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August 29, 2023

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Re: **MPSC Case No. U-21389**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the **PUBLIC** Direct Testimony and Exhibits of Dr. Laura S. Sherman and Peter D. Dotson-Westphalen on behalf of The Michigan Energy Innovation Business Council, Institute for Energy Innovation and Advanced Energy United, together with the Direct Exhibit List and Proof of Service. Thank you for your assistance in this matter.

Very truly yours,

Justin K. Ooms Digitally signed by Justin K. Ooms
Date: 2023.08.29 15:52:12 -04'00'

Justin K. Ooms

JKO/srd
Enclosure
c. All parties of record.

**STATE OF MICHIGAN**

**MICHIGAN PUBLIC SERVICE COMMISSION**

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| In the matter of the Application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) | **Case No. U-21389** |

**DIRECT TESTIMONY OF DR. LAURA S. SHERMAN**

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION,**

**AND**

**ADVANCED ENERGY UNITED**

## Table of Contents

## I. INTRODUCTION AND QUALIFICATIONS

**Q. State your name, business name and address.**

A. My name is Dr. Laura S. Sherman, and I am the President of the Michigan Energy Innovation Business Council ("Michigan EIBC") and the Institute for Energy Innovation ("IEI"), located at 115 West Allegan, Suite 710, Lansing, Michigan 48933.

**Q. On whose behalf are you appearing in this case?**

A. I am appearing here as an expert witness on behalf of Michigan EIBC, IEI, and Advanced Energy United ("United"), collectively referred to as "MEIU."

**Q. Summarize your educational background.**

A. I have a Ph.D. from the University of Michigan Earth and Environmental Sciences Department, conferred in May 2012. I also have a Bachelor of Science degree from Stanford University in Geological and Environmental Sciences, conferred in June 2005.

**Q. Summarize your experience in the field of electric utility regulation.**

A. Since April 2019, I have served as the President of Michigan EIBC and IEI. Prior to that, starting in February 2017, I was a Senior Consultant at 5 Lakes Energy focusing on energy policy and utility regulation. I also served as the Vice President for Policy Development for the Michigan EIBC and IEI. In these capacities, I have written testimony in many non-adjudicated dockets before the Michigan Public Service Commission ("Commission" or "MPSC"). From 2014–2016, I served as a Policy Advisor on energy, environment, and agriculture issues to Senator Michael Bennet (D-CO) in the U.S. Senate. In that capacity, I provided policy expertise, conducted research, developed legislation, and analyzed regulations. Prior to that, my doctoral (2007–2012) and postdoctoral (2012–2014) research was focused on the tracing of pollutants emitted during energy generation. My work experience is set forth in detail in my résumé, attached as Exhibit MEIU-1 (LSS-1).

**Q. Summarize your professional development coursework in the field of electric utility regulation.**

A. In August 2017, I completed the Electric Utility Consultants Inc. ("EUCI") course titled "Optimizing the Interconnection Process for Renewables & Storage: A National Forum for Addressing Process and Technical Issues." In December 2017, I completed the EUCI course titled "The Electric Vehicle-Utility Industry Nexus." In January 2018, I completed the EUCI course titled "Evolution of Electricity Markets: Disruptive Innovation & Economic Impacts: Highly Interactive Course Designed to Provide A Practical Overview of Evolving U.S. Power Markets."

**Q. Have you testified before this Commission or as an expert in any other proceeding?**

A. Yes. I previously testified as an expert witness in the following cases:

- U-20134 (Consumers Energy Company ["Consumers Energy," "Consumers" or the "Company"] general electric rate case);
- U-20165 (Consumers Energy Integrated Resource Plan case);
- U-20162 (DTE Electric Company ["DTE Electric"] general electric rate case);
- U-20471 (DTE Electric Integrated Resource Plan case);
- U-18232 (DTE Electric Renewable Energy Plan case);
- U-20649 (Consumers Energy Voluntary Green Pricing Program case);
- Consolidated U-20713 (DTE Electric Voluntary Green Pricing Program case)/U-20851 (DTE Electric Renewable Energy Plan case);
- U-20693 (Consumers Energy general electric rate case);
- U-21090 (Consumers Energy Integrated Resource Plan case);
- U-21131 (Consumers Energy Legally Enforceable Obligation case);

- U-21134 (Consumers Energy Voluntary Green Pricing Program case);
- U-20836 (DTE Electric general electric rate case);
- U-21224 (Consumers Energy general electric rate case);
- U-21172 (DTE Electric Voluntary Green Pricing Program case);
- U-21193 (DTE Electric Integrated Resource Plan case); and
- U-21297 (DTE Electric general electric rate case).

**Q. Have you provided analysis in support of testimony or comments in any other utility regulatory proceeding?**

A. Yes. In my roles at Michigan EIBC and IEI, from July 2017 through July 2018, I supported and reviewed filings made on behalf of MEIU in Commission Case Nos. U-18351 and U-18352, focused on the creation of the voluntary green pricing programs. In March 2018, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20095, focused on the Public Utility Regulatory Policies Act of 1978 ("PURPA") regulations and capacity determinations. In March and April 2018, with input from Michigan EIBC member companies, I provided comments and reply comments in Commission Case No. U-18383, focused on the development of a distributed generation ("DG") tariff. In June 2018, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-18361, focused on the development of new code of conduct rules. In October 2018, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20147 regarding the Commission Staff report on distribution system planning. Similarly, in March 2020, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20147 regarding the updated Commission Staff draft report on distribution system planning. In November 2020 and February 2021, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20905 regarding the implementation of FERC Order 872 in Michigan. In June 2021, with input from Michigan EIBC member companies, I provided comments on Consumers Energy's Draft Electric Distribution Infrastructure Investment Plan in Case No. U-20147. In November 2021, with input from Michigan EIBC member companies, I provided comments on the draft Interconnection and Distributed Generation Standards. In February 2022, in collaboration with United and with input from Michigan EIBC member companies, I provided comments on the MPSC Staff's draft report on Data Access and Privacy Recommendations. In June 2022, with input from Michigan EIBC member companies, in Case No. U-20890, I provided comments on the issues raised by DTE Electric and Consumers Energy in their petition for rehearing regarding the Interconnection and Distributed Generation Standards. In September 2022, with input from Michigan EIBC member companies, in Case No. U-20898, I provided comments on issues related to utility-business models. Also in September 2022, with input from Michigan EIBC member companies, in Case No. U-21099, I provided comments on demand response aggregation, resource adequacy, and dual participation of storage resources. In January, April, September, and October 2022, with input from Michigan EIBC member companies, in Case Nos. U-21219 and U-18461, I provided comments on the revisions to the Integrated Resource Plan ("IRP") Filing Requirements and Planning Parameters. In May 2023, with input from Michigan EIBC member companies, in Case No. U-20959, I provided comments on customer data access issues and in Case No. 21251, I provided comments on grid system data access issues. In July 2023, with input from Michigan EIBC member companies, in Case No. U-20890, I provided comments on a filing from Indiana Michigan Power regarding options for customers seeking to interconnect distributed generation systems <20 kW in nameplate capacity.

In addition to this work, I have been involved on behalf of 5 Lakes Energy and Michigan EIBC in multiple workgroup proceedings at the Commission, including those focused on electric vehicle (“EV”) deployment, DG tariffs, IRP requirements, energy waste reduction, and distribution system planning. Over the last two years, I have been involved on behalf of Michigan EIBC/IEI in the MI Power Grid workshop proceedings at the Commission, including those focused on new technologies and business models, customer data access, updating the state’s interconnection rules, demand response, distribution system planning, pilot programs, competitive procurement, advanced planning, and updating the IRP parameters and filing requirements.

**Q. Please summarize your experiences working with advanced energy companies on issues related to electric utility regulation.**

A I have served as the President of Michigan EIBC and IEI since April 2019. Prior to that, from November 2017 through April 2019, I served as Vice President of Policy Development for Michigan EIBC and IEI. In these roles, I have led the trade organization’s work on regulatory and legislative issues. As described above, I have participated in many workgroups at the Commission and written comments in a number of non-adjudicated cases. I also communicate formally and informally with Michigan EIBC member companies about each regulatory proceeding to understand how the advanced energy industry is affected by each proposed rule or case.

**Q. What is the purpose of your testimony?**

A. The purpose of my direct testimony is to describe, based on my experiences as the President of Michigan EIBC and IEI, support for certain aspects of the Company's EV proposals, as well as proposed modifications therein, concerns regarding the proposed distributed energy resource ("DER") Optimization plan, and issues related to the DG program.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

- Exhibit MEIU-1 (LSS-1): Résumé of Dr. Laura S. Sherman
- Exhibit MEIU-2 (LSS-2): Discovery response U21389-MEIBC-CE-0098
- Exhibit MEIU-3 (LSS-3): Discovery response U21389-MEIBC-CE-0099
- Exhibit MEIU-4 (LSS-4): Discovery response U21389-MEIBC-CE-0264
- Exhibit MEIU-5 (LSS-5): Andrew Satchwell, et al., Lawrence Berkeley National Laboratory, Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities (2014).
- Exhibit MEIU-6 (LSS-6): Galen Barbose, Lawrence Berkeley National Laboratory, Putting the Potential Rate Impacts of Distributed Solar into Context (2017).

## II. TRANSPORTATION ELECTRIFICATION

**Q. Please summarize Consumers Energy's transportation electrification proposals in this case.**

A. Consumers Energy's proposals regarding transportation electrification are presented primarily in the testimony of Jeffrey A. Myrom.[1] The Company proposes to (1) maintain the PowerMIDrive residential program as approved in Case No. U-21224;[2] (2) complete the PowerMIDrive public charging pilot approved in previous cases and develop a permanent Level 2 and long-duration Level 1 program with strategically targeted off-peak and equitable locations;[3] and (3) complete the PowerMIFleet pilot approved in previous cases and shift to a permanent program focused on off-peak charging for public transit, school bus, non-profit, and small- to medium-sized business fleets.[4]

In support of these proposals, witness Myrom discusses forecasted EV market growth in Michigan;[5] the proposed transportation programs, budget, and customer safeguards through 2030;[6] the proposed permanent PowerMIDrive public charging program;[7] the proposed permanent PowerMIFleet program;[8] stakeholder input, annual reporting to the Commission, and various proposed tariff provisions.[9]

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[1] Direct testimony of Jeffrey A. Myrom on behalf of Consumers Energy Company ("Myrom Direct"), Case No. U-21389.

[2] *Ibid*, p. 3.

[3] *Ibid.*

[4] *Ibid.*

[5] *Ibid*, p. 5.

[6] *Ibid*, p. 8.

[7] *Ibid*, p. 11.

[8] *Ibid*, p. 14.

[9] *Ibid*, p. 17.

**Q. Do you consider the Company's forecast of EV market growth to be reasonable?**

A. Yes. In addition to the considerations described by witness Myrom,[10] at approximately the same time that Consumers Energy filed witness Myrom's testimony, the U.S. Environmental Protection Agency ("EPA") proposed Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles.[11] EPA projects that under this rule "EVs could account for 67% of new light-duty vehicle sales and 46% of new medium-duty vehicle sales in MY [model year] 2032."[12] This is an even faster pace of electrification than that projected by witness Myrom. Notably, a faster pace of EV adoption also means that the Company is likely to significantly exceed the $254 million positive net present value associated with vehicle electrification, which witness Myrom projected based on his "low scenario" of EV adoption, due to the additional revenue from EV charging.[13]

**Q. The Company, through witness Myrom, proposes to continue regulatory asset treatment of the transportation electrification budget until near 2030. Do you support that proposal?**

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[10] *Ibid*, p. 5.

[11] 40 CFR Parts 19, 86, 523, 600, 1066, and 1867 in Docket EPQ-HQ-OAR-2022-0829, available from https://www.govinfo.gov/content/pkg/FR-2023-05-05/pdf/2023-07974.pdf.

[12] U.S. EPA. "Biden-Harris Administration Proposes Strongest-Ever Pollution Standards for Cars and Trucks to Accelerate Transition to a Clean-Transportation Future," available from https://www.epa.gov/newsreleases/biden-harris-administration-proposes-strongest-ever-pollution-standards-cars-and.

[13] Myrom Direct, p. 9.

A. Yes, I do. Witness Myrom explains that the necessary infrastructure upgrades and programming must precede the growth from electric transportation to help optimize future load.[14] He also says that the Company anticipates revisiting regulatory asset treatment in future rate cases after 2028.

I note, however, that in addition to the need to anticipate infrastructure requirements, regulatory asset treatment is justified by the fact that the net revenue from EV charging is associated with the life of the vehicle and not the initial adoption of an EV. Thus, regulatory asset treatment aligns cost recovery with the additional net revenue and provides rate reduction benefits to non-EV drivers sooner. While revisiting this matter circa 2028 is appropriate, it is likely that at that time, the numbers of EVs in use will still be increasing rapidly.

**Q. Do you have any observations to offer regarding the proposed permanent PowerMIDrive program and the permanent PowerMIFleet program?**

A. Yes. I note that a common element of each of these programs is separate metering on a Time of Use ("TOU") rate.[15] The Company appears to have developed each element of its proposed programs with a goal of shifting load to off-peak times. This is a commendable and important strategy. However, I caution that this strategy will likely need to change within the foreseeable future. As EV penetration increases, using TOU rates to shape load may become inadequate. This is because at high EV penetration levels, if most vehicles

[14] *Ibid*, p. 11.

[15] *Ibid*, pp. 11–15.

begin to charge at the beginning of the low-price period, the surge in demand may not be tenable for generation ramping or for power flow stability. In addition, as solar and wind energy become increasingly important in power supply, grid stress will be associated with periods of lower renewable generation relative to load. These periods will not be consistent as to season or time of day. At some point in the future it will therefore be necessary to move from TOU rates toward more sophisticated load-shaping strategies for EVs, which are likely to include some level of communications from the utility to either charging infrastructure or vehicles. Since charging infrastructure is more likely to be in known (or knowable) places, utility considerations of generation requirements and of power flows will be better addressed through communicating with charging infrastructure. I therefore recommend that the Company require that Level 2 and direct current fast charging ("DCFC") equipment for which they provide rebates are networked. I also recommend that the Company consider conducting a near-future pilot effort to begin to explore how to manage charging in response to grid conditions.

**Q. Do you have any other concerns about the Company's transportation electrification proposals?**

A. Yes. Witness Myrom testifies that if demand for rebates is significantly higher than the transportation electrification budget, the Company will prioritize some rebates and waitlist others.[16] That is not acceptable. On account of the rest of their proposals, the Company and their other customers are well-protected from any adverse consequences of faster uptake of rebates than anticipated. The Company correctly anticipates that it will receive

[16] *Ibid*, pp. 18–19.

significant net revenue from each EV adopted and has designed its programs to incent off-peak charging. If withholding rebates results in either slower EV adoption or more use of on-peak charging, it will be detrimental to other customers. The Company also proposes deferring transportation electrification expenditures through a regulatory asset, and the Company will not therefore suffer loss of income if EV expenditures are higher than budgeted.

By comparison, when new customers are added and costs of line extensions are rebated to the customer as a construction allowance, it is generally expected that the revenue from the customer will cover the Company's investment without burdening other customers. In these cases, the Company does not have the protection of a regulatory asset treatment for line extensions if the volume of line extensions happens to exceed the Company's forecast in its last general rate case.

There is no reason, by comparison, in the case of EV rebates, which are protected by regulatory asset treatment, that customers who seek rebates under these programs should be waitlisted. Permanent programs crafted under these conditions should not be budget-limited. The Company should neither prioritize nor waitlist requests for transportation electrification program participation.

**Q. Do you have other recommendations related to the rebates provided through the proposed permanent PowerMIDrive and PowerMIFleet programs?**

A. Yes. According to witness Myrom, the Company proposes

> transitioning the PowerMIDrive Public Charging program from the pilot's historical focus on fast charging infrastructure enabling statewide travel, to a focus on strategic off-peak Level 2 locations and Level 1 long-duration locations.[17]

For the PowerMIDrive program, the Company proposes to continue to provide up to a $7,500 rebate per 100 amps of at least two plugs providing Level 2 charging, at least five plugs providing Level 1 charging, or the same numbers of plugs (respectively) providing charging to residents living in multi-dwelling units or otherwise without access to overnight charging.[18] For the PowerMIFleet program, the Company proposes to continue to provide up to a $7,500 rebate per two plugs providing Level 2 fleet charging or workplace charging and up to a $15,000 rebate per DC plug of 50 kW or less designed for off-peak, long-duration charging of four or more hours.[19] As the costs of these different types of charging infrastructure change and as the adoption of EVs takes place, I recommend that the Company consider revisiting the levels of these rebates in general electric rate cases, which the Company has recently filed approximately annually. It is important that the rebates sufficiently support the adoption of charging infrastructure, especially when considering the calculated benefits of that EV charging to other customers. In other words, if the costs of specific types of EV chargers increase but the benefits of the program have also increased, the Company should consider increasing the level of the rebates accordingly.

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[17] *Ibid*, p. 11.

[18] *Ibid*, pp. 11–12.

[19] *Ibid*, p. 15.

Relatedly, given the relatively lower costs associated with Level 1 chargers and likely lower managed charging benefits of Level 1 charging, I recommend that the Company revisit the level of rebates provided for these chargers to ensure that it is appropriate. It may not be necessary or valuable to provide the same level of rebates to Level 1 chargers as are provided for Level 2 chargers (i.e., up to $7,500 per rebate).

**Q. Are there gaps in the Company's transportation electrification proposals that should be addressed?**

A. Yes. The Commission should require the Company to prepare and make available on-line load capacity maps that will enable third-party charging infrastructure developers to determine best locations for DCFC. The Commission's Grid Integration Study, filed in Case No. U-21251, clearly identifies the importance of utilities providing this information to other stakeholders, and describes various approaches to publishing this information, including a potential approach for bi-directional hosting capacity analysis with specific commentary on how this could be done in the Company's existing hosting capacity maps.[20] Similar capabilities have been successfully implemented in other jurisdictions and provide valuable information for the siting and sizing of charging infrastructure. National Grid's System Data Portal in Massachusetts is one such example.[21] In the present case, the Commission should order the Company to proceed to implement the Commission's

[20] Michigan Public Service Commission, "Grid Integration Study Report," June 30, 2023, available from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000008L2jEAAS.

[21] National Grid, "Massachusetts System Data Portal," available from https://www nationalgridus.com/Business-Partners/MA-System-Portal.

recommendations to improve and expand data provided in utility hosting and load carrying capacity maps.

**Q. Are there other important gaps in the Company's proposed transportation electrification programs?**

A. Yes. As described above, the Company proposes to shift the PowerMIDrive program from its previous focus on fast charging infrastructure to a focus on Level 2 and Level 1 long-duration charging infrastructure. According to a discovery response in this case (Exhibit MEIU-2 (LSS-2)), "92% of the DCFC rebate funding is paid or committed to customer projects" and the Company does not propose in this case to extend this funding. However, as described above, the pace of EV adoption is likely to be even faster than predicted by the Company and programs that help offset the upfront costs of installing DCFC have been very successful at deploying infrastructure, fostering private investment, and accelerating EV adoption.[22] As such, I recommend that the rebates for DCFC under the PowerMIDrive program be extended by the Company.

**Q. If the Company were to extend the rebates for DCFC under the PowerMIDrive program, would you recommend any modifications to those rebates?**

A. Yes, as described above, it is important to align the level of all of the rebates under the program with actual costs to site hosts or charging providers for the relevant infrastructure. The current rebates ($70,000 per site) are misaligned with the costs of DCFC infrastructure

[22] *See for example:* Connecticut Public Utilities Regulatory Authority Final Decision, Docket No. 21-08-06, "Annual Review of the Electric Vehicle Charging Program ‐ Year 1," December 15, 2021.

and should be increased. In 2019, the International Council on Clean Transportation ("ICCT") released a working paper that estimated hardware and installation costs for charging infrastructure across U.S. metropolitan areas.[23] While the data is a few years old, it is useful to illustrate the general magnitude of costs for different types of charging. For DCFC, the paper estimated the hardware cost was $75,000 per single-port networked 150 kW DCFC and $140,000 per single-port networked 350 kW DCFC.[24] The estimated installation costs varied depending on the number of chargers and the power levels but ranged from $28,000-$39,000 for three to five 150 to 350 kW chargers.[25] As such, according to the ICCT paper, a four-stall DCFC site could cost between $328,000 and $599,000. This is significantly more than Level 2 charging, which according to the estimates in the ICCT paper, would cost around $15,000 for a four single-port site with networked chargers.[26]

Utility programs across the country have recognized the higher costs of DCFC and have set their level of utility investments accordingly. For example:

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[23] Nicholas, M., The International Council on Clean Transportation, "Estimating electric vehicle charging infrastructure costs across major U.S. metropolitan areas," August 2019, available from https://theicct.org/sites/default/files/publications/ICCT_EV_Charging_Cost_20190813.pdf.

[24] *Ibid.*

[25] *Ibid.*

[26] *Ibid.*

- Rocky Mountain Power in Utah offers make-ready infrastructure as well as investments of $45,000 per single-port charger and $63,000 per multi-port charger, covering up to 75% of total charger and installation costs.[27]
- Tucson Electric Power's make-ready program, which was recently extended, offers utility investment of up to $40,000 per DCFC port, covering up to 75% of project costs.[28]
- NV Energy's Electric Vehicle Infrastructure Demonstration DCFC Program offers $40,000 per DCFC for up to five charging ports, with a maximum investment of $200,000 per site.[29]

I recommend that the Company conduct a review of the costs of DCFC infrastructure and set its rebate levels accordingly.

**Q. Are there any alternatives to extending the DCFC rebates under the PowerMIDrive program?**

A. Yes. As an alternative to the extension of the PowerMIDrive program DCFC rebates, the Company could develop a "make-ready" infrastructure program. "Make-ready" infrastructure refers to the electrical equipment necessary to operate a charging station.

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[27] Rocky Mountain Power, Electric Service Schedule No. 120, available from https://www.rockymountainpower net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/120_Plug-in_Electric_Vehicle_Incentive_Pilot_Program.pdf.

[28] Tucson Electric Power, "Smart EV Charging Program," available from https://www.tep.com/smart-ev-charging-program/.

[29] NV Energy, "Commercial Electric Vehicle Charging Station Incentives," available from https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/cleanenergy/handbooks/electric-vehicle-charging-station-incentives-programs-handbook.pdf at 10.

This can include sub-panels, main-panels, conductors, wiring, transformers, and other equipment on both the customer and utility side of the meter. Make-ready programs offer utility investments in make-ready infrastructure to support market deployment of charging stations. Through make-ready programs, utilities might, for instance, invest in rate-based distribution upgrades and branch line extensions, while leaving investments in chargers, charger ownership, operation and maintenance, marketing, customer service, and network operation to experienced private sector providers.

**Q. Have other Commissions approved make-ready programs for DCFC infrastructure?**

A. Yes. Make-ready programs have become a common practice among utilities across the country with programs approved in states including California,[30,] Connecticut,[31] Georgia,[32] Illinois,[33] Massachusetts,[34]

[30] California Public Utilities Commission, Docket No. A.14-04-014, "Decision Regarding Underlying Vehicle Grid Integration Application and Motion to Adopt Settlement Agreement," January 28, 2016; California Public Utilities Commission, Decision 22-11-040, "Decision on Transportation Electrification Policy and Investment," November 21, 2022.

[31] Connecticut Public Utilities Regulatory Authority Final Decision, Docket No. 21-08-06, "Annual Review of the Electric Vehicle Charging Program – Year 1," December 15, 2021.

[32] Georgia Public Service Commission, Docket No. 44280, "Order Adopting Settlement Agreement as Modified," December 30, 2022.

[33] Illinois Commerce Commission Order, 22-0432/22-0442 (Cons.), "Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX and Investigation into Commonwealth Edison Company Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45," March 23, 2023.

[34] Massachusetts Department of Public Utilities, Docket 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017; Massachusetts Department of Public Utilities, Docket 21-90, "Order on Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022; Massachusetts Department of Public Utilities, Docket 17-13, "Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for Approval of its Electric Vehicle Market Development Program, and of its Electric Vehicle Market Development Program Provision, pursuant to G.L. c. 164, §§ 76, 94, and Acts of 2016, c. 448," September 10, 2018; Massachusetts Department of Public Utilities, Docket 21-91, "Order on Petition of Massachusetts

Minnesota,[35] Missouri,[36] New Mexico,[37] New York,[38] Pennsylvania,[39] Rhode Island,[40] and Virginia.[41] In general, make-ready programs provide that the utility covers the costs of the infrastructure to power EV charging equipment. A make-ready program provides a reasonable balance between accelerating EV adoption, returning some net revenue from EV charging to those customers, and retaining substantial net revenue for the benefit of non-EV customers. I recommend that Consumers support a make-ready program for public charging and fleet charging at both Level 2 and DCFC stations.

## III. <u>DER OPTIMIZATION</u>

**Q. What does the Company propose regarding the management of DERs?**

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Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022.

[35] Minnesota Public Utilities Commission, Docket 18-643, "Order Approving Pilots with Modifications, Authorizing Deferred Accounting, and Setting reporting Requirements," July 17, 2019.

[36] Missouri Public Service Commission, Docket 2018-0132, "Order Approving Second Stipulation and Agreement," February 6, 2019.

[37] New Mexico Public Regulation Commission Final Order Adopting Recommended Decision, Case No. 20-00237-UT, "I/M/O Public Service Company of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program," November 12, 2021.

[38] New York Public Service Commission, Case 18-E- 0138, "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs," July 16, 2020.

[39] Pennsylvania Public Utilities Commission, Docket No. R-2018-3000124, "Opinion and Order," December 20, 2018.

[40] Rhode Island Public Utilities Commission, Docket No. 4780, "Re: the Narragansett Electric Company d/b/a National Grid Proposed Power Sector Transformation Vision and Implementation Plan," May 5, 2018.

[41] Virginia Division of Public Utility Regulation, Case No. PUR-2019-00154, "Final Order. Petition of Virginia Electric and Power Company for approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service," March 26, 2020.

A. According to witness Matthew S. Henry, the Company proposes to address DER management using a DER Optimization initiative, which is planned in two-waves.[42] Wave 1 will deploy multiple de-centralized DER gateways to test "use cases regarding DER interactions such as solar smoothing, volt-var management, and peak load management."[43] Wave 2 will integrate these DER gateways under a centralized DER management system ("DERMS").[44] However, the Company does not propose cost recovery for any of these activities in this case.

**Q. How does the Company define "DER Gateway" and "DERMS"?**

A. The Company presents the development of a number of un-connected DER gateways as an initial step to gain learnings before developing a system-wide DERMS. According to witness Henry,

> A DER gateway is a hardware and software platform that can be installed throughout the electric distribution system to manage and optimize one, or an aggregation of many, DERs. The DER gateway platform includes software, an operating system, firmware, hardware, communications, interfaces, and cybersecurity features.[45]

In contrast, according to witness Henry,

> The Company defines DERMS as an enterprise scale software platform that is located at the utility's operational center. A DERMS monitors, controls, and optimizes DER in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system. An

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[42] Direct Testimony of Matthew S. Henry on behalf of Consumers Energy Company ("Henry Direct"), Case No. U-21389, p. 55.

[43] *Ibid*, p. 51.

[44] *Ibid*, p. 56.

[45] *Ibid*, p. 49.

> enterprise DERMS can be implemented to communicate with any number of DER gateways to create a centralized DER management solution.[46]

**Q. Is the Company's definition of DERMS accurate and complete?**

A. No. The Company's definition focuses expressly on a centralized system within the utility's control center and the related functionality. Other industry stakeholders have defined DERMS much more broadly. For example, the Smart Electric Power Alliance ("SEPA") defines DERMS as "a control system specifically designed to handle DERs" and identifies both centralized DERMS like those that fit under the Company's definition as well other types such as "edge" DERMS and "fleet" DERMS with their own applications and structure.[47]

**Q. What did the Company propose related to DERMS in its general rate case in 2020 (Case No. U-20697)?**

A. In testimony filed in February 2020, the Company proposed rate recovery for a projected $1,184,000 for development of a DERMS. According to witness Richard T. Blumenstock,

> The Company will deploy DERMS functionality to optimize and control a limited number of DERs and address potential local operational challenges associated with DER penetration at the circuit and/or substation level. This will allow the Company to initially learn by monitoring and controlling DERs on a small subset of circuits and/or substations to understand the unique challenges associated with managing DERs in front of the meter. As DERMS mature, the Company will follow small-scale DERMS deployment with an Enterprise DERMS solution integrated with ADMS.[48]

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[46] *Ibid*, p. 52.

[47] Ealey, B., "DERMS Terms – Going Beyond the Buzzword," *Smart Electric Power Alliance*, March 25, 2021, available from https://sepapower.org/knowledge/derms-terms-going-beyond-the-buzzword/.

[48] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, Case No. U-20697, p. 153.

Witness Blumenstock went on to explain that the Company planned to first deploy a "small focused DERMS" on a small subset of circuits under a "first phase" from 2020 to 2022 at a cost of approximately $3,000,000.[49]

**Q. What did the Commission decide relative to these DERMS proposals in Case No. U-20697?**

A. In its Order in Case No. U-20697, with respect to the Company's DERMS proposals, the Commission found that:

> For the reasons articulated in the PFD, the Commission adopts the findings and recommendations of the ALJ. The Commission agrees with the ALJ that Consumers' proposal lacked clarity, and the company failed to explain how reliability would benefit from the DERMS program or how the information that will be generated from the program will then be integrated into the reliability program. *See*, 8 Tr 3859-3863. Additional planning, including details on the sequencing of DERMS and other technologies to enhance system monitoring and controls and their integration with existing systems such as Consumers' outage management system, AMI, and distribution supervisory control and data acquisition, is needed and prudent to pursue while DER penetration is still low. The Commission also notes that it may be valuable to further understand the evolving role and expectations of the distribution utility under the Federal Energy Regulatory Commission (FERC) Order 2222[6] when planning and designing new systems of this nature. The Commission encourages Consumers to include additional detail about how DERMS and other technologies will be sequenced and utilized to the benefit of its customers as part of its distribution investment and maintenance plan to be filed by September 30, 2021, including the opportunity for other stakeholders to comment on those plans as part of the draft plan shared by August 1, 2021. *See*, August 20, 2020 order in Case No. U-20147 (August 20 order).[50]

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[49] *Ibid*, pp. 153–154.

[50] Commission Order in Case No. U-20697, December 17, 2020, p. 33.

**Q. What did the Company propose related to DERMS in the subsequent general rate case, Case No. U-20963?**

A. In March of 2021, in Case No. U-20963, the Company proposed rate recovery for $1,191,000 for development of a DERMS. Although the Company acknowledged that the Commission disallowed these costs in Case No. U-20697, the Company argued "that the investments are still necessary, because the company needs to learn more about monitoring and controlling DERs before DER penetration begins to increase."[51] According to witness Richard T. Blumenstock,

> The Company will deploy DERMS functionality to optimize and control a limited number of DERs and address potential local operational challenges associated with DER penetration at the circuit and/or substation level. This will allow the Company to initially learn by monitoring and controlling DERs on a small subset of circuits and/or substations to understand the unique challenges associated with managing DERs in front of the meter. As DERMS mature, the Company will follow small-scale DERMS deployment with an Enterprise DERMS solution integrated with ADMS.[52]

This testimony is exactly word-for-word the same as the testimony filed by witness Blumenstock in the previous case (Case No. U-20697; as quoted above).

**Q. What did the Commission decide relative to these DERMS proposals in Case No. U-20963?**

A. Intervening parties in Case No. U-20963, including the Attorney General, Clean Energy Organizations ("CEO"), and Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively "MNSC"),

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[51] Commission Order in Case No. U-20963, December 22, 2021, p. 37.

[52] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company in Case No. U-20963, p. 160.

argued that the proposed DERMS spending was unsupported and premature given the limited number of DERs on the system and the statutory cap on DG. In light of these arguments, the Commission found that:

> Consumers' evidence in the instant case makes no attempt to address the issues articulated by the Commission in the December 17 order. Consumers provided no substantiation for the prediction that DERs will increase more than 100 fold to 550 MW in 2022, made only very general statements in support of its request, and ignored the obvious barrier of the existing DG cap. The Commission can only reiterate its remarks from the December 17 order, and adopts the findings and recommendations of the ALJ. The Commission continues to seek the information addressed in the above quote from the December 17 order, page 33, and awaits a demonstration of how DERMS will provide an advantage to ratepayers by unlocking the benefits of DERs for customers. This is the type of evidentiary support that may result in approval of rate base treatment for this cost category in the future.[53]

**Q. What did the Company propose related to DERMS in its last general rate case, Case No. U-21224?**

A. In April of 2022, in Case No. U-21224, the Company proposed to deploy a DERMS by the end of 2023, starting with the installation of

> up to five de-centralized DERMS controllers. … The distributed system is also connected to the cloud-based DERMS which manages the registration and scheduling of all the distributed sites and can perform aggregated functions.[54]

The Company indicated that these installations would cost $1,200,000.[55] The Company also requested full recovery of the $1,168,389 spent on the Cadillac DERMS installation

[53] Commission Order in Case No. U-20963, December 22, 2021, p. 40.

[54] Direct Testimony of Mark A. Ortiz on behalf of Consumers Energy Company, Case No. U-21224, p. 53.

[55] *Ibid.*

in 2021 despite the Commission disallowing cost recovery for the expenses associated with that installation in the previous rate case (Case No. U-20983).[56]

**Q. What was the outcome of that proposal in Case No. U-21224?**

A. A settlement agreement was reached in Case No. U-21224 addressing all of the issues in the case with no objecting parties.[57] The Company's proposed DERMS spending was not part of the settlement agreement and, as such, was not approved for cost recovery.

**Q. What do you conclude from the previous Commission decisions on DERMS in Case Nos. U-20697, U-20963, and U-21124?**

A. It is clear from the Commission Orders in these previous general rate cases that prior to approving rate recovery for a DERMS, the Commission wanted the Company to more fully explain how investments in a DERMS program would benefit reliability, how a DERMS would be integrated into existing distribution automation systems, and how a DERMS would be sequenced with other technologies and utilized to benefit customers. In essence, it does not appear that the Commission was convinced that spending on a DERMS was valuable in and of itself, especially given the low penetration of DERs, without further understanding of how the DERMS would be integrated into other systems and future operations to the benefit of customers.

[56] *Ibid*, pp. 53–54.

[57] Commission Order Approving Settlement Agreement in Case No. U-21224-0442, January 19, 2023.

It is also clear, from the Company's testimony and apparent actions related to DERMS, that the Company failed to heed the request from the Commission for this additional analysis. Specifically, despite the Commission Order in Case No. U-20697 and the Commission's specific request for more information related to a future DERMS, Company witness Blumenstock provided almost word-for-word the same testimony in the subsequent rate case (Case No. U-20963). When the Commission again denied this spending in Case No U-20963, in the next rate case (Case No. U-21124), the Company proposed to recover costs associated with the Cadillac DERMS installation despite that spending being rejected in Case No. U-20963.

**Q. How is the DER Optimization proposal in the current case different from these previous DERMS proposals?**

A. As discussed previously, the Company does not request rate recovery for any DERMS related proposals in the current case. Instead, the Company describes a two-step DER Optimization initiative which involves (1) deployment of de-centralized DER Gateways and (2) integration of these DER gateways under a centralized DERMS. The Company proposes that these initial DER Gateways will be implemented in conjunction with other Company projects including the "Cadillac Solar Gardens project, the 200 Building project, Parkview Battery project, and the EV School Bus project."[58] According to the Company in a discovery response (Exhibit MEIU-3 (LSS-3)), in the current case,

> The DER Optimization initiative's implementation has been refined based on industry best practices as well as feedback received in Case No. U-21224. The refinement more clearly distinguishes the implementation plan to begin with various local DER optimization solutions (DER Gateways)

[58] Henry Direct, p. 55.

> prior to proceeding with a system-wide DER optimization solution (DERMS). The Company has applied industry best practice research from EPRI as a foundational model for the deployment strategy as shown in Exhibit A-114. Lastly, a key difference is that the Company has extended the implementation timeline and is not requesting cost recovery for the DER Optimization Initiative in this Case No. U-21389.

In a follow-up discovery response (Exhibit MEIU-4 (LSS-4)), witness Henry provided more detail as follows:

> To provide additional context, the current case includes more details on the location of the initial DER Gateway projects (see page 55 of my direct testimony), which were originally referred to as "de-centralized DERMS controllers" in Case No. U-21224. The Company has also further detailed and clarified in this case the two-wave approach of starting with smaller DER gateway deployments prior to the deployment of a centralized DERMS. In the current case, the Company has utilized additional industry research as a basis for the deployment strategy, as explained in parts a. and b. above. Finally, the timeline for the deployment of these projects has been updated and the Company has not requested any recovery of costs in the current case.

**Q. Does this proposal appear materially different from the DERMS proposals in previous rate cases?**

A. Not entirely. It does appear that the Company has incorporated additional industry best practice research, including a progression from simple to more complex functionality starting with de-centralized DER Gateways and moving to a more complex DERMS. It is also true that one key difference with this proposal is that the Company is not seeking cost recovery in this case. It appears either that the Company plans to proceed with certain Wave 1 DER Gateway deployments without rate recovery or plans to seek such rate recovery retroactively in a future general rate case.

Despite these differences, it is unclear to me that the DERMS proposal in this case is significantly different from the proposals in previous rate cases. In previous cases, the Company similarly proposed to initiate deployment of a DERMS with de-centralized projects (now called "DER Gateways"), which would ultimately be integrated into a centralized DERMS. Witness Henry outlines several potential "releases" (i.e., use cases) for Wave 2 including the ability to directly integrate with individual DERs, the ability for third-party aggregators to integrate with the DERMS, integration with the demand response management system ("DRMS") and advanced distribution management system ("ADMS"), and functionality for DER to participate in wholesale markets.[59] These are similar use cases to those provided in previous cases. The Company fails in this case to outline clearly, in response to the Commission's requests, how investments in a DERMS program would benefit reliability, how a DERMS would be integrated into existing management systems, and how a DERMS would be sequenced with other technologies and utilized to benefit customers.

**Q. Prior to seeking cost recovery in a future rate case, what additional issues should the Company explore?**

A. Overall, while it may ultimately make sense for the Company to deploy a centralized enterprise DERMS platform, it is important to first consider the business case for establishing such a DERMS and whether or not a less extensive deployment or use of third-party vendors may be able to provide some or all of the needed functionality and DER

[59] *Ibid*, p. 56.

management services that the Company seeks. Formulating a well-defined business case is the key to evaluation and decision-making around scale adoption and implementation.

This step should involve identifying and articulating the Company's operational challenges, strategic objectives and vision, and desired program benefits. Careful consideration needs to be given to identifying the objectives that are aligned with the needs of all grid stakeholders and the enablement of DER adoption. DERMS is a very ambitious technology which can enable a wide range of use cases and benefits across many different facets of the power system. These can range from distribution-focused functions intended to maintain reliability or improve efficiency to market functions like energy market participation, demand response and beyond. If the Company were to seek recovery, the specific desired use cases, their value proposition, and the expected impacts on customers would all be critical considerations. The development of a business case is also essential in the process of making informed technological choices and ensuring that all reasonable alternatives have been evaluated. Where there may be other solutions which meet one or more of the identified needs or benefits, consideration of those solutions is part of ensuring the reasonableness and necessity of the Company's proposal.

The need to establish a well-defined business case was highlighted in previous cases given the current limited DER penetration in the Company's service territory. [redacted]

[redacted] Given that the Company's current DG cap is limited to 4% of the Company's 5-year average load and that many (if not all) of the utility-scale solar projects that the Company has procured are transmission-connected, I would expect that it would be many years (and require a shift in the Company's position relative to customer-owned DG systems) before [redacted] of the Company's annual energy needs are met by distribution-connected renewables.

Given this, if the Company were to seek cost recovery for a DERMS in the future, their business case must convey strong evidence about the need for DER management services pertaining to uptake of DERs in its service territory. This business case should include and be developed considering a more comprehensive DER forecasting study with different time horizons, for instance, of 5, 10 and 20 years, to gain a clear understanding of anticipated uptake of electrification and penetration of DER and develop the business case taking this future into consideration. Forecasts of DER by technology type (e.g., solar, solar plus storage, EVs, etc.) could also aid in the market research and vendor selection process since it will be easier to identify third-party vendors that have expertise in providing services related to certain DER types or DER management objectives. This research and assessment should be undertaken before the Company moves to implement a centralized enterprise DERMS platform because, as described more fully below, the Company may find that such an investment is not necessary to provide the desired benefits.

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[60] EPRI, *DER Management Systems (DERMS) Adoption Pathways*, Case No. U-20893, Consumers Energy Exhibit A-114, p. 3.

**Q. What other studies should the Company consider conducting related to the opportunities and limitations of a DERMS?**

A. Prior to any large-scale deployment of a DERMS or other DER management service options and subsequent requests for recovery, the Company should undertake a study on the hierarchy and scenarios for direct market participation of DER aggregators, bid management, capacity services, or any other functions or services for which the Company intends to utilize the DERMS. As described further below, this study should capture the impacts of these functions and services on DER owners. A clear understanding of the opportunities and potential customer challenges related to using distribution-connected resources for market functions will be critical in the holistic evaluation of a proposed DERMS in the future.

The Company should also conduct a thorough analysis of the distribution reliability functionalities of a DERMS and the limitations around controlling DERs. This information will be very helpful in formulating a business case and ensuring that regional and technical limitations are utilized to make informed decisions around controls and implementation.

**Q. What other factors should the Company consider when assessing the potential impact of DER management services?**

A. The Company should also consider the potential impacts on DER owners of a DERMS including, for example, increased interconnection processing times, overall longer project timelines due to additional integration requirements, and increased installation costs. It is imperative for the Company to gauge how the integration of a DERMS could cause project delays and financial repercussions for DER owners, impacting the anticipated returns and overall satisfaction. The Company should quantify any expected additional installation costs and explore strategies to minimize the financial impact of any added requirements on DER owners.

In addition, the Company should develop effective methods to educate, train and notify DER owners regarding changes related to a DERMS. Clear communication strategies should be developed to educate DER owners on how to maximize the benefits that a DERMS can provide. The diverse landscape of DERs and geographical disparities can add a layer of complexity around configuration challenges and can create technical limitations. By preparing to address these issues, the Company can position itself for successful implementation and long-term DER owner satisfaction.

**Q. Are there other issues that the Company should explore prior to seeking cost recovery in a future rate case?**

A. Yes. At this early stage in the Company's exploration and initiation of the DER Optimization initiative, it would be valuable for the Company to seek information from the competitive market regarding cost-effective technologies and solutions. Although the utility will always have a critical role to play in signaling specific needs to the system that DERs can answer to and provide, there is no reason to assume that a utility-owned and operated centralized DERMS is the only means to achieve some or all of the desired capabilities and functionality. Depending on the use cases and available solutions, DER management can be achieved cost-effectively by third-party services, which can perform similar functions to that of a centralized utility owned enterprise DERMS and can remain responsive to a utility control center. These third-party service providers are specialized companies that offer expertise in managing DERs effectively based on strategic objectives that the utility aims to achieve. This approach can also provide avenues for interoperability between different DERs and third-party service providers.

Given that the Company is in the early stages of deployment of this initiative and is not yet seeking cost recovery, this is the ideal time to seek more information (e.g., through a Request for Information) from the competitive market to determine the most cost-effective, best-fit solutions. The Company could also conduct pilot projects with third-party service providers to perform proof of concepts and gain enhanced understanding around implementation of DER management solutions. Throughout these initial explorations, I recommend that the Company participate in industry benchmarking exercises to identify how peer utilities are approaching the DER management challenges.

**Q. Can you provide some examples of these third-party DER management solutions?**

A. Yes. There are a number of third parties who provide DER management solutions. For example, SolarEdge provides grid services and near-real-time aggregative control for monitoring and controlling DERs, including PV inverters, residential storage, and EVs, for the creation of a virtual power plant.[61] Another provider, Stem, offers services relating to

[61] SolarEdge, "Grid Services and VPP Solution: The Grid of the Future, Today," available from https://www.solaredge.com/sites/default/files/grid-services-and-vpp-solution.pdf.

optimization of DERs like battery storage systems to provide grid services and demand response ("DR").[62]

As described above, while the ownership of the DER management service platform can be held by a third party, its operation and responsiveness can still be aligned with the utility's control center. The key lies in having a robust communication interface and secure data exchange mechanisms in place between third-party service provider and utility and in ensuring that the third-party can provide the desired benefits. There are multiple examples across the U.S. which demonstrate the feasibility of this approach, including:

1. Sacramento Municipal Utility District ("SMUD") and Sunverge partnership: This project demonstrates how intelligent energy storage technology, solar PV, and smart home devices can provide multiple grid management benefits, while maximizing control for the utility. Sunverge successfully integrated energy storage technology with SMUD's Demand Response Management System to automate demand response events for customers on a TOU Critical Peak Pricing tariff. A key takeaway from the project was that the operational benefits from DERs are highly location-specific.[63]

2. Nuvve and San Diego Gas and Electric ("SDG&E"): Nuvve partnered with SDG&E to deploy a vehicle-to-grid ("V2G") aggregator technology to manage EV charging and

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[62] Stem, "Investor-owned Utilities: Flexible Solutions for Lower Risk and Greater Efficiency," available from https://www.stem.com/customers/investor-owned-utilities/.

[63] Sunverge, "SMUD and Sunverge Demonstrate the Potential of Aggregated Distributed Energy Storage & Solar," available from https://cdn2 hubspot net/hubfs/2472485/Website Content/Sunverge_CaseStudy_01_SMUD.pdf.

discharging. Through this partnership, the electric school bus fleet equipped with V2G charging through Nuvve's platform can provide energy back to the grid during emergency load reduction events.[64]

3. Omega Grid and SMUD: The city of Sacramento worked with Omega Grid to use a blockchain-based software service to test a hyperlocal EV charging program to track customer rewards. The pilot project offered blockchain-based tokens for charging vehicles when there is a surplus of solar power on the grid.[65]

**Q. What are the potential benefits to third-party-owned and -operated DER management services?**

A. There are multiple potential benefits of using third-party owned and operated DER management services, including:

1. Using a third-party service for DER management in a limited geographic area initially serves as the proof of concept before committing to a full-scale deployment. This can also help utilities to assess whether the solution aligns with their grid management goals, responds to control center commands and delivers the expected benefits.

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[64] Nuvve, "Nuvve Partners With San Diego Gas & Electric to Allow Electric School Buses to Give Energy Back to the Grid and Prevent Blackouts Through the Emergency Load Reduction Program (ELRP)," July 18, 2022, available from https://investors nuvve.com/news-releases/news-release-details/nuvve-partners-san-diego-gas-electric-allow-electric-school.

[65] Thill, D., "Chicago startup will help test hyperlocal electric vehicle incentive in California," *Energy News Network*, September 13, 2019, available from https://energynews.us/2019/09/13/chicago-startup-will-help-test-hyperlocal-electric-vehicle-incentive-in-california/.

2. Third-party services for DER management are often modular, offer flexibility and can be tailored to the utility's need. As a result, the implementation is more utility objective-oriented.

3. Third-party services for DER management can help in mitigating risks associated with system maintenance, updates, and ongoing support, since the third-party provider is solely responsible for the reliability and performance of the system.

4. By outsourcing the ownership and operation of DER management services, a utility can save on significant upfront investment in hardware, software, and infrastructure.

5. Third-party-owned and -operated DER management services also minimize the need to provide education and training for employees within the utility on the operation of new software and minimize the need to change utility processes and procedures.

**Q. Are other utilities already successfully partnering with third-parties to establish broad DER management services?**

A. Yes. There are utilities across the U.S. and globally using third-party solutions for DER management. These include:

1. National Grid (working with Opus One Solutions): National Grid worked with Opus One Solutions in New York to provide a technical and financial platform for DERs

using the GridOS Transactive Energy Management System.[66]

2. National Grid (working with EnergyHub): National Grid centralized its 'Bring Your Own Device' programs using EnergyHub's Mercury DERMS. The company is also using the platform for enrollment, forecast-based dispatch, and reporting and settlement capabilities for its commercial and industrial resources.[67]

3. Con Edison (working with Smarter Grid Solutions): Con Edison integrated Smarter Grid Solutions' Strata Grid and Cirrus Flex platforms with the utility's systems and control room processes. These third-party solutions allowed Con Edison to automate optimized and aggregated dispatch of utility-scale energy storage systems and trading of any residual capabilities in the wholesale market.[68]

**Q. What are your recommendations regarding the Company's proposed DER Optimization initiative?**

A. First, as the Company begins its DER Optimization initiative, it must establish the business case for establishing the proposed DERMS, including identifying the challenges the Company seeks to solve and desired program benefits. This should include considerations

[66] Opus One Solutions, "Launching the World's First Transactive Energy Market at National Grid," available from https://www.opusonesolutions.com/customers_projects/launching-the-worlds-first-transactive-energy-market-at-national-grid/.

[67] O'Leary, K., "National Grid selects EnergyHub as the platform provider to enhance its Bring Your Own Device demand response program," May 30, 2018, available from https://www.energyhub.com/blog/national-grid-bring-your-own-device-demand-response-program/.

[68] Smarter Grid Solutions, "Endurant (Con Edison)," available from https://www.smartergridsolutions.com/media-center/case-studies/endurant-con-edison.

of forecasted DER adoption, any regional or technical limitations around controlling DERs, and the potential impacts on DER owners.

Second, the Company should seek information and assess the ability of third-parties to provide the DER management services sought by the Company. It seems likely, given prior filings and rate recovery requests, that the Company may proceed with Wave 1 of the DER Optimization initiative and seek rate recovery retroactively. Therefore, the Company, at the onset of Wave 1, should explore all potential solutions to determine which available technology most cost-effectively solve its grid challenges.

Third, given the remaining questions and potential opportunities, the Company should bring stakeholders together with Commissioners and Commission Staff to understand, evaluate, and explore the use cases, functions, and value of DER Gateways, DERMS and its associated systems. While there may be significant utility benefits to centralized DER control, these systems could also provide significant benefits to customers, third-parties, and regulators if implemented properly. In addition, given that these technologies are new to the Company, stakeholders with expertise in other states and with other utilities may be able to provide valuable knowledge, insights, and even operational experience.

## IV. DISTRIBUTED GENERATION

**Q. Please describe the current caps for the distributed generation program.**

A. The caps for each subsection (referred to as "categories") of the DG program were established in 2008 in PA 295 and were retained in Section 173(3) of PA 342, which provides that:

> (3) An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years. The electric utility or alternative electric supplier shall notify the commission if its distributed generation program reaches the 1% limit under this subsection. The 1% limit under this subsection shall be allocated as follows:
>
> (a) No more than 0.5% for customers with an eligible electric generator capable of generating 20 kilowatts or less.
>
> (b) No more than 0.25% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 150 kilowatts.
>
> (c) No more than 0.25% for customers with a methane digester capable of generating more than 150 kilowatts.[69]

There is admittedly no requirement in the statute that an electric utility increase the size of its DG program above 1% of its average in-state peak load for the preceding 5 calendar years. However, there is also no statutory prohibition on a utility either increasing the size of its DG program or simply allowing customers to continue to participate in the DG program once they reach the initial caps. It is also important to note that because 25% of the total cap is statutorily reserved for methane digesters, only 75% of the total amount is available for other (mostly solar) DG systems.

**Q. Why were these caps established?**

A. The caps for the DG program were established in 2008 as part of PA 295 alongside the introduction of net metering in the state. At that time, it was unclear how the policy of net metering would affect uptake of solar PV systems, the grid, and utility revenue streams. Subsequently, the 2016 energy laws ended net metering in favor of a cost-of-service-based DG tariff. See MCL 460.6a(14).

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[69] MCL 460.1173(3).

**Q. Have there been any safety or reliability issues related to or resulting from the DG program?**

A. No, not to my knowledge. The interconnection process governs the interconnection of any electric generator to the distribution grid and requires each utility to carefully assess the effects of the generator on the safety and integrity of the grid before approving an application. For example, if solar DG installations in a given neighborhood begin to increase significantly, stressing a local circuit, the utility will quickly identify those issues during the interconnection process. If those increasing installations mean that grid upgrades are needed before the *nth* rooftop solar system can be installed safely, that *nth* customer is statutorily required to pay for the upgrades or is not allowed to interconnect their system to the grid. As such, non-participating ratepayers do not pay for these upgrades. Instead, that individual *nth* person must decide how to proceed and must pay the costs of any necessary upgrades to maintain the safety and reliability of the grid.

**Q. Does the Company propose any changes related to the DG program, tariff, or cap in this case?**

A. No, not to my knowledge.

**Q. What changes occurred related to the DG program cap in the Company's last general rate case?**

A. In the Company's last general rate case (Case No. U-21224), the Commission approved a settlement agreement which increased the DG program size from 2% of the Company's

5-year average in-state peak load to 4% of the Company's 5-year average in-state peak load.[70] As part of that same settlement agreement, the parties agreed to increase the credit to customers for outflow from DG systems to include transmission costs.[71]

**Q. What conclusions do you draw from the Company's last general rate case?**

A. MEIU appreciates that the Company did agree to double its DG program cap (from 2% to 4%) in the settlement agreement in its last general electric rate case (Case No. U-21124).[72] Similarly, DTE Electric recently increased its DG program cap from 1% to 6% of its average in-state peak load for the preceding five calendar years through the Commission-approved settlement agreement in its IRP case, Case No. U-21193.[73] Although there may be reasons why the Company may want to limit DG installations, including a preference for Company-owned capital investments, the settlement agreement in Case No. U-21124 implies to me both that the Company can decide to increase customers' access to the DG program if it wishes and that there is no justifiable reason from a ratepayer, Commission, or societal perspective to limit customers' ability to access the DG program.

**Q. What do you recommend in this case relative to the DG cap?**

A. Given that there is no technical, safety, or cost-based reason to maintain the DG cap, I propose that the Company should eliminate the limits on the DG program moving forward.

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[70] Commission Order Approving Settlement Agreement, Case No. U-21224-0442, January 19, 2023.

[71] *Ibid.*

[72] *Ibid.*

[73] Commission Order Approving Settlement Agreement, Case No. U-21193-0527, July 26, 2023 (Settlement Agreement, p. 15).

In this respect, it is worth noting that studies by Lawrence Berkeley National Laboratory have found that solar penetration of up to 10%, ***even under full retail net metering*** (which provides a higher credit to DG customers than the Commission's cost-of-service-based DG tariff), results in nominal if any adverse impact to other ratepayers.[74] It is thus entirely reasonable to expect that, under the cost-of-service-based DG tariff, solar penetration even in excess of 10% in Consumers' service territory would likewise result in no adverse impact to other ratepayers.

## V. CONCLUSIONS AND RECOMMENDATIONS

**Q. Please summarize your conclusions and recommendations to the Commission.**

A. I recommend that the Commission:

- Require that Level 2 and DCFC infrastructure for which the Company provides rebates is networked.
- Encourage the Company to conduct a near-future pilot effort to begin to explore how to manage charging in response to grid conditions.
- Reject the Company's proposal to waitlist customers seeking EV rebates under the now permanent PowerMIDrive and PowerMIFleet programs.
- Encourage the Company to regularly revisit the levels of rebates for Level 1, Level 2, and DCFC infrastructure based on the costs of installation as well as net revenue from charging.

[74] See Exhibits MEIU-5 (LSS-5) and MEIU-6 (LSS-6).

- Require the Company to improve and expand data provided publicly in utility hosting and load carrying capacity maps.
- Encourage the Company, in the short-term, to extend the rebates for DCFC under the PowerMIDrive program and, in the long-term, to develop a make-ready program for public charging and fleet charging at both Level 2 and DCFC stations.
- Require the Company to establish the business case for any future proposed DERMS, including identifying the challenges the Company seeks to solve, desired program benefits, forecasted DER adoption, any regional or technical limitations around controlling DERs, and the potential impacts on DER owners.
- Require the Company to seek information and assess the ability of third-parties to provide any DER management services sought by the Company.
- Require the Company to bring stakeholders together with Commissioners and Commission Staff to understand, evaluate, and explore the use cases, functions, and value of DER Gateways, DERMS and its associated systems.
- Encourage the Company to eliminate limits on enrollment in the DG program.

