Estimating the Value of Improved Distributed Photovoltaic Adoption Forecasts for Utility Resource Planning

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Motivation

- Many utilities have witnessed, or are anticipating, rapid growth in customer-owned distributed photovoltaics (DPV). This has prompted utilities to take a closer look at how they account for DPV growth within their resource planning processes and, in particular, their DPV adoption forecasting methods.
- Current resource planning practices in this area vary widely, and the state-of-the-art in DPV adoption forecasting is undergoing continuous refinement.
- Utility resource planners may have an interest in improving their DPV forecasting techniques, but such improvements entail costs related to new tools, training, staffing, or contractors.
- Assessing whether such investments are worthwhile therefore requires some understanding—and ideally quantification—of the potential benefits associated with improved DPV adoption forecasting.

Overview

This report seeks to inform decision-making by utility resource planners by estimating how improved DPV adoption forecasts can reduce future utility capital and operating costs.

- We simulate future capital and operating costs for the entire Western Interconnection under varying assumptions about the accuracy of the DPV forecasts used to develop generation-expansion plans
- We then describe a simplified probabilistic method that individual utilities could implement for their own service territories to estimate the potential benefits from improving their DPV forecasting capabilities
- Those benefits can then be compared against the associated costs of investing in improved DPV forecasting capabilities
- Note: This analysis exclusively considers the bulk power system; depending on their locational precision, improved DPV forecasts could also benefit distribution system planning, but those impacts are outside the scope of this work

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Methodology - Models

Using a suite of models, we explore the capacity expansion and operation of the Western Interconnection over a 15-year period (2016-2030) across a wide range of scenarios encompassing varying levels of DPV growth and misforecasting.

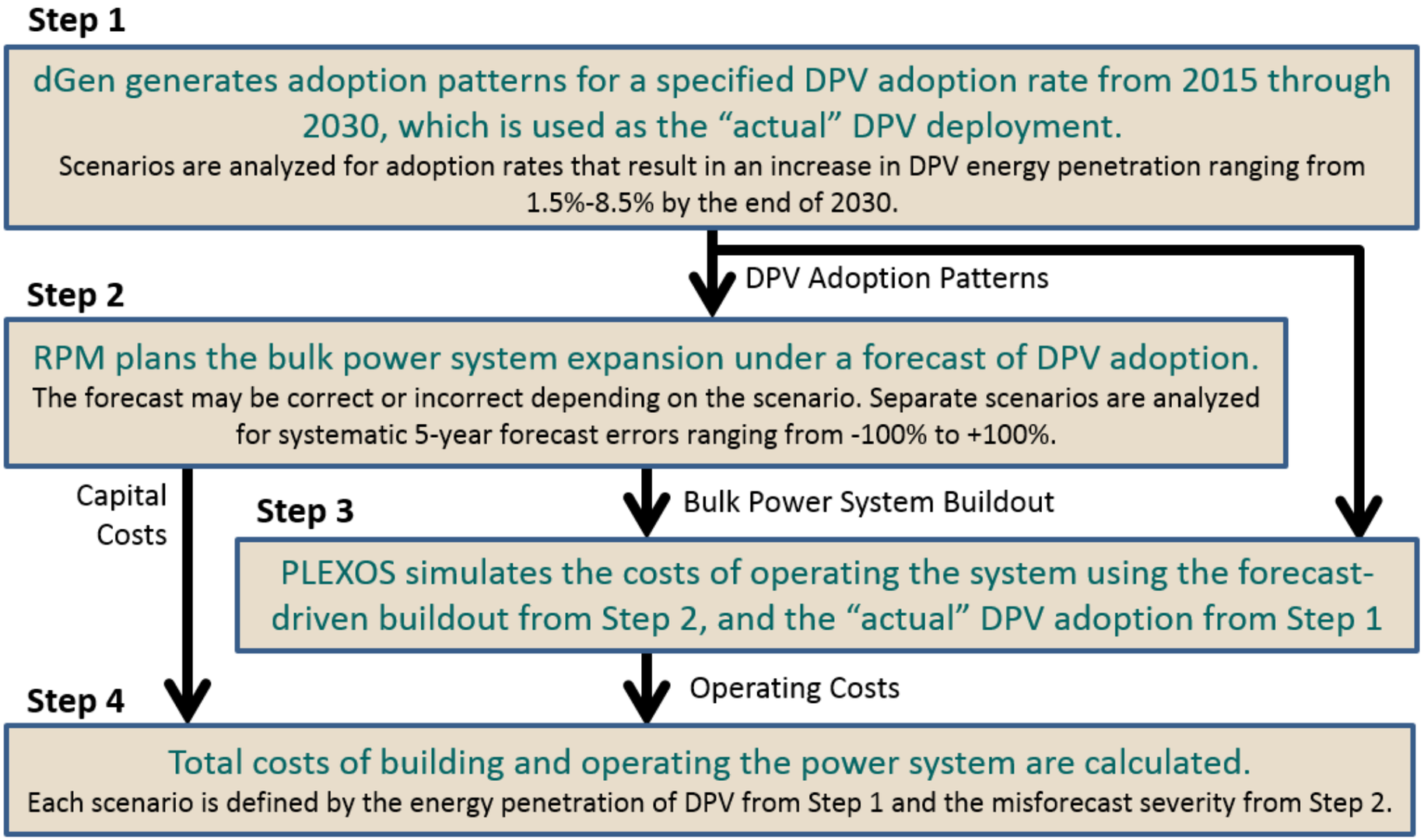
- **The Distributed Generation Market Demand Model (dGen):** NREL's customer adoption model projects patterns of DPV adoption over time (Sigrin et al. 2016).
- **The Resource Planning Model (RPM):** NREL's capacity-expansion model projects the least-cost buildout of the bulk power system (Hale et al. 2016).
- **PLEXOS:** A commercial production cost model used to simulate the operation of the bulk power system using the capacity mix developed by RPM.

