* should be part of any such rate case, and anticipates that the Commission will grant intervention to assure such broad participation, just as it did when the initial model net metering tariff and interconnection guidelines were developed following adoption of net metering by the Kentucky General Assembly.

The Council hopes that this comment period will assist all stakeholders and the Commission in framing the issues and understanding the concerns of other stakeholders in advance of the filing of a specific rate case, and will provide opportunities to work collaboratively toward developing reasonable, fact-based policies that are fair to all stakeholders, and the development of rates for crediting of distributed generation under the Act that are fair, just, and reasonable to participating and non-participating customers.

Prior to providing specific comments, the Council believes that there are a few key points that should guide the Commission's review of any proposed tariff pursuant to the 2019 Act.

First, the Commission must assess the full range of costs *and* benefits specific to each utility in establishing the rate at which energy fed into the grid by net metering customers will be credited. As noted by the Commission in the February 18, 2019 to Senator Brandon Smith:

> Utilities and the territories they serve have quite distinct differences, and it is because of these variations that the ratemaking process should reflect a utility's unique characteristics and the specific cost of serving that utility's customers. The same holds true for examining the quantifiable benefits and costs of net-metered systems.

February 18, 2019 Letter to Senator Brandon Smith, Attachment 1.

Second, KRS 278.466 allows utilities to use the ratemaking process to recover costs necessary to serve its net metering customers, "without regard for the rate structure for customers who are not eligible customer generators." The utility proposing an alternative rate structure for customers taking service under the replacement tariff bears the burden of demonstrating through sufficient data and appropriate analysis, that any changes to the rate design, including the current fixed charge currently applicable to both participating and non-participating ratepayers of that class, are fair, just, and reasonable, and properly allocate costs of service and credit for benefits (including avoided costs). Despite spending copious amounts of money to convince legislators and ratepayers to the contrary, no evidence has been produced to date from any jurisdictional utility in Kentucky that net metering customers cost more to serve than other residential customers, or that any material cross-subsidization is occurring intra-class between participating and non-participating ratepayers. The Council's own analysis, which did not account for any benefits provided by net metering customers to other customers, the grid, or the utility, showed no evidence of cross-subsidization occurring between customer classes at any more than a miniscule level. This finding is consistent with the 2017 Lawrence Berkeley National Laboratory Report *Putting The Potential Rate Impacts of Distributed Solar Into Context,* which concluded that "for the vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future." The 2017 LBNL Report, authored by Galen Barbose, is appended as Attachment 2.

Additionally, while utilities deserve an opportunity to seek to recover their costs and a fair rate of return on prudent investments for providing reliable service through fair, just, and reasonable rates, abrupt changes to the current net-metering relationship would violate the rate-setting principle of gradualism and could dramatically slow the rate at which distributed generation from renewable sources is incorporated into the grid.[2] A significant reduction of the value of the credit provided for fed-in electricity from distributed generators under the net-metering tariff, could encourage those customers to exit the grid

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[2] Naim R. Darghouth, *Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment*, Lawrence Berkeley National Laboratory Energy Technologies Area July 2015, annexed as Attachment 3.

entirely, to the detriment of the system and other customers. Changes to net metering valuation necessarily have policy implications that affect economic development, utility customers, both participating and not, and the environment; all of which deserve consideration.

Finally, as the Commission noted in the February 18, 2019 letter, it has "broad authority to consider all relevant factors presented during a rate proceeding, *which would include evidence of the quantifiable benefits and costs of a net-metered system."* (Emphasis added). The consideration of "quantifiable" benefits of distributed solar should include those benefits recognized by the jurisdictional utilities when they have proposed and requested Commission approval for utility-installed solar capacity.

These issues are discussed in greater detail below.

I. Net Metering Reform is a Complex Topic and a Wide Variety of Stakeholders with Unique Interests Should be Given the Right to Intervene in Individual Rate Cases to Ensure Full Consideration of the Issues.

The Kentucky Resources Council ("KRC" or the "Council") was founded in 1984, and since then has worked to ensure that individuals affected by environmental and energy policy decisions have a voice in the policy-making process. KRC provides, without charge, legal and technical assistance to those who live "downhill, downwind, or downstream," and whose homes, health, lands, and quality of life are threatened by environmental and energy policy decisions that too often are made without consideration of their unique voices. In this role, KRC has represented numerous clients before this Commission and has consistently represented specific groups of organizations and citizens with unique and important interests distinct from the general "consumer."

Until recently, the Kentucky Resources Council's clients have consistently been granted permission to intervene in various proceedings before this Commission, including rate cases. However, last November, this Commission denied the request of the Metropolitan Housing Coalition to intervene in a case where LG&E and Kentucky Utilities requested an average rate increase of $9.63 per month for KU customers. The Sierra Club, Association for Community Ministries, and the Community Action Council were also denied intervention. As the Commission is aware, those movants have challenged their exclusion and that case is currently pending before the Kentucky Supreme Court.

While the Council appreciates the Commission's attempt to develop a record to draw from in considering individual rate proceedings that may be filed after January 1, 2020 proposing to change the valuation of electricity generated by eligible customer-generators under the net metering tariff, inviting general public comments on net metering in this case is not a substitute for the ability of an interested stakeholder to participate fully as an intervening party in an individual utility's net metering rate case, where each party presents testimony and evidence under oath and subject to cross-examination, and where the record is developed with respect to data and factors specific to the utility and its unique service territory. Net metering reform is one of, if not the, most hotly contested utility issues throughout the nation, with consumers and other stakeholders engaging and seeking to participate in the policy making process at unprecedented levels. It is also a complex undertaking in which there is no consensus among states. Given the wide variety of unique interests that will be at play in these proceedings, a fair rate structure for net metering can only be established when the full gamut of interested stakeholders are given the opportunity to participate fully in individual rate cases. As such, those with specific interests and information, such as low-income advocates, potential solar net metering customers, solar installers and businesses, environmental groups, and others that meet the legal requirements should be given a seat at the table to ensure a fair process and an outcome that all parties will respect as legitimate.

The Council appreciates the recognition by the Commission, in the February 18, 2019 Letter to Senator Brandon Smith, that the costs and benefits of net-metered systems for each utility system may vary depending on the utility's "unique characteristics and the specific cost of serving that utility's customers," and that in the individual rate case in which the examination of the "quantifiable benefits and costs of net-metered systems" will occur, "broad participation among all stakeholder interests" should be allowed.

II. In Determining the Dollar Value of The Credit Provided to Net Metering Customers for their Excess Energy Generation, the Commission's Analysis Should be Thorough and Transparent and Assess the Full Range of Costs and Benefits Provided by Distributed Technologies.

The 2019 Net Metering Act redefines net metering going forward, so that instead of netting the difference between the amount of energy fed back to the grid and the amount of energy consumed on a kilowatt basis, net metering will be the difference in dollar value between the electricity fed back to the grid and the electricity consumed by the customer generator. The Net Metering Act directs the Commission to set the rate of compensatory credit in proceedings initiated by one or more utilities, which will necessarily involve determine the value to the utility, other customers, and the grid, of the energy the customer-generator feeds back to the grid. Numerous studies and state utility commissions have considered this question and there is no overarching consensus as to how to value these resources. However, almost all methodologies agree that both the costs and benefits of the distributed resource should be assessed and that the process should be based upon reliable data.

So too, this Commission has indicated that in a rate proceeding brought under the 2019 Act, it will receive and consider evidence "of the quantifiable benefits and costs of a net-metered system" as being relevant factors in the rate proceeding. Attachment 1, p 2.

Utilities frequently argue, and will likely argue in this case, that net metering customers should be compensated at the "avoided" cost rate under PURPA, which is the cost the utility would have to pay to purchase or generate energy itself. However, the avoided cost rate fails to recognize that net metering customer-generators are not utilities and such generation is very different than that of a traditional power producer. Unlike power purchased from a traditional producer or produced by the utility, the utility incurs no transmission and little-to-no distribution costs since customer-generated energy is either consumed on site or consumed by the customer's neighbor, the next closest energy user in the system. In addition, line losses, which average about five (5) percent of electricity transmitted and distributed annually in the United States, are avoided with customer-generated energy, resulting in further savings.[3] Thus, any proposal to credit net metering customers at the avoided cost rate, fails to take into consideration the unique characteristics of distributed generation and the benefits utilities receive from these energy sources in comparison to other wholesale power purchases.[4] The Commission has itself noted that a categorical setting of the rate to be credited for fed-in electricity would be arbitrary, since that "[b]enefits of generation from net-metered systems vary for a number of reasons, including locational benefits, specific utility load factors, etc." While a rate *formula* may be established by the Commission in a rate case under the 2019 Act, the specific costs and benefits will vary in value depending on the "unique characteristics" of the utility, including the rate design and territory served.

While it is clear that net metering provides benefits to utilities, as well as to other customers and the grid, there is no clear consensus on a valuation methodology for quantifying the rate that should be paid to consumers. While the weight given to various factors may necessarily be specific to the location or

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[3] U.S. Energy Information Administration, available at: https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 (based upon data averaged from 2013-2017).

[4] The General Assembly considered, and rejected, setting the value of fed-in electricity from net-metering systems, at the avoided cost.

utility,[5] there is an overwhelming consensus that distributed energy generation fed back to the grid can and does provide a host of benefits, including those described above but also others that differentiate customer-sited generation from wholesale power purchases. This full range of benefits, in addition to costs, should be taken into account in coming to a fair valuation to credit net metering customers for the excess energy they produce.

In recent years, numerous cost-benefit, location-specific studies have been done relating to net metering and distributed solar[6] and several additional studies have reviewed solar valuation studies in order to understand trends and explore ways to standardize valuation methodologies. These studies show at the very minimum that an assessment of a range of benefits in addition to costs is standard. Most, if not all studies take into account avoided energy costs and avoided capital and capacity investment, and a majority of the studies consider

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[5] For example, many studies add value for aiding in meeting a solar carve out requirement for renewable energy portfolio standards, however, this would not be applicable in a state like Kentucky that does not have a renewable energy portfolio standard. Thus, while other studies are instructive, variables used in computing the value of solar in Kentucky must be specific to the unique situation existing in the Commonwealth.

[6] While the Kentucky Net Metering Act applies to other forms of renewable energy besides solar, we focus on solar here since it is by far the most common form of net metered energy in Kentucky and nationwide and most valuation studies focus on solar. The principles and analysis here can apply equally to other renewable energy options, as well.

reduced financial risks due to predictable pricing of net metered solar, reduced costs of environmental compliance, and avoided greenhouse gas emissions.[7] Other categories assessed by at least some studies include grid resiliency, other environmental benefits, and societal benefits.

As a recent analysis by ICF for the U.S. Department of Energy notes, the value of solar in any given study necessarily depends on the data considered and assumptions made.[8] The study explains the important differences that caused the studies analyzed to arrive at varying conclusions:

> Some differences are caused by variables that are geographically and situationally dependent, while other differences are driven by the input assumptions used to estimate their value. Studies use a range of assumptions for factors that influence results, such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates. Furthermore, the stakeholder perspective – whether costs and benefits are examined from the view of customers, the utility, the grid, or society at large – is a key influencer of the methodology employed by the studies and their resulting direction and outcomes.

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[7] ICF, "Review of Recent Cost-Benefit Studies Relating to Net Metering and Distributed Solar (May 2018) (prepared for the U.S. Dept. of Energy) available for download at: https://www.icf.com/blog/energy/value-solar-studies; Environment American, "Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society" (2016), available at: https://environmentamerica.org/sites/environment/files/reports/AME%20ShiningRewards%20Rpt%20Oct16%201.1.pdf.

[8] ICF, "Review of Recent Cost-Benefit Studies Relating to Net Metering and Distributed Solar (May 2018) (prepared for the U.S. Dept. of Energy") available for download at: https://www.icf.com/blog/energy/value-solar-studies

> Overall observations from this analysis show, not surprisingly, that a major challenge in studying and developing an approach to [net energy metering], the value of solar, and [distributed energy resource] valuation is that some value components are relatively easy to quantify, while others are more difficult to represent by a single metric or measure.[9]

Recognizing a need for a standardized approach, both the Interstate Renewable Energy Council and the National Renewable Energy Laboratory have developed guides for regulators to use in assessing the costs and benefits of distributed renewable energy.[10] The Interstate Renewable Energy Council study came to three major conclusions on valuing distributed solar generation ("DSG"):

> - DSG primarily offsets combined-cycle natural gas facilities, which should be reflected in avoided energy costs.
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> - DSG installations are predictable and should be included in utility forecasts of capacity needs, so DSG should be credited with a capacity value upon interconnection.
>
> - The societal benefits of DSG policies, such as job growth, health benefits and environmental benefits,

[9] *Id.* at iii.
[10] Interstate Renewable Energy Council, "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," (October 2013) available for download at: https://irecusa.org/2014/02/solar-will-you-marry-me-for-a-contract-period-of-20-years/; National Renewable Energy Laboratory, "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric System (September 2014), available at: https://www.nrel.gov/docs/fy14osti/62447.pdf.

> should be included in valuations, as these were typically among the reasons for the policy enactment in the first place.[11]

The National Renewable Energy Laboratory model focused on recommended methodologies for calculating costs and benefits from the utility perspective. Despite the decision to focus on the utility perspective and not the customer and societal perspectives,[12] the NREL model recommends, and provides methods for calculating the following broad categories of costs and benefits: 1) energy displaced by customer-generated energy; 2) environmental benefits and costs, including avoided emissions, avoided water use, and avoided land impacts; 3) transmission and distribution losses; 4) generation capacity value associated with deference of capital investments; 5) transmission capacity value for reducing the

[11] Interstate Renewable Energy Council, "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," 3 (October 2013) available for download at: https://irecusa.org/2014/02/solar-will-you-marry-me-for-a-contract-period-of-20-years/

[12] However, the report recognizes that there are additional costs and benefits from the perspective of other stakeholders that were not included in the report. "While various benefits and costs can accrue to different entities—such as utilities, consumers, and society as a whole—the focus here is primarily on quantifying the benefits and costs from the utility or electricity-generation system perspective and providing the most useful information to utility and regulatory decision makers." National Renewable Energy Laboratory, "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric System, 1 (September 2014), available at: https://www.nrel.gov/docs/fy14osti/62447.pdf.

need for additional transmission capacity; 6) distribution capacity value for reducing the need from distribution capacity; 7) benefits and costs of ancillary services (operating reserves and voltage control);[13] 8) other benefits and costs such as fuel price hedging/diversity and market-price suppression.[14] While these models add to a dizzying array of costs and benefits that can be assessed and varying methodologies for calculating those, it is regardless important for the Commission to consider the host of benefits provided by net-metered energy sent back to the grid, in addition to the costs, and to consider the costs and benefits not just to utilities, but to a variety of stakeholders and society as a whole.

Despite the variability of methodologies used and factors considered and the locational differences between states, is noteworthy that a significant number of studies have found that the value of customer-generated distribution generation is *higher* than the retail rate. Environment America Research and Policy Center conducted a review of sixteen (16) analyses on the value of rooftop solar in 2016.[15] The studies reviewed were published between November 2012

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[13] The penetration rate of net-metered distribution generation in Kentucky almost certainly too small to have a quantifiable impact in this category.

[14] National Renewable Energy Laboratory, "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric System (September 2014), available at: https://www.nrel.gov/docs/fy14osti/62447.pdf.

[15] Environment American, "Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society" (2016), available at:

and August of 2016 and include analyses undertaken in a variety of states for or by public utility commissions, environmental groups, utility companies, and consulting firms. On average, the studies found that the median value of rooftop solar was 16.35 cents per kWh while the average residential electric rate was 13.05 cents per kWh. Thirteen of the sixteen studies found that the value of rooftop solar was higher than Kentucky's average retail rate of electricity, which is 8.57 cents per kWh as of 2017.[16] Of the three studies that did not, two were written by or commissioned by the utility industry.

In 2016, the Brookings Institute also analyzed "the accumulating national literature on costs and benefits of net metering," and found that these studies, whether conducted by PUCs, national laboratories, or academia, increasingly conclude "that the economic benefits of net metering actually outweigh the costs and impose no significant cost increase for non-solar customers."[17] An assessment of solar valuation studies by the Rocky Mountain Institute reached similar conclusions and found that the average value of solar of the studies assessed was

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https://environmentamerica.org/sites/environment/files/reports/AME%20ShiningRewards%20Rpt%20Oct16%201.1.pdf.

[16] U.S. Energy Information Administration, "State Electricity Profiles," available at: https://www.eia.gov/electricity/state/kentucky/

[17] Mark Muro and Devashree Saha, "*Rooftop solar: Net Metering is a Net Benefit,"* (May 23, 2016), available at: https://www.brookings.edu/research/rooftop-solar-net-metering-is-a-net-benefit/

17 cents per kWh, compared to an average residential retail rate of 12.5 cents per kWh.[18]

Similar conclusions have been reached in other southeastern states comparable with Kentucky in terms of solar penetration. A 2014 study commissioned by the Mississippi Public Utilities Commission found that after comparing the per-MWh costs of distributed solar generation to its benefits, expressed as avoided costs, distributed solar would provide levelized net benefits to Mississippi over a period of 25 years.[19] The study concluded that:

> [S]olar net metered projects have the potential to provide a net benefit to Mississippi in nearly every scenario and sensitivity analyzed. This may never happen if net metering participants are not expected to receive a reasonable rate of return on investment.[20]

In addition, while the Mississippi study found a net benefit from net metering, it is noteworthy that this analysis did not include potential environmental and public

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[18] Rocky Mountain Institute, Energy Innovation Lab, *"A Review of Solar PV Benefit and Cost Studies*" (Sept. 2013), available for download at: https://rmi.org/insight/a-review-of-solar-pv-benefit-and-cost-studies/

[19] Elizabeth Stanton, et al., Synapse Energy Economics, Inc., "Net Metering in Mississippi" (Sept. 19, 2014), available at: https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf

[20] *Id.* at 49. The study found that residents would need to receive slightly above the retail rate for energy sent back to the grid to make solar economical, however, these conclusions may be different now given that the costs to install rooftop photovoltaic systems have dropped since 2014 when this study was completed.

health benefits and instead focused on the money that utilities would save for every MWh of distributed solar adopted. When environmental and societal benefits have been considered along with avoided costs, the benefits of distributed generation have been even higher. For example, a 2015 study commissioned by the Maine Public Utility Commission assessed a value of solar of 33 cents per kilowatt hour, compared to an average retail rate of just 13 cents per kilowatt hour when reductions in air and climate pollution and other societal benefits were also taken into account.[21]

As to whether the mitigation of climate change and reduction of greenhouse gas emissions should be considered a quantifiable benefit, the Council believes that it must. There are several sources to which the Commission could look to assign a dollar value to mitigation of GHG emissions. A number of utility IRPs have, as part of demonstrating that a particular mix of generation and other measures represent the least cost alternative, assigned a range of values to GHG emissions, assuming as reasonable the observation that GHG emission control under the Clean Air Act will occur and that such costs must be considered in charting a course to meeting customer demand in the future. Additionally, in

[21] Clean Power Research, "Maine Distribubed Solar Valuation Study" (March 1, 2015), available at: https://www.nrcm.org/wp-content/uploads/2015/03/MPUCValueofSolarReport.pdf

filings before this Commission, jurisdictional utilities have recognized the value of solar as a hedge against GHG emissions, and have requested approval by the Commission of solar additions to their generating assets for that reason.

While some utilities in Kentucky have argued that the benefits of solar are "intangible" and "lack market value" when advocates of distributed renewable generation have raised the issue of GHG emission mitigation, utilities have themselves identified those very benefits as reasons for approving new utility-owned solar arrays.

In defending the proposal to construct a 10-mW solar array in the Public Service Commission Case 2014-00002 as the least-cost option to "meet customer needs while at the same time complying with recently enacted and anticipated air quality regulations in the most cost-effective manner," the Chief Operating Officer of Louisville Gas and Electric Company made these observations *under oath*:

> "[C]onstructing the Brown Solar Facility will allow the Companies to add a renewable resource with relatively minor impact to customer revenue requirements in the coming years."
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> "[T]he Brown Solar Facility will broaden and further diversify the Companies' fuel supply sources and reduce future greenhouse gas emissions."
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> "The Companies believe it is prudent at this time to construct a facility to expand their renewable energy sources. A number of developments have

> enabled the Companies, for the first time, to present a feasible proposal to the Commission for a solar generation facility. The declining price of solar panels, available federal tax credits, and renewable energy certificates have helped create this opportunity.… These developments, along with the increased likelihood of carbon constraints, have created a reasonable opportunity for the Companies to add a renewable source to their generation portfolio and gain the valuable experience that will result from constructing and operating that source."

Thus, according to the sworn testimony of the COO for LG&E/KU, adding renewable energy to the utility portfolio has measurable value, the likelihood of carbon constraints and decline in future greenhouse gas emissions have tangible value, and diversification of fuel supply sources likewise has measurable value.

Other testimony in that case indicated that expanding solar generation produced benefits:

> "The Companies believe it is prudent at this time to construct a facility to expand their renewable energy sources."
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> "Given the increasing likelihood of carbon constraints, the ability to sell renewable energy credits, and the availability of federal tax credits if a solar facility is operational by the end of 2016, the Companies believe a solar facility will be a prudent fuel-diverse addition to the generation portfolio and will reduce future greenhouse gas emissions."

In describing the factors that led to the decision to construct the combined-cycle gas and the solar arrays, the LG&E/KU witness in charge of energy supply and analysis gave these factors as being key to the decision:

> [The] decision was reached after an extensive process that considered: (1) the Companies' load forecast and the uncertainty associated with it; (2) the impact of the Companies' demand-side management ("DSM") programs on future generation resource needs; (3) the potential for future regulation of greenhouse gas ("GHG") emissions by the U.S. Environmental Protection Agency ("EPA"); (4) the issuance and evaluation of a Request for Proposals ("RFP") for capacity and energy to replace the retired generation facilities and meet future load growth; and (5) the uncertainty associated with future natural gas prices.

Distributed solar provides many of these same benefits to the utility and other customers that the utility-owned array would, according to the utility witnesses, provide with respect to price volatility, adapting to greenhouse gas regulation, and more.

With respect to whether GHG emission mitigation has quantifiable value, the prefiled written testimony in that case of Mr. Sinclair argued that it does:

> Q. You have previously testified that regulation of CO2 was essentially "unknown and unknowable." Has your position changed?
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> A. Somewhat. As I said, the future remains highly uncertain regarding CO2 regulation in the U.S. Many people believe that the Clean Air Act is not really suited for regulating CO2 emissions and that new legislation is needed from Congress. Given the current climate in Washington, it is hard to envision bipartisan support for GHG legislation. Second, court challenges continue related to past actions taken by EPA to regulate CO2 emissions and threats of future litigation are being made should EPA press ahead on regulations for existing power stations. In this environment, much remains unknown about if, when, and how CO2 might be regulated in the future. However, the Companies feel that enough is known that the risk of future

CO2 regulations should be part of a 30-year analysis related to the next generation resource and that a resource should be economically robust with or without future CO2 regulations. I would add, however, that there is not enough known about the potential for CO2 regulations to evaluate material changes to the Companies' existing generation fleet." (Italics added).

Mr. Sinclair also noted that:

"I would point out that the Companies are recommending the construction of a NGCC unit and a solar facility, both of which become more economically attractive the greater the weight one places on future CO2 emission costs."

"While the Brown Solar Facility is not a lowest reasonable cost resource absent REC prices greater than $57/REC, as can be seen in Tables 35, 36, and 37 in the Resource Assessment, the Companies are proposing to move forward with the project because *(i) it is a prudent hedge against both GHG regulations and natural gas price risk; (ii) it will reduce the Companies' GHG emissions; (iii) it affords the Companies the opportunity gain operational experience with an intermittent renewable resource; and (iv) it does not materially add to revenue requirements over the next 30 years."* (Emphasis added).

Thus, what tipped the scales in favor of solar even where renewable energy credits are below the cutpoint that they would make the solar array the least-cost resource was, according to the utility witness, the value of solar as a prudent hedge against greenhouse gas regulations and natural gas price risk, and the reduction it would provide in GHG emissions by the companies. These same benefits accrue to the utility and other utility customers from an increase in distributed solar generation, yet the utilities claim that those values are intangible and unquantifiable in the latter context.

In the 2013 LG&E and KU Resource Assessment in Case No. 2104-00002, it is noted that:

> "As long as Kentucky does not have a renewable portfolio standard, the Companies would have the option to sell the Renewable Energy Certificates (RECs) that are created when the facility produces electricity. Today, the market price in Ohio for solar RECs from Kentucky is $24-28 per REC."
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> "Given the increasing likelihood of CO2 constraints and the ability to sell Renewable Energy Certificates ("RECs"), the Companies also recommend building a 10 MW solar facility at the existing E.W. Brown station. The solar facility is a prudent hedge against both GHG regulations and natural gas price risk, it will reduce GHG emissions, it affords the Companies the opportunity to gain operational experience with a solar PV resource, and it does not materially add to revenue requirements over the next 30 years."

The testimony of John Voyles on behalf of LG&E/KU further underscores that there are tangible, measurable benefits to expanded solar generation within a utility system in the Commonwealth:

> Given the increased likelihood of carbon constraints, the Companies believe the Brown Solar Facility will be a valuable addition to their generation portfolio[.]

Finally, the testimony of the Director of Environmental Affairs in support of the E.W. Brown solar array noted the value of solar with respect to environmental permitting and regulatory compliance costs, noting that "[t]here will be no requirements for an air permit or water withdraw/discharge permit."

It is curious indeed that when expanding solar generation is proposed by the utility, values and benefits described as "intangible" and "unquantifiable" take on a quantifiable, measurable, and tangible form. In weighing the costs and benefits of distributed solar generation to a utility system and to other customers, it is clear from the testimony of the witnesses in the Brown solar array case that the value of solar as a prudent hedge against greenhouse gas regulations and natural gas price risk, and in the reduction it would provide in GHG emissions for the companies, is both quantifiable and substantial.

In sum, a full range of costs and benefits should be assessed by the Commission in determining the rate of compensation for excess energy produced by net metering customers. In assessing benefits from the utility perspective, the vast majority of studies cited above support the inclusion of benefits beyond the almost universally agreed benefits of avoided energy costs and capital investments. Additional benefits appropriate for consideration are described above and should be considered in any comprehensive analysis. In addition, the benefits and costs assessed should include benefits beyond those from the utility perspective, such as job growth (or lack of job losses), public health, and other environmental benefits. Finally, in analyzing the costs and benefits the Commission chooses to take into account, the methodologies employed to calculate those benefits should be evidence-based and reasonable.

III. Available Data Does not Support the Utilities' Argument that Net Metering Customers are Causing Cost Shifting or that Net Metering Customers Are Not Paying Their Fair Share of Fixed Costs.

