ENERGY SYSTEMS INTEGRATION GROUP

ESIG REPORT

Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment

A WESTERN CASE STUDY

EXECUTIVE SUMMARY

Within the rapidly transforming energy industry, the increasing adoption of distributed generation technologies—such as rooftop solar and batteries installed behind the meter at homes and businesses—has the potential to transform the way we plan and operate energy systems. While ample research has been conducted on the relationship between distributed generation and distribution wires, transformers, and other equipment used to get electricity to homes and businesses, the impact of distributed generation on the high-voltage bulk transmission systems that connect major cities, planning areas, and states has received limited attention. This study explores how increasing distributed generation deployments—namely, distributed solar photovoltaic (PV) generation often paired with storage—impact zonal transmission flows and the need for transmission investment. It also investigates potential synergies between transmission and resource expansion under distributed- and utility-scale-generation–dominant futures. Given that distributed generation is anticipated to play an important role in the ongoing energy transition, this study seeks to bridge this research gap and provide insights into the transmission use and planning implications of distributed generation to help grid planners ensure a more efficient and reliable grid.

While ample research has been conducted on the relationship between distributed generation and distribution wires, transformers, and other equipment used to get electricity to homes and businesses, the impact of distributed generation on the high-voltage bulk transmission systems that connect major cities, planning areas, and states has received limited attention.

Study Scenarios

The study compared three long-term futures of the United States' Western Interconnection simulated with varying levels of distributed generation. The study assumed that the Western system follows a common trajectory for generation and transmission builds from present-day through 2030. This 2030 reference case was used as the starting point for three divergent futures, or scenarios, which were centralized, hybrid, and distributed. For a study horizon spanning 2031 to 2040, each scenario featured a unique set of inputs, variables, and results.

Two of the three futures, the centralized and hybrid scenarios, were simulated with varying levels of distributed generation defined as an input. The centralized and hybrid scenarios included distributed generation adoption rates equal to 100% and 200%, respectively, of the 2022 National Renewable Energy Laboratory's Standard Scenarios future projections.[1] The third future, the distributed scenario, represented a theoretical "information-only" bookend case in which distributed generation resources were simulated as the primary method of meeting long-term planning objectives. Distributed generation resources represented in the study included many combinations of solar and battery project configurations with a range of tariff assumptions that impact distributed generation operating paradigms.

See the full report: Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment: A Western Case Study

1 See https://www.nrel.gov/analysis/standard-scenarios.html.

Modeling Framework

Each of the three futures was modeled in the PLEXOS software using both long-term capacity expansion (LTCE) and short-term (ST) dispatch functionalities. The basis for the study's zonal topology and many key assumptions was the PLEXOS WECC 2023 Zonal Dataset, released by Energy Exemplar in January 2023. This dataset includes a baseline of existing and planned generation resources, zonal load forecasts, and zonal line limits representing the transfer capability between zones in the Western Interconnection. The dataset was expanded to align with the study methodology, including adding candidates for transmission expansion as well as sophisticated representation of distributed generation operations.

For each of the three scenarios, long-term capacity expansion modeling was used to identify generation and transmission investment during the 2031–2040 study period, with all scenarios starting from the common 2030 reference case. The model's objective was to find the least-cost generation and transmission expansion plan accounting for both capital costs and production costs for the 10-year study horizon. The long-term capacity expansion optimization solved for a variety of constraints including energy balance, resource adequacy, and clean energy policy constraints such as state renewable portfolio standards and other clean energy targets.

All three scenarios were able to select zonal transmission upgrades from a list of over 80 transmission expansion candidates compiled during the study process. In the centralized and hybrid scenarios, which incorporated distributed generation build trajectories as an input, the long-term capacity expansion model selected additional resources from a set of utility-scale generation technologies. In the distributed scenario, the model was limited to selecting only distributed generation during the study horizon.

Using the generation and transmission build selections from the long-term capacity expansion model, the PLEXOS short-term dispatch stage was used to simulate each scenario's hourly operations in a full-year chronological simulation for a 2035 study year. The short-term functionality incorporated operating reserves, which were not included in the long-term capacity expansion modeling to reduce computational complexity. The short-term dispatch model enabled an acute focus on hourly inter-zonal transmission flows, utilization, and congestion.

Key Findings

This study framework provided unique insights into the implications of distributed generation on the bulk transmission system. Findings were derived by comparing the scenario results of both the long-term capacity expansion and short-term simulations. Comparisons of the simulated futures led to the following findings.

Distributed generation can significantly impact inter-zonal transmission flows.

The scenarios investigated in this study exhibited a range of transmission flow and congestion patterns resulting from varying distributed generation build-out assumptions and operational constraints. The modeled adoption of distributed solar and batteries across the Western Interconnection changed diurnal transmission flow and generation patterns. Specifically, it tended to create a midday nadir in net load, and a need for morning and evening flexibility that must be served by storage and other generators on the system. These shifts in generation dispatch had corresponding impacts on zonal transmission flows as power is moved from where it is generated to where it is needed in response to this new system dynamic.

The operational limitations of these generators and zonal lines drove divergent transmission flow patterns between scenarios. The timing and magnitude of distributed generation adoption changed flow and congestion patterns and demonstrated the potential to similarly impact the timing and size of transmission needs. This result is sensitive to the location, capacity, design, and participation behavior of distributed generators and batteries.

At moderate levels, distributed generation adoption could cause certain inter-zonal transmission investments to be delayed or avoided.