The costs of misforecasting DPV adoption are calculated by comparing the NPV of utility costs under each DPV misforecasting scenario to a scenario where the utility perfectly forecasts DPV adoption

Except where otherwise noted, we follow the same assumptions as the central scenario of NREL's 2016 Standard Scenarios (Cole et al. 2016b), which draws from NREL's 2016 Annual Technology Baseline (Cole et al. 2016a) and the U.S. Energy Information Administration's (EIA's) 2016 Annual Energy Outlook (EIA 2016) for exogenous inputs such as technology and fuel prices.

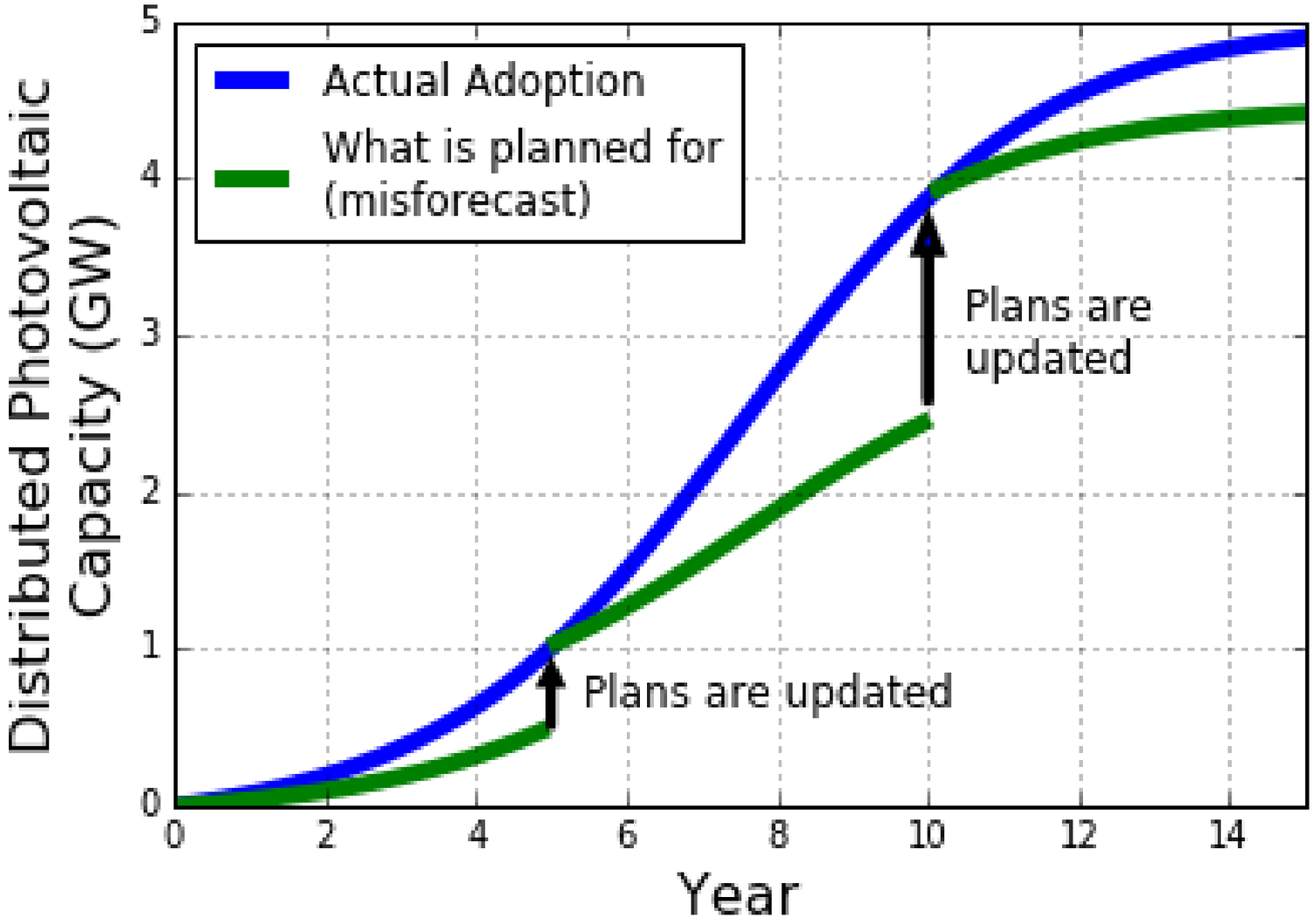
- **Sensitivity cases** explore alternate assumptions for load growth, natural gas prices, and REC prices

Methodology – Workflow



Methodology – Systematic misforecasts

The misforecasts that RPM plans for (step 2 in previous slide, represented by the green lines here) are modeled in three 5-year steps over a 15 year period, to simulate the periodic updates of a utility resource planning process. The situation shown is a systematic -50% underforecast (i.e., in each 5-year planning cycle, the utility incorrectly plans for only half of the incremental increase in DPV that will ultimately end up occurring).