**Q. Does that complete your testimony?**

A. Yes.

**STATE OF MICHIGAN**

**MICHIGAN PUBLIC SERVICE COMMISSION**

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| In the matter of the application of Consumers ELECTRIC COMPANY for authority to increase its rates for the generation and distribution of electricity and other relief. . | ) ) ) ) ) ) | **Case No. U-21389** |

**DIRECT TESTIMONY OF PETER D. DOTSON-WESTPHALEN**

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION, AND**

**ADVANCED ENERGY UNITED**

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**I. INTRODUCTION AND QUALIFICATIONS**

**Q. State your name, business name and address.**

A. My name is Peter D. Dotson-Westphalen, and I am the Senior Director of Regulatory and Government Affairs for Enerwise Global Technologies, LLC d/b/a CPower ("CPower"), located at 1001 Fleet Street, Suite 400, Baltimore, Maryland 21202.

**Q. On whose behalf are you appearing in this case?**

A. I am appearing here as an expert witness on behalf of Michigan Energy Innovation Business Council ("Michigan EIBC"), the Institute for Energy Innovation ("IEI"), and Advanced Energy United ("United"; collectively "MEIU").

**Q. Summarize your educational background.**

A. I have a Bachelor of Arts from the University of Vermont in Environmental Studies, conferred in May 2006.

**Q. Summarize your business experience.**

A. In 2007, I was hired as a contractor in Constellation New Energy, Inc.'s ("Constellation") Markets, Pricing, and Structuring team as a Pricing Analyst, where my responsibilities included customer reviewing customer load data and performing risk analysis, pricing retail electric contracts, reneweable energy credits, and researched electric and natural gas markets. In 2008, I was hired as a full-time employee in Constellation's demand response ("DR") team as an Analyst. I worked in a variety of capacities, including providing support with sales, operations, metering installations, and coordinated partnerships with manufacturers and system integrators of building automation systems to implement automated demand response strategies. I was promoted in 2009 to Senior Analyst, where I continued performing these functions, in addition to coordinating the integration of the DR business into Constellation's customer relationship management, contract management, and financial reporting systems. In 2011, I was promoted to Manager, Market Development where I continued work on the systems integration work internally within Constellation, as well as provided support for the Market Development team members across the California Independent System Operator, Inc. ("CAISO"), Electric Relibiliaty Council of Texas ("ERCOT"), Independent System Operator of New England, Inc. ("ISO-NE"), New York Independent System Operator, Inc. ("NYISO"), and PJM Interconnection ("PJM") markets to track pricing trends and understand all DR program rules, and proposed changes to the market rules. During my tenure in this role, I also assisted in an internal effort to review customer generator eligibility to participate in DR programs and ensure compliance with federal rule changes adopted by the Environmental Protection Agency.

In 2014, I assumed responsibility for the CAISO and ERCOT markets where I oversaw all portfolio management and regulatory activities pertaining to the DR business in these regions. In November 2014, I joined CPower following Constellation's sale of the DR business as Director, Market Development and continued coverage of the CAISO and ERCOT markets. From 2015 through 2016, I served as Vice Chair of ERCOT's Demand Side Working Group, as well as Chair of the Texas Committee of the Advanced Energy Management Alliance ("AEMA"), an industry association comprised of DR and distributed energy resource ("DER") companies and customers. In 2016, I accepted the role of Market Compliance Officer within CPower. In this role, I oversaw CPower's internal program to maintain compliance with all market rules and regulations.

In 2017, I had the opportunity to rejoin the Market Development team as Senior Director, Market Development and was responsible for the NYISO market, as well as some select state regulatory work throughout the Midwest. From 2018 through 2022, I served as Chair of the NYISO's Price Responsive Load Working Group, as well as Chair of AEMA's New York and New England Committee, In my work as Senior Director, Market Development, I managed CPower's portfolio of DR resources participating in the NYISO's wholesale markets providing capacity and ancillary services, as well participation in utility DR programs. I also led Cpower's advocacy efforts within NYISO's stakeholder process as well before the New York Public Service Commission. Additionally, I continued working on DR- and DER-related regulatory issues in select Midwestern states, as well as coordinated CPower's advocacy efforts surrounding Federal Energy Regulatory Commission ("FERC") Order 2222 across all FERC jurisdictional markets, including direct participation in both NYISO's and the Midcontinent Independent System Operator's ("MISO") stakeholder processes concerning implementation of FERC Order 2222.

In May, 2023, I was promoted to Senior Director, Regulatory and Government Affairs, where I focus on regulatory activities at MISO and in the states that are within MISO's footprint.

**Q. Have you testified before the Michigan Public Service Commission ("Commission") or as an expert in any other proceeding?**

A. No.

**Q. Have you provided analysis in support of testimony or comments in any other utility regulatory proceeding?**

A. Yes. I have participated in several FERC and state commission proceedings, workshops, and professional meetings, mostly focused on demand response and the integration of distributed energy resources in wholesale and retail markets. I have similarly written or co-written comments submitted in several state commission and FERC proceedings, mostly focused on DER aggregation and participation in wholesale and retail demand-side resource programs.

**Q. Summarize your experiences working with advanced energy companies on issues related to electric utility regulation.**

A I have been professionally involved in regulatory and policy work on behalf of my employers since 2011. I have participated in regional transmission organization ("RTO") and independent system operator ("ISO") stakeholder and governance processes across the United States, including holding several committee and work group leadership positions, as well as participated in numerous FERC and state utility commission proceedings pertaining to DR and DERs since 2014.

**Q. What is the purpose of your testimony?**

A. My testimony is geared toward demonstrating that Consumer Energy's DR tariffs and programs (jointly referred to herein as the Company's "DR offerings") need limited modification in light of the Commission's recent Orders in Case Nos. U-21099 et al.[1] I have three recommendations. First, the Company should include language in its DR tariffs or program documents that clearly state whether customers who participate under the tariff are eligible or ineligible to participate in MISO DR with an Aggregator of Retail Customers ("ARC"). Second, the Company should unbundle wholesale and retail elements of its tariff-based DR programs in order to eliminate anticompetitive effects and allow ARCs to enroll customers who participate in the Company's retail DR programs in wholesale DR programs. Third, the Company should adopt a tariff model that allows ARCs to sell MISO Zonal Resource Credits ("ZRC") developed by the ARC from the Company customers to the Company.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

- Exhibit MEIU-7 (PDW-1): Discovery response U21389-MIEIBC-CE-0255
- Exhibit MEIU-8 (PDW-2): Discovery response U21389-MIEIBC-CE-0254
- Exhibit MEIU-9 (PDW-3): Discovery response U21389-MEIBC-CE-0258

[1] *In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations as required by MCL 460.6w*, order of the Michigan Public Service Commission, entered December 21, 2022 (Case Nos. U-21099 *et al.*) ("December 21 Order"); *In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations as required by MCL 460.6w*, order of the Michigan Public Service Commission, entered February 23, 2022 (Case Nos. U-21099 et al.) ("February 23 Order"; jointly with the December 21 Order, the "U-21099 et al. Orders").

- Exhibit MEIU-10 (PDW-4): Discovery response U21389-MEIBC-CE-0260
- Exhibit MEIU-11 (PDW-5): Discovery response U21389-MEIBC-CE-0256_McLean_ATT_1
- Exhibit MEIU-12 (PDW-6): Discovery Response U21389-MEIBC-CE-0640

## II. DEMAND RESPONSE TARIFF AND PROGRAM ELIGIBILITY

**Q. What Consumers Energy DR tariffs and programs are registered by the Company as Load Modifying Resources with MISO?**

A. In Company witness McLean's testimony, he describes the portfolio of tariff and contractually based programs offered by the Company. These include the Residential Device Cycling, Residential Dynamic Peak Pricing ("DPP"), Residential Smart Thermostat program, Small and Medium Business ("SMB") Smart Thermostat, Business DR Rate Options – which include the General Interruptible ("GI") and General Interruptible 2 ("GI2"), Rate Energy Intensive Primary ("EIP"), and Long Term Industrial Load Retention Rate ("LTILRR") rates, as well as the Business DR Contractual program. In witness McLean's response to a discovery question in this case (Exhibit MEIU-7 (PDW-1)), he confirmed that all of the Company's DR offerings are registered as Load Modifying Resources ("LMR"), except for the DPP (including Critical Peak Pricing and Peak Time Rewards) and EIP rates. In the same response, McLean also stated that, "the Company makes the appropriate reductions within the load forecast," for those DR offerings that are not registered with MISO.

**Q. Are customers participating in Consumers Energy's DR offerings ineligible to participate with ARCs?**

A. Yes. In witness McLean's response to a discovery question in this case (Exhibit MEIU-8 (PDW-2)), he stated that "customers that participate in the Company's contractual or interruptible tariff DR programs are not allowed to participate in additional DR programs through the Company or a third party."

**Q. Why are customers participating in Consumers Energy's DR offerings ineligible to participate with ARCs?**

A. A customer that is participating in one of the Company's offerings that the Company registers with MISO as part of a LMR during the same season would be double counting the same customer's contribution toward Resource Adequacy if they were to participate with an ARC. MISO's market rules do not allow the same customer account to be registered in MISO DR programs by different Market Participants in the same season.[2] Similarly, for those Company DR offerings not registered with MISO as LMRs that are accounted for through appropriate reductions to the load forecast, participation in capacity-based MISO DR program with an ARC would also be considered double counting.

**Q. Do you agree that customers participating in the Company's DR offerings would constitute double counting of the same MWs if the customers were also to participate as part of an LMR with an ARC?**

A. Yes, I agree that double counting would occur if such a scenario were to happen. However, I believe that MISO's market rules are sufficient to prevent this from occurring and

[2] Midcontinent Independent System Operator, Inc., Electric Tariff, Module C, 38.6 at A.i., is available at https://www.misoenergy.org/legal/tariff/ (accessed on August 23, 2023).

incorporate appropriate checks and balances to ensure that the same customer account is not registered as an LMR in the same season with different MISO Market Participants. For example, the Commission and Consumers Energy each have a role to play in MISO's registration review process for DR resources, with the Commission serving in the role of Relevant Electric Retail Regualtory Authority ("RERRA"), and with Consumers Energy serving in the role of Local Balancing Authority ("LBA") or of Load Serving Entity ("LSE") (or as both the LBA and LSE in the case of full-service utility customers).[3] This process allows ten business days to review the relevant account information that could include a check to determine if the customer is participating in a utility DR offering that would be considered to be ineligible.

**Q. Is there any language in the current tariff or program language for the Company's DR offerings that explicitly indicates to the reader that participation in a particular rate schedule or program would not allow a participating customer to also work with an ARC?**

A. In a sense. There is language currently in Section D, subsection F, of the General Terms and Conditions of the Rate Schedules of the Company's tariff that states, "[f]ull Service Customers shall not participate in any regional transmission organization wholesale market program until the Michigan Public Service Commission issues an order authorizing

[3] The Demand Response Business Practice Manual, BPM-026-r9 ("MISO DR BPM"), p. 30, is available at https://www.misoenergy.org/legal/business-practice-manuals/ (accessed on August 23, 2023).

participation."[4] While that language was appropriate prior to the Commission issuing its Orders in Case Nos. U-21099 et al., it is no longer appropriate.

**Q. Has the Company proposed edits to the current tariff language in this proceeding?**

A. Yes, the Company has proposed edits in this proceeding to the same section of its tariff that attempt to address the Commission's action in the Orders noted above. The edits proposed would add, "Non-Residential Customers with load exceeding 1MW may participate in any regional transmission organization wholesale market program per the terms of the Commission order in Case No. U-21099 dated February 23, 2023. All other . . . ,"[5] directly in front of the current tariff language. This proposed language, however, both falls short of capturing the full scope of the Commission's Orders and fails to provide the clarity I believe is needed to ensure that all parties are clear on a customer's eligibility to work with an ARC.

**Q. Do you have any recommendations on how to provide clarity within the tariff and program language for its DR offerings?**

A. Yes, I do. I recommend that the Commission direct the Company to file updated tariff language that explicitly states within each specific rate schedule or program rules whether participation under the DR offering would make a customer ineligible to participate with an ARC, or that if by participating with an ARC the customer would be rendered ineligible

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[4] Consumers Energy Company, Rate Book for Electric Service (M.P.S.C. No. 14), Sheet D-1.00.

[5] Exhibit No. A-16 (SCH-2) in Direct Testimony of Shawn C. Hurd on behalf of the Consumers Energy Company, Case No. U-21389.

to participate in the specific DR offering. The Company should include a simple statement substantially similar to the following in each of the specified tariffs: "*Full Service Customers with 1MW of load at a single site, or in aggregate across multiple accounts as part of the same corporate entity, enrolled in MISO demand response programs through an Aggregator of Retail Customers are not eligible to particiate under this [rate schedule]/[program]*." Additionally, if a specific Company DR offering is applicable to only specific seasons, the language included in the tariff or program rules should be clear as to which seasons a customer would be ineligible to participate with an ARC.

The clarity provided to all parties involved in reviewing and approving a customer's inclusion in a DR registration with MISO will help ARCs and customers determine eligibility and reduce instances where the Company or the Commission may need to reject MISO registrations during the review process. Additionally, it will be beneficial to also include reference to the other tariff rates a customer may be eligible to take service under if they choose to participate in MISO's DR programs with an ARC.

As I will discuss further in Section III of my testimony below, including my suggested language in the individual rate schedules or program rules will allow for each tariff or program to be tailored and explicit in what products or services at wholesale or retail are compatible (or incompatible) with the other available options for a customer to participate in when taking service under a particular rate schedule under the Company's tariff.

**Q. How does federal regulatory policy impact the ability of Consumers Energy to include eligibility restrictions in its DR offerings?**

A. The proposed language above follows in line from a determination in FERC Order 2222.[6] FERC has long had a policy of cooperative federalism toward demand-side resource participation in wholesale markets. Initially, in 2009, FERC demonstrated its cooperative approach through an "opt out" mechanism adopted in FERC Order 719, which allowed state regulators to adopt blanket prohibitions on ARC participation in order to prevent conflicts with retail regulatory models.[7] FERC did not repeal the "opt out" rule for demand response in Order 719, but in Order 2222, it introduced a more nuanced, and, in my opinion, better, approach than a blanket opt out rule.

In FERC Order 2222, at paragraph 161, FERC stated, "We find that it is appropriate to place narrowly designed restrictions on the market participation of distributed energy resources through aggregations, if necessary to prevent double counting of services."[8] In other words, FERC encourages states to proscribe participation more narrowly to avoid double counting and other conflicts, as in a tariff-by-tariff approach to determine eligibility. At paragraph 162 of Order 2222, FERC stated, "…relevant electric retail regulatory authorities continue to have authority to condition participation in their retail distributed

[6] Order No. 2222, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, 85 Fed. Reg. 67,094 (October 21, 2020) (codified at 18 C.F.R. §35.28(g) (12) (2022)) ("Order 2222").

[7] Order No. 719 Wholesale Competition in Regions With Organized Electric Markets, 73 Fed. Reg. 64,100, 64,107 (October 28, 2008) (codified at 18 C.F.R. §35.28(g)(1)(iii) (2022)) ("Order 719"), P 47.

[8] Order 2222, P 161.

energy resource programs on those resources not also participating in RTO/ISO markets…" By including language explicitly in tariffs that are incompatible with wholesale market participation, it provides clarity to all entities involved to understand whether participation by a customer in one tariff or program makes them ineligible to participate to provide products in the wholesale market. The suggested tariff language I propose herein is not only fully consistent with FERC regulation of DR but will also help ARCs and customers determine their eligibility to work with an aggregator.

## III. HARMONIZATION OF WHOLESALE AND RETAIL DEMAND RESPONSE BENEFITS

**Q. Do you see any issues with the design of Consumers Energy's DR offerings that bundle both wholesale and retail products and services together?**

A. Yes, I do. While witness McLean's testimony and responses to discovery questions do confirm that the vast majority of the Company's DR offerings are (or will be if the proposed tariff changes are approved in this proceeding) limited to being called upon to address MISO emergencies during which LMRs are dispatched,[9] he also confirmed that additional payments beyond those associated with the Resource Adequacy value LMRs provide are made to participants. For example, in the Business DR Contractual program included herewith as Exhibit MEIU-11 (PDW-5), participating customers are paid for the energy reductions achieved during each event. However, LMRs are only eligible to receive capacity payments associated with the ZRCs accredited to the LMR,[10] which witness

[9] See Exhibits MEIU-9 (PDW-3) and MEIU-10 (PDW-4); see also Direct Testimoy of Steven Q. McLean on behalf of Consumers Energy Company, Case No. U-21389 ("McLean Direct"), pp. 18, 21, 23, 24.

[10] MISO DR BPM, pp. 14–15.

Mclean also confirmed in his response to a discovery question (see Exhibit MEIU-12 (PDW-6)). However, witness McLean also stated that the Company does not dual register participants in its DR offerings in the any other MISO DR participation model other than LMR.[11] The basis for payments associated with the kWh consumption reductions achieved during each event based upon MISO's baseline methodologies result in cost savings to the Company from avoiding the need to generate or purchase energy to serve customers' load from the MISO market.

This is not a wholesale service. Rather, this is a retail service with benefits initially accruing to the Company as a LSE, and then to participating customers. It is unclear based upon the information available whether the energy cost savings are realized as a benefit only to the participating customers, or if they also accrue to the Company or other non-participating customers.

Another issue that I see is that continuing the Company's DR offerings as they currently are structured will perpetuate anticompetititive practices that present barriers to a level playing field for ARCs to compete in the competitive marketplace created by the Commission's Order in Case Nos. U-21099 et al. that partially removed the partial ban on third-party DR aggregators in Michigan from working with full-service customers of utilities. The issue is that the DR offerings that bundle multiple products and services together create "tying arrangements" that are, at least, disfavored—if not also raising anti-

[11] See Exhibits MEIU-9 (PDW-3) & MEIU-10 (PDW-4).

competitive implications. It is my view that the straightforward solution to address this problem is to separate out the various products and services into separate tariffs.

**Q. What do you mean by a "tying arrangement?"**

A. There are formal definitions of tying arrangements in the antitrust and economic literature.[12] For purposes of brevity, a tying arrangement can exist where two different products or services are bundled together and offered to a customer. When both of the products or services are competitive services in a competitive market context, there is no concern or competitive harm. However, where the seller has a monopoly or market power over one of the services, and the provision of that service is tied or bundled together with a competitive service, it creates the potential for the seller to engage in an unfair competitive practice that restricts access to the monopoly service unless the customer also procures the competitive service from the seller.

**Q. How do Consumers Energy's tariffs constitute a "tying arrangement" that raises antitrust concerns?**

A. The Commission has already determined through its Orders in Case Nos. U-21099 et al. that participation in wholesale DR for qualified customers receiving supply and distribution service is a competitive service in Michigan.[13] It is now Michigan's policy that eligible customers may participate in MISO's DR programs through an aggregator or through

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[12] For example, please see the Federal Trade Commission website available here: https://www.ftc.gov/advice-guidance/competition-guidance/guide-antitrust-laws/single-firm-conduct/tying-sale-two-products#:~:text=Typically%2C%20the%20%22tied%22%20product,can%20violate%20the%20antitrust%20laws. (accessed on August 22, 2023).

[13] See U-21099 et al. Orders.

Consumers Energy on a competitive basis. The problem lies in the fact that Consumers Energy is the *only* entity that offers, and can offer, retail DR opportunities because it is a utility with a monopoly over serving its customers and today offers the opportunity to participate in retail DR exclusively through the utility.

Certain of Consumers Energy's effective DR offerings may, and in one instance that I evaluated, definitely do, create a situation in which both retail and wholesale values are bundled together in a way that is anticompetitive. Specifically, the Business DR Contractual program includes both wholesale and retail DR elements and, as explained below, is anticompetitive.

As I noted above, MISO only compensates LMRs for the ZRCs accredited to the resource and does not compensate for the energy reductions that are delivered during LMR events. However, witness McLean states that DR "[p]articipants are compensated for capacity and *energy* reductions during events"[14] and that, ". . . customer[s] receive[] payment for energy based on performance during events. Incentive payments are *priced for market competitiveness*…"[15] when discussing how particpants are compensated for reducing their load during peak demand events.

In the sample customer agreement for the Business DR Contractual program provided in witness McLean's discovery response in this case (MEIU-11 (PDW-5)), section numbers

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[14] McLean Direct, p.16 (emphasis added).

[15] *Ibid* (emphasis added).

9 and 10 define the payments made to participating customers. Section 9.a. defines "Emergency Capacity Payments" which are specifically for the capacity that customers agree to provide, and align with what the Company, or an ARC, may register as an LMR with MISO.[16] Section 10 defines "Emergency Event Energy Payments," which states that, "[i]n Program Periods when one or more Emergency Events are called, Consumers Energy will pay Customer an energy payment of $50/MWh multiplied by the event's Delivered Capacity multiplied by the hours for each such event…"[17] Section 10.a. also states that during non-program periods, "Consumers Energy may call one or more Emergency Events. The customer is under no obligation to participate. If they choose to participate, they will be paid $1,000/MWh multiplied by the event's average Delivered Capacity delivered during the event. Delivered Capacity is capped at customers contracted nomination."[18] Witness McLean also stated in testimony that, "[t]he Company is also exploring DR program enhancements and new design to align with the MISO seasonal resource adequacy construct…includ[ing] expanding the Business DR Contractual program to more seasons to deliver more value beyond the currently offered summer season,"[19] which may result in expanded program periods in which customers may participate.

This example clearly illustrates a tying arrangement whereby participants in this particular DR offering by the Company are compensated for additional services that benefit the

[16] Exhibit MEIU-11 (PDW-5), p. 3.

[17] *Ibid*.

[18] *Ibid*.

[19] McLean Direct, p.18.

utility—in this case, energy—above what the wholesale market compensates LMRs. If an ARC registers an eligible full service customer as an LMR, it will not receive energy payments for the load reductions achived by customers when MISO dispatches LMRs. Further, the grid conditions or scenarios under which the Company may dispatch participants for voluntary performance outside of the Business DR Contractual program period were not defined in the available materials, prompting yet another example of a DR service opportunity ARCs are not able to provide to interested customers.

If any full service customer wants the opportunity to participate in the retail DR opportunity available under the Business DR Contractual program, it may do so only if it participates in wholesale DR (i.e., as an LMR) with Consumers Energy. This raises competitive concerns because ARCs, which are permitted to compete to provide DR services for MISO DR, are not able to offer the retail DR opportunity over which Consumers Energy has a monopoly.

**Q. Do you see any other issues with the design of Consumers Energy's DR offerings?**

A. Yes, I do. The principal concern I have with the Company's DR offerings, as discussed above, is that some of them blend wholesale and retail DR value streams into one offering. By combining these different value streams in one DR offering, it leads to lower participation by customers because customers have different capabilities. All of the Company's DR offerings should be evaluated to allow customers and ARCs working with customers to sign up to provide discrete services that they are able to provide and compensate them appropriately for such services. Several of the Company's DR offerings do provide wholesale benefits and are registered as LMRs to receive capacity credit as supply side resources, whereas others are intended only to address retail level issues, such as reducing peak demand during summer months or reduce electric consumption during hours of high electric pricing. Others, like the Business DR Contractual program, combine both wholesale and retail services under a single DR offering. For example, in the Business DR Contractual program, the Company registers the participating customers as LMRs with MISO. LMRs historically have been infrequently dispatched by MISO, but the capacity credits in the form of ZRCs are used by Consumers Energy to offset the total amount of ZRCs it must procure or self-supply to meet its Resource Adequacy Requirements as an LSE. Consumers Energy is also able to utilize the expected ZRCs converted from the participants in future Planning Years in its integrated resource plan, as well as to meet its requirements as an LSE for the Commission's Capacity Demonstration process. Additionally, Consumers Energy also may call upon Business DR Contractual participants outside of the defined program period for events to offset the need to procure energy from the wholesale market in instances where Consumers Energy's generation fleet is unable to meet its customers' load. Since these dispatches are substituting for Consumers Energy's retail supply obligations, this particular type of dispatch is a retail DR service.

**Q. How can these issues be addressed?**

A. These problems can be addressed via one of a number of relatively straightforward solutions that will provide additional benefits to the Company. The most straightforward approach (but not the most optimal) would be to unbundle the two types of DR and allow customers to enroll directly with Consumers Energy to participate in: 1) a wholesale DR offering from Consumers Energy, 2) a retail DR offering from Consumers Energy, or 3) both. Under this approach, a customer who would want to participate in the retail DR offering will not have to forego its competitive option to work with an ARC but could sign up for the retail DR service on an à la carte basis.

Another option, which I believe would be optimal and the most beneficial approach for all customers, Consumers Energy, and ARCs, would be to unbundle the two types of DR similar to the first option, but to create the ability for ARCs to enroll customers in the Consumers Energy retail DR offering on an aggregated basis. This approach would leverage the customer recruitment and enablement efforts and expertise of ARCs to bring customers into the Consumers Energy retail program. Creating the ability for ARCs to enroll customers will also reduce some of the administrative burden and costs associated with the utility's needing to engage with customers on individual basis.

**Q. How do you recommend that Consumers Energy implement these solutions?**

A. Consumers Energy should propose new, or modify its existing, DR offerings to separate out the wholesale and retail benefits, products and services that may be provided. Regardless of whether the Company chooses to modify its existing DR offerings or propose new ones for consideration by the Commission, however, having separate DR offerings that allow for customers to participate to provide one or more services simultaneously allows the customers to stack the value of their load flexibility to provide all the services for which it is capable. This also circumvents other potential administrative barriers to enabling dual participation at wholesale and retail levels. As discussed in section II of my testimony, including explicit language about eligibility should also be included in these new or revised tariffs so that all entities are aware of what tariffs or programs customers may participate in simultaneously and how they may stack, and recognize, the value provided.

**Q. What benefits are there to separating the products and services provided by DR participants?**

A. The benefits of creating separate DR offerings for wholesale and retail DR services go beyond addressing the anticompetitive concerns. Doing so will also increase participation because it will allow more customers with varying levels capability or limitations upon their flexibility to participate. Having a retail DR offering will allow for "value stacking" for appropriate customers.

**Q. Should DR aggregators be eligible to participate in these newly created or redesigned DR offerings?**

A. Yes, aggregators should be eligible to participate. Customers should be able to choose whether to participate directly with the utility if they so choose or to participate instead with a qualified aggregator. Aggregators also can enable greater participation in DR by building a portfolio of customers with disparate capabilities that may not otherwise individually meet the full requirements of a particular program to be paired together to create a firm resource to provide the desired grid services.

**Q. Do DR aggregators add to consumer costs if they are allowed to participate in a utility's DR offerings?**

A. No, they do not. It is a total misconception that by enabling aggregator participation, costs to customers will increase. Quite the contrary, aggregator participation lowers administrative and other utility costs (e.g., costs to acquire customers), and increases customer participation. This is because aggregators, rather than utility personnel, manage most of the customer-facing responsibilities such as developing curtailment plans, registering customer accounts with the relevant RTO/ISO or utility, calculating performance and payments to customers, and responding to customer service questions related to DR participation.

Aggregator business models generally are based upon sharing in the total revenue streams received from providing the grid products and services with the customers providing them. Aggregators must cover their costs and earn a profit from the available RTO/ISO market revenue or from the rate set (and approved by its regulator) in a utility's DR offering and do not have the ability to pass costs or seek ratepayer recovery of costs. If the aggregator cannot recover its costs, the aggregator loses money rather than increasing cost to consumers.

Aggregators help to identify and monetize customers' load flexibility and sell these capabilities to the utility or RTO/ISO. The price for each grid product or service could be market-based or be established within a tariff or program rules. Aggregator participation does not mean that the cost of the DR capability increases. Rather, aggregators are paid the market or tariff rate for the products and services provided by the participating customers, and share in those revenue streams with the customers based upon the value each customer is able to provide to the aggregator's portfolio.

**Q. Are there examples of existing programs elsewhere that can provide a model that Consumers Energy can refer to when considering a redesign of their DR tariffs?**

A. Yes, I would recommend that the Company look at Con Edison Company of New York, Inc.'s ("CONED") Commercial System Relief Program ("CSRP") and Distribution Load Relief Program ("DLRP") as examples of how to design programs that address specific and distinct distribution-level services that allow for the same customer to participate in one or both of these programs, while also participating in the wholesale market to provide capacity, energy, and/or ancillary services. The ability to stack additional values based upon a customer's interest and load curtailment capabilities can maximize the value of the resource. These programs also are designed to prevent double counting or double compensation for providing the same service in concert with the applicable wholesale market rules.

## IV. DEMAND RESPONSE FEED IN TARIFF

**Q. Are there other models for DR tariffs that Consumers Energy should consider that can allow aggregators to participate?**

A. Yes, there is a model that I recommend Consumers Energy to implement that would enable aggregators to participate. A DR feed in tariff ("FIT") is a tariff that allows for DR aggregator participation and allows the utility to purchase ZRCs registered with MISO towards meeting its Resource Adequacy Requirements as an LSE in MISO, as well as satisfy its Capacity Demonstration requirements under Michigan law.

Under the DR FIT, the utility purchases the DR capabilities of its customers that opt to contract with an ARC. The utility uses the credit that it receives for the capacity resource sourced from the utility's customers to satisfy its obligation as a LSE, and utilizes the aggregator-developed resources within its service territory towards its short- and long-term resource plans. ARCs work with the utility's customers to develop DR potential and serve as the MISO Market Participants to register the DR as LMRs. Once a participating ARC has successfully registered the LMRs and converted the registered MWs to ZRCs, it transfers the ZRCs within MISO's Module E Capacity Tracking tool ("MECT") to the Company's account. Once the ZRC transfer in MECT is complete, then the Company can utilize the ZRCs to satisfy its obligations as an LSE as part of a Fixed Resource Adequacy Plan ("FRAP") or Self-Schedule and reduce the amount of ZRCs it may otherwise need to procure in the Planning Resource Auction ("PRA").

Under the DR FIT, the price at which the utility will purchase ZRCs from participating ARCs is clearly stated within the tariff and approved by the Commission and will be determined to be cost-effective. As needed, the cost-effectiveness of the DR FIT price for ZRCs can be revisited to ensure that ratepayers are getting value and benefits from ARC participation in the tariff. Additionally, having a clear stated price will promote more robust competition amongst participating aggregators to provide the greatest value to those utility customers that elect to participate with an ARC. As I noted above, ARCs do not add to consumer costs by enabling participation in such a tariff, as the price established under the tariff is applicable to all participants and may be periodically reviewed to ensure that it remains cost-effective. In fact, all consumers stand to benefit from enabling aggregators from increased participation to provide cost-effective DR.

**Q. Does the DR FIT allow for regulatory oversight of aggregator activities?**

A. Yes, it does. Since the DR FIT is a utility tariff that must be proposed by a utility and receive approval from the Commission, it may contain provisions regarding aggregator qualifications, capabilities, or other reasonable requirements to allow only those aggregators that satisfy the requirements established in the tariff to be eligible to participate. Additionally, as participating aggregators need to be MISO Market Participants, ARCs must adhere to all of MISO's market rules and are subject to regulatory oversight by FERC.

**Q. Are there other benefits of the DR FIT model?**

A. Yes, ARC participation through a DR FIT model enables more robust participation from a diverse set of customers that may not otherwise be eligible to participate in a utility's existing DR tariffs or programs directly.

**Q. Why should Consumers Energy propose a DR FIT model?**

A. Consumers Energy should propose a DR FIT model for a variety of reasons, most importantly to address gaps in the current DR market in light of the Commission's Order in Case Nos. U-21099 et al. While the utility can procure DR from aggregators through an

RFP or bilateral agreement, there are substantial costs to running them and they do not occur with sufficient frequency to spur development of the DR market. A DR FIT model is attractive because it lowers transactions costs to participate (because the terms of the tariff are fixed), allows the utility an efficient means to meet its resource adequacy needs from its own customers' DR, and allows the DR market to grow to scale over time.

Moreover, while Michigan's market is now open for full service utility customers that meet eligibility requirements to work with ARCs, there remain structural barriers to ARCs developing new DR resources in the MISO area. One barrier that is common to all new entrants including DR is the structure of MISO's PRA, which is conducted for the prompt year only, with Auction Clearing Prices ("ACP") known only after resources must be registered. In recent years, there have been highly volatile ACPs. Customers generally are unwilling to participate in DR without knowing how much their load flexibility is worth, and selling directly into the PRA does not provide a durable or reliable price signal of the value of a customer's load reduction. As such, reliance on selling LMR ZRCs into the PRA will not lead to the development of a robust and long-lasting DR portfolio by ARCs. A DR FIT tariff mechanism can overcome this MISO barrier by including a stated price customers can expect without the wild fluctuations of the PRA.

Another barrier ARCs face is the procurement practices of utilities that exclude DR or other demand-side resources that can qualify with MISO as Planning Resources and receive ZRCs. "All source" procurements seemingly should be a mechanism through which ARCs could sell DR capacity, however, in recent solicitations held by utilities within Michigan, LMRs and energy efficiency resources were prohibited from consideration since they were not *generation* resources, even though they are able to qualify as a Planning Resource with MISO.

Absent other procurement mechanisms, such as those approved by the Commission in DTE Electric Company's ("DTE") most recent Integrated Resource Plan ("IRP") in Case No. U-21193, whereby DTE will conduct procurement events specifically for ZRCs sourced from MISO-qualified DR resources,[20] or enabling DR aggregators to aggregate customers and participate in Consumers Energy's DR offerings as I discussed above, ARCs lack a viable means to sell ZRCs from DR resources to Consumers Energy. The DR FIT model would enable eligible ARCs to participate in a tariff where the barriers discussed here do not exist.

## V. CONCLUSIONS AND RECOMMENDATIONS

**Q. Please summarize your conclusions and recommendations to the Commission.**

A. I recommend that the Commission:

1. Direct Consumers Energy to file updated tariffs with language that explicitly clarifies the eligibility of customers to participate in wholesale DR with an ARC.
2. Direct Consumers Energy to propose new or modify existing DR offerings to unbundle the wholesale and retail benefits, products and services that may be provided by its customers under such tariffs.

[20] See *In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief*, order of the Public Service Commission, entered July 26, 2023 (Case No. U-21193), at Exhibit A p. 13.

3. Direct Consumers Energy to work with DR aggregators to develop a DR FIT tariff model to be proposed with the Commission.

**Q. Does that complete your testimony?**

A. Yes.

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| | | |
|---|---|---|
| In the matter of the Application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) | **Case No. U-21389** |

## Direct Exhibit List of MEIU

| Witness | Exhibit # | Exhibit Description |
|---|---|---|
| Dr. Laura S. Sherman | MEIU-1 (LSS-1) | Résumé of Dr. Laura S. Sherman |
| Dr. Laura S. Sherman | MEIU-2 (LSS-2) | Discovery response U21389-MEIBC-CE-0098 |
| Dr. Laura S. Sherman | MEIU-3 (LSS-3) | Discovery response U21389-MEIBC-CE-0099 |
| Dr. Laura S. Sherman | MEIU-4 (LSS-4) | Discovery response U21389-MEIBC-CE-0264 |
| Dr. Laura S. Sherman | MEIU-5 (LSS-5) | Andrew Satchwell, et al., Lawrence Berkeley National Laboratory, Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities (2014). |
| Dr. Laura S. Sherman | MEIU-6 (LSS-6) | Galen Barbose, Lawrence Berkeley National Laboratory, Putting the Potential Rate Impacts of Distributed Solar into Context (2017). |
| Peter D. Dotson-Westphalen | MEIU-7 (PDW-1) | Discovery response U21389-MIEIBC-CE-0255 |
| Peter D. Dotson-Westphalen | MEIU-8 (PDW-2) | Discovery response U21389-MIEIBC-CE-0254 |
| Peter D. Dotson-Westphalen | MEIU-9 (PDW-3) | Discovery response U21389-MEIBC-CE-0258 |

| | | |
|---|---|---|
| Peter D. Dotson-Westphalen | MEIU-10 (PDW-4) | Discovery response U21389-MEIBC-CE-0260 |
| Peter D. Dotson-Westphalen | MEIU-11 (PDW-5) | Discovery response U21389-MEIBC-CE-0256_McLean_ATT_1 |
| Peter D. Dotson-Westphalen | MEIU-12 (PDW-6) | Discovery Response U21389-MEIBC-CE-0640 |

**STATE OF MICHIGAN**

**MICHIGAN PUBLIC SERVICE COMMISSION**

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| | | |
|---|---|---|
| In the matter of the Application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) | **Case No. U-21389** |

**EXHIBITS OF DR. LAURA S. SHERMAN**

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION,**

**AND**

**ADVANCED ENERGY UNITED**

# LAURA S. SHERMAN, Ph.D.

cell: 607.592.3026
laura@mieibc.org

## PROFESSIONAL EXPERIENCE:

April 2019 – present **Michigan EIBC/IEI**, Lansing, MI **President**

- Organize and lead a staff of five employees, contractors, and student interns.
- Work with and inform each organization's Board of key decisions, upcoming events, long-term strategy, etc.
- Fundraise and coordinate both organization's annual budgets.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.
- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.

Oct. 2017-March 2019 **Michigan EIBC/IEI**, Lansing, MI **VP for Policy Development**

- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Coordinate regulatory interventions and engagement in regulatory stakeholder processes among member companies.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.
- Support policy initiatives focused on wind energy, solar energy, electric vehicles, storage, taxation, and corporate purchasing of renewable energy.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.

Feb. 2017-March 2019 **5 Lakes Energy**, Lansing, MI **Senior Consultant**

- Research, analysis, communication, and advocacy surrounding complex energy issues.
- Lead wind and solar siting project to address opposition to deployment in coordination with philanthropy, industry, and stakeholders across nine Midwest states.
- Focus areas include renewable energy development, community engagement, stakeholder coordination, business sustainability, and electric vehicles.
- Support newsletter, website, and social media communications.

April 2015-Dec. 2016 **U.S. Senate**, Washington, DC **Legislative Assistant/Policy Advisor**

- Policy advisor to Senator Michael Bennet (D-CO) on agriculture, energy, environment, land, and natural resource issues.
- Legislative topics included: farming and ranching, public land conservation and management, water policy, energy development, renewable energy including energy tax incentives and transmission permitting, energy efficiency, endangered species, climate change, sportsmen's issues, environmental pollution and regulations, air quality, and biofuels.

- Drafting legislation; building coalitions; negotiating policy solutions; writing speeches; staffing the Senator at hearings of the Agriculture and Finance Committees.

2014-2015 **U.S. Senate**, Washington, DC **AAAS Congressional Science Fellow**

- Competitively selected AAAS Fellow sponsored by the American Geophysical Union. Served in the Office of Senator Michael Bennet (D-CO).
- Drafting legislation; helping to facilitate political coalitions; meeting with constituents; interacting with federal agencies; delivering policy briefings and recommendations.

2012-2014 **University of Michigan**, Ann Arbor, MI **Postdoctoral Research Fellow**

- Successfully obtained competitive grant funding for novel method to track air pollution from power plants and metal smelters into rainfall across the Great Lakes region.
- In collaboration with epidemiologists, developed and utilized new methods to assess the sources and pathways of human exposure to mercury pollution.
- Published five manuscripts; presented talks and organized scientific sessions at national and international conferences.

2007-2012 **University of Michigan**, Ann Arbor, MI **Graduate Researcher**

- Competed for and received National Defense Science and Engineering Graduate Fellowship and Graham Environmental Sustainability Institute Doctoral Fellowship.
- Developed groundbreaking methods to "fingerprint" mercury pollution from coal-fired power plants and trace it into rainfall, lake sediments, and fish.
- Published eight manuscripts, was interviewed for "The Environment Report" on NPR and general-circulation science magazines, presented research at national and international conferences.
- Ph.D. dissertation received university-wide ProQuest Distinguished Dissertation Award and departmental John Dorr Graduate Academic Achievement Award.

2005-2007 **Massachusetts Institute of Technology**, Boston, MA **Research Scientist**

- Found evidence for early life on Earth in ancient rocks. Published two manuscripts.

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## SERVICE & LEADERSHIP:

2021-present **Board Member** of Zero Emission Transportation Association Education Fund Board
2020-present **Board Member** of University of Michigan Earth and Environmental Sciences Alumni Board
2019-2020 **Board Member** of Advancing Women in Energy
2017-2019 **Communications Chair** for Advancing Women in Energy
2013-2014 **Supported** the Ann Arbor Energy Commission on community solar projects
2009-2014 **Peer reviewer** of more than 20 scientific manuscripts
2009 **Initiator and organizer** of new departmental seminar series, University of Michigan
2008-2010 **President** of department student organization (GeoClub), University of Michigan
2008 **Lead organizer** of Michigan Geophysical Union Poster Conference
2007-2008 **Department Steward** to Graduate Employees Union, University of Michigan

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## EDUCATION:

**Ph.D.** 2012 Earth and Environmental Sciences, **University of Michigan** (GPA: 8.837 out of 9.0)

**B.S.** 2005 Geological and Environmental Science, **Stanford University** (GPA: 4.007 out of 4.33)

**Question:**

2. Please provide the following data on the PowerMIDrive Public Charging pilot:

a. Number of DCFC ports for which applications were received.

b. Number of DCFC ports energized using funding through the pilot.

c. Amount (dollars) of funding awarded to DCFC projects.

   i. Percentage of existing funding already awarded to DCFC projects.

d. Amount (dollars) of funding that remains available for DCFC projects.

   i. Percentage of existing funding that remains available for DCFC projects.

**Response:**

a. To date the company has received 516 DCFC rebate applications.

b. 39 DCFC sites are operational and thus have received rebates to date.

c. Given the 39 DCFC sites to date that have received rebates of $70,000 each, the total rebates awarded to date is $2,730,000.

   i. Regarding the percentage of funding, 37 of the 39 rebates paid to date were from the first approval of DCFC funding in Case No. U-20134, and thus 100% of the rebate funds from that Case are expended. The next 2 of 39 rebates paid to date are from the additional 100 DCFC rebates approved in Case No. U-20697. However, the Company has committed 90 of those yet unpaid DCFC rebates to customers whose projects are in progress. Thus, only 8 of the 100 DCFC rebates approved in Case No. U-20697 remain unallocated. This means that 92% of the DCFC rebate funding is paid or committed to customer projects.

d. Given the detail in “c” above, a total of $560,000 in DCFC rebates is not yet committed to DCFC customer sites, which is equivalent to 8 DCFC rebates of $70,000 each.

   i. Only 8 of the 100 DCFC rebates approved in Case No. U-20697 remain to be awarded to customer sites, which is 8% of the DCFC rebate funding available per Case No. U-20697.

**Witness:** Jeffrey A. Myrom
**Date:** June 30, 2023

**Question:**

3. Referring to the DER Optimization Initiative discussed by witness Henry, please identify and describe all of the differences between the DER Optimization Initiative proposed in the pending case and the DERMS Initiative proposed in Case No. U-21224.

**Response:**

The DER Optimization initiative's implementation has been refined based on industry best practices as well as feedback received in Case No. U-21224. The refinement more clearly distinguishes the implementation plan to begin with various local DER optimization solutions (DER Gateways) prior to proceeding with a system-wide DER optimization solution (DERMS). The Company has applied industry best practice research from EPRI as a foundational model for the deployment strategy as shown in Exhibit A-114. Lastly, a key difference is that the Company has extended the implementation timeline and is not requesting cost recovery for the DER Optimization Initiative in this Case No. U-21389.

**Witness:** Matthew S. Henry
**Date:** June 30, 2023

**Question:**

2. In response to 21389-MEIBC-CE-0099, the Company states, in part, "The Company has applied industry best practice research from EPRI as a foundational model for the deployment strategy as shown in Exhibit A-114."

a. Please indicate whether the Company relied on the EPRI report in Exhibit A-114 when it prepared its DERMs Initiative proposed in Case No. U-21224.

b. Please identify with citation to Exhibit A-114 each and every "best practice" referenced by EPRI that the Company relied upon in preparing its DER Optimization Initiative.

c. Please identify each and every change made by the Company to its DERMs Initiative proposed in Case No. U-21224 when preparing its DER Optimization Initiative.

**Response:**

a. No, the Company did not rely on the EPRI report in Exhibit A-114 when it prepared its DERMS Initiative in Case No. U-21224 because this report was not published until September 2022, which is after the aforementioned case was submitted.

b. As described in my direct testimony on page 60, "The Company intends to implement a combination of three parallel pathways that can be defined as 'Progressing from Few to Many Connected DER,' 'Progressing from Autonomous Local Controllers to Connected Central Control,' and 'Progressing from Simple to Complex Functions.' These three pathways can be observed in Exhibit A-114 on page 4, pages 5-6, and page 6, respectively.

c. An overview of the differences between the DERMS initiative proposed in Case No. U-21224 and the DER Optimization initiative in the current Case was provided in response to discovery request 21389-MEIBC-CE-0099. To provide additional context, the current case includes more details on the location of the initial DER Gateway projects (see page 55 of my direct testimony), which were originally referred to as "de-centralized DERMS controllers" in Case No. U-21224. The Company has also further detailed and clarified in this case the two-wave approach of starting with smaller DER gateway deployments prior to the deployment of a centralized DERMS. In the current case, the Company has utilized additional industry research as a basis for the deployment strategy, as explained in parts a. and b. above. Finally, the timeline for the deployment of these projects has been updated and the Company has not requested any recovery of costs in the current case.

**Witness:** Matthew S. Henry
**Date:** July 18, 2023

LBNL-6913E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

# Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities

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Contributing authors
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**Environmental Energy Technologies Division**

**September 2014**

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

## Disclaimer

# Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities

Prepared for the
Office of Energy Efficiency and Renewable Energy
Solar Energy Technologies Office
U.S. Department of Energy

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September 2014

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We would also like to thank and acknowledge members of the Project Advisory Group for their valuable feedback and input throughout the entire project:

| | |
|---|---|
| Justin Baca | *Solar Energy Industry Association (SEIA)* |
| Lori Bird | *National Renewable Energy Laboratory (NREL)* |
| Nadav Enbar | *Electric Power Research Institute (EPRI)* |
| Miles Keogh | *National Association of Regulatory Utility Commissions (NARUC)* |
| Kelly Knutsen | *U.S. Department of Energy, SunShot Program* |
| Virginia Lacy | *Rocky Mountain Institute (RMI)* |
| Carl Linvill | *Regulatory Assistance Project (RAP)* |
| Eran Mahrer | *Solar Electric Power Institute (SEPA)* |
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| Tom Stanton | *National Regulatory Research Institute (NRRI)* |
| Joseph Wiedman | *Keyes, Fox & Wiedman LLP* |

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# Acronyms

APS – Arizona Public Service
BAU – business-as-usual
CAGR – compound annual growth rate
CapEx – capital expenditures
CFE – Comision Federal de Electricidad
DOE – U.S. Department of Energy
EE – energy efficiency
EPE – El Paso Electric
EPRI – Electric Power Research Institute
FAC – fuel adjustment clause
FCM – Forward Capacity Market
FERC – Federal Energy Regulatory Commission
GRC – general rate case
IRP – integrated resource plan
ISO-NE – Independent System Operator New England
LBNL – Lawrence Berkeley National Laboratory
LRAM – lost revenue adjustment mechanism
NAPEE – National Action Plan for Energy Efficiency
NE – northeast
NEM – net energy metering
NEVP – Nevada Power
NPV – net present value
O&M – operations and maintenance
PACE – PacifiCorp East
PNM – Public Service Company of New Mexico
PPA – purchased power agreement
PSCO – Public Service Company of Colorado
PUC – public utilities commission
PV – solar photovoltaic
REC – renewable energy certificate
ROE – return-on-equity
RPC – revenue-per-customer
RPS – renewable portfolio standard
SEEAction – State Energy Efficiency Action Network
SEIA – Solar Energy Industries Association
SEPA – Solar Electric Power Association
SPP – Sierra Pacific Power
SRP – Salt River Project
SW – southwest
T&D – transmission and distribution
TOD – time-of-delivery
TOU – time-of-use
UOG – utility owned generation
WACC – weighted average cost-of-capital
WACM – Western Area Power Administration, Colorado-Missouri Region
WALC – Western Area Power Administration, Lower Colorado Region

# Executive Summary

Deployment of customer-sited photovoltaics (PV) in the United States has expanded rapidly in recent years, driven in part by public policies premised on a range of societal benefits that PV may provide. With the success of these efforts, heated debates have surfaced in a number of U.S. states about the impacts of customer-sited PV on utility shareholders and ratepayers, and such debates will likely become only more pronounced and widespread as solar costs continue to decline and deployment accelerates. To inform these discussions, we performed a scoping analysis to quantify the financial impacts of customer-sited PV on utility shareholders and ratepayers and to assess the potential efficacy of various options for mitigating those impacts.

The analysis relied on a pro-forma utility financial model that Lawrence Berkeley National Laboratory previously developed for the purpose of analyzing utility shareholder and ratepayer impacts of utility-sponsored energy efficiency programs. Using this model for the present study, we quantified the impacts of net-metered PV for two prototypical investor-owned utilities: a vertically integrated utility located in the southwest (SW) and a wires-only utility and default service supplier located in the northeast (NE). For each utility, we modeled the potential impacts of PV over a 20-year period, estimating changes to utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity (ROE). The analysis is thus focused on utility shareholder and ratepayer impacts, and thus does not consider all relevant aspects of these debates. Other important boundaries of the study scope and methods (and potential sources of misinterpretation) are highlighted in Text Box 1 within the main body of the report.

The utility shareholder and ratepayer impacts of customer-sited PV were first assessed under a set of base-case assumptions related to each utility's regulatory and operating environment, in order to establish a reference point against which sensitivities and potential mitigation strategies could be measured.[1] The base-case analyses were performed with total penetration of customer-sited PV rising over time to stipulated levels ranging from 2.5% to 10% of total retail sales (compared to current penetration levels of 0.2% for the U.S. as a whole and of roughly 2% for utilities with the highest penetrations, excluding Hawaii).[2] Each of these PV penetration cases were compared to a scenario with no customer-sited PV over the entire analysis period. Although the estimated impacts of customer-sited PV reflect an assumption of net metering, those impacts should not be attributed to net metering, per se, as some amount of customer-sited PV deployment could occur even in the absence of net metering.

Key findings from the **base-case analysis** are as follows:

- **Utility Costs and Revenues.** Customer-sited PV reduces both utility revenues and costs (i.e., revenue requirements). In the case of the SW Utility, the impacts on revenues and costs are roughly equivalent under the 2.5% PV penetration scenario. At higher PV penetration

[1] See Sections 3 and 4 for a full description of base-case assumptions. Variations around these and other base-case assumptions are explored within the sensitivity analysis.
[2] Specifically, penetration of customer-sited PV rises from zero in year-1 to levels ranging from 2.5% to 10% of retail sales in year-10, and then remains constant as a percentage of retail sales for the latter 10 years of the 20-year analysis period. This approach was taken in order to capture end-effects that occur after PV additions take place.

levels, however, revenue reductions exceed cost reductions, in part because of a declining marginal value of PV. In the case of the NE Utility, revenue reductions exceed cost reductions across all of the future PV penetration levels considered, and the divergence is considerably wider than for the SW Utility. This occurs because the NE Utility has higher assumed growth in certain fixed costs that customer-sited PV does not reduce.

- **Achieved ROE.** Impacts on achieved shareholder ROE varied by utility and PV penetration level (see Figure ES-1). Under the scenario with PV penetration rising to 2.5% of retail sales (roughly the same order of magnitude as the current largest state markets), average achieved shareholder ROE was reduced by 2 basis points (a 0.3% decline in shareholder returns) for the SW utility and by 32 basis points (5%) for the NE Utility. Under the more aggressive 10% PV penetration scenario, average ROE fell by 23 basis points (3%) for the SW Utility and by 125 basis points (18%) for the NE Utility. These ROE reductions occur because of the proportionally larger effect of customer-sited PV on utility revenues than on utility costs, under our base-case assumptions. ROE impacts were larger for the wires-only NE utility, because of both its higher assumed growth in fixed costs and its proportionally smaller ratebase (as it does not own generation and transmission).

- **Achieved Earnings.** The impact of customer-sited PV on shareholder earnings for the SW Utility was somewhat more pronounced than the ROE impacts, because of lost earnings opportunities associated with deferred capital expenditures that would otherwise generate earnings for shareholders. Under the 2.5% PV penetration scenario, average earnings for the SW Utility were reduced by 4% (compared to a 0.3% reduction in ROE). Because of the lumpy nature of capital investments and the way in which they change the timing of general rate cases (GRCs) and setting of new rates, those earnings impacts do not necessarily scale with the penetration of customer-sited PV; under the 10% PV penetration scenario, earnings for the SW Utility were reduced by 8%. Because the NE Utility does not own generation or transmission, the lost earnings opportunities from customer-sited PV are less severe, and thus impacts on earnings are similar to impacts on ROE, ranging from a 4% reduction under the low-end PV penetration scenario to a 15% reduction in earnings at the high-end PV penetration scenario.[3]

- **Average Rates.** The ratepayer impacts of customer-sited PV were relatively modest compared to the impacts on shareholders. In the 2.5% PV penetration scenario, customer-sited PV led to a 0.1% increase in average rates for the SW Utility and a 0.2% increase for the NE Utility. Under the more aggressive 10% PV penetration scenario, average rates rose by 2.5% and 2.7% for the SW and NE Utilities, respectively. These rate impacts reflect the net impact of customer-sited PV on utility costs and sales, where reduced costs are spread over a smaller sales base. Note, though, that these impacts represent the increases in average rates across all customers, including those with and without PV, and thus do not measure cost-shifting, per se.

[3] The prototypical NE Utility in our analysis may present a case where the ROE of future investments does not cover the cost of equity, in which case the deferral of future capital investments would benefit shareholders; however, a cost of equity test, which is beyond the scope of this study, would be required to make such a determination.

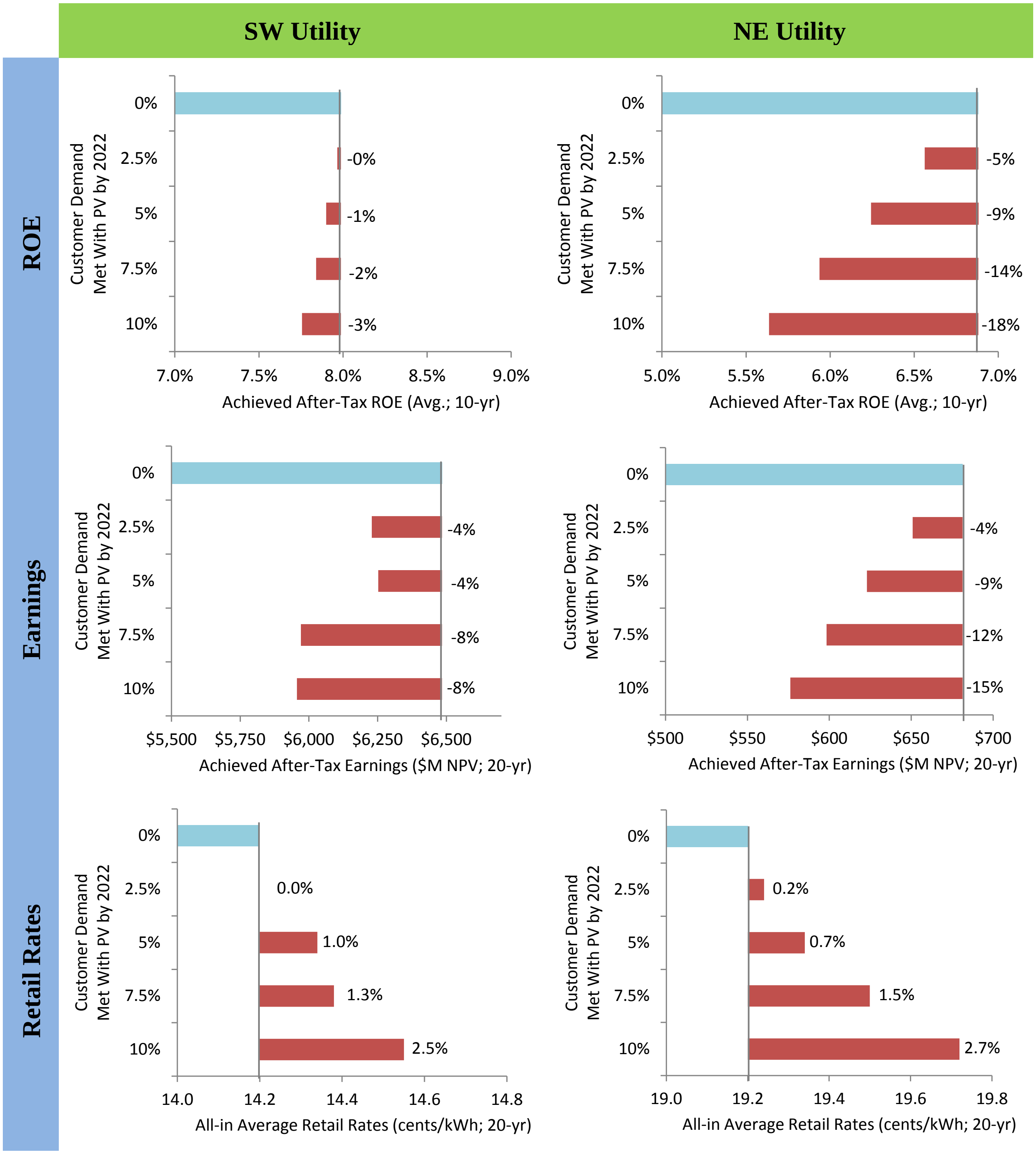



**Figure ES-1. Impacts of Customer-Sited PV on Average Achieved ROE, Earnings, and All-in Retail Rates**

One key objective of this scoping study was to illustrate the extent to which the potential impacts of customer-sited PV on utility shareholders and ratepayers depend on underlying conditions of the utility. To explore these inter-relationships, we compared the impacts from PV under a wide array of sensitivity cases, each with varying assumptions about the utilities' operating or regulatory environment (see Table 3 in the main body for the full list of sensitivity cases). The sensitivity cases all focus specifically on impacts from customer-sited PV at a penetration level of 10% of total retail sales. This is the highest penetration level examined within this study, and was used for the sensitivity cases in order to most clearly reveal the underlying relationships between the impacts of PV and the sensitivity variables (that is, to distinguish the signal from the noise). Were lower PV penetration levels assumed, the impacts of PV would be smaller and the ranges across sensitivity cases would be narrower, but the fundamental results would be qualitatively the same.