In addition to arguing that excess renewable energy generation from customers should be compensated at the utility's avoided cost rate, the utilities have argued that solar net metering customers do not pay their fair share for the costs of service and that non-participating customers, and particular low- or fixed-income customers, are being required to subsidize the participating ratepayers. The utility industry makes these same arguments across the country and would have consumers and policy makers believe that these arguments are true regardless of the unique situations in each state. While some states with high levels of distributed energy penetration may have legitimate concerns that cost shifts do or could occur, the assertion that distributed energy customers in Kentucky are not paying their fair share or are being subsidized by other ratepayers has not been supported by any data provided by the utility companies in Kentucky. Absent such evidence, there is no basis in this state and at this time for imposing additional charges on customer-generators. Instead, the Council's own analysis using publicly available data shows that any cross-subsidization is negligible.

First, all residential customers in each utilities' service area pay the same fixed service charges that are designed to recover the costs to maintain the grid, including net metering customers. These charges have increased drastically in many service areas in recent years, and utilities continue to request increases in fixed charges for *all* customers to compensate for a lack of customer growth and a reduction in per capita energy usage across the board, a trend that is anticipated to continue.[22] While the costs net metering customers incur for the electricity they consume are offset by electricity they supply back to the grid, these credits count only against energy consumed, not other fixed charges. Thus, net metering customers pay the same fixed charges as all other residential customers every month, regardless of any credits they receive for energy produced.[23] As the

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[22] *See, e.g.*, *In the Matter of: Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2018-00294; *In the Matter of: Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295.

[23] While the utilities will argue that these fixed costs do not capture the total cost of service and that some costs are built into the volumetric rates, that is not a net metering issue, but an overarching ratemaking issue that implicates the

utilities continue to seek upward adjustments in their fixed customer charges and to move costs from the volumetric to the meter charges, any perceived intra-class "subsidization" will become all the more marginal.

Second, solar net metering has such low penetration rates in Kentucky, (which under the now "hard" cap of 1% will remain low), that any impact to other ratepayers is negligible, if not undetectable. The Kentucky Resources Council did an analysis of the economic impact on residential customers from net-metered energy sold back to the grid at retail rates using 2016 data from the Department of Energy's Energy Information Administration. The analysis looked at the cost to each utility for crediting net metering customers at the retail rate rather than the avoided cost rate, with an assumed difference between the two of roughly seven (7) cents per kilowatt hour, for excess power supplied to the grid. Contrary to the utilities' arguments that crediting net metering customers at the retail rate results in cross-subsidization, our analysis found that for 2016, the economic impact for any non-participating customer ranged from a high of 4 cents per month, or 48

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continuing problem of a utility business model built largely around selling increasing amounts of electricity while demand continues to decline. Isolating and according disparate rate treatment for customers who use less electricity because of generation of electricity from solar panels, than is accorded other customers in the same class who may use less electricity due to efficiency investments or weatherization, for example, is hardly fair, just, or reasonable.

cents per year, to a low of 0.1 cents per month, or 1.3 cents per year. The average economic impact on non-participating customers was 4 cents per year. Thus, while the utilities argue that cost shifting is occurring in some jurisdictions, the reality in Kentucky is that any cost-shift or cross-subsidization is negligible.[24]

A January 2017 study by the Lawrence Berkley National Laboratory confirms this analysis on a nationwide level.[25] According to this report, at a solar net-metering penetration rate of 0.4% and with purely volumetric rates, the impact to average retail electricity prices is no more than three one-hundredths of one cent per kWh. Kentucky currently has a distributed solar penetration rate of less than 0.1% and utilities charge a fixed rate which is not subject to reduction through net metering, in addition to volumetric rates. This means the impact to retail electric prices in Kentucky should be even lower than projected in this report for the foreseeable future. Furthermore, because the 2019 Net Metering Act caps net metering at 1% of a utility's peak load, utility companies are not

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[24] Tom FitzGerald, "The Economic Impact on Kentucky Residential Customers of Energy 'Sold' To Utilities From Net Metering Solar Customers in 2016," (February 28, 2018) annexed as Attachment 4.

[25] Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context" (Lawrence Berkeley National Laboratory, Jan. 2017) available at: https://emp.lbl.gov/sites/all/files/lbnl-1007060.pdf

required to offer net metering when penetration rates rise to a level where retail rate net metering is projected to have impacts on non-participating ratepayers.

Further, while Kentucky utilities may have a monopoly in their service territories, that monopoly status does not prohibit customers from seeking to reduce their energy consumption or reliance on energy from the grid. Utility customers have always had the option to take whatever measures they see fit to control their own energy use and reduce their bills by using less energy. To compensate net metering customers at anything less than the retail rate for energy they produce and which is used behind the meter to reduce their own energy consumption is contrary to this principle and treats net metering customers differently than all other customers that seek to reduce their energy usage. This is unreasonable, unfair, and contrary to longstanding ratemaking principles.

In conclusion, the utility industry's argument that solar net-metering customers are not paying their fair share to upkeep the grid and that their decreased energy usage and utility credits they receive for energy produced are creating an unfair burden on other ratepayers is simply not true in Kentucky. As the analysis above makes clear, there is no need to raise rates on net metering customers to recover for any cross-subsidization because net metering customers' effect on other customers is negligible. Imposing additional fixed costs on net metering customers above what other retail customers pay or putting net metering customers in a separate rate class is contrary to the requirement that rates be fair, just, and reasonable, and is not supported by any evidence provided by the utilities to date. Any assertion by the utility industry that cost shifts are occurring or that net metering customers impose additional costs on utilities must be supported by valid, transparent data.[26]

IV. The Commission's Decisions Relating to Net Metering Should Take into Account General Principles Inherent in Ratemaking and Consider the Public Policy Impacts of Any Significant Changes to the Current Compensation Scheme.

Finally, in assessing any changes to the current compensatory credit formula under the 2019 Net Metering Act, the Commission has recognized that the standard principles of utility ratemaking apply (Attachment 1 p. 2) and that the establishment of what are fair, just, and reasonable rates requires taking into account the impact its decisions will have not just on utility companies, but on

[26] Note also that cross-subsidization within a class is inherent in flat rate electricity pricing. Ahmad Faruqui, *The Ethics of Dynamic Pricing*, 23 Electricity J. 13, 19 (July 2010) ("A flat rate that charges the same price around the clock essentially creates a cross subsidy between consumers that have flatter-than-average load profiles and those that have peakier-than-average load profiles. This cross subsidy is invisible to most consumers but over a period of time it can run into the billions of dollars.").

other stakeholders, as well. The Commission has historically considered such factors as economic development and environmental protection in approving rates and should be as mindful of those factors in this case. In addition, this Commission has the benefit of having seen the impacts in other states that have resulted from drastic changes in net metering policy. Given some of these consequences, which in some cases have necessitated a reversal in policy, the Council urges the Commission to consider the long-term implications of any changes to the pre-Net Metering Act compensatory credit scheme and make prudent decisions that are fair to all stakeholders.

First, any changes in utility rates for net metering customers should allow customers that want to subscribe to net metering to be able to simply calculate their potential rate of return based on their intended usage. Residential consumers are not as savvy as commercial and industrial customers and should not be forced to rely on a solar energy installer to calculate their expected rate of return if the rate structure is too complicated. For consumers to be protected, they must have the ability to understand the rate of return on an investment in a solar system. This includes not only being able to calculate the rate, but also certainty in what the rates will be over time. Thus, any rate structure should be straightforward and understandable to the average residential ratepayer.

In addition, in considering changes to net metering compensation rates, the Commission must consider the economic development impacts such a decision might have on Kentucky as a whole. The solar industry is one of the fastest growing industries in the entire nation. Although only .10% of Kentucky's electricity generation is supplied by solar, as of 2018, 1410 people worked in the solar industry in Kentucky and solar jobs are expected to grow 10% in 2019. Kentucky ranked 17th in the nation in solar jobs added in 2018, despite ranking 45th for installed solar capacity. In addition, 56 solar companies operate in Kentucky.[27] Nationwide, solar installers represent the fastest growing profession in the entire country, with a growth rate of 63% expected through 2028 and paying median salaries of $42,680.[28]

In other jurisdictions unexpected and dramatic changes to net metering have resulted in crippling impacts to the solar industry. In addition to significant economic impacts on a viable and growing industry, drastic changes in net metering have also resulted in the need to go back and revise these policies after these unintended consequences become apparent. This puts additional strain on

[27] The Solar Foundation, "Kentucky Solar Jobs Census 2018," available at: https://www.thesolarfoundation.org/solar-jobs-census/factsheet-2018-KY/
[28] U.S. Bureau of Labor Statistics, "Occupational Outlook Handbook: Fastest Growing Occupations," available at: https://www.bls.gov/ooh/fastest-growing.htm

already limited government resources, from legislators, utility commissioners, and judges hearing appeals. Furthermore, it creates even more uncertainty for consumers interested in investing in rooftop solar and stunts an industry that has seen rapid growth in recent years and is projected to grow far more than most industries.

For example, in 2015 in Nevada, regulators tripled the fixed charges solar customers would pay over the next four years and reduced the credit received for excess energy supplied to the grid by more than 75%. Prior to these changes, Nevada had one of the most robust and developed solar markets in the country and the industry employed thousands of people. After the new rates took effect on January 1, 2016, major solar companies left the state altogether and hundreds of solar workers were laid off. New solar installations dropped 92 percent in the first quarter of 2016. The fallout from this decision was so significant that the Nevada legislature, almost unanimously, passed new legislation, A.B. 405, in 2017 in attempt to remedy these adverse impacts and the Nevada Public Utilities Commission issued an order later that year implementing the new law and restoring net metering compensation to close to the retail rate.

One of the most important factors in promoting renewable energy, and any business or economic development initiative generally, is stability. As shown by the situation in Nevada, drastic, unexpected, or retroactive shifts in policy could paralyze the solar industry and cause major harm to business owners and workers that made investments in their businesses and careers under existing policies with the expectations that those policies would continue until a 1% cap on net metering was reached, as stated in Kentucky's former law. Thus, any changes in net metering policy should provide stability and long-term regulatory certainty to all parties, including utilities, businesses, energy consumers, and independent energy producers. Drastic changes to policies in which heavy investments have been made stunt economic development and are unfair to energy businesses that are not guaranteed a significant rate of return on their investments like the utility companies.

The Public Service Commission has considered economic development principles in the past in approving rates and has approved lower rates for industrial customers that meet certain qualification to encourage job creation and economic development in the state. While utility rates must always be fair, just, and reasonable, the Commission is authorized to and does consider economic development impacts in ratemaking decisions.[29] All things being equal, Kentucky

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[29] *See PSC of Ky. V. Commonwealth*, 320 S.W.3d 660 (Ky. 2010) (Finding that the PSC could authorize utilities to offer reduced gas and electric rates to industrial customers to promote economic development in Kentucky).

could add 1000 solar jobs over the next decade. Alternatively, if states like Nevada serve as any guide, Kentucky could lose out on those 1000 potential jobs and see additional job cuts if residential solar demand flatlines due to dramatic policy changes. While economic development should clearly not be the only consideration in the Commission's decision and the decision should be fair and reasonable to all stakeholders, avoiding drastic impacts to a significantly growing industry that provides well-paying jobs to Kentuckians should and can be avoided.

Finally, in making decisions in this case, it is important to keep in mind that utility regulation springs from the state's police power to protect the health, safety, morals and general welfare of its citizens. Regulation was a response to the growth of the public's dependence on powerful utilities that provide essential services, and governments sought through the police power to protect the public from the effects of unchecked monopoly power. Thus, in assessing a value of solar, it is important to not only assess criteria that impacts utilities, but to also assess public interest factors, since the role of the Commission stems from the power of government to protect the health, safety, morals, and general welfare of the public.

CONCLUSION

The Council appreciates this opportunity to provide preliminary comments in response to the Commission's invitation for public comment. These comments will be supplemented with oral and written testimony at the public hearing scheduled in this case, and copies of all reports to which these comments refer are available in digital format or have been included as attachments.

Respectfully submitted,

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Chairman

Robert Cicero
Vice Chairman

Talina R. Mathews
Commissioner

February 18, 2019

VIA EMAIL

Senator Brandon Smith
Chair, Natural Resources
and Energy Committee
702 Capital Avenue
Annex Room 252
Frankfort, KY 40601

Re: Senate Bill 100, House Floor Amendment 1

Dear Senator Smith:

Because of the extensive changes to Senate Bill 100 (SB 100) adopted by the House of Representatives in House Floor Amendment 1 (HFA 1), the Public Service Commission is compelled to oppose the bill. As explained in our Feb. 14, 2019 letters to you and Rep. Gooch, the original language in SB 100 would have established a practical approach to addressing a utility's compensation for net-metered systems through the ratemaking process. In its current form, however, SB 100 is fatally flawed.

First, there are the procedural challenges presented by the provision in HFA 1 requiring the establishment of a ratemaking proceeding before the Commission no later than one year from the effective date of the Act. The Commission does not have sufficient staff to adequately conduct concurrent ratemaking proceedings for all retail electric suppliers during such a compressed timeframe. Utilities and the territories they serve have quite distinct differences, and it is because of these variations that the ratemaking process should reflect a utility's unique characteristics and the specific cost of serving that utility's customers. The same holds true for examining the quantifiable benefits and costs of net-metered systems. Attempting to rush the consideration of these issues within an artificially compressed timeframe or trying to force the Commission to address the issue for all electric utilities and customer-generators in one administrative case, as HFA 1 appears to be aimed at doing, is not in the best interests of ratepayers or any other stakeholder.

Second, the Commission has concerns regarding the language describing what the Commission *shall* consider in reviewing a net metering tariff. The Commission has broad authority to consider all relevant factors presented during a rate proceeding, which would include evidence of the quantifiable benefits and costs of a net-metered system. S*ee Kentucky Public Service Com'n v. Commonwealth ex rel. Conway*, 324 S.W.3d 373, 383 (Ky. 2010) (The Commission has "plenary authority to regulate and investigate utilities and to ensure that rates charged are fair, just, and reasonable under KRS 278.030 and KRS 278.040."). Benefits of generation from net-metered systems vary for a number of reasons, including locational benefits, specific utility load factors, etc. Statutory language explicitly dictating *only* what the Commission is to consider in a rate proceeding (as HFA 1 does in Section 2, paragraph 5) is antithetical to standard principles of utility ratemaking.

Third, the Commission questions the rationale behind the provision in HFA 1 mandating that an entity representing solar installer interests be granted intervenor status when the existing statute applies not only to solar systems but also to wind, biomass and hydro energy generating systems as well. This provision seems to indicate that solar installer interests are driving this discussion, perhaps to the detriment of the broader interests of all stakeholders, especially ratepayers. With a few limited exceptions[1], the Attorney General is the only entity granted the statutory right to intervene in proceedings before the Commission. KRS 367.150(8)(b). All other intervention before the Commission is permissive, and granting or denying intervention is within the Commission's discretion. In making its determinations, the Commission considers whether the prospective intervenor (1) has a special interest in the case that is not otherwise adequately represented; or (2) is likely to present issues or to develop facts that assist the Commission in fully considering the matter without unduly complicating or disrupting the proceedings. 807 KAR 5:001, Section 4(11)(a). As these factors appropriately assess the need for intervention in a given proceeding, HFA 1's grant of special status to a particular commercial interest is both unusual and unnecessary.[2]

Finally, that a sentence allowing third-party leased systems is included in an amendment with no discussion of the possible implications highlights the need for more robust discussion. These issues are larger than net metering. As the electric utility sector undergoes significant and rapid changes, more holistic, forward-thinking examination is due. Addressing these complex issues and the positions of competing stakeholder interests is not only a priority of the Commission, but it is our mandate.

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[1] *See, e.g.*, KRS 278.020(9), granting a person over whose property a proposed electric transmission line will cross a right to intervene in the proceeding addressing the construction.

[2] Also, it should be noted that the issue of intervention before the Commission is currently the subject of litigation in both the Franklin Circuit Court and the Kentucky Court of Appeals as the General Assembly oft has been reluctant to enact legislation dealing with an issue that is the subject of pending litigation.

The original provisions of Senate Bill 100 create a transparent process that would have allowed broad participation among all stakeholder interests with the ability of the Commission to fulfill its statutory directive to establish rates are fair, just and reasonable to all ratepayers. Unfortunately, instead of permitting the Commission to conduct proceedings addressing net-metered systems using established principles of utility ratemaking, the provisions of HFA 1 create a process that appears to favor the interests of a particular group over other stakeholders, including ratepayers. As such the Commission requests that the Senate reject HFA 1 to Senate Bill 100.

Sincerely,

Kentucky Public Service Commission

Michael J. Schmitt, Chairman

Robert J. Cicero, Vice Chairman

Talina R. Mathews, Commissioner

cc: President Robert Stivers II
Kentucky Senate

Speaker David Osborne
Kentucky House of Representatives

LBNL-1007060

Putting the Potential Rate Impacts of Distributed Solar into Context

Authors:

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January 2017

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Disclaimer

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1. Introduction

The rapid growth of distributed solar in a number of states has raised questions about its potential effects on retail electricity prices, prompting concerns by some utilities and stakeholders about cost-shifting between solar and non-solar customers. These concerns have, in turn, led to a proliferation of proposals to reform retail rate structures and net metering rules for distributed solar customers, often extending to states that have yet to witness significant solar growth. These proposals have typically been met with a great deal of contention and often absorb substantial time and administrative resources, potentially at the expense of other issues that may ultimately have greater impact on utility ratepayers. Given these inevitable tradeoffs, state regulators might ask: How large could the effect of distributed solar on retail electricity prices conceivably be? And how does that compare to the many other factors that also influence electricity prices—and over which state regulators and utilities might also have some control?

This paper seeks to address these questions, with the aim of helping regulators, utilities, and other stakeholders gauge how much attention to devote to evaluating and addressing possible impacts of distributed solar on retail electricity prices. The objective is neither to dismiss concerns nor to raise alarm, but rather to provide some metrics and benchmarks that could help to set priorities. To be sure, in focusing on the potential effects on retail prices, we address just one motivation behind rate reforms for solar customers—namely, concerns about cost-shifting between solar and non-solar customers. Other motivations, including impacts on utility shareholders and economic efficiency, are also relevant and may ultimately provide a more compelling rationale for retail rate reforms, but are outside the scope of this paper. Several other important limitations to the study scope are noted in the text box to the right.

Limitations to the Scope of this Paper

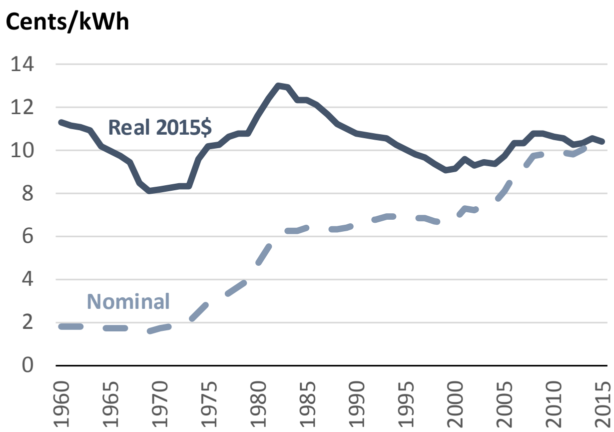
This paper presents illustrative comparisons between the effects of distributed solar and other drivers of retail electricity prices. **It does <u>not</u>:**

- **Address distributed energy resources as a whole.** While this paper focuses specifically on distributed solar, retail rate reforms in some states may be motivated by distributed energy resources more broadly and by other technologies that enable customer price-responsiveness.
- **Provide state- or utility-specific analysis.** The analyses presented here are based on U.S. average or otherwise illustrative conditions, and draw from a variety of pre-existing studies. The paper may inform, but is not a substitute for, detailed state- or utility-specific studies.
- **Support any particular approach to defining the value of solar.** This paper shows, generically, how the effects of distributed solar on retail electricity prices are a function of the value of solar to the utility. However, the paper makes no assumptions or conclusions about how to estimate that value.
- **Provide a cost-benefit analysis of distributed solar or any other type of policy or resource.** This paper focuses narrowly on retail electricity price effects. It does not address the full set of costs and benefits relevant to evaluating the resources and policies discussed.

We begin by discussing historical trends in U.S. and regional average retail electricity prices, key drivers for those trends, and current projections. Next, we present a simple, fundamentals-based model for approximating the effects of distributed solar on retail electricity prices, and use that model to gauge the magnitude of effects that might plausibly occur under current and forecasted penetration levels. We then discuss a number of other important drivers for future retail electricity prices, including: energy efficiency programs and policies, natural gas prices, renewables portfolio standards, state and federal carbon policies, and electric industry capital expenditures. We characterize the potential effects of each of those drivers on future retail electricity prices, based on a combination of literature review and back-of-the-envelope style analyses. Finally, in the Summary and Conclusions section, we directly compare the potential retail price effects of distributed solar and each of the other issues discussed, and offer high-level conclusions.

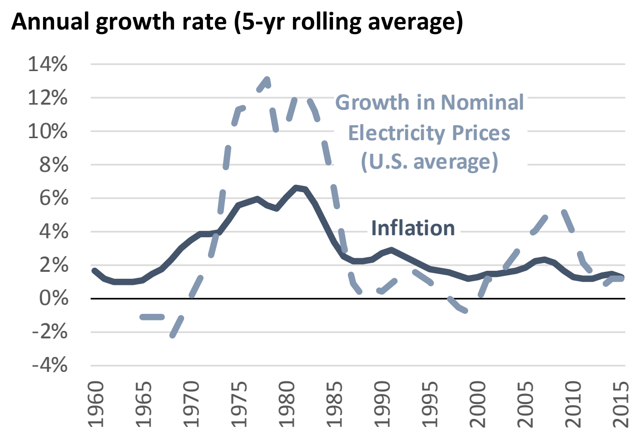
2. U.S. Retail Electricity Prices: Historical Trends and Current Projections

To provide some historical context to questions about the possible effects of distributed solar on retail electricity prices, it is useful to begin by reviewing how prices have evolved over time and where they are currently projected to go. As shown in Figure 1, U.S. average retail electricity prices, in real (inflation-adjusted) terms, have fluctuated over time, with extended periods of increasing and decreasing prices.[1] Average prices in 2015 were nearly identical to the long-term historical average since 1960 (10.4 cents/kWh, in real 2015$), and were well below the highs of the early 1980s. Nominal electricity prices—what consumers directly observe—have generally risen over time, albeit with several prolonged periods of relatively stable prices. On average, retail electricity prices have risen in nominal terms by 3.2% (or 0.16 cents/kWh) per year since 1960, roughly equal to the average rate of inflation over that period. Nominal electricity prices and inflation have not moved in lock-step though, with electricity prices rising more slowly than inflation in some periods, and considerably faster in others, as shown in Figure 2.



Notes: Represents U.S. average retail electricity prices across all customer segments and utilities, as reported by EIA (2012, 2015c, 2016e). Converted to real dollars based on GDP price deflator (BEA 2016).

Figure 1. Historical trends in U.S. average retail electricity prices



Notes: Growth rates for nominal electricity prices and inflation both calculated as a rolling 5-year compound annual growth rate. See Figure 1 notes for sources.

Figure 2. Escalation of nominal electricity prices compared to inflation

The first significant rise in electricity prices (in both real and nominal terms) coincides with the oil price shocks of the 1970s and the resulting increases in fuel prices, inflation, and interest rates (Joskow 1989 and Kahn 1988). High interest rates especially impacted construction costs for the many nuclear power plants built during this era, some of which also suffered construction delays, leading to steep rate

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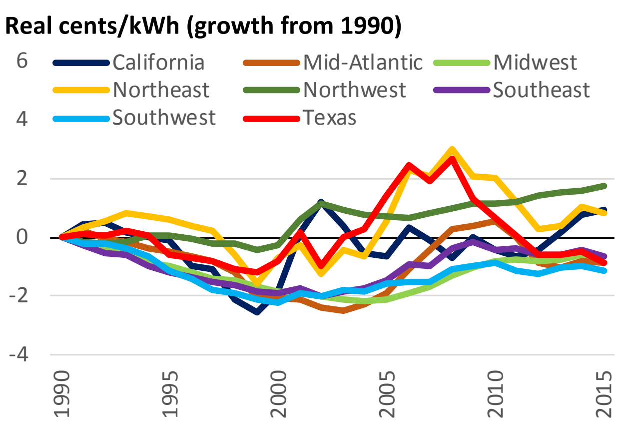
[1] Average retail electricity rates—that is, total revenues divided by total sales—are an admittedly blunt metric, glossing over distinctions among customer classes and between investor-owned and publicly owned utilities, and ignoring distinctions in retail electricity rate structures that often include non-volumetric charges. Also important to note is that trends in average electricity prices do not necessarily mirror trends in average customer bills or costs, as can be particularly germane when discussing demand-side resources, such as energy efficiency or distributed solar.

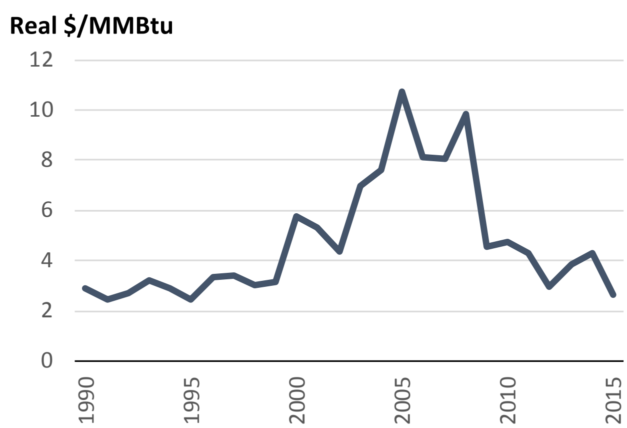
increases as those costs were passed into utilities' rate bases (Hirsh 1999). Slowing growth in electricity sales further exacerbated the effects of capital cost escalation on electricity prices, as utilities' increasing revenue requirements were spread across fewer (or more slowly growing) units of electricity sales. As a result of this confluence of factors, U.S. average retail electricity prices rose by 4% per year from 1973-1983, in real dollars (and by 12% per year in nominal terms). As fuel prices and inflation rates began to subside in the mid-1980s, and as electricity sales growth recovered, U.S. average electricity prices resumed their downward trajectory (in real dollars, and remained relatively flat in nominal terms) until roughly the end of the millennium.

Starting around 2000, electricity prices again hit an inflection point and began an upward bend. The trend extends across most regions, albeit to varying degrees. As shown in Figure 3, most regions saw at least a 1-2 cent/kWh increase in average retail prices over the 2000-2015 period, and in some cases larger price swings in the intervening years. A relatively sizeable literature has sought to explain retail electricity pricing dynamics over the past two decades, generally in connection with restructuring of wholesale and retail electricity markets. As summarized by Morey and Kirsch (2016), these studies draw varying conclusions about the effects of deregulation: in some cases finding evidence that it reduced retail electricity prices (relative to what they otherwise would have been), in other cases finding no such effect, and in yet other cases finding that the effects have varied (e.g., depending on retail switching levels or on whether a state was past its transitional rate-freeze period).