Methodology – Adjustments

Misforecasting DPV can cause a failure to meet resource adequacy or Renewable Portfolio Standard (RPS) requirements, if no remedial actions are taken. We make two cost adjustments to represent actions taken to meet both of these requirements.

- In scenarios where DPV overforecasting results in a reserve margin shortfall, we add the annualized cost of sufficient natural gas combustion turbine capacity to make up for the shortfall. This is categorized as a capital cost.
- We adjust costs related to RPS requirements by adding or subtracting costs to represent the buying or selling of Renewable Energy Credits (RECs) for any deviation from the required amount of RECs. These cost adjustments are categorized as an operating cost.

The relative magnitude of these adjustments is shown on slide 12.

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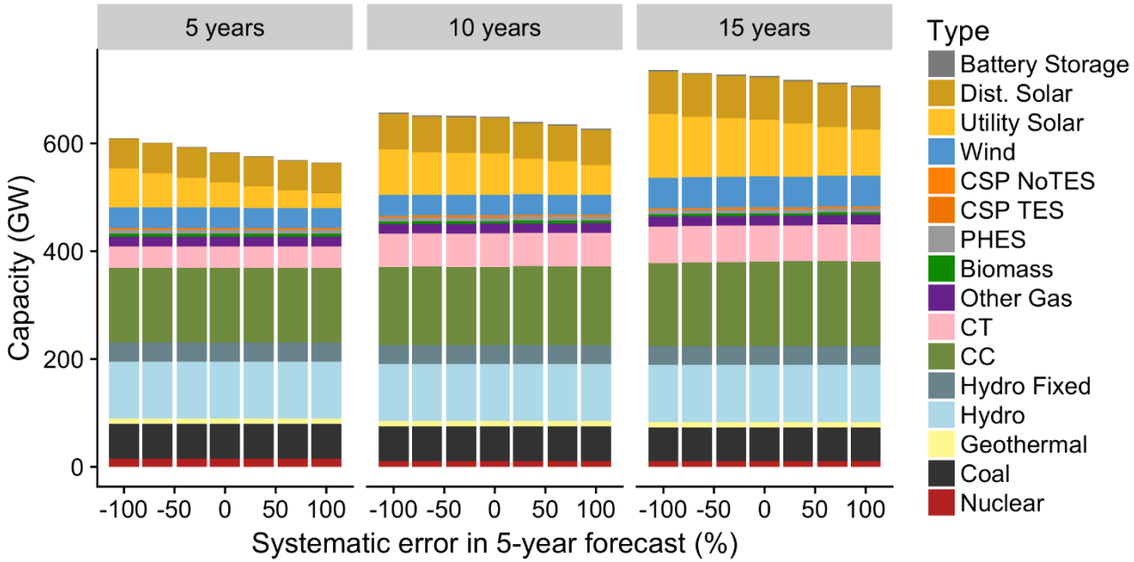
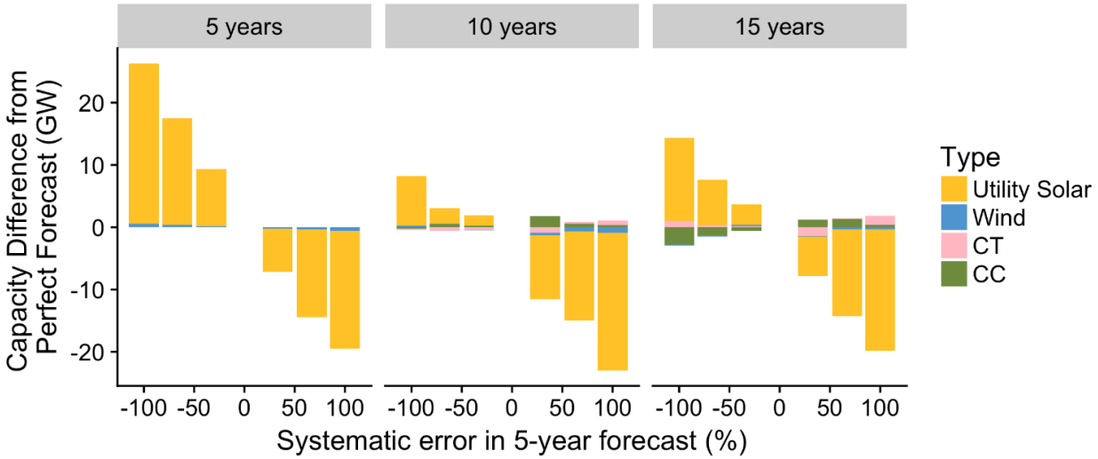
Misforecasting DPV most strongly influences how much UPV capacity is built





All else being equal, each forecasted GWh of DPV generation generally corresponds to roughly a GWh reduction in generation from utility-scale photovoltaics (UPV) added to the system.

- This is strongly driven by the similarity between the energy and capacity services provided by the two solar technologies.
- Also partially driven by the technology's status as a renewable resource, in regions where both technologies can contribute to RPS requirements.

