Financial Impacts of Net-Metered Distributed PV on a Prototypical Western Utility's Shareholders and Ratepayers

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Executive Summary

Distributed solar PV (DPV) under net energy metering (NEM) with volumetric retail electricity pricing (i.e., uniform compensation of generation in excess of consumption, regardless of its characteristics such as time of generation) has raised concerns among utilities and regulators. Electric investor-owned utilities (IOUs) are concerned about the effects of DPV on sales and future earnings opportunities from deferred or avoided capital investments under existing regulatory and business models. At the same time, utility regulators are concerned about possible increases in retail rates and cost-shifting from customers with DPV (i.e., participants) to non-DPV customers (i.e., non-participants). In instances where costs increase faster than sales, there is upward pressure on retail rates.

NEM reforms have been proposed and, in certain cases, adopted by state public utility commissions. Importantly, most reforms change the DPV system payback periods and, thus, have the potential to reduce distributed solar PV deployment. Regulators must weigh utility and ratepayer concerns as they consider changes to NEM and retail rate design, and ultimately make a determination that they believe serves the public interest.

This study quantifies the financial impacts of net-metered DPV on a prototypical Western IOU and identifies the key sensitivities and utility attributes driving lesser or greater magnitude of impacts. We also identify and assess the efficacy of strategies to mitigate financial impacts to help frame, organize, and inform ongoing discussions of NEM reforms among regulators, utilities, and other stakeholders. We build on prior quantitative analysis of the financial impacts of net-metered PV (Satchwell et al., 2014; Satchwell et al., 2017) in two areas: assessing a wider range of sensitivities specific to the ability of DPV to avoid or defer utility costs (i.e., "DPV value") and modeling mitigation strategies that have been proposed as specific alternatives to NEM.

We estimate the financial impacts using a pro forma financial model - the FINancial impacts of Distributed Energy Resources (FINDER) model - that calculates annual utility costs and revenues based on specified assumptions about the utility's physical, financial, operating, and regulatory characteristics. The prototypical Western utility is characterized to generally represent a vertically-integrated IOU in the region based on publicly available data of financial, physical, and operating characteristics. Financial impacts are quantified at three DPV deployment levels (i.e., 1%, 4%, and 8% of 2027 retail sales) representing the range of forecasted DPV deployment among Western states. We also analyze several sensitivity cases with different assumptions about the value of DPV than what is assumed in the base cases. Finally, we analyze several ratemaking and regulatory measures for mitigating the potential negative financial impacts on utility shareholders, specifically: net billing at avoided cost rate, NEM with a grid access charge, and an increased monthly customer charge for residential and commercial customers.

Figure ES - 1. Financial impacts of net-metered PV on the prototypical Western utility's achieved earnings and ROE, average retail rate, and total customer bills (at 8% DPV deployment level)

The study makes several important findings about the financial impacts of net-metered DPV on utility shareholders and ratepayers:

- First, these impacts on shareholders and ratepayers increase as the level of DPV deployment increases, though the magnitude is small even at high DPV penetration levels (see base value in Figure ES - 1). Because most Western utilities currently have distributed generation deployments less than 1% of annual retail sales, policymakers and regulators likely have time to study and deliberate changes to NEM before observing material financial impacts.
- Second, the study explicitly links different estimates of DPV value to shareholder and ratepayer impacts and finds that even rather dramatic changes in DPV value result in modest changes to shareholder and ratepayer impacts (see sensitivity ranges in Figure ES - 1). Also, the range of financial impacts under alternative DPV value assumptions are greater for shareholders than ratepayers on a percentage basis and driven by differences in the amount of incremental CapEx that is deferred, as well as the amount of incremental distribution OpEx that is incurred.
- Third, the mitigation cases demonstrate that what constitutes a financial impact from a particular perspective matters. While all the mitigation cases improved utility earnings, ROE, and average non-participating customer bills (relative to the case with NEM only), average DPV participating customer bills increased further and, in some cases (i.e., grid access charge and 30% electricity export at avoided cost), pushed DPV system payback times beyond the system lifetime. Regulators and policymakers may improve their understanding of multiple perspectives by incorporating feedback effects between changes in rate design or compensation mechanisms and DPV deployment rates.

1. Introduction

Large increases in the deployment of distributed solar PV generation have been associated with net-energy metering (NEM).[1] NEM is a billing mechanism that credits customers with distributed generation systems for electricity they export to the grid. Use of NEM in conjunction with volumetric retail electricity pricing (i.e., uniform compensation of generation in excess of consumption, regardless of its characteristics such as time of generation), however, has also raised concerns among utilities and regulators of higher retail electric power rates and shifting of costs from NEM to non-NEM customers. While current amounts of distributed solar PV (DPV) in many jurisdictions are small and thus any retail rate and cost-shifting concerns may be anticipatory in nature, NEM reforms have been proposed and, in certain cases, adopted by state public utility commissions. Importantly, most reforms change the DPV system payback periods and have the potential to reduce distributed solar PV deployment. Barbose et al. (2016), for example, modeled effects of a reduction in NEM compensation for grid exports from retail to wholesale electric power rates. They found that this reduction in NEM compensation would reduce residential 2050 solar PV deployment by approximately 20%.

Electric investor-owned utilities (IOUs) are concerned about the effects of DPV on sales and future earnings opportunities from deferred or avoided capital investments under existing regulatory and business models. Because current retail rate design typically allocates a significant portion of fixed costs to volumetric energy charges, any reduction in electricity sales without a similar reduction in fixed costs will erode utility earnings and return-on-equity (ROE). In addition, IOUs increase their earnings base by investing in capital, which may be growth-related (e.g., new distribution system investments and generating plants to serve increasing load). Thus, stagnant or declining sales as a result of DPV may reduce these future earnings opportunities.[2]

At the same time, utility regulators are concerned about possible increases in retail rates and cost-shifting from customers with DPV (i.e., participants) to non-DPV customers (i.e., non-participants). In instances where costs increase faster than sales, there is upward pressure on retail rates. In addition, customers who invest in DPV and can significantly reduce or even eliminate the volumetric portion of their bills via NEM may not adequately pay the full amount of their fixed costs, which places an increased cost burden on non-participating customers. Regulators must weigh utility and ratepayer concerns as they consider changes to NEM and retail rate design, and ultimately make a determination that they believe serves the public interest.

While these concerns are qualitatively understood, there is a lack of empirical and quantitative analysis to bound the magnitude of these concerns and the efficacy of alternative utility regulatory and business

[1] Residential solar continues to grow with a 7% increase in residential solar deployment in 2018 (SEIA and Wood Mackenzie, 2019). Growth in distributed solar over the previous 5-7 years is also attributable to significant declines in costs (Barbose et al., 2018) and tax credits.

[2] In addition to DPV, there are other reasons for and factors driving declines in retail sales, including energy efficiency (Barbose, 2017). Future growth in electric vehicles, among other sources of electrification, that increase electricity consumption may counter the prevailing trend of declining sales.

models. Many of the concerns expressed by utilities and regulators depend critically on the specific changes in costs and revenues that are a function of utility cost compositions (e.g., proportion of fixed versus variable costs), physical system attributes (e.g., hourly loads), and fixed cost recovery mechanisms, among others.

This study quantifies the financial impacts of net-metered DPV on a prototypical Western IOU and identifies the key sensitivities and utility attributes driving lesser or greater magnitude of impacts.[3] We also identify and assess the efficacy of strategies to mitigate financial impacts to help frame, organize, and inform ongoing discussions of NEM reforms among regulators, utilities, and other stakeholders. We build on prior quantitative analysis of the financial impacts of net-metered PV (Satchwell et al., 2014; Satchwell et al., 2017) in two areas: assessing a wider range of sensitivities specific to the ability of DPV to avoid or defer utility costs (i.e., "DPV value") and modeling mitigation strategies that have been proposed as specific alternatives to NEM.

We quantify the shareholder and ratepayer impacts for a Western, vertically-integrated IOU (i.e., owns generation, transmission, and distribution assets) at three DPV deployment levels (i.e., 1%, 4%, and 8% of 2027 retail sales) representing the range of forecasted DPV deployment among Western states.[4] Results are compared against a case without DPV, incremental energy efficiency, or other DERs in order to isolate the DPV impacts. The DPV is installed linearly over ten years to reach its terminal deployment level (as a percentage of retail electricity sales) with impacts measured over 20 years to capture utility system economic end-effects (i.e., cost avoidance or deferral).[5] We also assess the sensitivity of impacts to different assumptions about the "DPV value" (i.e., ability of DPV to avoid or defer utility costs) and the extent to which DPV impacts can be mitigated through regulatory and ratemaking measures.

Several key boundaries apply to this study. First, the study uses a pro forma revenue requirements model and not a detailed dispatch or planning model. As such, the impacts of DPV on utility costs are based on a coarser set of assumptions than might be possible with models representing the utility generation dispatch and power flows on distribution feeders. Second, we assess financial impacts on a prototypical IOU generally representative of the Western region and under existing regulatory and business models. There are other regional features and conditions that may produce different results and that are not explored in this analysis. This also implies that results should be considered with respect to the range of assumptions we explore in this study. Third, we do not consider the effect of DPV deployment on broader social externalities (e.g., reduced emissions, economic development, and

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[3] This report series is one piece of a larger project funded by the U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy (EERE) Solar Energy Technologies Office (SETO) and led by the Western Interstate Energy Board (WIEB). For information about that larger project, including links to other reports, see: https://westernenergyboard.org/wieb-board/projects/barrier-mitigation-to-enhance-distributed-solar-photovoltaic-deployment/.

[4] Distributed generation (DG) penetration assumed in the Western Interconnection (WECC)'s regional transmission expansion study ranged from 0.1% to 7.9% in the 2026 forecast year (WECC, 2017).

[5] We limit our analysis to 20 years despite DPV system lifetimes in excess of 20 years due to the effects of discounting costs and revenues, in addition to increasing uncertainty in utility cost and load forecasts.

energy security), even though these are clearly relevant to policymakers. The results of this analysis, therefore, should be considered in the full context of the costs and benefits of distributed energy resources (DERs), including DPV.

The report is organized as follows: Section 2 provides an overview of the analytical approach and describes the physical, financial, and operating characteristics of the prototypical Western utility, as well as how we characterized the DPV. Section 3 presents the utility shareholder and ratepayer impacts among different DPV deployment levels as compared to a case without DPV and serves as the reference point to compare our sensitivity and mitigation cases. Section 4 assesses the impacts with different DPV value assumptions. Section 5 explores mitigation cases and their efficacy in reducing or eliminating financial impacts. Section 6 summarizes key findings and implications to help frame, organize, and inform ongoing discussions of net-metering reforms among regulators, utilities, and other stakeholders. The report also includes several appendices with detail about assumptions, calculations, and results underlying the analysis.

2. Methodology

In this section, we describe the underlying model used in the analysis, as well as our key assumptions used to characterize a prototypical Western utility and DPV. The prototypical Western utility is characterized to generally represent a vertically-integrated IOU in the region based on publicly available data of financial, physical, and operating characteristics.

2.1 FINDER Model

For the present analysis, we used a pro forma financial model - the FINancial impacts of Distributed Energy Resources (FINDER) model - that calculates annual utility costs and revenues based on specified assumptions about the utility's physical, financial, operating, and regulatory characteristics. The model was adapted from a tool 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 previously applied the model to evaluate the incremental impact of aggressive EE programs on utilities in the U.S. (Cappers and Goldman, 2009; Cappers et al., 2009; Cappers et al., 2010; Satchwell et al., 2011) as well as the incremental impact of increasing DPV penetration on utilities in the northeastern and southwestern regions of the U.S. (Satchwell et al., 2014). Applications of the FINDER model include analysis efforts through technical assistance to several state public utility commissions (PUCs) (e.g., Arizona, Nevada, Massachusetts, and Kansas). The FINDER model has also been used in regional workshops and training for state regulators and energy offices in the Midwest and Southeast to support the State and Local Energy Efficiency Action Network (SEE Action). Through these various applications, the overall structure of the model has been reviewed and vetted by regulators, utility staff, stakeholders (e.g., consumer advocates), EE program administrators and PV installers. Most recently, the FINDER model was used to assess the financial impacts of a combined portfolio of aggressive EE and net-metered DPV resulting in the development of more robust class-level characterizations and increased disaggregation of customer usage patterns over time (i.e., 8760 load profiles), as well as deriving participating and non-participating customer bills (Satchwell et al., 2017; Satchwell and Cappers, 2018). For a more detailed description of the FINDER Model and its key calculations, see Appendix A.

2.2 Analytical Approach

We estimate the financial impacts as the change from the Western utility's costs and revenues without DPV compared to three different DPV deployment levels: 1%, 4%, and 8% of 2027 retail sales (collectively, "base cases"). We also analyze several sensitivity cases with different assumptions about the value of DPV than what is assumed in the base cases. Due to the way in which these alternate assumptions also change utility characteristics in the without DPV comparison point, we compare sensitivity case results to the base case results in terms of the percentage change compared to their respective without DPV runs. We also analyze several ratemaking and regulatory measures for mitigating the potential negative financial impacts on utility shareholders that were only applied to the 4% and 8% DPV deployment levels. Finally, we report the combined portfolio impacts over a 20-year analysis period (2018-2037) using a 7% nominal discount rate for utility shareholder metrics, which approximately represents a regulated electric utility's weighted average cost of capital (WACC), and a 5% nominal discount rate for ratepayer metrics, meant to represent a lower hurdle rate than the utility.[6]

2.3 Utility Characterization

We developed a 20-year cost and load forecast for the prototypical Western utility by starting with the 2014 general rate case filing of Public Service of Colorado. The general rate case filing was the most recent for the utility that included a cost-of-service study and provided reasonable starting year cost levels, starting year class-level retail sales, peak demand, and customer counts, and class-level cost allocation and rate design. Growth in retail sales, peak demand, and customers are based on Public Service of Colorado's 2016 integrated resource plan (IRP), which was the most recent. Growth in utility cost categories (e.g., generation CapEx, distribution CapEx, operations and maintenance) are based on historical 5-year average annual growth rates among Western utilities derived from their FERC Form 1 filings. Last, the Western utility's hourly load shape is based on Public Service of Colorado's 2017 hourly load (reported in EIA Form 930) and we used a simple average of load in hours before and after missing values to have a complete 8760-hour load shape. Importantly, while many of the input assumptions were seeded with a single utility's data, the utility in this analysis is not meant to represent Public Service of Colorado specifically.

We refer to four key assumptions in the Western utility characterization when describing financial impacts:

1. Non-fuel costs (inclusive of return of (i.e., depreciation) and on capital investments, fixed O&M, interest expense, and taxes) grow by 3.3% per year over the 20-year analysis period (2018-2037) (see Figure 1). Western utilities have seen median[7] generation, transmission, and distribution CapEx costs increase by 6.4%, 3.6%, and 3.8% per year from 2012 to 2016, respectively (calculated based on utility FERC Form 1 data), and we assume similar, rounded CapEx cost escalations (i.e., 6%, 4%, and 4% annual growth in generation, transmission and distribution CapEx costs, respectively). Utility fuel and purchased power (energy and capacity) costs grow by 2.6% per year over the same 20-year analysis period. Our fuel and purchased power costs for non-renewable generation technologies are based on EIA fuel, heat rate, and variable O&M cost assumptions (EIA, 2016). Wind and solar PPA costs are based on NREL's Annual Technology Baseline LCOEs in the "Wind TRG 4" and "Solar CF 20%" forecasts (NREL, 2018).