The three study scenarios differed significantly from each other in terms of transmission, generation, and battery capacities at the end of the study horizon in 2040. The results from the long-term capacity expansion modeling indicated that significant additional inter-zonal

TABLE ES-1

Summary of Capacity Expansion Results Through 2040

	Centralized Scenario	Hybrid Scenario	Distributed Scenario
Zonal transmission expansion candidates	11 projects totaling 18 GW (238 GW-miles)	8 projects totaling 12 GW (166 GW-miles)	11 projects totaling 16 GW (526 GW-miles)
Generation nameplate capacity	431 GW	418 GW	537 GW
Total storage capacity	252 GWh	328 GWh	1,090 GWh

Inter-zonal transmission builds, generation nameplate capacity, and energy storage capacity—all results of long-term capacity expansion modeling—illustrate the key differences between the studied scenarios.

Source: Energy Systems Integration Group.

transmission capacity will be needed in addition to projects planned in the near-term under all future scenarios.

Relative to the centralized scenario, the hybrid scenario, which has a distributed generation adoption rate doubling our study's status quo (centralized) trajectory from 2031 onward, required about 30% less inter-zonal transmission in terms of both GW and GW-miles as shown in Table ES-1. The hybrid scenario also exhibited a lower overall generation nameplate capacity but required about 30% more storage capacity than the centralized scenario. These comparisons between the centralized and hybrid scenarios support the finding that distributed generation above present-day trajectories could cause certain inter-zonal transmission to be delayed or avoided. However, the results also indicated that significant inter-zonal transmission expansion was required under all scenarios, and that high levels of distributed generation may result in higher GW-miles of inter-zonal transmission investments.

The status-quo (centralized) and accelerated (hybrid) distributed generation adoption scenarios shared many common inter-zonal transmission investments.

Notably, the eight inter-zonal transmission candidates selected in the hybrid scenario were also all selected in the centralized scenario, though often in different years. The centralized scenario required three additional inter-zonal transmission projects—for a total of 11 projects—that were not required in the hybrid scenario. These three projects were avoided in the hybrid scenario during the study horizon because of the increased distributed generation levels in this scenario. It is important to note that distributed generation adoption rates and locations were fixed as an input, and that distributed generation capacity in the hybrid scenario was scaled in the same relative locations as the centralized scenario. Therefore, the sensitivity of this finding to the relative locations of distributed generation was not explored.

The commonality between the selected inter-zonal transmission candidates in the centralized and hybrid scenarios indicates the opportunity for "least-regrets" transmission investments in futures with distributed generation adoption rates near or above status-quo trajectories.

In contrast, the distributed scenario displayed significantly less commonality, featuring unique projects and timings for its transmission portfolio. Consideration

The commonality between the selected inter-zonal transmission candidates in the centralized and hybrid scenarios indicates the opportunity for "least-regrets" transmission investments in futures with distributed generation adoption rates near or above status-quo trajectories.

of the distributed scenario leads to the study's final finding.

High levels of distributed generation could increase the need for inter-zonal transmission investment.

While significant inter-zonal transmission was selected in all three study scenarios, the transmission built in the distributed scenario was almost double that of the centralized scenario as measured by GW-miles. The large increase in transmission GW-miles in the distributed scenario illustrates the need for longer lines to help transport high levels of solar and balance the system between regions where existing inter-zonal capacity is limited. The distributed scenario also required more than four times the storage capacity of the centralized scenario, including small amounts of long-duration storage in each zone, although these two scenarios met the same system planning and policy requirements over the study horizon.

Therefore, distributed generation and storage alone may not reduce the need for transmission investments. Much of the transmission built in the distributed scenario was built later in the study horizon—when clean energy policy constraints forced the model to serve an increasing percentage of system load with non-emitting resources.

Unlike the other two scenarios, the distributed scenario was free to build distributed solar and storage in locations determined by the model. Thus, the location, timing, and magnitude of both distributed generation and transmission builds differed significantly from the centralized and hybrid scenarios. **Our examination of the distributed scenario results highlighted that the need for transmission investment was sensitive to the location, timing, and magnitude of distributed generation builds.**

Study Takeaways

In aggregate, these findings highlight the complex trade-offs between investments in distributed generation, storage, and bulk transmission in the Western Interconnection. Indeed, distributed generation resources could change flows on inter-zonal transmission infrastructure and even potentially defer or eliminate certain future inter-zonal transmission infrastructure investments, but the need for such investments is sensitive to many other factors. The findings also make clear that while moderate levels of distributed generation could help to reduce bulk-scale transmission investment, the need for such investment is not eliminated or significantly reduced.

This study highlights the critical nature of forecasted capacities, locations, and operational behaviors of distributed generation and storage as part of integrated transmission planning efforts. The results suggest the potential benefits of simultaneously planning for transmission, distributed generation resources, and utility-scale resources in order to optimize power planning outcomes.

Finally, this study reinforces the perspective that there is no single solution in the pursuit of achieving long-term system needs and clean energy policy goals, only trade-offs. More detailed engineering and economic assessments should be performed to explore these trade-offs in specific contexts. This study is intended to be illustrative and exploratory in nature; the scenarios considered were approximations of future outcomes relating to different levels of distributed generation. While many realistic system constraints were included in this modeling, much more analysis including a nodal topology would be required to inform investment decisions.

Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment: A Western Case Study, by the Energy Systems Integration Group's DER-Transmission Project Team is available at https://www.esig.energy/distributed-generation-impact-on-transmission/.

To learn more about the topics discussed here, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. https://www.esig.energy.