Both figures show the influence of forecast error on cumulative capacity for a scenario with DPV growth over 15 years equal to 5% of total generation. The top figure shows each technology's cumulative capacity (to place the impacts in context), whereas the bottom figure shows the difference in cumulative capacity between each misforecast scenario and the perfect forecast scenario (to more clearly show what technologies were impacted).

Misforecasting DPV has opposite impacts on system-wide capital and operating costs

Following the previous trend, underforecasting DPV tends to result in higher capital costs (primarily more UPV being built than otherwise would have been), whereas overforecasting DPV tends to result in lower capital costs.

Conversely, overforecasting DPV tends to result in higher operating costs (primarily from more fuel being burnt, to make up for the solar resource that was expected but did not materialize), whereas underforecasting results in lower operating costs.

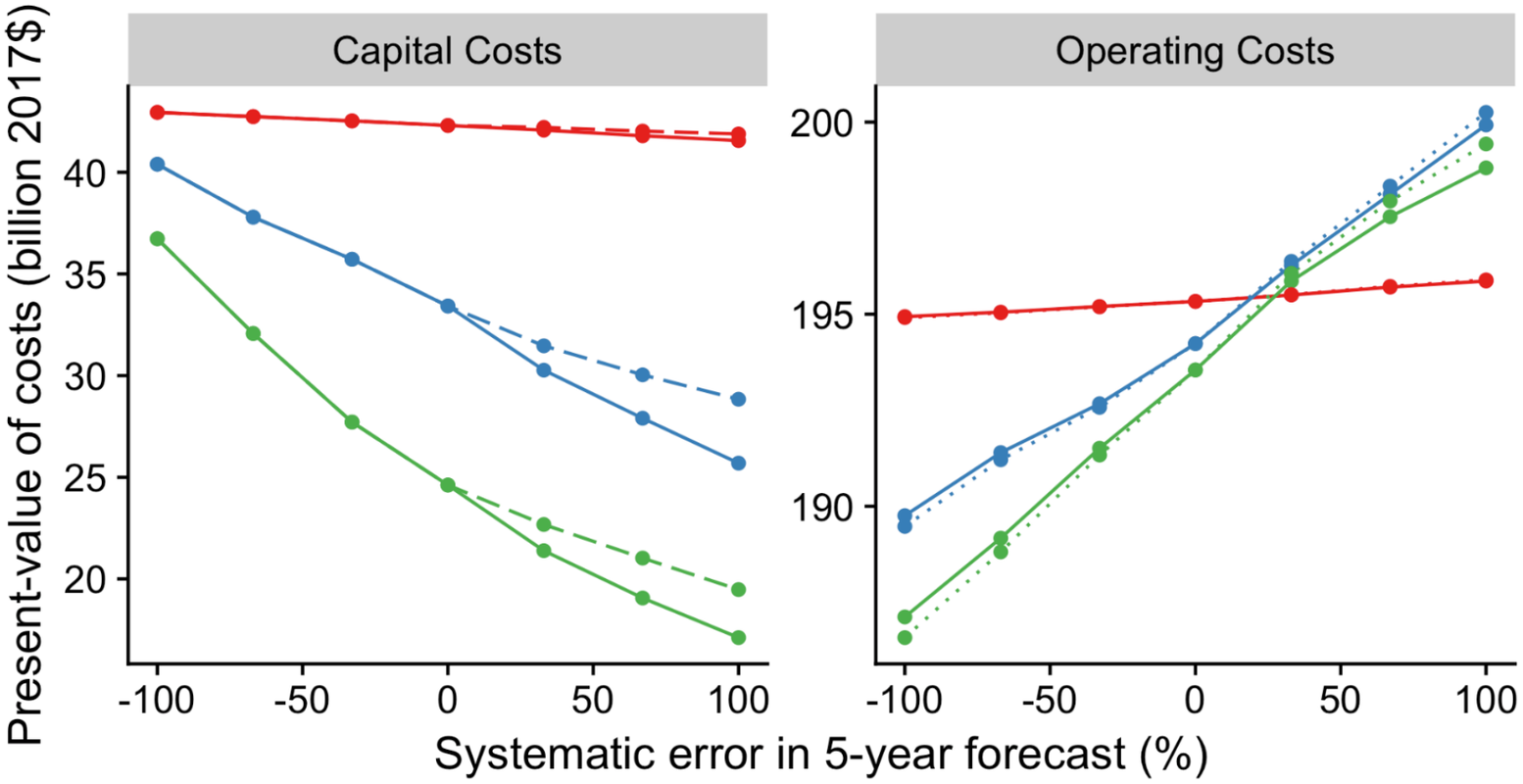


Figure shows the impact of forecast error on the net present value of capital and operating costs for the Western Interconnection for a 15 year period, including adjustments made for reliability and RPS requirements.