Notes: Values represent the change in price relative to 1990. See Figure 1 notes for sources.

Figure 3. Growth in regional retail electricity prices



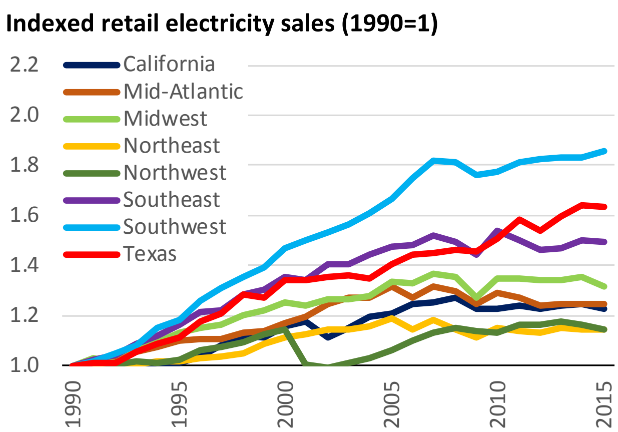
Notes: Annual average of daily prices for NYMEX Henry Hub futures contracts for delivery in the following month.

Figure 4. Annual average natural gas prices

Many of the same studies also highlight the impact of natural gas prices, which were especially volatile over this period. As shown in Figure 4, gas prices rose sharply from 2000 through 2008, before dropping back down with the recession and expansion of shale extraction. The effects on regional electricity prices are most apparent for the Northeast and Texas—both of which show a discernible "bump" in electricity prices, coinciding more-or-less with the years of high gas prices. Those regions both have relatively high proportions of gas-fired generation as well as restructured power markets, which, for reasons discussed in Section 4.2, are particularly sensitive to changes in gas prices. Not surprisingly, econometric analyses of retail prices over this period consistently find strong positive relationships between state-level electricity prices and either natural gas prices or the proportion of electricity generated from gas (Fagan 2006, Joskow 2006, Ros 2015, Su 2015, Swadley and Yucel 2011, Taber et al. 2006, Zarnikau and Whitworth 2006).

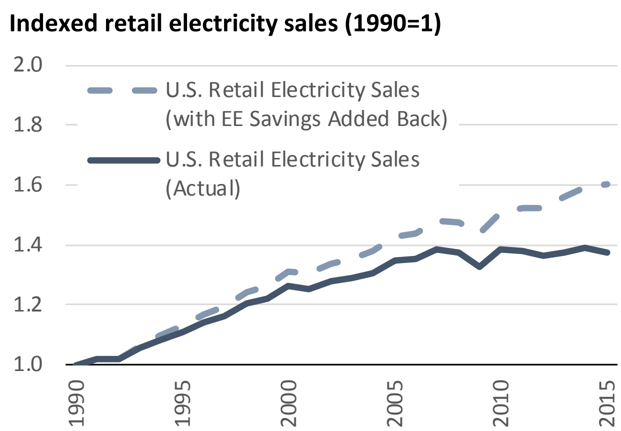
Recent retail electricity price trends have also been driven by capital expenditures (CapEx), which have risen sharply in recent years. Annual CapEx outlays in the electric power sector roughly tripled from 2000 to 2015, with transmission and distribution (T&D) investments representing the vast majority of that growth (EEI 2015, ABB 2016). As these investments enter utilities' rate bases in subsequent rate cases, the associated costs are passed on to ratepayers. Accordingly, annual depreciation and financing-related expenses by major electric utilities grew by roughly 50% over the same time span (ABB 2016).

Reduced growth in electricity sales has also affected the recent trajectory of retail electricity prices. Almost every region in the United States has seen effectively zero growth in electricity sales since 2008 or earlier, as shown in Figure 5. Although growth rates have been steadily declining over a longer period of time, such an extended period of flattened demand is wholly unprecedented, with the closest analogue being two brief periods of dampened growth in the aftermath of the 1970s' oil price shocks. This recent episode of low demand growth is partially the result of the recession, though other factors have also clearly played a role (Faruqui 2013).



Notes: Data represent total retail electricity sales, including both bundled and energy-only sales, as reported by EIA (2015c, 2016e).

Figure 5. Growth in regional retail electricity sales



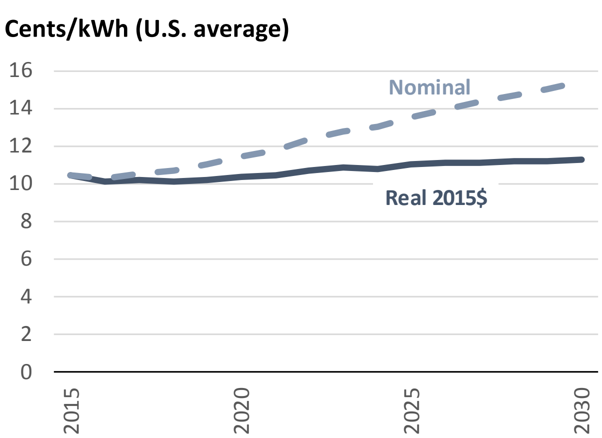
Notes: Savings from federal appliance standards based on Meyers et al. (2016). Savings from utility ratepayer-funded programs are based on ACEEE data (e.g., Berg et al. 2016) and decayed over time to reflect a 10-yr. avg. measure life. The figure does not account for possible rebound effects.

Figure 6. Impact of energy efficiency programs and policies on U.S. retail electricity sales

One key contributor has been increasing energy efficiency. As shown in Figure 6, federal appliance efficiency standards and utility ratepayer-funded energy efficiency (EE) programs have significantly slowed retail electricity sales growth. The erosion of sales growth has accelerated in recent years, as new standards have taken effect and utility programs have become more aggressive. In total, federal efficiency standards and utility efficiency programs reduced U.S. retail electricity sales by an estimated 14% in 2015, relative to what they otherwise would have been (but without accounting for possible rebound effects). State appliance standards and building codes, not counted here, would add further to that total. In the absence of those efficiency interventions, U.S. retail electricity sales would have grown by roughly 1.3% per year since 2000: still below historical growth rates (e.g., 2.3% per year from 1990-2000), but substantially greater than actual growth over that period (0.6% per year).

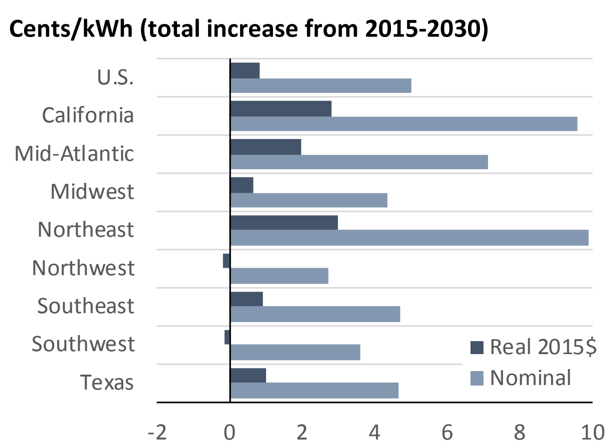
The precise impact of declining sales growth on retail electricity prices can be difficult to assess, as its effects can work in opposing directions. On the one hand, slower growth allows utilities to purchase less fuel and, over the long-term, defer some investments that they might otherwise need to make. Slower demand growth also puts downward pressure on wholesale electricity prices in competitive markets, at least in the short-run. On the other hand, reduced sales can push prices upward in the near-term for regulated services, as fixed or growing infrastructure costs are spread over a more slowly growing quantity of sales. Thus, even if customer bills are lower, the price per kilowatt-hour may be higher. Consistent with this latter dynamic, Morey and Kirsch (2013) estimated that recession-induced reductions in electricity sales increased state-level residential and commercial electricity prices by approximately 0.8 cents/kWh, on average.

State and regional clean energy policies have also been linked to increases in retail electricity prices, though most available evidence points to relatively limited impacts to-date. In particular, analyses of state renewables portfolio standards (RPS) have generally suggested effects on the order of 0.5 cents/kWh or less in recent years, though those impacts can be greater in states with retail choice or more-stringent RPS standards, and have grown over time as RPS percentage targets rise (Barbose 2016, Morey and Kirsch 2013, Tra 2016, Wang 2014). More details on the historical effects of RPS policies are provided in Section 4.3. Greenhouse gas cap-and-trade programs have also been established in California and the Northeast—however the effects of those policies on retail electricity prices also appear to have been modest thus far, largely due to low emissions allowance prices and the fact that revenues from allowance sales are often partially credited back to ratepayers (CARB 2016, RGGI 2016a).



Notes: Projected U.S. average retail electricity prices based on EIA's 2017 Annual Energy Outlook reference case (EIA 2017).

Figure 7. Projected U.S. average retail electricity prices



Notes: See Figure 7 for source. Based on projected retail prices for EIA Electricity Market Module regions, aggregated into the larger regional groupings shown here.

Figure 8. Projected growth in regional electricity prices

These many considerations aside, it is clear that retail electricity prices in the United States have generally been on a slight upward trajectory since 2000, even after adjusting for inflation, marking a departure from the earlier era of steadily declining prices. Current projections suggest that those recent trends are not an intermittent episode, but potentially the beginning of a longer-term shift. As shown in Figure 7, EIA's most-recent reference case forecast projects that U.S. average retail electricity prices will continue to gradually rise, increasing by just under 1 cent/kWh in real terms (and 5 cents/kWh nominal) through 2030, similar to the pace of escalation since 2000. As shown in Figure 8, price escalation is projected to extend across most regions, though to varying degrees, with the largest projected increases in the Northeast and California.

Future electricity prices are, of course, highly uncertain, and key sources of uncertainty—including many of the same drivers discussed above—are explored in Section 4 of this paper. Those uncertainties, combined with the end to the era of steadily declining prices, may heighten sensitivity about possible price effects associated with the growth of distributed solar. So how large might those effects be?

3. Scaling the Effects of Distributed Solar on Retail Electricity Prices

Much debate has occurred around the existence and size of any cost-shifting from distributed solar, particularly for solar compensated via net energy metering (NEM) with volumetric retail rates. These debates have focused to a large degree on how to properly value the costs and benefits of distributed solar. One threshold issue is the time horizon: whether to consider only short-run avoided costs from distributed solar, consisting mostly of avoided fuel and power purchase expenses, or to also consider longer-term avoided costs, including potential deferral of generation and T&D investments. Another threshold issue is the scope of benefits to consider: for example, whether to focus only on avoided costs directly incident on the utility, or to also include broader societal benefits, such as avoided environmental externalities. Beyond those are many narrower, though also important, methodological issues related to how to properly evaluate specific costs and benefits.

For the present purposes, we abstract from those technical and policy questions and show, generically, how the effect of distributed solar on average retail electricity prices is a function of three basic drivers: its penetration level, the net avoided costs to the utility, and the compensation rate provided to distributed solar customers. Understanding these basic functional relationships can help to scale expectations about the magnitude of any plausible impacts on electricity prices, without necessarily having to arbitrate all the technical details of how to value distributed solar.

We focus specifically on cost-of-service based pricing, where total utility revenues are approximately equal to total utility costs, and average retail electricity prices are equal to utility revenues divided by sales.[2] In order to generalize the effects of distributed solar, we specify the three key drivers as follows, each of which is expressed as a ratio or percentage term:

- ***Penetration level*** is expressed in terms of total distributed solar generation as a percentage of total retail electricity sales.

- ***Net avoided costs*** are expressed as the value of solar (VoS) to the utility (i.e., benefits minus costs) relative to the utility's average cost of service (CoS). VoS refers to the *net* avoided costs to the utility per unit of solar generation, and CoS refers to the utility's average all-in cost per unit of retail sales. For the purpose of estimating retail price effects, the VoS should consider only costs and benefits directly incident on utility ratepayers, but may be based on either short- or long-run avoided costs, depending on whichever time horizon is deemed most relevant.[3] In

[2] The assumed equivalence between utility revenues and costs does not hold perfectly, particularly in the short-run between utility rate cases, but should be reasonably accurate over the longer term as rates are re-set in successive rate cases. Other persistent exceptions may still exist, though, for example due to disallowed costs and performance incentives.

[3] Although a broader scope of costs and benefits—such as non-energy benefits and societal costs and benefits—may be relevant in other contexts and to policy-making more generally, they are not directly relevant to evaluating the effects on electricity prices.

cases were only short-term avoided costs are considered (e.g., avoided fuel and power purchase expenses), the VoS/CoS ratio would be relatively low. If additional avoided costs are deemed appropriate to include, as may be the case under a longer term analysis, the VoS/CoS ratio would be greater.

- ***Solar compensation rate*** is the payment or bill savings per unit of solar generation, relative to the CoS. Under full NEM with flat volumetric rates and no fixed customer charges or demand charges, the customer is effectively paid the average retail electricity price for all solar generation. In this case, the compensation level is equal to roughly 100% of the CoS (assuming the retail price is reflective of the CoS). Under other crediting mechanisms or rate designs, the compensation might be higher or lower than the CoS. For example, under rate structures with fixed charges or demand charges, as are common for commercial customers and increasingly so for residential customers, the solar compensation rate would be less than 100% of the CoS.

Relying on those three terms, we can then express the percentage change in average retail electricity prices resulting from distributed solar, as follows (see Appendix A for the derivation):

$$Percent\ Change\ in\ Retail\ Electricity\ Price = \ Penetration \times \left[\frac{Solar\ Comp.Rate}{CoS} - \frac{VoS}{CoS}\right]$$

To be sure, this simplified construct ignores various complexities of electric ratemaking processes, not least of which being the lag between the time that costs are incurred and when they are added into rates. To the extent this simplification introduces bias, it would likely be to overstate the effects. In addition, although it can be used to estimate an average effect across all customers, the above expression may be more usefully applied on a customer-class specific basis, given differences between residential and commercial rate structures, and the manner in which revenue requirements are allocated to individual customer classes.

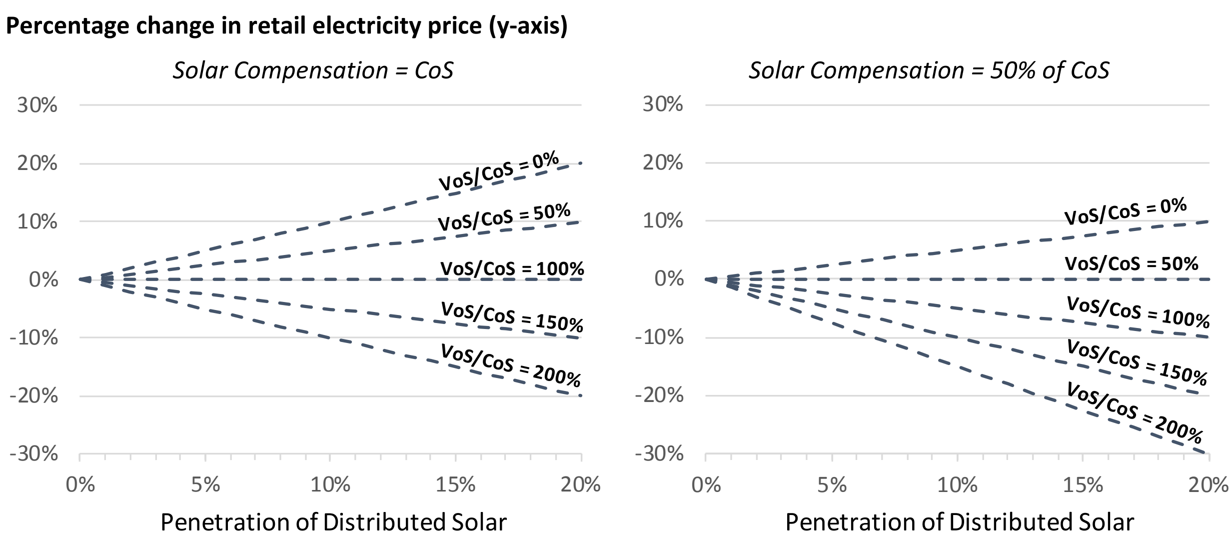


Figure 9. Impacts of distributed solar on average retail electricity prices: A simple model of underlying drivers

Based on the expression above, the family of curves shown in Figure 9 illustrate the percentage change (either increase or decrease) in average retail electricity prices resulting from varying levels of distributed solar. The figure on the left represents the case where solar compensation is equal to exactly the CoS, which corresponds to full NEM with flat volumetric prices and is roughly representative of how residential customers with distributed solar are often compensated. If, for example, the value of solar is equal to half the utility's cost of service (VoS/CoS=50%), then a 10% solar penetration would lead to a 5% increase in retail electricity prices under this compensation regime. The figure on the right corresponds instead to a scenario where solar is compensated at a rate equal to 50% of the utility's cost of service—as would be the case if fixed customer charges were used to meet half the utility's revenue requirement. This figure may also be a better reflection of the relationships under many commercial rate structures with demand charges that comprise a large fraction of the customer bill. At this compensation rate and a VoS equal to 50% of the utility's CoS, distributed solar would have no impact on retail electricity prices, regardless of penetration level. If the VoS were greater, distributed solar would result in a reduction in average retail electricity prices.

The examples above are purely illustrative, but the curves can provide some practical insight if we consider current and projected solar penetration levels. As shown in Table 1, eight utilities reached net-metered PV penetration levels greater than 5% of retail electricity sales in 2015, and four utilities (all in Hawaii) topped 10% of sales within the residential sector. However, the U.S. average penetration was just 0.4% across all electric utilities, and most utilities have yet to reach even one-tenth of that. Thus, for the overwhelming majority of utilities, current PV penetration levels are far too low to result in any discernible effect on retail electricity prices, even under the most pessimistic assumptions about the value of solar and generous assumptions about compensation provided to solar customers (e.g., full NEM with volumetric rates).

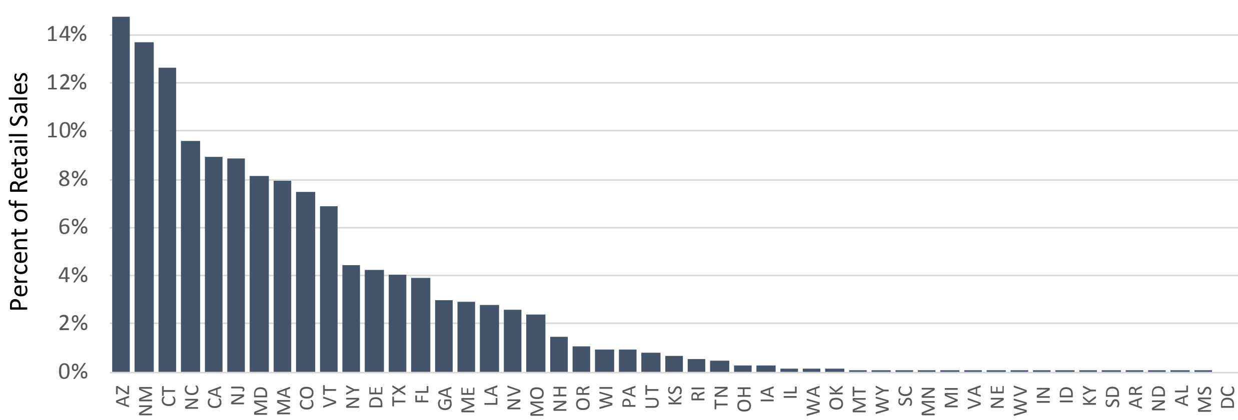
Table 1. Top-ten utilities for net-metered PV penetration, as of year-end 2015

Penetration among all customers			***Penetration among residential customers only***		
Utility	State	% of Sales	Utility	State	% of Sales
Hawaii Electric Light	HI	12.4%	Maui Electric	HI	18.0%
Maui Electric	HI	12.1%	Hawaii Electric Light	HI	16.9%
Hawaiian Electric	HI	8.1%	Hawaiian Electric	HI	16.8%
Kauai Island Utility Cooperative	HI	7.9%	Kauai Island Utility Cooperative	HI	10.5%
Otero County Electric Cooperative	NM	5.6%	San Diego Gas & Electric	CA	7.7%
San Diego Gas & Electric	CA	5.5%	City of Moreno Valley	CA	6.5%
Washington Electric Cooperative	VT	5.3%	Pacific Gas & Electric	CA	5.3%
Town of Hardwick	VT	5.3%	Otero County Electric Cooperative	NM	5.2%
Trico Electric Cooperative	AZ	4.1%	Groton Dept. of Utilities	CT	4.5%
Pacific Gas & Electric	CA	3.6%	Southern California Edison	CA	3.9%
	Total U.S.	***0.4%***		***Total U.S.***	***0.6%***

Notes: Based on data for NEM PV capacity and retail electricity sales reported through form EIA-861 (EIA 2016g). Net-metered PV generation is estimated using the PVWatts software with the program's default assumptions (NREL 2016).

Going forward, penetration levels will rise and, for a growing number of utilities, may reach some threshold of significance in terms of the effects on retail electricity prices. Across a collection of recent forecasts, distributed solar generation is projected to reach 1-2% of U.S. retail electricity sales by 2020, 2-4% by 2030, and 4-7% by 2040 (BNEF 2016, EIA 2017, Cole et al. 2016, GTM/SEIA 2016, IHS 2016).[4] The low end of those ranges effectively corresponds to a scenario in which distributed solar capacity additions continue at the same pace as in 2015 (roughly 3 GW per year).

Even with relatively robust growth nationally, high penetration levels are expected to remain concentrated within particular states and regions. Under the National Renewable Energy Laboratory (NREL)'s most recent reference case projection (Cole et al. 2016), three states within the contiguous U.S. surpass 10% penetration by 2030 (not counting Hawaii), and seven others pass the 5% mark, but more than half of all states remain below 1% penetration (see Figure 10). Most utilities are thus quite unlikely to see any appreciable effects of distributed solar growth on retail electricity prices. For example, even if one were to assume that distributed solar had zero net value to the utility (an extremely pessimistic assumption), and that all PV generation was compensated under net metering with purely volumetric retail rates (a relatively favorable scenario for solar customers), a 1% penetration would result in just a 1% increase in average retail electricity prices. Relative to projected U.S. average electricity prices in 2030, this equates to a 0.1 cents/kWh increase. Most utilities are unlikely to see an effect even of this magnitude, given more-realistic assumptions about the value of solar and a lower solar compensation rate for most commercial and many residential customers.



Notes: Based on central case scenario from Cole et al. (2016), which projects solar adoption in the contiguous United States (i.e., excludes Hawaii and Alaska). Penetration levels calculated from projected capacity based on estimated state-level capacity factors (NREL 2016) and retail sales projections developed by applying EMM-level growth rates from the Annual Energy Outlook 2016 reference case (EIA 2016a) to historical state-level retail sales data (EIA 2015c).

Figure 10. NREL-projected rooftop solar penetration levels in 2030

For those utilities that currently, or may in the future, face higher penetration levels, questions about the value of solar become more pertinent. Over the *short-run*, the VoS might be approximated based on a utility's cost of fuel and power purchases, which average 40% of total electric utility expenses

[4] These studies all define distributed solar slightly differently; for example, EIA defines it as all solar <1 MW in size, whereas Cole et al. (2016) define it to include all rooftop PV, regardless of size.

nationally (EIA 2015c). Taking a 40% VoS/CoS ratio as an *illustrative* lower bound and assuming full NEM with purely volumetric rates, a utility with 5% solar penetration would see roughly a 3% increase in average retail prices in the short-run, based on the relationships previously described. Outside of Hawaii (which has substantially higher penetration) or California (where residential penetration has reached this level and rates are steeply tiered), few utilities are likely to have witnessed effects on this scale thus far—and even then, the impacts may be concentrated primarily within the residential customer class.

Table 2. Summary of recent value-of-solar studies

Region	Author (Year)	VoS (2015 cents/kWh)		VoS/CoS	
		Core	Core+	Core	Core+
Arizona (APS)	SAIC (2013)	3.7	n/a	31%	n/a
Arizona (APS)	Crossborder Energy (2013a)	24.6	n/a	204%	n/a
Arizona (APS)	Crossborder Energy (2016)	16.9	18.9	144%	161%
California	E3 (2013)	n/a	14.6	n/a	98%
California	Crossborder Energy (2013b)	11.0	20.2	74%	135%
Colorado (PSCo)	Xcel (2013)	7.2	8.4	71%	83%
Maine	Clean Power Research (2015)	13.8	24.3	106%	185%
Massachusetts	Acadia (2015)	15.9	23.2	93%	136%
Mississippi	Synapse (2014)	14.6	17.4	148%	176%
Nebraska	Lincoln Electric System (2014)	3.8	n/a	47%	n/a
Nevada	E3 (2014b)	n/a	13.1	n/a	134%
Nevada	SolarCity/NRDC (2016)	10.3	11.2	109%	118%
North Carolina	Crossborder Energy (2013c)	11.6	12.9	122%	136%
PJM Region	Clean Power Research (2012)	7.5	17.6	51%	121%
Tennessee Valley Authority	TVA (2015)	6.9	7.3	73%	77%
Texas (Austin Energy)	Clean Power Research (2013a)	9.1	11.2	90%	111%
Texas (San Antonio)	Clean Power Research (2013b)	13.3	16.0	143%	173%
Utah	Clean Power Research (2014)	8.3	11.9	97%	139%
Vermont	VT Public Service Dept. (2014)	n/a	24.4	n/a	163%

Notes: "Core" VoS estimates consist of only avoided energy, RPS purchases, generation capacity, reserves, ancillary services, T&D capacity, and losses, and are net of any solar integration costs. "Core+" estimates include additional ratepayer benefits, which, depending on the study, may include items such as: reduced fuel price risk, reduced costs of future carbon regulations, and cost savings associated with reduced wholesale electricity and/or natural gas prices. Broader societal benefits are excluded from both VoS categories, as the present analysis is focused solely on ratepayer impacts. Cells are marked "n/a" if the VoS value was not estimated or identifiable. For studies that included multiple scenarios, we selected the reference case. For studies that presented ranges, we report the mid-point. The VoS/CoS percentages are calculated by dividing the VoS by the average retail electricity price for the corresponding state or utility, in the year in which the study was performed.

Over the *long-run*, a broader set of avoided costs are typically considered. Estimates of the long-term VoS for particular states and utilities vary considerably, as shown in Table 2, reflecting differences in scope, methodology, and the characteristics of regions analyzed (Hallock and Sargent 2015, Hansen et al. 2013). A VoS/CoS ratio can be estimated from each of these studies, by taking the average retail electricity price in each state or utility service territory as a proxy for the average cost of service. Based on this approach, most studies fall within a VoS/CoS range of roughly 50-150% (the 10^{th} and 90^{th}

percentile values are 49% and 146%), when considering only "core" avoided cost categories (see table notes for a list of which items are included in that set). When considering a broader set of potential ratepayer benefits (labeled "core+" in the table), the VoS/CoS ratios are higher, ranging from 90-174% (the 10th and 90th percentile values).