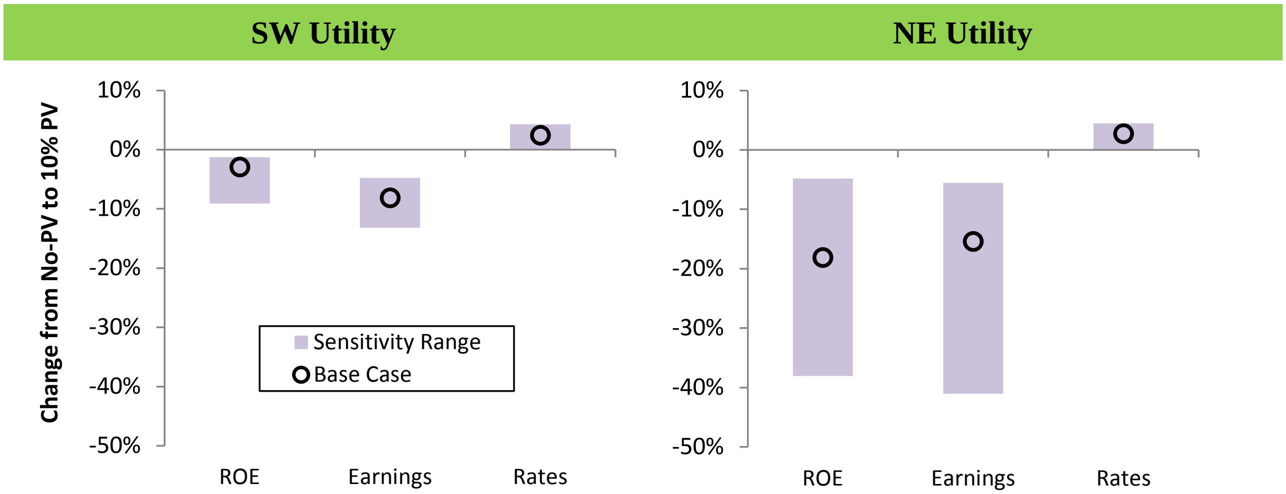



**Figure ES-2. Impacts of Customer-Sited PV across Sensitivity Cases**

Key themes and relationships illustrated through the **sensitivity analysis** are as follows[4]:

- The magnitude of shareholder impacts varies considerably across the sensitivity cases, as illustrated in Figure ES-2. Specifically, achieved earnings were reduced by 5% to 13% for the SW utility and by 6% to 41% for the NE utility, with similar ranges in the impacts on achieved ROE, illustrating the degree to which these impacts potentially depend on utility-specific conditions. By comparison, the ratepayer impacts were relatively stable across sensitivity cases, with increases in average rates ranging from 0% to 4% for the SW utility and from 1% to 4% for the NE utility.

- The impacts to both prototypical utilities are particularly sensitive to the capacity value and avoided T&D costs from customer-sited PV. Important to note, however, is the divergent set of implications for ratepayers vs. shareholders. The greater the capacity value and avoided T&D costs from PV, the greater the deferral of utility capital expenditures. This reduces the impacts of customer-sited PV on retail rates. Indeed, under one set of assumptions for the SW Utility, customer-sited PV results in a slight decrease in average rates. For utility shareholders, however, increased deferral of capital expenditures leads to greater erosion of earnings.

[4] The focus of our sensitivity analysis is on how the metrics vary between cases with and without PV and how the size of that difference varies depending upon underlying utility conditions, not on how the absolute level of the shareholder and ratepayer metrics varies between sensitivity cases.

- The impact of customer-sited PV on average retail rates also depends on underlying load growth (prior to the effects of PV on load). With lower load growth, as may occur in the case of a utility with aggressive energy efficiency programs, customer-sited PV results in a larger increase in average retail rates, because of the smaller base of retail sales over which fixed costs must be recovered, and because of reduced opportunity for cost savings from deferred capital expenditures. Shareholder impacts from customer-sited PV can also be sensitive to underlying load growth, though those relationships are complex and can be idiosyncratic depending upon details of the particular utility and the choice of metric used.

- The shareholder impacts of customer-sited PV tend to be more severe when retail rates rely predominantly on volumetric energy charges and also tend to be more severe when longer lags exist within the ratemaking process (e.g., longer periods between rate cases or use of historic test years). The heightened shareholder impacts in these cases occur because of greater revenue erosion associated with PV.

- The shareholder and ratepayer impacts from customer-sited PV also depend, though often to a lesser extent, on the magnitude and growth rates of various utility cost elements; however, the degree and direction of those sensitivities depend on the type of cost and how it is recovered. For example, the erosion of shareholder profitability from customer-sited PV is unaffected by fuel costs (assuming they are a pass-through), but may be highly sensitive to capacity costs for utility-owned generation.

Finally, we analyzed a number of (though by no means all) options for mitigating the possible impacts of customer-sited PV on utility shareholders and ratepayers (see Table ES-1). As in the sensitivity analysis, we again focused on the impacts under the 10% PV penetration scenario, in order to most clearly reveal the effects of the mitigation measures considered. These mitigation scenarios borrow, to some degree, from the kinds of measures that have been implemented or suggested in connection with energy efficiency programs. Most target shareholder impacts associated with either revenue erosion or lost earnings opportunities from customer-sited PV, and in some cases may exacerbate the ratepayer impacts from customer-sited PV.

**Table ES-1. Mitigation Measures Examined in This Study**

| Mitigation Measure | Revenue Erosion | Lost Earnings Opportunities | Increased Rates |
|---|---|---|---|
| Revenue-per-Customer (RPC) Decoupling | ● | | ○ |
| Lost Revenue Adjustment Mechanism (LRAM) | ● | | ○ |
| More Frequent Rate Cases | ● | | ○ |
| No Regulatory Lag | ● | | ○ |
| Current & Future Test Years | ● | | ○ |
| Increased Demand Charge & Fixed Charge | ● | | ○ |
| Shareholder Incentive | | ● | ○ |
| Utility Ownership of Customer-Sited PV | | ● | ○ |
| Customer-Sited PV Counted toward RPS | | | ● |

● Primary intended target of mitigation measure
○ May exacerbate impacts of customer-sited PV

Key themes and findings from the **analysis of mitigation options** include the following:

- Decoupling and lost-revenue adjustment mechanisms may moderate revenue erosion from customer-sited PV, and thereby mitigate its impacts on shareholder ROE and earnings; however, the size (and even direction) of impact varies greatly depending upon the design of these mechanisms and characteristics of the utility. Depending on the utility's underlying rate of cost growth, similar outcomes may also be achieved by transitioning to more-frequent rate cases, use of current or future test years, and reduced regulatory lag. However, to the extent that these various mitigation measures serve to restore shareholder ROE and earnings, they may entail some corresponding increase in average retail rates, exemplifying the kind of tradeoffs inherent in many potential mitigation measures.

- Increased fixed customer charges or demand charges may also moderate revenue erosion, and the associated impacts on shareholder ROE and earnings, from customer-sited PV. Importantly, though, the effectiveness of those measures depends critically on the underlying growth in the number of customers or customer demand. For the prototypical NE utility in our analysis, a shift in revenue collection from volumetric energy charges towards larger fixed customer charges (when implemented for all customers, not just those with PV) actually *exacerbates* the erosion of shareholder ROE, due to the low rate of growth in the number of utility customers relative to growth in sales. Moreover, such shifts in rate design are not without other consequences, including that they dampen incentives for customers to invest in energy efficiency and PV.

- Shareholder incentive mechanisms, similar to those often implemented in conjunction with utility-administered energy efficiency programs, as well as utility ownership or financing of customer-sited PV, both offer the potential for substantial shareholder earning opportunities, though the associated policy and regulatory issues may be significant. The significance of the potential earnings boost is most pronounced for wires-only utilities with otherwise limited investment opportunities: in the case of the NE Utility in our analysis, nearly all of the earnings erosion that would otherwise occur as a result of customer-sited PV is offset in a scenario where the utility owns just one-tenth of the customer-sited PV deployed in its service territory offsets.

- Allowing utilities to automatically apply all net-metered PV towards their RPS obligations, without providing any explicit payment to the customer, has the potential to substantially mitigate the rate impacts from PV. However, such an approach is not without tradeoffs, as it effectively entails transferring ownership of renewable energy certificates (RECs) as a condition of service under net metering, and it achieves cost savings by, in effect, reducing the amount of incremental renewable generation required to comply with the RPS.

**Policy Implications and Areas for Further Research**

In summary, the findings from this scoping study point towards several high-level policy implications. First, even at 10% PV penetration levels, which are substantially higher than exist today, the impact of customer-sited PV on average retail rates may be relatively modest (at least from the perspective of all ratepayers, in aggregate[5]). At a minimum, the magnitude of the rate impacts estimated within our analysis suggest that, in many cases, utilities and regulators may have sufficient time to address concerns about the rate impacts of PV in a measured and deliberate manner. Second and by comparison, the impacts of customer-sited PV on utility shareholder profitability are potentially much more pronounced, though they are highly dependent upon the specifics of the utility operating and regulatory environment, and therefore warrant utility-specific analysis. Finally, we find that the shareholder (and, to a lesser extent, ratepayer) impacts of customer-sited PV may be mitigated through various "incremental" changes to utility business or regulatory models, though the potential efficacy of those measures varies considerably depending upon both their design and upon the specific utility circumstances. Importantly, however, these mitigation strategies entail tradeoffs – either between ratepayers and shareholders or among competing policy objectives – which may ultimately necessitate resolution within the context of broader policy- and rate-making processes, rather than on a stand-alone basis.

As a scoping study, one final objective of this work is to highlight additional questions and issues worthy of further analysis, many of which will be addressed through follow-on work to this study and further refinements to LBNL's utility financial model. Although by no means an exhaustive list, these areas for future research include examining: the relative impacts of customer-sited PV compared to other factors that may impact utility profitability and customer rates; the combined impacts of customer-sited PV, aggressive energy efficiency, and other demand-side measures; the rate impacts of customer-sited PV and various mitigation measures specifically on customers without PV and differences among customer classes; a broader range of mitigation options; potential strategies for maximizing the avoided costs of customer-sited PV; and continued efforts to improve the methods and data required to develop reliable and actionable estimates of the avoided costs of customer-sited PV.

[5] We do not evaluate rate impacts for individual customer classes or rate classes, and the average rate impacts described within this report may not capture more substantial impacts that could occur within individual customer or rate classes.

# 1. Introduction

Electricity generation from customer-sited photovoltaic (PV) systems currently constitutes just 0.2% of total U.S. electricity consumption, though it has reached higher penetration levels in various states and utility service territories, and has grown at a rapid pace of roughly 50% per year over the past decade.[6] This recent growth has been fueled by a combination of falling PV system prices, the advent of customer financing options, and various forms of policy support at the federal, state, and local levels that are premised on the range of societal benefits that PV may provide. One critical element in the value proposition has been net energy metering (NEM or simply "net metering"), a billing mechanism that allows customers to export electricity generated by their PV systems to the grid and apply that excess generation against electricity consumption at other times, in effect receiving credit for all PV generation at the prevailing retail electric rate.

Heated debates surrounding the financial impact of customer-sited PV and net metering on utility shareholders and ratepayers have surfaced in a number of states, and these will likely become more widespread as solar deployment expands, and as states approach statutory caps on the allowed amount of net-metered PV.[7] Utility executives are often concerned about revenue erosion and reduced shareholder returns when customers with net-metered PV are able to avoid charges for fixed infrastructure costs, as well as potential cost-shifting between solar and non-solar customers. At the same time, net metering is viewed as essential by customers with PV to protect their investments, by the solar industry to grow their businesses, and by states and environmental advocates to achieve climate or other environmental policy goals. To date, however, progress on these issues has been hampered by a lack of evidence about the magnitude of the financial impacts on utility shareholders and ratepayers, the conditions under which those impacts may become more or less significant, and the efficacy of potential mitigation options.

Debates about net metering are taking place against the backdrop of a larger set of discussions about existing utility business and regulatory models. One dimension of those broader discussions has focused on the poor alignment between the traditional utility business model – whereby utility profits are closely tied to their volume of sales and capital investments – and recent advances in technology and public policy driving growth of demand-side resources, which tend to reduce sales and opportunities for capital investments (Kind 2013, Fox-Penner 2010). Arguably the greatest progress on those issues has occurred with respect to utility ratepayer-funded energy efficiency (EE) programs, where the unintended consequences of the "utility throughput incentive" to increase sales and add capital investments to the utility's ratebase have been long-recognized and a variety of regulatory tools have been developed and deployed to better align utility financial interests with EE goals (Wiel 1989, Moskovitz et al. 1992, Eto et al.

[6] The highest state-level penetration rates for customer-sited PV are in Hawaii (3.8% of retail electricity sales at year-end 2013), New Jersey (1.7%), and California (1.1%), while the highest penetration rates for individual investor-owned utilities are for the three largest Hawaii utilities (5.1%-6.0%), Pacific Gas & Electric (2.3%), San Diego Gas & Electric (2.0%), and Arizona Public Service (2.0%). These values are derived from data on customer-sited PV capacity installed through year-end 2013, as reported by GTM/SEIA (2014) and by SEPA (2014).
[7] Recent challenges to existing net metering tariffs have been raised in regulatory proceedings in Arizona, California, Colorado, Georgia, Idaho, Louisiana, and Nevada (among others); and issues related to the potential rate impacts or cost-shifting from net metering have been prominently featured within energy policy forums (Borenstein 2013) and among major news outlets (Cardwell 2013, Tracy 2013).

1994, Harrington et al. 1994, Stoft et al. 1995, Kushler et al. 2006, NAPEE 2007). Among the goals of the present study is to leverage this base of experience and illustrate how some of the same regulatory and ratemaking strategies could also be applied in the context of distributed PV.

As the attention of policymakers and electric industry observers has turned towards customer-sited PV, studies representing a diversity of perspectives have highlighted potential misalignments between net metering and utility cost structures (Brown and Lund 2013, Cai et al. 2013, DOE 2007, Duthu et al. 2014, Graffy and Kihm 2014, SEPA-EPRI 2012, Wood and Borlick 2013). A number of those studies and several others (Bird et al. 2013, Blackburn et al. 2014, Linvill et al. 2013, Kihm and Kramer 2014, Shirley and Taylor 2009) identify regulatory and ratemaking options for mitigating adverse rate impacts from distributed PV, while many others (also) discuss possible broader changes to utility business and regulatory models that are compatible with, or that could facilitate the growth of, distributed PV (EPRI 2014, Hanelt 2013, Harvey and Aggarwal 2013, Lehr 2013, Moskovitz 2000, Newcomb et al. 2013, Nimmons and Taylor 2008, Richter 2013a, Richter 2013b, Rickerson et al. 2014, RMI 2012, RMI 2013, Wiedman and Beach 2013).

Quantitative analyses relating to the financial or economic impacts of customer-sited PV and net metering have thus far consisted mostly of cost-benefit studies performed from the perspective of utility ratepayers or society more broadly; see Hansen et al. (2013) for a meta-analysis of cost-benefit studies and E3 (2014) for a more recent example. The results of those studies hinge on the methods and assumptions used to estimate the value of distributed PV to the utility, and considerable disagreement exists around which particular sources of value to consider and how to quantify them (APPA 2014, Bradford and Hoskins 2013, Cliburn and Bourg 2013, Keyes and Rábago 2013, Stanton and Phelan 2013). Competing studies have thus often led to divergent results (E3 2013, Beach and McGuire 2013). By comparison, few analyses beyond several recent research notes by Wall Street analysts (Dumoulin-Smith et al. 2013, Goldman Sachs Global Investment Research 2013) and a limited base of theoretical work (Oliva and MacGill 2012) have sought to examine the financial implications of net metering for utility shareholders. Moreover, little if any published research has quantitatively compared possible options for mitigating any potential adverse impacts on either utility shareholders or ratepayers.

This report seeks to build upon, and address gaps within, the aforementioned body of research through a scoping analysis that quantifies the potential financial impacts of net-metered PV on utility shareholders and ratepayers. The analysis leverages a pro-forma utility financial model that Lawrence Berkeley National Laboratory (LBNL) developed for the purpose of analyzing the shareholder and ratepayer impacts of utility-sponsored EE programs (Cappers et al. 2009, Cappers and Goldman 2009a, Cappers et al. 2010, Satchwell et al. 2011). Using this model, we quantify the financial impacts of customer-sited PV for two prototypical investor-owned utilities: a vertically integrated utility located in the Southwest and wires-only utility and default service supplier located in the Northeast. For each utility and under a range of PV penetration levels, we model the impact of net-metered PV on utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity (ROE). We examine the sensitivity of those impacts to various aspects of the utility operating and regulatory environment (e.g., load growth, cost growth, the frequency of general rate cases), as well as to alternate assumptions about the value of PV to the utility (i.e., avoided costs). Finally and importantly, we quantify the impact of a number of possible mitigation approaches that might be used to reduce any negative impacts to shareholders and/or ratepayers from growing amounts of customer-sited PV. These mitigation measures include alternative rate designs, utility revenue decoupling, utility ownership of distributed PV, and various other strategies. Key boundaries to the study scope and methods (and potential sources of misinterpretation) are highlighted in Text Box 1.

The remainder of the report is organized as follows. Section 2 provides an overview of the utility pro-forma financial model and describes its previous applications. Section 3 identifies key assumptions used to model the two prototypical utilities and presents base-case projections of their costs, revenues, retail rates, and profits without PV. Section 4 presents the corresponding base-case results for the two prototypical utilities under a range of PV penetration levels. Section 5 presents our sensitivity analyses, which illustrate how the utility shareholder and ratepayer impacts of PV are dependent upon various aspects of the utility operating and regulatory environment. Section 6 presents the results of the mitigation analyses, which examine the extent to which any negative financial impacts from distributed PV may be mitigated through a set of regulatory and ratemaking measures. Finally, Section 7 offers a number of policy implications and identifies areas for further research. Additional details about modeling assumptions and results are included in the appendices.

**Text Box 1. Key Boundaries of the Study Scope and Methods**

Issues surrounding the impacts of customer-sited PV and net metering are complex, and discussions of these issues are invariably contentious. In the interest of ensuring that the findings from this analysis are interpreted and applied appropriately, we highlight a number of important boundaries of the study scope and methods.

- First, the study is not a detailed analysis of the value of PV. It relies on a financial model, not a utility production cost or planning model. This financial model contains a relatively high level of detail in its representation of utility ratemaking and revenue collection processes, but less detail in its representation of the physical utility system. As a result, the impacts of distributed PV on utility cost-of-service are based on a coarser set of assumptions than what might be possible with utility operations or planning models. For this reason, we include sensitivity analyses to examine how the financial impacts of PV would vary with alternate assumptions related to avoided costs.
- Second, the model, as configured for this study, captures financial effects at the utility level, not at the customer-class level. As such, we do not directly quantify cost-shifting or cross-subsidization among customer classes, although the modeled impacts on average retail electricity rates may, under many of the scenarios, be considered a proxy for the impacts on non-PV customers. Future follow-up analyses may explore participant/non-participant impacts more explicitly and in greater depth.
- Third, the analysis is focused narrowly on the financial impacts of customer-sited PV on utility shareholders and ratepayers when compensated under net metering. It does not analyze costs and benefits for customers with PV systems, or for society-at-large, and therefore does not consider costs that PV customers incur for their systems nor any broader social benefits (e.g., reduced emissions, economic development, energy security). By limiting the scope of our analysis to net-metered PV, we do not address potential impacts to utility shareholders or ratepayers that may occur under other compensation schemes, nor do we address the impacts that might occur under complete “grid defection”, whereby customers with PV and distributed storage bypass utility service entirely (RMI 2014).
- Fourth, the estimated impacts of customer-sited PV are based on comparisons to scenarios with no customer-sited PV. Thus, even though these impacts reflect an assumption of net metering, they should not be attributed to net metering, per se, as some amount of customer-sited PV deployment could occur even in the absence of net metering.
- Finally, we seek to understand how PV may impact two prototypical utilities along the spectrum of electric utility operating and regulatory environments in the United States. Although our sensitivity analyses capture a broader range of assumptions about utility operating and regulatory environments, we have by no means exhausted all possible combinations of conditions that utilities may face, and thus some care must be taken in generalizing from the results.

## 2. Model Description

For the present analysis, we used a *pro forma* financial model that calculates utility costs and revenues, based on specified assumptions about its physical, financial, operating, and regulatory characteristics (Figure 1). The model was adapted from a tool (the Benefits Calculator) initially constructed to support the National Action Plan on Energy Efficiency (NAPEE) and intended to analyze the financial impacts of EE programs on utility shareholders and ratepayers under alternative utility business models (NAPEE 2007). LBNL has since expanded and applied the enhanced model to evaluate the impact of aggressive EE programs on utilities in the U.S. (Cappers and Goldman, 2009a, 2009b; Cappers et al., 2010; Satchwell et al., 2011). Applications of the LBNL model and analysis of model outputs have been used as part of technical assistance to state public utility commissions (PUCs) considering aggressive EE goals and/or alternative utility business models (e.g., Arizona, Nevada, Massachusetts, and Kansas). The model has also been used to support the State and Local Energy Efficiency Action Network (SEEAction), which builds on the NAPEE effort, with analysis used in workshops and trainings. Through these various applications, the overall structure of the model has been reviewed and vetted by regulators, utility staff, and EE program administrators. We chose to use this model in order to connect the much more extensive analysis of the impacts of EE on utilities to the analysis of the impact of PV on utilities.

Within the remainder of this section, we provide a brief overview of the financial model used for the present analysis, first discussing how the model calculates utility costs and revenues and then describing how changes in costs and revenues are used to evaluate the impact of PV on three stakeholder metrics. The three metrics include two utility shareholder metrics (achieved ROE and achieved earnings) and one ratepayer metric (average retail rates).[8]

The model quantifies the utility's annual costs and revenues over a 20-year analysis period. Importantly, the model performs all calculations at the total utility level, and does not differentiate among rate classes or between PV participants and non-participants. Utility costs are based on model inputs that characterize current and projected utility costs over the analysis period. Some costs are projected using stipulated compound annual growth rates (CAGRs); other costs are based on schedules of specific investments (e.g., generation expansion plans). The costs cover several categories of the utility's physical, financial, and operating environment, including fuel and purchased power, operations and maintenance, and capital investments in generation and non-generation assets (i.e., transmission and distribution investments). The model calculates the utility's ratebase, which grows with additional capital investments and declines with depreciation of existing assets. The model also estimates interest payments for debt used to finance a portion of capital investments and includes taxes on earnings. The details of how we modeled our prototypical utilities' costs are in Section 3.

The utility's collected revenues are based on retail rates that are set in periodic general rate cases (GRCs) throughout the analysis period (see Figure 1). By default, the model assumes that rate

[8] Previous analysis with the same model included a second ratepayer metric: total customer utility bills. In this report, we report utility collected revenues, which is the same as total customer utility bills.

cases occur at some specified frequency, though the model also allows the utility to file a GRC when making capital investments of a certain amount or higher.

GRCs are used to establish new rates based on the revenue requirement set in a test year (including an authorized ROE for capital investments), the test year billing determinants (i.e., retail sales, peak demand, and number of customers), and assumptions about how the test year revenue requirement is allocated among the billing determinants. The model allows for different types of test years (i.e., historical test years, current test years, and future test years).[9] The particular rate design of the utility consists of a combination of a volumetric energy charge ($/kWh), volumetric demand charge ($/kW), and fixed customer charge ($/customer). Model inputs specify the relative size of those three rate components, and can be modified to represent different rate designs. The model used for this study did not have the capability to represent more complex rate designs, such as time-of-use (TOU) pricing or tiered (i.e., inclining or declining block) rates, though future versions of the model will possess that capability.

The rates established in a GRC are then applied to the actual billing determinants in future years to calculate utility collected revenue in those years. The model accounts for a period of regulatory lag whereby rates established in a GRC do not go into effect until some specified number of years after the GRC. In between rate cases, certain costs are passed directly to customers through rate-riders (e.g., fuel-adjustment clause [FAC]). Our average all-in retail rate metric, a measure of impacts from the utility customer perspective, reflects the average revenue collected per unit of sales which accounts for periodic setting of new rates, rate-riders, and delays in implementing new rates.

The financial performance of the utility is measured by the achieved after-tax earnings and achieved after-tax ROE, both of which are commonly used by utility managers and shareholders.[10] We calculated the prototypical utilities' achieved after-tax ROE in each year as the current year's earnings divided by current year's outstanding equity (i.e., the equity portion of the ratebase).[11] Achieved after-tax ROE may – and often does – differ from the utility's authorized ROE, which is established by regulators in a GRC and is used to determine the amount of return a utility can receive on its capital investments. This is because utility rates are set such that the test-year revenue requirement (based on the test year costs and billing determinants) would produce earnings that are sufficient to reach the authorized after-tax ROE. Actual utility revenues and costs may differ from those in the test year, leading to achieved earnings, and hence *achieved* ROE, that deviates from the authorized level. In general, achieved ROE will be less than authorized ROE if, between rate cases, utility costs grow faster than

[9] Many states allow the utility to file an adjustment to its historical test-year costs during a GRC (i.e., pro-forma adjustment period) to update and correct them to better reflect expectations about normal cost levels.

[10] ROE is considered to be a measure of how well a company is performing for its shareholders. While a high ROE typically indicates efficient use of shareholder's money, it is not always the case that a high ROE indicates a stable and profitable business. ROE is dependent on several factors, including the ratio of debt to equity which may artificially inflate a company's ROE if the company is making investments mostly with debt. ROE is also a useful metric when comparing companies within an industry, because the metric is normalized.

[11] The model does not take into account cash flow and changes in financing costs that may result from under- or over-recovery of costs, which may impact ROE.

revenues. Conversely, achieved ROE will generally be greater than authorized ROE if, between rate cases, utility costs grow slower than revenues.

We calculated the prototypical utilities' achieved after-tax earnings as collected revenues minus costs in each year. Similar to achieved after-tax ROE, achieved after-tax earnings can be different than the utility's authorized earnings, because the *achieved* earnings are based on actual profitability in a given year and the *authorized* earnings are set in the GRC revenue requirement, based on the authorized ROE.

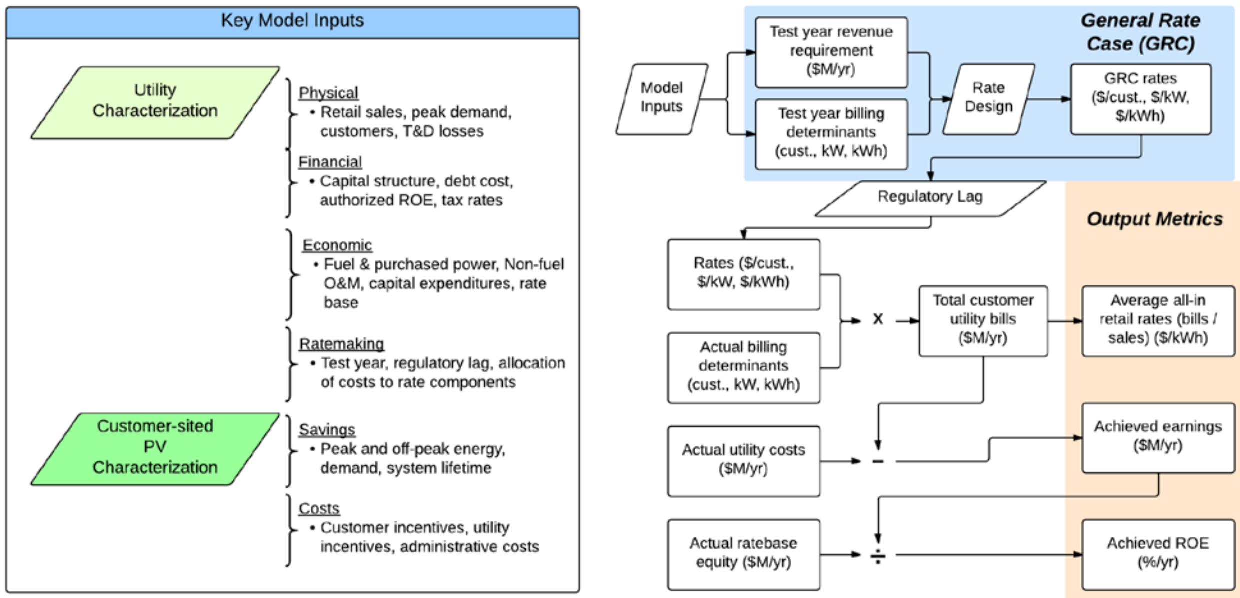


**Figure 1. Simplified Representation of the Model and Calculation of Stakeholder Metrics**

A key part of analyzing the impact of PV on utility profitability and customer rates is to capture how the addition of PV changes utility costs and billing determinants. In general, PV reduces fuel and purchased power costs, and it can also reduce utility costs related to ongoing and incremental capital expenditures (including return, depreciation, and taxes related to those capital expenditures). In terms of the impacts on billing determinants, PV reduces volumetric sales and customer peak demand, which reduces utility revenues collected on a volumetric basis through energy and demand charges. Changes to utility costs and billing determinants then flow through the model to calculate our key stakeholder metrics. We expand on our characterization of the impact of customer-sited PV on utility costs and billing determinants in Section 4.

Aside from the traditional cost-of-service business model, alternative regulatory mechanisms can also be implemented in the model. The model includes the ability to represent decoupling mechanisms (i.e., sales based or revenue-per-customer), lost revenue adjustment mechanisms, and shareholder incentive mechanisms. The model can also analyze alternative ratemaking approaches (e.g., high fixed customer charge) by changing the way utility revenues are collected among different billing determinants. We describe the intent and design of each of these and other alternatives in more detail in Section 6, where they are considered as options to mitigate the impact of PV on utility profitability.

# 3. Prototypical Utilities without Customer-Sited PV

Our analysis results are based on characterizations of two prototypical utilities: a vertically integrated utility in the southwest and a wires-only utility and default service supplier in the northeast (see Table 1). The choice of these two prototypical utilities was intended to capture both a broad spectrum of utility operating and regulatory environments, as well as two regions of the United States that have thus far seen the greatest levels of customer-sited PV deployment. In this section, we describe the key assumptions used to model these utilities (with further details included in Appendix A), and present 20-year projections of the utilities' costs (i.e., revenue requirements), average retail rates, collected revenues, shareholder earnings, and return on equity without PV. **These projections represent the base-case utility characterizations**; alternate assumptions about various aspects of the utilities' operating and regulatory environments are explored through the sensitivity analyses in Section 5.

**Table 1. Prototypical Utility Characterization: Key Inputs**

| Key Input* | Southwest Utility | Northeast Utility |
|---|---|---|
| **Utility type** | Vertically integrated | Wires-only |
| Asset Ownership | Generation, Transmission, and Distribution | Distribution only |
| 2013 Retail Sales Level (CAGR) | 30,460 GWh (2.1%) | 21,957 GWh (1.4%) |
| 2013 Peak Demand Level (CAGR) | 6,531 MW (2.1%) | 5,655 MW (1.5%) |
| 2013 Retail Customer Count (CAGR) | 1,094,658 (2.7%) | 1,239,682 (0.3%) |
| Average Fuel and Purchased Power Costs CAGR | 5.6% | 6.6% |
| Non-fuel Operations & Maintenance (O&M) Costs CAGR | 2.6% | 3.4% |
| 2013 Ratebase (net accumulated depreciation) | $7.39B | $2.03B |
| RPS Compliance Strategy | Build & Buy | Buy |
| 2013 All-in Retail Rate Level | 11.34 ¢/kWh | 12.82 ¢/kWh |
| Frequency of General Rate Case (GRC) Filings | Every 3 years** | Every 3 years |
| Regulatory Lag (i.e., period of time between filing of GRC and when new rates take effect) | 1 year | 1 year |
| Test Year | Historic | Historic |
| Authorized ROE | 10.00% | 10.35% |
| Debt and Equity Share (Ratio) | 46%:54% (0.85) | 57%:43% (1.32) |
| Weighted Average Cost-of-Capital (WACC) | 8.33% | 7.86% |

* All monetary values and growth rates are expressed in nominal terms

** For the Southwest Utility, we assume that GRCs also occur after any capital investment exceeding $900M.

## 3.1 Southwestern vertically integrated utility

We developed long-range (i.e., 2013-2032) cost and load forecasts for the prototypical Southwestern Utility ("SW Utility") by starting with data originally provided by Arizona Public Service (APS) staff for a 2009 project (Satchwell et al. 2011) and then updated those forecasts based on information from the 2012 APS Integrated Resource Plan (IRP) and other recent regulatory filings. Various assumptions, like annual energy and peak demand growth, were then further modified in order to create a more generic prototypical southwestern utility. Thus, although data from APS were used to seed the initial utility characterization, ***the prototypical SW Utility used in this analysis is not intended to represent APS, specifically***. When modifying assumptions to reflect regionally representative data, we ensured that those changes were internally consistent with other input assumptions.

The SW Utility's costs and revenues are driven by, among other things, projected load growth, the utility's capacity expansion plan, compliance with the renewables portfolio standard (RPS), and rate design.[12] With respect to load growth, the SW Utility has retail sales of 30,460 GWh and a peak demand of 6,531 MW in 2013 (exclusive of any savings from PV), both of which are forecasted to grow at a compound annual rate of 2.1% per year over the 20-year time horizon. This load growth is representative of SW regional load forecasts (see Appendix A) and is lower than what APS forecasted in its 2012 IRP (i.e., 2.7% annual growth in energy and 2.7% annual growth in peak demand).

The SW Utility has a 2013 installed capacity of 4,797 MW of conventional generation, including nuclear, coal, mid-merit gas, and peaking gas units. The SW Utility also has existing and owned renewable generating capacity of 206 MW. The SW Utility purchases capacity through short-term capacity contracts to make up for a shortfall between the installed capacity and the peak load plus a 14% planning reserve margin. The SW Utility follows a generation expansion plan based on the APS 2012 IRP, which assumes incremental capacity additions, periodically adding additional peaking plants and additional mid-merit plants. No utility-owned generation is retired during the analysis period in the base-case, though we examine early retirements of coal generation in one of the sensitivity cases discussed in Section 5.

The SW Utility complies with a mandated RPS of 20% retail sales by 2025 through a combination of utility-owned renewable resources and renewable energy purchased power agreements (PPAs). We assumed an RPS requirement larger than the actual APS requirement to reflect more typical requirements of utilities in the southwest. Periodic investments in utility-owned renewable plants are assumed to each contribute 25 MW toward peak demand (e.g. firm capacity) and produce 219 GWh/year of renewable energy. Any remaining shortfall in the RPS requirement is met through signing new renewables PPAs at a contract price of $70/MWh. The amount of utility-scale solar added for the RPS (exclusive of customer-sited PV) varies from year to year, ultimately constituting roughly 6.5% of annual sales by 2022. Thus, the total penetration of solar from both utility-scale and customer-sited PV well exceeds the contribution from customer-sited PV alone.

The SW Utility revenue requirement allocation (i.e. the rate design) is based on typical APS customer bills from its 2011 rate case. The SW Utility collects revenues based on annual retail sales, peak demand, and number of customers. As noted previously, revenue requirements are allocated at the utility-level; we do not separately identify particular rate classes or revenue allocations thereof. Total non-fuel revenues are collected among billing determinants as follows: 16% from customer charges, 14% from demand charges, and 70% from energy charges. This percentage allocation holds constant throughout the analysis period. Total fuel and purchased power revenues are collected exclusively through energy charges, and the SW Utility is assumed to have a fuel adjustment charge (FAC) that allows all fuel and purchased power costs to be passed through to customers on an annual basis.

[12] Appendix A describes all input assumptions for the SW Utility.

The resulting SW Utility revenue requirement is \$3.6B in 2013 and grows at 4.3% per year through 2032 (see Figure 2). Operations and maintenance (O&M) costs (inclusive of non-fuel O&M expenses from incremental capital expenditures) are the largest non-fuel cost component of the revenue requirement and grow at 2.6% per year from 2013 to 2032. Fuel and purchased power costs are the single largest component of the revenue requirement and grow at 5.6% per year during the 20-year analysis period.

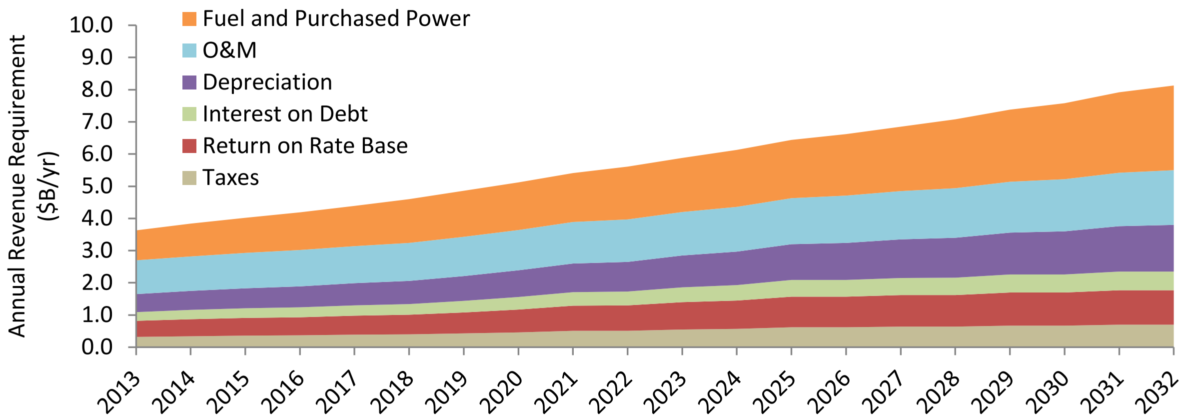



**Figure 2. SW Utility Revenue Requirement**

Since the SW Utility collects revenues based on its allocation among billing determinants (i.e., retail sales, peak demand, and number of customers), growth in utility collected revenues is tied to growth in billing determinants between rate cases. Non-fuel collected revenues are based on rates per billing determinant set during the SW Utility GRC. Due to assumed regulatory lag, these rates take effect one-year after the filing of a GRC. Figure 3 shows that non-fuel costs are *higher* than non-fuel collected revenues over the first half of the analysis period (prior to the addition of any customer-sited PV), due to the higher growth rate of non-fuel costs relative to growth in billing determinants. Non-fuel costs and revenues are better aligned in later years of the analysis period, because new generating investments in those years trigger more frequent GRC filings. SW Utility all-in average retail rates, reflecting fuel and non-fuel collected revenues, increase from 11 cents/kWh in 2013 to 18 cents/kWh in 2032 (2.5%/yr).

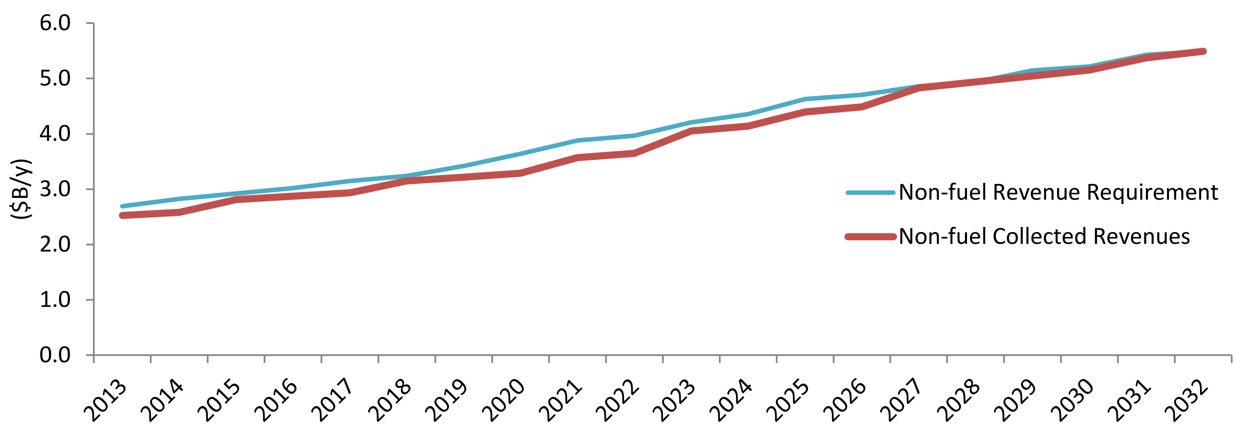



**Figure 3. SW Utility Non-Fuel Collected Revenues and Non-Fuel Revenue Requirement**

**Text Box 2. A Note on Terminology: Fuel Costs vs. Non-Fuel Costs**

Throughout this report, we distinguish between two broad categories of costs: fuel costs and non-fuel costs. When used within the context of this distinction, "fuel costs" refers to all costs that are fully passed through to customers, via annually adjusted FAC charges. These include (as applicable, depending upon the utility): fuel costs for utility-owned generation, all purchased power costs associated with long-term contracts and short-term purchases of energy and capacity, and transmission access costs. Within our analysis, utility shareholders are indifferent to fuel costs or any impact that customer-sited PV may have on these costs or the associated revenues.

"Non-fuel costs" simply refers to all remaining utility costs, which include both fixed and variable costs. These costs are recovered through retail rates established in GRCs based on test-year costs and billing determinants. We refer to revenues from those GRC-established rates as "non-fuel revenues." Growth in those revenues between rate cases is a function of growth in the utility's billing determinants (which, in our analysis, consist of retail sales, peak demand, and number of customers). Given the periodic nature of GRCs and the temporal lags therein, non-fuel costs and non-fuel revenues may not align with each other, which in turn affects utility earnings and ROE (either positively or negatively, depending on the direction of the misalignment). As discussed further, customer-sited PV impacts the relative growth rates of non-fuel costs and non-fuel revenues, and this is one of the key drivers for its utility shareholder impacts.

The utility achieves an average after-tax ROE of 8.0% from 2013-2022 and 8.4% from 2013-2032.[13] The utility's achieved after-tax ROE is less than its authorized ROE of 10% in most years. Achieved after-tax earnings are $3.4B from 2013-2022 and $6.5B from 2013-2032.[14] Achieved after-tax earnings are also less than authorized earnings in most years of the analysis period (see Figure 4). "Under earning", where levels of achieved earnings are less than authorized earnings, occurs because utility costs grow at a faster rate between rate cases than do billing determinants. The utility can increase earnings by either increasing sales or decreasing costs between rate cases. SW Utility earnings and ROE increase significantly in later years when the utility increases its ratebase equity through several generation investments. Those investments also trigger more frequent GRC filings, which in turn leads to more frequent rate increases, boosting revenue growth.

[13] We calculate average ROE on a levelized basis, using a discount rate equal to the utility's weighted average cost of capital (WACC).

[14] We calculate earnings on a net present value (NPV) basis, using a discount rate equal to the utility's WACC.

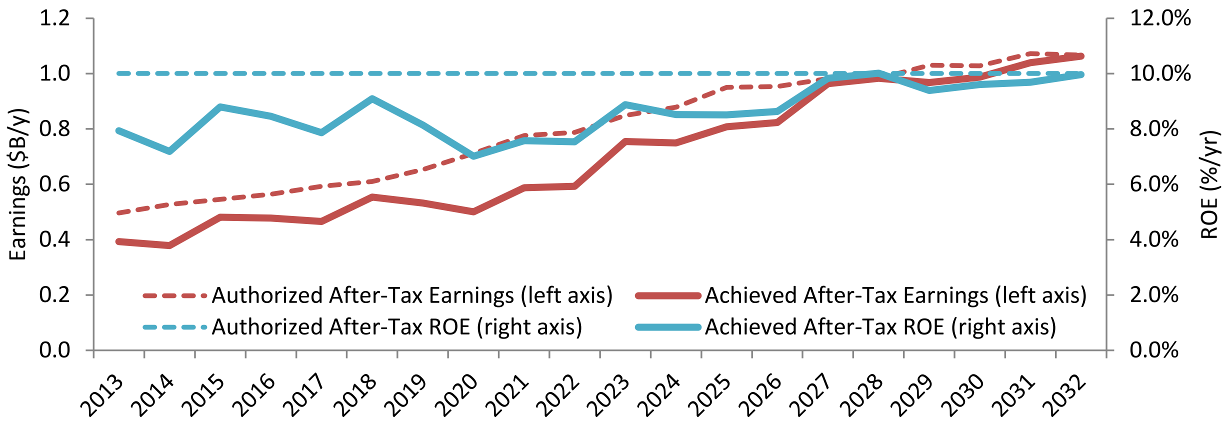



**Figure 4. SW Utility Achieved and Authorized Earnings and ROE**

### 3.2 Northeastern wires-only utility and default service provider

The prototypical Northeastern Utility ("NE Utility") is a "wires-only" utility in a restructured northeastern state, with substantially different asset ownership than the vertically integrated structure of the SW Utility. Specifically, the NE Utility owns and operates the distribution network, but does not own transmission or generation assets. The utility serves as the default supplier of generation service for customers within its distribution service territory, and all energy and generation capacity required to serve those customers is procured through market purchases.

We developed long-range (i.e., 2013-2032) cost and load forecasts for the prototypical NE Utility by starting with data provided by the Massachusetts Department of Public Utilities (DPU) for a 2009 project (Cappers et al., 2010), which are generally consistent with the Massachusetts Electric Company ("Mass Electric"). We then updated those data based on publicly available information from a 2009 rate case and FERC Form 1 data, and updated assumptions about current and future energy, capacity, and renewables prices using the 2013 Synapse Avoided Energy Supply Costs in New England (AESC) report. Thus, although data from Mass Electric were used to seed the initial utility characterization, ***the prototypical NE Utility used in this analysis is not intended to represent Mass Electric, specifically***.

The NE Utility's costs and revenues are driven by five key assumptions: the load forecast, growth in O&M costs, power supply costs, rate design, and compliance with an RPS.[15] First, the NE Utility has 2013 retail sales of 21,957 GWh and 5,655 MW of peak demand, which grow at 1.4% and 1.5% per year, respectively (exclusive the effect of PV). The retail sales and peak demand growth rates are lower than our assumptions for the SW Utility and are consistent with expected load growth in the northeast. The ISO-New England (ISO-NE) 2013 Regional System Plan forecasts 1.1% per year retail sales growth and 1.4% per year peak demand growth for the entire region through 2022.[16]

[15] Appendix A describes all input assumptions for the NE Utility
[16] ISO-NE 2013 Regional System Plan (p. 7). http://www.iso-ne.org/trans/rsp/index.html

Second, the NE Utility experiences O&M cost growth (including O&M costs from incremental generating plants) of 3.4% per year for the entire analysis period. This is higher than the SW Utility, which is assumed to experience O&M cost growth of 2.6% per year.

Third, we assume power supply costs (i.e., energy and capacity) and transmission access charges[17] are a pass-through to customers recovered through a "tracker" or bill "rider". The achieved revenues for these costs are therefore determined based on actual commodity costs each year, rather than on rates set during GRC. These power supply and transmission access costs are the largest component of the total NE Utility revenue requirement, ranging from 50% to 60% of total costs each year of the 20-year analysis period.

Fourth, similar to the SW Utility, we assume a revenue requirement allocation (i.e., rate design) for the NE Utility that is based on typical Mass Electric customer bills. We used the company's most recent cost-of-service and rate design studies to determine the percentages of total non-fuel revenues collected among energy, demand, and customer charges. Total non-fuel revenues are collected among billing determinants as follows: 23% from customer charges, 21% from demand charges, and 56% from energy charges, which are constant through the analysis period. All purchased power and transmission access charges are entirely collected from energy charges.

Fifth, the NE Utility complies with a mandated RPS obligation that starts at 8% of annual retail sales in 2013 and increases by 1% of annual retail sales each year of the analysis period (reaching 27% by 2032). The RPS obligation is met through the purchase of renewable energy credits (RECs), at an average price of $35/MWh. The RPS is also assumed to include a solar carve-out, wherein a small portion of the RPS is met with solar RECs, assumed for our purposes to consist of utility-scale solar. This utility-scale solar (which rises to 1.7% of retail sales by 2022) is additional to the customer-sited PV, though it is a substantially lower penetration of utility-scale solar than in the SW Utility.

The NE Utility revenue requirement is $2.2B in 2013 and grows at 5.7% per year through 2032. Default service customer supply costs and transmission access charges grow at 6.6% per year and are the largest component of the NE Utility revenue requirement. The revenue requirement does not include the power supply costs and transmission access costs associated with competitive suppliers who purchase power for non-default service customers (i.e., competitive supply customers), although those costs are included for reference in Figure 5.

[17] While we assume the NE Utility does not own and earn a return on transmission assets, there are instances where a "wires-only" utility may be part of a holding company that also owns and operates a separate transmission company (Transco). The Transco may be making investments in transmission assets which create earnings for the holding company. While customer-sited PV may impact the earnings of Transcos, they are outside the scope of the present analysis, which focuses only on the financial impacts to the regulated distribution utility.

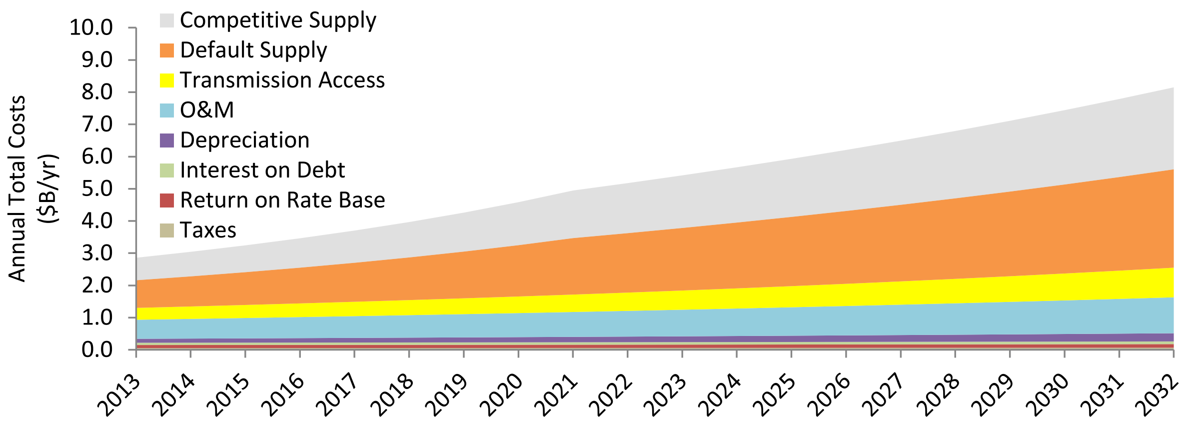



**Figure 5. NE Utility Revenue Requirement**

Similar to the SW Utility, the NE Utility collects revenues based on allocation among billing determinants (i.e., retail sales, peak demand, and number of customers), which ties growth in utility collected revenues to growth in billing determinants between rate cases. Non-fuel collected revenues are based on rates per billing determinant set during the NE Utility general rate case (GRC) and take effect one-year after the filing of a GRC. Figure 6 shows that non-fuel costs are *higher* than non-fuel collected revenues in all years of the analysis period, which occurs because those costs grow at a faster rate between rate cases than growth in billing determinants. NE Utility all-in average retail rates (that include fuel and non-fuel collected revenues) increase from 13 cents/kWh in 2013 to 28 cents/kWh in 2032 (4.2% per year).

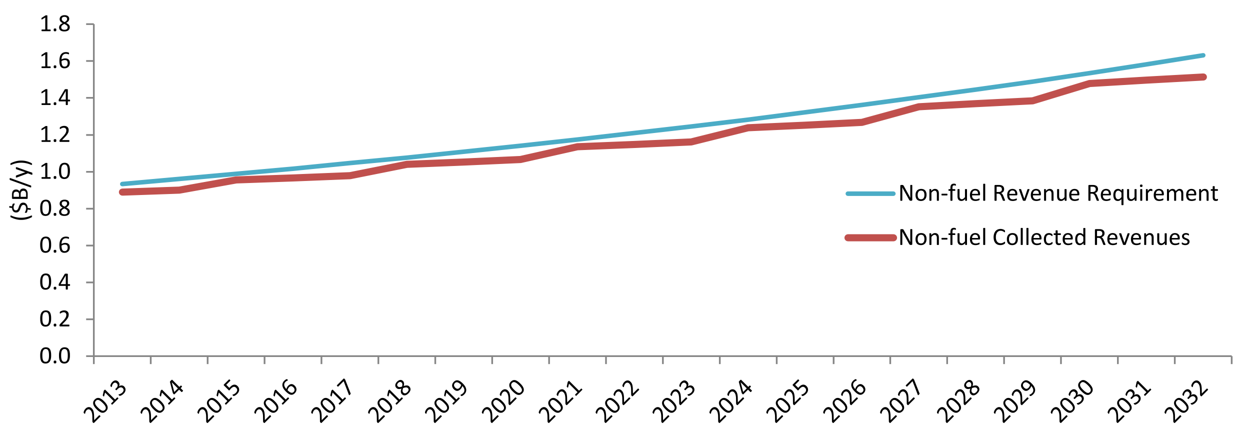



**Figure 6. NE Utility Non-Fuel Collected Revenues and Non-Fuel Revenue Requirement**

The NE Utility's achieved after-tax ROE and achieved after-tax earnings are below the authorized levels over the entirety of the analysis period (see Figure 7).[18] Specifically, the utility achieves an average after-tax ROE of 6.9% from 2013-2022 and 6.5% from 2013-2032, compared to its authorized ROE of 10.35%. Total achieved after-tax earnings are $461M over

[18] The "sawtooth" pattern of the annual achieved ROE and achieved earnings reflect the steady decline in both metrics during periods between each rate case, and then increases in both metrics in the year following each rate case, as rates are re-set to bring revenues and costs into closer accord.

the 2013-2022 period and are $681M over the full 20-year period from 2013-2032. Achieved earnings are less than authorized earnings for reasons similar to those discussed with respect to the SW Utility, though the gap is greater in the NE utility because of the greater underlying difference between the growth rates of non-fuel costs and non-fuel revenues. It is also worth noting that the NE Utility's earnings are 10-14% of the SW Utility's earnings, because the NE Utility does not build, own, and earn a return on generating assets under cost-of-service regulation.