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[6] The Northwest Power Planning Council likewise uses a consumer discount rate lower than the IOU discount rate. For discount rates used in the Northwest Power Planning Council Sixth Plan, see: https://www.nwcouncil.org/sites/default/files/SixthPowerPlan_Appendix_N.pdf

[7] We considered median values more representative than mean values due to the relatively small sample size of Western IOUs.

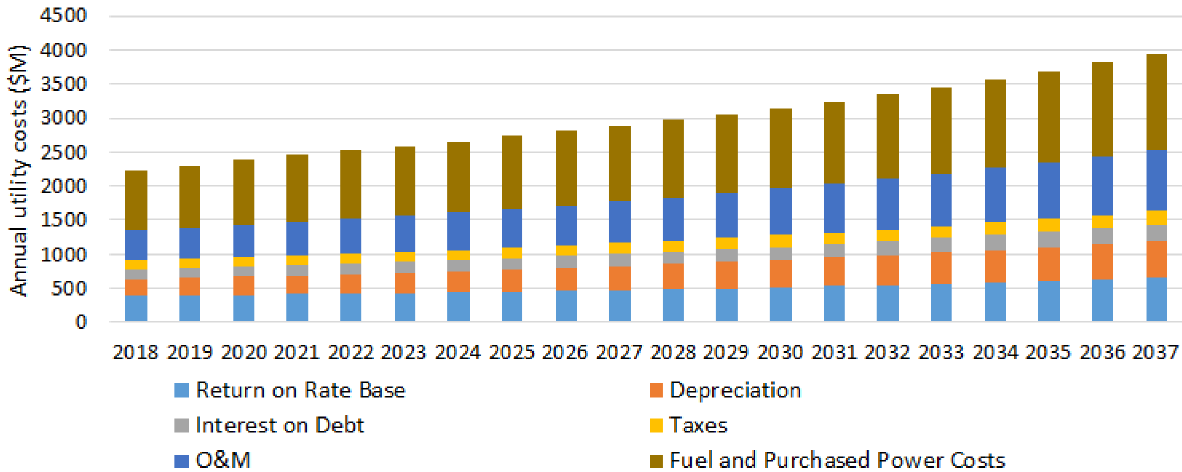

Figure 1. Forecasted Western utility costs (without DPV)

2. The Western utility's retail sales grow by about 1.0% per year and annual peak demand grows by about 0.9% per year. Our load growth assumptions are based on a specific utility's IRP forecasts in order to match any incremental generation or purchased power, though the retail sales forecasts are higher than historical, median sales growth among Western utilities. From 2012 to 2016, Western utility median sales slightly declined by about 0.3% per year based on EIA-861 data.
3. We assume no incremental generation additions in the base case analysis, as Public Service of Colorado is forecasting PPAs to meet incremental load in its 2016 IRP. We make this assumption about no incremental generation additions in order to maintain consistency between our load and cost assumptions.[8] Given that Western utilities averaged flat, or declining, load growth over the last 5 years, we believe our assumption is reasonable. Nevertheless, we consider the case of incremental generation additions in our sensitivity analysis (see Section 4).
4. We assume a flat retail rate design for all customer classes (as opposed to inclining block or time-of-use rates). Residential customer rates and bills collect 90% of revenues via volumetric energy rates with the remainder of revenues (10%) collected via a monthly, fixed customer charge. Commercial and industrial (C&I) customer rates and bills collect about 40% of revenues via an energy charge, 55% of revenues via a demand charge (based on class monthly non-coincident peak), and the remaining via a fixed, monthly customer charge. We model a residential demand charge and increased C&I demand charge in the mitigation case analysis (see Section 5). The rate structure and proportion of revenues collected via volumetric (energy and demand) versus fixed charges is consistent with Western utilities that range from about 5% to 12% of the average residential customer's monthly bill via a fixed monthly customer charge based on EIA-861 data in 2017 (see Figure 2).

[8] We assume retirement of three units during the 20-year analysis period to maintain consistency with Public Service of Colorado's IRP loads and resources table.

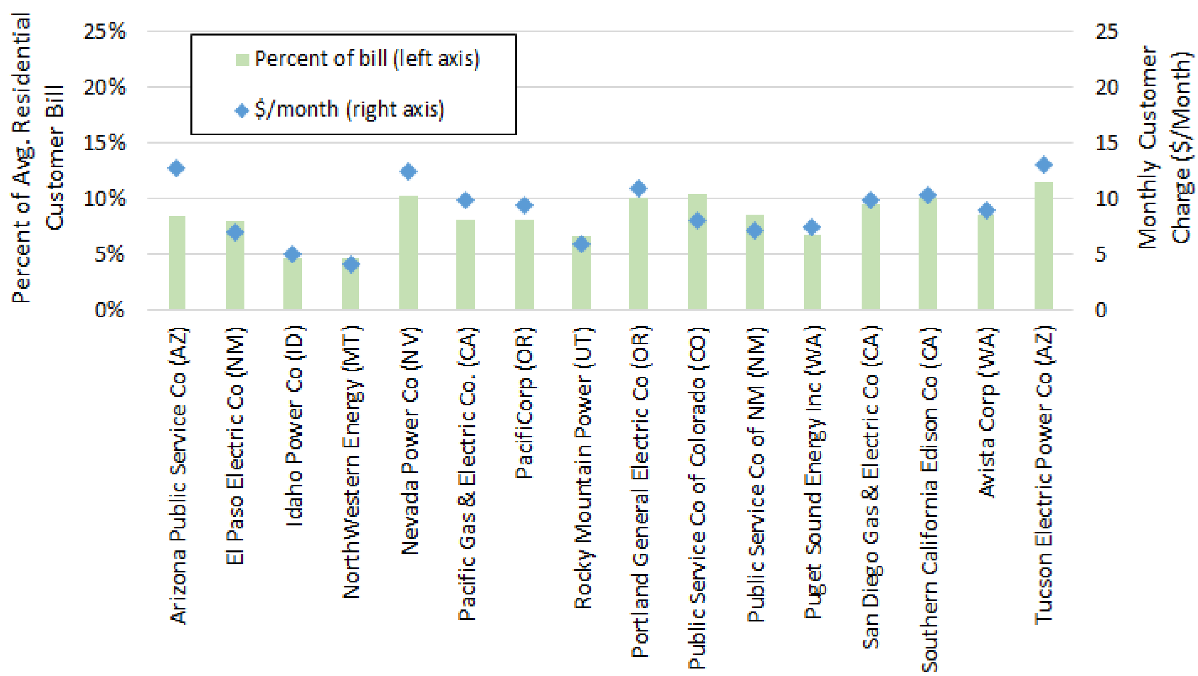

Figure 2. Western investor-owned utility monthly fixed customer charges and percent of average residential customer bill from fixed charges (based on 2017 EIA-861 data of utility total residential revenues, sales, and customers and utility residential fixed charges collected from individual utility tariff sheets)

2.4 DPV Characterization

The FINDER Model derives the impacts of DPV through several key static and dynamic interrelationships. DPV impacts utility billing determinants, specifically retail sales and peak demand, which has an effect on utility costs and subsequently retail rates. DPV reduces volumetric sales based on a direct relationship between the assumed annual DPV penetration, expressed as a percentage of annual sales on a customer-class basis, and the utility's class-level sales. The model derives reductions in the utility's peak demand through dynamic relationships of several variables that take into account: 1) the specific timing of DPV relative to the utility's hourly load and 2) potential differences in alignment between when the DPV causes reductions in the utility's load and the utility system annual peak demand.

The timing of DPV production (savings) and the utility annual peak demand is a key driver in the analysis. DPV reduces energy only in hours when the PV systems operate (i.e., during the daylight hours) and may also reduce utility system demand depending on whether the reduction in energy is coincident with utility system peaks. Thus, the timing of DPV energy and demand savings in relation to customer class and utility peak demands (monthly and annual) drives projections of future costs, retail rates, and revenues collected on a volumetric basis through energy and demand charges.

To calculate the DPV shape, we relied on NREL's System Advisor Model (SAM). We simulated five solar profiles with typical meteorological year (TMY) weather data for different locations in Colorado's main metro areas (i.e., Boulder, Aurora, Denver, Colorado Springs, and Pueblo). These simulations relied on PV Watts default assumptions (i.e., azimuth of 180 degrees, DC to AC ratio of 1.2, and tilt of 40 degrees). To estimate a single input profile for FINDER, we applied a population-weighted average solar output of the five metro area's solar shapes.

We further analyzed DPV's capacity contribution to peak load reduction by simulating DPV profiles using 2017 weather data. While the TMY weather data described above provides an ideal average profile, it does not provide an understanding of DPV's contribution to peak load reduction for our underlying load year of 2017. To determine this value, we simulated the additional solar profiles and sampled the capacity factor of our DPV simulation in the top-20 load hours of 2017 for Public Service of Colorado. The resulting capacity contribution to the top-20 load hours was 22%.[9] This value became our base case capacity contribution to peak load reduction for DPV. We performed this analysis for a number of other Western utilities and found that this capacity value in the top-20 load hours ranged from 7% to 26%, which we use to inform our sensitivity cases in Section 4.

We note two particular feedback effects that the FINDER model does not account for in the present study and that would have potential implications for our results. First, we do not represent the feedback effects between retail rate impacts and DPV adoption rates. An increase in retail rates will improve the economics of DPV investment to customers (i.e., lower payback time for PV system) which, all else being equal, would be expected to drive greater PV adoption and thus lead to increased reductions in the utility's future load. These effects, however, have been found to be small (Darghouth et al., 2016).[10] Second, we do not represent the feedback effects of changes in retail rate designs or NEM alternatives on overall customer energy consumption (e.g., fixed customer charge may reduce financial incentive to invest in energy efficiency or net billing may encourage DPV system design to maximize exports), all else being equal. Instead, we construct an annual load and PV penetration forecast adhered to regardless of these factors.

2.5 Sensitivity and Mitigation Case Analyses

In addition to the base case impacts presented in Section 3, we examine the sensitivity of those impacts to different assumptions about the ability of DPV to defer or avoid utility costs in Section 4. In Section 5, we also quantify the impact of a number of possible mitigation approaches that might be used to reduce any negative impacts to shareholders or ratepayers from growing amounts of net-metered DPV.

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[9] DPV capacity factors are often calculated based on probabilistic simulation and modeling methods such as Effective Load Carrying Capability (ELCC). However, carrying out such a simulation is not the focus of this study. Alternatively, we quantify DPV capacity contribution as the percentage of the nameplate capacity that is available during top-20 load hours. This factor provides a simple and intuitive measure of the value provided by DPV in terms of capacity and can be represented in the FINDER model.

[10] Darghouth et al., 2016 also addressed a separate feedback mechanism between increasing PV penetration and the timing of time-of-use (TOU) periods. The analysis found that higher PV penetration causes TOU peak periods to shift into the evening hours, which in turn dampens further adoption.

These mitigation measures include net billing at avoided cost, NEM with a grid access charge for DPV customers, and increased customer charge for all residential and commercial customers regardless of DPV ownership.

The sensitivity case analysis considers how the base case results depend on the cost deferral value of DPV, which is a key source of uncertainty (see, e.g., Hansen et al., 2013). We focus on the sensitivity of results in the 4% and 8% DPV deployment cases in order to more clearly highlight and compare the relative degrees of sensitivity across the various cases examined.

The mitigation case analysis considers the extent to which ratemaking and regulatory measures can mitigate financial impacts of DPV. Though by no means exhaustive, this set of measures includes many of the regulatory and ratemaking strategies that have been considered or implemented in connection with net-metered DPV (see e.g., Stanton, 2019). These measures specifically target the shareholder impacts from customer-sited DPV (associated with either revenue erosion or lost earnings opportunities), but may potentially exacerbate the ratepayer impacts from customer-sited PV, exemplifying one kind of tradeoff that can often arise when implementing such measures.

3. Base Case Results

In this section, we describe the financial impacts to the prototypical Western utility's shareholders and ratepayers at three DPV deployment levels: 1%, 4%, and 8% of 2027 annual retail sales. DPV installations ramp-up at a linear rate over the ten-year analysis period (i.e., 2018 to 2027). We report financial impacts on a 20-year present-value basis in order to capture "end effects" (i.e., the impacts of DPV systems installed during 2018-2027 on utility costs that continue well into the years afterwards). Each DPV deployment level is compared to a case without DPV to show the incremental impact. Financial impacts at DPV deployment levels not explicitly modeled but within the range of our cases would likely fall within the range, though not necessarily in a linear relationship (i.e., all else being equal, halving or doubling the DPV penetration would not necessarily halve or double the financial impacts, respectively).

3.1 Impacts of DPV on Utility Retail Sales and Peak Demand

The DPV portfolios reduce the Western utility's annual retail sales and peak demand. Retail sales grow by 1.0% per year in the case without PV, but the annual growth rate declines to 0.9%, 0.6%, and 0.2% in the 1%, 4%, and 8% DPV deployment cases, respectively, from 2018 to 2027 as DPV systems are installed. Because the DPV penetration levels are specified in terms of a percent reduction of retail sales, they each reduce the Western utility's sales on a one-for-one basis. As shown in Figure 3, the reduction in retail sales increases as the DPV deployment level increases.