Given these VoS estimates, what effects on retail electricity prices might be observed in those regions with the highest projected levels of distributed solar penetration? As noted, NREL's latest reference case projects that three states in the contiguous U.S. reach 10% penetration of distributed solar by 2030, and similar penetrations might be reached more broadly on a utility-specific basis and among residential customers.[5] At that penetration level and considering a VoS/CoS ratio of 50-150%, the resulting effect on retail electricity prices would be between a 5% increase and a 5% decrease, under full net metering with purely volumetric rates. Assuming an otherwise average price of electricity, this would equate to roughly a 0.5 cent/kWh increase or decrease. By comparison, for the distribution in projected state-level 2030 penetration rates shown in Figure 10, the average retail price impact would be ±0.2 cents/kWh. At current penetration rates, the average retail price impact is ±0.03 cents/kWh.[6]

To be sure, these retail price effects are intended for illustrative purposes only, and in any given instance could be smaller or larger. For example, the estimates presented above are all based on net-metering with fully volumetric prices. In cases where some portion of solar customers take service under rates with fixed charges or demand charges—both of which are already commonplace—the ranges cited above would be shifted downward. At the same time, the preceding estimates draw from VoS studies that, in most cases, are based on current (low) levels of solar deployment. At higher solar penetration levels, the VoS is expected to decline, leading to higher retail price effects (Mills and Wiser 2013). Moreover, the existing VoS studies referenced in the preceding analysis are based on particular utilities or regions, and cannot necessarily be extrapolated to other contexts. Given these limitations and others, more-refined and regionally specific analysis would certainly be needed to accurately estimate the effects of future distributed solar growth on retail electricity prices for any specific utility or state. However, the back-of-the-envelope style calculations presented here offer some rough sense of scale for the possible impacts, and in most situations likely provide a plausible set of bounds.

[5] For example, Entergy (Louisiana) and Duke (Indiana) both considered distributed solar penetration levels close to 10% in their latest integrated resource plans (Mills et al. 2016).

[6] The average retail price impacts at current and projected state-level penetration rates are calculated by first computing the impact for each state, applying the same 50%-150% VoS/CoS ratio to each state's penetration rate, and then multiplying the resulting percentage impact by the state's retail electricity price. Averages across states are load-weighted.

4. Other Drivers for Changes to Retail Electricity Prices

Changes in retail electricity prices resulting from distributed solar growth—whether large or small, positive or negative—are not happening in a vacuum. A host of other factors will also influence the trajectory of retail electricity prices over time, some by potentially greater amounts, and many of these are also within the sphere of influence by utilities, state regulators, and policymakers. In this section, we review a number of these other drivers, characterize their potential impact on future electricity prices, and highlight some of the ways in which states and utilities may be able to manage their effects on retail electricity prices.

We focus on a set of drivers with relatively broad geographical applicability, namely: energy efficiency programs and policies, natural gas prices, renewables portfolio standards, state and federal carbon policies, and capital expenditures by electric utilities. Drawing on existing studies and several illustrative analyses, we describe the potential effects of each in terms of the projected impact or range of impacts on average retail electricity prices in the year 2030, highlighting regional differences where possible. In the final section of the paper, we compare these drivers directly to the potential effects of distributed solar, as discussed in the previous section.

To be clear, the analysis presented here is not comprehensive, in terms of either its depth or the breadth of issues discussed.[7] Rather, the intent is simply to provide some illustrative and approximate benchmarks against which the potential impacts of distributed solar might be gauged (and that could inform more-detailed state- or utility-specific analyses). We also reiterate that this analysis by no means considers the full set of benefits and costs that might be relevant to evaluating the issues discussed. Rather, the focus is narrowly on retail electricity price effects, as this is the particular issue motivating many of the debates related to retail rate reforms for distributed solar customers.

4.1. Energy Efficiency Programs and Policies

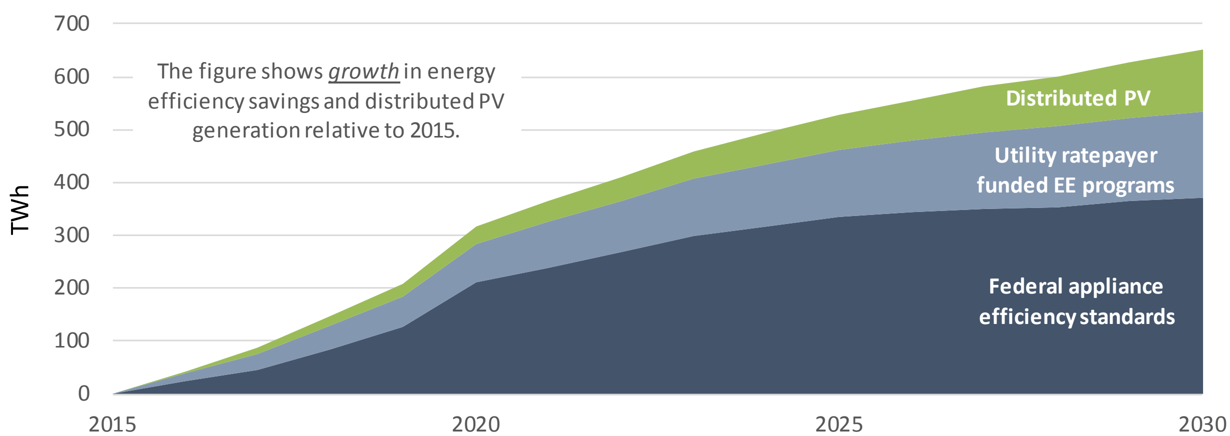
Net-metered solar and energy efficiency (EE) both reduce electricity sales, putting upward pressure on regulated electricity prices in the near-term, as embedded costs are recovered across a smaller base of sales (even if the resources are cost-effective over the long-run). One can thus gain some sense for the relative impact of distributed solar compared to EE, based on their relative penetration levels, while also acknowledging some important differences between the two types of resources, such as solar intermittency and relatively broad participation in energy efficiency programs.

Historically, energy efficiency policies and programs have had an inordinately greater impact on retail electricity sales than distributed solar. As noted earlier in Section 2, utility energy efficiency programs and federal appliance efficiency standards together reduced total U.S. retail electricity sales by roughly

[7] For example, other factors that may affect future retail electricity prices include electric vehicles, storage, and wholesale market reforms.

14% in 2015.[8] By comparison, all net-metered PV installed through the end of 2015 reduced retail electricity sales by just 0.4% (i.e., 35 times smaller than the effects of energy efficiency to-date). Even in those regions with relatively high distributed solar penetration, the effects of energy efficiency have thus far generally been far greater. For example, in San Diego Gas & Electric's service territory, annual energy savings from all efficiency programs and policies were equal to 31% of its electricity sales in 2015, compared to 5.5% penetration of distributed solar (CEC 2016).

Going forward, energy efficiency will likely continue to outpace distributed solar, though not as starkly as in the past. Energy savings from federal appliance standards and utility EE programs are projected to grow by 535 TWh over the 2015-2030 period (see Figure 11). Other efficiency policies for which projections are not available, such as state-level appliance standards and building codes, would add further to this total. By comparison, generation from distributed PV is projected to grow by 116 TWh over this timeframe (based on NREL's latest reference case). The effects of projected energy efficiency growth are thus roughly five times as great as growth in distributed PV, at the national level.



Notes: Data on federal appliance efficiency standards are adapted from Meyers et al. (2016), relying on supporting documentation provided directly by the authors. Data on utility ratepayer-funded EE programs are adapted from the mid-case projection in Barbose et al. (2013), requiring extrapolation from 2025 to 2030 and application of a decay function to accumulate savings from measures installed in successive years. Data on distributed PV are adapted from Cole et al. (2016), with generation estimated from reference-case nameplate capacity based on state-specific capacity factors. The EE projections in the figure are intended to represent savings net of free riders, but do not reflect any possible rebound effects, nor does the figure include naturally occurring EE.

Figure 11. Growth in U.S. energy efficiency savings and distributed PV generation

Assuming a value of energy efficiency savings comparable to the range considered previously for solar—equal to 50-150% of the utility's average cost of service—projected growth in energy efficiency savings through 2030 would result in roughly a ±0.8 cents/kWh change in U.S. average retail electricity prices. Of course, the value of energy efficiency could be greater or less than the value of distributed solar. For example, solar is intermittent, which would lessen its value relative to energy efficiency, but can potentially provide additional grid services that energy efficiency cannot. Solar and energy

[8] To be clear, this 14% represents the cumulative effect in 2015 of efficiency programs and federal standards implemented over time (as opposed to the incremental effect of just those efficiency measures implemented in 2015).

efficiency also have different hourly and seasonal profiles, which may lead to higher or lower avoided costs relative to one another. Notwithstanding these differences, it is nevertheless reasonably clear from the preceding comparison that energy efficiency is likely to have a substantially greater impact on retail electricity prices than distributed solar, at least at the national level.

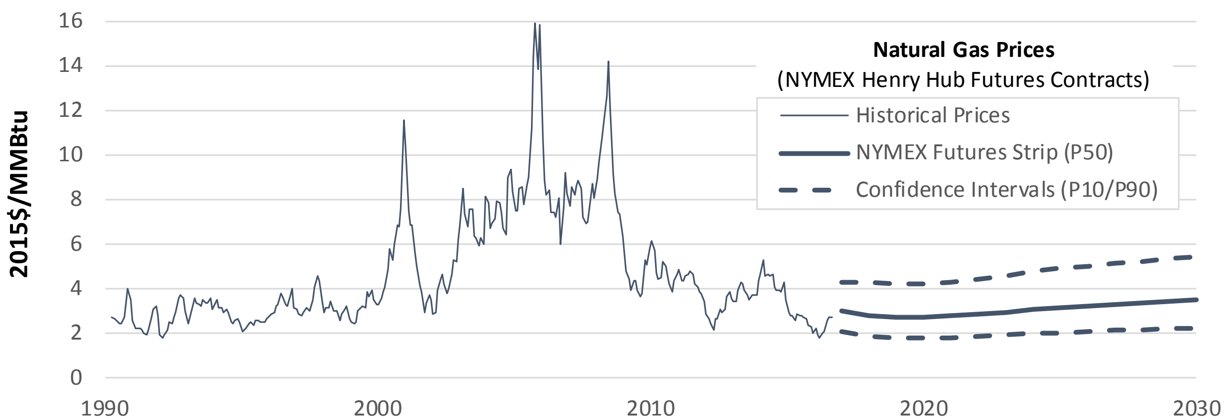
Even in those states with the highest projected solar penetration levels, growth in distributed solar generation is likely to be outpaced by EE. For example, the California Energy Commission's latest demand forecast projects that statewide annual energy savings from EE programs and policies will grow by 57 TWh from 2015-2026 (CEC 2016). By comparison, the CEC projects that distributed PV will grow by 15 TWh over this period, reaching 8% penetration in 2026 and equal to roughly one-quarter the size of expected EE growth.

The purpose of this comparison is not to cast energy efficiency as a bigger "problem" than distributed solar, but rather to highlight the following two points. First and foremost, experiences with energy efficiency demonstrate that short-term rate impacts from distributed energy resources—even if at a much greater scale than would occur at projected penetration levels of distributed solar—may be acceptable provided that: (a) the resources yield net cost savings to utility ratepayers over the long run, and (b) adequate opportunities exist for all ratepayers to participate. With respect to the latter, overall participation levels in EE programs can be quite high, particularly when including appliance and building efficiency standards, and extra effort is often made to specifically target low-income customers. As the cost of solar continues to decline (making it more affordable to low- and moderate-income customers), as grid-friendly PV technologies advance (increasing the value of solar to the utility), and as initiatives to broaden solar access continue (such as community solar and other programs specifically targeting low- and moderate-income customers), issues related to the rate impacts and cost-shifting from distributed solar may become more similar to those of energy efficiency. Second, to the extent that erosion of utility sales from demand-side measures remains a concern, any regulatory response may be more effective if directed at demand-side resources more broadly, including electric vehicles and storage for example, rather than focusing in isolation on distributed solar.

4.2. Natural Gas Prices

Electricity prices have become increasingly linked with natural gas prices, as a greater share of electric power generation is fueled by gas. Nationally, natural gas-fired generation has grown from 9% of total U.S. electricity generation in 1988 to 33% in 2015, and represents more than 50% of electricity generation in many states and regions (EIA 2016b). Reliance on natural gas for electric power generation is generally expected to continue to increase over time, in part due to expectations of continued low natural gas prices.

Although gas prices are currently at historical lows, they have exhibited tremendous volatility in the past, and future prices remain highly uncertain. This is evident in Figure 12, which shows natural gas prices alternating over the past two decades between prolonged periods of lows and highs. Given that historical volatility, substantial uncertainty exists in the long-term trajectory of natural gas prices. As an illustration of that uncertainty, Figure 12 shows confidence intervals for natural gas futures prices going forward, derived by Bolinger (2016). These confidence intervals diverge over time and have a distinct upward skew, though are far narrower than historical price variability. At the upper-bound (P90) confidence interval, 2030 gas prices are roughly $1.9/MMBtu higher than the "expected" trajectory extrapolated from the NYMEX futures strip. Utilities and regulators have some ability to limit ratepayers' exposure to this price uncertainty, chiefly by diversifying fuel sources used for electricity generation, along with limited gas price hedging.[9]



Notes: Historical Prices are the monthly average price of NYMEX Henry Hub futures contracts for delivery in the following month, converted to real dollars based on quarterly GDP deflators (BEA 2016). Confidence Intervals for NYMEX futures prices were derived by Bolinger (2016), based on historical volatility in returns on natural gas futures contracts and NYMEX futures prices as of Sept. 19, 2016. The confidence intervals shown here represent the 10th and 90th percentile values (P10 and P90).

Figure 12. Historical natural gas prices and confidence intervals for future prices

The manner in which gas prices affect retail electricity prices depends on the structure of the electric power industry in the particular state or region. Where retail prices are based on cost-of-service, fuel costs are often a direct pass-through.[10] In this case, the effect of gas prices on retail electricity prices should be more-or-less proportional to the price of gas and the percentage of load served by gas-fired generation. Take, for example, a utility that meets one-third of its annual energy demand with natural gas-fired generation (roughly the national average). At current gas prices, natural gas fuel supply costs would represent approximately 0.7 cents/kWh of the total retail price of electricity for that utility.[11] Naturally, this amount would be larger if gas prices were to rise or reliance on gas-fired generation were to increase, both of which are generally expected to occur.

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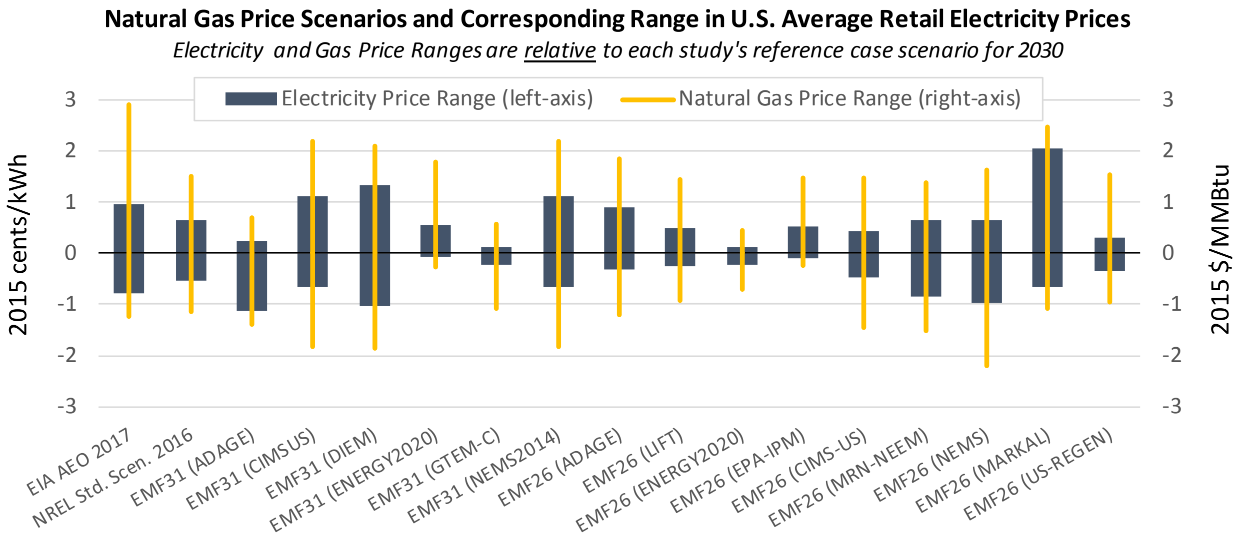
[9] Financial hedges against gas price risk are limited to relatively short time horizons, as gas futures contracts generally are not liquid beyond several years, and long-term fixed-price gas supply contracts are relatively uncommon (Bolinger 2013).

[10] Although the specifics can vary from state to state, fuel and power purchase costs are often recovered through designated cost trackers, line-item charges that are updated regularly outside of rate cases. In the case of power purchased from gas-fired generators, the price of delivered power is typically indexed to prevailing gas prices, and thus gas-price risk is passed through to the utility and its ratepayers.

[11] This estimate is based on a natural gas price of $2.84/MMBu and the U.S. average heat rate of 7244 Btu/kWh for natural gas fired generation, both derived from monthly data for natural gas deliveries to the electric power sector for the twelve-month period ending May 2016 (EIA 2016b, EIA 2016c, EIA 2016d).

In restructured states where retail load is served primarily by power purchased through centralized wholesale markets, natural gas prices can have an outsized impact on electricity prices by virtue of being the "marginal" resource in a disproportionately large percentage of hours.[12] During times that gas is on the margin, it sets the market-clearing price, and all power purchased through the wholesale market, regardless of underlying fuel source, is priced at a level reflective of prevailing gas prices. In states with retail choice, retail suppliers typically procure energy on a relatively short-term basis, and therefore changes to gas commodity prices and the resulting effects on wholesale electricity prices are passed through to retail customers, if not immediately, once any short-term generation supply contracts expire and are renewed.



Notes: The ranges for EIA AEO 2017 are based on the low and high oil and gas resource and technology side cases (EIA 2017). The ranges for the NREL Standard Scenarios study are based on the low fuel price and high fuel price scenarios (Cole et al. 2016). The EMF31 studies are from the Stanford Energy Modeling Forum's project "EMF 31: North American Natural Gas Markets in Transition," which consists of a common set of scenarios explored by different modeling teams, using the models identified in parentheses (Stanford University 2016). The ranges shown are from low and high shale resource scenarios. The EMF26 studies are based on an earlier set of analyses by Energy Modeling Forum participants (Stanford University 2013), and the ranges shown are again from a set of low and high shale resource scenarios. For further details on scenario assumptions and modeling details, please refer to the source documents. All gas prices shown represent Henry Hub.

Figure 13. Retail electricity prices across natural gas price scenarios: Comparison of electricity market studies

To illustrate how natural gas prices—and uncertainty therein—could affect future retail electricity prices, Figure 13 compares retail electricity price projections from a broad set of recent long-term electricity market studies. These studies relied on different electricity market models to simulate future retail electricity prices under alternate assumptions about future natural gas prices. Although the specific scenario assumptions and definitions varied across the studies, most considered low and high gas price scenarios spanning a range of at least $3/MMBtu. Collectively, the results across these studies suggest that U.S. average retail electricity prices in 2030 would increase by roughly 0.4 cents/kWh, on average, with each $1/MMBtu increase in the price of natural gas. Given this average implicit

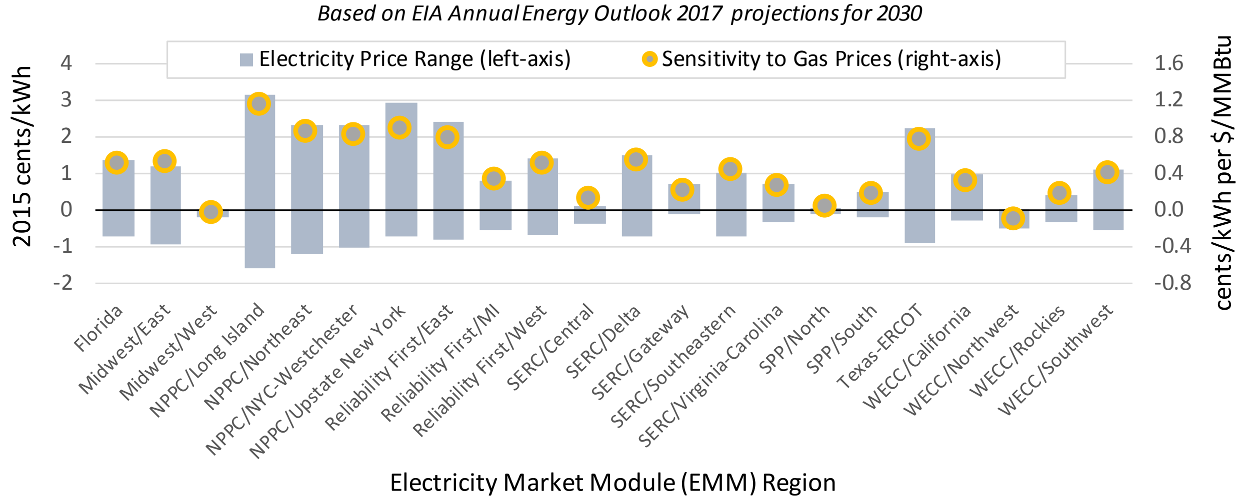
[12] As one example, Rose (2007) examined market clearing prices in the PJM market in 2006. Although natural gas represented just 5.5% of total electricity generation over the year, it was the marginal resource in 15% to 40% of all hours each month.

"sensitivity" span a range of 1.3 cent/kWh between the 10th and 90th percentile gas price trajectories shown in Figure 12. Under the upper confidence interval trajectory, U.S. average retail electricity prices are 0.8 cents/kWh higher than under a gas-price trajectory that tracks the current NYMEX futures strip.

As to be expected, the sensitivity of retail electricity prices to natural gas prices may be more or less pronounced at the state or regional level. This is evident in Figure 14, which shows the range in average retail electricity prices across high and low gas-price scenarios, for each of EIA's Electricity Market Module (EMM) regions. Also shown is the implied sensitivity of retail electricity prices in each region to changes in gas prices. These sensitivity levels are particularly high for the NPPC regions (New England and New York), Reliability First/East (Pennsylvania, New Jersey, Maryland), and Texas—all of which have a relatively high proportion of gas-fired generation, organized wholesale power markets, and retail choice. For those regions, EIA's modeling suggests that average retail electricity prices would increase by 0.8-1.2 cents/kWh with a $1/MMBtu increase in the price of natural gas. At that level of sensitivity, retail electricity prices would be 1.5-2.2 cents/kWh higher under the P90 gas-price projection for 2030. In contrast, other regions that either have lesser reliance on gas-fired generation or have retained cost-of-service based retail pricing exhibit considerably less sensitivity to changes in natural gas prices and would see correspondingly smaller effects on retail electricity prices across potential gas-price trajectories.

Range in Regional Average Retail Electricity Prices across Low and High Gas-Price Scenarios

Based on EIA Annual Energy Outlook 2017 projections for 2030



Notes: Data are based on the low and high "oil and gas resource and technology" side cases. Upper and lower bounds of electricity price ranges are relative to reference case scenario. Sensitivity to Gas Prices refers to the ratio of the range in electricity prices, between the low and high cases, to the corresponding range in Henry Hub natural gas prices. For a map identifying EIA's EMM regions: https://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf

Figure 14. Regional differences in the sensitivity of retail electricity prices to natural gas prices

4.3. Renewables Portfolio Standards

State renewables portfolio standard (RPS) requirements currently exist in 29 states plus the District of Columbia (Barbose 2016). These requirements are scheduled to ramp up over time, with most states reaching their terminal RPS percentage target by 2020 or 2025—though several states have recently extended their RPS to 2030 or beyond. Many of these policies also include carve-outs for solar or DG.

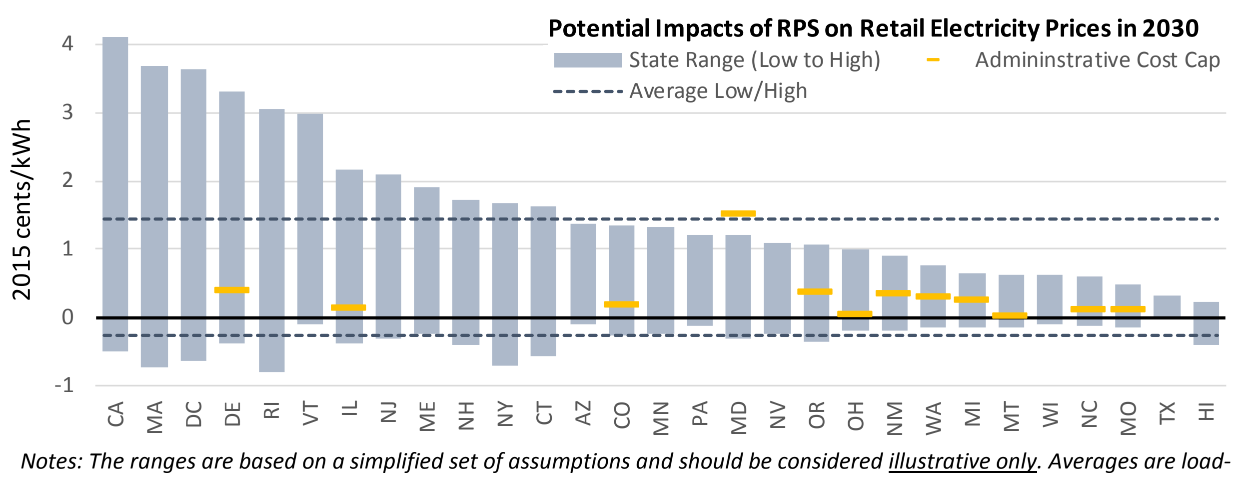
Given that renewables historically have been, and in some circumstances continue to be, higher-cost than conventional power, issues related to electric ratepayer impacts remain a focal point in the design and administration of RPS policies. Several econometric studies estimate that, historically, RPS policies have led to anywhere from a 3-7% (or roughly 0.3-0.7 cents/kWh) increase in average retail electricity prices in RPS states (Morey and Kirsch 2013, Tra 2016, Wang 2014). Bottom-up analyses of compliance cost data submitted to state public utility commissions have generally found smaller effects, with RPS compliance costs in 2014 equivalent to roughly 1% of retail electricity bills or 0.1 cents/kWh in RPS states, on average (Barbose 2016). Reported compliance costs vary considerably across states, however, from a slight negative cost (i.e., cost savings) to upwards of 6% of retail electricity bills. Those cross-state variations reflect differences in RPS target levels, resource mix, industry structure, renewable energy certificate (REC) prices, wholesale electricity prices, reliance on pre-existing resources, and cost calculation methods.