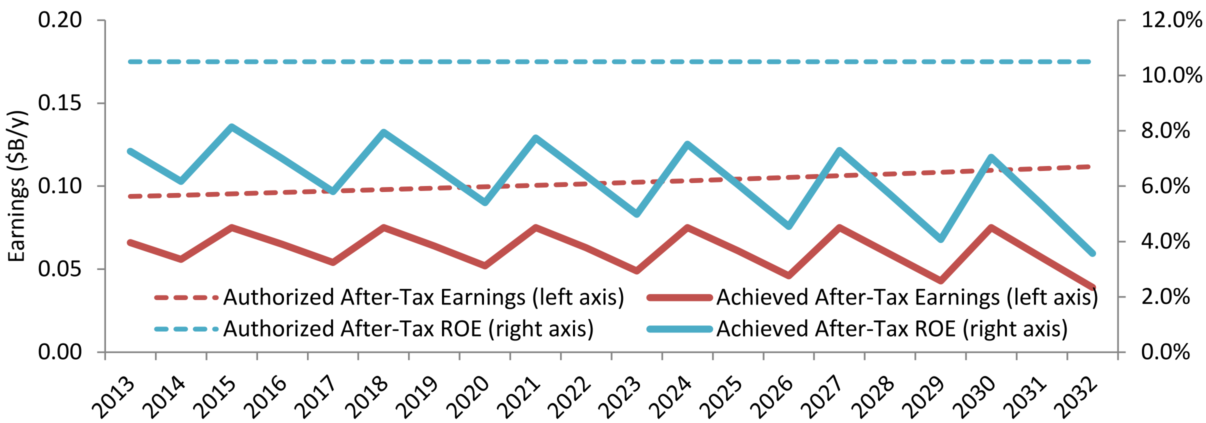



**Figure 7. NE Utility Achieved and Authorized Earnings and ROE**

# 4. Base Case Results: How does customer-sited PV impact utility shareholders and ratepayers?

This section characterizes the financial impacts of customer-sited PV on the two prototypical utilities, under our base case utility characterizations and at varying PV penetration levels. We begin by describing impacts of PV on the utilities' retail sales and peak demand, utility costs (i.e., revenue requirements), and utility collected revenues. We then describe utility shareholder impacts in terms of changes to achieved after-tax average ROE and achieved after-tax earnings, and describe ratepayer impacts in terms of changes to customer all-in average retail rates. This approach to modeling the financial impacts of PV, and the metrics used to measure those impacts, are largely analogous to those used in previous studies of the shareholder and ratepayer impacts of customer EE programs (Cappers et al., 2009a, Cappers et al., 2009b, Cappers et al., 2010 and Satchwell et al., 2011).

**Importantly, the base case results should not be interpreted as representative of an "expected-case" scenario or as indicative of what any particular utility might experience.** Rather, the purpose of the base case analysis is, first to provide a vehicle for explaining how changes in our modeled metrics (average retail rates and utility shareholder ROE and earnings) derive from the underlying impacts of customer-sited PV on utility revenues and costs, and how those impacts are related to the timing of GRCs. Second, the base case results serve as the reference point for the sensitivity analysis in Section 5 and the analysis of mitigation approaches in Section 6. Given these objectives, we primarily focus here on the *direction* of change in each metric; we largely defer discussion about the *size* of the impacts until the sensitivity analysis in Section 5, where the range in possible magnitude of the impacts can be appropriately framed within the context of utilities' regulatory and operating environments (and potential variations therein).

## 4.1 Customer-Sited PV Penetration Assumptions

Customer-sited PV adoption is a model input assumption. We specify annual capacity additions of customer-sited PV, such that the proportion of retail sales met by customer-sited PV grows linearly over the first 10 years of the analysis period (2013-2022). We examine four different PV penetration trajectories, which grow from 0% in 2012 to reach terminal penetration levels in 2022 equal to 2.5%, 5%, 7.5%, and 10% of customer sales.[19] Although the analysis period extends over 20 years, customer-sited PV is added only during the first 10 years in order to capture "end effects" (i.e., impacts on utility costs and revenues that occur in years beyond those when PV is added).

The assumed PV deployment rates, particularly in the case of 10% penetration, are aggressive compared to both current penetration levels and even to projected penetration levels over the next decade, at both state and national levels. As of year-end 2013, electricity generation from customer-sited PV in the United States was equivalent to 0.2% of total U.S. retail electricity

[19] In addition to customer-sited PV, some amount of utility-scale PV is also assumed for both of the two prototypical utilities, as described in Section 3.

sales, and was as high as 4% of retail sales in Hawaii and 1-2% in the next two largest state solar markets (New Jersey and California). Current penetration rates for individual utilities, or for residential customer classes, may be higher. In Hawaii, penetration of customer-sited PV has reached 5.1% to 6.0% of retail sales among the three investor-owned utilities, and 10-15% for residential customer classes. Outside of Hawaii, the highest utility-level penetration rates are in California, where total customer-sited PV generation has reached 2.3% of total retail sales (and 3.0% of residential retail sales) in Pacific Gas & Electric's service territory.

Projecting future growth in customer-sited PV is a highly speculative exercise. If one were to simply extrapolate average growth rates from the past five years, customer-sited PV penetration in 10 years would reach 0.8% of total U.S. retail electricity sales, and 3-5% in the largest state markets (excluding Hawaii, which would reach 20%). Projections from EIA's most recent Annual Energy Outlook anticipate lower growth in customer-sited PV, with total generation from end-use PV reaching roughly 0.6% of total U.S. retail electricity sales over 10 years (EIA 2014), while forecasts from GTM and SEIA project slightly faster growth, with residential and commercial PV penetration reaching almost 0.8% of U.S. retail sales in just four years, by 2017 (GTM/SEIA 2014). As a final point of comparison, customer adoption modeling conducted for the SunShot Vision study, which considered a 75% reduction in PV costs from 2010 to 2020, projected 3% penetration of customer-sited PV in the Northeast (or 1-8% among individual states in the region) and 7% penetration in the Southwest (with penetration levels of 3-11% among individual states) by 2030 (DOE 2012).

### 4.2 Impacts on Retail Sales and Peak Demand

The utilities' retail sales and peak demand with and without customer-sited PV are shown in Figure 8 for the SW and NE utilities, under the 10% PV penetration scenario. Throughout this analysis, we assume that all customer-sited PV is net-metered, with no binding limits on the amount of excess generation that can be carried over from billing period to the next. PV generation therefore reduces sales on a one-for-one basis; the difference between retail sales with and without PV thus grows proportionally with the linear growth in PV penetration over the first 10 years and then remains constant thereafter. PV generation does not, however, reduce peak demand on a one-for-one basis, but rather each kW of PV capacity reduces customer peak demand by less than one kW, because the timing of maximum PV output does not coincide perfectly with customer peak demand. Moreover, the marginal impact of PV on peak demand declines as PV penetration levels grow over the first 10 years, as the timing of the net system peak progressively shifts to early evening periods with lower solar power generation. For simplicity, we assume that the reduction in aggregate customer billing demand from PV is equivalent to the reduction in utility-wide peak demand.[20] Further details of how we model the reduction in peak demand with deployment of PV are described in Appendix B.

[20] In practice, customer peak demand used for billing of demand charges is often not the same as the customer's coincident peak demand. However, given the complexity and variety of demand charge structures, and limitations of the model, we make the simplifying assumption that the change in aggregate billing demand is equal to the change in utility peak demand.

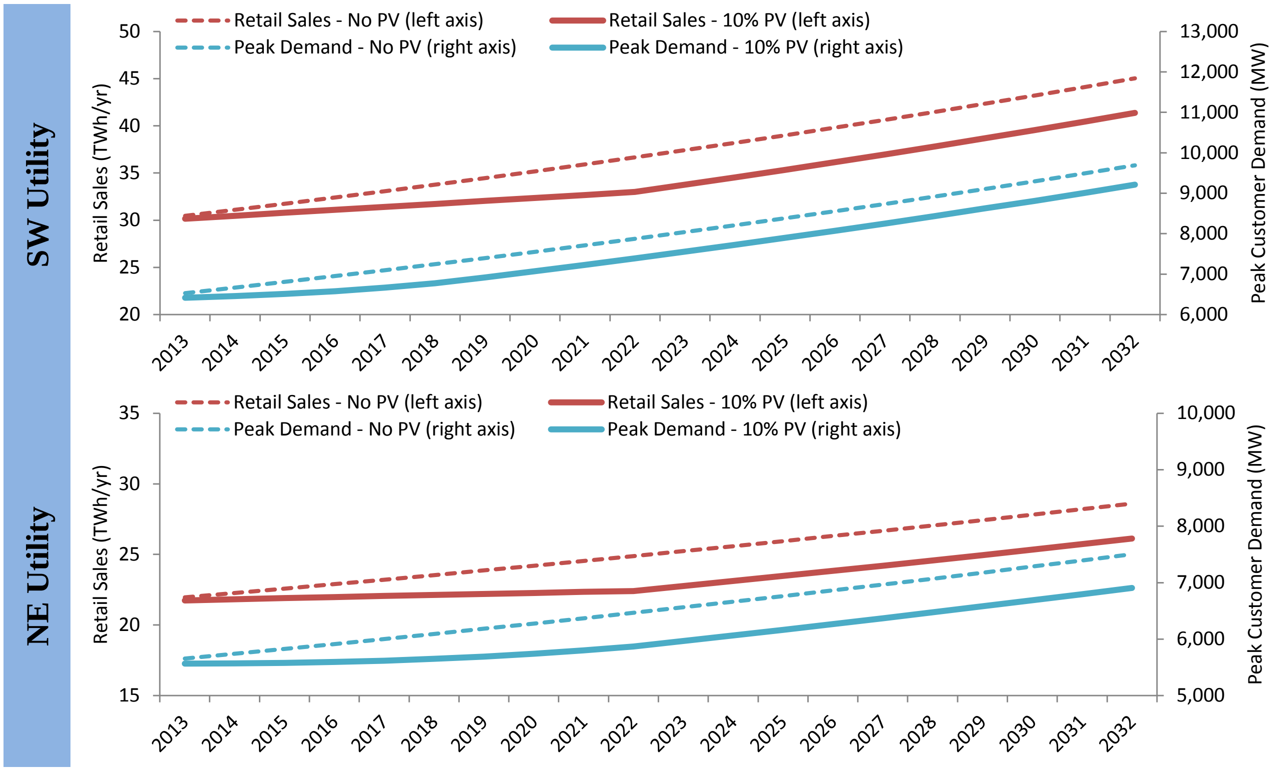



Figure 8. Utility Retail Sales and Peak Demand with and without PV Assuming 10% PV Penetration in 2022

## 4.3 Impacts on Utility Costs

The impact of customer-sited PV on utility costs (i.e., the revenue requirement) is a function of the changes in retail sales and peak demand described above, as well as a variety of other assumptions. The manner in which those cost impacts are modeled differs somewhat between the two prototypical utilities. We provide a high level overview of how these cost impacts are modeled for the base case analysis and describe the resulting change in total utility costs here, with additional details provided in Appendix B. Alternate assumptions related to these cost impacts are explored through the sensitivity analyses in Section 5, which includes both "high value of PV" and "low value of PV" scenarios.

The utility financial model calculates the utility revenue requirement as the sum of the six cost categories described previously (i.e., fuel and purchased power, O&M, depreciation, interest on debt, return on ratebase, and taxes). For the purpose of explaining how customer-sited PV affects revenue requirements, however, it is useful to describe the impacts in terms of the underlying changes to generation-related costs and transmission and distribution (T&D) costs.

### 4.3.1 Modeling the Impacts on Generation Costs

For the vertically integrated SW Utility, reductions in generation costs due to customer-sited PV are associated with reductions in fuel costs and purchased power costs, as well as the deferral of generation investments (including O&M costs associated with those deferred generation investments).[21] Fuel and purchased power costs, and the change in those costs due to customer-sited PV, are based on simplified dispatch logic. Deferrals of peaking plants (e.g., combustion turbines) are based on the number of years it takes before the peak demand with PV reaches the level of peak demand without PV for the year when the decision to build the generator would otherwise occur (see Figure 9). Similarly, deferrals of plants built primarily to supply energy (e.g., combined cycle gas turbines) are based on the number of years it takes before the sales with PV reaches the level of sales without PV for the year when the decision to build the generator would otherwise occur. Deferral of generation investment leads to reductions in depreciation costs, interest expenses (i.e., cost of debt to finance the generating plant), utility shareholder returns on the capital investment, and taxes (assessed on the shareholder returns). We refer to utility earnings foregone as a result of deferral of capital investments as the "lost earnings opportunity" effects of PV.

In addition to deferral of utility-owned generation, customer-sited PV also reduces market purchases of energy and capacity to meet residual load needs, as well as PPAs with renewable generators required to meet the utility's RPS obligation.[22] Those cost reductions are included within the model as purchased power costs. The reduction in RPS compliance costs occurs because customer-sited PV is reducing retail sales, not because it is being counted directly towards RPS obligations (though that possibility is considered within the mitigation measures evaluated within Section 6).

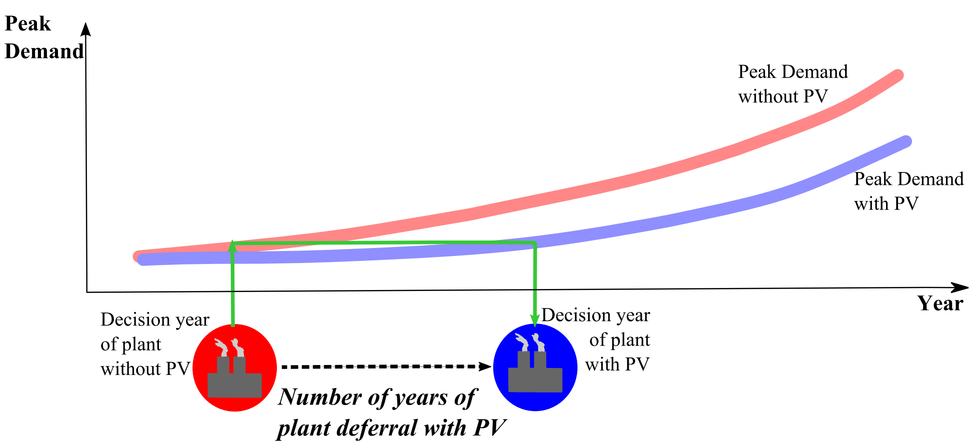



**Figure 9. Illustration of the Peaker Generation Investment Logic with PV in the Model**

In contrast to the SW Utility, the NE Utility does not own generating assets and is assumed to purchase all of its energy and capacity needs through wholesale contracts. Thus, generation-related costs reduced by the addition of PV consist entirely of purchased power costs for energy

[21] We do not include any explicit "integration costs" associated with short-term variability and uncertainty of PV, though we do account for a decline in its capacity credit and energy value with increased penetration. The costs of short-term variability and uncertainty have been reported to be less than 0.5 cents/kWh of renewable generation for APS (B&V 2012, Mills et al. 2013) and are therefore of secondary importance. Accounting for these integration costs would thus lead to a slight increase in estimated rate impacts of customer-sited PV, but no change to earnings and ROE, given that they consist of fuel costs that are passed through directly to customers in the FAC.
[22] A portion of the SW Utility's RPS obligation is assumed to be met with utility-owned renewable generation facilities; however, renewable PPAs are assumed to be the marginal RPS resource.

and capacity. For RPS compliance, the NE Utility purchases fewer renewable energy credits to meet the RPS with PV than without PV, based on the retail sales reduction.

Note also that the impacts of PV on generation-related costs are based on reductions in sales and peak demand at the bulk power system level. Since customer-sited PV is located at the customer premises, reductions in sales and peak demand at the bulk power system level are greater than at the customer level due to avoided T&D losses. For the SW Utility, T&D losses are assumed to be 7% and 15% for retail sales and peak demand, respectively, and for the NE Utility, are assumed to be 4.1% and 8%, respectively.[23]

### 4.3.2 Modeling the Impacts on T&D Costs

Here we describe the base-case assumptions related to the impacts of customer-sited PV on T&D costs, but note in advance that this is a topic of substantial uncertainty and disagreement, and for that reason it is one key element explored within the sensitivity analysis in Section 5.

For the SW Utility, T&D capital costs are modeled as non-generation capital investments, and a fraction of those investments (20%) is assumed to be proportional to growth in peak demand on the T&D system. In the base-case, we assume that PV reduces peak demand at the T&D level by 20% of the reduction in peak demand at the bulk power level. The corresponding reductions in T&D peak demand growth thereby reduce growth-related non-generation capital investments, resulting in reductions in depreciation expenses, shareholder returns on those investments, interest expenses, and taxes. For the base-case analysis, we assume therefore that customer-sited PV leads to a net reduction in distribution system capital expenses. Within the sensitivity analyses, however, we consider a case in which distribution costs *increase* as a result of PV.

For the NE Utility, the model treats transmission costs differently than distribution costs. The NE Utility does not own transmission facilities, but rather purchases transmission service from a regional transmission operator (ISO-NE) and passes those costs through to customers via a transmission access charge. Transmission charges are included in the model as a portion of purchased power costs and are calculated based on the average monthly peak demand of the utility. We assume that customer-sited PV reduces average monthly peak demand by 20% of the reduction in annual peak demand, leading to corresponding reductions in the portion of purchased power costs associated with transmission access charges.[24] In contrast, the NE Utility does own and operate distribution facilities, and distribution costs are therefore modeled as a capital investment, some portion of which is growth related (33%). Similar to the approach used to model T&D cost impacts for the SW Utility, the addition of PV reduces growth-related distribution system capital expenses for the NE Utility, leading to corresponding reductions in returns on ratebase, depreciation expenses, interest, and taxes.

[23] Losses for peak demand are greater than average losses due to the non-linear relationship between load levels and losses (Lazar and Baldwin 2011).
[24] The 20% assumption is based on an analysis of hourly load and PV generation in the Northeast over the span of one year.

### 4.3.3 Total Reduction in Utility Costs

Given the modeled relationships described above, the total reductions in utility costs (i.e., revenue requirements) resulting from customer-sited PV in the base-case analysis are shown in Figure 10, with further details on the underlying source of cost reductions listed in Table 2. For the SW Utility, customer-sited PV reduces total utility costs over the 20-year analysis period by $0.7 B (1.3% of total utility costs) under 2.5% PV penetration and by $2.2B (4.0% of total utility costs) under 10% PV penetration, compared to a case without any customer-sited PV. Similarly, for the NE Utility, the cost reductions range from $0.8B (1.5% of total utility costs) at 2.5% PV penetration to $2.3B (4.5% of total utility costs) at 10% PV penetration. As shown in the figure, the composition of the cost reductions differs significantly between the two utilities due to differences in the two utilities' physical and operating characteristics, with important implications for the shareholder and ratepayer impacts, as discussed below.

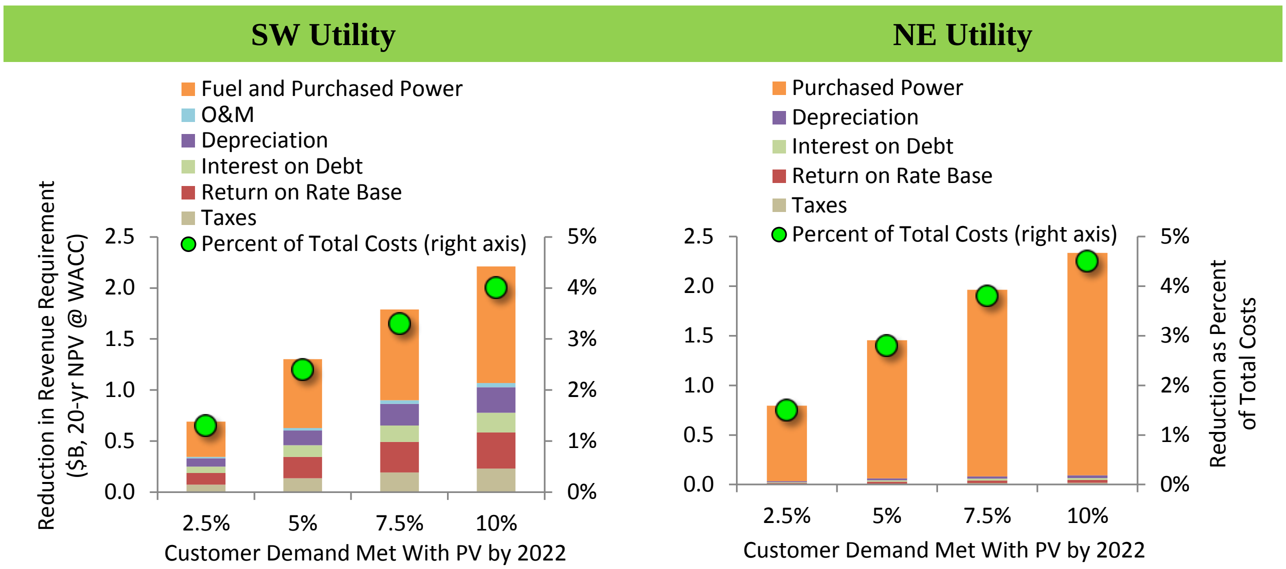



**Figure 10. Reduction in Utility Revenue Requirements with Customer-Sited PV**

**Table 2. Sources of Modeled Reductions in Utility Costs from Customer-Sited PV**

| Cost Category | SW Utility | NE Utility |
|---|---|---|
| Fuel & Purchased Power | • Reduced fuel costs for utility-owned generation<br>• Reduced energy and capacity market purchases and PPAs<br>• Reduced RPS procurement costs<br>• Reduced losses | • Reduced energy and capacity market purchases<br>• Reduced transmission access charges<br>• Reduced RPS procurement costs<br>• Reduced losses |
| O&M | • Reduced O&M due to deferred utility-owned generation | • None |
| Depreciation<br>Interest on Debt<br>Return on Ratebase | • Deferred utility-owned generation<br>• Reduced T&D CapEx | • Reduced distribution system CapEx |
| Taxes | • Deferred utility-owned generation<br>• Reduced T&D CapEx<br>• Reduced collected revenues | • Reduced distribution system CapEx<br>• Reduced collected revenues |

### 4.3.4 Implied Avoided Cost of PV

Discussions about the costs and benefits of customer-sited PV often rely on estimates or assumptions about the "avoided costs" from PV (often used interchangeably with the term "value of PV"), which is simply the reduction in costs resulting from customer-sited PV, per unit of customer-sited PV generation. Such avoided costs may be construed broadly at the societal level, or more narrowly by considering only reductions in costs for the utility, which would typically include the impact of PV on different utility cost components (e.g., energy, generation capacity, T&D capacity, losses).

For the purpose of comparison between our results and other estimates of avoided costs from customer-sited PV, we map the cost reductions from customer-sited PV estimated within our analysis to the categories often used in avoided cost calculations (see Figure 11). The simple calculations used to parse avoided costs into these categories become much more difficult when accounting for the deferral of "lumpy" investments like new generation plants. For simplicity, we conduct these approximations for 2018, the latest year before PV begins to displace lumpy investments for the SW Utility. To be clear, these avoided cost values should be considered simply for benchmarking purposes; the financial model used for this analysis does not, itself, distinguish among the specific set of cost categories in Figure 11, and more generally, the model does not contain the level of granularity in modeling the physical impacts of customer-sited PV on utility systems to be considered a refined, independent estimate of avoided costs. Additional details describing the methods used to approximate the breakdown of the value of PV are provided in Appendix B.

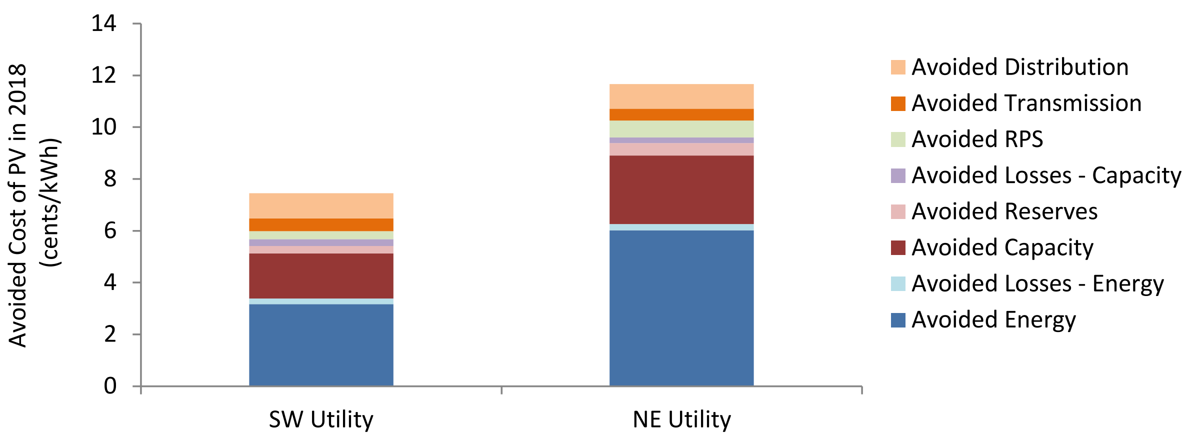



**Figure 11. Estimated Avoided Costs in 2018 for the SW and NE Utilities (6% PV Penetration)**

For the specific year shown, the total avoided cost value of PV is equal to 7.5 cents/kWh for the SW utility and 11.7 cents/kWh for the NE utility. For both utilities, avoided energy costs are the largest component, followed by avoided capacity costs and avoided distribution costs. These sources of avoided costs are augmented by: avoided transmission costs; reductions in the cost of planning reserves, which are based on a percentage of peak demand; avoided costs related to losses, which impact both the amount of energy purchased and the amount of generation capacity needed to meet peak demand and reserves; and avoided RPS procurement costs, resulting from the reduction in retail sales and corresponding reduction in RPS obligations (which are set as a percentage of sales).

Avoided costs are higher for the NE Utility than the SW Utility, primarily due to differences in the value of avoided energy costs and the value of avoided capacity costs. Avoided energy costs are higher for the NE Utility due to higher expected energy prices in the Northeast (primarily from natural gas) relative to the fuel costs for the SW Utility (a mix of gas and coal). The capacity value is higher for the NE Utility due to two factors: (1) customer-sited PV contributes slightly more to meeting peak demand due to the lower overall PV penetration from both utility-scale and distributed PV, compared to the SW utility; and (2) PV in the Northeast generates less energy than in the Southwest, leading to a higher capacity value in $/kWh terms in the Northeast.

As shown previously in Figure 10, reductions in utility costs from customer-sited PV do not scale in proportion to the PV penetration level, but rather exhibit diminishing returns. To more clearly illustrate this point, we plot the avoided cost per unit of PV energy, averaged over the full 20-year analysis period, for each PV penetration level considered (see Figure 12). For both the SW and NE utilities, the avoided cost of PV (per unit of PV energy) declines with increasing penetration levels. Specifically, the average value of PV for the SW Utility declines from 10.3 cents/kWh under the 2.5% penetration scenario to 8.5 cents/kWh under the 10% penetration scenario; for the NE Utility, it declines from 15.8 cents/kWh to 12.3 cents/kWh. The decline in avoided cost with increasing penetration is due to a decline in the contribution of PV to meeting peak demand (peak demand shifts into the early evening with higher PV penetration) and a decline in the cost of energy displaced by PV (PV begins to displace more efficient plants or plants with lower cost fuels). For reference, we also include the average cost of energy per unit of sales in the scenario without PV. This comparison shows that the reduction in utility costs from customer-sited PV is less than the average cost of generating and delivering electricity for both the SW and NE utility in this base-case analysis, and that this gap grows with PV penetration level.

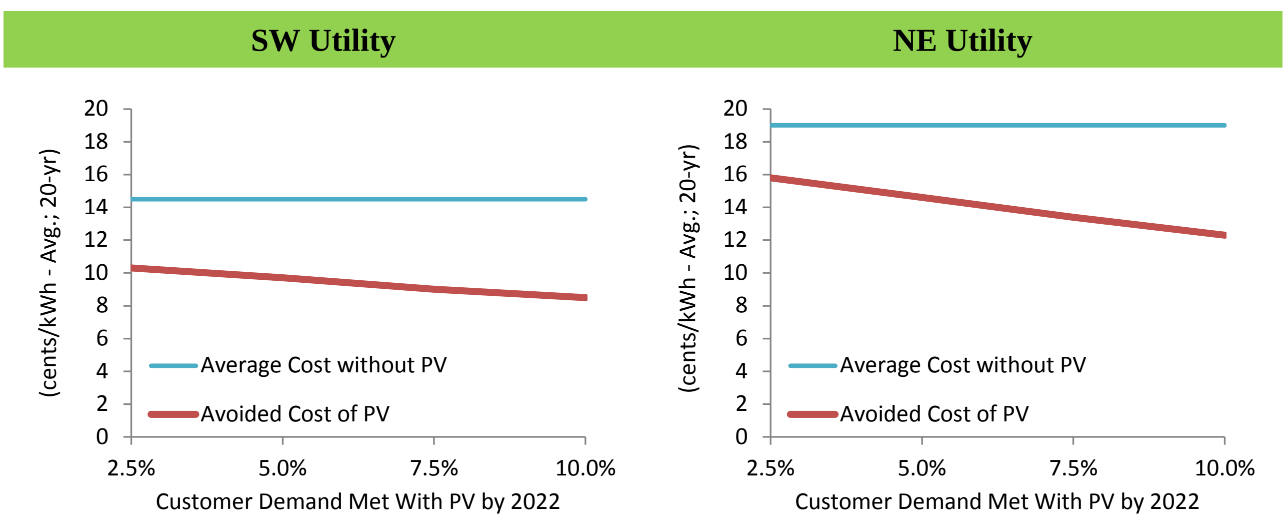



**Figure 12. Avoided Cost of PV at Varying Penetration Levels and Average Cost without PV**

## 4.4 Impacts of PV on Collected Revenues

All customer-sited PV within our analysis is net-metered under the same retail rates applicable to other customers, and without any PV-specific charges (e.g., additional fixed charges or standby charges for PV customers). The impacts of customer-sited PV on total utility collected revenues are thus a function of changes in billing determinants and in the rates for each billing determinant caused by PV. The change in billing determinants is simply the reduction in retail sales and peak demand, as described in Section 4.2, while the change in rates reflects the net effect of customer-sited PV on test-year costs (i.e., revenue requirements) and billing determinants used within each GRC.

Customer-sited PV reduces revenues related to both fuel costs and non-fuel costs (see Text Box 2 for explanation of this distinction). For the purpose of understanding how these revenue impacts ultimately translate to impacts on shareholder ROE and earnings, it is most useful, however, to focus specifically on impacts to non-fuel revenues. To illustrate, Figure 13 compares reductions in non-fuel revenues under each PV penetration scenario to the corresponding reductions in non-fuel costs. In the case of the SW Utility, the impacts on revenues and costs are roughly equivalent under the 2.5% PV penetration scenario. At higher PV penetration levels, however, reductions in non-fuel revenues exceed reductions in non-fuel costs. This occurs, in part, because of the declining marginal value of PV as penetration levels increase, as discussed in Sections 4.3.4. For the NE Utility, the divergence between reductions in non-fuel revenues and non-fuel costs is substantially wider. This is because of the greater assumed growth rate in non-fuel O&M costs for the NE Utility, as indicated previously in Table 1, and the assumption that those costs are not reduced as a result of customer-sited PV.

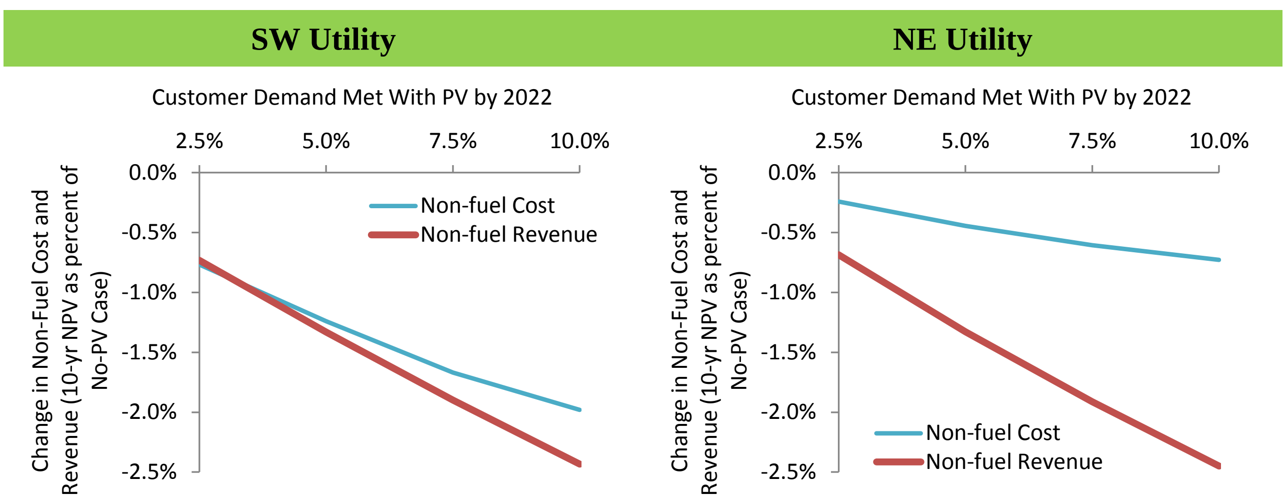



**Figure 13. Reduction in Utility Non-Fuel Revenue Requirements (Costs) and Collected Revenues**

## 4.5 Impacts of PV on ROE

Under our base-case assumptions, customer-sited PV leads to a reduction in the prototypical utilities' achieved ROE. This occurs because, as discussed in the preceding section, PV reduces collected non-fuel revenues by a greater amount than non-fuel costs (i.e., "revenue erosion effect"), which in turn reduces earnings and thereby reduces ROE. Importantly, even without PV, the utilities' achieved ROE is below their authorized ROE, because the utilities' costs grow faster than their revenues, as described earlier in Section 3. The addition of customer-sited PV exacerbates those underlying conditions, leading to further erosion of ROE. As discussed later in Section 6, there are several mechanisms (e.g., revenue decoupling) designed to reduce and/or remove the negative impact that reductions in sales growth, such as those caused by customer-sited PV, may have on shareholder ROE.

For the SW Utility, achieved average ROE over the first 10 years of the analysis period is 2 basis points lower at 2.5% PV penetration and 23 basis points lower at 10% PV penetration than it is without PV (see Figure 14). These basis point reductions represent, in relative terms, a 0.3% to 2.9% reduction in average utility shareholder returns over the first 10 years. For the NE Utility, the ROE impacts are somewhat more substantial, with a 32 basis point (4.7%) reduction at 2.5% PV penetration and a 125 basis point (18.1%) reduction at 10% PV penetration, relative to the no-PV case.

The larger ROE impacts for the NE Utility are due to two underlying factors. The first factor can be traced back to the greater assumed growth rate in non-fuel O&M costs for the NE Utility, which in turn leads to a greater divergence between the impact of customer-sited PV on non-fuel revenues and non-fuel costs (i.e., the dynamic discussed in relation to Figure 13). The other key factor underlying the difference in ROE impacts between the two utilities is the proportionally smaller ratebase (compared to retail sales) of the wires-only NE Utility, as that utility does not own generation assets. A given reduction in earnings will therefore have a proportionately larger ROE impact for the NE Utility, as ROE is equal to earnings divided by the ratebase equity.

The ROE impacts over the full 20-year analysis period are, in the case of the NE Utility, slightly smaller than the average impacts over just the initial 10 years. This is to be expected, as ROE impacts from customer-sited PV are driven chiefly by its effects on the relative growth of non-fuel costs and non-fuel revenues, and that impact occurs primarily during the initial 10 years when PV penetration is growing. In the latter 10 years, the relative growth of fuel costs to non-fuel revenues reverts largely back to the relationship that would have existed in the absence of any customer-sited PV. In contrast, for the SW Utility, the 20-year ROE impacts are slightly larger, but more irregular, than the average impacts over the initial 10 years. This phenomenon is an artifact of the irregular timing of large, lumpy capital expenditures – and the GRCs triggered by those expenditures – over the course of the 20-year analysis period. Notwithstanding those complexities, largely confined to the SW Utility in our analysis, the impacts of PV on achieved annual ROE are, in general, concentrated primarily within the initial 10 years of the analysis period and are more readily interpretable for that timeframe. Thus, throughout the remainder of this report, our discussions of ROE impacts focus solely on the first 10 years of the analysis period (though we continue to discuss earnings and rate impacts over the full 20-year period).

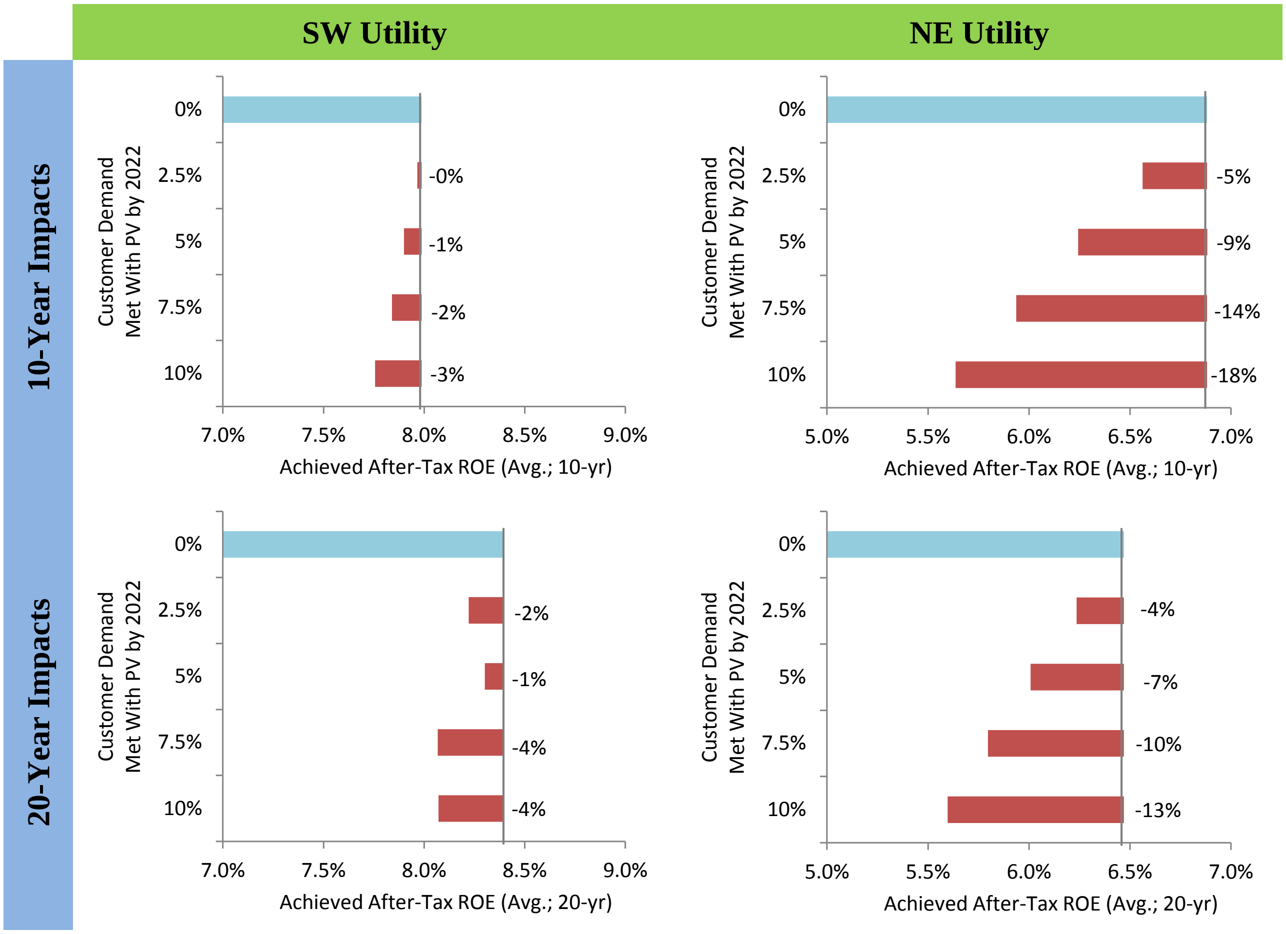



**Figure 14. Reduction in Achieved After-Tax ROE**

## 4.6 Impacts of PV on Earnings

Customer-sited PV may reduce shareholder earnings through two separate mechanisms. First, it can do so if it reduces utility revenues by a greater amount than it does costs (i.e., the "revenue erosion effect" that also drives the impacts on ROE). Second and separately, customer-sited PV may also diminish future earnings opportunities, by reducing or deferring capital investments that would otherwise contribute to the utility's ratebase (which we term the "lost earnings opportunity effect").[25] As will be explored further in Section 6, a variety of potential mechanisms exist for mitigating earnings erosion, including a number mechanisms that specifically seek to provide the utility with additional earnings opportunities.

[25] An increase in earnings is valuable to shareholders only if the return on future investments is greater than the cost of equity (see Koller et al., 2010), which presently would be the case for most utilities. The prototypical NE Utility in our analysis, however, may present a case in which the ROE of future investments may not cover the cost of equity, in which case the deferral of future capital investments would benefit shareholders. A cost of equity test is beyond the scope of this study. See Kihm et al. (2014) for the motivations of a utility to invest in capital in a future with increased EE and PV when returns on future investments are greater or less than the cost of equity.

Figure 15 shows the base-case earnings impacts for both utilities, across the range of PV penetration levels considered and over multiple timeframes. As to be expected, earnings impacts increase with PV penetration. For the SW Utility, achieved earnings over the first 10 years are $48M (1.4%) lower at 2.5% PV penetration, compared to the case with no PV, growing to $193M (5.7%) lower at 10% PV penetration. For the NE Utility, earnings over the first 10 years are reduced by $25M (5.5%) at 2.5% PV penetration and by $93M (20.2%) at 10% PV penetration. The earnings impacts are greater, on a percentage basis, than the impacts to ROE, given the additional effect of lost earnings opportunities.[26] This is especially true for the SW Utility (e.g., 2.9% reduction in ROE vs. 5.7% reduction in earnings over the first 10 years), where the potential for deferral of utility-owned generation facilities leads to relatively large lost earnings opportunities.

Additional earnings erosion occurs over the latter half of the 20-year analysis period, as deferral of capital investments continues beyond the initial 10-year period when customer-sited PV is installed. These "end-effects" are particularly pronounced in the case of the SW Utility, where PV results in deferral of generation plants in the latter 10 years (see Figure 16). Thus, at 10% PV penetration, achieved earnings over the full 20-year analysis period are $528M (8.1%) lower than with no PV, compared to the $193M (5.7%) reduction over the first 10 years, as noted above. For the NE Utility as well, additional earnings erosion occurs in years 11-20, though to a much more limited extent, given that the utility does not own generation and thus the only deferred capital expenditures are for distribution system investments. At 10% PV penetration, for example, achieved earnings by the NE Utility are reduced by 20.2% in the first ten-years, but only 15.4% over the full 20 years of the analysis period.

As with the impact of PV on achieved ROE, we see that the impact of PV on earnings, in percentage terms, is larger for the NE Utility than for the SW Utility, though the difference between the two utilities is not as large. As noted, the impact of customer-sited PV on achieved earnings is the combined result of the "revenue-erosion effect" (associated with the disproportionately larger reduction in collected revenues than in utility costs) and the "lost earnings opportunity" effect (associated with the deferral of capital expenditures). The former effect is larger for the NE Utility than for the SW Utility; as discussed previously, this is due to the larger assumed growth in non-fuel O&M costs for the NE Utility and the assumption that customer-sited PV does not reduce those costs. In contrast, the latter "lost earnings opportunity" effect is larger for the SW Utility, given that the SW Utility owns generation plants that are deferred by customer-sited PV. On net, though, the difference between the two utilities is greater with respect to the revenue erosion effect, and thus the earnings impacts are slightly greater for the NE Utility.

[26] The larger percentage impacts on earnings can also be explained mathematically: ROE equals earnings divided by the equity portion of the utility's ratebase. Customer-sited PV reduces earnings (the numerator) as well as the ratebase (the denominator), and thus the percentage reduction in ROE must necessarily be smaller than the percentage reduction in earnings.

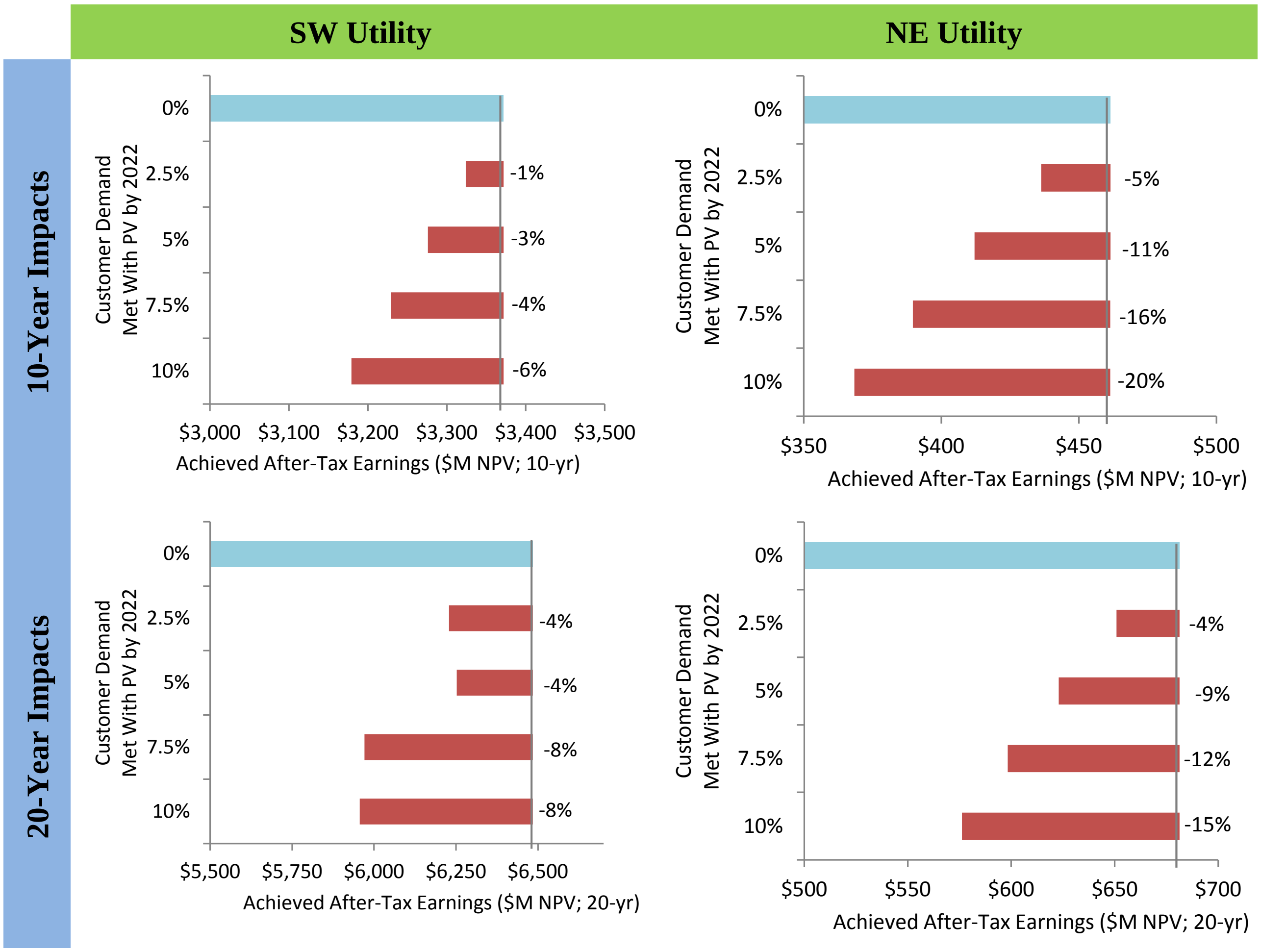



**Figure 15. Reduction in Achieved After-Tax Earnings**

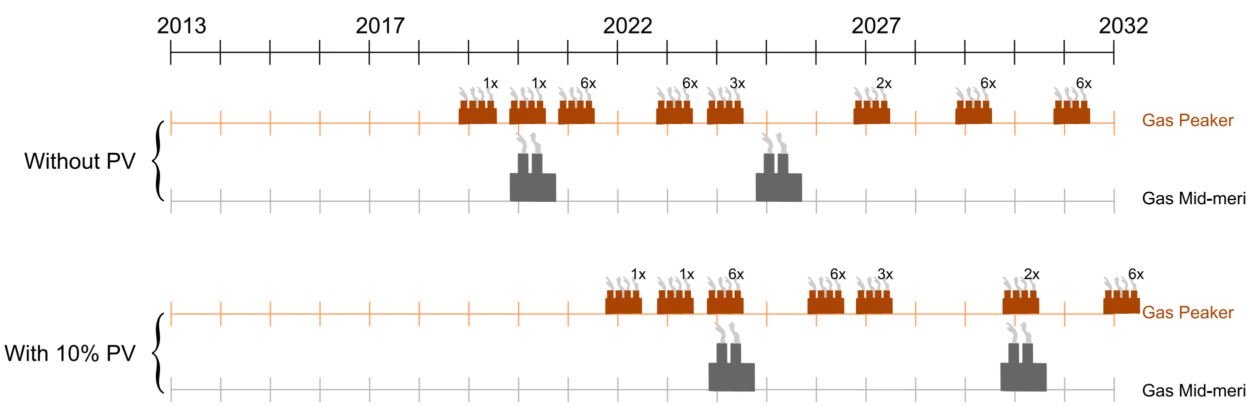



**Figure 16. Generation Investment Deferral for the SW Utility with 10% PV**

## 4.7 Impacts of PV on Average Retail Rates

Within the timeframe of our analysis, customer-sited PV impacts average, all-in retail rates in two, inter-related ways. First, it impacts the retail rates set within each GRC through the net result of reductions in the test-year utility costs and billing determinants used to establish rates.

As discussed in Section 4.3, under our base-case assumptions customer-sited PV generally reduces utility costs by less than it reduces retail sales. As a result, average retail rates established through each GRC increase with the addition of customer-sited PV. That particular dynamic is dependent on a variety of assumptions related to the ability of customer-sited PV to reduce utility cost, some of which are explored within the sensitivity analysis in Section 5. Second, customer-sited PV impacts average rates in the years between GRCs, though this effect is simply a mathematical artifact. Average rates are, by definition, equal to total collected revenues divided by total retail sales. Among customers with PV, the net-metered PV reduces both the revenues received from those customers (the numerator) and their retail sales (the denominator), but the reductions in revenues are necessarily smaller, given that some portion of revenues are derived from fixed customer charges (which are unaffected by PV) and demand charges (which are only marginally affected by PV).

The base-case impacts of customer-sited PV on average all-in retail rates over the first 10 years of the analysis period are shown in Figure 17, for both utilities and across the range of PV penetration levels considered.[27] For the SW Utility, the all-in average retail rate at 10% PV penetration is 0.23 cents/kWh (1.8%) higher over the first 10 years of the analysis period (i.e., 2013-2022) than it is without PV. The rate impacts for the NE Utility are similar, with an average rate that is 0.23 cents/kWh (1.5%) higher at 10% PV penetration than without PV. As to be expected, the rate impacts are smaller at lower PV penetration levels.

Over the entire 20-year analysis period, the impacts on average rates are generally somewhat higher than over just the first 10-year period. This is due to the fact that PV penetration is ramping up over time, and thus the average penetration level during the initial 10 years is lower than over the full 20 years. At 10% PV penetration, for example, average retail rates for the SW utility are 0.35 cents/kWh (2.5%) higher than without PV, while average rates for the NE Utility are 0.52 cents/kWh (2.7%) higher.

[27] We calculate the average all-in retail rate on a levelized basis using a customer discount rate of 5%.

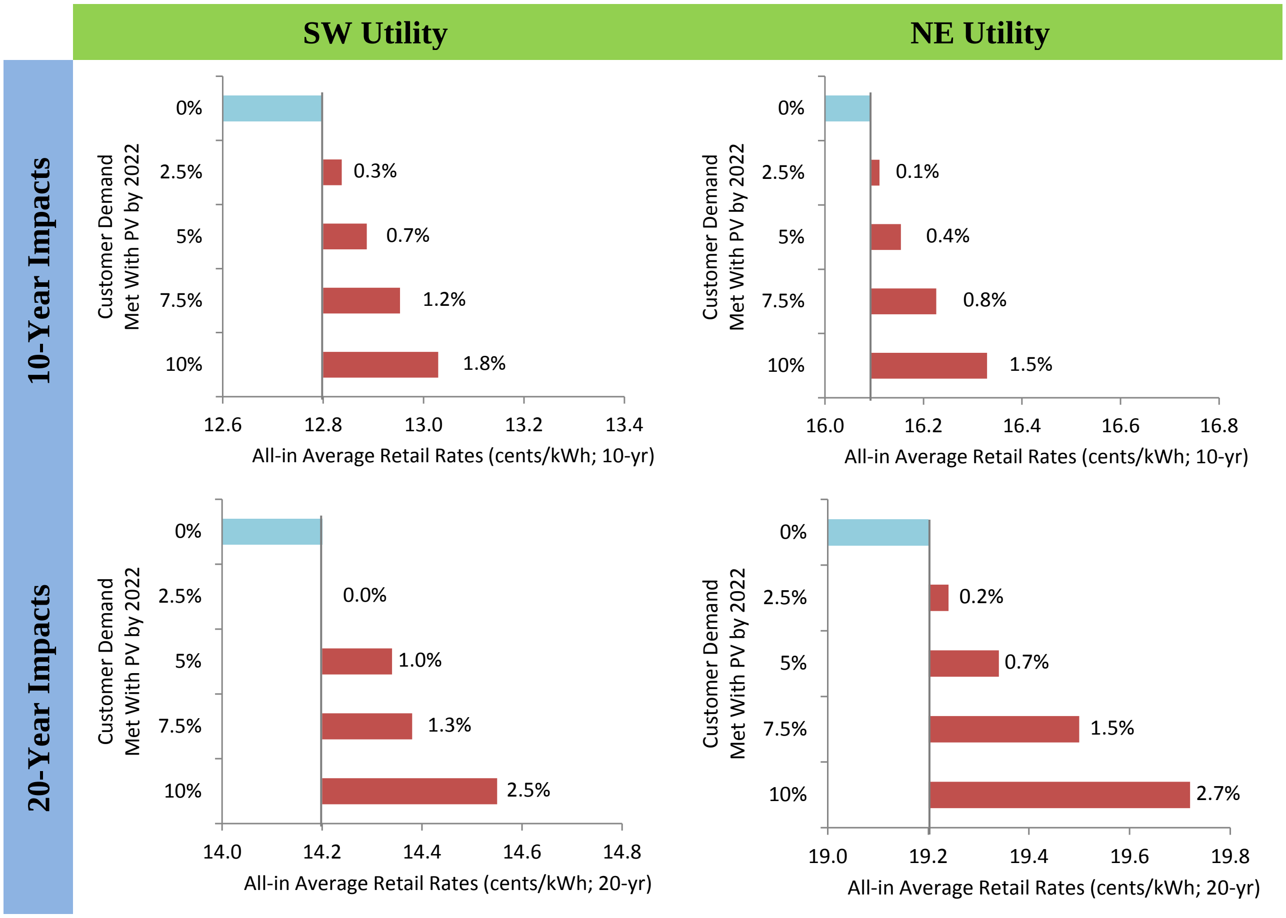



**Figure 17. Increase in All-in Average Retail Rates**

# 5. Sensitivity Results: How do the impacts of PV depend on the utility operating and regulatory environment and other key assumptions?

The base case results presented in Section 4 reflect a variety of assumptions about the two prototypical utilities. Actual conditions faced by U.S. utilities, however, vary considerably and many of the assumptions employed within our base case analysis relate to future trends that are subject to significant uncertainty. In order to examine how the impacts of customer-sited PV on utility shareholders and ratepayers may depend on assumptions about our prototypical utilities' operating and regulatory environments, we performed a series of sensitivity analyses (see Table 3, with further details provided in Appendix D). These alternate cases represent many of the most significant, though by no means all, potential sources of uncertainty and variation among utilities.[28] Moreover, even in regard to some of the sensitivities examined, some utilities may exhibit even more extreme divergence from our base-case assumptions. As such, our purpose here is not to bound the potential range of impacts, but rather to illustrate a number of key themes and considerations relevant to gauging the possible magnitude of those impacts.