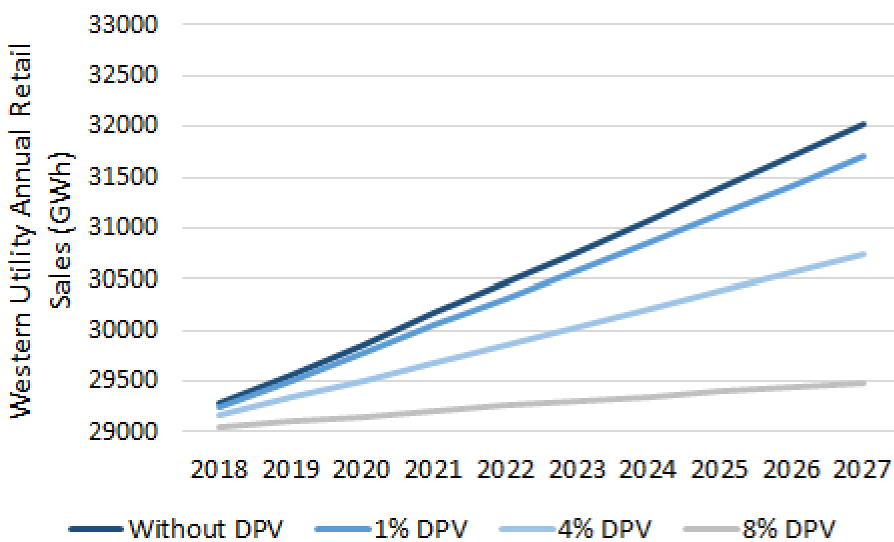

Figure 3. Forecasted Western utility annual retail sales without DPV and at increasing DPV deployment levels (1%, 4%, and 8% of 2027 retail sales)

The impacts of DPV on the Western utility's annual peak demand depends on the timing and coincidence of DPV relative to the utility's annual peak demand. Figure 4 shows the forecasted annual peak demand for the Western utility from 2018 to 2027 and the coincident peak demand savings attributable to the DPV deployment cases. The prototypical Western utility modeled in this study has peak loads that occur in July generally between 2pm and 6pm prior to the addition of DPV systems. The coincident peak demand impact of DPV in our study is less than the retail sales impacts on a percentage basis (e.g., 0.8% per year reduction in retail sales and 0.6% per year reduction in peak demand in 8% DPV deployment case) because the timing of maximum PV output does not coincide perfectly with the utility's annual peak demand.[11]

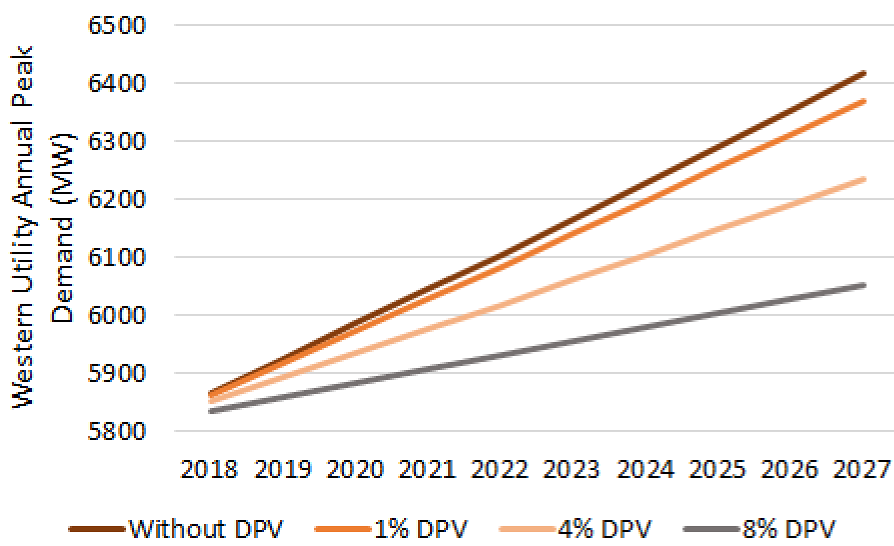

Figure 4. Forecasted Western utility annual peak demand without DPV and at increasing DPV deployment levels (1%, 4%, and 8% of 2027 retail sales)

3.2 Impacts of DPV on Utility Costs

The FINDER Model calculates changes in the utility revenue requirement under the DPV deployment cases based on changes in retail sales and peak demand. The change in utility costs is linked to the modeled relationship between changes in retail sales and peak demand inclusive of DPV and specific cost categories (see Table 1). Utility fuel and purchased power costs are incurred based on incremental sales or demand, so any reduction in retail sales or peak demand produces a commensurate (one-for-one) reduction in fuel and purchased power costs. This means that every kWh the DPV system produces and every kW of reduction in peak demand results in an equivalent kWh and kW reduction in fuel and purchased power costs.

The Western utility sees reductions in fuel costs for utility-owned generation, as well as reduced purchased energy and capacity costs (including PPAs). The Western utility also reduces RPS procurement costs as a result of the reduction in retail sales upon which RPS obligations are based.

[11] This is particularly the case for Public Service of Colorado that serves load near the Rocky Mountains, which results in lower DPV production in afternoon hours relative to other geographic locations due to the effect of mountain shadows (Rhodes et al., 2014). We consider lower and higher contribution of DPV savings to peak in the DPV value sensitivities in Section 4.

Because DPV 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 transmission and distribution (T&D) network losses. For the Western utility, we assume an average loss factor of 4%.[12]

The Western utility owns and operates generation, transmission, and distribution facilities, and makes investments in its T&D system to meet increasing energy, demand, and customer growth (i.e., "growth-related CapEx") or to replace or upgrade infrastructure (i.e., "non-growth-related CapEx"). We assume that the Western utility will continue to make non-growth-related T&D CapEx investments regardless of the level of energy, demand, and customer growth (e.g., replace broken or poorly operating infrastructure) as it must maintain a minimum level of service and reliability. However, we assume a portion (33%) of T&D investments are growth-related CapEx.[13] The addition of DPV reduces the growth-related CapEx proportional to reductions in annual peak demand, leading to corresponding reductions in utility costs (return on ratebase, depreciation expenses, interest, and taxes), all other things equal. As noted earlier, the Western utility has no incremental generation investments assumed in the base case; therefore, there are no reductions in incremental generation CapEx. We assess the sensitivity of results to fixed and variable cost assumptions in Section 4.

Table 1. Modeled sources of Western utility cost reductions

Cost category	Western utility
Fuel & Purchased Power	• Reduced fuel costs for utility-owned generation • Reduced energy and capacity market purchases and PPAs* • Reduced RPS procurement costs** • Reduced losses
Variable O&M	• None***
Depreciation	• Reduced T&D CapEx
Interest on Debt	
Return on Ratebase	
Taxes	• Reduced T&D CapEx • Reduced collected revenues

* We assume a solar integration cost of $3/MWh that is modeled as an increase to energy market purchases
**The reduced RPS procurement costs occur as a result of the reduction in retail sales, upon which RPS obligations are based. We do not assume in the base-case that DPV is used directly to meet RPS obligations.
***The Western utility's incremental CapEx does not include any new generating plants that could otherwise be deferred and reduce related variable O&M costs

12 A sample of Western state annual average T&D losses range from 2.4% (Montana) to 5.9% (Colorado) from 2013 to 2017 (EIA State Energy Profiles, Table 10). We chose 4% average T&D losses as an approximate median value among Western states.
13 The 33% proportion of growth-related CapEx assumption is consistent with other financial analyses using the FINDER model. We assess the sensitivity of this assumption in Section 4.

Given the modeled relationships described above, the Western utility's costs decline by 0.4%, 1.5%, and 2.9% ($118M, $462M, and $892M on a 20-year present-value basis at 7% discount rate) in the 1%, 4%, and 8%, DPV cases, respectively (see Figure 5). Virtually all of the cost reductions are attributable to lower fuel and purchased power costs. Non-fuel cost savings are relatively small for two key reasons. First, the Western utility characterization includes only a small amount of deferrable non-fuel costs (e.g., growth-related T&D capital expenditures are only 8-9% of total annual equity ratebase). Second, non-fuel costs reductions are driven by peak demand reductions from DPV, which are not as large as the retail sales impacts of DPV. For reasons described earlier, there is a mismatch between the timing of the Western utility's peak demand and maximum DPV system production. While utility retail sales are reduced on an equivalent basis with DPV energy production, utility peak demand is reduced by a lower amount than the maximum DPV output. The relatively small decrease in non-fuel costs compared to reductions in fuel and purchased power costs have important implications for the financial impacts on utility shareholders and ratepayers.

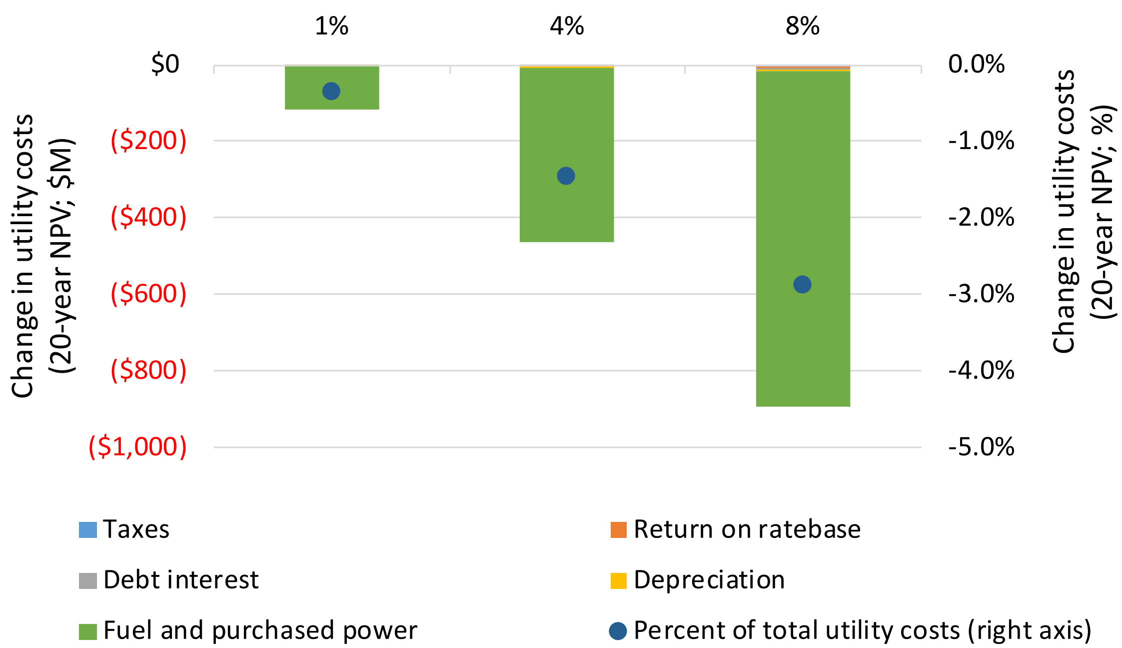

Figure 5. Change in the Western utility's costs at varying DPV deployment levels

3.3 Modeled DPV Value in Base Case

Figure 6 shows the modeled avoided cost of DPV (on a levelized, present-value basis) disaggregated by revenue requirement category. The avoided cost of DPV is $55/MWh in the 1% DPV case, $53/MWh in the 4% DPV case, and $52/MWh in the 8% DPV case. This slight decline in DPV value at the higher deployment level is due to lower PPA and purchased energy costs (per MWh of DPV) as the utility purchases less short-term, more expensive energy. The decline in marginal value of solar at increasing penetration levels due to progressively less expensive energy and capacity costs is a well-studied phenomenon (e.g., see Mills and Wiser, 2013 and Mills and Wiser, 2014).

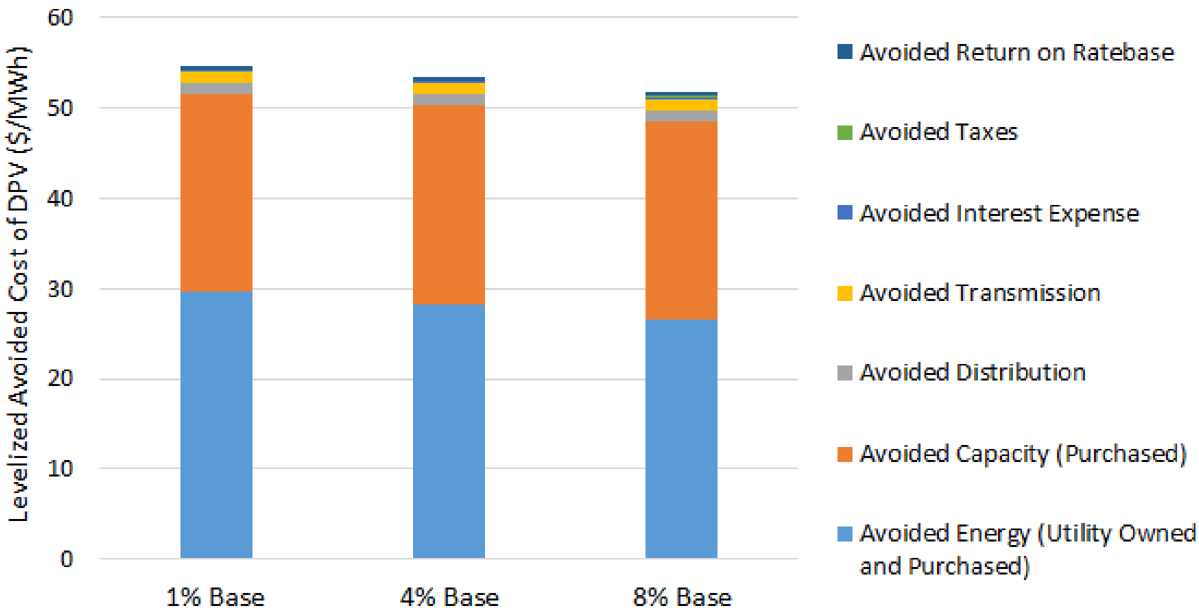

Figure 6. Modeled avoided cost of DPV at 4% and 8% DPV

The FINDER Model is not specifically designed to estimate the value of DPV; however, the estimates used within this study can be compared to those in the literature, which have often been developed using more-tailored tools (e.g., utility generation dispatch or distribution feeder models). Additionally, other studies consider factors that are outside the scope of the FINDER Model (e.g., environmental impacts). We compared our modeled DPV value to DPV value studies performed on Western utilities between 2009 and 2016 and mapped the avoided costs in those studies to our modeled cost categories to ensure we were comparing a consistent set of avoided costs. Furthermore, avoided cost values were inflated to start in 2018 using a GDP chain-type price inflator in order to account for different study years.

Figure 7 shows total levelized avoided cost of DPV for our modeled results (4% Base and 8% Base) compared to the other Western utility DPV value studies. For this comparison, we only included avoided costs from Western utility DPV value studies that were quantified for our prototypical Western utility. Our modeled results fall at the lower end of the range, though this is driven by two factors. First, we are assuming higher DPV penetration rates, especially in our 8% DPV case, than is assumed in many other Western utility studies, and the value of DPV has declining marginal value as the penetration rate increases (Mills and Wiser, 2013). The majority of the studies that we reviewed analyzed DPV penetrations less than 2% (Xcel, 2013; CPUC, 2013; Clean Power Research, 2014; E3, 2016) and only one study looked at one scenario with penetrations as high as 10% (RW Beck, 2009). Second, natural gas prices, which drive much of the proxy avoided energy and capacity costs for DPV value studies, have precipitously declined in the time since these Western utility studies were performed. This is evident in the Xcel study results that show a "low" gas-price case with results more aligned with our modeled results. In fact, we assumed slightly lower natural gas price forecasts in our analysis (based on more current EIA forecasts) than was assumed in the Xcel "low" gas-price case.

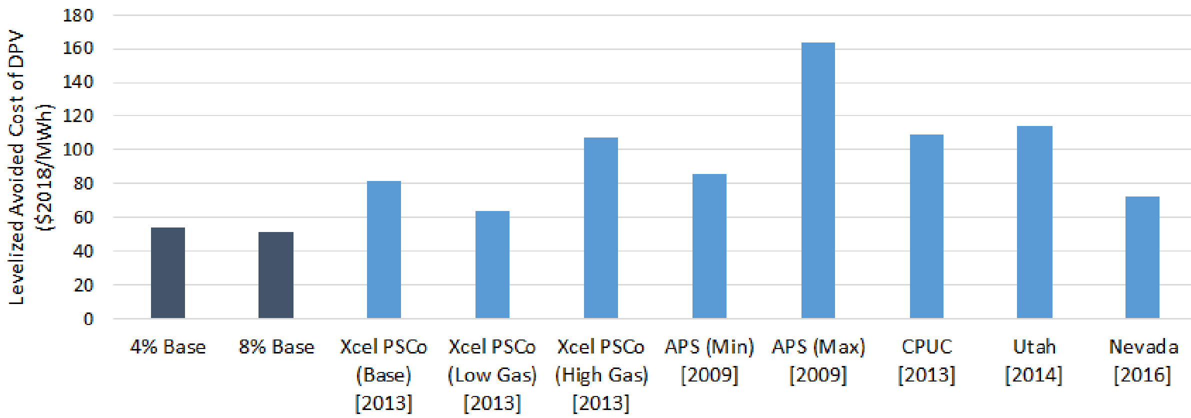

Figure 7. Comparison of modeled avoided cost of DPV and Western utility DPV value studies

Given the uncertainty and importance of the reduction of capital costs from the DPV impacts, we compared our modeled results to the Western utility DPV value studies on a proportional basis. Figure 8 shows the proportion of avoided cost of DPV attributable to avoided energy and capacity versus avoided capital expenditures (generation, transmission, and distribution CapEx). On this basis, our modeled results show a similar proportion (~95% of DPV value from avoided fuel, purchased energy, and purchased capacity) as many other Western studies and falling approximately in the middle of the distribution (ranging from ~70% to 100% of DPV value from avoided fuel, purchased energy, and purchased capacity).