As RPS requirements ramp up over time, the effects on retail electricity prices could potentially become more pronounced. A recent electric sector modeling study, Mai et al. (2016), estimated that incremental renewable energy growth used to meet rising RPS targets over the 2015-2030 period would lead to between a 0.1 cent/kWh decrease and a 0.1 cent/kWh increase in U.S. average electricity prices in 2030. That range reflects varying assumptions about future renewable energy technology costs and natural gas prices. For regions with relatively aggressive RPS policies, the range in potential electricity price effects is wider. For example, the study estimated between a 0.4 cent/kWh decrease and a 0.7 cent/kWh increase in average electricity prices in 2030 for the Pacific census region, and up to a 1.0 cent/kWh increase for the Northeast region. To be sure, these estimates reflect incremental RPS growth, and thus are additive to the effects of existing RPS resources, and are averaged across states with varying RPS targets.

To provide an illustrative and approximate range of the potential effect of RPS policies on future retail electricity prices at the individual state-level, we developed a simplified set of upper and lower bound assumptions to estimate the net cost of RPS compliance in each RPS state, for the year 2030. Those assumptions – which are described more fully and with supporting citations in Appendix B – differentiate between states where RPS compliance is achieved primarily through unbundled RECs and those where compliance occurs primarily through bundled power purchase agreements (PPAs) for renewable electricity. For the former group of states, the key assumptions relate to the price of RECs, where the upper bound estimates assume REC prices equal to each state's alternative compliance payment (ACP) rates; this is effectively the theoretical upper bound and represents a relatively extreme scenario in which RPS states face sustained REC shortages, in many cases well beyond their terminal RPS target year. For states relying instead on bundled PPAs for RPS compliance, the upper bound cost assumptions are effectively an extrapolation of historical compliance data. Upper bound estimates for all states also include additional costs for transmission and integration.

Based on this simplified analysis, RPS policies would result in between a 0.3 cent/kWh decrease and a 1.4 cent/kWh increase (the dashed lines in Figure 15) in the average retail price of electricity among RPS states in 2030. For some states, the ranges are considerably wider, particularly at the upper bound, which reaches as high as 3-4 cents/kWh in some cases. States with particularly high upper-bound estimates tend to be those with relatively high RPS target levels in 2030, large solar or DG carve-outs, and/or high ACP rates. More-sophisticated analyses could, of course, account for other important factors, and might suggest either wider or narrower ranges for some states.[13] One such factor is the existence of administrative cost caps in a number of states, also shown in Figure 15. As shown, those caps are typically well below the upper bound of the ranges estimated here, though utilities and regulators often have some discretion in interpretation and enforcement of these caps. If one were to assume that these administrative cost caps represent hard limits, the upper bound across all states would average 1.1 cents/kWh.

Whether RPS costs and retail price effects are ultimately nearer to the upper or lower end of the ranges in Figure 15 will depend on factors that are, at least partially, within the control of utilities, state agencies, and policymakers. In particular, REC prices and, to a lesser extent, renewables PPA prices are a function of the balance between regional supply and demand for RPS-eligible renewable electricity. State regulators and policymakers have potentially significant sway in helping to facilitate adequate supplies, for example, by establishing broad geographic eligibility for RPS resources, developing long-term contracting programs, and undertaking efforts to ease siting and transmission expansion. States can also manage RPS compliance costs and limit the effects on retail electricity prices through rules related to ACP rates (and other cost containment policies) and the disposition of ACP revenues, as in New Jersey, where these revenues are refunded to ratepayers.



Notes: The ranges are based on a simplified set of assumptions and should be considered illustrative only. Averages are load-weighted. Administrative cost caps are often specified by statute in percentage terms, in which case they are translated here into units of cents/kWh based on projected retail electricity prices in 2030.

Figure 15. Illustrative range in the potential impacts of RPS requirements on retail electricity prices

[13] For example, the evaluation of California's 50% RPS estimated a 0.8-7.2 cents/kWh increase (real 2015$) in retail electricity prices in 2030, relative to what would occur under a continuation of the prior 33% target (E3 2014a).

4.4. State and Federal Carbon Policies

Various states, as well as the federal government, have adopted or proposed policies and regulations to limit carbon dioxide emissions in the electric sector. This includes two regional cap-and-trade programs: The Regional Greenhouse Gas Initiative (RGGI), active since 2009 and currently covering nine states in the northeast and mid-Atlantic; and California's program, launched in 2013 and linked to the Canadian province of Quebec. In addition, a number of states (California, Oregon, and Washington) have adopted emissions performance standards for new power plants, effectively prohibiting utilities from procuring new coal-fired generation and/or requiring that they phase-out coal-fired generation from their generation mix. Alongside the myriad state-level policies are several policies at the federal level, including the EPA's Clean Power Plan (CPP)—currently under stay and facing an uncertain future—as well as a separate set of emissions standards applicable to new power plants. Recognizing these uncertain costs associated with future carbon policy, many utilities consider carbon regulatory risk within their resource planning processes (Barbose et al. 2008, Wilkerson et al. 2014).

To date, existing state and regional carbon policies have had limited impact on retail electricity prices, at least in the case of the two regional cap-and-trade programs. This is partly due to low allowance prices, which are attributed to complementary policies that accomplish most of the targeted emissions reductions, and to price caps in the RGGI market (Fowlie 2016).[14] In addition, California and many RGGI states allocate some portion of allowance revenues to fund direct ratepayer bill credits. In California, these bill credits have thus far exceeded the costs of cap-and-trade program participation and compliance, yielding net reductions in electricity bills.[15] Going forward, emissions targets under both regional programs reach their plateaus in 2020 (though California and RGGI states have adopted longer term goals), and electric sector participants have already achieved, or nearly achieved, their final 2020 target levels (Acadia 2016a).[16] Retail price impacts are thus likely to remain limited, at least under current emissions reduction schedules.

With respect to the CPP, implications for retail electricity prices—if maintained—will depend largely on how states implement the federal standard, given the substantial flexibility afforded. The set of studies shown in Figure 16 project that the CPP would result in anywhere from a 0.0-1.5 cent/kWh increase in U.S. average prices. Ranges across and within studies reflect varying implementation assumptions. Among the most critical implementation options is whether states pursue rate-based or mass-based compliance, and if the latter, how allowances are allocated. For example, NERA (2016) estimated

[14] Since the inception of RGGI and California's programs, quarterly allowance auction prices have ranged from $2-8 per metric ton and $10-14/ton, respectively (CARB 2016, RGGI 2016a). RGGI emission allowance costs in 2014 translated to roughly 3% of total wholesale electricity procurement costs in New York and 4% in New England in 2014 (RGGI 2016b).

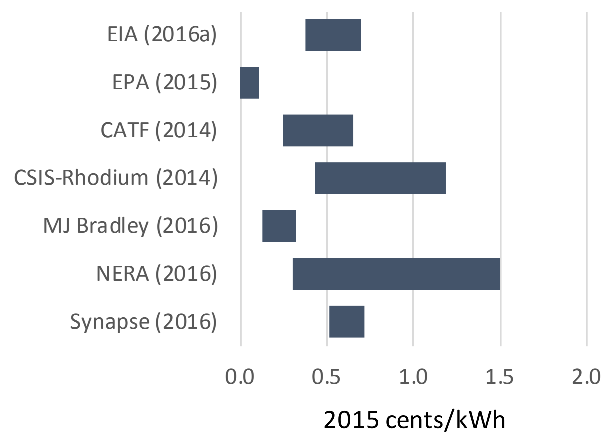
[15] In California, allowances are allocated to and then sold by the state's utilities, with most of the proceeds distributed to ratepayers through bill credits. Because utilities' allowance allocations have thus far exceeded their emissions, bill credits have been greater than compliance costs, yielding a net reduction in customers' bills. For example, the most recent filings from the state's three large investor-owned utilities estimate that refunds to ratepayers in 2017 will be $715 million for bundled customers, compared to $545.2 million in revenue requirements associated with cap-and-trade compliance. The values are based on the "Template D-4" tables in the utilities' GHG revenue requirement filings (PG&E 2016, SCE 2016, SDG&E 2016).

[16] In the case of the three California IOUs, emission allowances for 2020 are greater than their current emissions (CARB 2015).

roughly a 0.7 cent/kWh difference, depending on whether allowances are allocated entirely to generators or to local distribution companies (and credited to ratepayers). The scope of allowance trading may also be important; CSIS-Rhodium (2014) estimated a difference of 0.8 cents/kWh depending on whether trading occurs nationally or is confined to individual electricity market regions. Studies also show varying price impacts depending on the use of energy efficiency, which may raise retail prices while reducing average bills.

Such implementation decisions may have greater or lesser significance across individual states or regions, as illustrated in Figure 17, which compares regional retail price impacts from EIA's *Annual Energy Outlook 2016* (EIA 2016a). The greatest and most uncertain impacts are generally projected to occur in regions with either a relatively carbon-intensive generation mix or competitive markets. In carbon-intensive regions (e.g., the "Reliability First/West" region, covering much of Indiana, Ohio, and West Virginia), the effects on retail electricity prices are potentially higher simply because of the greater emission reductions required. In competitive markets (e.g., the NPPC regions, covering New England and New York), marginal-cost based pricing amplifies the effects of allowance prices and natural gas prices, which tend to be higher under the CPP as a result of coal-to-gas switching. In addition, decisions about whether to allocate allowances to distribution companies or generation owners has greater significance in competitive markets, where distribution companies do not own generation—in contrast to vertically integrated markets, where generation and distribution companies are one-and-the-same.

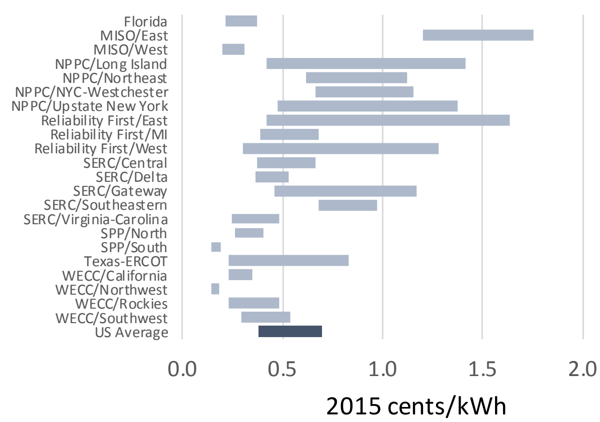
Increase in U.S. average retail electricity price relative to no-CPP scenario



Notes: Ranges represent price impacts across multiple CPP scenarios, typically for the year 2030, though some studies only report impacts for other years or the average impact over a period of years. Differences across studies partly reflect varying vintages and thus whether they evaluated the proposed or final CPP rule, whether they included the renewable energy tax credit extenders passed in 2015, and underlying assumptions about future natural gas prices.

Figure 16. Projected impact of CPP on retail electricity prices: Comparison of electricity market studies

Increase in regional average retail electricity price relative to no-CPP scenario

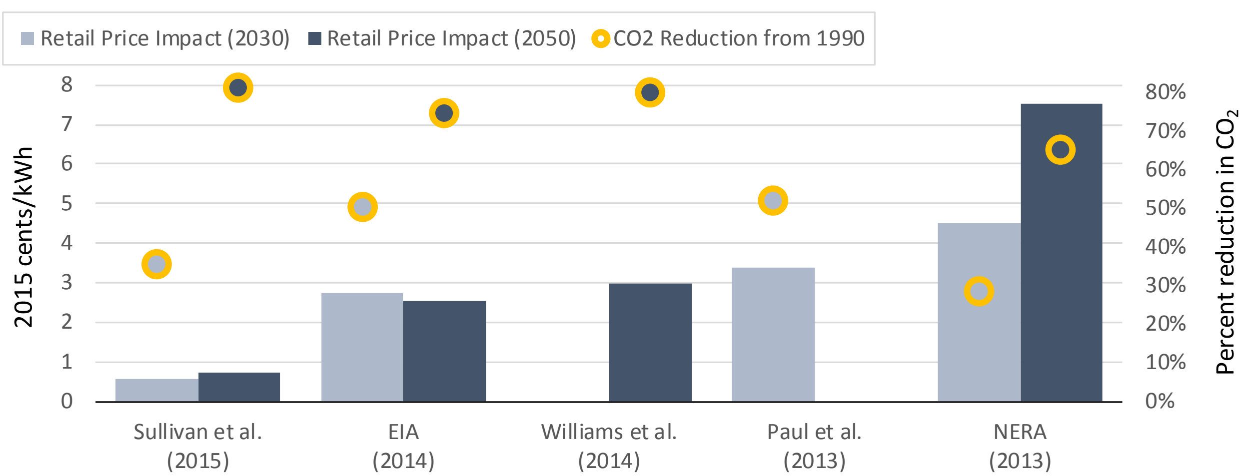


Notes: Data are from EIA's 2016 Annual Energy Outlook (EIA 2016a). The ranges for each Electricity Market Module region are calculated by comparing prices between each CPP scenario and the "Reference case without Clean Power Plan" scenario, for the year 2030. For a map identifying EIA's Electricity Market Module regions, see: https://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf

Figure 17. Regional differences in EIA's estimates of the CPP's impact on retail electricity prices

Beyond any uncertainties associated with CPP implementation options is a potentially much greater uncertainty related to the possibility of more-stringent carbon policies in the future, adopted at either the state or federal levels. The CPP, if implemented, is projected to reduce U.S. electric sector emissions to 15% below 1990 levels by 2030 (EIA 2016a). By comparison, total economy-wide greenhouse gas emissions may need to decline to 80% below 1990 levels by 2050, in order to limit anthropogenic warming to less than 2 degrees Celsius (IPCC 2014). Substantially more-stringent policies may therefore be enacted over the coming decade or beyond. California, for example, recently enacted legislation requiring statewide reductions in greenhouse gases to 40% below 1990 levels by 2030, and most RGGI states have adopted comparable goals as well (Acadia 2016b).

More-stringent carbon policies could put further upward pressure on retail electricity prices. As an illustration, Figure 18 summarizes a number of electricity market studies that analyze future federal carbon policy or emission reduction scenarios roughly consistent with a trajectory reaching an 80% reduction below 1990 levels by 2050. Among this set of studies, which vary considerably in their scenario designs and modeling assumptions, U.S. average retail electricity prices would increase by 0.6-4.5 cents/kWh in 2030 and by 0.7-7.5 cents/kWh in 2050, relative to each study's baseline "no policy" scenario. State regulators and policymakers have leverage to limit the size of these effects, both through the design and implementation of future carbon policies, as well as by managing ratepayers' exposure to carbon regulatory risk (Barbose et al. 2008, Wilkerson et al. 2014). Many utilities, for example, seek to manage those risks by including CO_2 prices within their integrated resource planning (IRP) processes, with Luckow et al. (2016) reporting that 66 out of 115 utility IRPs issued over the 2012-2015 period included a CO_2 prices.

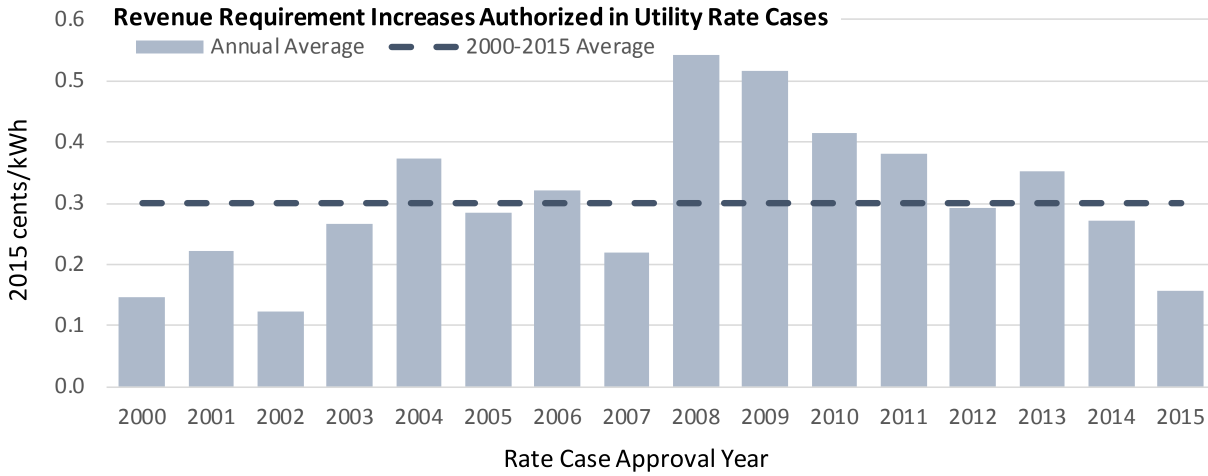


Notes: Each of the studies modeled scenarios with carbon dioxide emission taxes or targets that become progressively more stringent until 2040 (EIA 2014) or 2050 (all others). Retail price impacts represent the difference between U.S. average retail prices in the policy case and the study's baseline "no-policy" case. For Williams et al. (2014) and NERA (2013), the percentage emissions reductions shown are economy-wide; for the other studies, they are for the electric power sector, specifically. Not all studies reported results for the years 2030 and 2050. For EIA (2014), projections for the year 2040 are plotted in lieu of 2050 values. For Paul et al. (2013), 2035 values are plotted in lieu of 2030. And for NERA (2013), 2033 and 2053 values are plotted in lieu of 2030 and 2050, respectively.

Figure 18. Projected impact of potential long-term carbon policies on retail electricity prices: Comparison of electricity market studies

4.5. Electric Industry Capital Expenditures

Capital investments made under cost-of-service based regulation—which includes most T&D, as well as generation owned by regulated utilities—provide the basis for utility shareholder earnings, but put upward pressure on electricity prices.[17] These expenditures are passed-through to electricity prices via periodic rate cases, in which depreciation and financing costs associated with new capital investments are added to the utility's annual revenue requirements (and may be offset, to some extent, as pre-existing assets become fully depreciated and roll off the utility rate-base). Historically, incremental investments in the power system have been paid for by sales growth, allowing electricity prices to remain relatively stable. Going forward, however, slowing sales growth may amplify the effects of CapEx on retail electricity prices and prompt greater scrutiny by regulators when assessing the prudence of utility investments.



Notes: The figure is based on data from general rate cases for vertically integrated utilities (SNL Energy, April 2016). Revenue requirement increases are translated into units of cents/kWh by dividing the authorized dollar increase by each utility's retail electricity sales. Annual averages across rate cases in each year are weighted based on each utility's electricity sales.

Figure 19. Utility revenue requirement increases authorized in general rate cases

Capital expenditures (CapEx) in the electric industry have been on the rise, increasing by roughly 6% per year in real terms (8% nominal) since 2000, despite relatively flat load growth.[18] Total CapEx over that period is split roughly 40%/20%/40% among generation, transmission, and distribution system infrastructure, with T&D representing an even greater share of incremental growth in annual CapEx. As shown in Figure 19, revenue requirement increases authorized in utility rate cases have averaged 0.3

[17] In competitive markets, where generation capital investment costs are recovered through wholesale market prices, new generation capacity tends to put downward pressure on prices in the short-term. In the long-run, however, wholesale prices (including in any capacity markets) must be high enough to support profitable new entry in order for investment to occur (Stoft 2002).

[18] To estimate industry-wide CapEx, annual T&D-related CapEx data for IOUs (EEI 2015) was extrapolated to non-IOUs based on retail electricity sales. For generation-related investments, annual CapEx was estimated from annual capacity additions and capacity costs by fuel type (Bolinger and Seel 2016, EIA 2016h, EIA 2016i, Wiser and Bolinger 2016).

cents/kWh since 2000 (though have trended higher over the latter half of that period).[19] Assuming utilities file new rate cases every three years or so, this equates to an increase in revenue requirements of 0.1 cents/kWh annually. These data provide a rough indication for how regulated capital investments have impacted retail electricity prices historically, reflecting the net change in revenue requirements associated with new CapEx investments and pre-existing assets that became fully depreciated.

Going forward, many expect future CapEx investments in the electric industry to continue at a robust pace, driven by demands related to grid modernization, renewables growth and integration, retiring coal-fired generation, aging T&D infrastructure, security and weather risks, and load growth—even if relatively modest in many regions (ASCE 2013, Deloitte 2016, EEI 2016b, Ernst & Young 2014, Pfeifenberger et al. 2015). These sources of CapEx growth overlap to some extent with drivers discussed in previous sections, though also encompass a broader set of trends.

The impact of future CapEx on retail electricity prices will depend on both the level of investment as well as the cost of capital, which is currently quite low by historical standards. To illustrate, we consider two plausible (though perhaps not especially extreme) scenarios, as outlined in Table 3. In the low case, annual CapEx investment remains flat at current levels. This trajectory, which is based on analysis by the American Society of Civil Engineers, is intended to reflect the minimum pace of investment necessary to maintain acceptable reliability, but without any major transformation of the industry. At the high end, we assume annual CapEx continues to grow at the same rate as over the 2000-2015 period. The weighted-average cost of capital in the two cases reflect the historical range for regulated electric utilities since 2000. In estimating the corresponding effects on retail electricity prices, we focus on just the portion of CapEx investments assumed to be made by regulated entities.

Table 3. Estimated impact of future capital expenditures on retail electricity prices

	Low	**High**
Annual CapEx through 2030 ($2015)	$100 billion/yr (constant)	6% real annual growth, from $100 billion in 2015
Weighted-average cost of capital (WACC)	6%	9%
Impact on average retail electricity prices in 2030 ($2015)	1.6 cents/kWh	3.6 cents/kWh

Notes: The low case CapEx trajectory is based on ASCE (2016), which estimates total electric industry infrastructure investments needed through 2040 in order to meet load growth. The CapEx growth rate in the high case is equal to average annual growth from 2000-2015, where annual CapEx is calculated in the manner described in footnote 18. In both cases, we assume that 75% of future CapEx investments are made by regulated entities (based on a 50/50 split between generation and T&D, and the assumption that half of generation investments and effectively all T&D investments are made by regulated entities). The low and high WACC assumptions are based on the minimum and maximum annual industry averages over the 2000-2015 period, calculated from data published by Damodaran (2016) and S&P Global Market Intelligence (2016). Both scenarios assume an average 30-year depreciation life for new CapEx investments, and use forecasted U.S. retail electricity sales from the EIA's 2016 Annual Energy Outlook reference case to translate dollar costs into cents/kWh (EIA 2016a).

[19] These revenue requirement increases are expressed in units of cents/kWh in order to show how they translate into a retail price impact. However, these values do not represent authorized rate increases, per se. The net change in average electricity rates depends on how growth in revenue requirements compares to growth in electricity sales.

Across this set of scenarios, we estimate that the revenue requirements associated with future CapEx by regulated electric utilities equate to a 1.6-3.6 cent/kWh increase in U.S. average retail electricity prices in 2030. For some utilities—for example, those making investments in new nuclear generation capacity or undertaking major grid modernization initiatives—the potential impacts on retail prices may be greater than the range estimated above or may occur over a more-accelerated timeframe. To be sure, the above range does not consider reductions in revenue requirements that will naturally occur as pre-existing assets become fully depreciated over time. The purpose of this estimate, however, is to illustrate the potential significance of regulators' ongoing efforts to ensure and incentivize the prudence of future CapEx investments.

5. Summary and Conclusions

Concerns about the potential impacts of net-metered PV on retail electricity prices have led to an array of proposals to reform rate structures and net metering rules for solar customers. These proposals have typically been met with a great deal of contention and often absorb substantial time and administrative resources, potentially at the expense of other issues that may ultimately have greater impact on utility ratepayers. Given those tradeoffs, this paper seeks to help regulators, utilities, and other stakeholders gauge how much attention to devote to evaluating and addressing the possible effects of distributed solar on retail electricity prices.

Drawing on a combination of back-of-the-envelope style analyses and literature review, we characterize the potential effects of distributed solar on retail electricity prices, at both current and projected future penetration levels, and compare these estimates to a number of other important drivers for future retail electricity prices. Figure 20 provides a high-level comparison, based on indicative ranges for the potential retail price effects of distributed solar and each of the other issues analyzed.

Net-Metered PV: Impact at *current* penetration levels, across a range of VoS assumptions, with purely volumetric rates (U.S. average)

Net-Metered PV: Impact at *projected* 2030 penetration levels, across a range of VoS assumptions, with purely volumetric rates (U.S. average)

Net-Metered PV: Impact at *10% penetration*, across a range of VoS assumptions, with purely volumetric rates (high-pen. utility, U.S. avg. price)

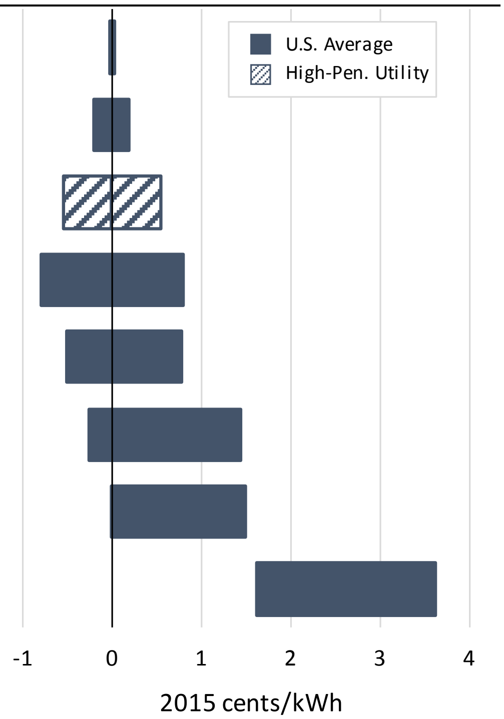
Energy Efficiency: Impact of projected 2015-2030 EE savings, if avoided costs are valued at the same rate as solar (U.S. average)

Natural Gas: Range in retail electricity price across 10th/90th percentile gas price confidence intervals for 2030 (U.S. average)

RPS: Impact in 2030 across low and high cost scenario assumptions (U.S. average, among RPS states)

Carbon: Impact of CPP in 2030 across multiple studies, each considering multiple implementation scenarios (U.S. average)

CapEx: *Gross* impact of electric-industry CapEx through 2030, across range of CapEx trajectories and WACC (U.S. average)



Notes: Current net-metered PV penetration equal to 0.4% of total U.S. retail electricity sales, as of year-end 2015. Projected 2030 net-metered PV penetration is 3.4%, based on Cole et al. (2016). VoS assumptions range from 50% to 150% of average cost-of-service. Please refer to the main body of the report for further details on how the ranges shown here were derived.