**Table 3. Sensitivity Cases**

| | Sensitivities | Description | SW Utility | NE Utility |
|---|---|---|---|---|
| Utility Operating Environment | Value of PV | Higher/lower PV capacity credit and ability of PV to offset non-generation capital expenditure (CapEx) | ● | ● |
| | Load Growth | Higher/lower load growth | ● | ● |
| | Fixed O&M Growth | Higher/lower growth rate of fixed O&M costs | ● | ● |
| | Non-Generating CapEx Growth | Higher/lower growth rate of non-generation CapEx | ● | ● |
| | Fuel Cost Growth | Higher/lower growth rate of fuel costs or wholesale energy market prices | ● | ● |
| | Coal Retirement | Early retirement of existing coal generation | ● | |
| | Utility-Owned Generation Share | Higher share of utility-owned generation | ● | |
| | Utility-Owned Generation Cost | Higher/lower cost of utility-owned generation | ● | |
| | Forward Capacity Market Cost | Higher/lower market clearing price in the ISO-NE forward capacity market | | ● |
| Utility Regulatory Environment | Rate Design | Higher/lower fixed customer charges | ● | ● |
| | Rate Case Filing Period | Shorter/longer period between general rate cases | ● | ● |
| | Regulatory Lag | Shorter/longer period from the filing of a general rate case to implementation of new rates | ● | ● |
| | Test Year | Use of current or future test year during general rate cases, instead of historical test year | ● | ● |
| | PV Incentives | $0.5/Watt rebate provided by the utility to customers with PV | ● | ● |

Three important structural features of the sensitivity analysis must be noted. First, for each sensitivity case, we characterize the impacts of customer-sited PV under the 10% PV penetration trajectory (i.e., where customer-sited PV ramps up to 10% of total retail sales over 10 years), ignoring the lower penetration levels considered within the base case analysis. We focus on this

[28] The set of sensitivities is partly constrained by the structure of the model. For example, as currently constructed, the model cannot explicitly represent time-differentiated or inclining block rates; the rate design sensitivities therefore consist only of varying combinations of flat volumetric, demand, and customer charges.

higher PV penetration in order to more clearly highlight and compare the relative degrees of sensitivity across the various cases examined, but acknowledge again that this is an arguably aggressive trajectory compared to current penetration levels and growth rates for most states and utilities. Were lower PV penetration levels assumed, the impacts of PV would be smaller and the ranges across sensitivity cases would be narrower, but the fundamental results would be qualitatively the same. Second, each sensitivity case varies a single assumption or small number of assumptions. In reality, however, a more complex set of interactions and interdependencies may exist among various modeling assumptions (e.g., between rate design and load growth). Third, variation in rate design and ratemaking assumptions are included in both the sensitivity analysis and the mitigation analysis in Section 6. The difference is that, for the sensitivity analysis, the alternate assumptions are applied both with and without customer-sited PV (to reflect the fact that such variations may exist independently of customer-sited PV), while in the mitigation analysis, the alternative assumptions are applied only in conjunction with PV and are defined somewhat differently. The significance of this distinction will be further discussed below.

We begin with an overview of the results across the full set of sensitivity cases, in order to illustrate in general terms how the magnitude of impacts from customer-sited PV depends on assumptions about the utility operating and regulatory environment. We then proceed by discussing specific sensitivity cases and explain why the shareholder and ratepayer impacts are larger or smaller than what is observed in the base case.

### 5.1 The *direction* of the impacts is generally consistent across the sensitivities considered, though the *magnitude* varies considerably

The shareholder and ratepayer impacts from customer-sited PV are directionally consistent across the sensitivity cases (see Figure 18 and Figure 19). Namely, with one exception, customer-sited PV results in a decrease in achieved shareholder earnings and ROE and an increase in all-in average retail rates, regardless of assumptions about the utility operating and regulatory environment.[29] The magnitude of those impacts, however, varies considerably across the cases, demonstrating that the financial impacts from customer-sited PV critically depend on the specific conditions of the utility. For the SW Utility, the reduction in achieved earnings from customer-sited PV ranges from roughly 5% to 13%, while the reduction in achieved ROE ranges from 1% to 9%, and the increase in average rates ranges from roughly 0% to 4%.[30] The impacts for the NE Utility are even more varied, ranging from a 6% to 41% reduction in earnings, a 5% to 38% reduction in ROE, and a 1% to 4% increase in average rates. The greater sensitivity in ROE and earnings impacts for the NE Utility are due to the fact that its ratebase and earnings are much smaller, relative to its total revenue requirements, and thus variations in the absolute level of those metrics lead to relatively large percentage changes.

[29] The exception to the otherwise consistent directional trends occurs for the SW Utility in the high Value of PV case, where PV results in a very slight decrease in average rates.
[30] Throughout this section, we focus on the earnings and rate impacts over the full 20-year analysis period in order to capture any "end-effects" associated with reduced capital expenditures in the latter decade, but focus on ROE impacts over only the first 10 years, during which the impacts are most pronounced and interpretable. [30]

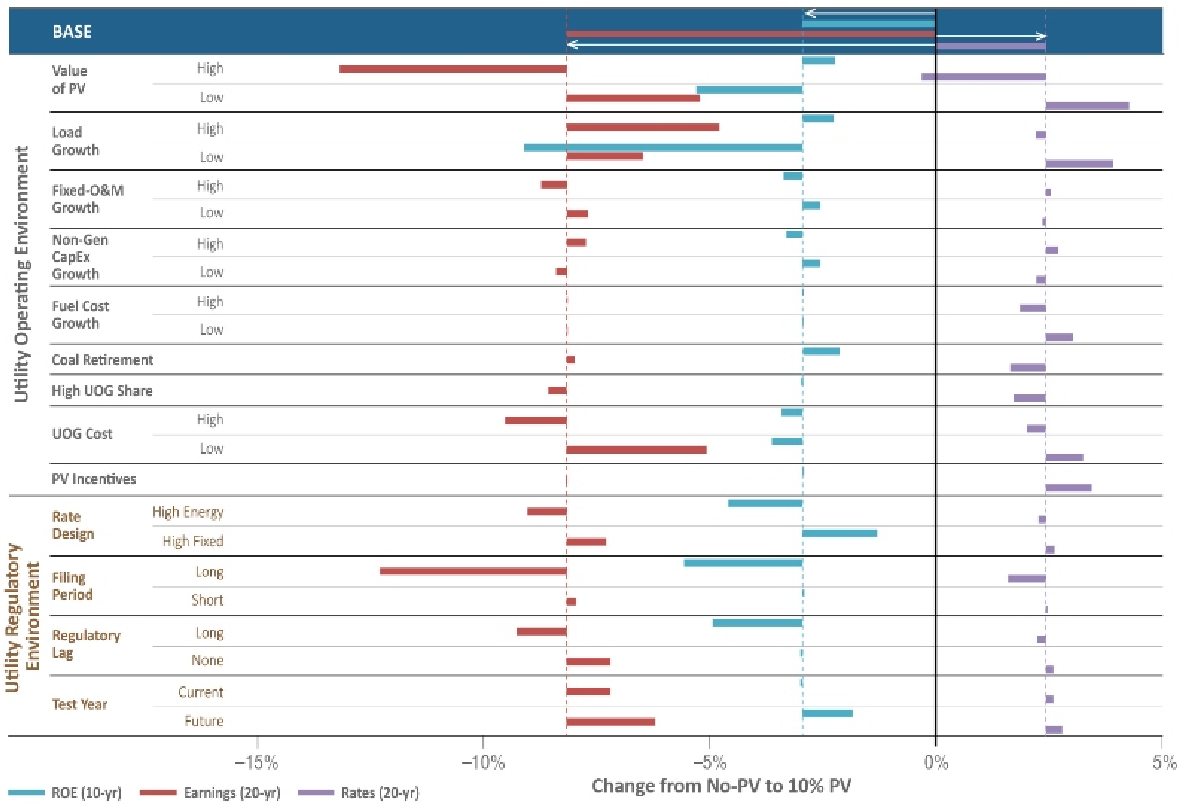



**Figure 18. All Sensitivity Results for SW Utility**

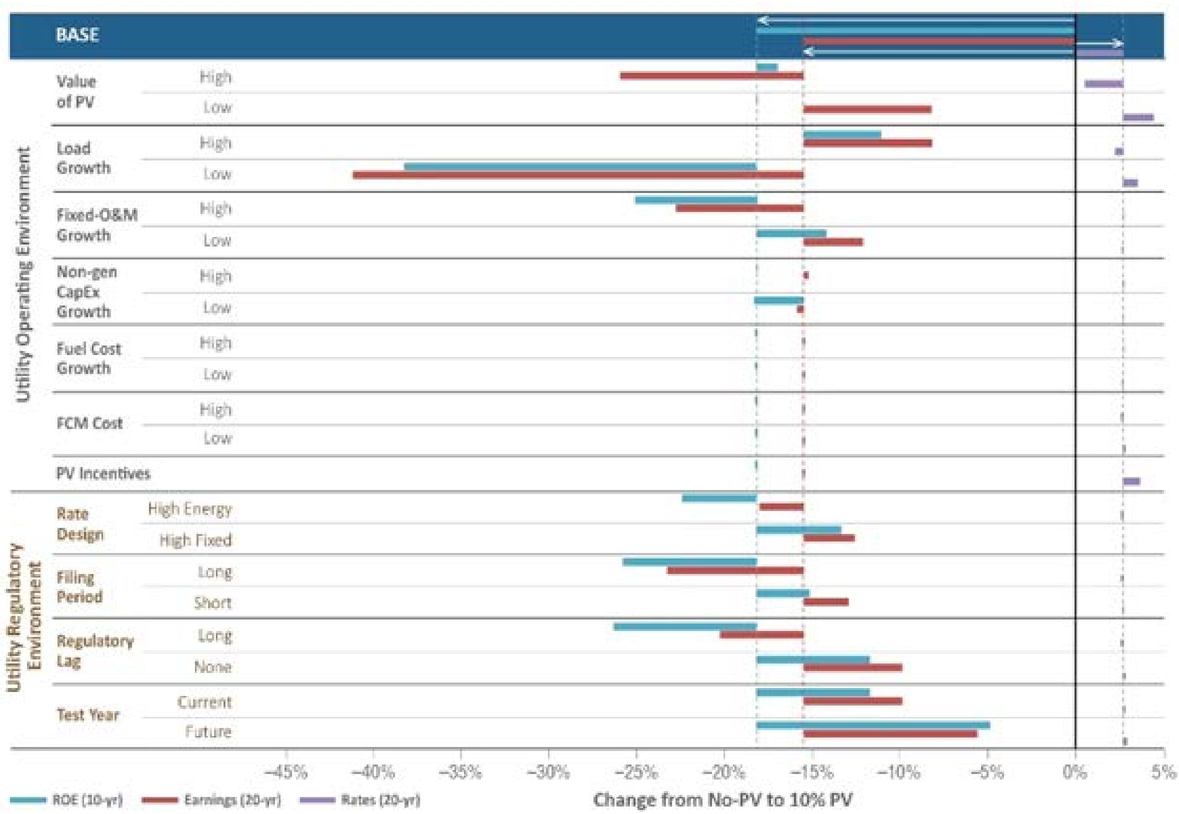



**Figure 19. All Sensitivity Results for NE Utility**

### 5.2 The financial impacts of customer-sited PV are particularly sensitive to the capacity value and avoided T&D costs of PV, with divergent implications for ratepayers vs. shareholders

As discussed throughout Section 4, the financial impacts of customer-sited PV on utility shareholders and ratepayers are driven, in part, by the associated impacts on utility costs (i.e., the avoided cost "value of PV"). Among the various sources of cost reductions, avoided generation capacity and T&D capacity costs are arguably the source of greatest uncertainty and disagreement (as evident when comparing the various studies summarized in Text Box 3). In the financial model used for the present analysis, the impacts of customer-sited PV on generation capacity and T&D capacity costs are driven by several parameters that define the "capacity credit" of customer-sited PV at the bulk power system level and on the distribution system. For the SW Utility, capacity credit assumptions affect the deferral of generation capacity investments as well as reductions in growth-related capital expenditures for T&D, while for the NE Utility, they affect the cost reductions associated with market purchases of generation and transmission capacity as well as reductions in growth-related capital expenditures for the distribution system.

We developed a set of alternate sensitivity cases to better understand the sensitivity of shareholder and ratepayer impacts from customer-sited PV to assumptions related to its capacity value and avoided T&D costs. These sensitivity cases involved modifying a number of parameters in the model (see Table 4), based on ranges for several of these parameters that exist in the literature (Hoff et al. 2008). With respect to the capacity credit at the bulk power level, in the High Value of PV scenario we slow the rate of decline of the capacity credit with increasing PV penetration, such that later vintages of PV installations contribute to a greater extent to reducing peak demand, while in the Low Value of PV scenario we assume a lower capacity credit for even early vintages of customer-sited PV. The scenarios also involve varying assumptions about the percentage of the capacity credit at the bulk power level that is then applied at the T&D level, where in the Low Value of PV case we assume 0% capacity credit for the purpose of T&D deferrals. Finally, in the Low Value of PV scenario, we also *increase* the growth rate for non-generation capital investments in conjunction with PV, to represent the possibility that integration costs for customer-sited PV could result in a net increase in distribution system expenditures.

**Table 4. Value of PV Sensitivity Case Assumptions**

| | Case | Capacity credit at 0% penetration (for generation deferral) | Change in capacity credit per 1% increase in PV penetration | Portion of generation capacity credit applied at the T&D level | T&D cost escalation rate (2013-2022) |
|---|---|---|---|---|---|
| **SW Utility** | High Value of PV | 78% | -1.0% | 40% | 1.9%/yr |
| | *Base* | 78% | -5.7% | 20% | 1.9%/yr |
| | Low Value of PV | 19% | -1.0% | 0% | 2.4%/yr |
| **NE Utility** | High Value of PV | 68% | -1.0% | 100% | 3.7%/yr |
| | *Base* | 68% | -4.6% | 33% | 3.7%/yr |
| | Low Value of PV | 19% | -1.0% | 0% | 4.7%/yr |

Given these alternate underlying assumptions, the resulting ranges in the value of PV are as shown in Table 5.[31] Roughly 60-75% of the difference in value of PV between the Low and High scenarios for each utility is associated with non-generation (i.e., T&D-related) capital expenditures, with the remainder associated primarily with some combination (depending on the utility) of generation capital expenditures and market purchases of generation and transmission capacity. As to be expected, the range of values in Table 5 span a narrower range than within the broader literature (Hansen et al. 2013) summarized in Text Box 3. Those latter estimates reflect variations across a much broader set of drivers for avoided costs (not just those associated with the capacity credit of customer-sited PV on the bulk power and T&D systems), as well as differences in the set of avoided cost categories included. Thus the value of PV sensitivity cases presented here should, by no means, be considered to represent the full possible range in the value of avoided costs to the utility or to society more broadly.

**Table 5. Average Avoided Costs across Value of PV Sensitivity Cases (20-yr)**

| | Low | Base | High |
|---|---|---|---|
| **SW Utility** | $0.04/kWh | $0.09/kWh | $0.13/kWh |
| **NE Utility** | $0.08/kWh | $0.12/kWh | $0.17/kWh |

Note: Values reported here are the avoided cost per unit of PV production (i.e. $/kWh-PV)

As shown in Figure 20, the impacts of customer-sited PV on shareholder earnings vary widely under these different assumptions related to the value of PV. Under the high value of PV scenarios, customer-sited PV results in greater reductions in capital expenditures than in the base case and thus, as a result, there are greater lost future earnings opportunities for the utility, exacerbating the earnings impacts. Under the low value of PV scenarios, the earnings impacts are correspondingly more moderate, as fewer capital expenditures are deferred.[32] The rate impacts from customer-sited PV are also quite sensitive to the value of PV, but move in the opposite direction: increasing under the low value of PV scenario (whereby customer-sited PV is less effective at reducing utility costs) and decreasing under the high value of PV scenario. Of some note, customer-sited PV leads to a slight reduction in average retail rates for the SW Utility under the high value of PV scenario. This occurs because the reduction in utility costs from PV exceeds the reduction in utility revenues.

The high degree of sensitivity of shareholder and ratepayer impacts to the value of PV – and the divergent implications of that sensitivity for shareholders versus ratepayers – has several implications. First, it reinforces the importance of efforts aimed at improving the data and methods for estimating the value of PV. Better understanding of the capacity value and avoided T&D costs of PV improves estimates of the impact of PV on shareholders and ratepayers. Second, it shows that, even within the somewhat limited range of assumptions about the value of PV considered here, it is conceivable that customer-sited PV could result in virtually no increase

[31] The value of PV is calculated as the difference in utility revenue requirements (on an NPV basis over 20 years) with and without PV, per unit of PV energy.

[32] In contrast to the earnings impacts, ROE impacts are relatively insensitive to alternate assumptions about the underlying value of PV. As previously discussed, ROE impacts from customer-sited PV are driven by its differential effect on utility costs vs. revenues. An increase (decrease) in the value of PV leads to a corresponding decrease (increase) in cost growth. However, that change in costs is a relatively small fraction of total utility costs, leading to the modest degree of sensitivity for the ROE impacts.

or perhaps even a slight decrease in average retail rates. And third, the results are suggestive of the potential to mitigate the ratepayer impacts of customer-sited PV through deployment strategies that seek to maximize its capacity deferral value (e.g., by placing PV in locations or with orientations that maximize its capacity credit). Policymakers must recognize, however, that such strategies may run counter to the financial interests of utility shareholders, whose earnings would be further eroded by greater reductions in capital expenditures.

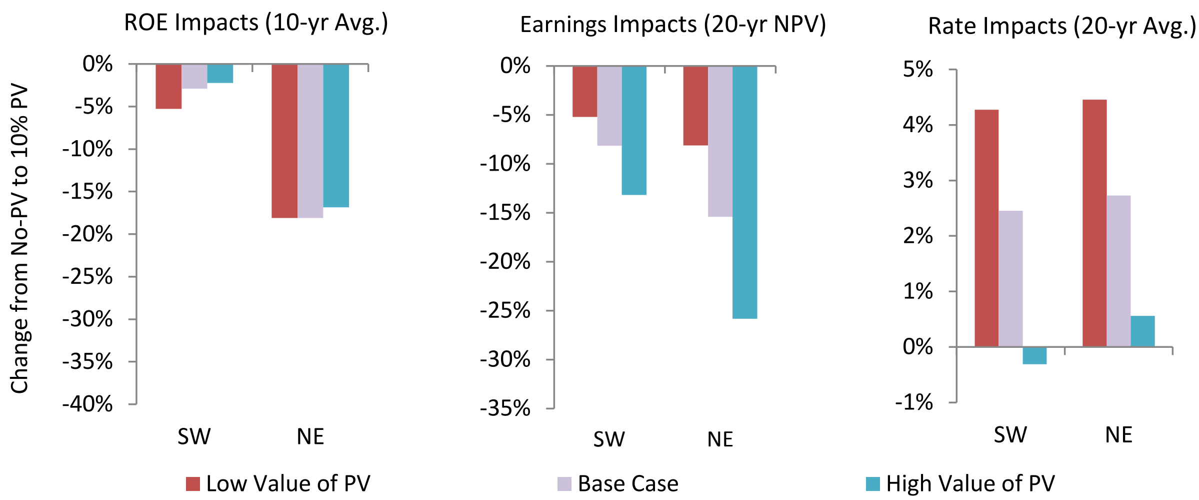
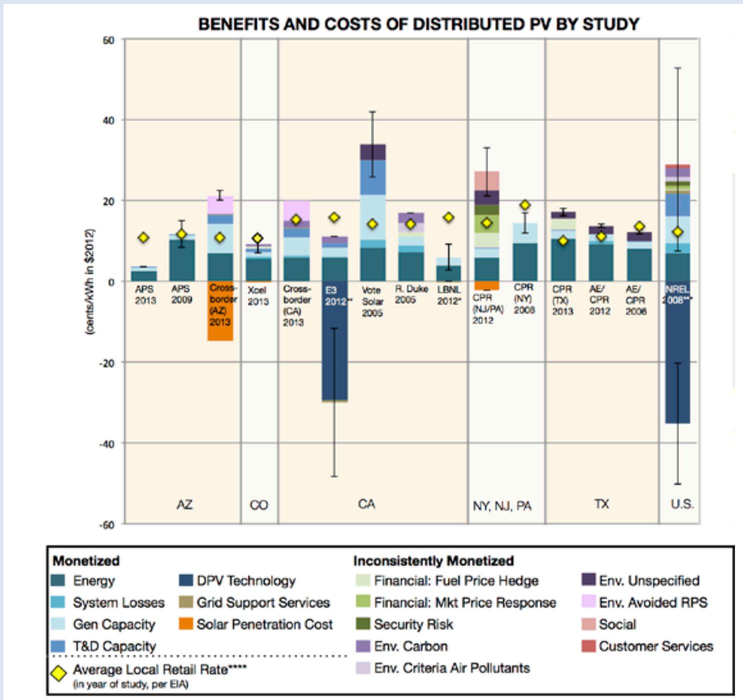



**Figure 20. Sensitivity of PV Impacts to Value of Solar**

**Text Box 3. Estimates of the Value of Customer-Sited PV**

The model used in this analysis is not specifically designed to estimate the value of PV; however, the estimates used within this study can be compared to those in the literature, which have often been developed using more-tailored tools. One recent meta-analysis (Hansen et al. 2013) compared estimates of the value of PV from studies conducted over the past decade, and found widely varying results, ranging from 3.6 cents/kWh to over 34 cents/kWh. The range in estimates is due in part to differences in assumptions about future costs, differences in methodologies, and differences in scope (e.g., value of PV from a societal perspective or a ratepayer perspective). Across studies, the range of the energy value of PV is 2.5 to 10.5 cents/kWh (driven in part by different fuel costs), the range of capacity value is 1 to 11 cents/kWh (driven by differences in the contribution of PV to reducing peak demand and the need for new capacity), the range in T&D value is 0 to 8.5 cents/kWh (depending on the ability of PV to defer investments), and the range in the environmental value is 0 to 4 cents/kWh (depending on which environmental impacts are quantified).

As described in Section 4, the value of PV in our Base Case declines from 10.3 to 8.5 cents/kWh for the SW Utility and from 15.8 to 12.3 cents/kWh for the NE Utility, when moving from the 2.5% to 10% penetration scenarios. The differences between the SW and NE Utilities are primarily due to differences in energy and capacity value. The value of PV estimated in our High and Low Value of PV sensitivities ranges from 4 to 17 cents/kWh across the utilities and scenarios at 10% PV penetration. These estimates of the value of PV all fall within the broad range reported in the literature. That said, a large portion of the change in value in our sensitivities is due to changes in non-generation capital expenditures.[33] The range of the value of PV in the broader literature, however, is driven in part by differences in estimates of avoided T&D costs, but other factors like differences in avoided energy, capacity, and environmental impacts contribute just as much to variations in the estimates of the value of PV.




*Source: Hansen et al. (2013)*

**Figure 21. Comparison of the Estimated Value of PV across Recent Studies**

[33] For example, the decrease in SW Utility non-generation capital expenditures from the High Value of PV case to the increase in the Low Value of PV case leads to a change in the value of PV of 7.3 cents/kWh. Similarly, the range due to differences in the non-generation capital expenditures in the High and Low Value of PV case for the NE Utility is 5.3 cents/kWh.

## 5.3 Low load growth exacerbates the impacts of customer-sited PV on rates and ROE

Load growth can vary substantially over time and among utilities, and is also subject to great uncertainty given the many underlying drivers at play (e.g., EE policies and programs, vehicle electrification, and macroeconomic trends). Within the context of the present analysis, load growth is important because of its relationship to the size and timing of utility capital expenditures (which also affects the timing of rate cases), the volume of retail sales over which fixed costs are spread, and the collection of utility revenues based on actual retail sales and peak demand levels. As discussed further below, however, these relationships are complex and, at times, somewhat idiosyncratic.

In order to characterize how the shareholder and ratepayer impacts of customer-sited PV depend on underlying load growth, we developed Low and High Load Growth sensitivities where the compound annual growth rates (CAGR) for both sales and peak demand were adjusted by +/- 2% relative to the Base Case (see Table 6).[34] The Low Load Growth cases thus entail roughly zero load growth for the SW Utility and slightly negative load growth for the NE Utility, while the High Load Growth cases entail growth rates on the order of roughly 3.5-4% per year. In conjunction with the load growth adjustments, we also adjusted the generation capacity expansion plan for the SW Utility and the amount of growth-related non-generation capital expenditure in order to maintain internal consistency across load growth scenarios.[35]

**Table 6. Load Growth Assumptions in the Low and High Load Growth Sensitivities (CAGR)**

| | | Low | Base | High |
|---|---|---|---|---|
| **SW Utility** | Sales | 0.1% | 2.1% | 4.1% |
| | Peak Demand | 0.1% | 2.1% | 4.1% |
| **NE Utility** | Sales | -0.6% | 1.4% | 3.4% |
| | Peak Demand | -0.5% | 1.5% | 3.5% |

As shown in Figure 22, the impact of customer-sited PV on achieved ROE varies with load growth, though the degree of sensitivity depends on whether ROE impacts are measured in absolute or relative terms. For both utilities, ROE impacts are less severe with higher underlying load growth and, conversely, more severe with lower underlying load growth. This occurs because higher load growth is associated with greater growth-related capital expenditures, which in turn creates greater opportunities for cost savings from PV through deferral of those expenditures, thereby muting the impacts of PV on achieved ROE. In addition, the increased

[34] Load forecasts for several SW balancing authorities are presented in Appendix A. The EIA Annual Energy Outlook projects load growth of 0.3%/yr in New England, for the period 2012 to 2040, with a range in year-over-year growth of 0.1% to 0.6%/yr. For the Mountain region, EIA projects average growth of 1.3%/yr, with year-over-year growth ranging from 1.0% to 1.7%. EIA also reports that over the past thirty years the national average load growth (three-year moving average) ranged from -0.8% (in 2009) to 5.2% (in 1989).

[35] More specifically, we adjusted assumptions related to non-generation capital expenditures to ensure that the amount of non-generation capital expenditures that are not related to growth was the same across all three scenarios. We further increased growth related capital expenditures in the High Load Growth case and decreases the growth related capital expenditures in the Low Load Growth case for both utilities. For the NE Utility, none of the non-generation capital expenditures are related to load growth in the Low Load Growth case (due to the decrease in load from year to year), and thus PV does not result in any reduction to those costs.

pace of capital expenditures under high load growth triggers more frequent GRCs (for the SW Utility), which further moderates the impacts of customer-sited PV on ROE, as the utility is able to set new rates more frequently and thereby achieve closer alignment between its revenues and costs. When ROE impacts are measured in terms of a percentage change from the no-PV case, the sensitivity is somewhat more acute than when measured in terms of absolute, basis-point changes. This is because higher (lower) load growth leads to higher (lower) absolute levels of ROE in cases without PV, for the reasons noted above.[36] Thus, for basic arithmetic reasons, the basis-point changes caused by the introduction of customer-sited PV lead to larger swings when measured as a percentage of the ROE without PV.

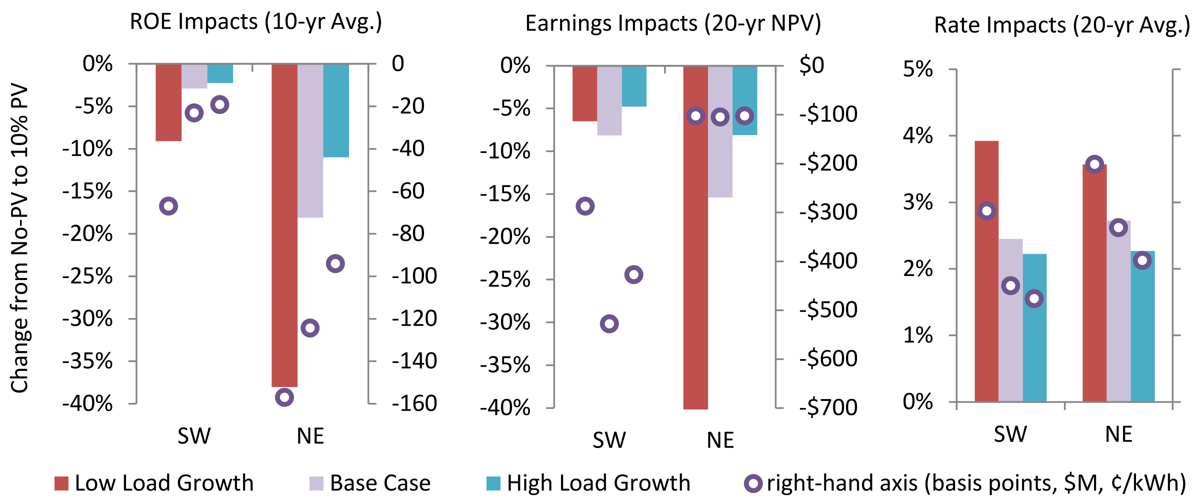



**Figure 22. Sensitivity of PV Impacts to Load Growth**

The sensitivity of the achieved earnings impacts from PV to load growth is somewhat more complex and involves several interrelated dynamics. The dependence of earnings impacts on underlying load growth partly are a function of the same dynamics described above in connection with ROE impacts (i.e., revenue growth between rate cases and frequency of rate cases). In addition, the underlying rate of load growth also affects the magnitude of capital expenditures, and thus the potential lost earnings opportunities associated with deferral of those expenditures. These various dynamics operate in opposing directions – for example, greater underlying load growth would tend to reduce earning erosion associated with lost revenues but increase earnings erosion associated with deferred capital expenditures – hence the irregular relationships exhibited in Figure 22. In the case of the NE Utility, these countervailing dynamics offset one another almost equally in both sensitivity cases, leading to effectively no change in absolute earnings impacts across cases. However, since the absolute earnings without PV are much smaller in the Low Load Growth case and much higher in the High Load Growth case, the earnings impacts on a percentage basis are highly sensitive to underlying load growth.

The retail rate impacts from PV are also sensitive to load growth, with larger increases in average rates occurring in the case of low load growth and smaller rate increases occurring with

[36] For the SW Utility, average ROE without PV was 7.4% in the Low Load Case and 8.6 % in the High Load Case, and for the NE Utility, it was 4.1% in the Low Load Case and 8.6% in the High Load Case.

higher load growth. This occurs due to the same dynamic discussed in connection with the ROE impacts: higher load growth requires greater capital expenditures in the case without PV, and thus greater opportunities for deferral of capital expenditures and cost savings from PV.

### 5.4 Shareholder impacts are more severe with retail rates that rely predominantly on volumetric energy charges and less severe when rates have larger fixed charges

Utility rate designs often follow similar general principles (e.g., stability in revenues, avoidance of undue discrimination, and fairness in allocation of costs among customer classes) but, in practice, allocation of revenue collection to energy, demand, and fixed customer charges can vary significantly across utilities. In order to examine how the impacts of PV may depend upon prevailing rate design, we developed sensitivity cases that assume varying degrees of reliance on energy charges and fixed customer charges.[37] Note that the sensitivity analysis here assumes these alternative rate designs both with and without PV, in recognition of the fact that a wide variety of rate designs are in use today for reasons unrelated to customer-sited PV. Within the mitigation analysis in Section 6, we instead explore the potential role of fixed customer charges and high demand charges as a strategy specifically for mitigating the financial impacts of customer-sited PV, in which case we consider a more extreme change in rate design that is implemented only in conjunction with the growth of PV.

Table 7 shows the composition of total utility revenues (or customer bills) for the base case and two sensitivity cases. For the High Energy Charges case, we assume that the costs allocated in the base case to fixed customer charges are instead allocated to volumetric energy charges (and leave the allocation to demand charges unchanged). For the High Customer Charges case, we assume a larger proportion of non-fuel costs are allocated to customer charges and correspondingly smaller proportion allocated to volumetric energy charges, compared to the base case (and leave fuel costs fully allocated to energy charges and the demand charges unchanged). The proportion of non-fuel costs allocated to customer charges was chosen such that the portion of total customer bills comprised of fixed customer charges doubles from the base case (e.g., fixed customer charges increase from 12% in the base case to 24% in the high customer charge case for the SW Utility).

**Table 7. Rate Design Sensitivity Cases (Percent of Total Utility Revenues, without PV)**

| | High Energy Charges | Base Case | High Customer Charges |
|---|---|---|---|
| **SW Utility** | | | |
| Energy Charges | 89% | 77% | 65% |
| Demand Charges | 11% | 11% | 11% |
| Customer Charges | 0% | 12% | 24% |
| **NE Utility** | | | |
| Energy Charges | 92% | 84% | 76% |
| Demand Charges | 8% | 8% | 8% |
| Customer Charges | 0% | 8% | 16% |

[37] Other important variations in utility rate designs may affect the impact of PV on utility shareholders and ratepayers, which we do not explore here but highlight as potential areas for follow-on analysis. These include tiered rates, time-of-use rates, and alternative PV compensation mechanisms such as value of solar tariffs.

As shown in Figure 23, the impacts of customer-sited PV on achieved ROE and earnings are more severe under the High Energy Charges case and less severe under the High Customer Charges case. In general, the greater the reliance on volumetric energy charges, the greater the impact customer-sited PV will have on a utility's collected revenue (given our assumption that the PV is net-metered and therefore offsets volumetric sales on a one-for-one basis) and the greater the resulting impact on shareholder ROE and earnings. Conversely, the greater the reliance on fixed customer charges or demand charges, the smaller the impact of PV on collected revenues and utility shareholder profitability.

The rate impacts of customer-sited PV are relatively insensitive to changes in rate design, with modestly smaller impacts under rate designs that rely heavily on volumetric energy charges and slightly larger impacts with rate designs relying more heavily on customer charges. These results may appear counter-intuitive on first glance and must be interpreted carefully, in light of how the average rate metric is calculated and what it means. As explained in Section 4, average all-in retail rates represent total collected revenue divided by total retail sales, across all customers, including both PV and non-PV customers. With higher fixed charges, the utility collects more revenues from customers with PV, which in turn translates to higher average retail rates and thus a greater change in average rates between cases with PV and without PV. By the same logic, the impact of PV on average rates is smaller when retail rates have larger volumetric energy charges. Importantly, however, we cannot infer from these results how the rate impacts for customers without PV vary with these alternate rate designs.

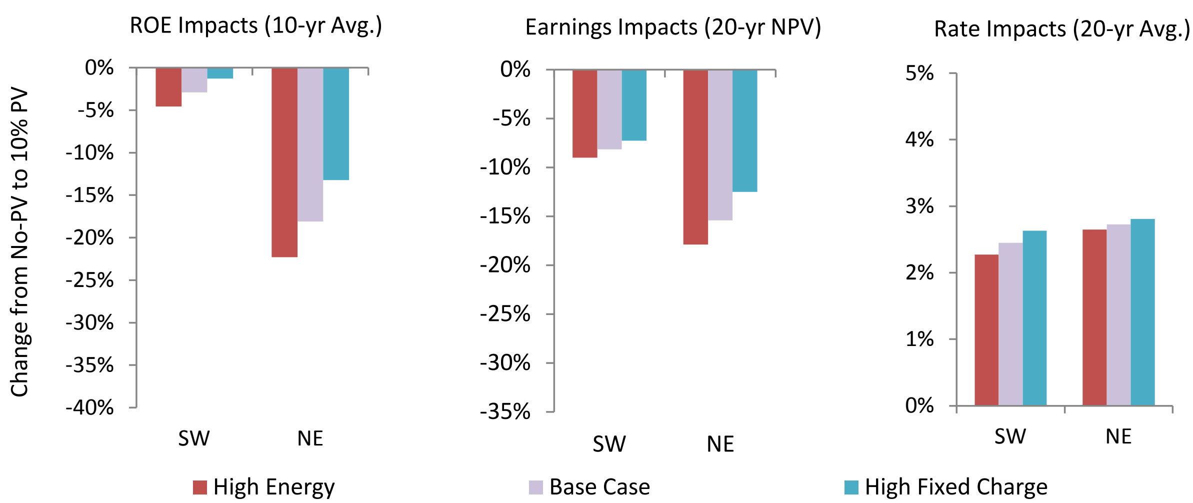



**Figure 23. Sensitivity of PV Impacts to Rate Design**

### 5.5 Greater lag between when a utility incurs costs and when those costs are reflected in new rates heightens the impacts of PV on utility shareholders, but mutes the impacts on ratepayers

Current ratemaking practices vary considerably across utilities and states, in terms of: rate case filing frequency, the period of time between the filing of a rate case and implementation of new rates (i.e., regulatory lag), and the type of test year. Accordingly, we developed a series of sensitivity cases to assess how the shareholder and ratepayer impacts of customer-sited PV may vary across differing ratesetting regimes. For the sensitivity cases, we consider longer (5-year) or shorter (2-year) periods between GRCs, longer (2-year) or shorter (0-year) periods of regulatory lag, and the use of current and future test years (i.e., where test year utility revenue requirement and billing determinants are based on the year of the GRC or on projections for the following year).[38]

This set of sensitivities is intended to reflect the range of practices used by utilities and regulators across the country. As in the case of the preceding rate design sensitivities, we apply the alternative-ratesetting-approaches to both the with-PV and without-PV cases, in order to assess how the shareholder and ratepayer impacts of PV may vary, given the range of ratesetting practices in place today. Later, in Section 6, we instead examine how these ratesetting practices might potentially serve as a strategy for mitigating the shareholder impacts of PV, if introduced in conjunction with the growth of customer-sited PV. For clarity the figures in this section present only the sensitivity cases where the impact of PV is the largest (longer periods between GRCs) or the smallest (future test years); the remaining results can be seen in Figure 18 and Figure 19 and Appendix D.

In general, the greater the lag between when a utility incurs costs and when those costs are reflected in new rates, the greater the impact of customer-sited PV on collected revenues and thus on shareholder profitability. As such, we observe larger impacts on achieved ROE and earnings in cases involving longer filing frequencies (i.e., less frequent rate cases), greater regulatory lag, or reliance on historic test years. Of these cases, the largest impact was observed with longer filing frequencies (see Figure 24). Conversely, the impacts are smaller with cases involving more frequent rate cases, less regulatory lag, or current or future test years. The shareholder impacts from PV are more sensitive to variations in these ratemaking conditions in the case of the NE Utility, given the more significant underlying misalignment between growth in non-fuel costs and retail sales.

The rate impacts exhibit the opposite set of relationships, though the degree of sensitivity is rather modest. The longer period of time between the setting of new rates results in a reduction in the impact of customer-sited PV on average retail rates. We therefore observe in Figure 24 that the increase in average all-in retail rates caused by PV is somewhat smaller in cases involving less frequent rate cases, greater regulatory lag, or reliance on historic test years (and is somewhat greater under the converse set of conditions).

[38] For the base case, we assume that the utilities file GRCs every three years and, in the case of the SW Utility, after any capital investment exceeding $900 million. We also assume that the utilities use an historical test year for establishing revenue requirements and that new rates go into effect one year after the GRC is filed.

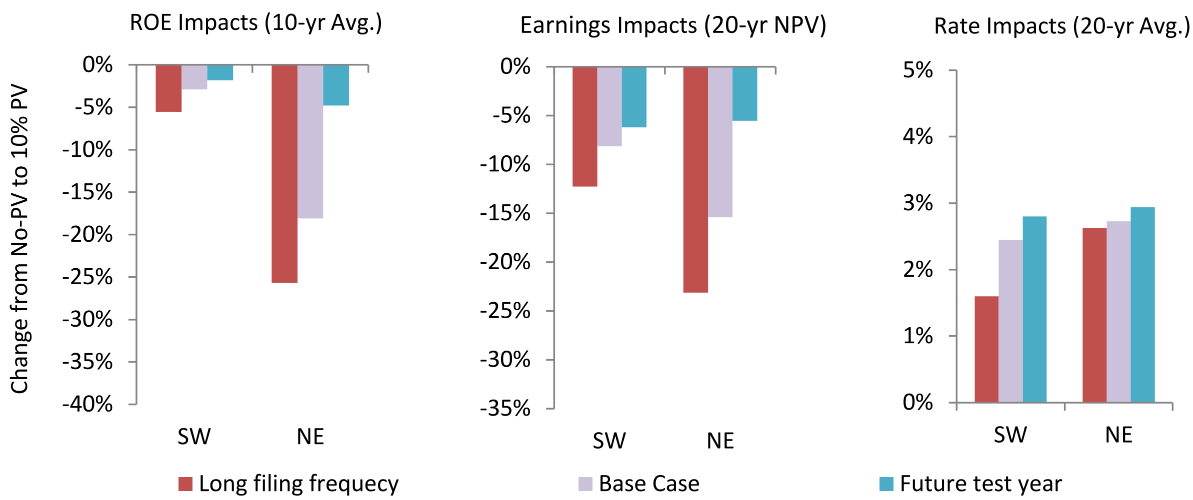



**Figure 24. Sensitivity of PV Impacts to Long Rate Case Frequency and use of a Future Test Year**

## 5.6 Shareholder and ratepayer impacts from PV vary modestly across the range of cost-related assumptions examined

We conducted a variety of other sensitivities that examine how shareholder and ratepayer impacts of PV depend on various cost-related elements of utility operating environments. These additional sensitivity cases included alternate assumptions about growth in fixed O&M costs, non-generation (i.e., T&D) capital expenditures, and fuel and purchased power costs; the capacity cost of utility-owned generation (SW Utility); ISO-NE FCM costs (NE Utility); the share of generation capacity consisting of utility-owned generation (SW Utility); early retirement of coal capacity with replacement by gas-fired generation (SW Utility); and ratepayer-funded rebates for customers to install PV.

As shown previously in Figure 18 and Figure 19, the shareholder and ratepayer impacts of PV vary to only a limited extent across most of these sensitivity cases, with two principal exceptions. The first is the set of sensitivities related to UOG costs for the SW utility, where higher costs lead to higher shareholder earnings erosion from PV, and lower costs lead to lower earnings erosion. Because shareholders generate earnings from capital investments in utility-owned generation, the higher the cost of that generation, the greater the earnings, and thus the greater erosion of earnings if those capital expenditures are deferred.

The other cost-related scenario exhibiting a significant degree of sensitivity is the case where the utility provides PV customers an up-front rebate (equal to $0.5/W), which results in a noticeable impact on average retail rates.[39] The rebate is an additional utility cost that is ultimately collected from all ratepayers, and thus the incremental increase in average retail rates, beyond that occurring in the base case, is due to the cost of the rebate program.[40] Although Figure 18

[39] Such financial incentives have been common practice in the United States, though in recent years they have been phased out and/or supplanted by other kinds of financial incentives.
[40] The model does not separate retail rate impacts of participants and non-participants, thus, we only represent rate impacts averaged across all customers.

and Figure 19 focus on the rate impacts over the full 20-year analysis period, it is more instructive in the case of this sensitivity to consider the impacts over just the first 10 years, during which the rebates are disbursed. Over that timeframe, the rate impacts from PV are roughly doubled relative to the base case with only net metering but no rebate program (a 3.6% increase in average all-in retail rates for the SW Utility, compared to 1.8% in the base case, and a 3.3% rate increase for the NE Utility, compared to 1.5% in the base case). Note, though, that we have not assumed in this sensitivity that ownership of RECs generated by the customer-sited PV are transferred to the utility in exchange for the rebate; if such a transfer were to occur, the utility would be able to apply those RECs directly towards its RPS obligations, which would offset some or all of the rate impacts associated with the rebate program costs. In Section 6, we explore the potential rate impacts associated with transferring ownership of these RECs to the utility.

Given these findings, the results for these cases illustrate several important relationships and themes. Of particular note, the sensitivity of shareholder impacts to underlying utility costs depends on the kind of cost and how it is recovered from ratepayers. Some costs are passed-through to customers through annual rate adjustments (e.g., fuel and purchased power costs).[41] Because those costs are fully recovered from ratepayers both with and without customer-sited PV, the growth of customer-sited PV does not impact recovery of those costs, and therefore the shareholder impacts of PV are independent of the magnitude of those costs or their rate of growth. Other costs, however, affect the utility's ratebase (e.g., non-generation capital expenditures and capacity costs for utility-owned generation). Utility shareholders earn a return on the equity of financing for those investments, and thus in general, the greater those underlying costs, the greater the impact of PV on shareholder earnings.

[41] The ability for utilities to pass particular costs to rates without a general rate case depends on the regulatory environment. We assume that the SW and NE Utility have fuel-adjustment clauses (FAC) that allow rates to be adjusted in response to changes in fuel and purchased power costs. Not all utilities will have these sorts of clauses and may instead rely on rate cases to adjust fuel and purchased power related rates.

# 6. Mitigation Results: To what extent can the impacts of PV be mitigated through regulatory and ratemaking measures?

This section examines the effectiveness of various measures that could be implemented by utilities and regulators to mitigate the financial impacts of PV on shareholders and/or ratepayers (see Table 8). Though by no means exhaustive, this set of measures includes many of the regulatory and ratemaking strategies implemented or discussed in connection with EE programs, or analogues that might apply to PV.[42] As suggested by Table 8, most of these measures specifically target the shareholder impacts from customer-sited PV (associated with either revenue erosion or lost earnings opportunities), and these measures may potentially exacerbate the ratepayer impacts from customer-sited PV, exemplifying one kind of tradeoff that can often arise.

**Table 8. Mitigation Cases and Targeted Intent**

| Mitigation Measure | Description | Revenue Erosion | Lost Earnings Opportunities | Increased Rates |
|---|---|---|---|---|
| Revenue-per-Customer (RPC) Decoupling | Revenue decoupling is implemented by setting a revenue per-customer target in rate cases and adjusting rates annually between cases to collect revenues at the target level | ● | | ○ |
| Lost Revenue Adjustment Mechanism (LRAM) | Rates are adjusted annually to compensate the utility for the incremental loss of revenue occurring as a result of customer-sited PV | ● | | ○ |
| Shareholder Incentive | Utility shareholders receive additional earnings for the successful achievement of policy goals (in this case, related to customer-sited PV deployment) | | ● | ○ |
| Shorter Rate Case Filing Frequency | The period between GRC filing is reduced | ● | | ○ |
| No Regulatory Lag | The lag between the filing of GRCs and implementation of new rates is eliminated | ● | | ○ |
| Current & Future Test Years | Current or future test years are used to set utility revenue requirement during GRCs | ● | | ○ |
| Increased Demand Charge & Fixed Charge | An increased share of non-fuel costs is allocated to demand or fixed customer charges | ● | | ○ |
| Utility Ownership of Customer-Sited PV | The utility owns customer-sited PV systems, leases the systems back to the host customers or to intermediaries, and earns a return on the assets | | ● | ○ |
| Customer-Sited PV Counted toward RPS | All net-metered PV counts toward the utility's RPS compliance obligations | | | ● |

● Primary intended target of mitigation measure
○ May exacerbate impacts of customer-sited PV

[42] For example, we do not consider value of solar tariffs, non-fuel cost trackers, formula rates, multi-year rate plans, or various other options identified in the literature (Bird et al. 2013, Lowry et al. 2013, Linvill et al. 2013, Kihm and Kramer 2014).

We examine each of the mitigation options in Table 8 in isolation, but note that several could be coupled with each other (or with other mitigation measures) as part of a more comprehensive solution (e.g., combining RPC decoupling with shareholder incentives). Potential solutions to mitigate the impacts of PV may be more viable if they address concerns of both ratepayers and shareholders; such "comprehensive business models" as they relate to utility-sponsored EE programs are discussed in more detail in Satchwell et al. (2011).

As with the sensitivity analysis, the analysis of mitigation measures focuses on the 10% PV penetration scenario, in order to clearly reveal the effects of the mitigation measures considered. Were lower PV penetration levels assumed for this portion of the analysis, the results would be qualitatively similar but less discernible. Unlike the sensitivity analysis, however, the mitigation analysis involves changes from base case conditions that occur only in conjunction with PV. Thus we gauge the effectiveness of each mitigation measure in terms of the extent to which it restores shareholder earnings, shareholder ROE, and/or average rates to the levels that occur without PV under the base case utility conditions.

We highlight key themes within this section that emerge from the analysis of mitigation measures. In doing so, we group functionally similar mitigation measures together and focus on the particular metric(s) and timeframe (either the first 10 years of the analysis period or the entire 20-year period) that are most relevant to the mitigation measure in question. For example, many of the mitigation measures serve principally to address the revenue erosion impacts from customer-sited PV, in which case our discussion of shareholder impacts focuses on achieved ROE over the first 10 years, along with any associated changes in average rates. Other measures may instead serve primarily to address lost earnings opportunities associated with PV, in which case our discussion of shareholder impacts focuses on earnings over the full 20-year analysis period. The full set of results for each mitigation case, including all three metrics both the 10- and 20-year analysis periods, are included for reference in Appendix E.

As a final prefatory note, in the course of discussing the results of this analysis, we highlight how many of the mitigation measures considered may have divergent consequences for shareholders and ratepayers, or may entail tradeoffs with other policy or social objectives (e.g., increasing fixed customer charges may dampen the long-run price signal for energy conservation). Because of those issues and complexities, we stress that the following analysis represents neither an endorsement of any particular measure nor a complete examination of the broader set of implications associated with the measures considered.

## 6.1 Decoupling and LRAM can moderate the ROE impacts from PV, though their effectiveness depends critically on design and utility characteristics

The traditional electric utility business model in the United States provides a financial incentive for the utility to increase electricity sales between rate cases, commonly referred to as the "throughput incentive" (Eto et al., 1997, RAP 2011). A bias among utilities therefore exists against resources or policies, like EE or customer-sited PV, that decrease sales. Several regulatory tools have been used in the context of EE to mitigate this disincentive, including various forms of revenue decoupling as well as lost revenue adjustment mechanisms (LRAM), and we developed mitigation cases to explore their potential applicability for customer-sited PV.

Revenue decoupling is designed to address the misalignment of incentives towards EE and other demand-side resources by "decoupling" utility revenues from sales.[43] Revenue-per-customer (RPC) decoupling is one form of decoupling that allows revenues to grow based on growth in the number of customers between rate cases, rather than on growth in retail sales.[44] Another design element of decoupling is the application of a revenue growth factor, commonly called a "k-factor". The k-factor allows the revenue (or revenue-per-customer) established in a GRC to grow between rate cases to better match growth in fixed costs between rate cases. This is particularly important for a utility facing the effects of high cost inflation and high fixed cost (e.g., labor costs, pension costs) growth.

An LRAM, like decoupling, is also intended to address the "throughput incentive," though it does so by reimbursing the utility specifically for lost revenues directly attributable to EE programs. Thus, unlike revenue decoupling, which fully severs the tie between sales and revenues, an LRAM is more narrowly focused on only sales reductions associated with EE programs (or, in our analysis, customer-sited PV).[45] In practice, implementation of an LRAM can be contentious, as it requires estimation of the amount of energy saved as a result of the EE measure (Carter 2001). In this respect, LRAMs may be easier to implement for customer-sited PV than for EE, because PV production can be directly metered whereas the change in sales due to EE is more speculative.

In order to illustrate their potential applicability to customer-sited PV, we developed mitigation scenarios involving two variants of RPC decoupling – one with a k-factor and one without a k-factor – and one mitigation case with an LRAM. For the mitigation case involving RPC decoupling without a k-factor, growth in collected revenues is set equal to growth in the number of customers between rate cases. For the mitigation case involving RPC decoupling with a k-factor, the k-factor is set at the value necessary to restore ROE to the level achieved in the base case without PV. Under the LRAM mitigation case, the utility collects additional revenue on an annual basis between rate cases, equal to the product of the energy produced by PV and the non-fuel volumetric energy rate.

We assess the impact of these mitigation measures on achieved ROE and average retail rates by comparing the scenarios with 10% PV and the mitigation measure to scenarios with 10% PV and no mitigation measure (see Figure 25). As a point of reference, this figure and others throughout the remainder of this section also show the change in each metric between 0% and 10% PV under base-case conditions (i.e., with no mitigation measure), in order to illustrate the extent to which each mitigation measure either offsets or exacerbates the effect of PV. We focus our assessment of the effectiveness of RPC decoupling and LRAM on the change in achieved

[43] Critics of decoupling contend that it removes the utility's incentive to manage its costs between GRCs, among other things.
[44] As of July 2013, 14 states had approved revenue decoupling mechanisms for at least one utility (IEE 2013). See RAP (2011) for a description of the different forms of decoupling. We model RPC decoupling because it is the most common.
[45] As of July 2013, 18 states had approved lost-revenue adjustment mechanisms for at least one utility (IEE 2013).

average ROE, though the earnings impacts (which are included in Appendix E) are qualitatively similar.

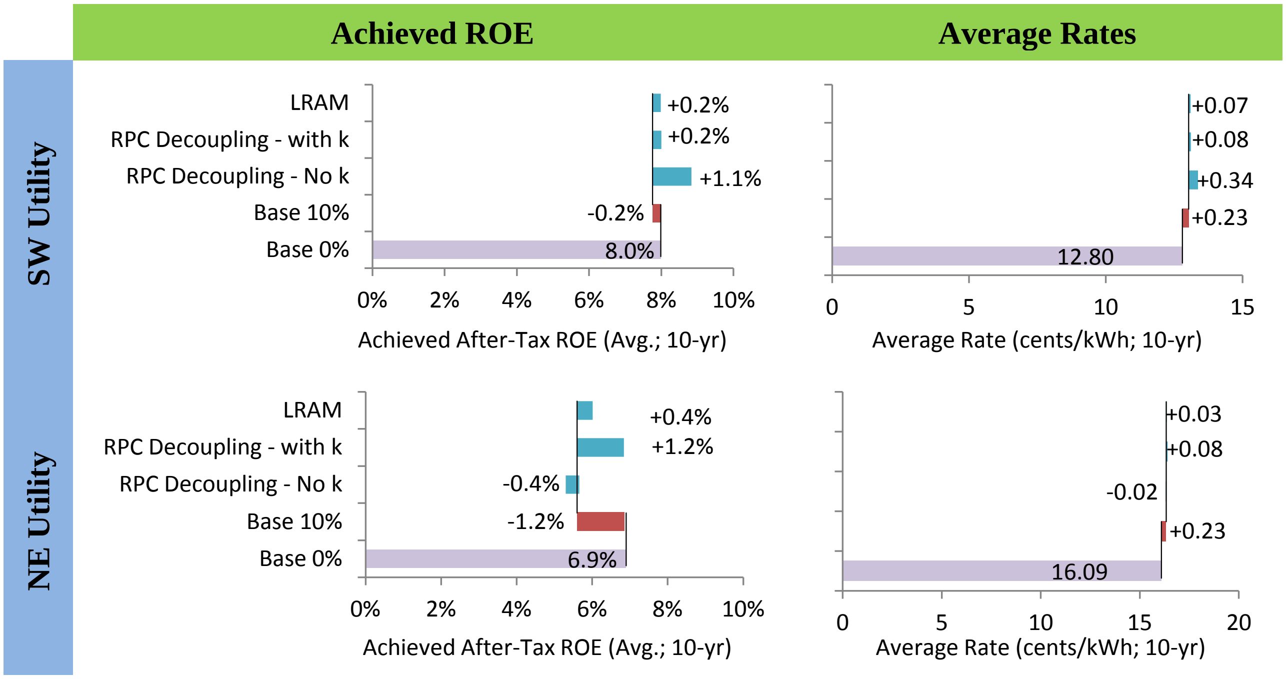



**Figure 25. Mitigation of PV Impacts through Decoupling and LRAM**

As shown in Figure 25, the various mitigation measures generally improve utility ROE, relative to cases with 10% PV and no mitigation measure, though to vastly varying degrees depending on the utility, the type of measure, and its design. With respect first to decoupling, implementing RPC decoupling *without* a k-factor leads to a 108 basis-point increase in achieved ROE for the SW Utility, resulting in an average ROE exceeding the level achieved without PV. This significant ROE improvement is due to the fact that growth in the number of customers is substantially higher than growth in non-fuel revenues in the base case with 10% PV,[46] and thus the utility collects substantially greater revenues when those revenues are tied more closely to growth in the number of customers, as occurs with RPC decoupling. Conversely, customer growth is low for the NE Utility relative to growth in non-fuel revenues, thus RPC decoupling without a k-factor actually exacerbates ROE erosion. For both utilities, RPC decoupling with a k-factor restores ROE back to the level achieved without PV, under base case conditions. This outcome is by design, based on choice of the k-factor (which, in the case of our analysis, requires a negative k-factor for the SW Utility and a positive k-factor for the NE Utility).