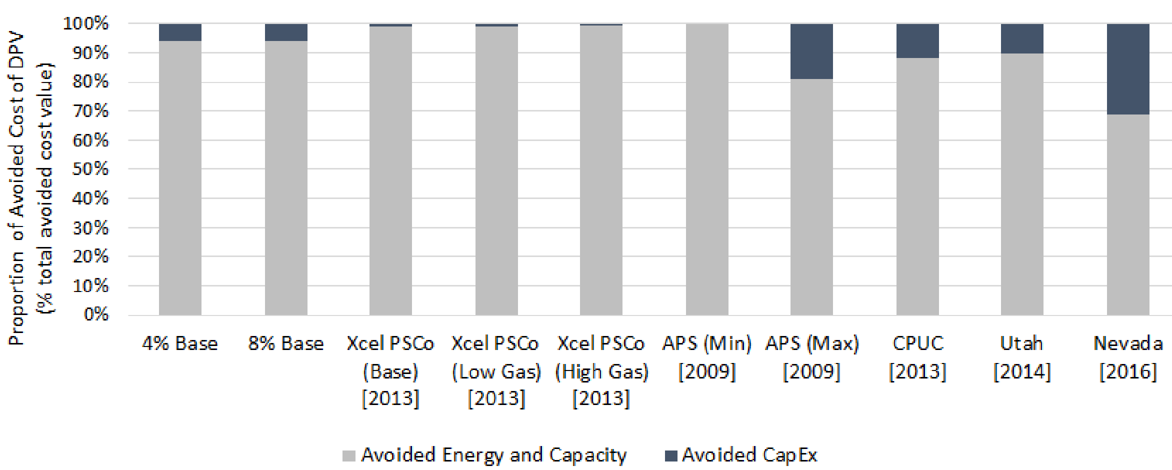

Figure 8. Proportion of DPV value from avoided energy and capacity versus avoided CapEx

3.4 Impacts on Achieved Earnings and ROE

DPV may reduce utility achieved earnings through two separate means. First, if DPV reduces utility revenues more than utility costs (as is likely under rate structures that recover the majority of utility costs via volumetric energy charges), then net revenues or earnings are likewise reduced (i.e., the "revenue erosion effect"). Second, and separately, DPV savings may also diminish future earnings opportunities by reducing the rate of growth or deferring capital investments (T&D CapEx in our base case assumptions, specifically) that would otherwise contribute to the utility's ratebase (i.e., the "lost earnings opportunity effect").[14] We emphasize that this latter effect refers to the dollar amount of earnings, not the rate of return on equity.

Figure 9 shows the earnings impacts for the Western utility over 20-years on a present-value basis. The after-tax earnings achieved by the Western utility decline as the DPV deployment level increases (0.4% reduction at 1% DPV, 1.5% reduction at 4% DPV, and 3.1% reduction at 8% DPV) compared to the case without DPV (BAU).

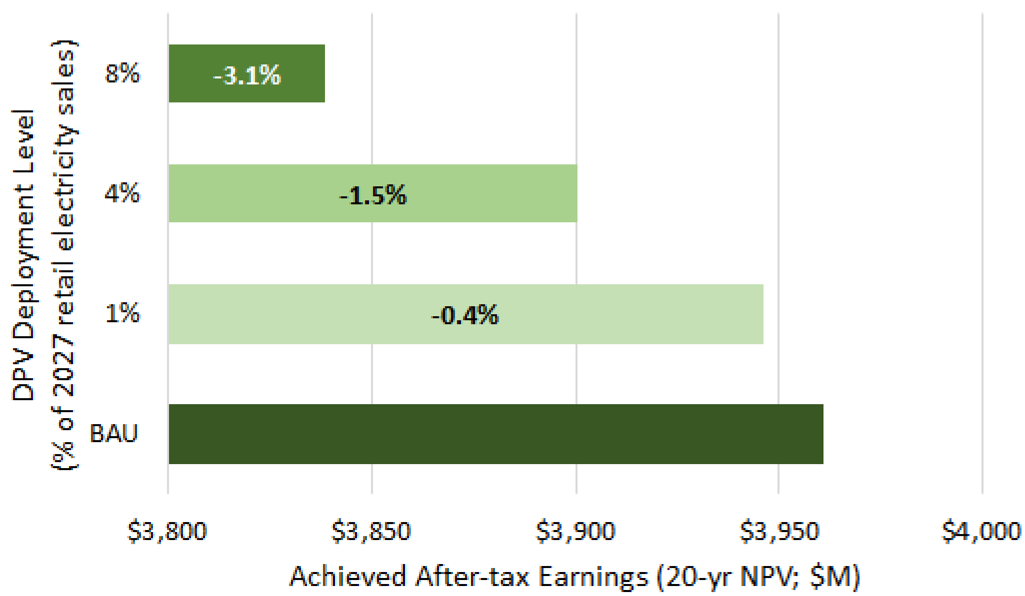

Figure 9. Impacts of DPV on Western utility achieved after-tax earnings

Similarly, the Western utility achieved average ROE declines as the DPV deployment level increases (0.4% reduction at 1% DPV, 1.6% reduction at 4% DPV, and 3.2% reduction at 8% DPV) (see Figure 10). It is important to note that the Western utility achieved ROE is below its authorized ROE in the BAU case (without DPV), as is the case for many electric utilities: an achieved average ROE of 7.9% over

[14] An increase in earnings is valuable to shareholders only if the return on future investments is greater than the cost of equity (Koller et al., 2015), which presently would be the case for most utilities. See (Kihm, 2009) for a discussion of the motivations for a utility to invest in capital in a future with increased EE when returns on future investments are greater or less than the cost of equity.

20 years compared to an authorized ROE of 9.75%. This occurs primarily because the Western utility's costs are assumed to grow faster than their revenues due to existing regulatory practices (e.g., use of historic test years[15], one-year lag in approving new rates filed as part of a GRC, no revenue decoupling mechanism) and modest sales growth. The addition of DPV assumed in our study, and its impacts on retail sales and peak demand exacerbates those underlying conditions, leading to further erosion of ROE. Potential mechanisms exist for mitigating earnings and ROE erosion that we explore in Section 5.

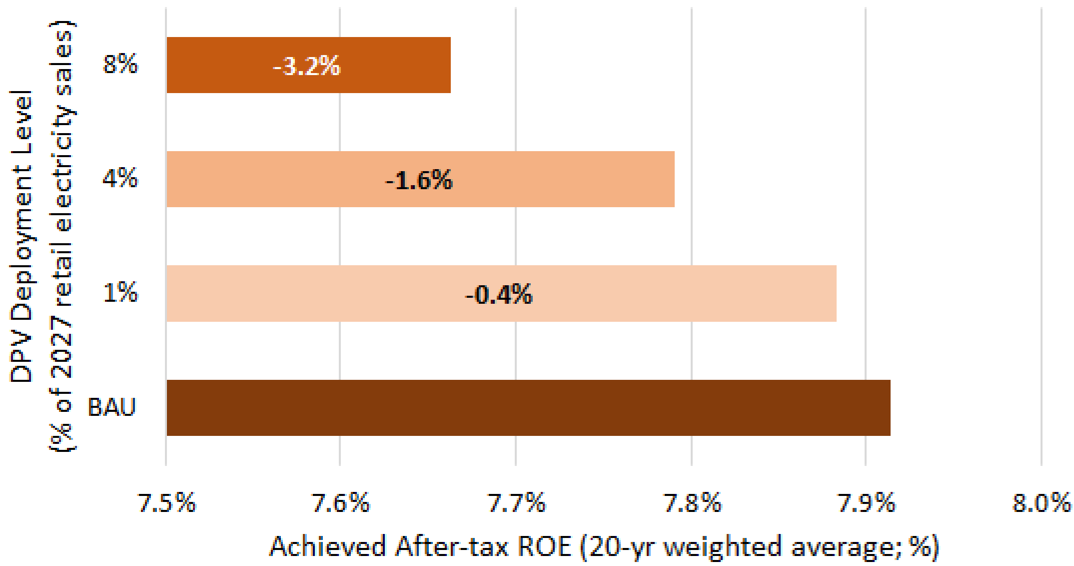

Figure 10. Impacts of DPV on Western utility achieved average, after-tax ROE

3.5 Impacts on Average Retail Rates and Total Customer Bills

Within the timeframe of our analysis, net-metered DPV affects average all-in retail rates in two, interrelated ways. First, DPV affects the retail rates set within each general rate case (GRC) through the net result of reductions in the test-year utility costs and billing determinants used to establish rates. DPV generally tends to reduce utility sales more than costs and, as a result, average retail rates established through each GRC increase with the addition of DPV in order to ensure the utility's rates collect sufficient revenue to recover authorized costs. Second, DPV affects average all-in retail rates in the years between GRCs, though this effect is simply a mathematical artifact. Average all-in rates are, by definition, equal to total collected revenues divided by total retail sales in any given year. Retail sales (i.e., the denominator) are reduced due to the incremental DPV. Because of these lower volumetric energy billing determinants, the revenues (i.e., the numerator) collected on an annual basis will also be reduced. However, the reduction in revenues are necessarily smaller than the reduction in retail sales, given that some portion of revenues are derived from fixed customer charges (which are unaffected by

15 The authorized "test year" is the period for which the utility estimates revenues, costs, and sales for the purposes of setting new rates in a general rate case.

DPV) and demand charges (which are only marginally affected by DPV). Thus, DPV tends to increase average all-in retail rates in between GRCs as well. The Western utility's all-in average retail rate increases as the DPV deployment level increases (0.3% increase at 1% DPV, 1.1% increase at 4% DPV, and a 2.4% increase at 8% DPV) (see Figure 11).

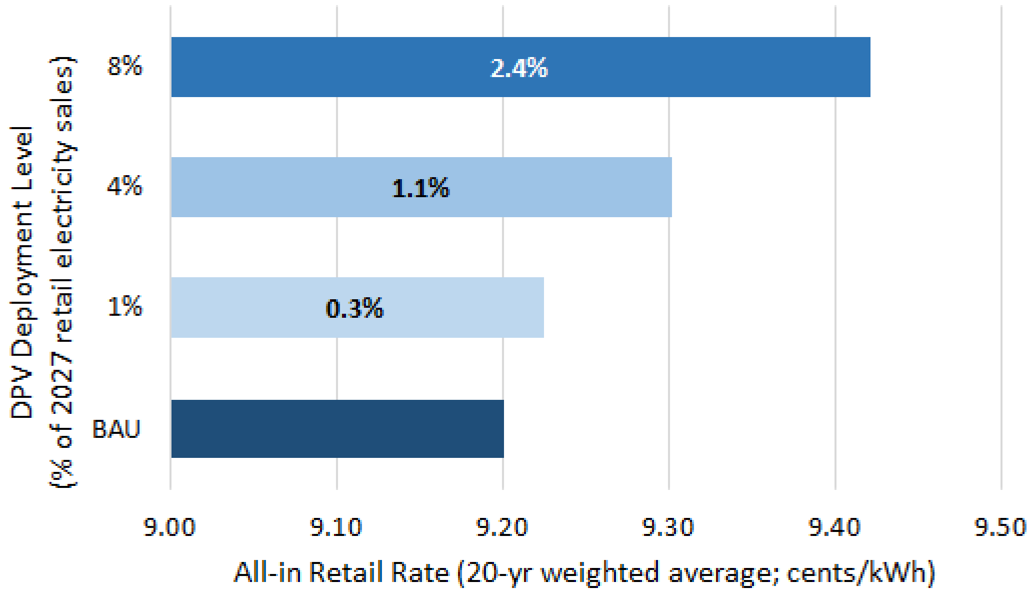

Figure 11. Impacts of DPV on Western utility average all-in retail rates

Although retail rates increase (for reasons discussed earlier), the reduction in sales associated with DPV exceeds the impact from the rate increase, resulting in a decline in total customer bills[16] (0.5% reduction at 1% DPV, 1.8% reduction at 4% DPV, and a 3.6% reduction at 8% DPV) (see Figure 12). Importantly, these bill savings reflect the aggregate impact across all customers and *do not reflect the distribution of customer bill impacts among participating and non-participating customers*.

[16] From another perspective, total customer bills are the same as total collected revenue for the utility.

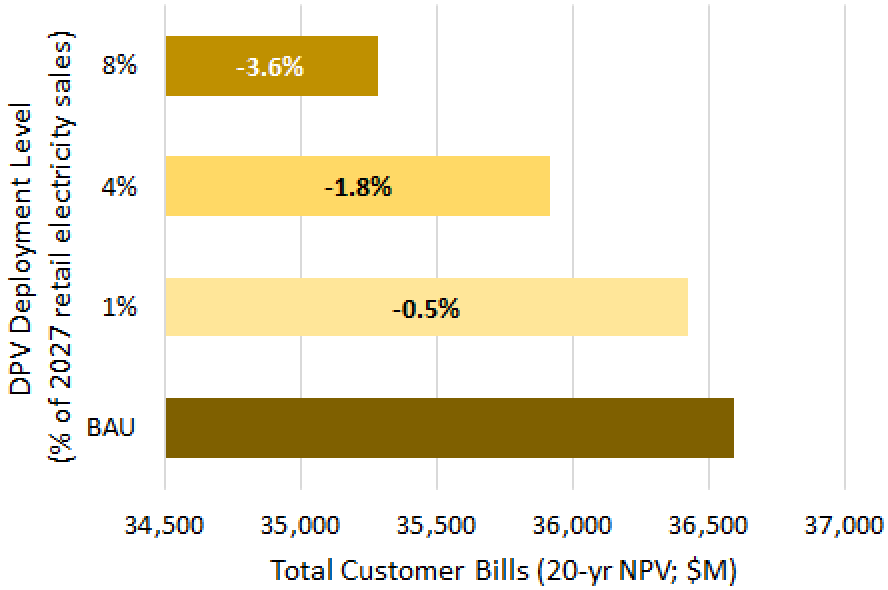

Figure 12. Impacts of DPV on Western utility total customer bills

4. Sensitivity Analysis Results

In this section, we assess the sensitivity of our base case results using different assumptions about the ability of DPV to defer or avoid utility costs. The sensitivity cases reflect the key drivers of our results, but are not a complete list of all the sources of uncertainty and variation in modeled assumptions. There are other utility characteristics that might also change the magnitude and, in more extreme instances, the direction of impacts (e.g., higher or lower assumed load growth, higher or lower proportion of revenues from fixed charges, current or future test years).[17] As such, our purpose here is not to bound the full range of impacts, but rather to illustrate some key themes and considerations related specifically to DPV value. We focus on the sensitivity of results in the 4% and 8% DPV deployment cases in order to more clearly highlight and compare the relative degrees of sensitivity across the various cases examined.

As discussed in Section 3, the financial impacts of net-metered DPV on utility shareholders and ratepayers are driven, in part, by the associated impacts on utility costs (i.e., the deferred or avoided cost "value of PV"). Among the various sources of cost reductions, deferred or avoided generation capacity and T&D capacity costs are arguably the source of greatest uncertainty and disagreement (Hansen et al., 2013). In the FINDER Model used for the present analysis, the impacts of DPV 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 Western utility, capacity credit assumptions affect the deferral of utility fuel costs and market purchases of generation, as well as reductions in growth-related capital expenditures for T&D.