Figure 20. Indicative ranges for potential effects on average retail electricity prices

These ranges, which are based on data and analysis presented in earlier sections of the report, are intended to provide a *rough* sense for the relative magnitude of each of these drivers. This illustrative comparison certainly should not be considered a substitute for state- or utility-specific analysis. Indeed, as discussed within the main body of this paper, regional and other factors may lead to effects that fall well outside the ranges shown here. It is also important to reiterate that this paper focuses narrowly on the question of retail price effects, as this is the particular issue motivating much of the discussion surrounding retail rate reforms for distributed solar. It is not a cost-benefit analysis, and certainly does not address the full set of issues relevant to evaluating the particular resources and policies discussed.

With these considerations in mind, we offer the following summary points:

- **For the vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future.** At current penetration levels (0.4% of total U.S. retail electricity sales), distributed solar likely entails no more than a 0.03 cent/kWh long-run increase in U.S. average retail electricity prices, and far smaller than that for most utilities. Even at projected penetration levels in 2030, distributed solar would likely yield no more than roughly a 0.2 cent/kWh (in 2015$) increase in U.S. average retail electricity prices, and less than a 0.1 cent/kWh increase in most states, where distributed solar penetration is projected to remain below 1% of electricity sales. These estimates assume a relatively low VoS equal to just 50% of the average utility CoS, and relatively generous solar compensation levels based on full NEM with volumetric pricing.

- **For states or utilities with particularly high distributed solar penetration levels, retail electricity price effects may be more significant, but depend critically on the value of solar and underlying rate structure.** Four utilities, all in Hawaii, currently have solar penetration rates on the order of 10% of electricity sales, and three other states are projected to reach this mark by 2030. Assuming a utility value of solar ranging from 50% to 150% of its average cost of service, this level of distributed solar would yield a maximum 5% increase in retail electricity prices (e.g., 0.5 cents/kWh for a utility with electricity prices otherwise equal to the national average), under net metering with purely volumetric rates. Under rate structures with fixed charges or demand charges—as are already common, particularly for commercial customers—the effects would be shifted downward.

- **Energy efficiency has had, and is likely to continue to have, a far greater impact on electricity sales than distributed solar.** Distributed solar and energy efficiency can both impact retail electricity prices by virtue of reducing electricity sales. Utility energy efficiency programs and federal appliance efficiency standards together reduced U.S. retail electricity sales in 2015 by an amount 35-times larger than that of distributed solar. Projected growth in energy efficiency savings from those policies through 2030 is almost 5-times greater than projected growth in distributed solar generation. Assuming, for the sake of simple comparison, that the value of energy efficiency savings to the utility is based on the same VoS range as above (50-150% of the utility CoS), growth in energy efficiency savings over the 2015-2030 period would result in up to a ±0.8 cent/kWh change in U.S. average retail electricity prices.

- **Natural gas prices impose substantial uncertainty on future electricity prices.** Electricity prices have become increasingly linked with gas prices, and are likely to become more so with continued growth in the share of electricity generated from gas. Although current gas prices are near historical lows, future prices remain highly uncertain, and that uncertainty is skewed upward. Gas-price confidence intervals developed Bolinger (2017) suggest a 10% probability that gas prices in 2030 will be at least $1.9/MMBtu higher than expected (based on the current NYMEX gas futures strip). Based on a broad set of electricity market modeling studies, an increase in gas prices of this magnitude would lead to roughly a 0.8 cent/kWh increase in U.S. average retail electricity prices. Restructured regions, which have more acute sensitivity to natural gas prices, could see retail electricity price increases of more than twice that amount.

- **Though their historical effects on retail electricity prices appear small, state RPS programs could lead to greater impacts if supply does not keep pace with demand.** RPS compliance cost data suggest that the policies have thus far increased retail electricity prices by just 0.1 cents/kWh, on average, in RPS states. Rising targets over the coming years may put upward pressure on costs, which could be amplified if supplies of eligible renewable energy don't keep pace. At the extreme (and arguably rather implausible) upper end—which assumes that REC prices in all markets are trading at their caps and that other administrative cost caps are not enforced—we estimate that retail electricity prices in RPS states could increase by 1.4 cents/kWh in 2030, on average, and by 3-4 cents/kWh in some states. Smaller retail price effects are expected in practice, and even decreases in average prices are possible, depending in part on how barriers to renewables development are addressed.

- **The effects of state and federal carbon policies on future retail electricity prices are highly dependent on program design and implementation details.** Existing cap-and-trade programs in California and the Northeast have had limited impacts on retail electricity prices to-date. In large part, this is because complementary policies have accomplished much of the targeted emission reductions, and because auction proceeds are used for ratepayer bill credits. Studies of the CPP—currently under stay and facing an uncertain future—have estimated that it could result in anywhere from 0.0-1.5 cent/kWh increase in U.S. average retail electricity prices. Much of that range reflects differences in assumptions about how states implement the federal standard, such as whether states pursue rate-based or mass-based compliance, how allowances are allocated, the scope of allowance trading, and the degree of reliance on energy efficiency. Over the long-term, additional or more-stringent carbon policies at the state or federal levels are also possible and could yield a wider range of potential effects on retail electricity prices.

- **Future capital expenditures in the electricity industry will put upward pressure on retail electricity prices.** Capital expenditures (CapEx) in the electric industry have been on the rise, increasing by roughly 6% per year in real terms (8% nominal) since 2000, despite relatively flat load growth. Going forward, the impacts of continued utility CapEx on retail electricity prices will depend on both the pace of future investments as well as utilities' cost of capital. Considering a plausible range of assumptions for those two factors, we estimate a 1.6-3.6 cent/kWh impact on U.S. average retail electricity prices in 2030, as a result of future CapEx by regulated utilities (some portion of which will be offset as existing CapEx investments become fully depreciated). For some utilities—

for example, those making investments in new nuclear generation capacity or undertaking major grid modernization initiatives—the potential impacts on retail prices may be greater than the range estimated above or may occur over a more-accelerated timeframe.

The most basic conclusion of this paper is that, in most cases, the effects of distributed solar on retail electricity prices are, and will continue to be, quite small compared to many other issues. That is not to say that reforms of net metering rules or retail rate structures for distributed solar customers are unwarranted. However, other objectives, such as economic efficiency, likely provide a more compelling rationale. Reforms may thus best be tailored to meeting those objectives—for example, through rate structures that accurately signal the long-term marginal cost of producing and delivering electricity.

Where concerns about minimizing retail electricity price remain a priority, other issues may prove more impactful. Among the issues explored in this paper, future electric-utility capital expenditures are expected to have, by far, the greatest impact on the trajectory of retail electricity prices. That is not to say anything about the potential benefits or prudence of such investments, but clearly this is an area where regulatory oversight can play a crucial role in managing retail electricity price escalation. Similarly, resource planning and procurement processes provide another important point of leverage over future retail electricity prices, where utilities and regulators can manage ratepayers' exposure to natural gas price risk and the possible costs associated with state or federal carbon regulations. Regulators and policymakers in states with RPS policies also have significant influence over retail electricity prices by developing RPS rules and other supportive policies that ensure renewable electricity supply keeps pace with growing RPS demand, keeping REC prices in check.

For states and utilities with exceptionally high distributed solar penetration levels, the effects on retail electricity prices could begin to approach the same scale as other important drivers (at least among residential customers, where solar compensation is based on full net metering with predominantly volumetric rate structures). In these cases, questions about the value of solar become more important to assessing possible cost-shifting. Efforts to encourage higher value forms of deployment also offer a strategy for mitigating any cost-shifts, for example by directing development toward geographic regions with the greatest T&D deferral opportunities, by developing mechanisms to leverage the capabilities of advanced inverters, or by incentivizing the pairing of solar with storage or demand response. Such strategies represent an alternative (and potentially less contentious) approach to addressing the effects of distributed solar on retail electricity prices (Barbose et al. 2016).

Experiences with energy efficiency also offer lessons for states witnessing especially high levels of distributed solar penetration. In particular, these experiences suggest that short-term retail price impacts from distributed energy resources may be more acceptable, provided that they yield net savings to ratepayers over the long run, and that adequate opportunities exist for all ratepayers (especially low- and moderate-income customers) to participate. As solar costs continue to decline, grid-friendly PV technologies advance, and initiatives to broaden solar access continue, issues of cost-shifting from distributed solar will become more similar to those of energy efficiency. As this occurs, concerns about cost-shifting may naturally soften, to a degree.

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Appendix A. Derivation of a Simplified Model for Estimating the Impact of Distributed Solar on Retail Electricity Prices

In Section 3, we present a simplified model to estimate the impact of distributed solar on retail electricity prices, expressed in terms of the following equation:

(1) $$Percent\ Change\ in\ Retail\ Price = \ Penetration\ \times \left[\frac{Solar\ Comp. Rate}{CoS} - \frac{VoS}{CoS}\right]$$

Here, we present the derivation for this expression. To begin, we define each of the following terms:

(2) $$Average\ Retail\ Price\ (P) \equiv \frac{Utility\ Revenues\ (R)}{Retail\ Sales\ (Q)}$$

(3) $$Cost\ of\ Service\ (CoS) \equiv \frac{Utility\ Costs\ (C)}{Retail\ Sales\ (Q)}$$

(4) $$Value\ of\ Solar\ (VoS) \equiv \frac{Net\ Avoided\ Costs\ (\Delta C)}{Solar\ Generation\ (q)}$$

(5) $$Solar\ Penetration\ Level\ (Pen) \equiv \frac{Solar\ Generation\ (q)}{Retail\ Sales\ (Q)}$$

(6) $$Solar\ Compensation\ Rate\ (p) \equiv \frac{Solar\ Customer\ Revenues\ or\ Bill\ Savings\ (r)}{Solar\ Generation\ (q)}$$

With this additional nomenclature, we can restate the original equation as follows, where P_o is the utility's average price prior to the addition of distributed solar:

(7) $$\frac{P}{P_o} - 1 = \frac{q}{Q} \times \left[\frac{p}{CoS} - \frac{VoS}{CoS}\right]$$

The left-hand side of the expression is the percent change in average retail electricity price, expressed here as a function of a given quantity of distributed solar generation (q), solar compensation rate (p), and value of solar (VoS). We can then proceed to derive equation (7).

We first make the simplifying assumption that utility costs are equal to utility revenues. This equivalence does not hold perfectly, particularly in the short-run between utility rate cases, but is reasonably accurate over the longer term, as rates are re-set in successive rate cases. With this assumed equivalence, the average retail price (P) is the same as the cost of service (CoS) and can thus be expressed as:

(8) $$P = \frac{C}{Q}$$

To model the change in price with the introduction of distributed solar, we represent the compensation to solar customers as an explicit payment for all solar generation (such as under a feed-in tariff), rather than as a reduction in electricity sales as would occur under net metering. The two approaches are effectively equivalent from the utility's perspective, but modeling the compensation as an explicit payment allows for a more generalizable and flexible relationship that can be applied in cases without net metering or where the underlying rate structure includes charges that cannot be displaced by distributed solar.

Distributed solar thus introduces two changes to utility costs: the first is an additional cost associated with payments to solar customers (*r*), and the second is a net reduction (*ΔC*) in other operating costs and—potentially, over the long term—capital costs. From equation (8), the average retail price is thus equal to the following, where C_o is the utility's costs prior to the addition of distributed solar:

(9) $$P = \frac{C_o + r - \Delta C}{Q}$$

We then multiply both the numerator and denominator by the same term ($1/C_o$) and make substitutions for various terms using equations (4), (6), and (8):

(10) $$P = \frac{C_o + (p \cdot q) - (VoS \cdot q)}{Q} \cdot \frac{1/C_o}{1/C_o}$$

$$= \frac{1 + (p \cdot q)/C_o - (VoS \cdot q)/C_o}{1/P_o}$$

We can then substitute for C_o using equation (3), and with some further re-arranging of terms, arrive at equation (7):

(11) $$\frac{P}{P_o} - 1 = \frac{p \cdot q}{CoS \cdot Q} - \frac{VoS \cdot q}{CoS \cdot Q}$$

$$= \frac{q}{Q} \times \left[\frac{p}{CoS} - \frac{VoS}{CoS}\right]$$

Appendix B. Assumptions Used to Estimate RPS Compliance Costs

In Section 4.3, we present an illustrative and approximate range of the potential effect of state RPS policies on retail electricity prices in 2030. That range is based on a generic set of upper and lower bound assumptions applied to each RPS state, summarized in Table B-1. Here, we provide further details and supporting citations for the particular assumptions used in that analysis.

Table B - 1. Assumptions for estimating RPS impacts on retail electricity prices

Primary mode of RPS compliance	States	Assumptions for Low and High RPS Cost Estimates*
Unbundled RECs	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, OH, PA, RI, TX, VT	**Low:** REC prices equal $1/MWh for primary and secondary tier requirements, and $10/MWh for solar or DG tiers. Merit-order effect from main-tier and solar carve-out resources reduces retail supply costs by $5-30/MWh of RE, depending on region. No added integration or transmission costs. **High:** REC prices equal to each state's ACP. No merit-order effect. $10/MWh integration cost adder and $20/MWh transmission cost adder.
Bundled PPAs	AZ, CA, CO, HI, MI, MN, MO, MT, NC, NM, NV, OR, WA, WI	**Low:** General RPS resources yield cost savings of $10/MWh of RE, and DG tiers have zero net cost, relative to non-RE and including integration or transmission costs. No merit-order effect. **High:** General RPS resource cost per MWh-RE equal to historical compliance cost for each state, plus $10/MWh for integration costs and $20/MWh for transmission costs. Net cost of DG carve-out resources equal to $100/MWh-RE. No merit-order effect.

* *All $/MWh values are stated in terms of real 2015 dollars, and refer to dollars per MWh of renewable electricity.*

We first distinguish between states where RPS compliance is achieved primarily through unbundled RECs and those where compliance occurs primarily through bundled power purchase agreements (PPAs) for renewable electricity. The former set consists entirely of states with retail choice, while the latter consists primarily of states where regulated retail suppliers continue to conduct long-term procurement for most load. For each set of states, we then estimate retail price impacts based on a standardized set of low and high assumptions for: (a) the incremental cost of procuring renewable electricity or RECs relative to non-renewables, (b) the merit-order effect, (c) incremental transmission costs, and (d) renewables integration costs.

Unbundled REC States: For these states, REC prices in the low case are roughly equivalent to those currently observed in voluntary REC markets and in highly oversupplied RPS markets, such as Texas. In the high case, REC prices are instead assumed to be equal to the corresponding alternative compliance payments (ACP), as would occur under sustained shortages in REC supplies. We also consider two indirect impacts on retail electricity prices. The first of these is the “merit-order effect”: that is, the tendency of low-marginal-cost renewables to suppress wholesale electricity market prices. Great uncertainty exists around the magnitude and longevity of this effect. For the high-cost case, we assume no merit order effect, as might be expected over the long-run, as capacity additions and retirements in the power market fully adjust to the presence of RPS resources. For the low-cost case, we use the upper bounds estimated in Wiser et al. (2016), which vary by region: $5/MWh of renewable energy in Texas, $17/MWh in PJM states, and roughly $30/MWh in Northeastern states.[20] We also considered indirect RPS costs associated with socialized integration costs and transmission expansion costs. Our low RPS cost case assumes zero additional integration and transmission costs, while our high case includes a $10/MWh adder for integration costs and a $20/MWh adder for transmission costs.[21]

Bundled PPA States: RPS costs in these states consist of the incremental cost of RE resources procured to meet RPS obligations, relative to non-renewable resources that would have otherwise been procured. For the low case, we assume that resources used to meet general RPS obligations yield a net *savings* of $10/MWh of RE in 2030, based on the lower bound estimate from Mai et al. (2016). This value is inclusive of transmission and integration costs. For the high case, we instead assume that the incremental cost per MWh of general RPS resources is equal to the average historical cost per MWh in each state. Historical compliance costs for general RPS resources have varied from -$10/MWh to $50/MWh across these states, reflecting differences in policy and market conditions, as well as differences in RPS cost calculation methodologies (Barbose 2016). Those historical compliance-cost data typically do not reflect incremental transmission or integration costs; we therefore apply adders for transmission and integration costs, at the same levels used for unbundled REC states. For DG carve-outs, we assume higher costs than general RPS resources in both the low and high cost cases, reflecting the higher cost of DG resources compared to utility-scale RE. We do not include any merit order effect

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[20] These upper bounds are generally consistent with, though in some cases lower than, other estimates in the literature. For example, IPA (2013) estimated a value of $21/MWh for wind in the Midwest. A report on transmission in MISO (Fagan et al. 2012), estimated the price suppression benefits from 20 GW and 40 GW of wind, implying a wholesale price impact of $100-130/MWh of wind. Perez et al. (2012) estimate the wholesale price effect of solar in the mid-Atlantic region to be around $55/MWh of solar. A broad literature review conducted by Würzburg et al. (2013), drawing primarily on studies from Europe, created a common metric of $/MWh of RE per % of RE within the generation mix. The median value across studies was $0.73/MWh-RE per % RE. Using this value would lead to estimates of $3 to $50/MWh of RE, depending on each state’s RPS target in 2030.

[21] Accounting for integration and transmission costs is complicated, as some costs are charged directly to projects served and are therefore implicit in the REC price or the price of the PPA. Only those costs that are “socialized” are appropriate for inclusion in a separate cost adder. The integration cost assumptions used within the present analysis are based loosely on Wiser and Bolinger (2016), which reviewed 30 wind integration studies in the U.S., and found that virtually all estimated integration costs less than $10/MWh, even at penetration levels >20%, and most estimated costs less than $5/MWh. For transmission costs, we base our upper bound cost adder on Enernex (2010) and GE Energy (2010), which estimated total transmission costs associated with large scale build-out of renewable energy in the Eastern and Western Interconnections, respectively. The studies estimated total transmission costs on the order of $400/kW, which equates to roughly $20/MWh (assuming a 15% capital recovery factor and 35% capacity factor). These cost estimates include both dedicated transmission assets for specific renewables projects as well as network upgrades, and therefore likely overstate socialized transmission costs. As one other point of reference, Mills et al. (2012) reviewed planning studies in the U.S. and found a median cost of transmission for wind energy equal to $15/MWh.

for these states, as most retail load in these states is served through long-term contracts, thus any effect on wholesale prices would have limited impact on retail prices.

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Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment

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Energy Technologies Area

July 2015

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Abstract

The substantial increase in deployment of customer-sited solar photovoltaics (PV) in the United States has been driven by a combination of steeply declining costs, financing innovations, and supportive policies. Among those supportive policies is net metering, which in most states effectively allows customers to receive compensation for distributed PV generation at the full retail electricity price. The current design of retail electricity rates and the presence of net metering have elicited concerns that the possible under-recovery of fixed utility costs from PV system owners may lead to a feedback loop of increasing retail prices that accelerate PV adoption and further rate increases. However, a separate and opposing feedback loop could offset this effect: increased PV deployment may lead to a shift in the timing of peak-period electricity prices that could reduce the bill savings received under net metering where time-varying retail electricity rates are used, thereby dampening further PV adoption. In this paper, we examine the impacts of these two competing feedback dynamics on U.S. distributed PV deployment through 2050 for both residential and commercial customers, across states. Our results indicate that, at the aggregate national level, the two feedback effects nearly offset one another and therefore produce a modest net effect, although their magnitude and direction vary by customer segment and by state. We also model aggregate PV deployment trends under various rate designs and net-metering rules, accounting for feedback dynamics. Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures. Whereas flat, time-invariant rates with net metering lead to higher aggregate national deployment levels than the current mix of rate structures (+5% in 2050), rate structures with higher monthly fixed customer charges or PV compensation at levels lower than the full retail rate can dramatically erode aggregate customer adoption of PV (from -14% to -61%, depending on the design). Moving towards time-varying rates, on the other hand, may accelerate near- and medium-term deployment (through 2030), but is found to slow adoption in the longer term (-22% in 2050).

1 Introduction

Deployment of distributed solar photovoltaics (PV) has expanded rapidly in the United States, growing by over 400% since 2010 in terms of total installed capacity and averaging 40% year-over-year growth in capacity additions (GTM and SEIA 2015). This rapid growth has been fueled by a combination of steeply declining costs, the advent of innovative financing options, and supportive public policies at the federal, state, and local levels. Key among the supportive policies has been net energy metering (or simply net metering or NEM), which typically compensates each unit of PV generation at the customer's prevailing retail electricity rate. Net metering allows homes and businesses with onsite PV systems to offset their electricity consumption regardless of the temporal match between PV production and electricity consumption. As state incentive programs and federal tax credits are phased out, net metering has become increasingly pivotal to the underlying customer economics of distributed PV.

The rapid growth of net-metered PV has provoked concerns about the financial impacts on utilities and ratepayers (Accenture 2014, Kind 2013, Brown and Lund 2013, Eid et al. 2014). Central to these concerns is the contention that net metering at the full retail electricity price allows PV customers to avoid paying their full share of fixed utility infrastructure costs, thus requiring the utility to raise retail prices, including for non-PV customers, to recover those costs in full (Borlick and Wood 2014). Compounding that concern is the possibility of the feedback effect where increased retail electricity prices accelerate distributed PV adoption, resulting in even higher prices as fixed utility infrastructure costs are spread over an ever-diminishing base of electricity sales (Cai et al. 2013, Costello and Hemphill 2014, Felder and Athawale 2014, Graffy and Kihm 2014).

A wide array of corrective measures – ranging from incremental changes to utility rate design to fundamental changes to utility business and regulatory models – has been suggested to address concerns about under-recovery of fixed costs associated with distributed PV and other demand-side resources (Bird et al. 2013, Fox-Penner 2010, Harvey and Aggarwal 2013, Jenkins and Perez-Arriaga 2014, Lehr 2013, SEPA and EPRI 2012, McConnell et al. 2015). Proposals to modify rate designs for PV customers come in many varieties (Faruqui and Hledik 2015, Linvill et al. 2013, Glick et al. 2014). Frequently they entail reallocating a portion of cost recovery from per-kilowatt-hour volumetric charges to fixed customer charges and/or per-kilowatt demand charges (NC Clean Energy Technology Center 2015), while other proposals involve replacing net metering with alternate mechanisms that compensate PV customers for all or some PV generation at a price different than the retail electricity rate (e.g., using a feed-in tariff or value-of-solar tariff; Blackburn et al. 2014).

Decision-making on these issues, however, is hampered by several key informational gaps. Fundamentally, significant disagreement exists about whether, or the extent to which, net-metered PV under existing rate designs causes retail electricity rates to increase. One aspect of that disagreement revolves around the question of feedback effects: Does distributed PV lead to ever-spiraling rate increases as each successive rate increase further accelerates PV adoption? Prior studies of this issue have generally remained conceptual and hypothetical; few have sought to quantitatively examine the magnitude or likelihood of effects, with the notable exceptions of Cai et al. (2013), Chew et al. (2012), and Costello and Hemphill (2014). Furthermore, analyses and discussions of retail rate feedback effects have focused only on the possible positive feedback associated with under-recovery of fixed costs. A separate – and potentially offsetting – feedback may occur when increasing PV penetration causes a shift in the temporal profile of wholesale electricity prices (see Table 1). Numerous studies have demonstrated that the capacity value and wholesale market value of PV erode as penetrations increase (Mills and Wiser 2013, Hirth 2013, Gilmore et al. 2015), and Darghouth et al. (2014) explored the implications of this effect for time-based retail rates and the customer-economics of PV systems. No studies to our knowledge, however, have estimated the impact of this effect on the deployment of distributed PV or contrasted it with the fixed-cost feedback mechanism that is the focus of current broader literature.

Key informational gaps also exist with respect to the effect of rate-design changes on PV deployment. Studies have focused on the impacts of retail rate structure on the customer economics of PV (Mills et al. 2008, Darghouth et al. 2011, Ong et al. 2010, Ong et al. 2012) but generally have not translated those findings into deployment effects. Where deployment effects have been explored (e.g., Drury et al. 2013), analyses have considered a relatively narrow range of retail rate structures and have not accounted for the two possible feedback effects between PV deployment and retail electricity prices noted above. Understanding these deployment impacts will be critical for regulators and other decision makers as they consider potential changes to retail rates – whether to mitigate adverse financial impacts from distributed PV or for other reasons – given the continued role that PV may play in advancing energy and environmental policy objectives and customer choice.

Table 1. Feedback mechanisms between PV adoption and retail electricity prices addressed in this paper

Rate Feedback Effect	Description	Affected Rates
Fixed Cost Recovery Feedback	Increases in average retail rates required to ensure fixed-cost recovery	Flat and Time-varying
Time-varying Rate Feedback	Changes in the timing of peak and off-peak periods under time-varying rate structures	Only Time-varying

Our research builds on the aforementioned literature and addresses critical informational gaps for decision makers by modeling customer adoption of distributed PV under a range of rate designs. The analysis leverages the National Renewable Energy Laboratory (NREL) Solar Deployment System (SolarDS) model, which simulates PV adoption by residential and commercial customers within each U.S. state through 2050 and has been used widely for scenario analysis of future PV-adoption trends (Denholm et al. 2009). We build on prior applications of this tool (e.g., Drury et al. 2013) by incorporating the two key feedback mechanisms between PV adoption and retail electricity prices mentioned previously: (a) increases in average retail rates required to ensure utility fixed-cost recovery and (b) changes in the timing of peak-to-off-peak periods under time-varying rate structures (see Table 1). In doing so, we show whether and under what conditions retail rate changes caused by distributed PV might accelerate or decelerate future PV deployment. Given these feedback dynamics, we then consider deployment trends under a range of possible changes to retail rate design and net-metering rules, including widespread adoption of fixed customer charges, flat vs. time-varying energy charges, feed-in tariffs, and "partial" net metering (whereby PV generation exported to the grid is compensated at an avoided-cost rate). Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures, but that concerns over feedback effects may be somewhat overstated as the two feedback mechanisms operate in opposing directions.

2 Data and Methods

This section describes the SolarDS model, data sources, and assumptions, followed by descriptions of our analysis scenarios and our methods for modeling electricity rate feedbacks. One item on scope deserves note upfront: we do not explore customer defection from the grid as a possible result of combined solar/storage solutions, which may go through substantial price reductions over the study period (Bronski et al. 2014). The reason for this is that the primary tool used in this analysis (SolarDS) is not equipped to evaluate storage solutions or defection decisions.

2.1 SolarDS model, data sources, and assumptions

The SolarDS model simulates the customer adoption of distributed PV using a bottom-up approach (where customer-adoption decisions depend on an economic comparison between PV system costs and reduction in the customer's electricity bill) with data from 216 solar resource regions and more than 2,000 electric utilities. It is an economic model, and assumes that deployment is driven by economic considerations. There are two central elements to the model:

1) **Customer economics of PV.** SolarDS calculates PV system lifetime cash flows based on simulated PV output from NREL's PVWatts model for 216 solar resource regions (Dobos 2014), utility-specific average revenue per kWh (a proxy for retail rates) from U.S. Energy Information Administration (EIA) Form 861, and assumptions about PV system costs, performance degradation rates, and state and federal incentives.