We see an improvement in achieved average ROE when we implement a LRAM in the case with 10% PV. A LRAM is designed to mitigate only the revenues lost due to the customer-sited PV savings (as opposed to the RPC decoupling mechanism that is designed to mitigate *all* lost revenues). To calculate the additional revenues to the utility from the LRAM, we multiplied the

[46] Non-fuel revenues are the point of comparison because we assume the utility collects fuel revenues on an annual basis through an FAC, which perfectly matches fuel revenues with fuel and purchased power costs. Growth in non-fuel revenues is a function of growth in billing determinants (retail sales, peak demand, and number of customers).

energy savings from customer-sited PV by the non-fuel volumetric energy rate. In the SW Utility the LRAM virtually achieves ROE comparability, but in the NE Utility an LRAM is not enough to achieve ROE comparability. This is due primarily to the fact that the LRAM, as implemented in our analysis, only compensates the utility for lost non-fuel *energy* revenues and does not include utility revenues collected via a *demand* charge, which are also reduced by customer-sited PV. The NE Utility collects a larger proportion of non-fuel revenues from a demand charge than the SW Utility, and the LRAM, therefore, only compensates the NE Utility for a small proportion of lost revenues.

To the extent that decoupling and LRAM mitigate the ROE impacts from customer-sited PV, they do so by increasing revenues, which necessarily increases average retail rates (given that average rates are simply total revenues divided by total retail sales).[47] Thus, while these measures may mitigate the impact of PV on shareholders, tradeoffs exist in the form of increases in average retail rates (albeit fairly modest ones for the particular scenarios examined here), above and beyond any rate increases that occur as a result of customer-sited PV. In particular, excluding the case of RPC decoupling without a k-factor, the decoupling and LRAM cases result in additional rate increases of 0.07 to 0.08 cents/kWh (0.5 to 0.6%) for the SW Utility and 0.03 to 0.08 cents/kWh (0.2 to 0.5%) for the NE Utility. The fact that increase in rates needed to achieve ROE comparability is similar between the two utilities, even though ROE must increase to a greater degree for the NE Utility, reflects the relatively small ratebase of the NE Utility compared to the SW Utility.

### 6.2 Shareholder incentive mechanisms may be used to create utility earnings opportunities from customer-sited PV

While decoupling and LRAM mechanisms may mitigate the revenue erosion from demand-side resources such as PV and EE, they do not address the other fundamental disincentive that the traditional electric utility business model creates towards those resources. Namely, those resources, to the extent that they defer capital expenditures by the utility, also erode its opportunity to generate earnings from those capital investments. One solution to correcting that incentive misalignment is to allow the utility to collect additional revenues for successful implementation of EE programs or achievement of energy savings goals, thereby creating positive earnings opportunities from EE investments by the utility.

Such so-called "shareholder incentive mechanisms" for EE have been used in many forms over the past two decades. Most commonly, shareholder incentives are based on a share of EE program costs or are calculated as a portion of the net benefits resulting from EE program implementation.[48] Depending on their specific design, shareholder incentive mechanisms may

[47] It may not always be the case that a decoupling mechanism results in increased customer bills. In particular, if a utility without decoupling collects more than its revenue requirement, the implementation of decoupling would result in a refund to customers. In addition, some jurisdictions (e.g., Colorado) have authorized "dead-bands" in conjunction with decoupling, in order to ensure that customer bills do not increase or decrease beyond a certain amount (e.g., 2%).

[48] As of July 2013, 28 states had approved a shareholder incentive mechanism for at least one utility, broken out as: 8 states with incentives based on a percentage of EE program costs, 13 states with incentives based on shared net

encourage utilities to meet or exceed energy savings targets (e.g. performance targets or cost bonus mechanisms), to invest shareholder funds in EE programs (e.g. cost capitalization programs), or to pursue efficiency options that produce the greatest net benefit (e.g., shared net benefits) (Cappers and Goldman 2009).

Because shareholder incentives for EE have generally been implemented in conjunction with utility-administered EE programs, we developed a mitigation case involving a shareholder incentive mechanism for customer-sited PV implemented in conjunction with a utility-administered PV rebate program.[49] For the purpose of isolating the impact of the shareholder incentive, we also include this rebate program in the comparison case without the shareholder incentive. Specifically, we assume that the utility offers a $0.5/W rebate for customer-sited PV (i.e., the same program explored earlier within the sensitivity analysis), and that the shareholder incentive is equal to 10% of the rebate cost (i.e., $0.05/W of customer-sited PV capacity installed in each year), where these additional revenues go directly to utility earnings. This is similar to a "cost capitalization" shareholder incentive mechanism, as has been used for utility-administered EE programs.

As shown in Figure 26, implementation of the modeled shareholder incentive mechanism increases both utilities' average achieved earnings, relative to what occurs with 10% PV and no shareholder incentive.[50] Under the specific shareholder incentive mechanism modeled here, earnings are not fully restored to the level achieved with no PV; naturally, the extent of earnings gains is a function of the design of the modeled shareholder incentive mechanism, where greater or lesser earnings gains could be achieved simply by increasing or decreasing the specified $0.05/W shareholder incentive. Important to note though is that shareholder incentives are generally not intended to achieve complete earnings comparability, but instead to compensate the utility only for the portion of earnings erosion associated with deferred/avoided capital expenditures (i.e., the lost earnings opportunity effect).

As in the case of decoupling and LRAM, any increase in achieved earnings associated with a shareholder incentive mechanism is the direct result of increased utility revenues, which by definition implies an increase in average retail rates and thus a tradeoff between the impacts on shareholders and ratepayers. In the case of the specific shareholder incentive mechanism modeled here, the shareholder incentives increase average retail rates by 0.04 cents/kWh for the SW Utility and 0.05 cents/kWh for the NE Utility (in addition to the increases that occur as a result of customer-sited PV under base-case assumptions).

benefits, 4 states with incentives based on a percentage of avoided costs, and 3 states with incentive mechanisms approved but specifics yet to be determined (IEE 2013).

[49] Even in cases where such programs are not offered, utilities may still be in a position to help or hinder the development of customer-sited PV through administrative practices related to net-metering and interconnection. A shareholder incentive may thus still be applicable in those cases by rewarding utilities for helping to reach policy goals related to the deployment of customer-sited PV.

[50] We focus here on achieved earnings over the first 10 years, as that is the period over which shareholder incentives are provided (given that they are tied to administration of the PV rebate program, which is offered only over the initial 10 years). As discussed earlier (see Figure 15), additional earnings erosion from customer-sited PV occurs in the second 10-year period, due to deferral of capital expenditures in those years.

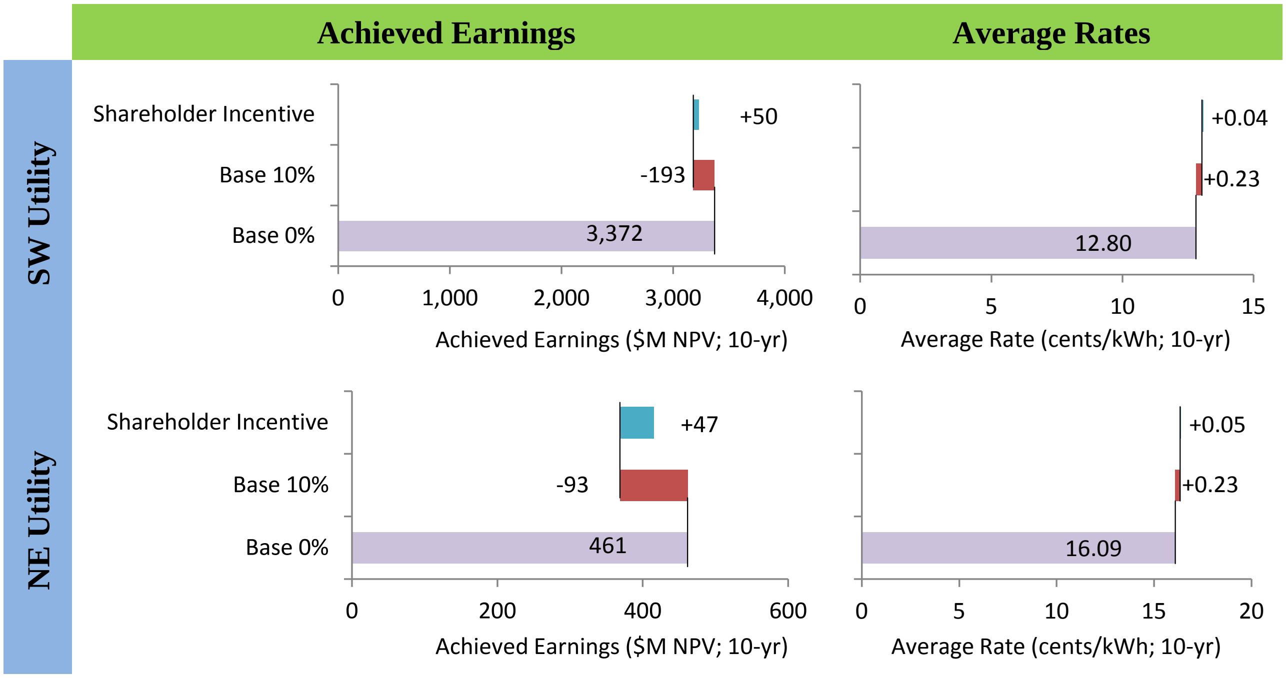



**Figure 26. Mitigation of PV Impacts through Shareholder Incentives**

## 6.3 Alternative ratesetting approaches may also significantly mitigate ROE impacts from customer-sited PV

Similar to decoupling and LRAM, the mitigation measures in this section may also serve to mitigate the revenue erosion from customer-sited PV and the associated impacts on shareholder ROE. However, while decoupling and LRAM achieve that outcome by potentially increasing revenue collection through rate adjustments in between rate cases, the mitigation measures considered in this section do so by reducing the amount of time between when utilities incur costs and when those costs are reflected in rates. These options, herein referred to as "alternative ratesetting approaches", include: more-frequent filing of rate cases, use of current or future test years in rate cases, and reduced regulatory lag between filing of rate cases and implementation of new rates. These measures boost utility revenues and shareholder ROE specifically in situations where utility costs are growing faster than its billing determinants, as is the case for both of the prototypical utilities under base-case conditions with 10% PV.

Alternative ratesetting approaches such as these have been discussed in the literature as a mitigation measure to address the disincentive for utilities to pursue EE, and might similarly be considered in the context of customer-sited PV (e.g., Carter 2001, Lowry et al. 2013). In Section 5, we found that utilities with more contemporaneous ratesetting approaches are less sensitive to the addition of customer-sited PV, while here we consider the adoption of alternative ratesetting approaches specifically as means to mitigating the financial impacts of PV on utility shareholders (i.e., where these ratesetting approaches are adopted in conjunction with PV).

To be sure, these ratesetting approaches entail a variety of important tradeoffs. More frequent filing of rate cases can reduce the incentives for utilities to minimize costs between rate cases and could potentially lead to perpetual rate cases (Carter 2001), which are costly and time consuming for regulatory staff and intervenors. Future test years require the use of sophisticated cost forecasts for establishing revenue requirements and billing determinants, which can be contentious (Costello 2013). And administrative process requirements can limit the potential for reducing regulatory lag between when new rates are adopted and when they go into effect.

Notwithstanding these important tradeoffs and limits, our analysis shows that these alternative ratesetting approaches may mitigate the impact of PV on achieved ROE. In fact, for the particular utilities and mitigation cases examined here, in most cases these measures more-than-offset the erosion in shareholder ROE caused by PV under base-case utility conditions, in which case they may be deemed as going "too far" in attempting to mitigate the effects of PV. As shown in Figure 27, the increase in ROE is most pronounced when switching from an historical test year to a future test year, resulting in an average ROE for both utilities that substantially exceeds the levels achieved under base case conditions without PV. Switching from an historical test year to a current test year or reducing regulatory lag by one year (which are functionally equivalent within the financial model used for this analysis) also increase achieved ROE to levels above the base-case ROE with no PV. Shortening the rate case filing frequency from three years to two years also mitigates the ROE impacts, though to a lesser extent than the other measures, and in the case of the NE Utility, only partially restoring achieved ROE back to the level achieved in the base case without PV.

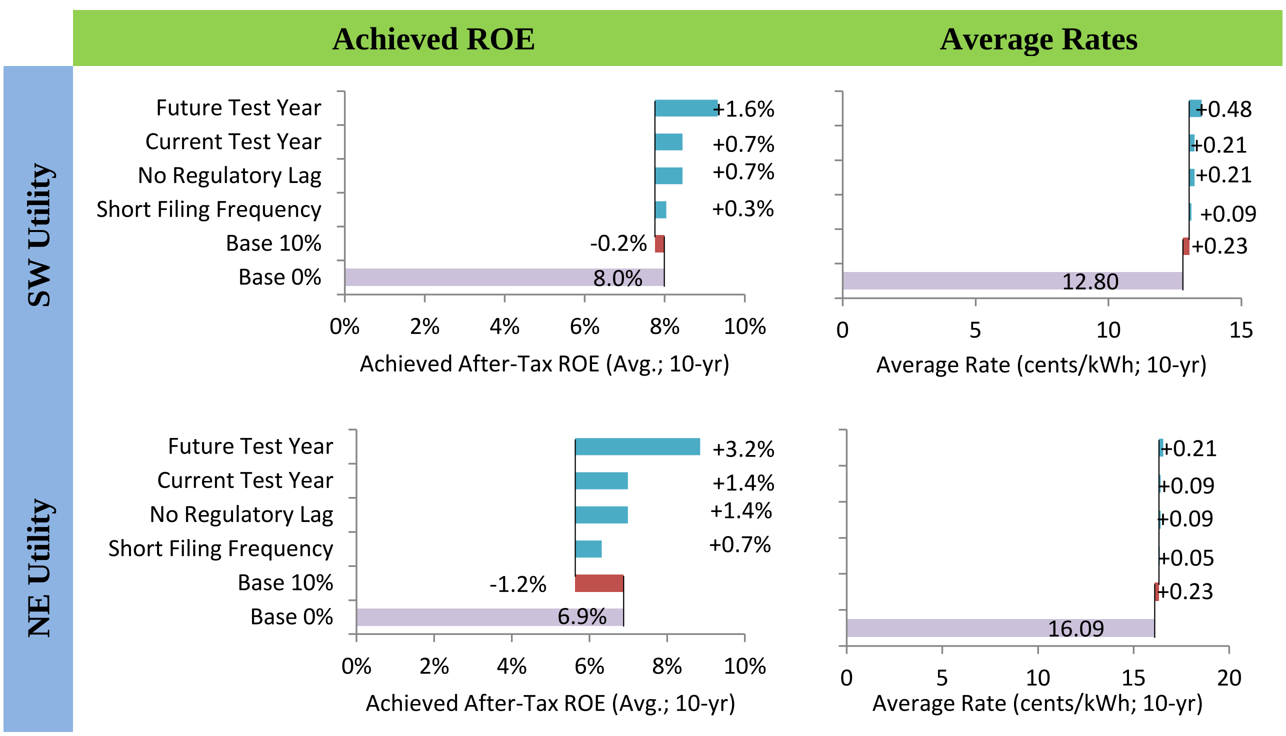



**Figure 27. Mitigation of PV Impacts through Alternative Ratesetting Approaches**

As with decoupling and LRAM, improved shareholder ROE under the mitigation measures considered here occurs as a result of increased revenue collection, which by definition entails an increase in average retail rates (beyond that which occurs in the base case with no PV). As noted above, however, in the case of these alternative ratesetting approaches, the increased revenues and thus the associated increase in average retail rates occurs specifically in cases where the utility's costs are increasing faster than its billing determinants. Under these particular conditions, more-contemporaneous ratesetting approaches improve the ability of the utility to reflect those cost increases in its retail rates, thereby potentially mitigating the impacts of customer-sited PV on shareholder ROE while exacerbating its impacts on average rates.

## 6.4 Increased fixed customer charges and demand charges can moderate the impact of PV on shareholder ROE, but in some cases may exacerbate those impacts

We assess the effectiveness of changes in rate design as a mitigation measure where the utility increases the share of revenue collected through demand or fixed customer charges in response to increased deployment of customer-sited PV. Because a large proportion of the utility's total costs are fixed in the short run (i.e., do not vary between rate cases with changes in consumption), collection of revenue based on a fixed charge may better match revenues to costs between rate cases, especially in an environment with low load growth. Similarly, an increase in revenue collected from demand charges may reduce the impact to utility collected revenues from declines in retail energy sales, because EE and PV do not reduce demand by as much as they reduce energy sales. Such changes to rate designs have often been proposed on occasion in order to mitigate the revenue erosion impacts of EE, and have been discussed more broadly as a strategy for better aligning utility revenues and costs (RAP 2011, EEI 2013, Hledik 2014).[51]

Important policy tradeoffs, however, arise in connection to increased fixed customer charges or demand charges, and corresponding decreases in volumetric energy charges. The first is that higher fixed charges reduce the incentive for customers to conserve energy and to invest in PV. Alternatively, high fixed charges might motivate customers to invest in onsite generation with storage, and to bypass the utility altogether – which would further exacerbate the problems that the change in rate design was intended to address in the first place. These potential dynamics highlight one important difference between high fixed customer charges and RPC decoupling: although both measures similarly tie utility revenues more closely to the number of customers (and growth therein), RPC decoupling does so in a manner that maintains the same volumetric charges for customers, and thus does not diminish customers' incentive for EE and distributed generation (or provide an increased incentive for grid defection). A separate but related policy tradeoff is that, in general, increased fixed customer charges limit customers' ability to manage their total utility bill, which may raise concerns related specifically with respect to low- and fixed- income customers. Increased demand charges may entail less severe tradeoffs than occur with high fixed customer charges, but many utilities do not have the meter capabilities to record and bill demand for residential customers, and thus a greater reliance upon demand charges for residential customers would require deployment of the necessary metering and billing systems.

[51] In particular, a form of rate design called straight-fixed variable (SFV) , where by fixed utility costs are recovered primarily through fixed customer charges, has been implemented in three states for electric utilities and 9 states for gas utilities (EEI 2013). Similarly some utilities are implementing fixed charges that are applied only to customers with PV (e.g., APS in Arizona, Dominion Virginia Power in Virginia). The motivation for targeted fixed charges is to ensure that customers with PV still contribute to covering a portion of the fixed costs of the utility system needed to serve customers with PV. Challenges in making these decisions include: determining what portion of costs are truly fixed in the long-run, determining how much of a cross-subsidy between participants and non-participants is acceptable, and balancing market transformation goals with considerations of equity, among others. We do not model targeted fixed customer charges, but note the importance of this issue for future analyses.

Although we do not examine these various policy tradeoffs within the context of the present analysis, we highlight their potential importance for decision-makers and for future studies.

For the purpose of our mitigation analysis, we specified two scenarios involving alternative rate designs – a high demand charge case and a high fixed customer charge case – applied to all customers. Both entail shifting all non-fuel costs that were recovered through volumetric charges in the base case to either demand charges (in the high demand charge case) or fixed customer charges (in the high fixed customer charge case). The resulting share of revenue collected through volumetric, demand, and fixed charges is shown in Table 9. Note that the high fixed customer charge case in this mitigation analysis is more heavily weighted towards customer charges than the high fixed customer charge case in the sensitivity analysis in Section 5. Note also that the shift in revenue allocation, from one scenario to another, is more severe for the SW Utility than for the NE Utility, because the NE Utility relies on energy market purchases to meet its entire retail sales obligation, and those costs are collected through volumetric energy charges in all cases. Finally, it is important to reiterate that these rates are applied to all customers (i.e., both those with PV and without PV) and to all rate classes, though we acknowledge that many of the rate design discussions surrounding PV involve changes to rate design just for customers with PV.[52]

**Table 9. Rate Design Mitigation Cases (Percent of Total Utility Revenues)**

| | Base Case | High Demand Charges | High Customer Charges |
|---|---|---|---|
| **SW Utility** | | | |
| Volumetric Charges | 77% | 24% | 24% |
| Demand Charges | 11% | 63% | 11% |
| Customer Charges | 12% | 12% | 65% |
| **NE Utility** | | | |
| Volumetric Charges | 84% | 64% | 64% |
| Demand Charges | 8% | 28% | 8% |
| Customer Charges | 8% | 8% | 28% |

In general, the results of these mitigation scenarios show that shifting revenue collection from volumetric energy charges to demand charges or fixed customers charges can mitigate shareholder impacts from customer-sited PV, though the degree of mitigation – and, indeed whether or not the shareholder impacts from PV are mitigated or *exacerbated* – depends critically on the specific circumstances of the utility. In describing the shareholder impacts of these mitigation measures, we focus here on the impacts to ROE, as rate design measures principally serve principally to address issues associated with revenue erosion, rather than lost earnings opportunities; however the impacts of each mitigation measure on achieved earnings are included for reference in Appendix D.

As shown in Figure 28, moving to a rate design with high fixed customer charges has dramatically different impacts on the SW Utility and NE Utility. In particular, the SW Utility sees a significant improvement in achieved average ROE with a high fixed customer charge,

[52] The financial model used for this analysis does not distinguish between participants and non-participants, or among customer classes, but future editions of the model and future research will explore differential rate designs for customers with and without PV, and for different rate classes.

with the increase in ROE more than offsetting the erosion in ROE that occurs under the 10% PV scenario with base case rate design assumptions. In contrast, the NE Utility sees a further erosion of shareholder ROE under the high fixed customer charge case.

The differing results for the two utilities reflect underlying differences in the relative growth rate for the number of customers compared to growth rate for retail sales. The SW Utility has customer growth of 2.7% per year compared to 1.7% annual growth in retail sales with 10% PV, while the NE Utility has customer growth of 0.3% per year compared to 1.0% annual growth in retail sales with 10% PV (from 2013 to 2032). As a result, tying growth in revenues more closely to growth in the number of customers increases revenue collection by the SW Utility, better aligning revenues and costs between rate cases, while the opposite occurs for the NE Utility. These divergent results for the two utilities mirror those that occur under the mitigation scenario involving RPC decoupling without a k-factor, for the same underlying reasons.

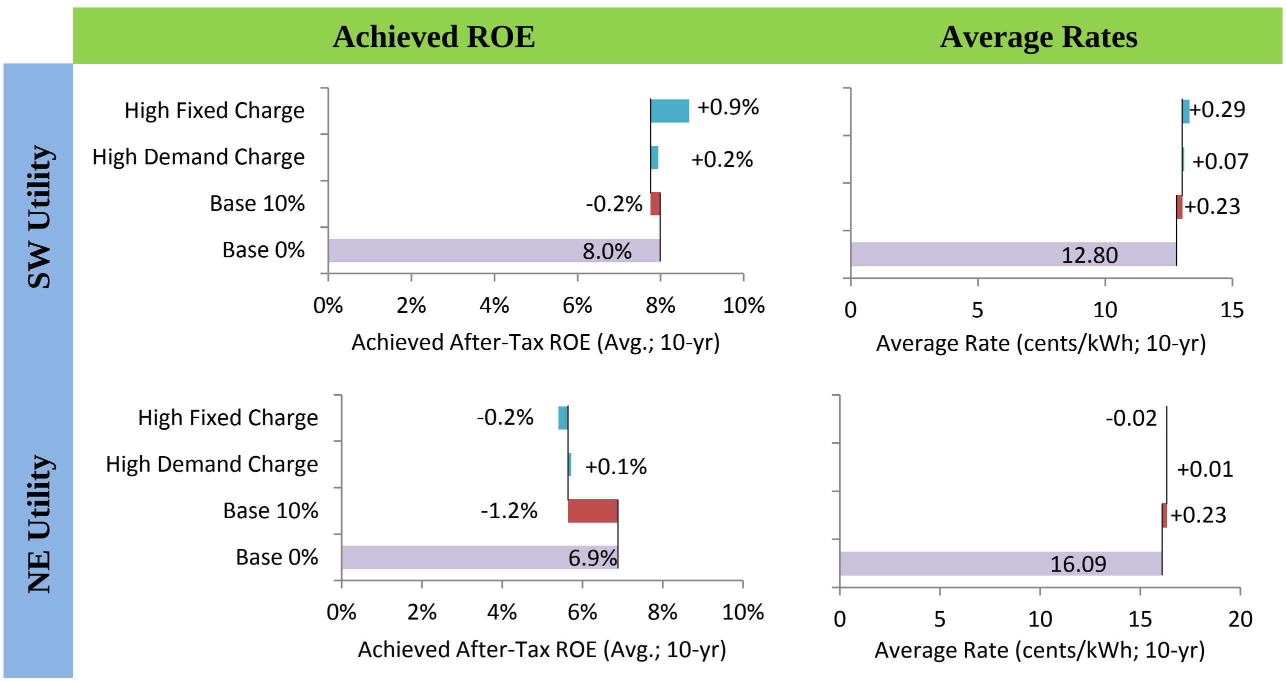


**Figure 28. Mitigation of PV Impacts through Increased Customer Charges or Demand Charges**

Moving to a rate design with high demand charges has a much more modest impact, compared to the high fixed charge scenario, resulting in a small increase in achieved ROE (relative to the base case at 10% PV penetration) for both utilities. These increases in achieved ROE reflect the fact that, for both prototypical utilities, growth in peak demand is greater than growth in retail sales with 10% PV. Tying non-fuel revenues to peak demand therefore allows the utility to collect greater revenues between rate cases than under the base case rate design.

Any increase in achieved ROE due to a shift towards higher fixed customer charges or demand charge is the direct result of an increase in total utility revenue collection. As with all of the other mitigation measures discussed thus far that also serve to increase revenues, some increase in average retail rates also occurs (beyond the increase that occurs in the base case with PV). As such, Figure 28 shows that average rates increase under the high fixed charge scenario for the

SW Utility and under the high demand charge scenario for both utilities. Important to note, however, is that such an increase in rates represents the average increase across all customers, and the impacts may differ substantially between customers with and without PV. Therefore one cannot conclude from this analysis how a move towards these particular rate design scenarios would impact customers without PV, and whether or not it would mitigate any increase in those customers' rates that otherwise occur as a result of customer-sited PV.[53]

### 6.5 Utility ownership of customer-sited PV may offer sizable earnings opportunities, potentially offsetting much of the earnings impacts from PV that otherwise occur

As with EE, customer-sited PV can erode shareholder earnings as a result of deferred or avoided capital expenditures, in addition to the earnings erosion associated with any mismatch in its effect on utility costs and revenues. In order to mitigate the shareholder impacts of lost earnings opportunities resulting from EE, utilities in some jurisdictions have been allowed to finance customer EE measures and earn an authorized return on those investments. Similarly, the lost earnings opportunities resulting from customer-sited PV could be mitigated by allowing customer-sited PV to become a regulated investment opportunity for utilities (SEPA 2008, SEPA 2009). This might involve full utility ownership of customer-sited PV assets, as proposed by APS and Tucson Electric Power (TEP), or may consist of utility financing of customer investments, similar to Public Service Electric and Gas (PSE&G)'s Solar Loan Program.[54]

To be sure, utility ownership or financing of customer-sited PV may raise a variety of significant policy and regulatory questions, not the least of which being whether a regulated utility should be allowed to provide a service similar to that provided by unregulated, competitive companies (including, in some cases, unregulated affiliates of the utility). In the case of a regulated utility, ratepayers would generally bear some portion of the risk of such investments. Furthermore, some states no longer allow regulated utilities to own generation (as in our NE Utility), in which case utility ownership of customer-sited generation may be prohibited or would require special authorization.[55]

Putting aside those important policy questions, we assume for the purpose of our analysis that the regulated utility is allowed to own customer-sited PV[56] and earn its authorized rate of return on those assets. We consider two scenarios: one bookend scenario in which the utilities own 100%

[53] As noted elsewhere in this report, LBNL expects to conduct follow-up analyses to examine the differential impacts of changes in rate design on customers with and without PV.

[54] The APS and TEP proposals differ in important ways, but both would involve utility ownership of PV systems installed on customer rooftops. Under the PSE&G Solar Loan program, the regulated utility provides loans to residential and commercial customers to purchase PV systems (which are net-metered), and the utility is allowed to add the cost of the program to its ratebase.

[55] See Wiser et al. (2010) for examples of utility ownership of customer-sited PV, including the Massachusetts Green Communities Act of 2008, which allows the state's regulated electric distribution companies to construct, own, and operate up to 50 MW of solar generation each.

[56] We assume that customer-sited PV costs $5.5/W_{dc}$ in 2010 and declines linearly to $2.1/W_{dc}$ in 2020, which corresponds to the mid-point cost reduction case from DOE's SunShot Vision Study (DOE 2012). We also assume that the utility is able to take advantage of the 30% investment tax credit (ITC) for installations prior to the end of 2016 and a 10% ITC for installations after 2016 (as would be the case for systems owned by any commercial entity, including a regulated utility).

of customer-sited PV capacity in their service territories, and another in which they own 10% of PV capacity. As in all other scenarios, PV systems are assumed to be installed behind the customer-meter and interconnected via a standard net metering arrangement; thus the impacts on utility billing determinants under this mitigation scenario are the same as in the base case. However, the utility is assumed to receive additional revenues from customers with PV systems that are owned or financed by the utility, and those revenues are assumed to be sufficient to provide the utility both a return *of* and *on* its investment. For the purpose of modeling this mitigation measure, we assume that these additional revenues can be approximated by adding the up-front cost of the customer-sited PV systems to the utility's ratebase, in the year in which the systems are installed.[57] With this approach, the SW and NE Utility capital costs increased by $2.8 billion and $2.6 billion, respectively, under the scenario where 100% of customer-sited PV is owned by the utility, and by proportionally smaller amounts under the scenario with utility ownership of 10% of all customer-sited PV.

For the purpose of examining this set of mitigation strategies, we focus on the impacts to shareholder ROE and earnings over the full 20-year analysis period, given that the lost earnings opportunities associated with customer-sited PV occur over that entire span (Figure 29). We do present impacts on rate impacts, as the incremental changes to average rate impacts for these mitigation cases are assumed to fall solely on PV customers, and thus changes to average rates for all customers (which is what the financial model estimates) are not a meaningful measure.

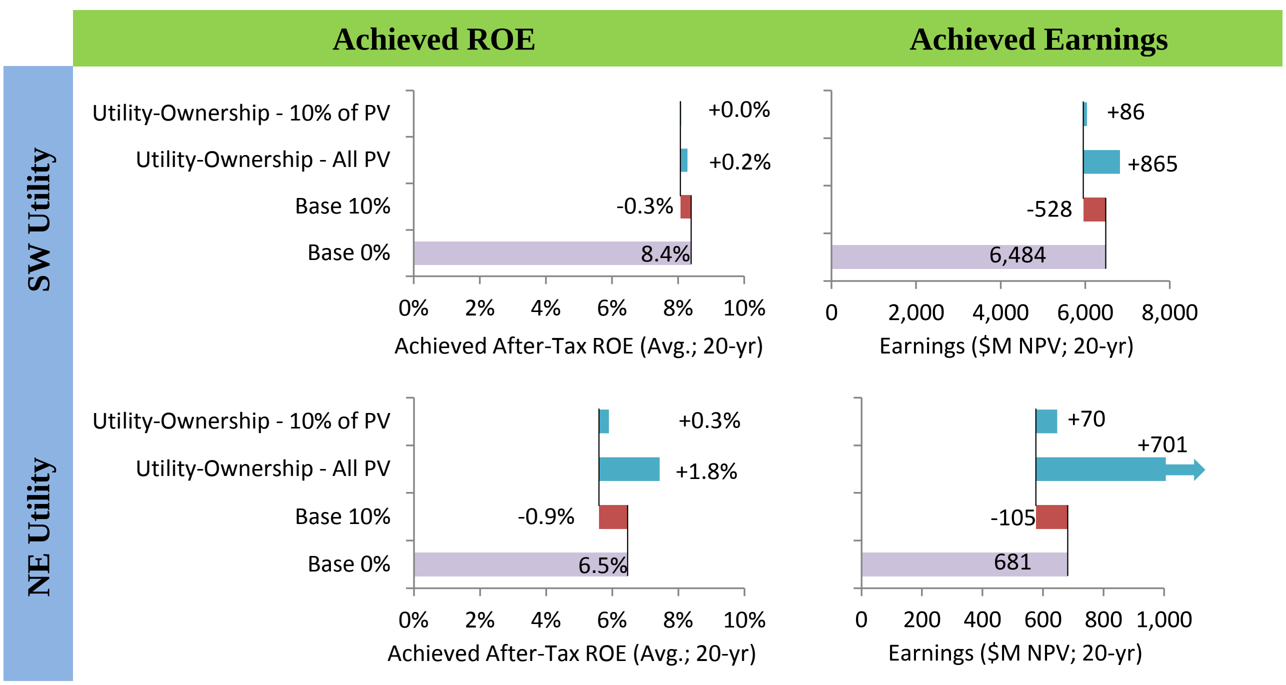



**Figure 29. Mitigation of PV Impacts through Utility Ownership of Customer-Sited PV**

[57] This modeling approach is thus akin to a cost capitalization shareholder incentive for EE programs, where EE program costs are added to the utility ratebase and recovered from all ratepayers. In the case of utility-owned, net-metered PV, revenues required to recover the cost of utility-owned PV would, in all likelihood, be recovered only from participating customers (e.g., via on-bill financing or some other mechanism), but for simplicity, we model revenue impacts as though they were recovered through base rates.

Under the scenarios in which the utilities own all customer-sited PV, achieved earnings and ROE rise significantly. In fact, for the NE Utility, where the only other utility investments are in the distribution system, allowing all PV to be owned by the utility leads to a doubling of achieved earnings over the 20-year analysis period. The SW Utility has a much larger ratebase prior to the addition of customer-sited PV, so the impact of utility ownership of PV is less dramatic, though the increase in earnings nevertheless more-than-offsets the decline in earnings that occurs under the base case with 10% PV. Under the arguably more realistic scenario in which the utilities own 10% of customer-sited PV, the increase in achieved earnings is only 10% of what occurs when the utilities own 100%. Thus, although achieved earnings and ROE increase for both utilities, those increases do not restore profitability back to the levels that occur under the base case without PV.

## 6.6 Automatically counting customer-sited PV towards RPS compliance can substantially mitigate the rate impacts from PV

The preceding mitigation measures all focused on addressing impacts of customer-sited PV on utility shareholders, and in most cases involved some corresponding increase in average rates. In contrast, one option for potentially mitigating the impacts on utility ratepayers is to automatically count all customer-sited PV directly toward the utility's RPS compliance obligation (without requiring any explicit payment by the utility).[58] This differs from the base case, where customer-sited PV indirectly reduces RPS compliance obligations by virtue of reducing retail sales, but RECs generated by customer-sited PV systems are assumed to remain the property of the system owner and are not automatically applied towards RPS compliance. In effect, this mitigation approach entails transferring ownership of RECs as a condition of receiving service under net-metering, thereby reducing the number of RECs that the utility would otherwise be required to procure in order to meet its RPS obligations.[59]

As do all other mitigation options, this one also involves a variety of tradeoffs. First is that it tantamount to reducing existing RPS requirements, as it reduces the amount of renewables that the utility would otherwise procure (without leading to any increase in customer-sited PV). Second, to the degree that customers' decisions to add PV is driven by their desire to retain or sell RECs from their PV system, automatically transferring REC ownership to the utility may degrade the value of PV to the customer and reduce deployment (as well as raise concerns about unlawful taking of private property). For these reasons and others, such transfers of REC ownership have often been controversial (Holt et al. 2007).

[58] Although not considered here, multipliers that are applied to RECs from customer-sited PV for purposes of RPS compliance would similarly serve to mitigate the rate impacts from customer-sited PV by reducing RPS compliance costs.

[59] In general, customer-sited PV is allowed by regulators to be counted towards utility RPS compliance; however, in most cases, ownership of the associated RECs remains with the owner of the system, unless the utility provides some kind of direct payment or explicit financial incentive. Recently, however, APS proposed an approach, termed "track and record", whereby all distributed solar in its service territory would be applied towards its RPS requirements, regardless of whether or not the systems received any direct financial incentive from the utility.

As shown in Figure 30, applying RECs generated by customer-sited PV toward the utilities' RPS compliance obligations without requiring any explicit utility payment offsets a substantial portion of the increases in average retail rates that otherwise occur in conjunction with customer-sited PV. In the case of the SW Utility, the rate impacts are reduced by roughly half, relative to the base case with 10% PV, while for the NE Utility, the rate impacts are offset almost in entirety. The degree of mitigation depends, among other factors, on the cost of avoided RECs, which in turn reflects the cost of renewable energy relative to non-renewable generation: when RECs are expensive, allowing customer-sited PV to count toward the RPS leads to a greater reduction in utility costs and thus a greater reduction in average rates. Thus, the mitigation is larger for the NE Utility, where assumed REC prices are higher ($35/MWh) than for the SW Utility (with an "effective" price of RECs of $23/MWh).[60] By the same logic, the results shown in Figure 30 would differ if other assumptions were made about the underlying cost of RECs (or, more generally, about the cost of renewable energy relative to the cost of non-renewable energy that RPS procurement displaces). Applying customer-sited PV toward utility RPS obligations does not impact utility ROE or earnings, as we assume that the avoided RPS compliance costs are an annual pass-through to customers.[61]

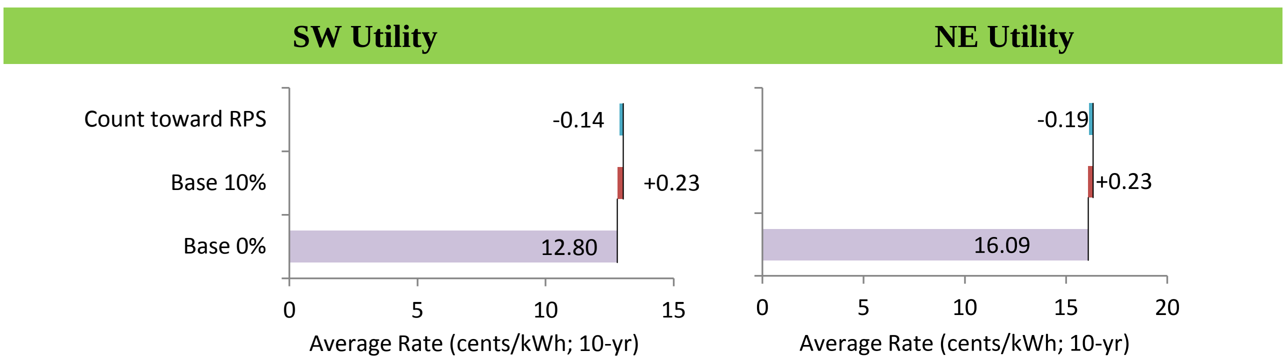



**Figure 30. Mitigation of PV Impacts by Applying RECs from Customer-Sited PV towards RPS Obligations**

[60] For simplicity of modeling, we apply this REC price for all RPS obligations of the NE Utility; had we assumed higher REC prices, such as those typical of solar set-aside markets, the mitigation of rate impacts would be even greater. The SW Utility is assumed to purchase RECs and energy as a bundled product, and thus the effective REC price is simply the difference between the cost of power purchase agreements (PPAs) for renewables and for conventional generation.

[61] We assume that the SW Utility meets its RPS obligation through a combination of utility-owned renewable generation and PPAs, but that PPAs are the marginal resource and are treated as pass-through costs.

# 7. Conclusion

This analysis relied upon a *pro-forma* financial model to quantify the potential impacts of customer-sited PV on two prototypical investor-owned utilities: a vertically integrated utility located in the southwest and wires-only utility located in the northeast. For each utility, we modeled the impacts of customer-sited PV over a 20-year period, estimating changes in utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity. These impacts were evaluated under a base-case set of assumptions for each utility, as well as under a wide range of sensitivity cases that considered alternate assumptions about the utilities' operating and regulatory environments. Finally, we analyze a number of possible options for mitigating the impacts of customer-sited PV on utility shareholders and ratepayers.

## 7.1 Policy Implications

The findings from this analysis suggest several policy implications. First, even at penetration levels substantially higher than exist today, the impact of customer-sited PV on average retail rates *may* be relatively modest. We consider customer-sited PV penetration levels that ramp up to 10% of retail sales in 2022, compared to current rates of 1-2% in high-penetration states and a U.S. average of 0.2%. For the two prototypical utilities considered within our analysis, this PV deployment trajectory leads to roughly a 3% increase in average, all-in retail rates under our base-case set of assumptions, and to a 0% to 4% rate increase across the various sensitivity cases tested. These results should, of course, be considered in light of the nature and scope of our analysis – for example, that they are modeled results based on certain assumptions about the prototypical utilities and about how distributed PV impacts costs and revenues, and that the analysis considers the impact of distributed PV in isolation from other factors that may simultaneously place downward pressure on sales and/or upward pressure on rates. Nevertheless, our analysis suggests that distributed PV is unlikely, on its own, to lead to rate impacts of such a magnitude as to dramatically alter the customer-economics of PV, and to thereby result in a "death spiral" of departing load and concomitant rate increases. To the extent that efforts to mitigate the rate impacts of customer-sited PV are still warranted, utilities, policymakers, and solar stakeholders likely have sufficient time to address these concerns in a measured and deliberate manner.

Compared to the impacts on ratepayers, the impacts of customer-sited PV on utility shareholders are potentially much more pronounced. In the case of the two prototypical utilities in our analysis, for example, shareholder earnings fell by 8% for the SW utility and by 15% for the NE utility under the base-case assumptions and at 10% PV penetration, but fell by as much as 13% and 41% (for the SW utility and NE utility, respectively) under certain other conditions. The potential magnitude of these impacts – especially among wires-only utilities or other utilities with a relatively small ratebase – may create more immediate pressure on utilities to address shareholders concerns about the erosion of profits caused by customer-sited PV. However, as shown in the analysis, these impacts are highly dependent upon the specifics of the utility operating and regulatory environment, and it will therefore be important for policymakers and others to consider the particular conditions of any individual utility when assessing the possible impacts of customer-sited PV on the utility's shareholders.

Finally, our analysis shows that a variety of measures that constitute arguably "incremental" changes to utility business or regulatory models (as opposed to wholesale paradigm shifts) could be deployed to mitigate the impacts of customer-sited PV on utility ratepayers and shareholders. As shown, however, the potential efficacy of these measures may vary considerably depending upon both their design and upon the specific utility circumstances. For example, within our analysis, when revenue-per-customer (RPC) decoupling is implemented in conjunction with customer-sited PV, the result can range from a worsening of utility profitability to a dramatic improvement in profitability beyond the level achieved without PV, depending on the utility and the choice of design elements (e.g., a "k-factor"). Moreover, many potential mitigation strategies entail substantive tradeoffs. These tradeoffs may exist between ratepayers and shareholders; for example, decoupling and other mitigation measures that involve changes to the way the utility collects revenue may lead to increases in average retail rates. Important tradeoffs may also exist among competing policy and regulatory objectives – for example, among the various principles of ratemaking, or between policy objectives associated with ratepayer equity and environmental goals. Given the complex set of issues involved in implementing many of the possible mitigation measures, regulators may wish to address concerns about the ratepayer and shareholder impacts of customer-sited PV within the context of broader policy- and rate-making processes.

## 7.2 Future Research

As a scoping study, one key objective of the present research is to help identify additional questions and issues worthy of further analysis. Although by no means an exhaustive list, these areas for future research include the following, many of which will be addressed through follow-on work to the present study and refinements to LBNL's utility financial model:

- ***Benchmark the impacts of customer-sited PV against other factors affecting utility profitability and customer rates.*** Utility shareholder returns and earnings, as well as retail electricity rates, are impacted by many factors, and various forms of cross-subsidy exist within utility ratemaking. Understanding how the impacts of PV measure up against these other issues may help utilities and policymakers gauge the severity and importance of the impacts associated with customer-sited PV, and budget their resources accordingly.

- ***Examine the combined impacts from customer-sited PV, aggressive energy efficiency, and other demand-side measures.*** This report examined the impacts of customer-sited PV in isolation. In reality, however, the growth of customer-sited PV is often occurring in tandem with aggressive energy efficiency programs and other changes to electricity consumption patterns and end-uses, and adoption of distributed storage technologies could potentially expand greatly in the future. Understanding how the impacts from these trends may compound and interact will enable more informed judgments about the severity of, and options for holistically addressing, any possible impacts on utility shareholders and ratepayers.

- ***Examine differential impacts among customer groups.*** The present analysis considered the impacts on utility ratepayers as a whole, but did not differentiate between the impacts among separate customer classes (e.g., residential vs. commercial) or between customers with and without PV. These distinctions are important both because of differences in underlying rate design among customer classes, and because certain mitigation measures are aimed at increasing revenue collection from solar customers, specifically.

- ***Examine a broader range of mitigation options and combinations thereof.*** For reasons of tractability, the present study considered only a subset of possible measures for mitigating the utility and ratepayer impacts from PV, and considered only individual mitigation options in isolation. A wide variety of other measures have also been suggested and are worthy of further analysis, including (among others): stand-by rates, time-based pricing, two-way rates such as value-of-solar tariffs or feed-in tariffs, bi-directional distribution rates, non-fuel cost trackers, formula rates, multi-year rate plans, separate customer classes for PV customers, unbundled pricing of utility services, and performance-based ratemaking (e.g., see Bird et al. 2013, Lowry et al. 2013, Linvill et al. 2013, Kihm and Kramer 2014). Analyzing varying combinations of such measures may allow for identification of comprehensive utility business and regulatory models to address issues related to customer-sited PV.

- ***Continue improving methods for estimating the avoided costs from customer-sited PV.*** As our analysis has shown, the impacts of customer-sited PV on utility shareholders and ratepayers are highly sensitive to the value of avoided costs. However, those avoided costs are complex and are often highly specific to the particular utility (or even to a localized region within the utility's service territory). Continued refinements to the methods and data used to estimate avoided costs – especially those related to avoided generation, transmission, and distribution capacity costs – will be critical to enabling reliable and utility-specific analyses of the shareholder and ratepayer impacts of customer-sited PV.

- ***Identify strategies for maximizing the avoided costs of customer-sited PV.*** In addition to the kinds of ratemaking and regulatory measures mentioned above, utilities and regulators may also be able to mitigate the rate impacts of customer-sited PV by directing or incentivizing its deployment in such a manner to maximize the avoided costs (e.g., through integrated distribution system planning, geographically targeted incentive structures, etc.).

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# Appendix A: Utility Characterization Key Inputs

The impact of PV on utility shareholders and ratepayers depends on the underlying characteristics of the utility. Further details on key aspects of the two prototypical utilities are provided below.

## Southwest Regional Load Forecasts

For the SW Utility energy and peak demand growth, we adjusted the load forecasts in the APS 2012 IRP to values that were representative of the southwest (i.e., 2.1% annual growth in energy and peak demand). We used load growth values from the Western Interconnection's most recent transmission expansion study.

| Balancing Authority | Load Growth (CAGR, 2010-2021) | |
|---|---|---|
| | Annual Energy | Peak Demand |
| **APS** | 2.7% | 2.7% |
| **CFE** | 2.9% | 4.0% |
| **EPE** | 2.6% | 2.8% |
| **NEVP** | 0.8% | 0.9% |
| **PACE** | 1.6% | 3.0% |
| **PNM** | 1.1% | 0.9% |
| **PSCO** | 1.0% | 0.3% |
| **SPP** | 1.0% | 0.8% |
| **SRP** | 1.3% | 1.1% |
| **TEP** | 0.3% | 0.0% |
| **WACM** | 2.2% | 2.2% |
| **WALC** | 1.0% | 1.0% |

*Source: WECC ten-year plan*

## Southwest Utility Line-Item Capital Investments

Since the SW Utility is vertically integrated, we model periodic investments in new utility-owned generation. The generators include natural gas-fired peaker plants (combustion turbines), natural-gas fired mid-merit plants (combined cycle gas turbines), and utility-scale PV plants. The utility-scale PV plants contribute to meeting the utility's RPS obligation.

| Year | Investment Type | Nameplate Capacity (MW) | Capital Cost ($M) | Annual O&M Cost ($M) |
|---|---|---|---|---|
| 2013 | Utility-scale PV | 100 | 200.0 | 2.50 |
| 2014 | Utility-scale PV | 100 | 200.0 | 2.50 |
| 2017 | Utility-scale PV | 100 | 200.0 | 2.50 |
| 2019 | Utility-scale PV | 200 | 400.0 | 5.00 |
| 2019 | Natural gas peaker | 103 | 123.8 | 0.63 |
| 2020 | Natural gas peaker | 103 | 126.9 | 0.65 |
| 2020 | Natural gas mid-merit | 672 | 719.6 | 4.05 |
| 2021 | Utility-scale PV | 100 | 200.0 | 2.50 |
| 2021 | Natural gas peaker | 616 | 780.1 | 3.96 |
| 2023 | Utility-scale PV | 100 | 200.0 | 2.50 |
| 2023 | Natural gas peaker | 615 | 806.3 | 4.14 |

| | | | | |
|---|---|---|---|---|
| 2024 | Natural gas peaker | 308 | 420.1 | 2.12 |
| 2025 | Utility-scale PV | 200 | 400.0 | 5.00 |
| 2025 | Natural gas mid-merit | 672 | 841.1 | 4.55 |
| 2027 | Utility-scale PV | 100 | 200.0 | 2.50 |
| 2027 | Natural gas peaker | 205 | 301.6 | 1.52 |
| 2029 | Natural gas peaker | 615 | 904.8 | 4.77 |
| 2031 | Natural gas peaker | 615 | 904.8 | 5.00 |

**Validation of Range of Fixed Customer Charges**

In the sensitivity analysis (Section 5) we consider a range of potential fixed customer charges and volumetric charges. For the High Customer Charges case, we assume a larger proportion of non-fuel costs that were allocated to volumetric charges in the Base Case are instead allocated to customer charges (and leave the fuel costs fully allocated to volumetric charges and the demand charges unchanged). The specific proportion of non-fuel costs allocated to customer charges was chosen such that the fixed customer charge portion of customer bills doubles from the base case.

We verified the reasonableness of this range by estimating the fraction of a typical residential customer bill that is based on fixed customer charges at a sample of utilities in the Southwest and Northeast (see Figure 31). In the Southwest, 1% to 19% of typical residential bills are made up of fixed customer charges (with actual charges ranging from $1.6 to $18.5/month). In the Northeast, 4% to 14% of typical residential bills are made up of fixed customer charges (with actual charges ranging from $4 to $16.4/month).

In each case we estimated typical bills based on the average residential customer consumption for the state (based on EIA Form 861 for 2012), the volumetric rate for residential customers, and the fixed customer charges for residential customers at each of the utilities.

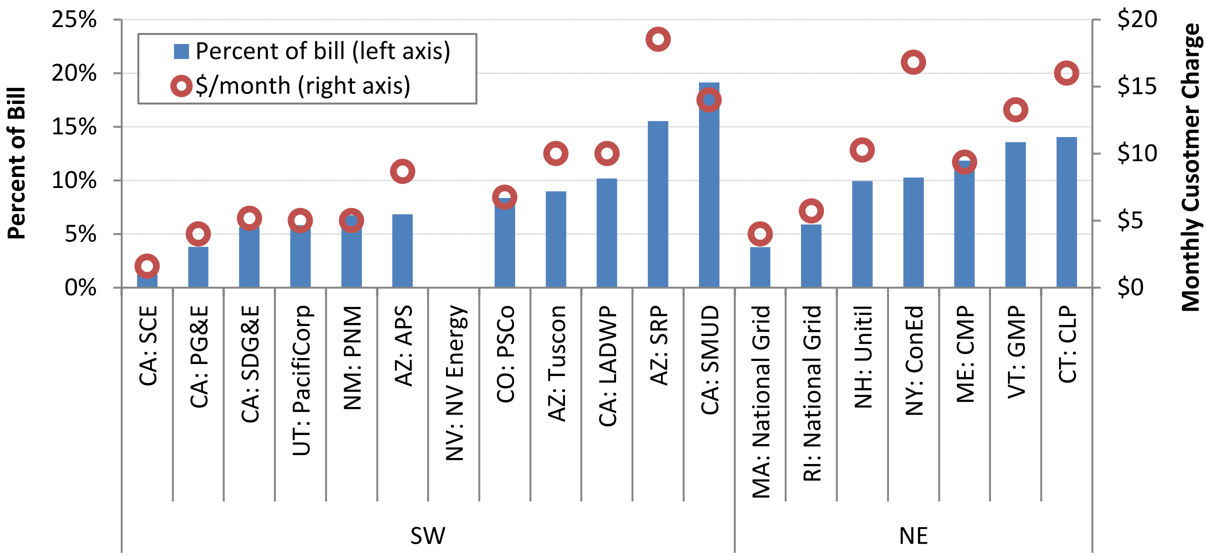


**Figure 31. Proportion of a Typical Residential Bill Derived from Fixed Customer Charges for Utilities in the Southwest and Northeast**

# Appendix B. PV Characterization

### Modeling the impact of PV on retail sales and peak demand

We assume that all customer-sited PV is on a net-metering rate that is otherwise the same as the rates for all other customers. PV generation therefore reduces sales on a one for one basis: one kWh of PV energy reduces the customer's sales billing determinant by one kWh. On the other hand, PV generation does not reduce the demand billing determinant on a one for one basis: one kW of PV reduces customer demand by less than one kW.

For the purpose of calculating the impacts of customer-sited PV on demand charge revenues, we use estimates of the capacity credit of PV (Hoff et al 2008) to estimate the reduction in peak demand from PV. At low penetration of PV, the contribution of PV to reducing peak demand is relatively high due to the correlation of PV production and peak demand. We also account for the decline in the capacity contribution of PV as PV penetration increases and peak net-load shifts into the early evening. For the SW utility, we use a relationship between the capacity credit of PV and PV penetration derived from NV Energy. For the NE Utility we use a relationship from Rochester Gas and Electric. We base the capacity credit of each increment of PV on the overall system level penetration of PV, which includes the assumed level of deployment of utility-scale PV.

### Modeling of impact of PV on costs

The capacity credit of PV also dictates the ability of customer-sited PV to defer generation investments for the SW Utility and the ability of PV to reduce capacity purchases from the FCM for the NE Utility. We further assume that only a fraction of the capacity credit at the system level applies to reducing utility investments in non-generation capital expenditures at the local level. In the High Value of PV scenario we slow the rate of decline of the capacity credit with increasing PV penetration, such that later vintages of PV installations still contribute to reducing peak demand.[62] We also assume that a greater fraction of the capacity credit at the system level can reduce non-generation capital investments. In the Low Value of PV sensitivity we assume a lower capacity credit for even early vintages of customer-sited PV[63] and we further assume that non-generation capital investments need to increase during the period when PV is being added.

Solar PV at low penetration levels tends to displace more expensive fuels due to its correlation with times of high demand. We define the time-of-delivery (TOD) energy factor as the ratio of the average fuel cost displaced by PV to the time-average marginal fuel cost over a year. The TOD energy factor of PV is greater than 100% at low penetration levels (indicating fuels displaced by PV are more expensive than the average marginal fuel). We also account for the decline in the TOD energy factor with increasing penetration of PV as PV begins to displace lower and lower cost fuels. We base the relationship of the TOD energy factor with penetration

[62] In particular we use the low rate of decline of the capacity credit of PV estimated for Portland General Electric in Hoff et al., 2008, but we still start with a high capacity credit at low penetration for our prototypical utilities.
[63] We use the low capacity credit and corresponding rate of decline of PV estimated for Portland General Electric in Hoff et al., 2008.

on merit-order dispatch analysis of generators in Arizona and ISO-NE for the SW and NE Utility, respectively. The TOD energy factor and marginal capacity credit of PV as PV penetration increases between 2013 and 2022 are shown for the SW Utility in Figure 32 and NE Utility in Figure 33.