15-year Increase in DPV
- + 1.5% DPV
- + 5.0% DPV
- + 8.5% DPV

Correction Type
- None
- Reliability
- RPS

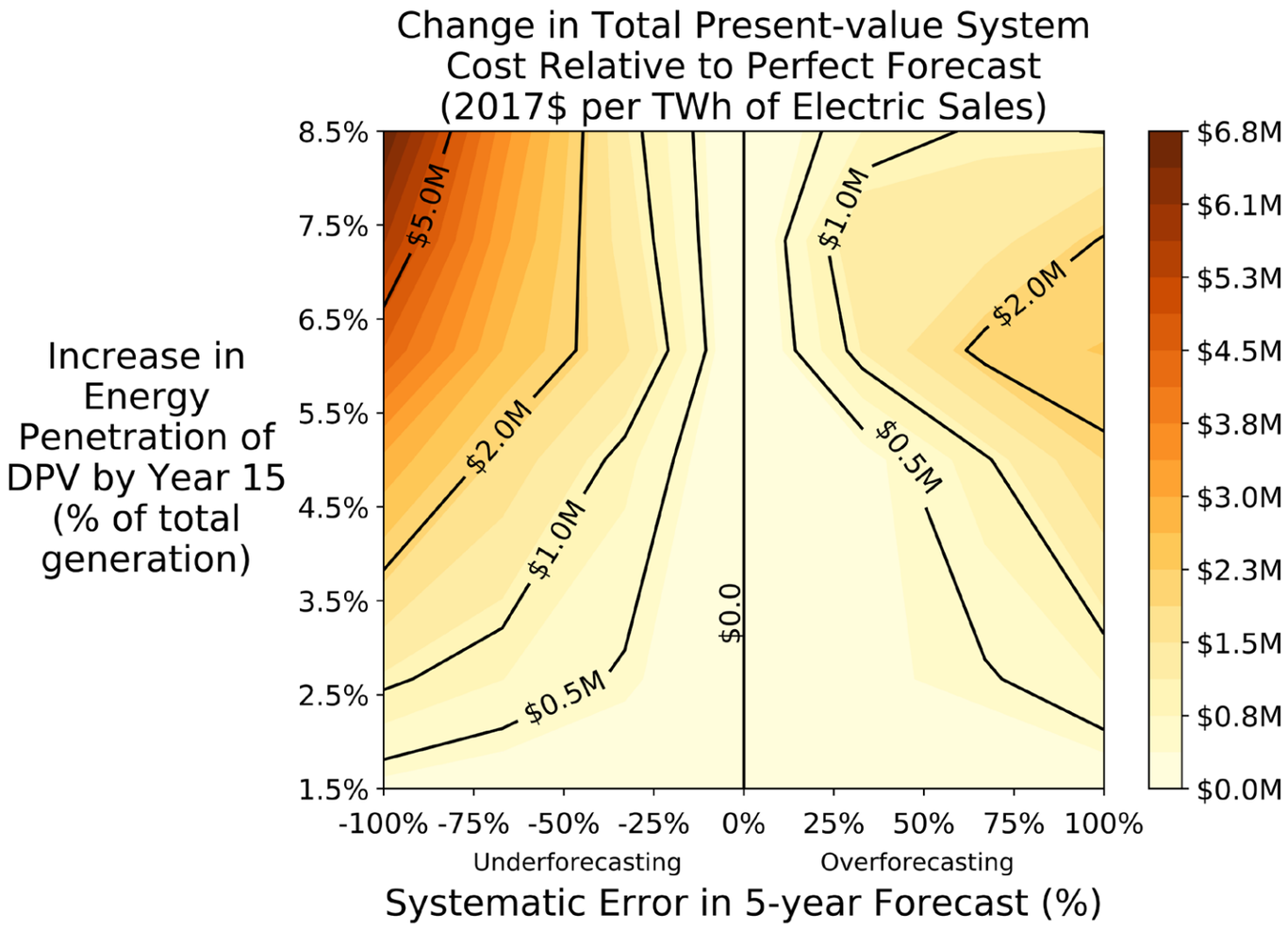
Present-value costs of misforecasting

Shown is the total present-value costs due to systematic DPV misforecasts in the Western Interconnection over a 15-year period. Results are normalized by TWh of retail sales, to facilitate projecting these results onto other regions, such as a utility service territory.

For example, if the energy penetration of DPV increases by 5% and a utility systematically misforecasts adoption by -50%, the total present-value cost is $1.32 million per TWh of retail sales. Therefore, the present-value cost over those 15 years is $13.2 million for a utility with sales of 10 TWh/year.

Present-value costs reach nearly $7 million/TWh when DPV is severely underforecast, and slightly exceeds $2 million/TWh when DPV is severely overforecast.

If the energy penetration of DPV increases by less than 2.5%, or if forecast error is less than ±25%, costs are less than $1 million/TWh