   For input parameters, we assumed the installed prices for PV systems follow a trajectory that draws from the SunShot PV price target (a 75% price decline from 2010 levels by 2020), as described in the U.S. Department of Energy's *SunShot Vision Study* (U.S. Department of Energy 2012): residential PV system prices fall to \$1.60/W in 2020 , and commercial PV system prices fall to \$1.34/W in 2020 (in 2013 U.S. dollars per peak watt-direct current), assuming an exponential decline in prices through 2020.

   PV compensation under net metering with flat, volumetric retail rates (as are common for U.S. residential customers) is determined by the average electricity rate distribution in each state (differentiated by commercial and residential customers). For retail rates that are time-varying (time-of-use, real-time pricing, or otherwise), we used the System Advisor Model (Blair et al. 2014) to calculate PV-induced bill savings with and without time-of-use rates, using 2013 rates available to residential customers in each state's largest utility. The ratio of bill savings with time-varying rates to that with flat rates as calculated through this approach was then used to estimate the customer's bill savings from PV under time-varying rates for other utilities in the state, and for both residential and commercial customers. Our demand-charge methodology for commercial customers was not changed from the original SolarDS model; for demand charges that apply to commercial customers, SolarDS assumes that PV can displace 20%–60% of demand charges, depending on the building type, insolation, and season, as calculated using the EnergyPlus model for the original SolarDS. Rate escalation assumptions are from EIA's *Annual Energy Outlook* (EIA 2014a), extrapolated to 2050.

Average utility-specific rates, solar renewable energy credit (SREC) prices, and available state and utility incentives were updated to 2013 levels. State and utility incentives were updated as per the Database of State Incentives for Renewable Energy (DSIRE) database (NCSU 2014). All state incentives and SREC prices are assumed to ramp down linearly to reach zero in 2030, except for incentives that identify an earlier end-date. The federal investment tax credit (ITC) was set to 30% for residential and commercial systems in 2014, and is assumed to revert to zero for residential customers and to 10% for commercial customers at year-end 2016. We assume that 70% of residential systems installed are third-party owned and hence benefit from the commercial ITC.

2) **Customer adoption.** Customer adoption depends on a comparison of electricity bill savings and the cost of the PV system (the "cash flow"). Using the PV system's lifetime cash flow, SolarDS adoption decisions are based on time-to-net-positive cash flow (i.e., payback period) for residential customers and internal rate of return for commercial customers.[1] SolarDS uses highly non-linear customer adoption curves linking payback and rate of return to adoption rates as a percent of maximum market size (adoption curves are available in Denholm et al. (2009)). Maximum market size is based on the number of solar-appropriate households for the residential sector and the available solar-appropriate roof space for commercial customers (see Denholm et al. (2009) for details related to residential and commercial building stock assumptions).

The size distribution of PV systems in the residential sector is based on the distribution of existing PV installations (Barbose et al. 2014).[2] For the commercial sector, PV system size is determined using roof size limitations and load assumptions from Denholm et al. (2009). In each geographical area considered, we aggregated adoption from each customer segment under each rate type and then summed up all installations to the state and national level.

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[1] We assume that customers do not foresee the changing rates due to PV penetration levels, and expect net metering to continue to be available over the lifetime of their system.

[2] We recognize that the distribution of PV system sizes may change with time. Lower prices provide some customers incentive to install larger systems, while some rate design choices, such as partial net metering, would encourage smaller systems.

Additional details about the input assumptions for and methodologies used in SolarDS are documented in Denholm et al. (2009).

2.2 Retail rate design and PV compensation scenarios

Eight rate design and PV compensation scenarios are modeled in this analysis, including a reference scenario that provides a baseline (see Table 2). This set of scenarios is by no means intended to be exhaustive, but rather consists of a representative and tractable number of the broader universe of potential rate design options. All scenarios include residential and commercial customer segments and project deployment of customer-sited PV through 2050.

For the reference scenario, we assumed a continuation of the current mix of rate designs and determined the proportion of customers facing flat rates, time-varying rates, and – for commercial customers – demand-charge rates using data from EIA Form 861 and previous SolarDS assumptions (Denholm et al. 2009). We assumed full net metering for the reference scenario, where all customer PV generation is effectively compensated at the retail rate.

Table 2. Rate design and PV compensation scenario assumptions

Scenario	Customer retail rate assumptions	PV compensation assumptions
Reference	Reference mix of flat rates, time-varying rates and demand charges from EIA Form 861 data	Net metering
$10 fixed charge	Reference mix, but with residential rates adjusted with $10 monthly charge	Net metering
$50 fixed charge	Reference mix, but with residential rates adjusted with $50 monthly charge	Net metering
Flat rate	All residential and commercial customers on flat rates	Net metering
Time-varying rate	All residential and commercial customers on time-varying rates	Net metering
Partial net metering	Reference mix	PV generation that displaces instantaneous load compensated at retail rates; PV generation exported to the grid compensated at avoided-cost rate
Lower feed-in tariff	not applicable	All PV generation compensated at $0.07/kWh
Higher feed-in tariff	not applicable	All PV generation compensated at $0.15/kWh

For the scenarios with monthly fixed customer charges, residential PV generation is assumed to only displace the variable portion of the rate. The variable portion of the rate is then calculated for each utility, such that the combination of the variable portion and fixed customer charge is equal to the utility-reported total revenue data from EIA Form 861. For the flat rate and time-varying rate scenarios, all customers are assumed to be on either the flat rate or the time-varying rate, respectively; these scenarios are designed to bound the potential rate mix options. For partial net metering, the PV generation that displaces instantaneous load is assumed to be compensated at the underlying retail rate, while PV generation exported to the grid -- assumed to be 50% and 30% of total PV generation for residential and commercial customers, respectively (E3 and CPUC 2013) -- is compensated at a lower, avoided-cost rate. That rate depends on regional PV penetration and natural gas prices. Detailed methods for determining PV energy and capacity value can be found in the next section. For the feed-in tariff scenarios, all PV generation is compensated at stipulated (and admittedly somewhat arbitrary) “lower” and “higher” fixed prices, independent of the customer’s retail rate.

2.3 Modeling rate feedbacks

The original SolarDS model assumes that retail rate structure and prices are independent of regional PV deployment and escalates those prices at a stipulated rate (e.g., based on retail price projections from the EIA *Annual Energy Outlook*). However, retail rates – and hence the economics of customer-sited PV – are projected to change with increasing PV deployment (Darghouth et al. 2014). In this analysis, we model two separate but interconnected retail-rate feedback mechanisms: fixed-cost recovery and time-varying rate feedback. The factors driving the time-varying rate feedback also affect the partial net metering PV compensation scenario, because exported PV generation is assumed to be compensated at an avoided-cost rate, which is dependent on the regional PV penetration level.

2.3.1 Fixed-cost recovery feedback

When PV is compensated at a retail rate greater than the underlying reduction in the utility's costs from PV (as described in more detail later in the text), we use a fixed-cost recovery adder to supplement the rates such that the utility still achieves full cost recovery. The fixed-cost recovery adder is modeled at the state level, separately for residential and commercial customers, as follows:

$$A_{FCR} = \frac{\left(r_{avg} - v_{PV}\right) \cdot G_{PV}}{L_{tot} - G_{PV}}$$

where A_{FCR} is the fixed-cost recovery adder for residential or commercial customers, r_{avg} is the average compensation rate for residential or commercial PV customers, v_{PV} is the calculated utility cost savings from PV, G_{PV} is the total residential or commercial customer-sited PV generation, and L_{tot} is the total residential or commercial load within the state. As indicated, the fixed-cost recovery adder, A_{FCR}, is calculated separately for the residential and commercial sectors using the appropriate compensation rate, PV generation, and load values for each sector.

There is considerable debate about the degree to which PV offsets utility costs and, more broadly, about the value of PV from a societal perspective (Hansen et al. 2013, Denholm et al. 2014, Brown and Bunyan 2014, IREC 2013). We narrowly focus on the value of PV in offsetting utility costs, where the value of PV, v_{PV}, consists of three components: the energy value, the capacity value, and miscellaneous value (which includes avoided transmission and distribution losses, transmission and distribution capacity offsets or additions, and other economic cost savings). Our use of value of PV in this context excludes any additional benefits to society that are not monetized by the utility (e.g. environmental and health benefits). It also excludes shorter term consumer benefits related to lower average wholesale prices.[3]

We assume energy and capacity value depend on regional PV penetration levels, where regions are based on EIA's electricity market module zones, and PV penetration levels include both utility-scale and distributed PV.[4] For the energy value of PV, we assume for simplicity that PV electricity displaces natural gas electric generation as the marginal resources in most regions during PV generation hours. We calculate natural gas generation prices using regional EIA natural gas price projections for the electricity sector and average natural gas plant heat rates (EIA 2014). We assume PV generation displaces less efficient (and therefore more expensive) natural gas generators at low PV penetrations and more efficient ones at higher penetrations: starting from zero PV penetration, PV displaces natural gas generation that is 10% less efficient than average, and this ramps linearly to displace natural gas generation that is 20% more efficient than average at 20% PV penetration, on an energy basis; these assumptions are based on findings from Mills et al. (2013). To estimate PV penetration, we aggregate PV generation at the regional level to account for the interconnected nature of electric grids. Ultimately, this approach results in the energy value of PV decreasing with increasing regional PV penetration.

We also model the declining capacity value of PV with increasing regional PV penetration. Hoff et al. (2008) modeled the relationship between the capacity credit of PV and PV penetration for three electric utilities with different load profiles. Because one driver of PV capacity value is PV's contribution to generation during peak periods, the capacity credit at low PV penetrations tends to be higher for regions with afternoon (summer) peaking periods than for regions with evening (winter) peaking periods. As PV penetrations increase, the marginal capacity credit of PV falls as the net load peaks shift toward evening hours. We use the three capacity credit curves from Hoff et al. (2008) as well as data on state winter-to-summer peak ratios to

[3] In the short term, PV generation can reduce wholesale electricity prices levels during times during which PV generates due to the merit-order effect (Sensfuß et al 2008), hence lowering average wholesale prices, as has been observed recently in Germany and California. However, as unprofitable generators exit the market and older generators retire, new generators will be built such that, in an equilibrium state, all generators are once again profitable. This implies changing wholesale price profiles, but not lower average electricity prices.
[4] As with the PV price assumptions detailed earlier, we assumed regional utility-scale PV deployment consistent with U.S. Department of Energy (2012), modeled by NREL's Regional Energy Deployment System. Distributed PV deployment is from SolarDS scenario results from this study.

interpolate over two curves with the nearest ratio. We then calculate the capacity value of PV at the state level for any given year assuming a capacity cost of $992/kW for new natural gas generation (EIA 2014b). As with energy value, this approach results in a decline in the value of PV with increasing regional PV penetration.

We aggregate all other PV-induced utility cost savings, including avoided transmission and distribution losses as well as deferred (or incurred) transmission and distribution capacity investments and any savings from environmental compliance, into a single "miscellaneous" value adder, which we set to $0.01/kWh based on an earlier analysis (Darghouth et al. 2010) and as a proxy for these potential benefits. Though there is increasing consensus that loss savings are reasonably quantifiable, the value of PV resulting from changes in T&D capacity investments and environmental compliance costs, for example, might increase or decrease with increasing PV penetration, and hence we keep this adder independent of regional PV deployment (Cohen et al. 2014).

In addition to feeding into the fixed-cost recovery and time-varying rate feedbacks, this value of PV estimate, or utility avoided-cost, is also used for the partial net-metering scenario: that scenario assumes that all exported PV generation is compensated at a rate representing the sum of the energy, capacity, and miscellaneous value components of PV (calculated for each state based on regional PV penetration). With an export of some PV generation, this mechanism also partially replaces the fixed-cost recovery adder that compensates for the difference between the retail electricity rate and the value of PV under full net metering.

2.3.2 Time-varying rate feedback

For time-varying retail rates, such as time-of-use or real time pricing, average PV compensation is assumed to change as PV penetration increases, resulting from the shift in the value of PV with penetration. Because the design of time-varying rates varies greatly from one utility to the next, we use existing time-of-use rates as our starting point rather than designing them from the bottom up using standard rate-design methods, as the latter method might produce rates very different from existing ones. As time-varying rates aim towards reflecting marginal cost trends, we then adjust those starting-point PV compensation levels to account for changing (net) peak times and levels using the same methods as described earlier.[5]

In particular, for time-of-use or real-time rates, the average compensation for PV generation depends on the coincidence between PV generation and peak price periods. At low PV penetrations, times of PV generation and peak electricity prices coincide reasonably well for

[5] We do not adjust demand-charge savings with increasing overall PV penetration. Customer demand charges are often based on non-coincident peak load, in which case demand-charge savings from PV would not change with overall PV penetration. For simplicity, we effectively assume widespread use of non-coincident demand charges in this analysis. Demand charges may sometimes be based on coincident (net) peak load, however, in which case PV-induced demand-charge savings would decline with increased overall PV penetration. By ignoring this possibility, we understate the magnitude of the time-of-use feedback effect described later.

afternoon-peaking utilities, hence the value of PV and PV compensation based on time-varying rates can be higher than average rates, as reflected in most time-varying rates available today. As PV penetrations increase, however, the marginal generation cost decreases during the hours when PV generates, driven by the same trends that impact the energy and capacity value of PV as discussed previously[6]; because this is reflected in time-varying rates, we would expect a decrease in PV compensation levels (as found in Darghouth et al. 2014). We therefore model the reduced PV compensation under time-varying rates by decreasing the PV compensation at the same rate as the reductions in energy and capacity value with increasing PV penetration, calculated as described in Section 2.3.1.

3 Results

This section presents our results for the feedback between electricity rates and PV deployment as well as the impact on deployment of varying rate designs and PV compensation mechanisms.

3.1 Feedback between distributed PV deployment and retail electricity rates

In our reference scenario, distributed PV deployment is estimated to increase to roughly 157 GW by 2050. The aggregate or combined impact of the two modeled feedback mechanisms (fixed-cost recovery and time-varying rate) never increases PV deployment by more than 3% in any single year, versus an otherwise identical scenario without these two feedbacks (Figure 1). As such, at least in the reference case and at an aggregate national level, we see no evidence that increased retail electricity prices from distributed PV would lead to a significant acceleration in PV adoption.

The dynamics of the counteracting effects underlying this result are critical to understanding the relationship between PV deployment and retail rates.[7] If we only consider the fixed-cost recovery feedback effect (resulting from the increase in retail rates necessary to recover utility fixed costs), PV deployment increases 8% over the case without any feedback by 2050 (Figure 2). On the other hand, if we only consider the time-varying rate feedback (where bill savings for PV customers decline under time-varying rates due to reduced value of PV), PV deployment decreases by 5% compared with the no-feedback case. In effect, the two feedback mechanisms cancel one another to a large extent (again, under our reference case rate design assumptions and at an aggregate national level).

[6] Mills and Wiser (2013) have modeled the impact of increased renewables on the economic value of solar at high penetrations in California. In a separate paper, Mills and Wiser (2015) also identify strategies that could mitigate this effect, including low-cost bulk storage options or increased customer demand elasticity.
[7] Note that the two countervailing feedback effects do not sum exactly to the total feedback owing to the minor interaction between the two effects.

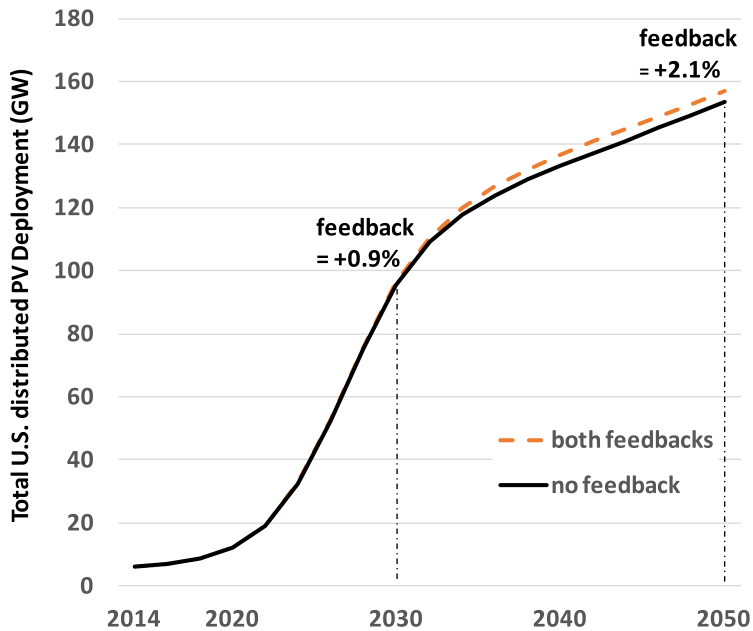

Figure 1. National distributed PV deployment under the reference scenario

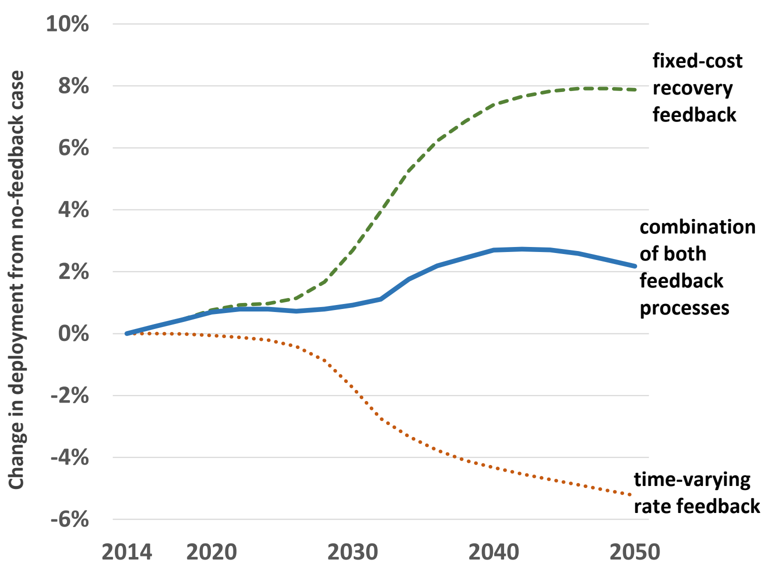

Figure 2. Percentage difference between national PV deployment with and without feedback under the reference scenario, broken out by the two feedback effects

The feedback effects differ between residential and commercial customers owing to the different retail rate structures characteristic of each sector. The rate increase resulting from the fixed-cost recovery adder is present for both flat and time-varying rates in the reference scenario. However, customers with time-varying rates experience a counteracting reduction in PV compensation due to the shifting temporal profile of time-varying rates with increased PV penetration. Most residential customers face flat, volumetric rates in the reference scenario, thus residential deployment increases through 2050 owing to the rate feedback, leveling out at just above 9% over the reference scenario without feedback (Figure 3), when considering both types of feedback. In contrast, most commercial customers face time-varying rates in the reference scenario, so total commercial deployment decreases by 15% compared with the no-feedback case. Because commercial PV deployment estimated by SolarDS is much lower than residential deployment, the net effect of the feedbacks over both customer segments is only slightly positive by 2050.

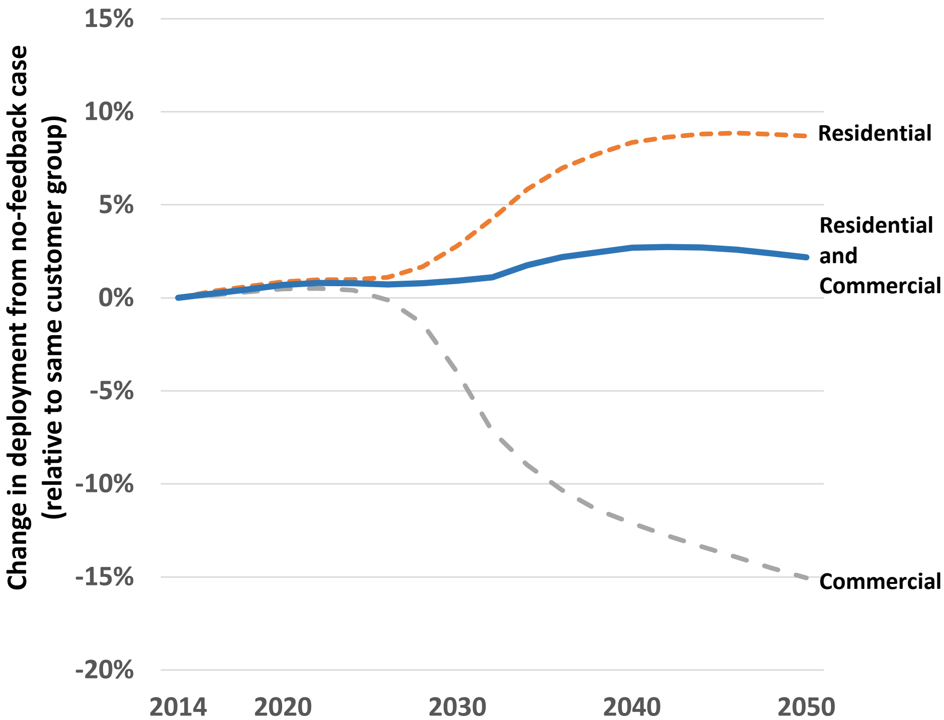

Figure 3. Percentage difference between national PV deployment with and without feedback effects under the reference scenario, broken out by market segment

The results presented to this point are at the national level, and show that the two feedback effects largely cancel each other out in the reference scenario owing to their differential impacts on residential and commercial PV deployment. At the state level, however, feedback effects vary more substantially, as shown in Figure 4 for the year 2050.

For the residential sector, the combined feedback effects increase PV deployment for most states, with a net effect ranging from a 2-6% (based on the 25th/75th percentile values among states) increase in deployment, compared to an equivalent scenario without feedbacks. The variability among states results from differences in residential PV penetration, underlying average retail rates, and percentages of customers on flat rates. States such as California with higher residential PV penetrations and predominantly flat rates experience much stronger feedback effects. States with a higher percentage of residential customers facing time-varying rates have a lower (or even negative) net feedback effect.[8]

Because most commercial customers are already on time-varying rates, the two feedback mechanisms yield a net decrease in commercial PV deployment in most states, as a result of the time-varying rate feedback outlined in section 2.3.2. The magnitude of the commercial customer feedback effects, however, varies substantially across states (i.e., a 9-22% reduction in deployment, based on the 25th/75th percentile values among states, relative to no feedbacks), because the change in energy and capacity value due to increased regional PV penetration varies widely from one region to the next. States with winter evening peaks have a low PV capacity value, even at low PV levels, hence the reduction in value with PV penetration is not substantial and the commercial feedback effect is muted.[9]

As Figure 4 shows, in aggregate considering both feedback effects, most states have a negative total feedback effect, with the median state showing a reduction in cumulative distributed PV deployment in 2050 of 1% relative to the reference case without feedback. This is in slight contrast with Figure 1, which shows a total feedback on a national basis of +2% in 2050. This is because the national results are more-significantly influenced by states with large PV markets, particularly California. Regardless, despite widespread literature suggesting a positive feedback effect, our results suggest that the combined effect of the two relevant feedbacks, at least in the reference case, is generally modest and often negative.

[8] In Arizona, for example, where a substantial share of residential customers face time-varying rates, the combined effects of the two feedback mechanisms reduce residential PV deployment compared with the no-feedback case.
[9] Note that we have chosen not to present state-level results as our focus is on trends at the national level, and while our assumptions capture the macro-level dynamics, they do not necessarily capture the state-level idiosyncrasies related to specific rate levels, mixes, or PV adoption factors, as SolarDS is not designed to make state-level projections.

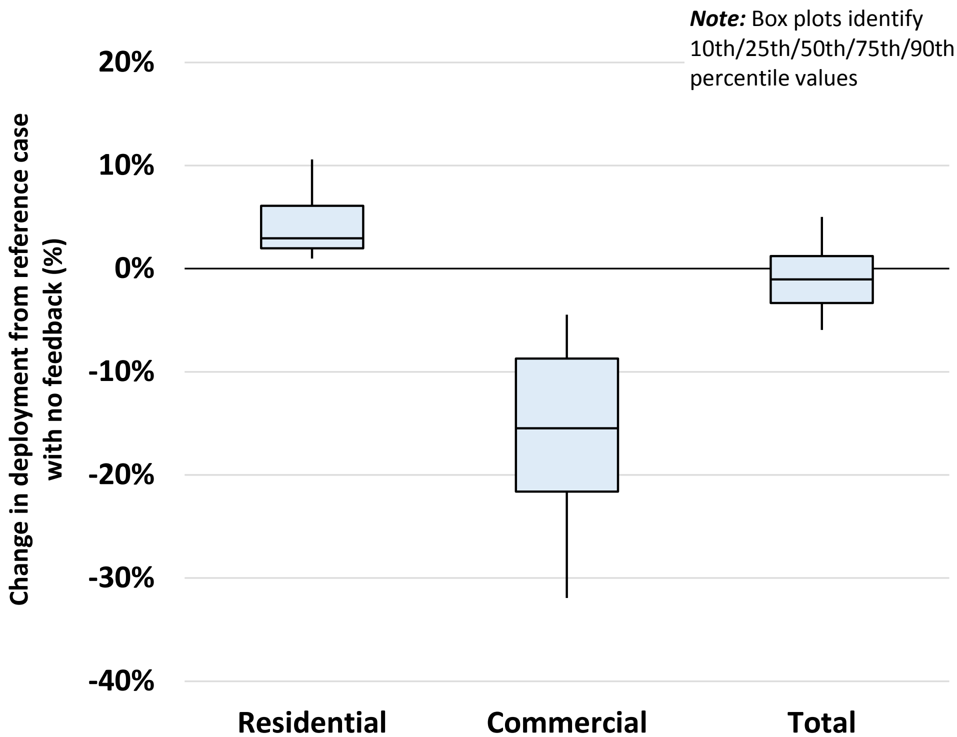

Figure 4. Distribution in feedback effects across U.S. states in 2050, for residential, commercial, and all customers

The results thus far have been for the reference scenario, which assumes residential and commercial rate distributions loosely based on 2013 levels. However, given long-term uncertainties in the rate mix, our scenarios with all customers on a flat rate vs. all on a time-varying rate bound results with respect to the rate mix assumptions (Figure 5). For the flat rate scenario in which all residential and commercial customers are served under a flat volumetric rate, feedback increases PV deployment by 3% in 2030 and 8% in 2050. For the time-varying rate scenario in which all residential and commercial customers are served under a time-differentiated rate, feedback reduces deployment by 6% in 2030 and 25% in 2050. Given the generally expected move, over time, to time-differentiated rates, it would seem that PV deployment feedback effects are predominantly in the negative direction.