4.1 Impacts of Alternate Assumptions on DPV Value

We developed a set of cases to better understand the sensitivity of shareholder and ratepayer impacts from DPV to assumptions related to its capacity value and avoided generation, transmission, and distribution costs. These sensitivity cases involved modifying a number of parameters in the model (see Figure 13), based on ranges that exist in either the literature or Western utility historical data.

[17] See Satchwell et al. (2014) for the results of a number of sensitivity cases beyond the value of DPV.

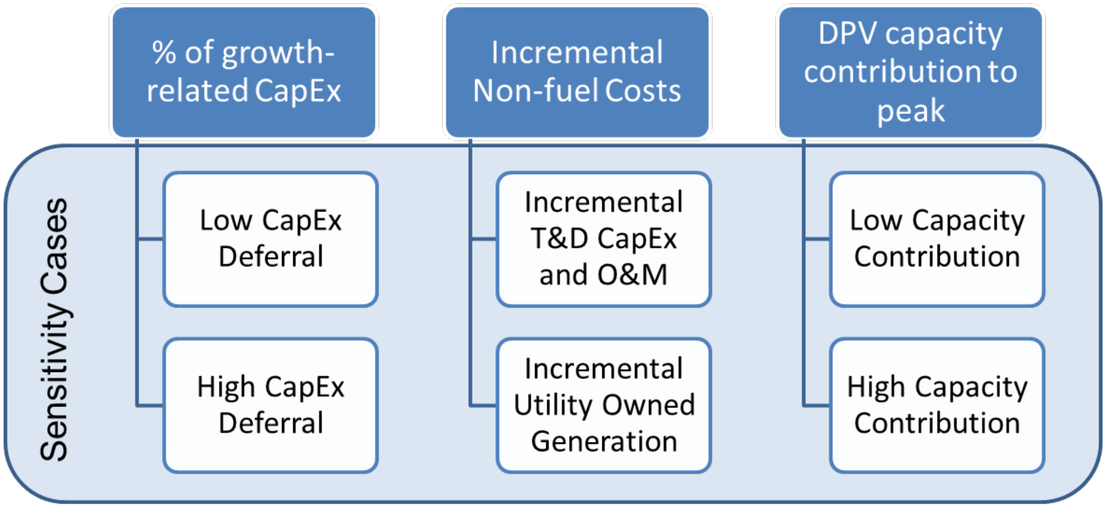

Figure 13. Modeled sensitivity cases among three key assumptions related to DPV value

In our first case, we change the assumed percent of T&D capital expenditures that are growth-related. Discussed in Section 3, we model two categories of T&D capital expenditures: load growth-related and non-load growth related. The base case assumes a portion (33%) of investments are growth-related CapEx and the addition of DPV reduces this growth-related CapEx proportional to reductions in annual peak demand. This results in corresponding reductions in returns on ratebase, depreciation expenses, interest, and taxes. For the sensitivity case, we bound the assumption with a low value of 10% growth-related T&D CapEx and high value of 90% growth-related T&D CapEx.[18]

Figure 14 shows the change in DPV value with alternate assumptions of the proportion of T&D CapEx that is growth-related. A lower proportion of growth-related T&D CapEx results in a lower DPV value, and vice-versa, where the change in value occurs exclusively among non-fuel cost categories. In the 4% DPV deployment case, the DPV value ranges from $51/MWh to $57/MWh and, in the 8% DPV deployment case, the DPV value ranges from $50/MWh to $55/MWh. The modeled DPV value results are not particularly sensitive to this assumption falling in a -4% to 6% range relative to the base case assumption.

[18] Appendix B shows the sensitivity case analysis results as change in DPV value, change in achieved earnings, and change in average all-in retail rates.

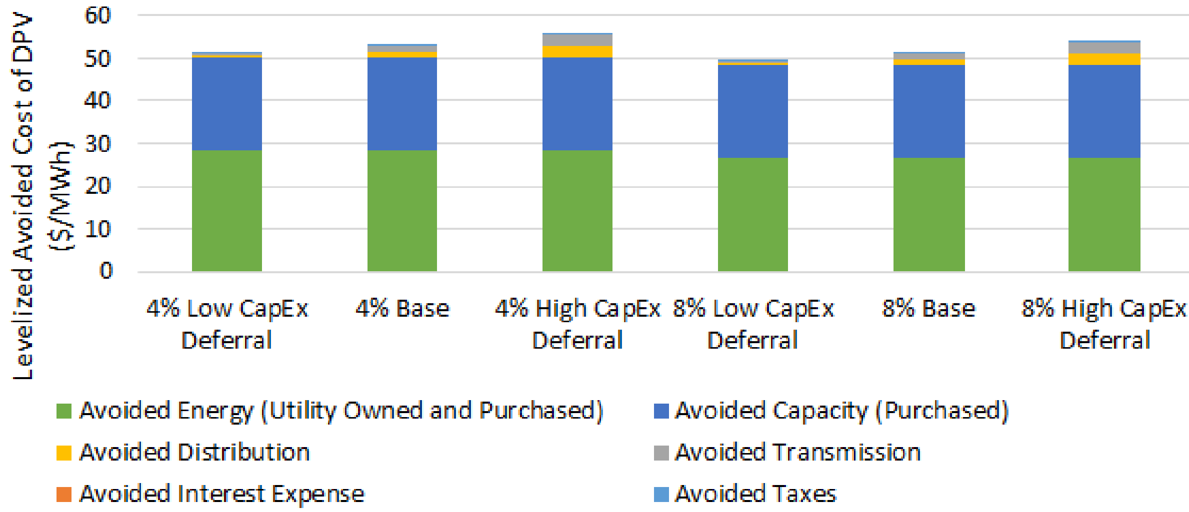

Figure 14. Sensitivity of DPV value to assumed proportion of growth-related CapEx

In our second case, we change assumptions related to incremental capital expenditures. In one case, we increase distribution capital investments and operations and maintenance (O&M) costs in conjunction with PV to represent the possibility that integration costs[19] for customer-sited PV could result in a net increase in distribution system expenditures. We assume incremental distribution O&M cost of $15/kW-year installed DPV (NREL, 2016) and incremental distribution CapEx of $30/kW installed DPV (CPUC, 2017). In another case, we add incremental utility generation to meet future capacity needs motivated by the fact that some Western utility DPV value studies assumed deferred generation. As discussed in Section 2, the base case utility characterization assumes the Western utility meets future capacity and energy through PPAs and short-term market purchases (as is consistent with the IRP data we used as the basis for our Western utility characterization). We base this sensitivity case on a simple loads and resources table and add mid-merit and natural gas generating plants in 100MW and 250MW increments to meet forecasted peak demand in the base case without DPV. Capital and O&M costs of the incremental generation are based on EIA overnight capital cost estimates for generating plants and inflated at 2% per year.

Figure 15 shows the change in DPV value assuming incremental distribution and generation capital expenditures and distribution O&M (OpEx) costs. The incremental distribution CapEx and OpEx costs do not result in additional value, as the costs are added incrementally with the installed DPV and counteract many of the avoided costs. Thus, the DPV value declines significantly in both the 4% DPV and 8% DPV deployment cases. In fact, DPV value at 8% deployment and assuming incremental distribution CapEx and OpEx is roughly half of the base case DPV value ($27/MWh compared to $52/MWh). The incremental utility generation assumption reduces the avoided purchased capacity value, as would be expected due to the incremental generation installed in lieu of the capacity

[19] For the purposes of our study, system integration costs are borne by the utility (and all ratepayers via retail rates) and are different from interconnection costs that are paid by DPV owners.

purchases. Also, as to be expected, the proportion of CapEx deferral value increases as the DPV defers or avoids some of the incremental generation. In total, however, the DPV value in the incremental utility generation case is about 10% lower than the base case assumption because the cost of utility-owned generation is lower relative to meeting the same capacity needs through PPAs and short-term market purchases. Thus, the incremental utility generation sensitivity case produces a lower total DPV value.

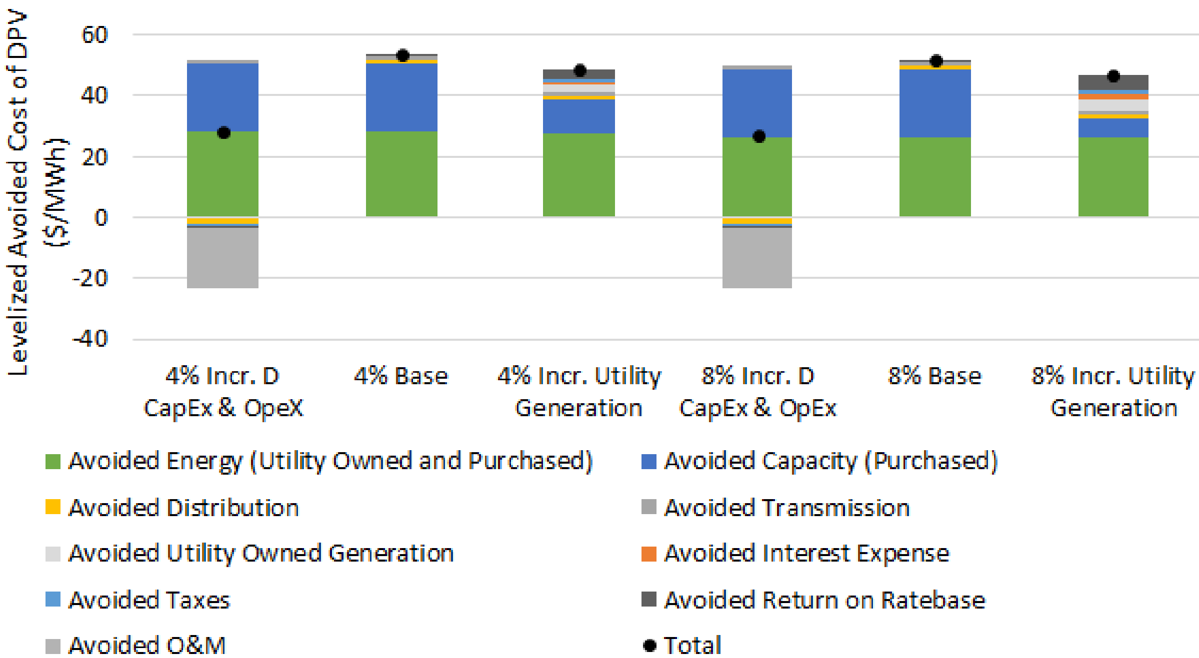

Figure 15. Sensitivity of DPV value to incremental non-fuel costs

In our third case, we change the amount of DPV coincident with the Western utility's annual peak demand (i.e., capacity contribution to peak). The base case assumes a 22% DPV capacity contribution to peak and we bound this assumption with a lower value of 12% and higher value of 32%. The range of Western utility capacity contribution to peak described in Section 2 informs these values. The DPV capacity contribution to peak drives the reduction in annual system peak demand upon which capacity and T&D CapEx costs are based. Thus, an increase in DPV capacity contribution to peak would result in greater avoided capacity-driven costs at the same DPV deployment level.

Figure 16 shows the change in DPV value with lower or higher assumed DPV capacity contribution to peak. As expected, a lower capacity contribution to peak results in lower DPV value, and vice-versa, with the largest change in avoided capacity purchases. In the 4% DPV deployment case, the DPV value ranges from $42/MWh to $59/MWh and, in the 8% DPV deployment case, the DPV value ranges from $40/MWh to $54/MWh. The modeled DPV value results are quite sensitive to this assumption falling in a -27% to 11% range relative to the base case assumption.

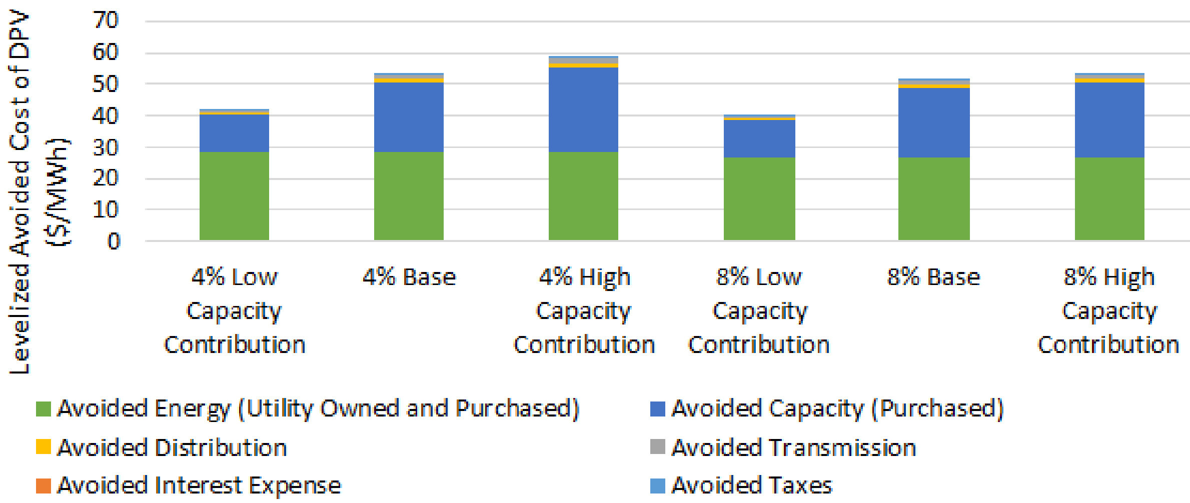

Figure 16. Sensitivity of DPV value to assumed DPV capacity contribution to peak

The results for all sensitivity cases show that DPV value is sensitive to alternate assumptions, but the degree depends on the specific assumption. For example, the assumed proportion of growth-related CapEx has a small range whereas the DPV capacity contribution to peak exhibits a much larger range of results. Importantly, we did not combine changes in more than one key assumption, which would likely drive greater change in DPV value than is observed in isolated cases (e.g., combine higher DPV capacity contribution to peak with higher CapEx deferral, which would likely leader to greater DPV value).

4.2 Impacts of Sensitivity Cases on Shareholder and Ratepayer Metrics

As shown in Figure 17 and Figure 18, the impacts of DPV on shareholder earnings and ROE vary under these different assumptions related to the value of DPV. The results, however, are consistent with the direction of change in the base case results (i.e., achieved earnings and average ROE decline with the addition of DPV even if the quantitative impact may vary from case to case). This demonstrates the robustness of our results to alternative assumptions about DPV value drivers and the generally stable and consistent relationship of the impacts of net-metered DPV on utility shareholders. Adding incremental distribution CapEx, distribution O&M costs, or substituting PPAs with utility generation alters the utility's non-fuel cost assumptions directly and, therefore, produces the most significant change in shareholder impacts. Across the range of sensitivity cases at 8% DPV, earnings impacts range from a 3.0% reduction to a 4.8% reduction, and ROE impacts range from a 2.8% reduction to a 5.4% reduction (on a percentage, not absolute, basis) compared to the base case without DPV.

Importantly, these percentage reductions translate into small reductions in earnings and ROE on an absolute basis. For example, achieved earnings decline by $123M (20-year present value) in the 8% DPV base case out of a total earnings bases of $3.96B (20-year present value). Even with DPV value assumptions driving the most impactful change in earnings (i.e., incremental distribution CapEx and O&M), the absolute reduction in earnings is $190M (20-year present value). The same is true for achieved average ROE impacts that are a 25 basis-point reduction at 8% DPV in the base case. The reduction in achieved ROE assuming incremental distribution CapEx and O&M is 42 basis points.