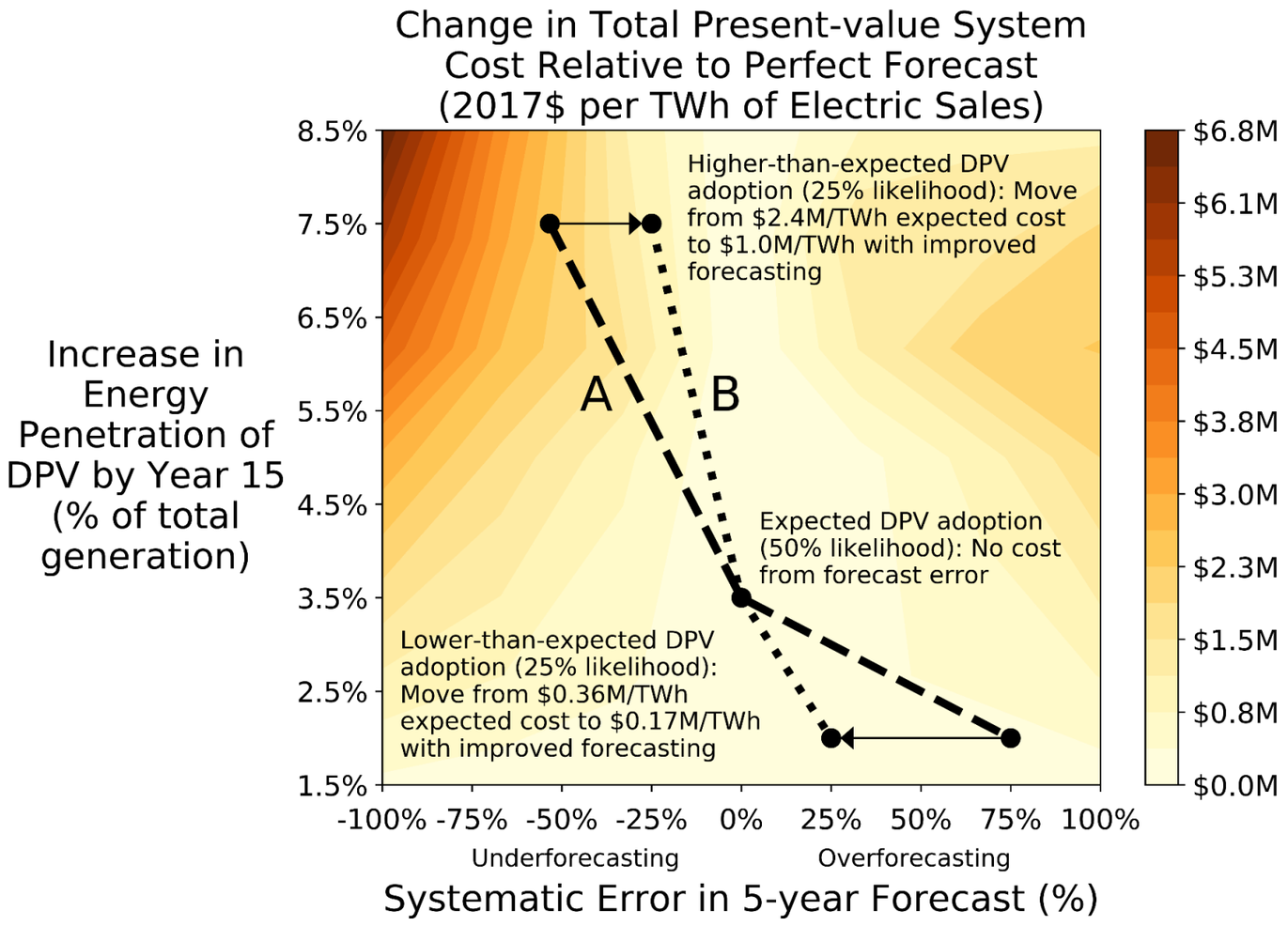


Estimating the value of improved forecasting

The value of improving DPV forecasting can be estimated by comparing the expected cost from misforecasting under current capabilities against the expected costs when the degree of forecast error is reduced.

In the example illustrated here, the expected cost of line A is $0.69 million/TWh, and the expected cost of line B is $0.29 million/TWh. Therefore, for a utility with 10 TWh/year of retail electricity sales, the expected present-value savings by moving from A to B would be $4 million

This probabilistic method of estimating the value of forecast improvements is outlined in detail in the full report. This includes a look-up table to facilitate calculations.



Sensitivities

Our sensitivities scenarios as much as double or significantly reduce the costs of misforecasting—suggesting that our base case is a reasonable central starting point for an estimate, but that it would be prudent to ask whether there are any critical differences for the utility system in question.

REC prices: Changing REC prices from ~$2/MWh to ~$22/MWh significantly increased the cost of overforecasting, and significantly decreased the cost of underforecasting. This only applies if the utility includes DPV RECs as part of their compliance plan.

Load growth: When DPV is underforecast, the cost of misforecasting tends to be larger with high load growth and smaller with low load growth. Under an overforecast, this sensitivity did not have a clear result due to complex interactions between reserve margins and path-dependent capacity-expansion decisions.

Natural gas prices: In the first 5 years of the analysis, higher natural gas prices increased the costs of overforecasting and decreased the costs of underforecasting, since DPV misforecasting influences how much generation comes from gas combustion. Later-year changes in capital investments cancel out this trend, resulting in total present-value costs that are relatively insensitive to gas prices.