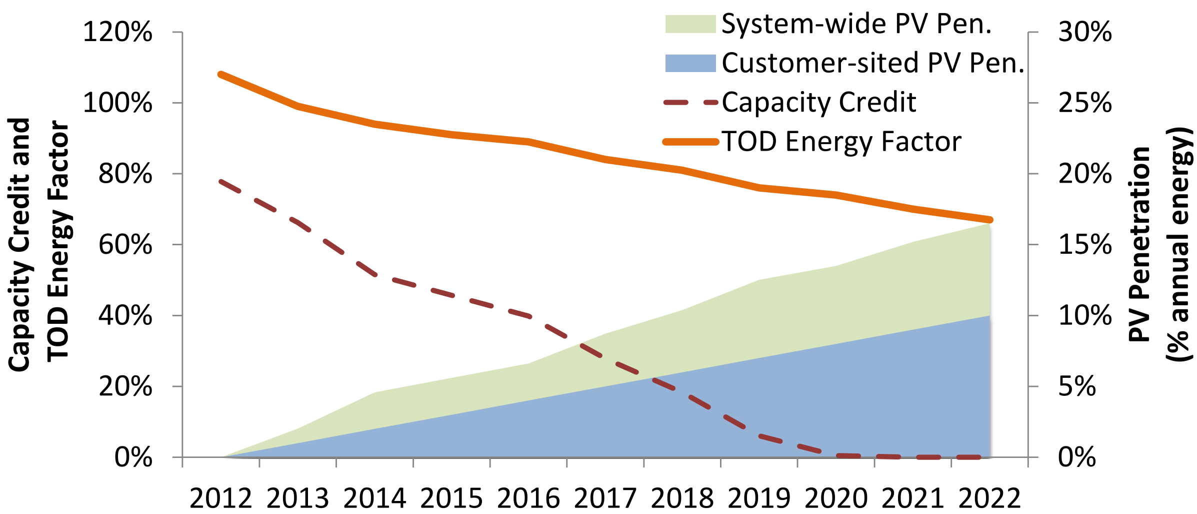


**Figure 32. Capacity Credit and TOD Energy Factor of PV for the SW Utility**

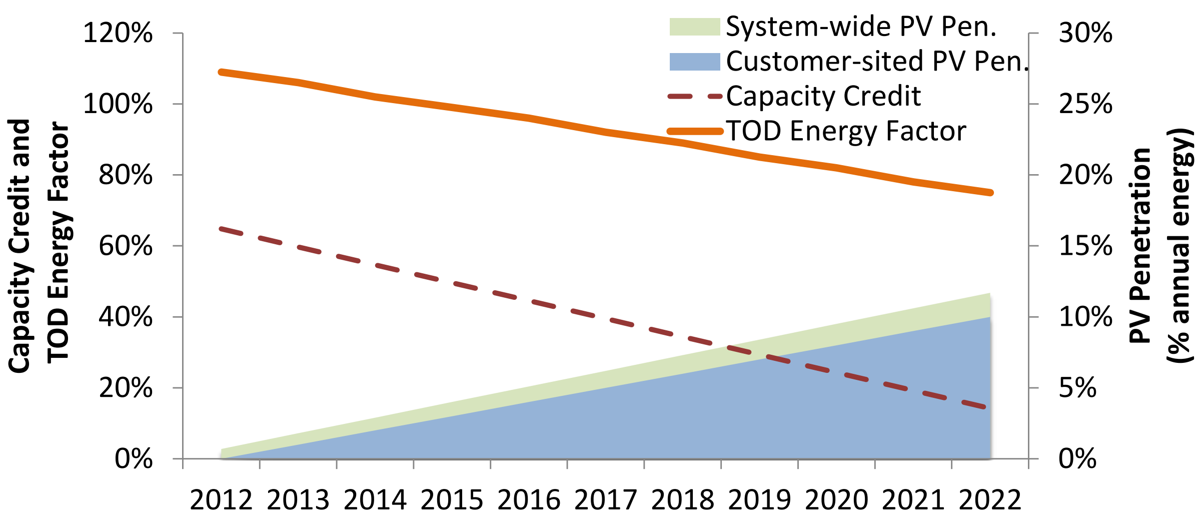


**Figure 33. Capacity Credit and TOD Energy Factor of PV for the NE Utility**

| Key Input | Southwest Utility | Northeast Utility |
|---|---|---|
| PV capacity credit at 0% PV penetration | 78% | 68% |
| Decline in incremental capacity credit per 1% increase in PV penetration | -5.7% | -4.6% |
| TOD Energy Factor at 0% PV penetration | 108% | 111% |
| Decline in TOD Energy Factor per 1% increase in PV penetration | -2.3% | -3.1% |

### Methods to approximate breakdown of value of PV

The model used to estimate the revenue requirement of the SW and NE Utility with and without PV involves many complex calculations. We benchmarked the avoided cost estimated by the model (see Figure 11) against a set of “back-of-the-envelope” calculations for the different value components of PV. We used values from 2018 as this year was the last year before PV began to defer lumpy conventional generation units in the SW Utility, which greatly complicates estimates of the change in the revenue requirement. The table below includes the method used to estimate each value component of PV, followed by the numerical parameters used in the model for the year 2018 for each of the utilities, and the resulting calculated value (as shown in Figure 11). In some cases, where a simple back-of-the envelope estimate was not available, we simply used a stipulated value for that component.

| PV Value Component | Method to Estimate Value | Southwest Utility | Northeast Utility |
|---|---|---|---|
| **Avoided Energy** | Average energy cost * TOD Energy Factor | $33/MWh * 98% = $32.4/MWh | $72/MWh * 89% = $63.8/MWh |
| **Avoided Losses – Energy** | Avoided Energy * Energy losses | $32.4/MWh * 7% = $2.3/MWh | $63.8/MWh * 4.1% = $2.6/MWh |
| **Avoided Capacity** | Capacity market price * Nameplate capacity of PV * PV capacity credit / Energy from PV | $88.6/kW-yr * 1008 MW * 41%/ 2030 GWh/yr = $17.9/MWh | $88.5/kW-yr * 945 MW * 47%/ 1408 GWh/yr = $27.9/MWh |
| **Avoided Losses-Capacity** | Avoided Capacity * Capacity Losses | $17.9/MWh * 15% = $2.7/MWh | $27.9/MWh * 8% = $2.2/MWh |
| **Avoided Reserves** | (Avoided Capacity + Avoided Losses-Capacity) * Reserve Margin | ($17.9/MWh + $2.7/MWh) * 14% = $2.9/MWh | ($27.9/MWh + $2.2/MWh) * 17.2% = $5.2/MWh |
| **Avoided RPS** | REC price * RPS Requirement | $23/MWh * 14% = $3.2/MWh | $35/MWh * 20% = $7/MWh |
| **Avoided Transmission** | SW: Assumption<br>NE: Transmission access charge * Percent of PV capacity credit that offsets transmission * Nameplate of PV * PV capacity credit / Energy from PV | Assumption = $5/MWh | $76.8/kW-yr * 20% * 945 MW * 47% / 1408 GWh/yr = $4.8/MWh |
| **Avoided Distribution** | Assumption | Assumption = $10/MWh | Assumption = $10/MWh |

# Appendix C. Base Case Results

We report the Base Case achieved earnings, return on equity, and all-in average retail rates with and without PV for the Southwest and Northeast Utility. In cases with PV we also report the percent change in the metric relative to the Base Case without PV.

***Southwest Utility***

| | Achieved After-Tax Earnings (% change from 0% PV Penetration) | | | | |
|---|---|---|---|---|---|
| **PV Penetration** | **0%** | **2.5%** | **5%** | **7.5%** | **10%** |
| **2013-2022 (10-year NPV @ WACC)** | $3.37B | $3.32B (-1.4%) | $3.27B (-2.9%) | $3.23B (-4.2%) | $3.18B (-5.7%) |
| **2013-2032 (20-year NPV @ WACC)** | $6.48B | $6.23B (-3.9%) | $6.25B (-3.6%) | $5.97B (-7.9%) | $5.96B (-8.1%) |

| | Achieved After-Tax ROE (% change from 0% PV Penetration) | | | | |
|---|---|---|---|---|---|
| **PV Penetration** | **0%** | **2.5%** | **5%** | **7.5%** | **10%** |
| **2013-2022 (10-year Avg. @ WACC)** | 7.99% | 7.97% (-0.3%) | 7.90% (-1.1%) | 7.84% (-1.8%) | 7.76% (-2.9%) |
| **2013-2032 (20-year Avg. @ WACC)** | 8.40% | 8.22% (-2.1%) | 8.30% (-1.1%) | 8.07% (-3.9%) | 8.07% (-3.9%) |

| | Average All-in Retail Rate (% change from 0% PV Penetration) | | | | |
|---|---|---|---|---|---|
| **PV Penetration** | **0%** | **2.5%** | **5%** | **7.5%** | **10%** |
| **2013-2022 (10-year Avg. @ 5%)** | 12.8 ¢/kWh | 12.8 ¢/kWh (0.3%) | 12.9 ¢/kWh (0.7%) | 13.0 ¢/kWh (1.2%) | 13.0 ¢/kWh (1.8%) |
| **2013-2032 (20-year Avg. @ 5%)** | 14.2 ¢/kWh | 14.2 ¢/kWh (0.0%) | 14.4 ¢/kWh (1.0%) | 14.4 ¢/kWh (1.3%) | 14.6 ¢/kWh (2.5%) |

***Northeast Utility***

| | Achieved After-Tax Earnings (% change from 0% PV Penetration) | | | | |
|---|---|---|---|---|---|
| **PV Penetration** | **0%** | **2.5%** | **5%** | **7.5%** | **10%** |
| **2013-2022 (10-year NPV @ WACC)** | $461M | $436M (-5.5%) | $412M (-10.7%) | $390M (-15.5%) | $368M (-20.2%) |
| **2013-2032 (20-year NPV @ WACC)** | $681M | $651M (-4.5%) | $623M (-8.6%) | $598M (-12.2%) | $576M (-15.4%) |

| | Achieved After-Tax ROE (% change from 0% PV Penetration) | | | | |
|---|---|---|---|---|---|
| **PV Penetration** | **0%** | **2.5%** | **5%** | **7.5%** | **10%** |
| **2013-2022 (10-year Avg. @ WACC)** | 6.88% | 6.56% (-4.7%) | 6.24% (-9.3%) | 5.94% (-13.7%) | 5.64% (-18.1%) |
| **2013-2032 (20-year Avg. @ WACC)** | 6.47% | 6.24% (-3.6%) | 6.01% (-7.1%) | 5.80% (-10.4%) | 5.60% (-13.5%) |

| | Average All-in Retail Rate (% change from 0% PV Penetration) | | | | |
|---|---|---|---|---|---|
| **PV Penetration** | **0%** | **2.5%** | **5%** | **7.5%** | **10%** |
| **2013-2022 (10-year Avg. @ 5%)** | 16.1 ¢/kWh | 16.1 ¢/kWh (0.1%) | 16.2 ¢/kWh (0.4%) | 16.2 ¢/kWh (0.8%) | 16.3 ¢/kWh (1.5%) |
| **2013-2032 (20-year Avg. @ 5%)** | 19.2 ¢/kWh | 19.2 ¢/kWh (0.2%) | 19.3 ¢/kWh (0.7%) | 19.5 ¢/kWh (1.5%) | 19.7 ¢/kWh (2.7%) |

# Appendix D: Sensitivity Analysis Results

We examine the sensitivity of the impact of PV to differences in the utility operating environment and regulatory environment from that modeled in the Base Case. This appendix includes a detailed description of the assumptions used in the sensitivity cases followed by tables with detailed results of the sensitivity cases for both the initial 10-year period (2013-2022) and the full 20-year analysis period (2013-2032). The sensitivity results show the earnings, ROE, and retail rates with and without PV, the difference in the metric, and the percent change in the metric with PV.

### *Sensitivity Case Definitions*

| | Sensitivity Case | Definition |
|---|---|---|
| Utility Operating Environment | High Value of PV | Incremental capacity credit of PV decreases at much slower rate with penetration. Increase offset of growth-related CapEx to 100% of PV capacity credit. |
| | Low Value of PV | Incremental capacity credit of PV at low penetration is only about 20%, and decreases at a slow rate with penetration. Decrease offset of Growth-related CapEx to 0% of PV capacity credit and increase capital expenditure growth rate by +1%/yr in years with new customer PV. |
| | High Load Growth | Load growth rate increased by +2%/yr and line item CapEx plan is shifted into earlier years (for SW Utility) |
| | Low Load Growth | Load growth rate decreased by -2%/yr and line item CapEx plan is shifted into later years (for SW Utility) |
| | High Fixed O&M Cost Growth | Fixed O&M cost growth rate increased by +2%/yr |
| | Low Fixed O&M Cost Growth | Fixed O&M cost growth rate decreased by -2%/yr |
| | High Non-Generating CapEx Growth | CapEx cost growth rate is increased by +1%/yr |
| | Low Non-Generating CapEx Growth | CapEx cost growth rate is decreased by -1%/yr |
| | High Fuel/Purchased Power Cost Growth | Fuel/purchased power cost growth rate is increased by +2%/yr |
| | Low Fuel/Purchased Power Cost Growth | Fuel/purchased power cost growth rate is decreased by -2%/yr |
| | Coal Retirement | 1200 MW of existing coal capacity is retired in 2018 and replaced with new natural gas-fired combined cycle plants (CCGT) |
| | High Utility-Owned Generation Share | Additional CCGT capacity (600 MW) is built in 2015 and 2018 to decrease the amount of short-term capacity purchased by the SW utility |
| | High Utility-Owned Generation Cost | Cost of building new utility-owned generation (UOG) is increased by +20% |
| | Low Utility-Owned Generation Cost | Cost of building new utility-owned generation (UOG) is decreased by -20% |
| | High FCM Cost Growth | Cost of purchasing capacity in the forward capacity market (FCM) is increased by +20% |
| | Low FCM Cost Growth | Cost of purchasing capacity in the FCM is decreased by -20% |
| Utility Regulatory Environment | Rate Design: High Fixed Customer Charge | Share of costs recovered through fixed customer charges is doubled and non-fuel costs recovered through volumetric energy charges is reduced |
| | Rate Design: High Volumetric Rates | Share of non-fuel costs recovered through volumetric energy rates is increased and fixed customer charges are eliminated |
| | Long Rate Case Filing Period | Filing period of general rate cases (GRCs) is increased by two years |
| | Short Rate Case Filing Period | Filing period of GRCs is decreased by one year |
| | Long Period of Regulatory Lag | Regulatory lag is increased by one year |
| | Short Period of Regulatory Lag | Regulatory lag is decreased by one year |
| | Current Test Year | Test year is changed from historic to current |
| | Future Test Year | Test year is changed from historic to future |
| | PV Incentives | Provide a $0.5/Watt incentive from the utility to customers with PV |

### *Southwest Utility – 10-year Sensitivity Results (2013 to 2022)*

| Sensitivity Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 3,372 | 7.99% | 12.80 |
| | 10% PV | 3,179 | 7.76% | 13.03 |
| | Difference | -193 | -0.23% | 0.23 |
| | **% Change** | **-5.7%** | **-2.9%** | **1.8%** |
| High Value of PV | 0% PV | 3,372 | 7.99% | 12.80 |
| | 10% PV | 3,127 | 7.81% | 12.82 |
| | Difference | -245 | -0.18% | 0.02 |
| | **% Change** | **-7.3%** | **-2.2%** | **0.1%** |
| Low Value of PV | 0% PV | 3,372 | 7.99% | 12.80 |
| | 10% PV | 3,192 | 7.57% | 13.17 |
| | Difference | -180 | -0.42% | 0.37 |
| | **% Change** | **-5.3%** | **-5.3%** | **2.9%** |
| High Load Growth | 0% PV | 4,276 | 8.55% | 12.65 |
| | 10% PV | 4,012 | 8.36% | 12.81 |
| | Difference | -263 | -0.19% | 0.16 |
| | **% Change** | **-6.2%** | **-2.3%** | **1.3%** |
| Low Load Growth | 0% PV | 2,662 | 7.37% | 13.04 |
| | 10% PV | 2,406 | 6.70% | 13.25 |
| | Difference | -256 | -0.67% | 0.21 |
| | **% Change** | **-9.6%** | **-9.1%** | **1.6%** |
| High Fixed O&M Growth | 0% PV | 3,219 | 7.62% | 12.98 |
| | 10% PV | 3,021 | 7.37% | 13.22 |
| | Difference | -198 | -0.26% | 0.24 |
| | **% Change** | **-6.2%** | **-3.3%** | **1.8%** |
| Low Fixed O&M Growth | 0% PV | 3,509 | 8.32% | 12.63 |
| | 10% PV | 3,321 | 8.10% | 12.85 |
| | Difference | -188 | -0.21% | 0.22 |
| | **% Change** | **-5.4%** | **-2.5%** | **1.7%** |
| High Non-Generating CapEx Growth | 0% PV | 3,412 | 7.61% | 12.97 |
| | 10% PV | 3,213 | 7.36% | 13.20 |
| | Difference | -199 | -0.25% | 0.24 |
| | **% Change** | **-5.8%** | **-3.3%** | **1.8%** |
| Low Non-Generating CapEx Growth | 0% PV | 3,332 | 8.35% | 12.65 |
| | 10% PV | 3,145 | 8.13% | 12.87 |
| | Difference | -187 | -0.21% | 0.22 |
| | **% Change** | **-5.6%** | **-2.5%** | **1.8%** |
| High Fuel Cost Growth | 0% PV | 3,372 | 7.99% | 13.32 |

| | | | | |
|---|---|---|---|---|
| | 10% PV | 3,179 | 7.76% | 13.50 |
| | Difference | -193 | -0.23% | 0.19 |
| | **% Change** | **-5.7%** | **-2.9%** | **1.4%** |
| Low Fuel Cost Growth | 0% PV | 3,372 | 7.99% | 12.35 |
| | 10% PV | 3,179 | 7.76% | 12.62 |
| | Difference | -193 | -0.23% | 0.27 |
| | **% Change** | **-5.7%** | **-2.9%** | **2.2%** |
| Coal Retirement | 0% PV | 3,389 | 7.72% | 13.01 |
| | 10% PV | 3,168 | 7.56% | 13.01 |
| | Difference | -221 | -0.17% | 0.01 |
| | **% Change** | **-6.5%** | **-2.1%** | **0.0%** |
| High Utility-Owned Generation Share | 0% PV | 3,407 | 7.63% | 12.85 |
| | 10% PV | 3,180 | 7.40% | 13.03 |
| | Difference | -228 | -0.23% | 0.18 |
| | **% Change** | **-6.7%** | **-3.0%** | **1.4%** |
| High Utility-Owned Generation Cost | 0% PV | 3,421 | 7.96% | 12.87 |
| | 10% PV | 3,187 | 7.69% | 13.06 |
| | Difference | -233 | -0.27% | 0.19 |
| | **% Change** | **-6.8%** | **-3.4%** | **1.5%** |
| Low Utility-Owned Generation Cost | 0% PV | 3,377 | 8.11% | 12.77 |
| | 10% PV | 3,171 | 7.82% | 13.00 |
| | Difference | -206 | -0.29% | 0.23 |
| | **% Change** | **-6.1%** | **-3.6%** | **1.8%** |
| High Fixed Customer Charge | 0% PV | 3,408 | 8.07% | 12.83 |
| | 10% PV | 3,268 | 7.97% | 13.10 |
| | Difference | -140 | -0.10% | 0.27 |
| | **% Change** | **-4.1%** | **-1.3%** | **2.1%** |
| High Volumetric Rates | 0% PV | 3,336 | 7.90% | 12.77 |
| | 10% PV | 3,091 | 7.54% | 12.96 |
| | Difference | -246 | -0.36% | 0.19 |
| | **% Change** | **-7.4%** | **-4.6%** | **1.5%** |
| Long Rate Case Filing Period | 0% PV | 3,177 | 7.51% | 12.66 |
| | 10% PV | 2,905 | 7.10% | 12.82 |
| | Difference | -271 | -0.42% | 0.16 |
| | **% Change** | **-8.5%** | **-5.5%** | **1.3%** |
| Short Rate Case Filing Period | 0% PV | 3,495 | 8.28% | 12.89 |
| | 10% PV | 3,293 | 8.04% | 13.11 |
| | Difference | -203 | -0.24% | 0.23 |
| | **% Change** | **-5.8%** | **-2.9%** | **1.8%** |
| Long Regulatory Lag | 0% PV | 3,157 | 7.49% | 12.65 |
| | 10% PV | 2,914 | 7.12% | 12.83 |
| | Difference | -243 | -0.37% | 0.18 |
| | **% Change** | **-7.7%** | **-4.9%** | **1.4%** |
| Short Regulatory Lag | 0% PV | 3,694 | 8.71% | 13.03 |

| | | | | |
|---|---|---|---|---|
| | 10% PV | 3,460 | 8.45% | 13.24 |
| | Difference | -234 | -0.26% | 0.21 |
| | **% Change** | **-6.3%** | **-3.0%** | **1.6%** |
| Current Test Year | 0% PV | 3,694 | 8.71% | 13.03 |
| | 10% PV | 3,460 | 8.45% | 13.24 |
| | Difference | -234 | -0.26% | 0.21 |
| | **% Change** | **-6.3%** | **-3.0%** | **1.6%** |
| Future Test Year | 0% PV | 4,031 | 9.50% | 13.27 |
| | 10% PV | 3,813 | 9.33% | 13.51 |
| | Difference | -218 | -0.17% | 0.23 |
| | **% Change** | **-5.4%** | **-1.8%** | **1.8%** |
| PV Incentives | 0% PV | 3,372 | 7.99% | 12.80 |
| | 10% PV | 3,179 | 7.76% | 13.26 |
| | Difference | -193 | -0.23% | 0.46 |
| | **% Change** | **-5.7%** | **-2.9%** | **3.6%** |

***Southwest Utility – 20-year Sensitivity Results (2013 to 2032)***

| Sensitivity Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 6,484 | 8.40% | 14.24 |
| | 10% PV | 5,956 | 8.07% | 14.59 |
| | Difference | -528 | -0.33% | 0.35 |
| | **% Change** | **-8.1%** | **-3.9%** | **2.5%** |
| High Value of PV | 0% PV | 6,484 | 8.40% | 14.24 |
| | 10% PV | 5,630 | 8.12% | 14.20 |
| | Difference | -854 | -0.27% | -0.04 |
| | % Change | **-13.2%** | **-3.2%** | **-0.3%** |
| Low Value of PV | 0% PV | 6,484 | 8.40% | 14.24 |
| | 10% PV | 6,145 | 7.92% | 14.85 |
| | Difference | -339 | -0.48% | 0.61 |
| | % Change | **-5.2%** | **-5.7%** | **4.3%** |
| High Load Growth | 0% PV | 8,929 | 8.99% | 13.93 |
| | 10% PV | 8,502 | 8.81% | 14.24 |
| | Difference | -427 | -0.18% | 0.31 |
| | **% Change** | **-4.8%** | **-2.0%** | **2.2%** |
| Low Load Growth | 0% PV | 4,434 | 7.62% | 14.61 |
| | 10% PV | 4,147 | 7.13% | 15.18 |
| | Difference | -288 | -0.49% | 0.57 |
| | **% Change** | **-6.5%** | **-6.4%** | **3.9%** |
| High Fixed O&M Growth | 0% PV | 6,235 | 8.06% | 14.57 |
| | 10% PV | 5,691 | 7.70% | 14.94 |
| | Difference | -544 | -0.36% | 0.37 |
| | **% Change** | **-8.7%** | **-4.5%** | **2.5%** |
| Low Fixed O&M Growth | 0% PV | 6,691 | 8.69% | 13.94 |
| | 10% PV | 6,176 | 8.39% | 14.27 |
| | Difference | -516 | -0.30% | 0.33 |
| | **% Change** | **-7.7%** | **-3.4%** | **2.4%** |
| High Non-Generating CapEx Growth | 0% PV | 6,908 | 7.96% | 14.73 |
| | 10% PV | 6,372 | 7.61% | 15.13 |
| | Difference | -535 | -0.35% | 0.40 |
| | **% Change** | **-7.7%** | **-4.4%** | **2.7%** |
| Low Non-Generating CapEx Growth | 0% PV | 6,131 | 8.81% | 13.84 |
| | 10% PV | 5,616 | 8.52% | 14.15 |
| | Difference | -515 | -0.28% | 0.31 |
| | **% Change** | **-8.4%** | **-3.2%** | **2.2%** |
| High Fuel Cost Growth | 0% PV | 6,484 | 8.40% | 15.25 |
| | 10% PV | 5,956 | 8.07% | 15.53 |

| | | | | |
|---|---|---|---|---|
| | Difference | -528 | -0.33% | 0.29 |
| | **% Change** | **-8.1%** | **-3.9%** | **1.9%** |
| Low Fuel Cost Growth | 0% PV | 6,484 | 8.40% | 13.47 |
| | 10% PV | 5,956 | 8.07% | 13.88 |
| | Difference | -528 | -0.33% | 0.41 |
| | **% Change** | **-8.1%** | **-3.9%** | **3.0%** |
| Coal Retirement | 0% PV | 6,713 | 8.28% | 14.63 |
| | 10% PV | 6,178 | 8.01% | 14.87 |
| | Difference | -535 | -0.27% | 0.25 |
| | **% Change** | **-8.0%** | **-3.2%** | **1.7%** |
| High Utility-Owned Generation Share | 0% PV | 6,708 | 8.21% | 14.44 |
| | 10% PV | 6,133 | 7.87% | 14.70 |
| | Difference | -575 | -0.34% | 0.25 |
| | **% Change** | **-8.6%** | **-4.1%** | **1.7%** |
| High Utility-Owned Generation Cost | 0% PV | 6,678 | 8.36% | 14.41 |
| | 10% PV | 6,042 | 7.98% | 14.70 |
| | Difference | -637 | -0.38% | 0.29 |
| | **% Change** | **-9.5%** | **-4.5%** | **2.0%** |
| Low Utility-Owned Generation Cost | 0% PV | 6,176 | 8.32% | 14.02 |
| | 10% PV | 5,864 | 8.16% | 14.48 |
| | Difference | -312 | -0.16% | 0.46 |
| | **% Change** | **-5.1%** | **-1.9%** | **3.3%** |
| High Fixed Customer Charge | 0% PV | 6,544 | 8.48% | 14.27 |
| | 10% PV | 6,067 | 8.24% | 14.64 |
| | Difference | -477 | -0.24% | 0.38 |
| | **% Change** | **-7.3%** | **-2.8%** | **2.6%** |
| High Volumetric Rates | 0% PV | 6,424 | 8.32% | 14.21 |
| | 10% PV | 5,844 | 7.90% | 14.54 |
| | Difference | -580 | -0.41% | 0.32 |
| | **% Change** | **-9.0%** | **-5.0%** | **2.3%** |
| Long Rate Case Filing Period | 0% PV | 6,289 | 8.08% | 14.15 |
| | 10% PV | 5,517 | 7.46% | 14.38 |
| | Difference | -772 | -0.62% | 0.23 |
| | **% Change** | **-12.3%** | **-7.6%** | **1.6%** |
| Short Rate Case Filing Period | 0% PV | 6,618 | 8.60% | 14.30 |
| | 10% PV | 6,091 | 8.29% | 14.65 |
| | Difference | -527 | -0.31% | 0.35 |
| | **% Change** | **-8.0%** | **-3.7%** | **2.5%** |
| Long Regulatory Lag | 0% PV | 6,068 | 7.86% | 14.06 |
| | 10% PV | 5,506 | 7.45% | 14.37 |
| | Difference | -562 | -0.40% | 0.32 |
| | **% Change** | **-9.3%** | **-5.1%** | **2.3%** |
| Short Regulatory Lag | 0% PV | 6,929 | 9.00% | 14.44 |
| | 10% PV | 6,430 | 8.75% | 14.81 |

| | | | | |
|---|---|---|---|---|
| | Difference | -499 | -0.25% | 0.38 |
| | **% Change** | **-7.2%** | **-2.8%** | **2.6%** |
| Current Test Year | 0% PV | 6,929 | 9.00% | 14.44 |
| | 10% PV | 6,430 | 8.75% | 14.81 |
| | Difference | -499 | -0.25% | 0.38 |
| | **% Change** | **-7.2%** | **-2.8%** | **2.6%** |
| Future Test Year | 0% PV | 7,397 | 9.67% | 14.64 |
| | 10% PV | 6,937 | 9.50% | 15.06 |
| | Difference | -459 | -0.16% | 0.41 |
| | **% Change** | **-6.2%** | **-1.7%** | **2.8%** |
| PV Incentives | 0% PV | 6,484 | 8.40% | 14.24 |
| | 10% PV | 5,956 | 8.07% | 14.73 |
| | Difference | -528 | -0.33% | 0.49 |
| | **% Change** | **-8.1%** | **-3.9%** | **3.4%** |

***Northeast Utility – 10-year Sensitivity Results (2013 to 2022)***

| Sensitivity Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 461 | 6.88% | 16.09 |
| | 10% PV | 368 | 5.64% | 16.33 |
| | Difference | -93 | -1.25% | 0.23 |
| | **% Change** | **-20.2%** | **-18.1%** | **1.5%** |
| High Value of PV | 0% PV | 461 | 6.88% | 16.09 |
| | 10% PV | 349 | 5.72% | 16.10 |
| | Difference | -112 | -1.16% | 0.01 |
| | % Change | **-24.3%** | **-16.8%** | **0.1%** |
| Low Value of PV | 0% PV | 461 | 6.88% | 16.09 |
| | 10% PV | 386 | 5.64% | 16.54 |
| | Difference | -75 | -1.24% | 0.44 |
| | % Change | **-16.3%** | **-18.1%** | **2.8%** |
| High Load Growth | 0% PV | 731 | 8.55% | 15.83 |
| | 10% PV | 633 | 7.61% | 16.05 |
| | Difference | -98 | -0.94% | 0.21 |
| | **% Change** | **-13.4%** | **-11.0%** | **1.3%** |
| Low Load Growth | 0% PV | 241 | 4.13% | 16.51 |
| | 10% PV | 150 | 2.56% | 16.79 |
| | Difference | -91 | -1.57% | 0.29 |
| | **% Change** | **-37.6%** | **-38.0%** | **1.7%** |
| High Fixed O&M Growth | 0% PV | 358 | 5.34% | 16.24 |
| | 10% PV | 262 | 4.01% | 16.48 |
| | Difference | -96 | -1.33% | 0.24 |
| | **% Change** | **-26.9%** | **-25.0%** | **1.5%** |
| Low Fixed O&M Growth | 0% PV | 554 | 8.26% | 15.96 |
| | 10% PV | 464 | 7.10% | 16.19 |
| | Difference | -90 | -1.16% | 0.23 |
| | **% Change** | **-16.2%** | **-14.1%** | **1.4%** |
| High Non-Generating CapEx Growth | 0% PV | 460 | 6.53% | 16.13 |
| | 10% PV | 366 | 5.35% | 16.36 |
| | Difference | -94 | -1.18% | 0.23 |
| | **% Change** | **-20.4%** | **-18.0%** | **1.5%** |
| Low Non-Generating CapEx Growth | 0% PV | 462 | 7.22% | 16.06 |
| | 10% PV | 370 | 5.90% | 16.30 |
| | Difference | -92 | -1.31% | 0.23 |
| | **% Change** | **-20.0%** | **-18.2%** | **1.5%** |
| High Fuel Cost Growth | 0% PV | 461 | 6.88% | 17.16 |

| | | | | |
|---|---|---|---|---|
| | 10% PV | 368 | 5.64% | 17.41 |
| | Difference | -93 | -1.25% | 0.26 |
| | **% Change** | **-20.2%** | **-18.1%** | **1.5%** |
| Low Fuel Cost Growth | 0% PV | 461 | 6.88% | 15.19 |
| | 10% PV | 368 | 5.64% | 15.41 |
| | Difference | -93 | -1.25% | 0.22 |
| | **% Change** | **-20.2%** | **-18.1%** | **1.4%** |
| High Forward Capacity Market Cost | 0% PV | 461 | 6.88% | 16.60 |
| | 10% PV | 368 | 5.64% | 16.83 |
| | Difference | -93 | -1.25% | 0.23 |
| | **% Change** | **-20.2%** | **-18.1%** | **1.4%** |
| Low Forward Capacity Market Cost | 0% PV | 461 | 6.88% | 15.59 |
| | 10% PV | 368 | 5.64% | 15.83 |
| | Difference | -93 | -1.25% | 0.24 |
| | **% Change** | **-20.2%** | **-18.1%** | **1.5%** |
| High Fixed Customer Charge | 0% PV | 428 | 6.38% | 16.06 |
| | 10% PV | 362 | 5.54% | 16.32 |
| | Difference | -66 | -0.84% | 0.26 |
| | **% Change** | **-15.4%** | **-13.2%** | **1.6%** |
| High Volumetric Rates | 0% PV | 495 | 7.38% | 16.13 |
| | 10% PV | 375 | 5.73% | 16.34 |
| | Difference | -120 | -1.65% | 0.21 |
| | **% Change** | **-24.3%** | **-22.3%** | **1.3%** |
| Long Rate Case Filing Period | 0% PV | 390 | 5.82% | 16.03 |
| | 10% PV | 282 | 4.32% | 16.24 |
| | Difference | -107 | -1.49% | 0.22 |
| | **% Change** | **-27.6%** | **-25.7%** | **1.3%** |
| Short Rate Case Filing Period | 0% PV | 499 | 7.44% | 16.13 |
| | 10% PV | 413 | 6.32% | 16.37 |
| | Difference | -86 | -1.12% | 0.24 |
| | **% Change** | **-17.2%** | **-15.0%** | **1.5%** |
| Long Regulatory Lag | 0% PV | 396 | 5.91% | 16.03 |
| | 10% PV | 285 | 4.37% | 16.24 |
| | Difference | -111 | -1.55% | 0.21 |
| | **% Change** | **-28.1%** | **-26.2%** | **1.3%** |
| Short Regulatory Lag | 0% PV | 530 | 7.91% | 16.16 |
| | 10% PV | 457 | 6.99% | 16.42 |
| | Difference | -73 | -0.92% | 0.26 |
| | **% Change** | **-13.8%** | **-11.6%** | **1.6%** |
| Current Test Year | 0% PV | 530 | 7.91% | 16.16 |
| | 10% PV | 457 | 6.99% | 16.42 |
| | Difference | -73 | -0.92% | 0.26 |
| | **% Change** | **-13.8%** | **-11.6%** | **1.6%** |
| Future Test Year | 0% PV | 624 | 9.30% | 16.25 |

| | | | | |
|---|---|---|---|---|
| | 10% PV | 579 | 8.85% | 16.54 |
| | Difference | -45 | -0.45% | 0.29 |
| | **% Change** | **-7.1%** | **-4.8%** | **1.8%** |
| PV Incentives | 0% PV | 461 | 6.88% | 16.09 |
| | 10% PV | 368 | 5.64% | 16.63 |
| | Difference | -93 | -1.25% | 0.54 |
| | **% Change** | **-20.2%** | **-18.1%** | **3.3%** |

***Northeast Utility – 20-year Sensitivity Results (2013 to 2032)***

| Sensitivity Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 681 | 6.47% | 19.19 |
| | 10% PV | 576 | 5.60% | 19.71 |
| | Difference | -105 | -0.87% | 0.52 |
| | **% Change** | **-15.4%** | **-13.5%** | **2.7%** |
| High Value of PV | 0% PV | 681 | 6.47% | 19.19 |
| | 10% PV | 505 | 5.36% | 19.30 |
| | Difference | -176 | -1.11% | 0.11 |
| | % Change | **-25.8%** | **-17.1%** | **0.6%** |
| Low Value of PV | 0% PV | 681 | 6.47% | 19.19 |
| | 10% PV | 626 | 5.63% | 20.05 |
| | Difference | -55 | -0.84% | 0.86 |
| | % Change | **-8.1%** | **-12.9%** | **4.5%** |
| High Load Growth | 0% PV | 1,272 | 8.68% | 18.71 |
| | 10% PV | 1,169 | 8.10% | 19.13 |
| | Difference | -103 | -0.58% | 0.42 |
| | **% Change** | **-8.1%** | **-6.7%** | **2.3%** |
| Low Load Growth | 0% PV | 250 | 2.81% | 19.99 |
| | 10% PV | 148 | 1.63% | 20.70 |
| | Difference | -103 | -1.18% | 0.71 |
| | **% Change** | **-41.0%** | **-41.9%** | **3.6%** |
| High Fixed O&M Growth | 0% PV | 476 | 4.56% | 19.48 |
| | 10% PV | 369 | 3.61% | 20.03 |
| | Difference | -108 | -0.95% | 0.55 |
| | **% Change** | **-22.6%** | **-20.8%** | **2.8%** |
| Low Fixed O&M Growth | 0% PV | 851 | 8.06% | 18.93 |
| | 10% PV | 749 | 7.26% | 19.44 |
| | Difference | -103 | -0.80% | 0.50 |
| | **% Change** | **-12.0%** | **-10.0%** | **2.6%** |
| High Non-Generating CapEx Growth | 0% PV | 713 | 6.09% | 19.30 |
| | 10% PV | 605 | 5.26% | 19.83 |
| | Difference | -108 | -0.83% | 0.53 |
| | **% Change** | **-15.1%** | **-13.7%** | **2.7%** |
| Low Non-Generating CapEx Growth | 0% PV | 652 | 6.81% | 19.10 |
| | 10% PV | 549 | 5.90% | 19.62 |
| | Difference | -103 | -0.91% | 0.52 |
| | **% Change** | **-15.8%** | **-13.3%** | **2.7%** |
| High Fuel Cost Growth | 0% PV | 681 | 6.47% | 21.35 |
| | 10% PV | 576 | 5.60% | 21.95 |

| | | | | |
|---|---|---|---|---|
| | Difference | -105 | -0.87% | 0.60 |
| | **% Change** | **-15.4%** | **-13.5%** | **2.8%** |
| Low Fuel Cost Growth | 0% PV | 681 | 6.47% | 17.56 |
| | 10% PV | 576 | 5.60% | 18.03 |
| | Difference | -105 | -0.87% | 0.47 |
| | **% Change** | **-15.4%** | **-13.5%** | **2.7%** |
| High Forward Capacity Market Cost | 0% PV | 681 | 6.47% | 19.89 |
| | 10% PV | 576 | 5.60% | 20.41 |
| | Difference | -105 | -0.87% | 0.52 |
| | **% Change** | **-15.4%** | **-13.5%** | **2.6%** |
| Low Forward Capacity Market Cost | 0% PV | 681 | 6.47% | 18.49 |
| | 10% PV | 576 | 5.60% | 19.02 |
| | Difference | -105 | -0.87% | 0.53 |
| | **% Change** | **-15.4%** | **-13.5%** | **2.8%** |
| High Fixed Customer Charge | 0% PV | 624 | 5.93% | 19.16 |
| | 10% PV | 546 | 5.31% | 19.69 |
| | Difference | -78 | -0.61% | 0.54 |
| | **% Change** | **-12.5%** | **-10.4%** | **2.8%** |
| High Volumetric Rates | 0% PV | 739 | 7.01% | 19.23 |
| | 10% PV | 607 | 5.88% | 19.73 |
| | Difference | -132 | -1.13% | 0.51 |
| | **% Change** | **-17.9%** | **-16.1%** | **2.6%** |
| Long Rate Case Filing Period | 0% PV | 560 | 5.33% | 19.12 |
| | 10% PV | 431 | 4.19% | 19.62 |
| | Difference | -130 | -1.14% | 0.50 |
| | **% Change** | **-23.1%** | **-21.4%** | **2.6%** |
| Short Rate Case Filing Period | 0% PV | 752 | 7.13% | 19.23 |
| | 10% PV | 655 | 6.36% | 19.77 |
| | Difference | -96 | -0.77% | 0.53 |
| | **% Change** | **-12.8%** | **-10.8%** | **2.8%** |
| Long Regulatory Lag | 0% PV | 565 | 5.38% | 19.12 |
| | 10% PV | 436 | 4.24% | 19.62 |
| | Difference | -129 | -1.14% | 0.50 |
| | **% Change** | **-22.8%** | **-21.1%** | **2.6%** |
| Short Regulatory Lag | 0% PV | 819 | 7.76% | 19.27 |
| | 10% PV | 739 | 7.17% | 19.82 |
| | Difference | -80 | -0.59% | 0.55 |
| | **% Change** | **-9.8%** | **-7.6%** | **2.8%** |
| Current Test Year | 0% PV | 819 | 7.76% | 19.27 |
| | 10% PV | 739 | 7.17% | 19.82 |
| | Difference | -80 | -0.59% | 0.55 |
| | **% Change** | **-9.8%** | **-7.6%** | **2.8%** |
| Future Test Year | 0% PV | 964 | 9.13% | 19.36 |
| | 10% PV | 911 | 8.84% | 19.93 |

| | | | | |
|---|---|---|---|---|
| | Difference | -53 | -0.29% | 0.57 |
| | **% Change** | **-5.5%** | **-3.1%** | **2.9%** |
| PV Incentives | 0% PV | 681 | 6.47% | 19.19 |
| | 10% PV | 576 | 5.60% | 19.90 |
| | Difference | -105 | -0.87% | 0.71 |
| | **% Change** | **-15.4%** | **-13.5%** | **3.7%** |

# Appendix E: Mitigation Analysis Results

We examine the effectiveness of different mitigation measures to lessen the impacts of PV modeled in the Base Case. This appendix includes detailed results of the mitigation cases for both the initial 10-year period (2013-2022) and the full 20-year analysis period (2013-2032). The mitigation results show the earnings, ROE, and retail rates at 10% PV compared to the Base Case at 10% PV without the mitigation measure.

***Southwest Utility – 10-year Mitigation Results (2013 to 2022)***

| Mitigation Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 3,372 | 7.99% | 12.80 |
| | 10% PV | 3,179 | 7.76% | 13.03 |
| | Difference | -193 | -0.23% | 0.23 |
| RPC Decoupling: No k-factor | 10% PV | 3,625 | 8.84% | 13.37 |
| | Difference from Base 10% | 446 | 1.08% | 0.34 |
| RPC Decoupling: with k-factor | 10% PV | 3,283 | 8.00% | 13.11 |
| | Difference from Base 10% | 104 | 0.24% | 0.08 |
| Lost Revenue Adjustment Mechanism | 10% PV | 3,277 | 7.99% | 13.10 |
| | Difference from Base 10% | 98 | 0.23% | 0.07 |
| Shareholder Incentive | 10% PV | 3,229 | 7.88% | 13.30 |
| | Difference from Base 10% | 50 | 0.12% | 0.27 |
| High Demand Charge | 10% PV | 3,269 | 7.94% | 13.10 |
| | Difference from Base 10% | 90 | 0.19% | 0.07 |
| High Fixed Customer Charge | 10% PV | 3,566 | 8.69% | 13.32 |
| | Difference from Base 10% | 387 | 0.93% | 0.29 |
| Short Rate Case Filing Frequency | 10% PV | 3,293 | 8.04% | 13.11 |
| | Difference from Base 10% | 113 | 0.28% | 0.09 |
| No Regulatory Lag | 10% PV | 3,460 | 8.45% | 13.24 |
| | Difference from Base 10% | 280 | 0.69% | 0.21 |
| Current Test Year | 10% PV | 3,460 | 8.45% | 13.24 |
| | Difference from Base 10% | 280 | 0.69% | 0.21 |
| Future Test Year | 10% PV | 3,813 | 9.33% | 13.51 |
| | Difference from Base 10% | 634 | 1.57% | 0.48 |
| Utility Ownership of PV - All PV | 10% PV | 3,751 | 8.01% | N/A |
| | Difference from Base 10% | 571 | 0.25% | N/A |
| Utility Ownership of PV - 10% of PV | 10% PV | 3,236 | 7.78% | N/A |
| | Difference from Base 10% | 57 | 0.03% | N/A |
| Customer-Sited PV Counted toward RPS | 10% PV | 3,179 | 7.76% | 12.89 |
| | Difference from Base 10% | 0 | 0.00% | -0.14 |

### *Southwest Utility – 20-year Mitigation Results (2013 to 2032)*

| Mitigation Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 6,484 | 8.40% | 14.24 |
| | 10% PV | 5,956 | 8.07% | 14.59 |
| | Difference | -528 | -0.33% | 0.35 |
| RPC Decoupling: No k-factor | 10% PV | 6,520 | 8.92% | 14.86 |
| | Difference from Base 10% | 564 | 0.85% | 0.27 |
| RPC Decoupling: with k-factor | 10% PV | 5,947 | 8.13% | 14.58 |
| | Difference from Base 10% | -8 | 0.06% | -0.01 |
| Lost Revenue Adjustment Mechanism | 10% PV | 6,053 | 8.23% | 14.64 |
| | Difference from Base 10% | 98 | 0.15% | 0.05 |
| Shareholder Incentive | 10% PV | 6,006 | 8.15% | 14.75 |
| | Difference from Base 10% | 50 | 0.08% | 0.17 |
| High Demand Charge | 10% PV | 6,059 | 8.22% | 14.64 |
| | Difference from Base 10% | 103 | 0.15% | 0.05 |
| High Fixed Customer Charge | 10% PV | 6,443 | 8.81% | 14.82 |
| | Difference from Base 10% | 487 | 0.74% | 0.23 |
| Short Rate Case Filing Frequency | 10% PV | 6,091 | 8.29% | 14.65 |
| | Difference from Base 10% | 136 | 0.22% | 0.06 |
| No Regulatory Lag | 10% PV | 6,430 | 8.75% | 14.81 |
| | Difference from Base 10% | 474 | 0.68% | 0.23 |
| Current Test Year | 10% PV | 6,430 | 8.75% | 14.81 |
| | Difference from Base 10% | 474 | 0.68% | 0.23 |
| Future Test Year | 10% PV | 6,937 | 9.50% | 15.06 |
| | Difference from Base 10% | 982 | 1.43% | 0.47 |
| Utility Ownership of PV - All PV | 10% PV | 6,821 | 8.29% | N/A |
| | Difference from Base 10% | 865 | 0.21% | N/A |
| Utility Ownership of PV - 10% of PV | 10% PV | 6,042 | 8.09% | N/A |
| | Difference from Base 10% | 86 | 0.02% | N/A |
| Customer-Sited PV Counted toward RPS | 10% PV | 5,956 | 8.07% | 14.45 |
| | Difference from Base 10% | 0 | 0.00% | -0.14 |

***Northeast Utility – 10-year Mitigation Results (2013 to 2022)***

| Mitigation Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 461 | 6.88% | 16.09 |
| | 10% PV | 368 | 5.64% | 16.33 |
| | Difference | -93 | -1.25% | 0.23 |
| RPC Decoupling: No k-factor | 10% PV | 345 | 5.28% | 16.31 |
| | Difference from Base 10% | -23 | -0.36% | -0.02 |
| RPC Decoupling: with k-factor | 10% PV | 450 | 6.88% | 16.41 |
| | Difference from Base 10% | 81 | 1.24% | 0.08 |
| Lost Revenue Adjustment Mechanism | 10% PV | 395 | 6.05% | 16.36 |
| | Difference from Base 10% | 27 | 0.41% | 0.03 |
| Shareholder Incentive | 10% PV | 416 | 6.36% | 16.68 |
| | Difference from Base 10% | 47 | 0.72% | 0.35 |
| High Demand Charge | 10% PV | 374 | 5.72% | 16.34 |
| | Difference from Base 10% | 6 | 0.08% | 0.01 |
| High Fixed Customer Charge | 10% PV | 353 | 5.40% | 16.31 |
| | Difference from Base 10% | -15 | -0.24% | -0.01 |
| Short Rate Case Filing Frequency | 10% PV | 413 | 6.32% | 16.37 |
| | Difference from Base 10% | 45 | 0.68% | 0.05 |
| No Regulatory Lag | 10% PV | 457 | 6.99% | 16.42 |
| | Difference from Base 10% | 89 | 1.36% | 0.09 |
| Current Test Year | 10% PV | 457 | 6.99% | 16.42 |
| | Difference from Base 10% | 89 | 1.36% | 0.09 |
| Future Test Year | 10% PV | 579 | 8.85% | 16.54 |
| | Difference from Base 10% | 211 | 3.22% | 0.21 |
| Utility Ownership of PV - All PV | 10% PV | 829 | 7.50% | N/A |
| | Difference from Base 10% | 461 | 1.87% | N/A |
| Utility Ownership of PV - 10% of PV | 10% PV | 415 | 5.95% | N/A |
| | Difference from Base 10% | 46 | 0.31% | N/A |
| Customer-Sited PV Counted toward RPS | 10% PV | 368 | 5.64% | 16.14 |
| | Difference from Base 10% | 0 | 0.00% | -0.19 |

### *Northeast Utility – 20-year Mitigation Results (2013 to 2032)*

| Mitigation Case | | After-Tax Achieved Earnings ($M NPV@WACC) | After-Tax Achieved ROE (% Avg.@WACC) | All-in Average Retail Rates (cents/kWh Avg.@WACC) |
|---|---|---|---|---|
| Base | 0% PV | 681 | 6.47% | 19.19 |
| | 10% PV | 576 | 5.60% | 19.71 |
| | Difference | -105 | -0.87% | 0.52 |
| RPC Decoupling: No k-factor | 10% PV | 469 | 4.60% | 19.64 |
| | Difference from Base 10% | -108 | -1.00% | -0.07 |
| RPC Decoupling: with k-factor | 10% PV | 642 | 6.27% | 19.76 |
| | Difference from Base 10% | 66 | 0.67% | 0.04 |
| Lost Revenue Adjustment Mechanism | 10% PV | 603 | 5.87% | 19.73 |
| | Difference from Base 10% | 27 | 0.27% | 0.02 |
| Shareholder Incentive | 10% PV | 624 | 6.07% | 19.93 |
| | Difference from Base 10% | 47 | 0.47% | 0.22 |
| High Demand Charge | 10% PV | 591 | 5.73% | 19.72 |
| | Difference from Base 10% | 15 | 0.14% | 0.01 |
| High Fixed Customer Charge | 10% PV | 502 | 4.91% | 19.67 |
| | Difference from Base 10% | -74 | -0.69% | -0.05 |
| Short Rate Case Filing Frequency | 10% PV | 655 | 6.36% | 19.77 |
| | Difference from Base 10% | 79 | 0.76% | 0.05 |
| No Regulatory Lag | 10% PV | 739 | 7.17% | 19.82 |
| | Difference from Base 10% | 163 | 1.57% | 0.10 |
| Current Test Year | 10% PV | 739 | 7.17% | 19.82 |
| | Difference from Base 10% | 163 | 1.57% | 0.10 |
| Future Test Year | 10% PV | 911 | 8.84% | 19.93 |
| | Difference from Base 10% | 335 | 3.24% | 0.21 |
| Utility Ownership of PV - All PV | 10% PV | 1,277 | 7.43% | N/A |
| | Difference from Base 10% | 701 | 1.84% | N/A |
| Utility Ownership of PV - 10% of PV | 10% PV | 646 | 5.90% | N/A |
| | Difference from Base 10% | 70 | 0.30% | N/A |
| Customer-Sited PV Counted toward RPS | 10% PV | 576 | 5.60% | 19.59 |
| | Difference from Base 10% | 0 | 0.00% | -0.13 |

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# Putting the Potential Rate Impacts of Distributed Solar into Context

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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**

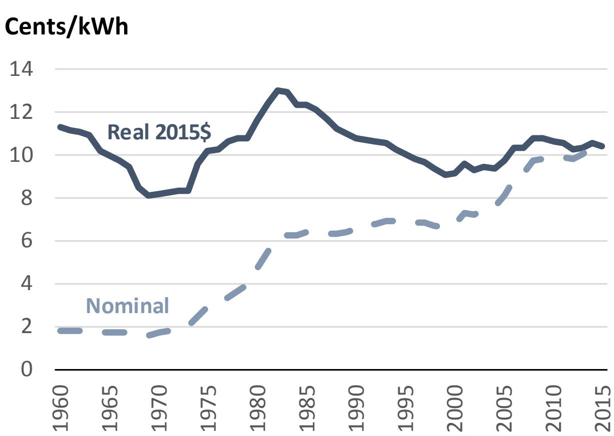
This paper presents illustrative comparisons between the effects of distributed solar and other drivers of retail electricity prices. **It does <u>not</u>:**

- **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.

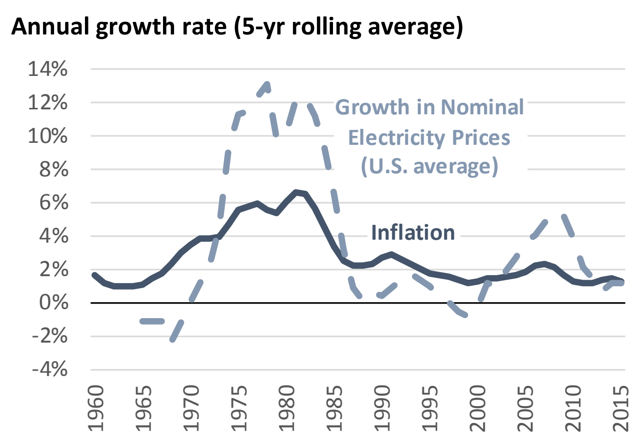
# 2. U.S. Retail Electricity Prices: Historical Trends and Current Projections

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.*

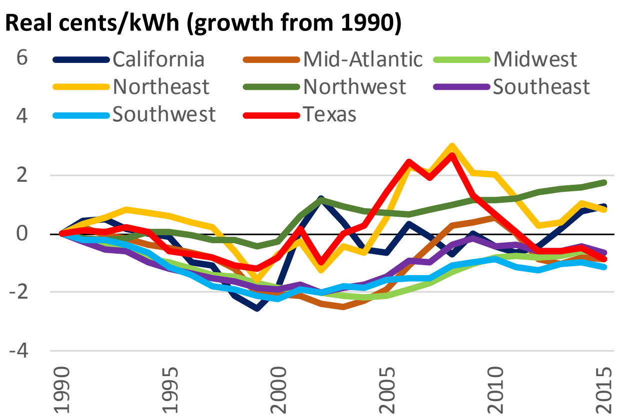
**Figure 2. Escalation of nominal electricity prices compared to inflation**

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

[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.

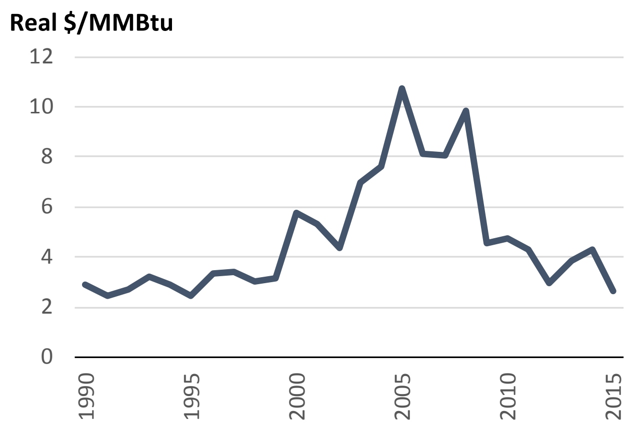
increases as those costs were passed into utilities' rate bases (Hirsh 1999). Slowing growth in electricity sales further exacerbated the effects of capital cost escalation on electricity prices, as utilities' increasing revenue requirements were spread across fewer (or more slowly growing) units of 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.*

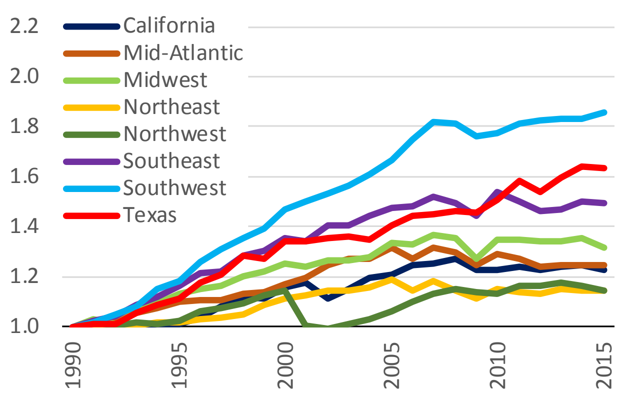
**Figure 4. Annual average natural gas prices**

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).