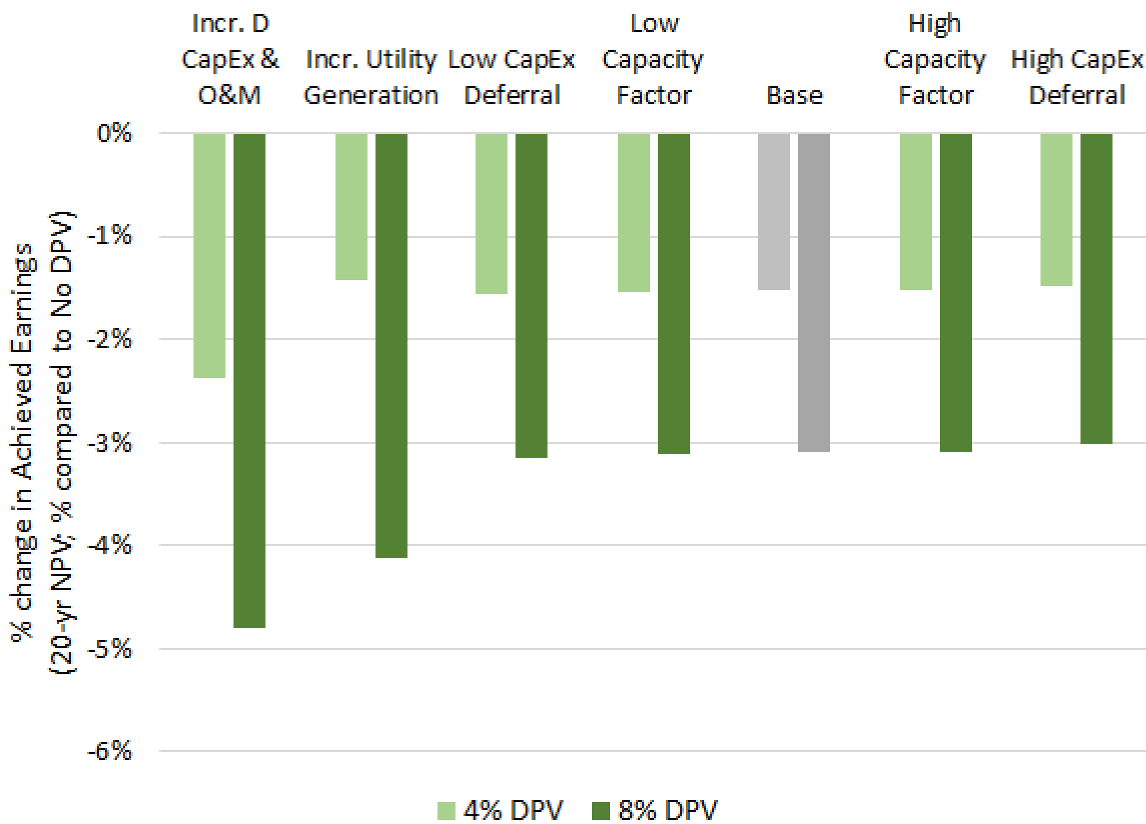

Figure 17. Sensitivity of Western utility achieved earnings to assumptions related to DPV value

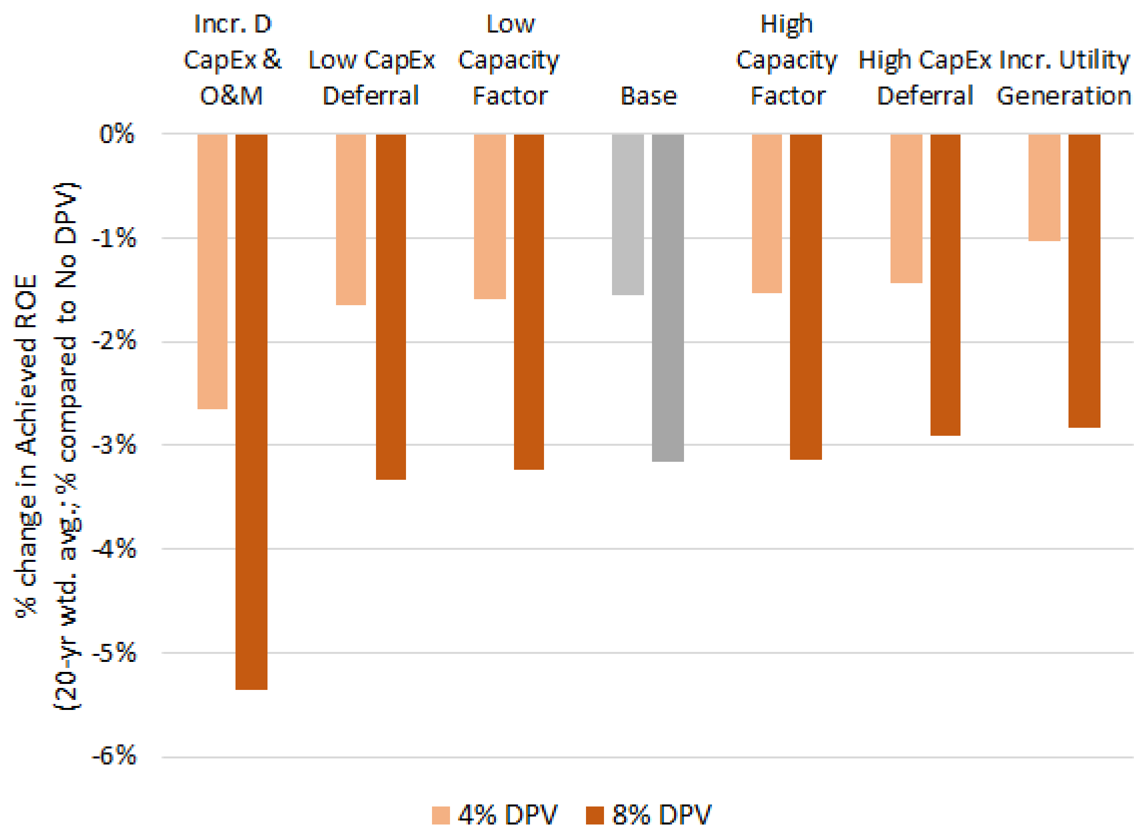

Figure 18. Sensitivity of Western utility achieved average ROE to assumptions related to DPV value

As shown in Figure 19 and Figure 20, the impacts of DPV on average all-in retail rates and customer bills vary under these different assumptions related to the value of DPV, as well as being directionally consistent (i.e., average all-in retail rates increase and total customer bills decrease with the addition of DPV). Relative to the base case without DPV, assumptions driving higher cost deferral (regardless of fuel and purchased power costs or CapEx-related costs) result in lower ratepayer impacts (i.e., lower average rate impacts and higher bill reductions). Across the range of sensitivity cases at 8% DPV, average retail rate impacts range from a 2.3% increase to a 3.4% increase and total customer bill impacts range from a 2.6% reduction to a 3.7% reduction compared to the base case without DPV.

Like the shareholder impacts, these percentage reductions translate into small changes in ratepayer metrics on an absolute basis. Specifically, average all-in retail rates increase by 0.22 cents/kWh in 8% DPV base case and by 0.32 cents/kWh with DPV value assumptions with the most impactful change in average all-in retail rates (i.e., incremental distribution CapEx and O&M). Similarly, there is a $1.31B decrease in *total* customer bills (out of ~$36B basis) at 8% DPV. The total customer bill savings in the high CapEx deferral DPV value sensitivity are $1.35B at 8% DPV.

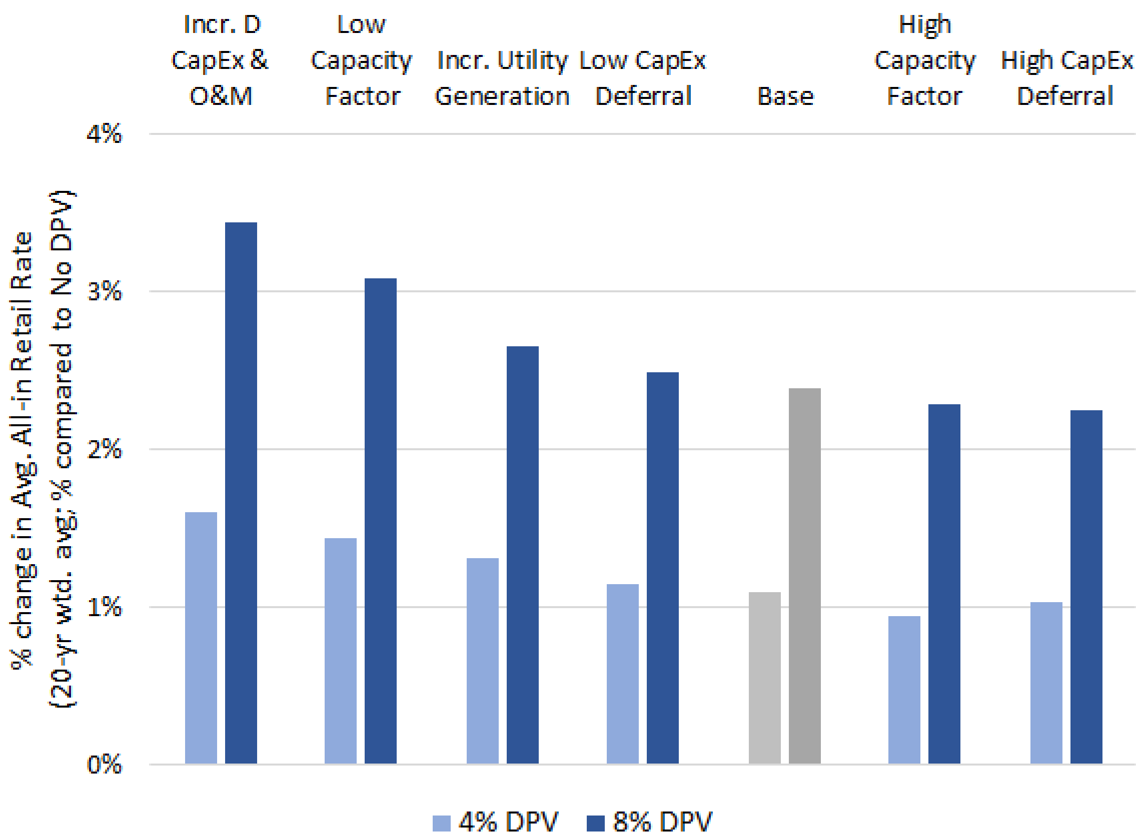

Figure 19. Sensitivity of Western utility average all-in retail rate to assumptions related to DPV value

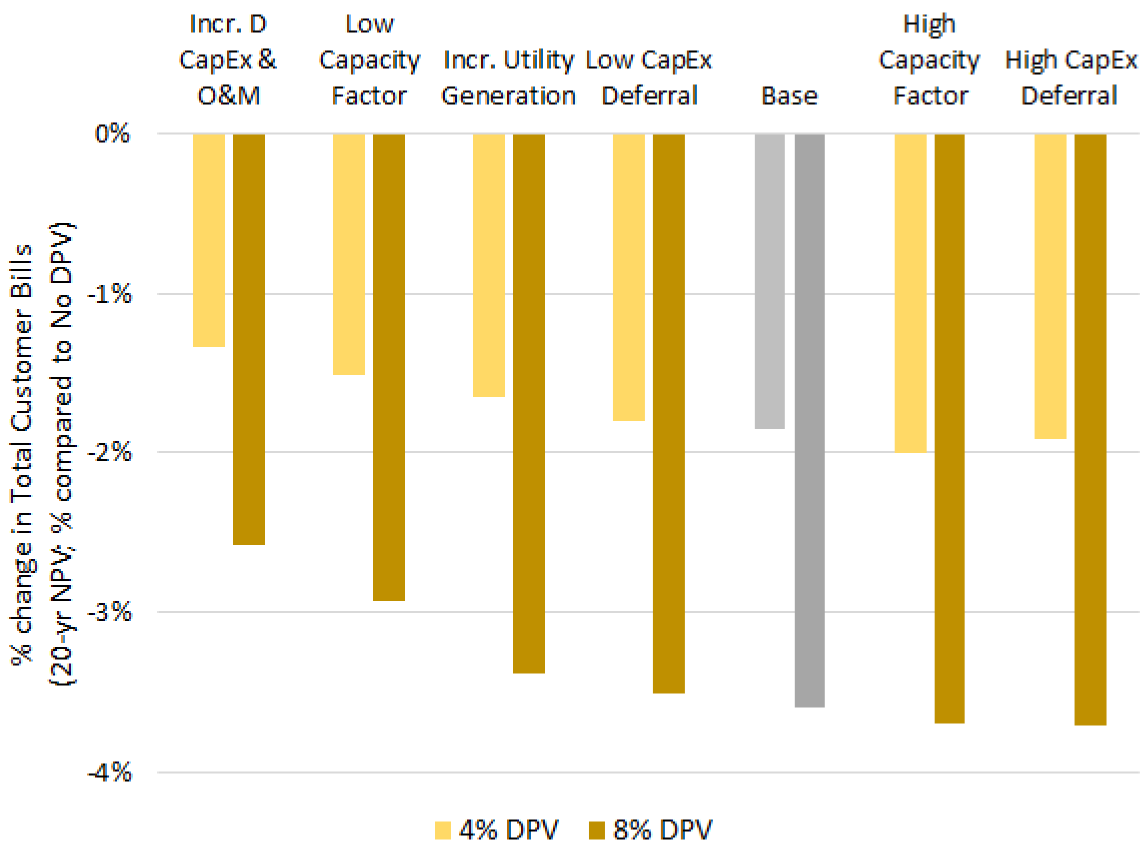

Figure 20. Sensitivity of Western utility total customer bills to assumptions related to DPV value

5. Mitigation Case Analysis

In this section, we assess the impact of regulatory and ratemaking approaches that have been recently proposed or implemented to mitigate the financial impacts of DPV specifically (e.g., net billing), though a subset have been proposed or implemented to mitigate utility fixed cost recovery concerns more broadly (e.g., increased customer charge) (Stanton, 2019). We apply the approaches at the 4% and 8% DPV deployment levels, as the mitigation strategies we employ have typically been implemented at higher levels of DPV deployment, which may necessitate addressing these concerns. Because some of the mitigation approaches apply to DPV owners specifically or are intended to address cost-shifting concerns, we also compare participating and non-participating average customer bills in this section, but focus exclusively on residential customers.[20]

While there are numerous ways to design each of the mitigation approaches with varying degrees of granularity, we model only a single design for each mitigation approach that is intended to assess directional change in impacts (i.e., whether earnings increase or decrease relative to net-metered DPV). Accordingly, our results should not be interpreted to represent the full possible range of impacts associated with different design criteria for the same mitigation approach. Our objective in the mitigation case analysis, therefore, is to understand whether impacts of DPV can be mitigated through existing ratemaking and regulatory measures without prescribing specific designs of measures or approaches.

Given the many possible designs of mitigation approaches, we present results in a qualitative fashion by focusing on the direction of change in key metrics relative to the base case set of results under NEM. We also calculated a simplified customer DPV economic analysis (exogenous to the FINDER Model[21]) in order to understand how the application of each mitigation scenario affected the payback period for the investment relative to a threshold representing the useful lifetime of a standard DPV system (i.e., 25 years).[22] While we explored the impacts of mitigation cases at the 4% and 8% DPV deployment levels, we found them to be directionally consistent at both penetration levels and present results in this section using a single directional or threshold metric.