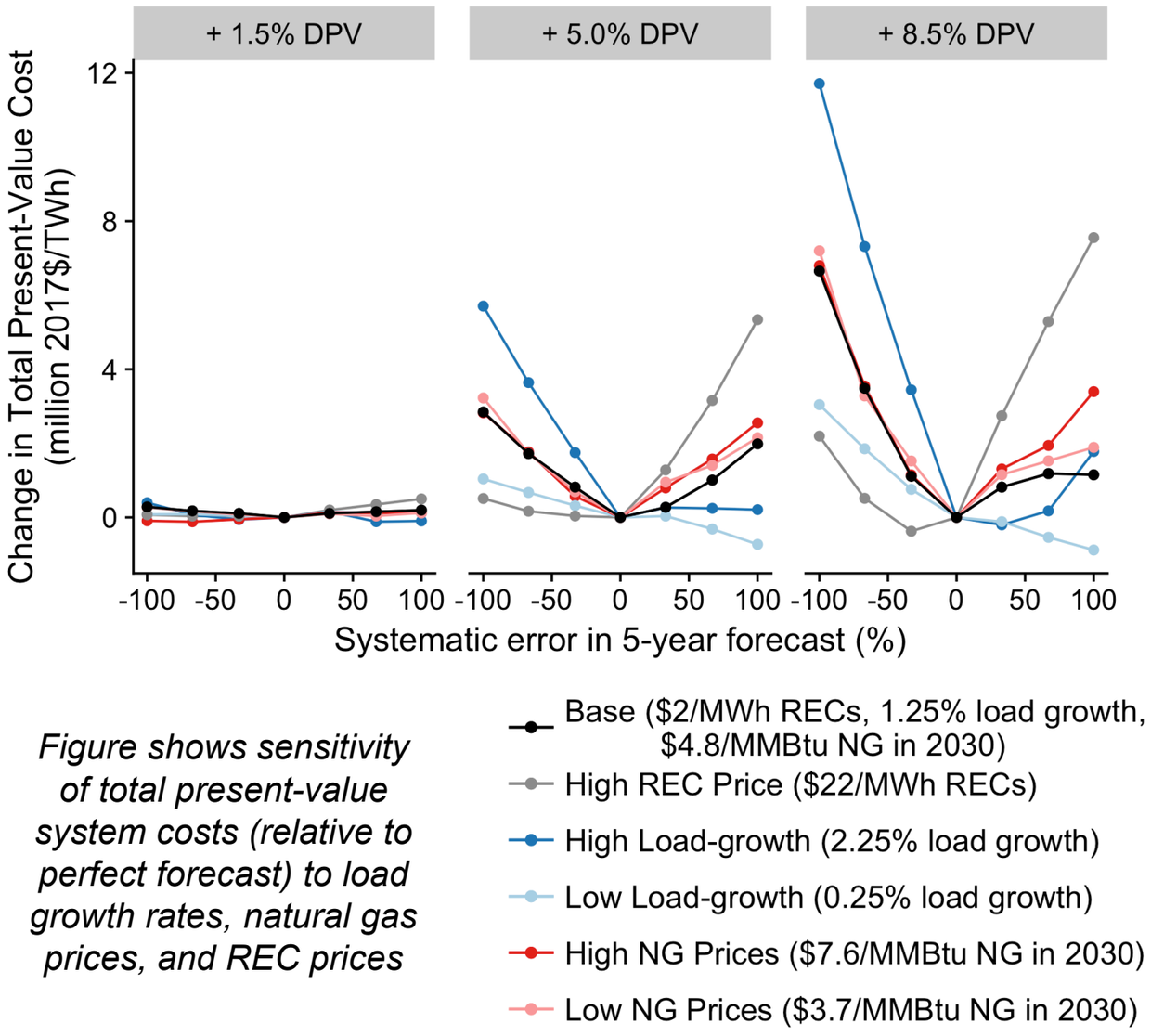
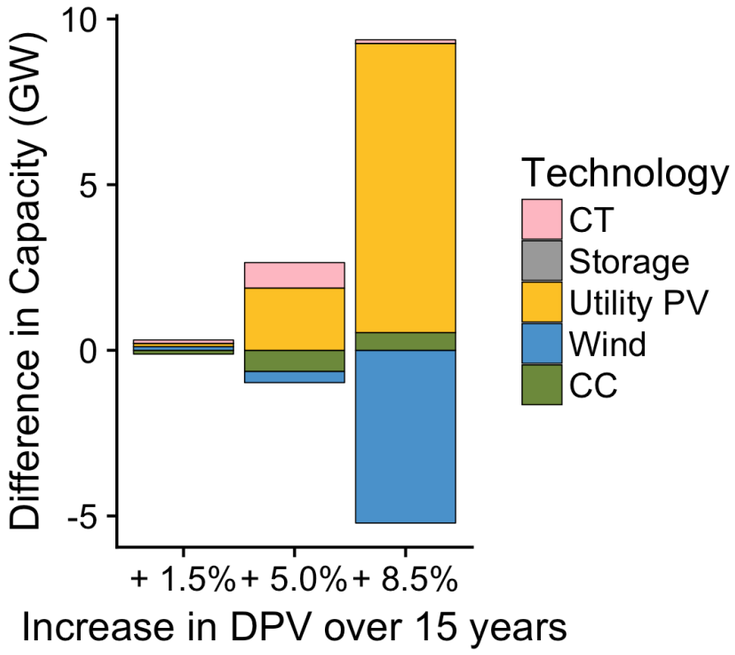
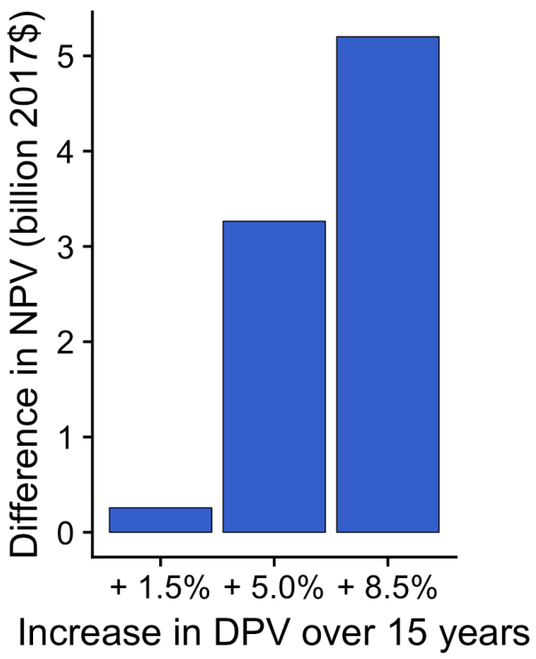