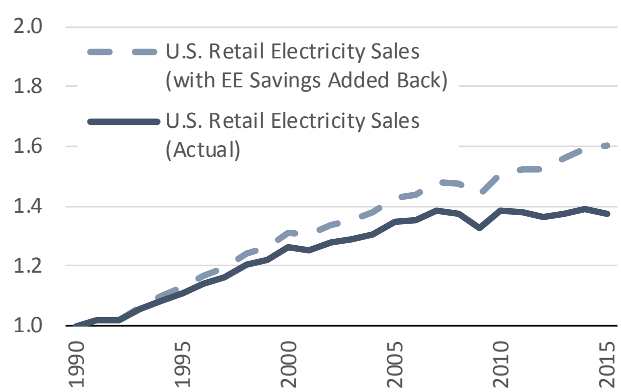
**Indexed retail electricity sales (1990=1)**




*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**

**Indexed retail electricity sales (1990=1)**



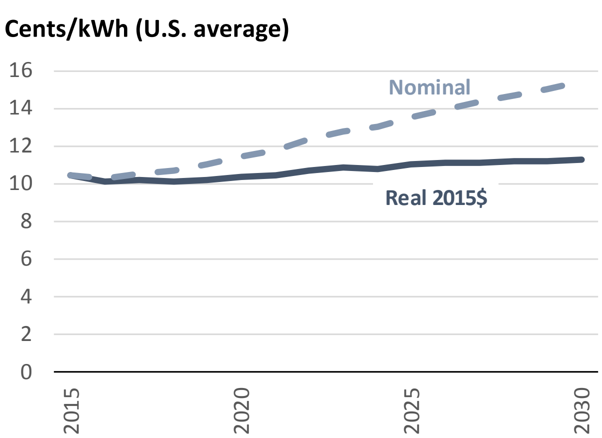

*Notes: Savings from federal appliance standards based on Meyers et al. (2016). Savings from utility ratepayer-funded programs are based on ACEEE data (e.g., Berg et al. 2016) and decayed over time to reflect a 10-yr. avg. measure life. The figure does not account for possible rebound effects.*

**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).

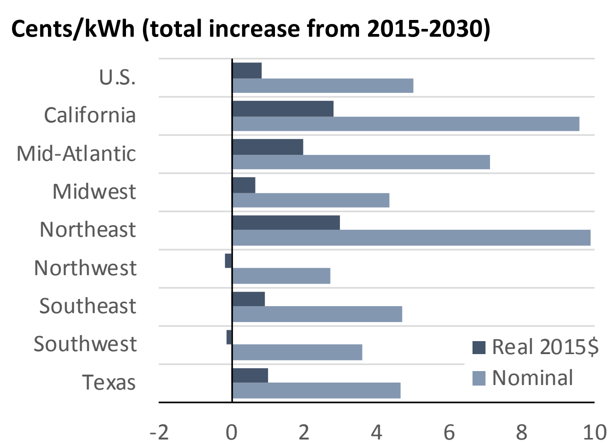
The precise impact of declining sales growth on retail electricity prices can be difficult to assess, as its effects can work in opposing directions. On the one hand, slower growth allows utilities to purchase less fuel and, over the long-term, defer some investments that they might otherwise need to 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.

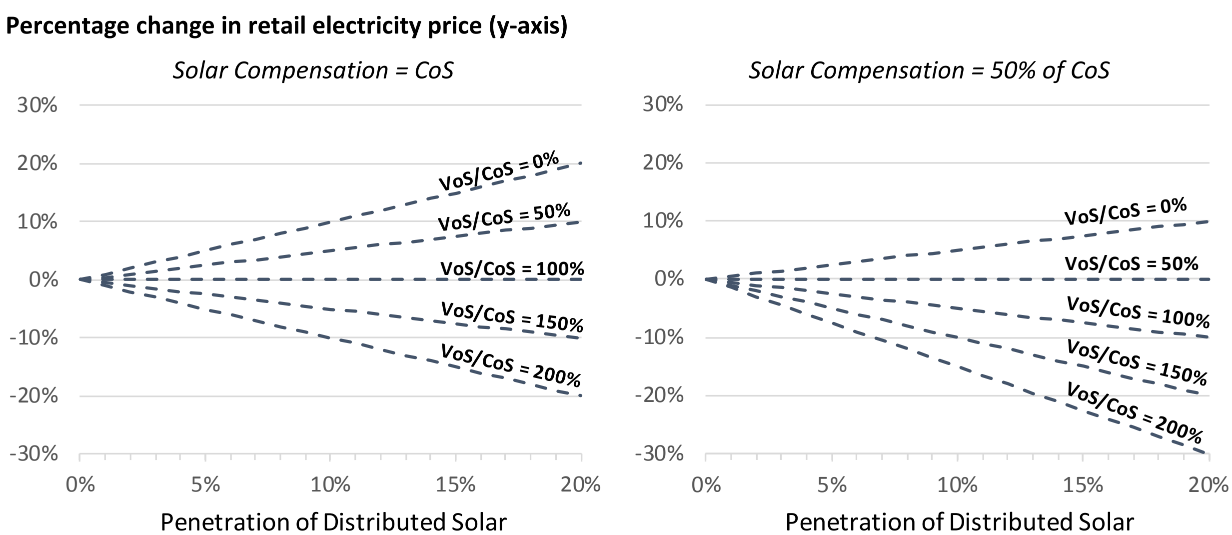



**Figure 9. Impacts of distributed solar on average retail electricity prices: A simple model of underlying drivers**

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).

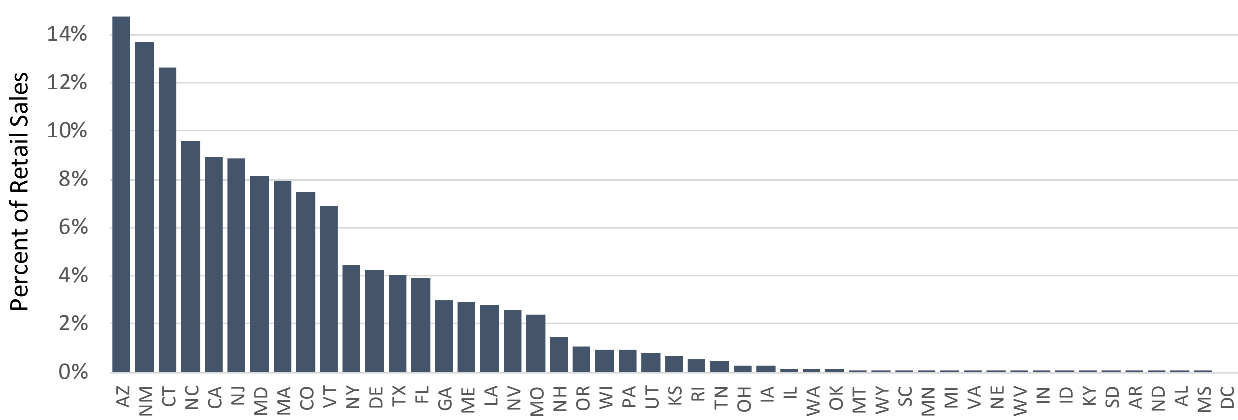
**Table 1. Top-ten utilities for net-metered PV penetration, as of year-end 2015**

| ***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 $10^{th}$ and $90^{th}$ 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

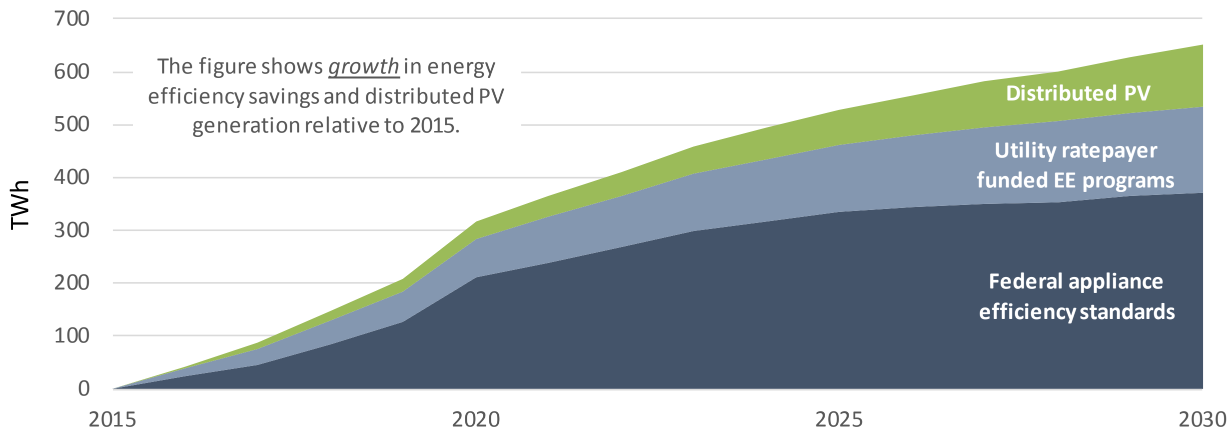
Net-metered solar and energy efficiency (EE) both reduce electricity sales, putting upward pressure on regulated electricity prices in the near-term, as embedded costs are recovered across a smaller base of sales (even if the resources are cost-effective over the long-run). One can thus gain some sense 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.

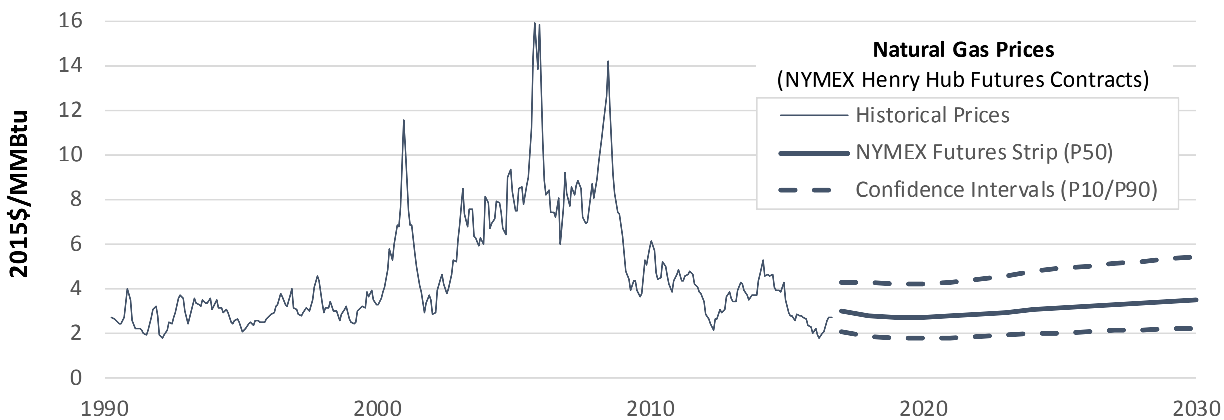
Even in those states with the highest projected solar penetration levels, growth in distributed solar generation is likely to be outpaced by EE. For example, the California Energy Commission's latest demand forecast projects that statewide annual energy savings from EE programs and policies will grow 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]



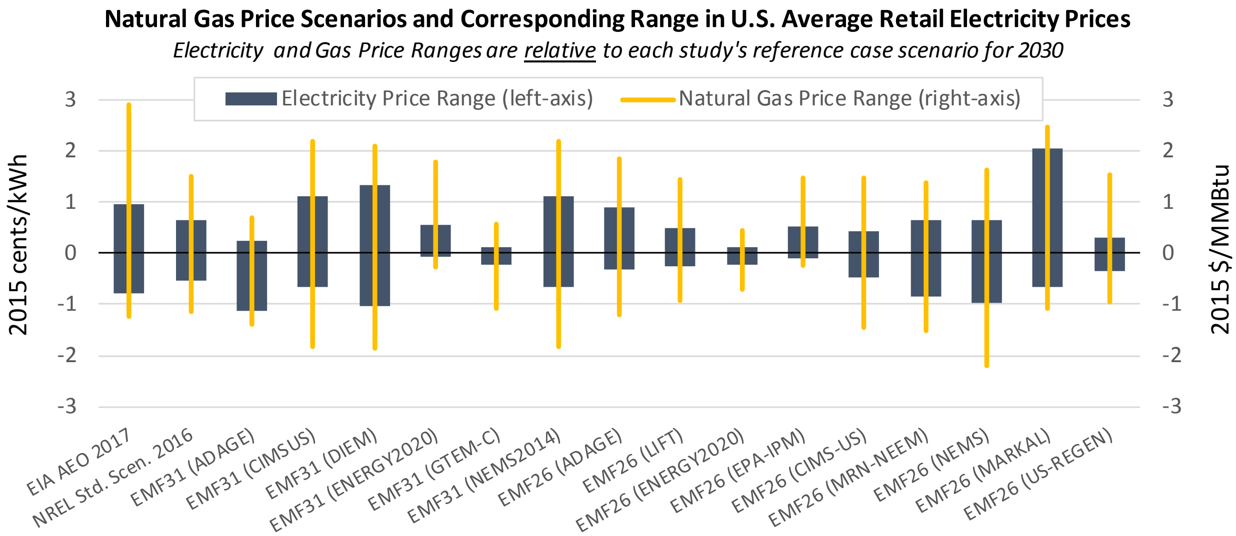

*Notes: Historical Prices are the monthly average price of NYMEX Henry Hub futures contracts for delivery in the following month, converted to real dollars based on quarterly GDP deflators (BEA 2016). Confidence Intervals for NYMEX futures prices were derived by Bolinger (2016), based on historical volatility 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.

[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.*

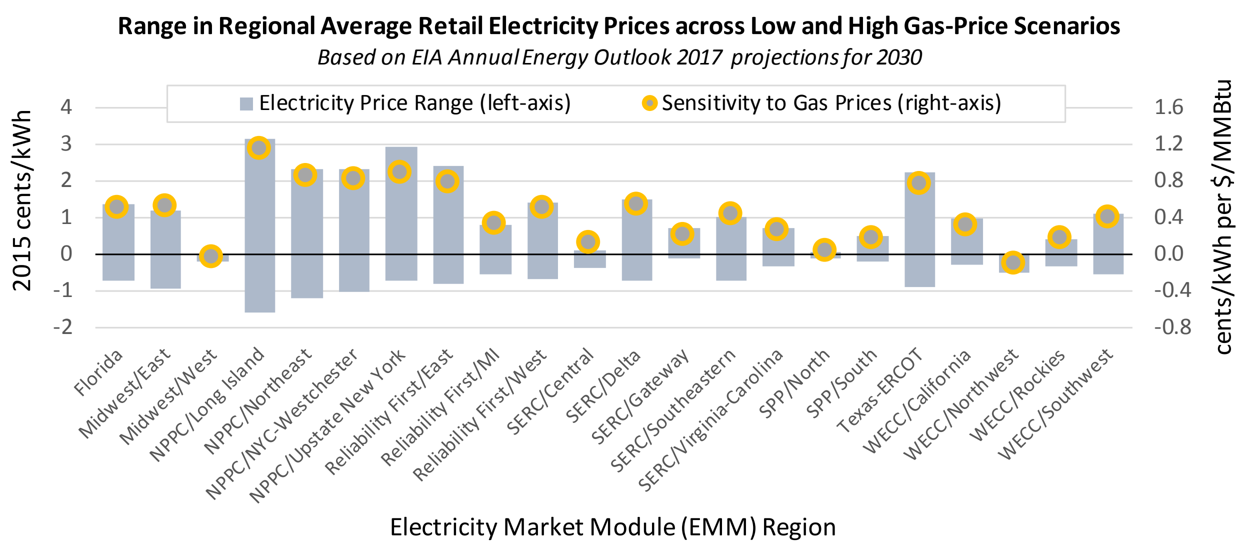
**Figure 13. Retail electricity prices across natural gas price scenarios: Comparison of electricity market studies**

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.




*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.

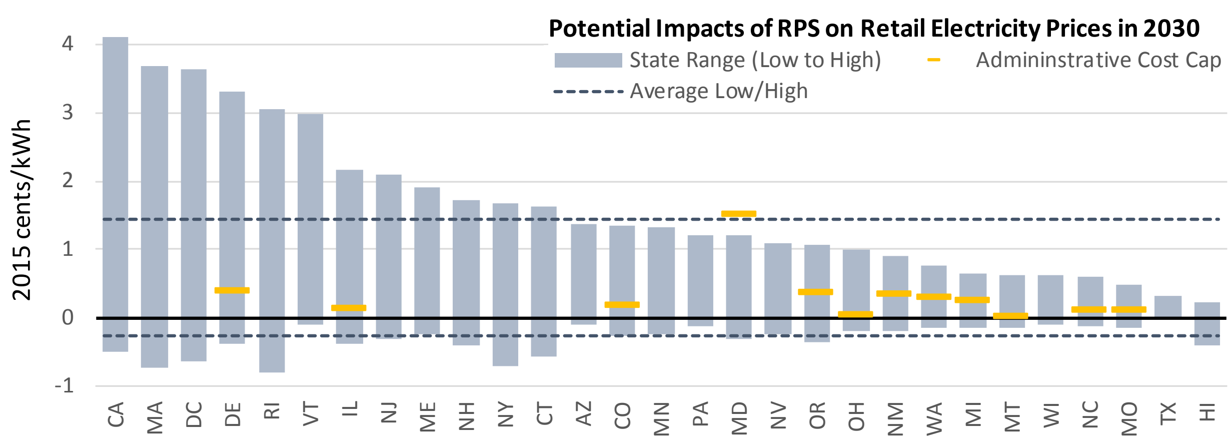
Given that renewables historically have been, and in some circumstances continue to be, higher-cost than conventional power, issues related to electric ratepayer impacts remain a focal point in the design and administration of RPS policies. Several econometric studies estimate that, historically, RPS 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.

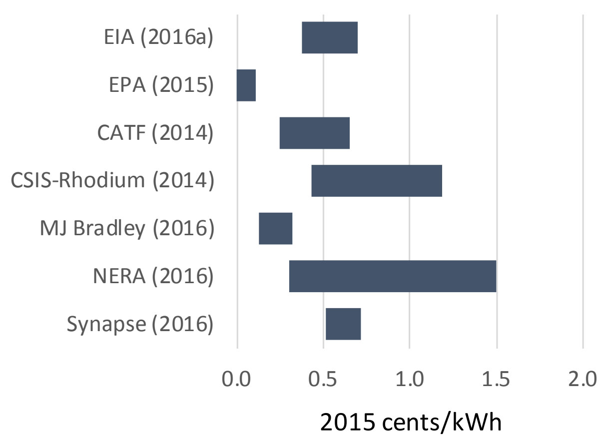
With respect to the CPP, implications for retail electricity prices—if maintained—will depend largely on how states implement the federal standard, given the substantial flexibility afforded. The set of studies shown in Figure 16 project that the CPP would result in anywhere from a 0.0-1.5 cent/kWh increase 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.

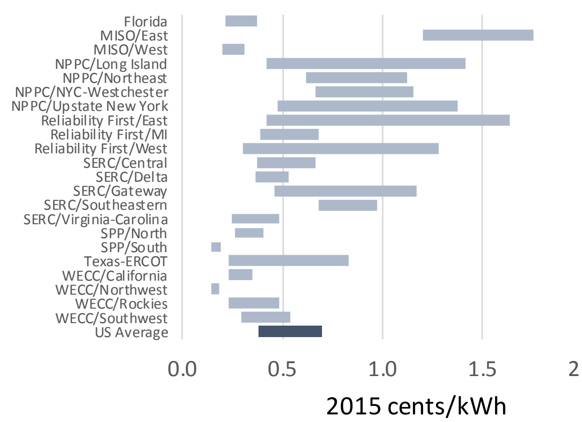
**Increase in U.S. average retail electricity price relative to no-CPP scenario**




*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**

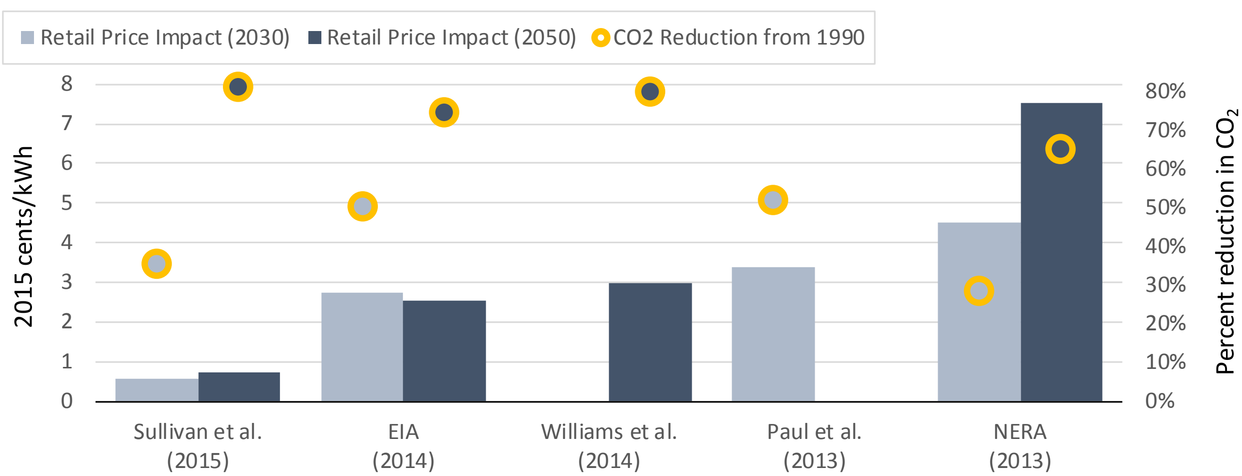



*Notes: Data are from EIA's 2016 Annual Energy Outlook (EIA 2016a). The ranges for each Electricity Market Module region are calculated by comparing prices between each CPP scenario and the "Reference case without Clean Power Plan" scenario, for the year 2030. For a map identifying EIA's Electricity 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.

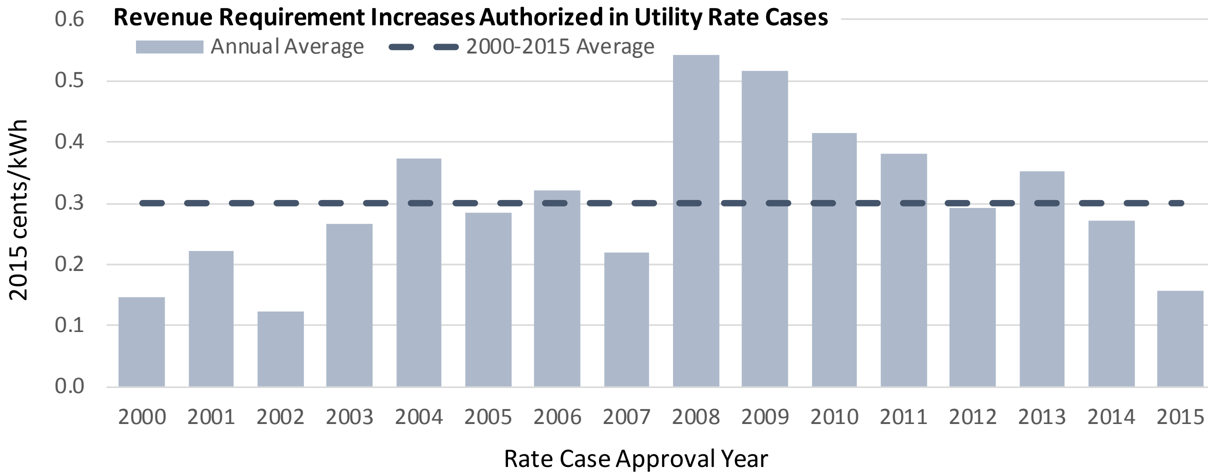



*Notes: Each of the studies modeled scenarios with carbon dioxide emission taxes or targets that become progressively more stringent until 2040 (EIA 2014) or 2050 (all others). Retail price impacts represent the difference between U.S. average retail prices in the policy case and the study's baseline "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).*

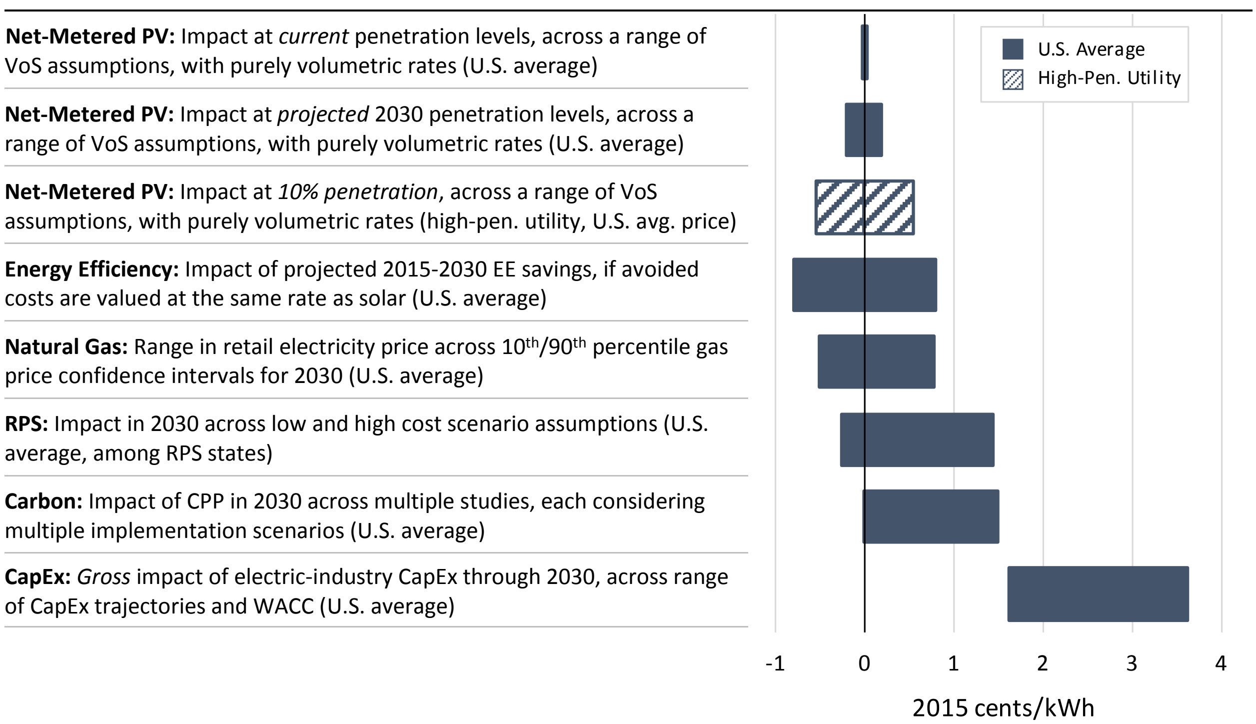
[19] These revenue requirement increases are expressed in units of cents/kWh in order to show how they translate into a retail price impact. However, these values do not represent authorized rate increases, per se. The net change in average electricity rates depends on how growth in revenue requirements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




*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.<br>**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.<br>**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

[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.

**STATE OF MICHIGAN**

**MICHIGAN PUBLIC SERVICE COMMISSION**

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|---|---|---|
| In the matter of the application of<br>Consumers ELECTRIC COMPANY<br>for authority to increase its rates for the generation and distribution of electricity and other relief.<br>. | )<br>)<br>)<br>)<br>)<br>) | **Case No. U-21389** |

**EXHIBITS OF PETER D. DOTSON-WESTPHALEN**

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION, AND**

**ADVANCED ENERGY UNITED**

**Question:**

2. Are all demand response programs listed in Witness McLean's testimony (including both Company-administered and behavioral) registered with MISO as Load Modifying Resources to receive supply-side capacity credit in the form of Zonal Resource Credits?

a. If no, please state which programs are not registered with MISO.

b. If no, please indicate whether the ZRCs associated with these programs as described in Witness Metz' testimony are instead accounted for as reduction in the Company's load forecast and resulting Planning Reserve Margin Requirement.

**Response:**

No, not all demand response programs are registered as Load Modifying Resources ("LMR") to receive Zonal Resource Credits.

a. Dynamic Peak Pricing ("DPP"), which is comprised of two components Critical Peak Pricing and Peak Time Rewards, as well as Rate EIP are not registered with MISO as an LMR.

b. For nonregistered DR resources the Company makes the appropriate reductions within the load forecast.

**Witness:** Steven Q. McLean
**Date:** July 17, 2023

**Question:**

1. Are customers participating in any of the Company's contractual or interruptible tariff DR programs able to participate in any other demand response programs, whether administered by the Company or a third party?

a. If yes, please explain.

**Response:**

No, customers that participate in the Company's contractual or interruptible tariff DR programs are not allowed to participate in additional DR programs through the Company or a third party.

**Witness:** Steven Q. McLean
**Date:** July 17, 2023

**Question:**

5. Witness McLean's testimony indicates that customers participating in the Business DR Contractual program are compensated "for their performance during MISO Emergency Events for up to 250% of their nominated value" and that customers' "[i]ncentive payments are priced for market competitiveness and are a component of the overall cost of having and managing a DR capacity resource." (McLean, p.16) Witness McLean also states that Business DR Contractual customers "…enter a contract with the Company, which outlines the terms of performance in keeping with MISO requirements for a Load Modifying Resource and payments as it relates to the contracted capacity and energy." (McLean, p. 17)

a. Are Business DR Contractual program participants dually registered by the Company in addition to MISO's Load Modifying Resource program in any other MISO DR programs (such as the Emergency Demand Response or Demand Response Resources programs)?

   i. If yes, are energy payments in the Business DR Contractual program paid to participating customers in the same manner as the Company will be paid by MISO during Emergency Demand Response or Demand Response Resources dispatches?

   ii. If no, what is the basis for determining the energy payment rate at which participating customers are compensated?

**Response:**

No, Business DR Contractual program participants are not dually registered by the Company in addition to MISO's Load Modifying Resource program in any other MISO DR program.

   i. N/A

   ii. Customers are paid based on MISO events called during the DR season. If no events are called customers are paid on their kW nomination and the kW contractual value in the customer's contract. If an event is called the customer's payment will be paid on their average performance for events during the season.

**Witness:** Steven Q. McLean
**Date:** July 17, 2023

**Question:**

7. Of the Interruptible demand response program tariff-based options available to customers, are any utilized by the Company to provide other wholesale or retail services aside from being registered with MISO as Load Modifying Resources?

a. If yes, please list the wholesale and/or retail services provided by participants in these interruptible options.

b. If yes, please describe the methodology for how each service provided by participants is accounted for within the tariff rate.

c. If yes, please describe the conditions or trigger under which customers are expected to perform by the Company.

d. If yes, please provide examples of the customer notification of each demand response event initiation by type of event (if different from program to program).

e. If yes, please provide examples of the customer notification of each demand response event conclusion by type of event (if different from program to program).

f. If yes, please provide the methodology for calculating penalties that will be assessed to customers associated with any under- or non-performance during events (for each type of event initiated by MISO or the Company)

**Response:**

No, the Demand Response tariff-based options are not utilized by the Company to provide other wholesale or retail services aside from being registered with MISO as Load Modifying Resources.

**Witness:** Steven Q. McLean
**Date:** July 17, 2023

# 2024 EMERGENCY COMMERCIAL AND INDUSTRIAL DEMAND RESPONSE CUSTOMER AGREEMENT

Customer and Consumers Energy are referred to herein collectively as the "Parties" and each individually as a "Party" to this Agreement.

Effective Date of Agreement: June 1, 2024
(Month/Day/Year)

| Company: | Customer: |
|---|---|
| **CONSUMERS ENERGY COMPANY**<br>a Michigan Corporation | ______________________<br>(Legal Name) |
| ONE ENERGY PLAZA<br>JACKSON MI 49201-2357 | ______________________<br>(Street & Number) |
| | ______________________<br>(City, State & Zip Code) |

1. **Initial Term:** Shall commence on June 1, 2024 and shall run through (select one):
   ___ **May 31, 2025 (1 year)**
   ___ **May 31, 2026 (2 year)**

2. This Agreement will become effective on the date identified above and will extend for an Initial Term through the end date identified above. The Customer must notify Consumers Energy Company ("Consumers Energy" or the "Company") by September 1st in the final year of the Initial Term of their desire to renew participation in the Demand Response Program ("Program") through the execution of a new Program Agreement and the amount of reduction/nomination kW for the following Program Period (June 1 through August 31). Customer participation under this Agreement shall be based on the limitations, terms and eligibility as described in the Company's Program and the Company's Electric Rate Book, as approved by the Michigan Public Service Commission.

3. **Program Description.** Participants in the Program help reduce peak demand when energy use is the highest and maintain a ready supply of energy for Michigan. Participants will receive an annual Emergency Capacity Payment for the Delivered Capacity amount specified in this Agreement within sixty (60) days after August 31st, the effective date of the DR season.

4. **Administration Solutions.** Customer agrees to work with Consumers Energy to develop an appropriate energy reduction plan for Customer's business; and (ii) to provide Consumers Energy access and use of contact, billing and energy usage data, and facility information concerning each Site Address (as defined below) ("Customer Data"). Consumers Energy shall manage Customer's curtailable electrical capacity in the Program and upon notification by Consumers Energy and acceptance by Customer, provide real-time support to Customer during demand response events ("Demand Response Events"); and enable data transfer, monitoring and reporting of meter data and provide technical assistance, maintenance, repair and hosting of the Monitoring System. In addition, as necessary, Consumers Energy will coordinate with Customer to capture kilowatt-hour ("kWh") pulses from Customer's primary utility meter to provide Customer near real-time, Internet-enabled power monitoring.

5. **Monitoring System.** Consumers Energy may equip one or more of Customer facility addresses (each address is referred to as a "Site Address") as identified on the Site Address Attachment attached hereto with the Monitoring System, which includes site devices owned by Consumers Energy that can enable power metering, data collection, near real-time data communication, and Internet-based reporting and analytics. There shall be

no cost to the Customer associated with the Monitoring System equipment or installation of the Monitoring System equipment.

6. **Customer Support Requirements.**

   a. **Representations and Warranties.** Customer holds all applicable licenses and/or permits pursuant to the Agreement that are required for the proper participation in the Program.

   b. **Demand Response Performance.** Customer has the intent and ability to generate and/or reduce electrical demand to achieve Contracted Capacity (as defined below) at each Site Address when notified by Consumers Energy Demand Response Events.

   c. **Acceptance Testing.** At each Site Address where the site devices are installed, Customer agrees to collaborate with Consumers Energy in a timely manner in testing, enabling and maintaining the Monitoring System.

   d. **Energy Reduction Plan.** Customer must provide to Consumers Energy their Energy Reduction Plan describing the equipment and steps that will be taken to meet their curtailment nomination.

   **Program Rules.** The terms of this Agreement reflect the current Program terms and conditions, which may be amended from time to time by Consumers Energy. Amendments are mutually agreed between the parties and recorded.

7. The current terms are summarized below:

| | |
|---|---|
| **Program Availability** | During the Program period of June 1 – August 31, emergency events could be called at any time Monday through Friday between 11 am and 7 pm in response to Midcontinent Independent System Operator, Inc. ("MISO") reliability emergencies ("Emergency Event(s)"). Customer is required to participate in any Emergency Event called by MISO. |
| **Event Frequency and Duration** | **Emergency Events** – Up to five (5) events during the Program Period, up to four hours each. |
| **Advanced Notification** | **Emergency Events** – Customer will receive at least a thirty (30) minute but no more than a six (6) hour notice in advance of an Emergency Event. Customers are advised to estimate load reduction capability over a twelve (12) hour timeframe for planning purposes. |
| **Dispatch Readiness Test** | After Customer's Energy Reduction Plan has been reviewed by Consumers Energy and Customer's site installation has been completed, Customer will receive an email from Consumers Energy asking Customer to select a date to participate in a thirty (30) minute Dispatch Readiness Test of Customer's Energy Reduction Plan. The Dispatch Readiness Test is optional to the Customer but recommended by Consumers Energy. |
| **Audit** | Consumers Energy may call one (1), one-hour audit ("Audit") per Program Period to confirm Contracted Capacity (as defined below). If called, this audit is required as the Customer's program payment will be determined by performance during the Audit event and the Customers Delivered Capacity (as defined below). |
| **Online Portal** | Customer may have access to an online portal "Dashboard" where Customer can monitor their performance during both an Emergency and Economic Event. Portal will be activated before the season starts on June 1. |

**8. Customer capacity.**

**a. Contracted Capacity.** For purposes of this Agreement, "Contracted Capacity" shall represent the Customer's performance obligation (in kilowatts ("kW"). The Contracted Capacity shall be based on an analysis of Customer's prior summer consumption data, their Energy Reduction Plan and pre-enrollment load reduction testing.

**b. Delivered Capacity.** For purposes of this Agreement, an event's "Delivered Capacity" shall be defined as the amount of load in kW reduced for each hour in a Demand Response Event. Delivered Capacity for each event hour is calculated as the difference between the measured energy demand and the baseline energy demand. Consumers Energy will use a MISO-approved baseline calculation method. MISO's default baseline is the Ten-Day Baseline. The Ten-Day Baseline is calculated as the average hourly demand from the previous ten (10) non-weekend non-holiday non-event days prior to the event. Customer is required to reduce the full amount specified as Contracted Capacity for the hourly average of an emergency event. Consumers Energy, at its discretion, can make an adjustment to the baseline determined by the M&V Method of plus or minus 20% based on the energy usage three hours prior to the beginning of the Emergency Event. An alternative baseline may be used, so long as it is pre-approved by MISO. If no Emergency Event is called, the Delivered Capacity will revert to the Contracted Capacity for the DR season. In a Program Period with multiple Emergency Events, the Delivered Capacity will be based on the Customers average event performance during the terms of this Agreement.

See Attachment A for examples of customer baseline calculations and performance obligations.

**9. Payments to Customer.**

**a. Emergency Capacity Payments.** For a single year contract, the capacity payment price is $25/kW. For a two (2) year contract, year one (1) the capacity payment price is $27/kW and the year two (2) capacity price is $30/kW. Delivered Capacity capped at 250% per Program Period as defined in section 8(b). Consumers Energy will pay Customer the Capacity Rate multiplied by the Delivered Capacity.

**10. Emergency Event Energy Payments.** In Program Periods when one or more Emergency Events are called, Consumers Energy will pay Customer an energy payment of $50/MWh multiplied by the event's Delivered Capacity multiplied by the hours for each such event as defined in section 8(b) above.

**a. During Non-Program Periods.** Consumers Energy may call one or more Emergency Events. The customer is under no obligation to participate. If they choose to participate, they will be paid $1000/MWh multiplied by the event's average Delivered Capacity delivered during the event. Delivered Capacity is capped at customers contracted nomination.

**11. Payment Timing.** After an Emergency Event and Customer's Delivered Capacity has been verified, Consumers Energy shall make Emergency Event Energy Payments for Customer's participation by the issuance of credits to the Customer's bill. The Emergency Capacity Payment will be made within sixty (60) days after August 31st, the effective end date of the DR season.

**12. Cancellation.** Customer or Consumers Energy may cancel this Agreement or request to amend nomination(s) for the next Program Period between October 1 – December 31, prior to the start of the next Program Period. Requests to amend nomination(s) shall be granted at the Company's discretion and shall only apply to the next Program Period. Cancellation requests must be submitted in writing to: ConsumersEnergy.DemandResponseProgram@cmsenergy.com. The customer will be notified by Consumers Energy if they cancel or are removed from the program.

**13. Confidentiality.**

**a. Nondisclosure to Third Parties.** In performing under the Agreement, each Party to this Agreement will be exposed to certain Confidential Information (as hereinafter defined) of the other Party. Each Party on its own behalf and on behalf of its employees, contractors and agents (collectively, "Representatives") agrees not to, except as required by applicable law or regulation, use or disclose such Confidential Information without the prior written consent of the other Party, either during or after the Term. To protect Confidential

Information, each Party agrees to: (i) limit dissemination of Confidential Information to only those Representatives having a "need to know"; (ii) advise each Representative who receives Confidential Information of the confidential nature of such information; and (iii) have appropriate agreements, policies and/or procedures in place with such Representatives sufficient to enable compliance with the confidentiality obligations contained herein. The term "Confidential Information" means all information which is disclosed, either orally or in written form, by either Party or its Representatives and shall be deemed to include: (w) any notes, analyses, compilations, studies, interpretations, memoranda or other documents prepared by either Party or its Representatives which contain, reflect or are based upon, in whole or in part, any Confidential Information furnished to a receiving Party or its Representatives pursuant hereto; (x) any information concerning the business relationship between the Parties; and (y) Customer Data.

**b. Exclusions from Confidential Information.** Notwithstanding the obligations in Section 13(a) above, Confidential Information does not include any information that:

i. is or becomes generally known to the public without breach of any obligation owed to the disclosing Party;

ii. was known to the receiving Party prior to its disclosure by the disclosing Party without breach of any obligation owed to the disclosing Party;

iii. is received from a third party without the receiving party having any knowledge of any breach by such third party of any obligation owed to the disclosing Party; or

iv. was independently developed by the receiving Party without reference to or reliance upon the disclosing Party's Confidential Information.

**14. Limitation of Liability.** Consumers Energy's and its contractors' and subcontractors' liability hereunder is limited to direct actual damages as the sole and exclusive remedy, and total damages under the Agreement shall not exceed $100,000 or the total amounts paid by Consumers Energy under the Agreement, whichever is less. In no event shall either Party, its parent, officers, directors, partners, shareholders, employees or affiliates, or any contractor or subcontractor or its employees or affiliates, be liable to the other Party for special, indirect, exemplary, punitive, incidental or consequential damages of any nature whatsoever connected with or resulting from performance or non-performance of obligations under the Agreement, including without limitation, damages or claims in the nature of lost revenue, income or profits, loss of use, or cost of capital, irrespective of whether such damages are reasonably foreseeable and irrespective of whether such claims are based upon negligence, strict liability contract, operation of law or otherwise.

**15. Additional Terms.**

**a.** Customer also agrees, with respect to Consumers Energy's management of the Monitoring System, it:

i. receives a limited, revocable, non-transferrable and non-exclusive right to use and access during the Term the Monitoring System and shall use the Monitoring System solely for its internal use subject to the terms of the Agreement and not for the benefit of any third party. Except as expressly permitted in the Agreement, Customer agrees that it shall not receive any right, title or interest in, or any license or right to use or access, the Monitoring System or any patent, copyright, trade secret, trademark or other intellectual property rights therein by implication or otherwise;

ii. shall use the Monitoring System in accordance with all applicable law;

iii. shall not and shall prohibit causing or permitting, the copying, reverse engineering, disassembly, decompilation or attempting to derive the source code of the Monitoring System, or other intellectual property of Consumers Energy or creation of any derivative work thereof;

iv. expressly disclaims any passing of title to the Monitoring System, any trade names, trade dress, trademarks, service marks, commercial symbols, copyrightable material, designs, logos and/or any other intellectual property of Customer;

v. shall not delete, alter, cover, or distort any copyright or other proprietary notices or trademarks from the Monitoring System and to use reasonable care to prevent the Monitoring System and Consumers Energy's intellectual property rights contained in the software from damage and unauthorized use.

**b. Miscellaneous.** Customer may not assign any of its rights or delegate any of its performance obligations hereunder without the prior written consent of Consumers Energy. The Agreement, including all attachments, constitutes the entire agreement between Customer and Consumers Energy and may only be amended in writing signed by each of the Parties. If any of its provisions shall be held invalid or unenforceable, this Agreement shall be construed as if not containing those provisions and the rights and obligations of the Parties hereto shall be construed and enforced accordingly. This Agreement shall be binding upon the Parties together with their successors and permitted assigns. Each Party shall be responsible for its Representatives' compliance with the Agreement. Customer shall promptly notify Consumers Energy in writing of any changes occurring during the Term to the Customer address(es) set forth in this Agreement.

**c. Force Majeure.** The Parties to this Agreement shall be excused from any failure or delay in the performance of their obligations if such obligations are prevented from being fulfilled due to Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure, shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance. A "Force Majeure" shall include any act, event, or occurrence beyond the Party's reasonable control, which the Party, despite its best efforts, is unable to prevent, avoid, overcome, delay or mitigate, including but not limited to: floods, epidemics, earthquakes, quarantine, blockade, war, insurrection or civil strife or terrorism, provided, however, that Force Majeure shall in no event include (i) failure of Subcontractors or Suppliers to deliver services, materials or components or receipt from any Subcontractor or Supplier of defective services, material or components unless same were themselves caused by a Force Majeure Event; (ii) technological impossibility; (iii) a governmental act or failure to act, or order or injunction, caused by any act or failure to act of the Seller or any Subcontractor or Supplier; (iv) strikes or work stoppages; or (v) inclement weather.

**d. Warranty Limitations.** THE MONITORING SYSTEM (AND ANY SOFTWARE, HARDWARE, OR OTHER COMPONENT THEREOF) AND ALL SERVICES HEREUNDER ARE PROVIDED AS IS BY CONSUMERS ENERGY WITHOUT ANY WARRANTY OF ANY KIND. ALL WARRANTIES, WHETHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, ARE EXPRESSLY DISCLAIMED TO THE FULLEST EXTENT PERMISSIBLE UNDER APPLICABLE LAW.

**e. Governing Law; Actions; Etc.:** This Agreement shall be deemed a Michigan contract and shall be governed by and interpreted in accordance with the laws of the State of Michigan; excluding any conflicts of laws principles that would result in this Agreement being interpreted in accordance with any different law. Venue for any lawsuit arising out of or in connection with this Agreement shall be exclusively in the courts of the State of Michigan or a Federal court sitting in the State of Michigan. Any legal action against Consumers Energy relating to this Agreement or the breach thereof shall be commenced within one year from the date on which the claimed breach, default or other cause of action arose (and, without limiting the foregoing, in all events not later than one year after the date of completion or other cessation of performance of the work hereunder). This Agreement is intended for the benefit of the parties herein only and does not grant any rights to any third parties unless otherwise specifically stated herein. If Customer defaults in the timely performance of any of its obligations hereunder, then Consumers Energy may, at its option, and in addition to any and all other rights or remedies it may have hereunder or at law or equity, terminate this Contract by written notice to Customer.

**IN WITNESS WHEREOF, and intending to be legally bound, the Parties have duly executed this Agreement by their authorized representatives as of the Effective Date.**

CONSUMERS ENERGY COMPANY

______________________________
(Customer)

By: ______________________________
(Signature)

By: ______________________________
(Signature)

______________________________
(Print or Type Name)

______________________________
(Print or Type Name)

______________________________
(Date)

______________________________
(Date)

**ATTACHMENT A -**
**CUSTOMER BASELINE CALCULATIONS AND PERFORMANCE OBLIGATIONS**

"Original Baseline Demand" calculation methodology – for interruptions called on normal business days, calculate an average hourly demand profile based on the demands created during the ten (10) non-interruption business days immediately preceding an interruption notification, excluding Saturday, Sunday and holidays as recognized in the Company's Electric Rate Book ("Normal Baseline Demand"). .

"Day of Adjustment" calculation methodology - starts at the point of the interruption event and counts back four (4) hours. (For purposes of clarification – for the "Day of Adjustment" calculation **only** the baseline **is** calculated beginning from the start of the interruption event and moving backwards by four (4) hours). The "Original Baseline Demand" will be ADJUSTED up/down on the day of an event by the ratio of (a) the sum of hourly demands for the three (3) hours beginning four (4) hours prior to the interruption event and (b) the sum of those same three hours unadjusted consumption baseline demands. The resultant change to the Original Baseline Demand is limited to +/- 20% of the Original Baseline Demand and is referred to as the "Adjusted Baseline Demand".

Demand Response Enactment Event examples:

*Prior 10 business day/24-hour baseline = 100 kW with a 20 kW Nomination amount (Use this information for all scenarios).

Scenario #1
4 hours prior "Day of Adjustment" = 70 kW average demand for the 3 hours.

What is the Adjusted Baseline Demand to reduce power against = (The 70 kW average demand during the 3 hour "Day of Adjustment" period represents a 30% decrease from the Original Baseline Demand, so the Original Baseline Demand will be reduced by only 20%, as per the "Baseline" calculation methodology). Adjusted Baseline Demand = 80 kW.

To FULLY comply during this event - Load reduction = 80 kW – 20 kW (Nomination) = Customer would need to reduce load to 60 kW to comply at 100%.

Scenario #2
4-hour prior "Day of Adjustment" = 110 kW average demand for the 3 hours.

What is the Adjusted Baseline Demand to reduce power against = (The 110 kW average demand during the 3 hour "Day of Adjustment" period represents a 10% increase from the Original Baseline Demand, so the Original Baseline Demand will be increased by 10%, as per the "Baseline" calculation methodology). Adjusted Baseline Demand = 110 kW.

To FULLY comply during this event - Load reduction = 110 kW – 20 kW (Nomination) = Customer would need to reduce load to 90 kW to comply at 100%.

Scenario #3
4-hour prior "Day of Adjustment" = 95 kW average demand for the 3 hours.

What is the Adjusted Baseline Demand to reduce power against = (The 95 kW average demand during the 3 hour "Day of Adjustment" period represents a 5% decrease from the Original Baseline Demand, so the Original Baseline Demand will be decreased by 5%, as per the "Baseline" calculation methodology). Adjusted Baseline Demand = 95 kW.

To FULLY comply during this event - Load reduction = 95 kW – 20 kW (Nomination) = Customer would need to reduce load to 75 kW to comply at 100%.

Scenario #4
4-hour prior “Day of Adjustment” = 125 kW average demand for the 3 hours.

What is the Adjusted Baseline Demand to reduce power against = (The 125 kW average demand during the 3 hour “Day of Adjustment” period represents a 25% increase from the Original Baseline Demand, so the Original Baseline Demand will be increased by only 20%, as per the “Baseline” calculation methodology.) Adjusted Baseline Demand = 120 kW.

To FULLY comply during this event - Load reduction = 120 kW – 20 kW (Nomination) = Customer would need to reduce load to 100 kW to comply at 100%.

## SITE ADDRESS ATTACHMENT
## SITE ADDRESSES

| SITE NAME | SITE ADDRESS | CONTRACT ACCOUNT NUMBER | METER NUMBER | ESTIMATED CAPACITY (kW) |
|---|---|---|---|---|
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# Attachment B

## CONSUMERS ENERGY DEMAND RESPONSE 2024 ENERGY REDUCTION PLAN

Consumers Energy Count on Us®

**Company Name:** ______________

**Facility Contact Name:** ______________

**Address Line 1:** _______________

**Address Line 2:** ______________

**Contract Account #:** ______________

**Contract Type:** ☐ Emergency ☐ Emergency with Generator

**DR Nomination:** _______kW

**DR Event Procedure:** Consumers Energy will notify you that a DR event has been dispatched.
Confirm phone, e-mail, and/or text notifications sent by Consumers Energy.
Manually shut down the following equipment by the time the DR event begins.
If applicable, turn on generator and transfer specified building load to the generator.

| Equipment | Shutdown Procedure | Load Reduction (kW) |
|---|---|---|
| | | |
| | | |
| | | |
| | | |
| | | |

| Equipment | Shutdown Procedure | Load Reduction (kW) |
|---|---|---|
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **TOTAL kW's** | | |

Did the customer participate in DR in previous seasons? If so, what was their nomination and how did they perform?

Date Completed: _________ By: _________

# ATTACHMENT C

Consumers Energy
Count on Us®

# CONTACT LIST

During a Demand Response event, Consumers Energy will contact the people in your facility who have been instructed on the implementation of your Energy Reduction Plan. **These notifications are automated and at least ONE contact is expected to respond to the message by pressing "1" to hear the message and then again pressing "1" to confirm receipt.**

Event alerts, warnings, enactments, and all clear notifications will come to you from
EMAIL ADDRESS: ConsumersEnergy.DemandResponseProgram@cmsenergy.com
PHONE and SMS: 800-500-6565 and 866-402-7267

If you have questions regarding web access, or have contact updates, please contact the Network Operations Center for Demand Response:
EMAIL ADDRESS: ConsumersEnergy.DemandResponseProgram@cmsenergy.com
PHONE: 800-500-6565

Please **type** in the information below for a **MINIMUM of THREE** contacts.

## Site Information

| | | |
|---|---|---|
| Site Name: | | |
| Site Address: | | |
| City: | State: | Zip: |
| Account Number: | | |

| Contact Name: | | | Web Access |
|---|---|---|---|
| Job Title: | | | Web Portal Access: Yes ☐ No ☐ |
| I would like to receive text message notification | Yes ☐ | No ☐ | |
| Direct Dial Phone Number: | EXTENSION: | | |
| Mobile Number: | | | |
| Pager Number: | | | |
| E-mail Address: | | | |

| Contact Name: | | | Web Access |
|---|---|---|---|
| Job Title: | | | Web Portal Access: Yes ☐ No ☐ |
| I would like to receive text message notification | Yes ☐ | No ☐ | |
| Direct Dial Phone Number: | EXTENSION: | | |
| Mobile Number: | | | |
| Pager Number: | | | |
| E-mail Address: | | | |

| Contact Name: | | | Web Access |
|---|---|---|---|
| Job Title: | | | Web Portal Access: Yes ☐ No ☐ |
| I would like to receive text message notification | Yes ☐ | No ☐ | |
| Direct Dial Phone Number: | EXTENSION: | | |
| Mobile Number: | | | |
| Pager Number: | | | |
| E-mail Address: | | | |

| Contact Name: | **Web Access** |
|---|---|
| Job Title: | Web Portal Access: |
| I would like to receive text message notification **Yes** ☐ **No** ☐ | **Yes** ☐ **No** ☐ |
| Direct Dial Phone Number: EXTENSION: | |
| Mobile Number: | |
| Pager Number: | |
| E-mail Address: | |

| Contact Name: | **Web Access** |
|---|---|
| Job Title: | Web Portal Access: |
| I would like to receive text message notification **Yes** ☐ **No** ☐ | **Yes** ☐ **No** ☐ |
| Direct Dial Phone Number: EXTENSION: | |
| Mobile Number: | |
| Pager Number: | |
| E-mail Address: | |

| Contact Name: | **Web Access** |
|---|---|
| Job Title: | Web Portal Access: |
| I would like to receive text message notification **Yes** ☐ **No** ☐ | **Yes** ☐ **No** ☐ |
| Direct Dial Phone Number: EXTENSION: | |
| Mobile Number: | |
| Pager Number: | |
| E-mail Address: | |

| Contact Name: | **Web Access** |
|---|---|
| Job Title: | Web Portal Access: |
| I would like to receive text message notification **Yes** ☐ **No** ☐ | **Yes** ☐ **No** ☐ |
| Direct Dial Phone Number: EXTENSION: | |
| Mobile Number: | |
| Pager Number: | |
| E-mail Address: | |

**Question:**

1. In witness McLean's response in U21389-MEIBC-CE-0258, he confirmed that the Company does not register customers participating in the Business DR Contractual program in any other MISO DR programs other than LMR, and in his response to U21389-MEIBC-CE-0260, he also affirms, "No, the Demand Response tariff-based options are not utilized by the Company to provide other wholesale or retail services aside from being registered with MISO as Load Modifying Resources."

a. Please confirm that MISO only compensates LMRs for the ZRCs associated with their accredited registration values and does not provide any compensation to LMRs for the energy reductions delivered when LMRs are called upon.

**Response:**

Confirmed.

**Witness:** Steven Q. McLean
**Date:** August 25, 2023

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*****

| | | |
|---|---|---|
| In the matter of the application for **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) ) | **Case No. U-21389** |

## PROOF OF SERVICE

STATE OF SOUTH CAROLINA )
) ss.
COUNTY OF BERKELEY )

Summer R. Dukes, the undersigned, being first duly sworn, deposes and says that she is a Paralegal at Potomac Law Group PLLC and that on the 29th day of August, 2023 she served a copy of the **PUBLIC** Direct Testimony & Exhibits of Dr. Laura S. Sherman and Peter D. Dotson-Westphalen on behalf of The Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United, together with the Direct Exhibit List upon those individuals listed on the attached Service List via email.

Summer Dukes Digitally signed by Summer Dukes
Date: 2023.08.29 15:52:45 -04'00'

Summer R. Dukes

**Administrative Law Judge**
Sally Wallace
Wallaces2@michigan.gov

**Consumers Energy Company**
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