The impacts of misforecasting distributed PV adoption on the economic drivers of capacity expansion

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Overview

Utility-scale capacity planning is important for deciding what types and how much generation capacity will be needed in the future to meet the electric demand within a region. There are many economic drivers of capacity expansion, including meeting demand, demonstrating reliability, and fulfilling policy requirements. Building new capacity requires significant lead time for permiting, siting, and construction. Because of this, significant effort has historically been put into identifying these drivers to accurately anticipate future needs, particularly load forecasting. More recently, the increased adoption of customer-owned distributed PV (DPV) has led to a need to forecast future adoption of DPV, since the generation from DPV alters what is required from utility-scale generators and therefore impacts the economic drivers of bulk power expansion. Here we analyse how systematic mis-forecasts of DPV adoption can lead to incorrect assessments of economic drivers of capacity expansion, leading to different build-outs than what would have been built under correct forecasts.

Methods

We utilize a framework linking dGen – a distributed generation adoption model, the Resource Planning Model (RPM) – a regional capacity expansion model, and PLEXOS – a production cost model, to study the capacity expansion and operation of the Western Interconnection from 2016 through 2030 across a range of DPV growth rates and misforecast severity. The DPV penetrations in 2030 range from 3% to 10% DPV across the Western Interconnection, with a systematic error in the five-year forecast ranging from -100% to 100%. Each balancing authority and all inter-region transmission is represented within the interconnection. In addition to ensuring that supply equals demand, the capacity expansion optimization includes constraints to meet planning capacity requirements, renewable portfolio standards (RPS), and operating reserve requirements. All capital and variable costs are midline costs from the Annual Technology Baseline [NREL, 2016]; fuel costs are reference fuel assumptions from the Annual Energy Outlook [EIA, 2016].

Economic drivers are represented as constraints in the model, such as a requirement to meet load or maintain reliability margins. We determined the magnitude of economic drivers in the capacity expansion plans from the marginal cost of meeting each constraint. These drivers can be interpreted as revenues and costs to each plant from the system perspective, thus providing insight into which drivers provided the most value for different technologies in each scenario. For example, a higher marginal cost of meeting the firm capacity requirement can be interpreted as a higher price in a capacity market. We compared these drivers across the range of forecast errors to identify the impacts of DPV misforecasting on the economics of utility-scale capacity expansion.

We allowed resources plans to update every 5 years to represent planners making adjustments for realized DPV investment. If an asset is built due to a mis-forecast in DPV, that asset remains on the system even in the case that it is not needed for its original purpose. Similarly, if additional capacity is needed, in many cases higher cost capacity must be procured on-the-fly to make up the difference. We used the build-out that was developed under each of the misforecast scenarios, but included the ‘actual’ DPV buildout in the operational modelling. This enabled us to analyse the performance of systems when they are operated in a future that is different than what they were optimized for. We analysed the costs of each system throughout the 15-year period, including capital costs from building assets and operational costs from running the ‘actual’ system with the correct DPV projection.

Results

We found that systematic mis-forecasts of DPV predominantly influenced the perceived need for firm capacity and the ability of each region to meet their renewable portfolio standard (RPS). While other drivers were also impacted – such as energy revenue and ancillary service needs – these were typically lower cost drivers, or were not impacted as strongly by changes in DPV. In early years, most capacity—typically utility-scale wind or solar capacity— was installed to meet RPS requirements or firm capacity shortages, Figure 1. Relative to decisions made under a perfect forecast, underforecasting DPV led to a greater perceived need for utility-scale assets to meet these constraints, whereas overforecasting resulted in capacity not being built due to incorrectly perceiving that those needs would be met by DPV. These changes led to a difference of up to 25 GW of installed capacity in the first model year, compared to the scenario planned without a DPV misforecast. These early changes propagated throughout the capacity projection, impacting future system needs and subsequent capacity built.