Figure shows sensitivity of total present-value system costs (relative to perfect forecast) to load growth rates, natural gas prices, and REC prices

Impact of considering DPV's capacity value during capacity-expansion planning

- Capacity value (CV) is the fraction of generator nameplate capacity that can be relied on to contribute to peak generation needs for resource adequacy purposes.
- In all other results in this deck, RPM endogenously estimates the CV of DPV and includes it in its capacity expansion decisions. Here we show the impact of assigning DPV a CV of zero (i.e., only taking the energy value of both existing and forecasted DPV into consideration while planning).
- By neglecting the CV of DPV, the preferred portfolio is altered. Under our specific assumptions, the largest impacts were increased utility-scale PV and less wind capacity, driven by increased preference for technologies with a higher ratio of capacity-to-energy value.
- Intuitively, neglecting DPV CV can also result in higher system costs, shown by the figure on the right.
- The impacts shown here assumed perfect forecasting, but misforecasting DPV can compound the effects of neglecting its CV.





Both figures show the difference between values when the CV of DPV is omitted during capacity-expansion planning, compared to a scenario where it is included. The left figure shows the difference in cumulative capacities in 2030, and the right figure shows the increase in system cost NPV. Values are for the entire Western Interconnection.

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Analysis boundaries and limitations

This analysis only quantifies bulk power system costs; we do not quantify any impacts of misforecasting DPV on distribution system planning.

- Ignoring benefits to distribution system planning would have a tendency to underestimate the value of more accurate DPV forecasting. Given that bulk power system planning does not require the same degree of locational precision as distribution system planning, however, it is not guaranteed that improvements in the former would translate to benefits in the latter.

Our present value estimates are for the entire Western Interconnection. Projecting these results onto other entities is, clearly, only a first-order estimate of the costs for that other entity. Developing such an estimate is most useful if it is followed by a robust discussion about how the specific situation of the utility is different than our modeled representation of the Western Interconnection. For example:

- The Western Interconnection is a large system with diverse flexibility and resource options, but limited ability to trade with its neighbors. More trading opportunities would be expected to decrease the costs of misforecasting, whereas a less flexible initial system or less varied capacity expansion options would likely increase costs.
- Portions of the Western Interconnection have a strong solar resource, and consequentially, UPV is often the predominant resource being built to meet RPS requirements. The tradeoff between forecasted generation from DPV and the amount of UPV procured may not be observed in areas with a weaker solar resource.

Conclusions

- **The utility-cost impacts of misforecasting DPV can be non-trivial.** Within our base-case analysis, systematically misforecasting DPV adoption over 15 years increased the present value of utility system costs by up to $7 million per TWh of electricity sales, relative to costs under a perfect forecast. Thus, for a relatively large utility with 10 TWh/year of sales, this would be a cost of $70 million in 2017 dollars. This cost is for relatively severe misforecasting—naturally, the cost impacts are lesser if DPV growth is slower or under a smaller degree of misforecasting. For example, with DPV growth less than 2.5% of total generation over 15 years or a forecasting error of just ±25%, the cost of misforecasting is less than $1 million per TWh of electricity sales.

- **The cost of misforecasting can be asymmetrical.** In our base-case analysis, the costliest *under*forecasting was nearly triple the costliest *over*forecasting. While these particular results are specific to the system modeled in this analysis, and was shown to be reversed in one of our sensitivity cases, there is a generalizable trend in the fact that underforecasting DPV increases capital costs but decreases operating costs while overforecasting does the opposite.

- **The cost of misforecasting is sensitive to market and planning conditions.** We observed present-value costs up to doubling under certain sensitivity cases, relative to the results of our base-case. In particular, one sensitivity case showed that higher REC prices can significantly increase the costs of overforecasting DPV and decrease the costs of underforecasting, if the utility included that DPV in its RPS compliance plan.

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Additional resources:

- Companion Technical Report: Gagnon, P., G. Barbose, B. Stoll, A. Ehlen, J. Zuboy, T. Mai, and A. Mills. 2018. *Estimating the Value of Improved Distributed Photovoltaic Adoption Forecasts for Utility Resource Planning*. NREL/TP-6A20-71042, Golden, CO and Berkeley, CA: National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory.
- NREL energy analysis publications and mailing list sign-up: www.nrel.gov/analysis/publications.html
- LBNL publications: https://emp.lbl.gov/publications
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