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[20] We did not calculate C&I participating and non-participating customer bills because showing a single, average bill would not capture the large diversity in underlying C&I customer load profiles, consumption levels, and DPV system design (Davidson, 2015). See Appendix C for a description of our methodology and assumptions for quantifying residential average participant and non-participant customer bills.

[21] Although changes in the underlying retail rate design and/or excess compensation structure will have implications for future adoption of DPV, the FINDER model does not include a feedback effect between changes in customer DPV economics and DPV penetration levels (e.g., see Darghouth et al., 2016). The result of this is that, in some cases, we modeled a DPV deployment rate that does not take into account any reduction in customer investment payback time associated with the application of the mitigation approach.

[22] For the solar payback calculation, we assume DPV capital costs of $3/W. To calculate total DPV system cost, we multiply the capital cost number by the DPV system size for customers who install DPV to meet our 4% and 8% solar penetration assumptions in the FINDER mitigation cases. The simple payback time is then calculated by dividing the total system costs by the annual discounted customer savings, which result from the installation of DPV at a customer site.

We model three mitigation approaches that have been the most commonly proposed and/or implemented among U.S. regulators and IOUs (see Figure 21): net billing at avoided cost (including two bounding cases), NEM with a grid access charge for DPV customers, and increased customer charge for all residential and commercial customers regardless of DPV ownership. We describe the intended objective, general design elements, FINDER modeling assumptions, and the results for each mitigation case. Results are presented as the directional change compared to the DPV with NEM cases, using a single metric for 4% and 8% DPV deployment.[23]

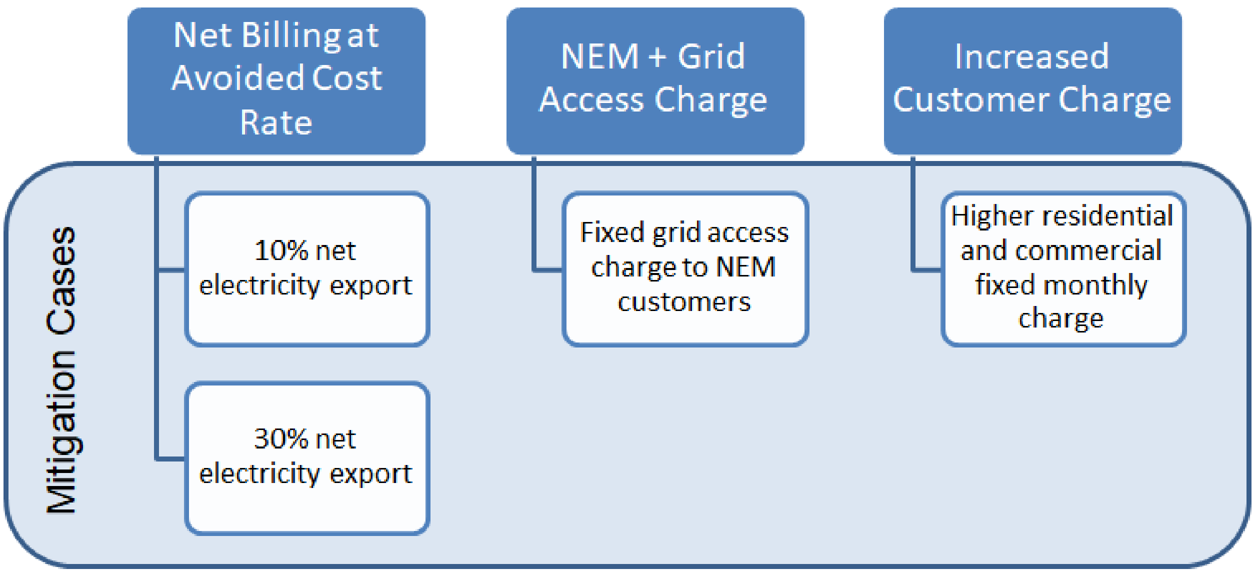

Figure 21. Modeled approaches to mitigate financial impacts of net-metered DPV

5.1 Net Billing at Avoided Cost Rate

One of the most common alternatives to NEM is "net billing", whereby DPV customers continue to be able to offset their own usage with contemporaneous solar generation (as under NEM), but any generation exported to the grid is credited at some specified price other than the retail rate (Satchwell et al., 2019). Net billing is intended to more accurately reflect the marginal value of exported energy from DPV systems to the utility grid. In practice, the specific design of net billing varies where net exports may be calculated on an instantaneous, hourly, or other temporal basis, with the range of exported energy driven largely by the netting interval. The compensation rate for exported energy may be based on an estimate of the marginal energy cost (with varying practices used to set the rate) and, in more limited cases, an adder for estimated T&D avoided cost value (e.g., Arizona).

[23] The "change from no DPV" case applies the mitigation approach at 4% and 8% DPV deployment and compares against the mitigation approach without DPV, similar to how results are compared in Chapter 4. The "change from NEM" case applies the mitigation approach at 4% and 8% DPV deployment and compares against 4% and 8% DPV deployment under NEM.

Estimating the precise impacts of net billing would require a representative (or full) sample of customer load data (e.g., hourly shapes) and DPV system production profiles to assess and net the hourly differences between generation consumed on-site versus exported to the grid. Lacking such customer-level data, we assume a single, average hourly shape for DPV and a single percentage of generation consumed on-site for the residential class. To bound the results and address some of the uncertainty, we run two net billing cases: one case assuming 10% and another assuming 30% of residential DPV production is exported to the grid and credited at an avoided energy rate (based on the Public Service of Colorado's forecasted qualifying facility rate in its 2016 IRP) instead of the full retail rate. We note, however, our two bounding cases may not reveal the full range of impacts and could affect both the direction and magnitude of change, and our conclusions about the efficacy of net billing as a mitigation measure.

Figure 22 shows the results of the net billing mechanism at 10% exported electricity and Figure 23 shows the results of the net billing mechanism at 30% exported electricity.[24] Because net billing is intended to more accurately value the share of exported DPV production at the utility's avoided or marginal costs, the compensation rate is typically less than full retail rate. Reducing the value of the DPV system's excess production relative to NEM results in a smaller credit applied to the DPV customer's bill and, therefore, an increase in DPV participant bills relative to NEM. When the increase is applied to an average DPV customer that exports 10% of the DPV produced energy, the customer still sees a payback period that is less than the 25-year lifetime of the system. However, when 30% of that energy is exported, and thus priced at the lower avoided cost rate, the total value of production from the DPV system drops such that the investment is no longer economic (i.e., the payback period exceeds the system's 25-year lifetime).

Average non-participants see no change in bills under net billing in both the 10% and 30% export scenarios relative to NEM. Because net billing is merely changing the amount credited to DPV participants for exported energy, we assume no explicit cost to all ratepayers and thus no change in collected revenue.

By lowering the value of exported DPV energy, DPV participants are paying higher bills resulting in the utility collecting more revenue, all else being equal. This results in higher achieved earnings and ROE for the utility, relative to NEM, in both the 10% and 30% export scenarios.

[24] Figure 22 through Figure 25 use several symbols to denote the directional and threshold changes inclusive of the mitigation approach, as well as coloring to denote improvement in a financial metric from a particular perspective. Arrows indicate whether the change in financial metric is an increase (upward arrow), decrease (downward arrow), or no change (flat line). For the DPV system lifetime threshold, the figures indicate whether the payback period is less than the system lifetime (<) or more than the system lifetime (>). Last, green coloring indicates an improvement and red coloring indicates a deterioration from the perspective of the participant, non-participant, or utility shareholder/manager.

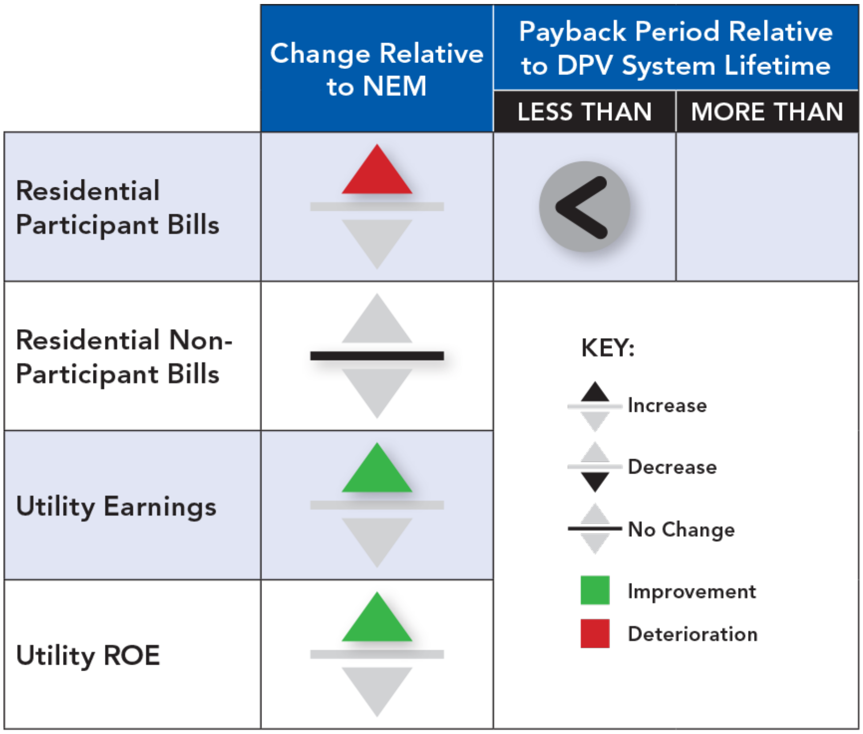

Figure 22. Change in financial metrics under net billing assuming 10% electricity export compensated at an avoided energy cost

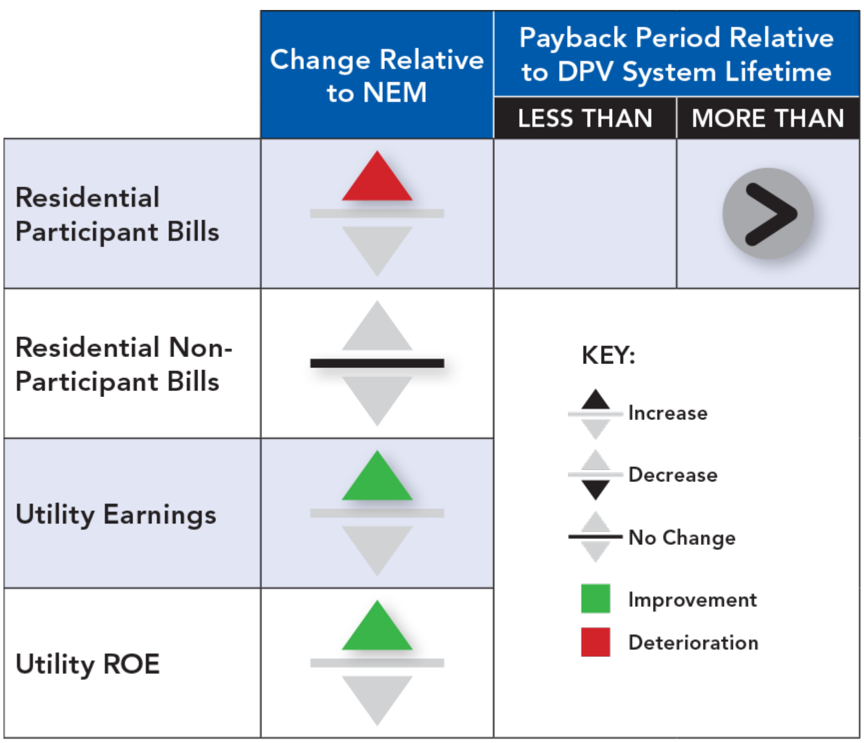

Figure 23. Change in financial metrics under net billing assuming 30% electricity export compensated at an avoided energy cost

5.2 NEM with a Grid Access Charge

A number of states have considered adding a fixed (i.e., grid access) or demand charge to NEM customer bills with the intent of improving the collection of fixed (i.e., non-fuel) and demand driven costs from DPV customers. These mechanisms have been proposed or approved as "standby", "grid-access", or "demand" charges (Stanton, 2019). The charges may either be on a fixed basis (e.g., $/month) or assessed on the DPV customer's demand (e.g., monthly non-coincident peak demand) or assessed based on the size of the DPV system (e.g., $/kW nameplate capacity). From a practical standpoint, DPV customer-specific charges may entail establishing a separate customer class in order to establish the proper charge amount in a cost-of-service study. Although there are few states that have adopted this approach on a mandatory basis for all DPV customers, the approach continues to be considered and may be a viable revenue recovery approach to mitigate the financial impacts of DPV. We modeled a grid access charge designed to fully recover the lost revenues associated with fixed utility costs.[25] To derive the value for the fixed charge to DPV customers, we quantified the annual lost fixed revenues (i.e., level of revenues associated with fixed costs that were avoided by DPV customers) under NEM. We then apportioned that annual avoided revenue associated with fixed costs to all DPV customers[26] so the fixed charge would collect the same amount of non-fuel revenue from the class-average DPV participant as is collected from the class-average non-participant. Thus, this grid access charge acts more like a rate rider with a balancing account allowed to change between rate cases than a fixed component of rates set at the time of a rate case. The result of these assumptions is that our estimate of the additional revenue from the grid charge likely overstates what it would look like in practice, which might collect a smaller amount of non-fuel revenues from DPV customers.

Figure 24 shows the change in financial metrics when adding a grid access charge to NEM. The grid access charge achieved its goal of collecting more revenue that enable the utility to recover a larger share of fixed costs. Specifically, utility achieved earnings and ROE exceeded the amount when NEM was applied to DPV customers absent the grid access charge (with NEM).

The grid access charge collects revenues only from DPV participants. Non-participating customers, therefore, experience no change in their bills relative to NEM. DPV participants, as they are the only customers that are assessed the grid access charge, experience higher average bills compared to the case with NEM only. The increase is so large, in fact, that the payback period of the DPV system now extends beyond the expected lifetime of the system suggesting DPV system investments are no longer economic.

[25] In effect, this design functions similar to a full revenue decoupling mechanism where the utility collects revenues to match its costs regardless of sales.

[26] Technically, we did not assume a separate NEM customer rate class within FINDER but rather calculated the grid access charge based on the reduced sales from DPV.