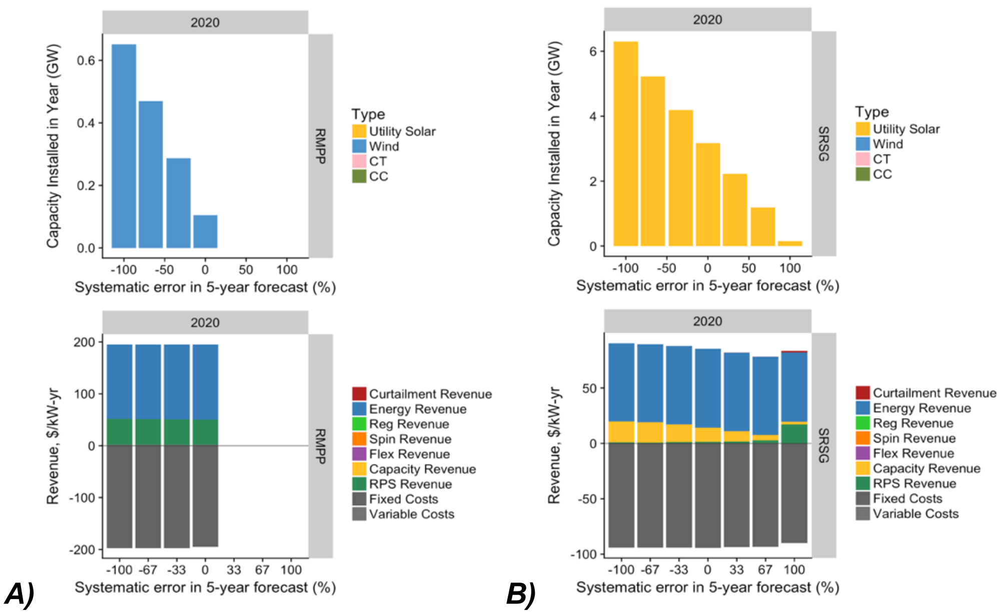

Figure 1. Installed capacity and economic drivers of those installations in the two regions in 2020. The first region installs wind to meet an RPS need. DPV is counted towards the RPS in this region, so overforecasting DPV removes this driver, resulting in underinvestment in wind capacity. The second region has a need for firm capacity, which increases at negative misforecasts. Reduced investment in utility scale solar also leads to a higher value per kW of meeting RPS targets at positive misforecasting of DPV.

The change in economic drivers and subsequent change in capacity built led to an overall change in the cost to operate the system. This increase came from both changes in the capacity mix driving increased or decreased renewable energy, or from a need to purchase RECs or capacity credits on the market. Overall, the capital cost increases when under-forecasting were countered by operating cost increases when over-forecasting DPV. Intuitively, the magnitude of this error increased at higher DPV penetrations. The combined increases to capital and operating costs from DPV mis-forecasts resulted in a total present value cost of up to $6 million 2017$ per TWh of electric sales over the 15-year planning period compared to the capacity buildout made with the correct DPV forecast.

Conclusions

Distributed PV planning is a growing field as these resources become more widely utilized. We here present an analysis of how misforecasting future DPV adoption can impact the economic drivers of capacity expansion, leading to non-optimal investment and higher costs of expansion and operation of the bulk power system. We found that the impacts of mis-forecasting on capacity drivers increase at higher DPV penetration due to the larger influence DPV has in these scenarios. Of these drivers, the economic value of new firm capacity and renewable energy were the most significantly impacted by misforecast DPV. In particular, we observe a strong relationship between the forecasted quantity of DPV and the amount of utility-scale PV that was built, due to the effect that anticipated DPV has on the forward-looking economic drivers of its utility-scale counterpart. Additionally, we characterized how misforecasting DPV could result in shortfalls of capacity for resource adequacy requirements, as well as failure to meet state RPS requirements. In practice, such shortfalls could lead to the need to procure expensive renewable energy credits or firm capacity.

References

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