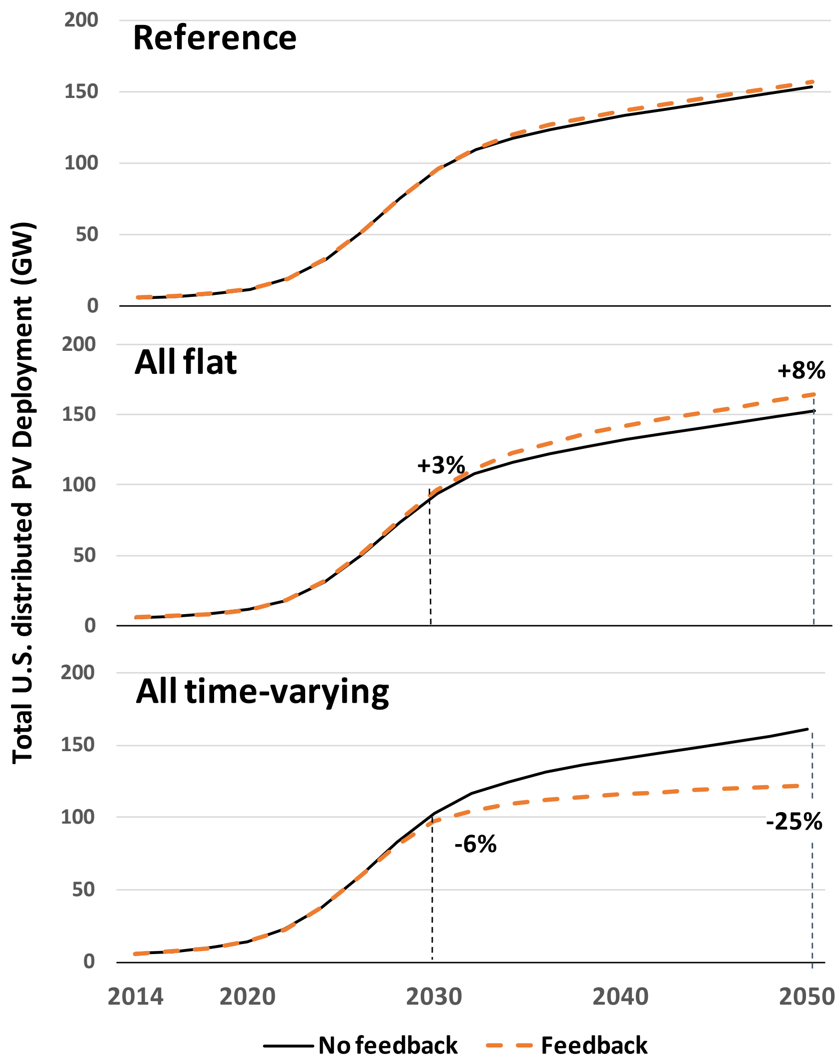

Figure 5. National distributed PV deployment with and without rate feedback for reference, flat rate, and time-varying rate scenarios

Finally, electric utilities and their regulators have begun to consider various changes to rate designs and PV compensation approaches to address concerns over fixed-cost recovery with increasing PV deployment, including the possible positive feedback effect described earlier. These changes have, thus far, been largely directed at residential customers given the prevalence of flat, volumetric rates with no demand charges and lower fixed customer charges. Two specific options sometimes discussed are increased fixed monthly customer charges, and implementation of partial net metering where instantaneous net excess PV generation is compensated at a rate consistent with utility cost savings (typically lower than the retail rate).

Figure 6 presents national residential PV deployment under the reference scenario without feedback and with feedback, and contrasts those results with the fixed-monthly customer charge and partial net metering scenarios, all with feedback. As shown, consistent with Figure

3, the fixed-cost recovery feedback effect leads to residential distributed PV deployment that is 9% higher than without feedback in the reference scenario. The application of monthly customer charges and partial net metering more than offsets this feedback effect, leading to cumulative residential PV deployment that is 17% to 77% lower than in the reference case without feedback. As such, while these rate designs might help address broader concerns from utilities and regulators related to fixed cost recovery issues, they are found to far exceed the levels needed to solely address *feedback* effects.

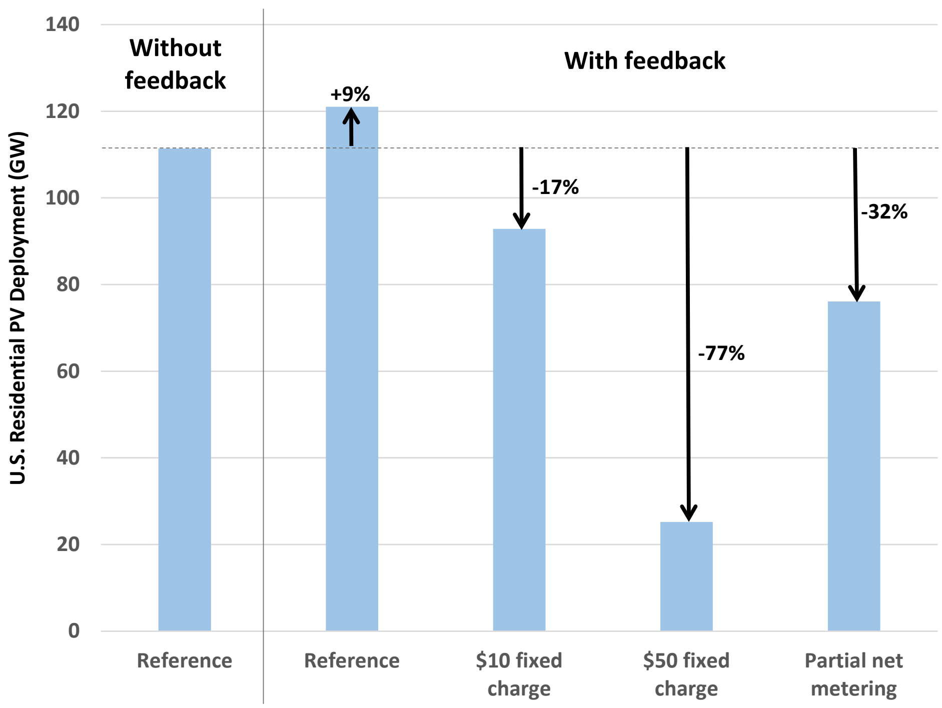

Figure 6. Assessing the degree to which fixed monthly charges and partial net metering offset fixed cost recovery feedback effects for residential customers

3.2 Impact of rate design and PV compensation mechanisms on distributed PV deployment

Whereas the previous section focused on the deployment effects of rate feedbacks, this section shows how various rate designs and PV compensation mechanisms impact total PV deployment, given the presence of those feedback mechanisms. Figure 7 shows the deployment paths for the eight scenarios listed in Table 2, with rate feedback effects included, demonstrating that PV deployment is highly sensitive to rate design choices and PV compensation mechanisms.

The flat rate scenario leads to the highest deployment in 2050, and the lower feed-in tariff scenario leads to the lowest. Most of the rate and compensation scenarios follow temporal trends similar to that of the reference scenario (with different magnitudes), but the time-varying rate scenario follows a different overall trajectory. Specifically, under the time-varying rate scenario, PV deployment is greater than in the reference scenario through about 2030, after which it falls below the reference deployment. This is because, at low solar penetrations, the higher average compensation for PV under time-varying rates boosts PV deployment. However, as regional PV penetration increases and the energy and capacity value of PV erodes, compensation for net-metered PV generation also erodes under time-varying rates, leading to lower deployment.

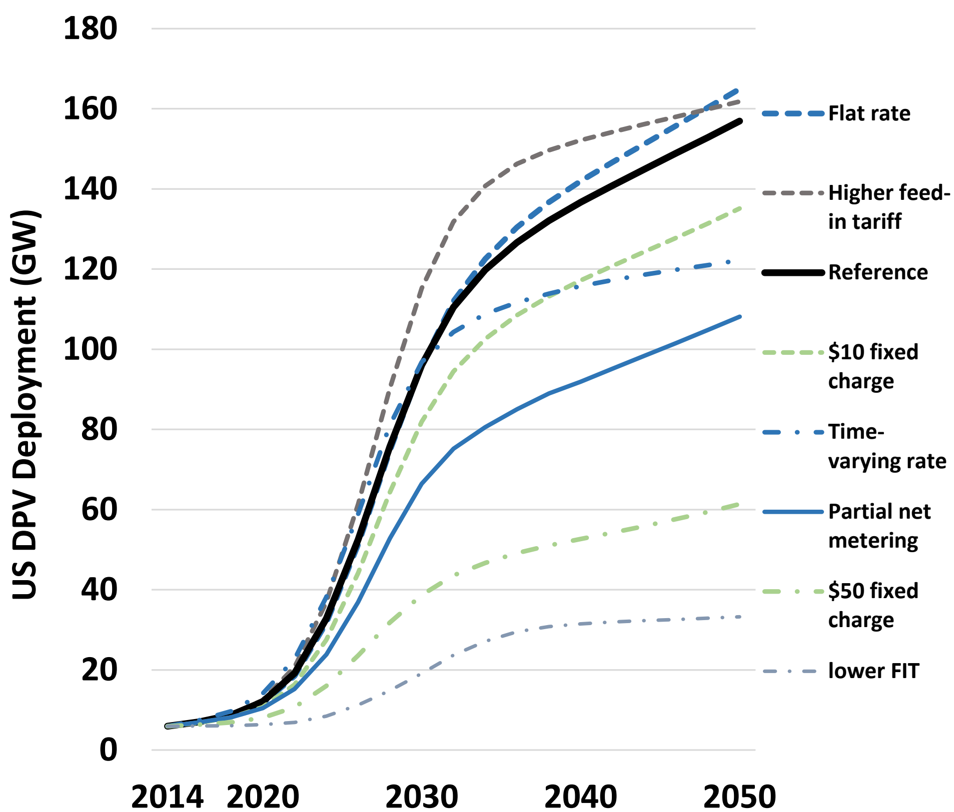

Figure 7. National distributed PV deployment by scenario (with rate feedback effects included)

Figure 8 focuses on 2050 cumulative PV deployment for each of the seven alternative scenarios relative to the reference scenario. Only the flat rate and higher feed-in tariff scenarios increase deployment; all other scenarios reduce deployment. The results indicate that, were all residential and commercial customers on a time-invariant flat rate with no fixed or demand charges, PV deployment would increase by 5% owing to the increased average compensation under that simple rate design. The higher feed-in tariff level of $0.15/kWh also increases deployment relative to the reference scenario; the difference is clearly related to the tariff's magnitude, and higher values would further increase deployment. A lower feed-in tariff level would lead to substantially lower deployment than the reference case, 79% lower for our $0.07/kWh feed-in tariff scenario. Due to the declining value of PV with increased penetration, the time-varying rate scenario leads to a reduction in cumulative PV deployment of 22% in 2050 compared with the reference scenario; as indicated earlier, time-varying rate structures actually increase PV deployment through about 2030.

Both fixed-charge scenarios reduce PV deployment in 2050: a $10/month charge applied to residential customers reduces total cumulative deployment by 14%, and a $50/month charge reduces deployment by 61%. Partial net metering, where PV generation exported to the grid (i.e., not consumed on site) is compensated at a calculated avoided-cost rate, reduces deployment by 31% because in this analysis the assumed avoided cost from PV is lower than the average retail rate, reducing average compensation and increasing the customer's PV payback time.

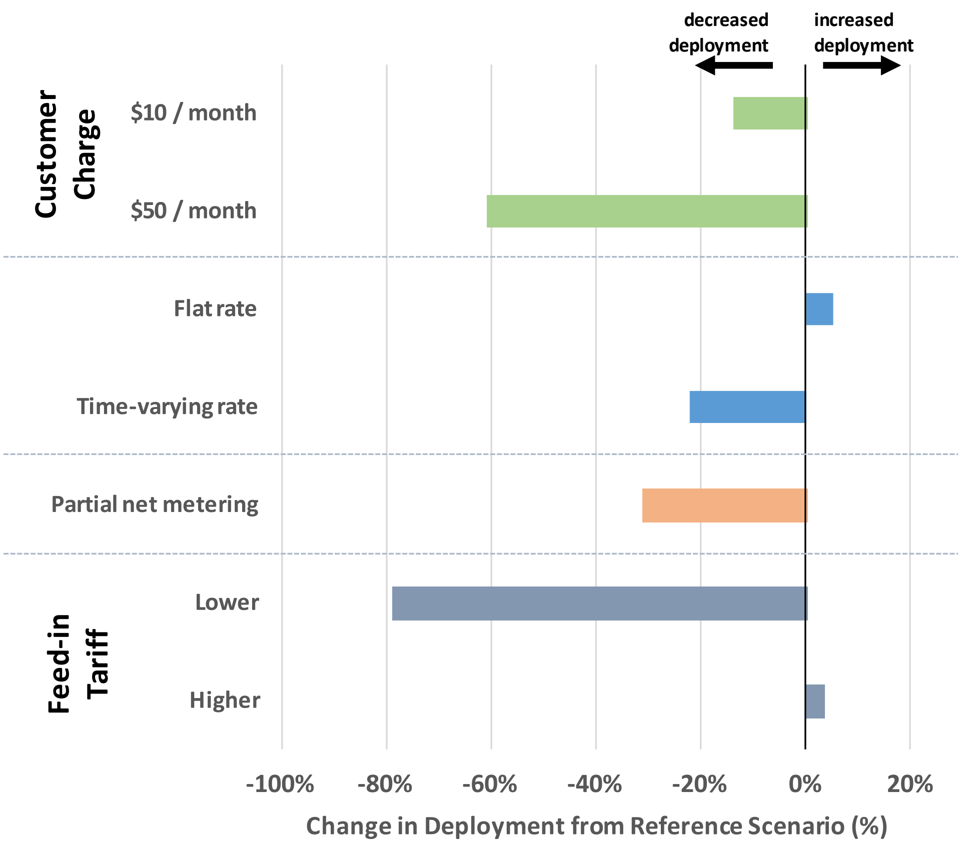

Figure 8. Change in modeled cumulative national PV deployment by 2050 for various rate design and compensation mechanism scenarios, relative to the reference scenario (with rate feedback effects included)

The distributions of PV deployment differences (compared with the reference scenario) across U.S. states vary substantially by scenario (Figure 9). For the two fixed-charge scenarios, the range is relatively small, primarily reflecting differences in the average residential retail rate and average annual customer load across states. For example, states with large annual average customer loads or high average retail rates will see a smaller impact from a given increase in fixed customer charges. The flat rate scenario increases deployment relative to the reference scenario in most states, though only by a modest amount, as a large percentage of customers are already on flat rates.

In comparison to many of the other scenarios, the significance of moving to time varying rates for PV deployment varies rather substantially across states, both in the magnitude and direction of the deployment impact. For about 75% of states, switching all customers to a time-varying rate reduces cumulative PV in 2050. The states most affected by this scenario are those with the highest PV deployment, where the energy and capacity value of PV erodes the most, along with PV compensation. In regions with low PV penetration, PV compensation under time-varying rates remains higher than the average rate, leading to higher deployment in those states under the time-varying rate scenario than under the reference scenario.

Using PV compensation mechanisms other than net metering produces a wide range of deployment impacts. In this analysis, partial net metering reduces deployment for all states, because the retail rate is always greater than the compensation that we assume applies to instantaneous net excess generation, reducing deployment. For feed-in tariffs, the impact can vary much more across states depending on average retail rates (relative to the feed-in tariff rate), the prevalence of time-varying rates, and PV penetration. For example, in states with lower PV penetration levels, even $0.15/kWh might decrease deployment, as compared with the reference scenario. The range of impacts widens with higher feed-in tariffs owing to the non-linear relationship between bill savings and customer adoption, where the marginal adoption rate increases as the payback time decreases.

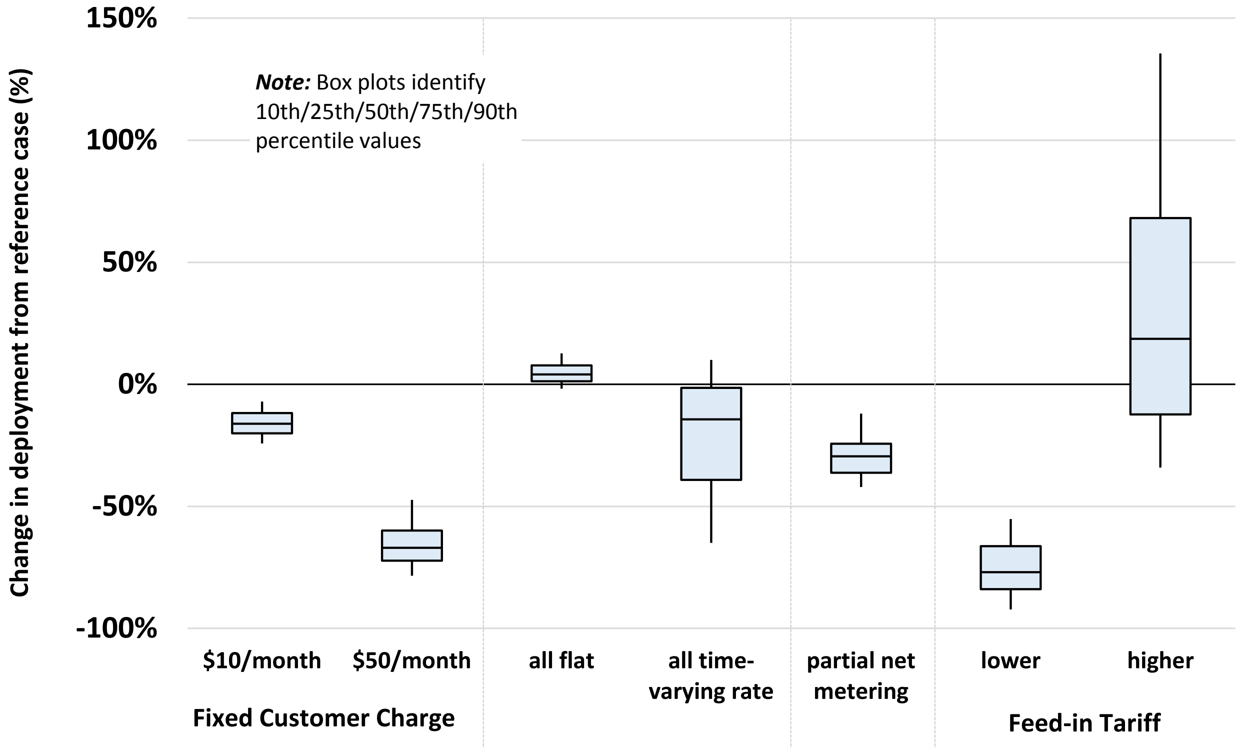

Figure 9. Distribution in deployment differences from the reference scenario for U.S. states in 2050, for all rate design and PV compensation scenarios (with rate feedback effects included)

4 Discussion and Conclusions

There has been significant recent interest in issues related to fixed-cost recovery with increasing distributed PV deployment, and concerns about the "utility death spiral" (Costello and Hemphill 2014, Felder and Athawale 2014, Cory and Aznar 2014, Blackburn et al. 2014, Satchwell et al. 2015). Some observers express concern that increases in net-metered PV adoption may threaten utility profitability, in part owing to a positive feedback loop: as PV deployment occurs, electricity rates increase because utilities must recover the same fixed costs over lower sales, making net-metered PV even more attractive for consumers, and accelerating PV deployment even further. Though our results do not speak comprehensively to the fixed-cost recovery issue or to the impact of PV on utility profitability, they do show that concerns about feedback effects—at least on a national basis—may be somewhat overstated, and that actual feedback effects are quite nuanced.

Our analysis suggests little change in national PV deployment due to rate feedback under our reference scenario, which includes customers on time-varying rates (mostly in the commercial sector) and flat rates (mostly in the residential sector).[10] This is because there are, in fact, two feedback effects of relevance—one related to fixed-cost recovery and the other related to time-

[10] As indicated earlier, but deserving reiteration here, we did not explore customer defection from the grid as a possible result of combined solar and storage solutions.

varying retail rates—and these two feedbacks operate in opposing directions. The fixed-cost feedback effect is found to increase cumulative national PV deployment in 2050 by 8%. But the feedback associated with time-varying rates reduces cumulative PV deployment by 5%. Current regulatory and academic discussions that focus solely on the fixed-cost recovery feedback therefore miss an important and opposing feedback mechanism that can offset the issue of concern.

Notwithstanding these aggregate national results, the net impact of the two feedback mechanisms can vary substantially across customer segments. In general, the prevalence of flat, volumetric electric rates among the residential customer class ensures a net positive feedback effect with increasing PV deployment in most cases (increasing cumulative national residential PV deployment in 2050 by 9%). In contrast, the prevalence of time-differentiated rates among commercial customers leads to a net negative feedback effect (decreasing cumulative national commercial PV deployment in 2050 by 15%). The net effect of these feedback mechanisms also varies across states, depending on the types of rates offered, the level of those rates, and PV deployment levels. Given these differences, the total feedback effect considering both residential and commercial customers is found to be –6% to +5% in the vast majority of states, and –1% in the median case. Thus, in most states, the feedbacks operate in the opposite direction of the expressed concern and, even where in the positive direction, are rarely particularly large.

Accounting for these feedback effects, we find that retail rate design and PV compensation mechanisms can have a dramatic impact on the projected level of PV deployment. For example, wider adoption of time-varying rates is found to increase PV deployment in the medium term but reduce deployment in the longer term, relative to the reference scenario based on current rate offerings; the changing pattern of deployment over time, relative to the reference case, is due to the decreasing energy and capacity value of PV with penetration, and the impacts of those trends on time-varying retail rates. The directional impact of feed-in tariffs or value-of-solar rates, on the other hand, depends entirely on the level of the tariff that is offered in comparison to prevailing retail electricity rates. In part to address concerns about the fixed-cost feedback effect (and in part to address many other concerns), a number of utilities have proposed increased fixed customer charges, especially for the residential sector, and/or a phase-out of net energy metering. Though a variety of considerations must come into play when contemplating such changes, our analysis suggests that a natural outcome of these changes would be a substantial reduction in the future deployment of distributed PV: we estimate that cumulative national PV deployment in 2050 could be ~14% lower with a $10/month residential fixed charge, ~61% lower with a $50/month residential fixed charge, and ~31% lower with “partial” net metering. Regulators would need to weigh these impacts with many other considerations when considering changes to underlying rate designs and PV compensation mechanisms.

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The Economic Impact On Kentucky Residential Customers Of Energy "Sold" To Utilities From Net Metering Solar Customers in 2016[1]

This paper explores the economic impact of net metering on non-participating residential ratepayers from excess electricity "sold" to the grid at retail rates. The analysis uses two data sets from the U.S. Energy Information Administration. They are *2016 Utility Bundled Retail Sales – Residential*[2], which provided the number of residential customers per utility in 2016, and *EIA_Net Metering_ Data All Utilities_2016*[3], which provides the amount, in MWh, of electricity "sold" to regulated utilities by net metering solar customers.

This analysis looks at the cost to each utility for crediting net metering customers at the retail rate rather than the avoided cost rate (this difference assumed to be roughly 7 cents per kwh) for excess power supplied to the grid. The electric utilities contend that they should be allowed to credit solar customers at the avoided cost rate and that paying above this rate results in additional costs which must be paid by all other ratepayers.

The analysis shows that, for 2016, the economic impact for any non-participating customer ranged from a high of 4 cents per month, or 48 cents a year, to a low of 0.1 cents per month, or 1.3 cents per year, with an average economic impact on non-participating customers of 0.3 cents per month, or 4 cents per year.

The total amount of "additional costs" paid by all utilities in Kentucky due to net metering in 2016 was $45,228 or $5,653 per utility with net metering customers. Data for all regulated utilities who reported net metering information to the US EIA is provided in the accompanying table.

This analysis assumes that excess generation from net metering customers is in fact only worth the avoided cost rate, which is subject to debate. For example, at times of peak demand in the summer when solar production is also at its peak, solar generation offsets the need for utilities to use their most costly peaking generation resources.

This analysis also does not account for any other benefits that net metering provides to the utility and other ratepayers. These benefits, which have been quantified by studies performed in other states, would offset the costs identified in this analysis. Therefore, these figures reflect the upper limit of potential costs that net metering might impose on other customers.

[1] Prepared by Tom FitzGerald, Kentucky Resources Council, February 28, 2018.
[2] US Energy Information Administration, 2016 Utility Bundled Retail Sales - Residential.
[3] US Energy Information Administration, Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files. (https://www.eia.gov/electricity/data/eia861/)

The Economic Impact On Residential Customers Of Energy “Sold” To Utility From Photovoltaic Customers in 2016

Assuming the utility credited for excess PV generation equal at the retail rate rather than the avoided cost (roughly 7 cents per kWh).

Utility Name (note that municipal utilities are not governed by the net metering law and thus are not included here)	**RESIDENTIAL Energy Sold Back MWH in 2016**	**RESIDENTIAL Energy Sold Back KWH in 2016**	**Value Of Credits Given in 2016 @ $0.07/kWh**	**# of Residential Customers**	**Annual Cost per Customer**	**Monthly Cost per Customer**
Clark Energy Coop Inc - (KY)	21.700	21,700	$ 1,519	24,477	$ 0.062	$ 0.0052
Cumberland Valley Electric, Inc.	0.000	-	$ -			$ -
Fleming-Mason Energy Coop Inc	0.000	-	$ -			$ -
Grayson Rural Electric Coop Corp	12.179	12,179	$ 853	14,166	$ 0.060	$ 0.0050
Inter County Energy Coop Corp	0.000	-	$ -			$ -
Jackson Energy Coop Corp - (KY)	0.000	-	$ -			$ -
Jackson Purchase Energy Corporatio	0.000	-	$ -			$ -
Kenergy Corp	0.000	-	$ -			$ -
Kentucky Utilities Co	121.335	121,335	$ 8,493	426,225	$ 0.020	$ 0.0017
Louisville Gas & Electric Co	66.992	66,992	$ 4,689	356,424	$ 0.013	$ 0.0011
Meade County Rural E C C	0.000	-	$ -			$ -
Nolin Rural Electric Coop Corp	253.000	253,000	$ 17,710	32,952	$ 0.537	$ 0.0448
Owen Electric Coop Inc	0.000	-	$ -			$ -
Salt River Electric Coop Corp	88.000	88,000	$ 6,160	46,901	$ 0.131	$ 0.0109
Shelby Energy Co-op, Inc	0.000	-	$ -			$ -
South Kentucky Rural E C C	58.046	58,046	$ 4,063	61,106	$ 0.066	$ 0.0055
Taylor County Rural E C C	0.000	-	$ -			$ -
Duke Energy Kentucky	0.000	-	$ -			$ -
Kentucky Power Co	24.866	24,866	$ 1,741	137,013	$ 0.013	$ 0.0011
TOTAL CREDIT AND AVERAGE COST	**646.118**	**646,118**	**$ 45,228**	**1,099,264**	**$ 0.04**	**$ 0.003**