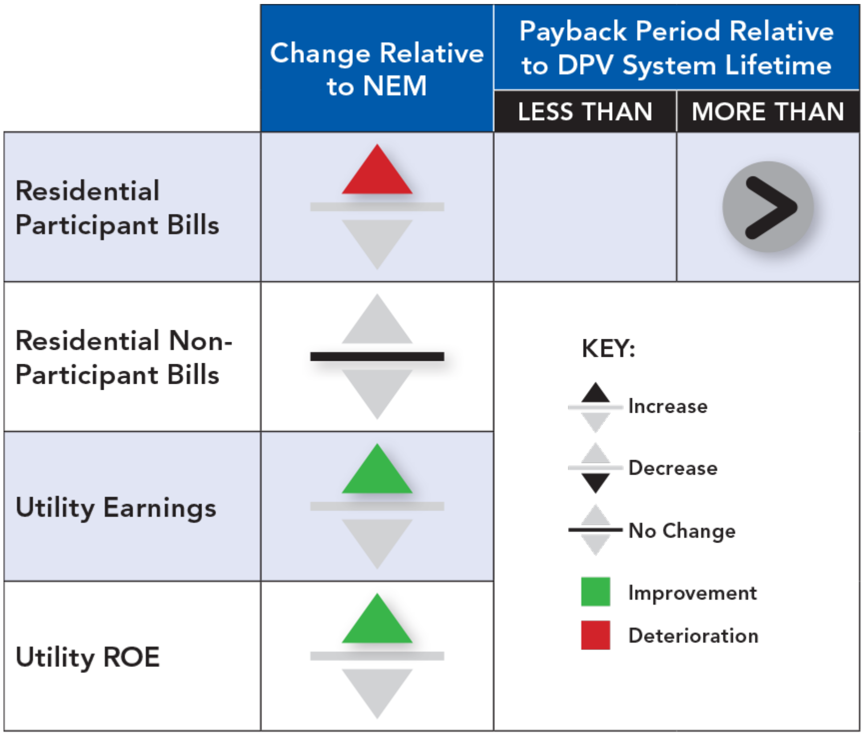

Figure 24. Change in financial metrics under NEM with a grid access charge

5.3 Increased Monthly Customer Charge for Residential and Commercial Customers

The most common approach to address under-recovery of utility fixed costs with DPV deployment is to allocate a larger share of revenue collection to fixed customer charges. In 2017, for example, there were 84 pending or decided utility proposals (in 35 states and DC) to increase residential fixed customer charges or implement minimum bills (NC CETC, 2018). As discussed in Section 2, the vast majority (90-95%) of Western utility residential customer electricity bills are based on volumetric consumption with the small remainder charged via a fixed, monthly fee. While this approach encourages customer energy management and investments in energy efficiency, some industry stakeholders contend there is a mismatch between the proportion of utility costs that are fixed (in the short term) and the proportion of revenues collected via fixed charges (Wood et al., 2016).

We modeled an increased fixed customer charge for residential and commercial class customers by doubling the proportion of revenues allocated to fixed charges (and a commensurate reduction in the proportion of revenues allocated to the volumetric energy rate), with respect to the base case rate design.[27]

Figure 25 shows the directional changes in financial metrics when applying a customer charge with and without NEM. The increased customer charge functions as intended by collecting a higher share of revenues from fixed charges than volumetric energy charges (and demand charges in the case of commercial customers). Customers with a DPV system will experience higher average bills as they are able to reduce a smaller proportion of their total bill relative to NEM with a lower fixed customer charge. However, the increased DPV participant average bills still result in payback periods less than the system average lifetime even with our assumed doubling of the customer charge. The increased revenue collected from DPV participants results in non-participants paying lower average bills compared to NEM with a lower fixed customer charge.

The additional revenue generated by the increased customer charge from DPV customers offsets the reduction in revenue from non-participants resulting in a smaller revenue erosion effect. This means the utility sees higher earnings and ROE than under NEM.

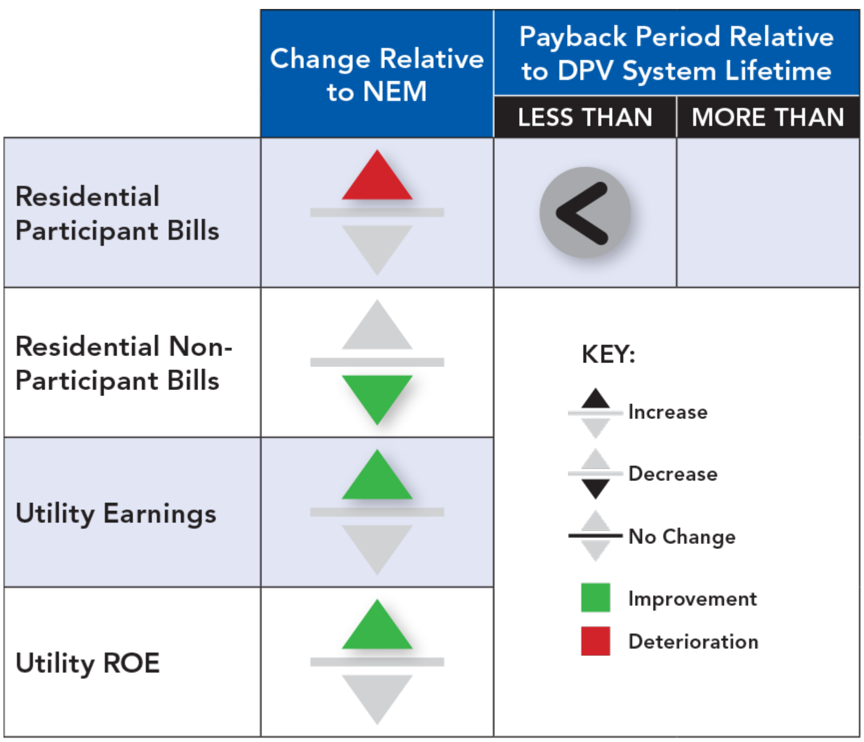

Figure 25. Change in financial metrics under NEM with an increased customer charge

[27] While the median requested increase among utilities in 2017 was about 50%, there were several examples of requests to double the existing fixed charge (NC CETC, 2018). However, given how small the customer charge is for the residential and commercial classes in the base cases (i.e., 10% and 2% of all non-fuel costs are allocated to the customer charge, respectively), doubling the customer charge is not a particularly meaningful increase.

6. Conclusions and Discussion

This analysis quantified the financial impacts of different levels of net-metered DPV deployment on a prototypical Western utility over 20 years and estimated changes in the Western utility's costs, revenues, achieved shareholder earnings and ROE, average all-in retail rates, and customer bills. We also quantified the sensitivity of results to different assumptions about the ability of DPV to avoid, defer, or increase utility fixed and variable costs. Last, we assessed the efficacy of several regulatory and ratemaking approaches to mitigate financial impacts on utility shareholders, participating, and non-participating customers.

This analysis makes several important findings about the financial impacts of net-metered DPV on utility shareholders and ratepayers:

- First, the financial impacts on shareholders and ratepayers increase as the level of DPV deployment increases, though the magnitude is small even at high DPV penetration levels (e.g., 2 to 4% change in financial metrics at 8% DPV deployment). Because most Western utilities currently have distributed generation deployments less than 1% of annual retail sales, policymakers and regulators likely have time to study and deliberate changes to NEM before observing material financial impacts.
- Second, the study explicitly links different estimates of DPV value to shareholder and ratepayer impacts and finds that even rather dramatic changes in DPV value result in modest changes to shareholder and ratepayer impacts. Also, the range of financial impacts under alternative DPV value assumptions are greater for shareholders than ratepayers on a percentage basis and driven by differences in the amount of incremental CapEx that is deferred, as well as the amount of incremental distribution OpEx that is incurred.
- Third, the mitigation cases demonstrate that what constitutes a financial impact from a particular perspective matters. While all the mitigation cases improved utility earnings, ROE, and average non-participating customer bills (relative to the case with NEM only), average DPV participating customer bills increased further and, in some cases (i.e., grid access charge and 30% electricity export at avoided cost), pushed DPV system payback times beyond the system lifetime. Regulators and policymakers may improve their understanding of multiple perspectives by incorporating feedback effects between changes in rate design or compensation mechanisms and DPV deployment rates. Even a simple payback and system lifetime threshold analysis, as was performed in this study, can be illustrative.

The mitigation analysis raises important issues about the implementation of new approaches within existing regulatory processes. For example, increasing the customer charge can be easily incorporated into general rate case processes. This is because increasing the customer charge entails increasing the proportion of revenue collection from fixed charges (informed by a cost-of-service and rate study). However, the administrative simplicity may not overcome some stakeholder concerns that increasing the fixed charge reduces incentives to invest in energy efficiency technologies by lowering the volumetric portion of customer bills.

Implementing a grid access charge for DPV customers, however, may not be as straightforward as increasing the customer charge. Adding a grid access charge may entail a separate rate class for DPV customers and accounting for the DPV system lifetime costs and benefits (in the form of utility cost savings) in the rate analysis, thus ensuring the grid access charge is cost-based and not merely a lost revenue recovery mechanism for the utility.

The net billing case and grid access charge case results, in particular, highlight the importance of assessing rate impacts on customer economics of DPV investments. One of the key financial benefits of investing in DERs are customer bill savings. The results show how interaction between costs and rates may change DER economics from their perspective and the importance of including participant impacts among considerations of retail rate, earnings, and ROE impacts. Notwithstanding the difficulty in obtaining customer hourly consumption and DPV system production data, customer bill impacts under different DPV compensation regimes should consider some distribution of customers to understand the tradeoffs and implications of different mitigation approaches.

As is true for many quantitative analyses, these study results should be considered in the broader context and value of DPV (e.g., environmental, jobs, customer choice benefits). While many of the impacts appear relatively small (on a percentage basis), they demonstrate how underlying ratemaking and regulatory mechanisms can change utility support for or customer interest in DERs, and the magnitude of impacts depends critically on utility physical, financial, and operating characteristics.

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Appendix A. FINDER Model Overview

The FINDER model quantifies the utility's annual costs and revenues over a 20-year analysis period in this study. Importantly, the model performs all cost calculations at the total utility level but has the ability to allocate those costs to different rate classes in order to assess differential revenue impacts. Key outputs include achieved return on equity (ROE) and earnings, average retail rates and customer bills, which can be used by utilities, policymakers, customer groups, and other stakeholders when assessing the impacts and implications of policy proposals and decisions.

Utility costs are based on model inputs that characterize current and projected utility costs over the analysis period. The model represents major cost 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). Some costs are projected using stipulated first year values and compound annual growth rates (CAGRs); other costs are based on schedules of specific investments (e.g., generation expansion plans). The model calculates the utility's ratebase over the analysis period, accounting for increases due to additional capital investments as well as decreases due to depreciation of existing assets. The model also estimates interest payments for debt and returns for equity shareholders based on an authorized amount used to finance capital investments and includes taxes on earnings.

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 a GRC occurs at some specified frequency (e.g., every three years); the model also allows the utility to file a GRC that may be triggered by a significant capital investment (e.g. new power plant, proposal to install advanced metering infrastructure).

GRCs are used to establish new rates for customers 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 to customer classes and among the billing determinants. The model allows for different types of test years (i.e., historical, current, and future test years)[28]. 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) for a particular customer class. Model inputs specify the relative share of different types of utility costs that are collected from each of these three rate components.

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

[28] 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 reflect expectations about normal cost levels. However, our model uses unadjusted historic test year values for ratemaking purposes.

whereby rates that are established in a GRC do not go into effect until some specified number of years after the GRC. In between general rate cases, certain costs are passed directly to customers through rate-riders (e.g., fuel-adjustment clause or FAC). The model derives an average all-in retail rate metric that reflects the average revenue collected per unit of sales at the utility or customer-class level and accounts for periodic setting of new rates, rate-riders, and delays in implementing new rates.

The financial performance of the utility is measured by achieved after-tax earnings and achieved after-tax ROE.[29] 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).[30] Achieved after-tax ROE may, and often does, differ from the utility's authorized ROE. The authorized ROE is typically established by regulators during a regulatory proceeding and used in a GRC to determine the amount of return that a utility may receive on its capital investments. Actual utility revenues and costs may – and nearly always do – differ from those in the test year, leading to achieved earnings, and hence achieved ROE, that deviates from the authorized level.[31] In general, achieved ROE will be less than authorized ROE if, between rate cases, utility costs grow faster than revenues. Conversely, achieved ROE will generally be higher than authorized ROE if utility costs grow slower than revenues between rate cases.

FINDER calculates the prototypical utilities' achieved after-tax earnings as collected revenues minus costs in each year. 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.[32]

Alternative regulatory mechanisms and rate structures can also be implemented in FINDER: decoupling mechanisms (i.e., sales based or revenue-per-customer), lost revenue adjustment mechanisms, and shareholder incentive mechanisms. Alternative rate structures (e.g., high fixed customer charge) are represented by changing the way utility revenues are collected among different billing determinants.

[29] Achieved ROE is considered a measure of how well a company is performing for its shareholders. Achieved ROE is dependent on several factors including the ratio of debt to equity, which may artificially inflate a company's achieved ROE if the company is making investments mostly with debt. Achieved ROE is also a useful metric when comparing companies within an industry because the metric is normalized by outstanding shareholder equity.

[30] The FINDER Model does not take into account changes in financing costs that may result from under- or over-recovery of costs, which may impact ROE.

[31] In a GRC, utility rates are set such that the test-year revenue requirement produces earnings that are sufficient to reach the authorized after-tax ROE based on the test year costs and billing determinants.

[32] Technically, state regulators do not explicitly authorize earnings in a GRC. They authorize a ROE, which when applied to the undepreciated portion of a utility's share of equity financed ratebase produces a level of earnings. For our purposes in this report, we refer to that as authorized earnings.

Appendix B. Sensitivity Case Results

Table B - 1. Full sensitivity case results at 4% and 8% DPV shows the sensitivity case results expressed in percentage changes. The change in DPV value is relative to the DPV value in the base case at the respective DPV deployment level (i.e., 4% or 8%). The change in achieved earnings and average all-in retail rates is relative to a case without DPV.

Table B - 1. Full sensitivity case results at 4% and 8% DPV

	Sensitivity Case	**Change in DPV Value** (% relative to base case)	**Change in Earnings** (% change relative to respective no DPV)	**Change in Average Retail Rates** (% change relative to no DPV)
4% DPV Deployment	Base	n/a	-1.5%	1.1%
	Low Capacity Contribution	-4.3%	-1.5%	1.4%
	High Capacity Contribution	6.1%	-1.5%	0.9%
	Incremental D CapEx and OpEx	-87.7%	-2.4%	1.6%
	Incremental Utility-Owned Generation	-9.5%	-1.4%	1.3%
	Low CapEx Deferral	-27.3%	-1.6%	1.1%
	High CapEx Deferral	10.5%	-1.5%	1.0%
8% DPV Deployment	Base	n/a	-3.1%	2.4%
	Low Capacity Contribution	-4.4%	-3.1%	3.1%
	High Capacity Contribution	6.3%	-3.1%	2.3%
	Incremental D CapEx and OpEx	-93.4%	-4.8%	3.4%
	Incremental Utility-Owned Generation	-9.9%	-4.1%	2.7%
	Low CapEx Deferral	-28.5%	-3.2%	2.5%
	High CapEx Deferral	3.7%	-3.0%	2.3%

Appendix C. Average Residential Participating and Non-Participating Customer Bill Calculations

We developed an analytical approach (similar to Satchwell and Cappers, 2018) intended to be illustrative of residential participant and non-participant average bill impacts. We do not model the entire population of customers for the Western utility but instead develop representative customer cohorts in the residential class that are likely to invest in DPV systems.

Specifically, we begin with the annual residential class-level retail rates for energy (¢/kWh), demand ($/kW), customer ($/customer), and balancing accounts (¢/kWh) charges derived from the FINDER model that takes into account the Western utility's financial, operational, and regulatory characteristics as well as class-level rate design. The annual retail rates also incorporate the modeled impacts of DPV for each of the deployment cases.

We assume residential participating and non-participating customers have similar annual usage (prior to installing DPV systems) and that are similar to the class average. This implies the two types of customers are, from a pre-DPV investment perspective, the same. For residential customers that install a DPV system, we assume that it is sized to reduce their total annual energy usage by 100% but does not affect their billing demand (Darghouth et al., 2017). DPV system savings were assumed at 100% of the class average residential customer's annual energy use because NEM incentivizes investment in solar systems to offset annual energy use. We acknowledge that this is an upper-bound assumption, as many jurisdictions do not allow customers to size PV systems to exceed average annual energy consumption.