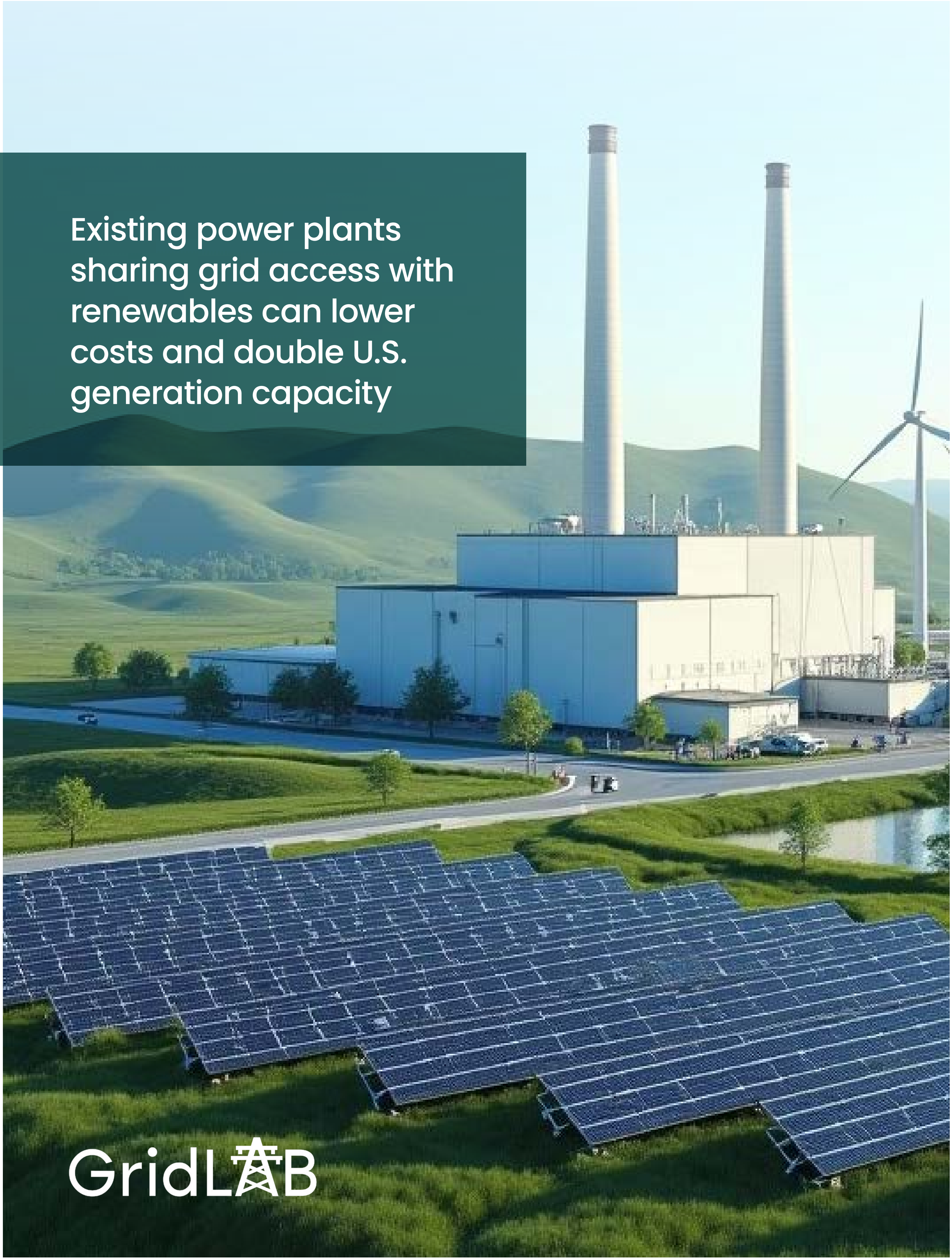
Existing power plants sharing grid access with renewables can lower costs and double U.S. generation capacity



GridLAB

ABSTRACT

Timely grid access for the growing backlog of queued renewable energy (RE) projects is crucial for meeting growing electricity demand with affordable power. Recent cost declines in renewable technologies now make it economically viable to site low-cost renewables near existing power plants, enabling shared grid access. Using high-resolution satellite imagery, we estimate the RE potential within a 6x6-mile buffer zone around existing fossil power plants in the United States (U.S.). We find that existing fossil power plants can economically share grid access with around 800 GW of RE currently, and around 1,000 GW by 2030 as the economics of RE continue to improve. This could nearly double U.S. generation capacity and lower electricity costs. By optimizing the use of existing infrastructure, this co-location strategy helps address the interconnection bottleneck, while also generating additional revenue for power plant owners and tax revenue for local communities. Adding RE at the interconnection of existing thermal power plants does not directly increase peak generation capacity in the grid, but by integrating storage with existing RE plants, it can enhance interconnection utilization. Despite limited commercial interest today, with appropriate policy and regulatory support, this strategy could become a mainstream solution for rapidly integrating low-cost electricity supply at scale.

Modeling results are available at: scarcitytosurplus.com

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CONTENTS

ACRONYMS

AI	Artificial Intelligence
CAISO	California ISO
CCGT	Combine Cycle Gas Turbine
CT	Combustion Turbine
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
GW	Gigawatt
IRA	Inflation Reduction Act
IRP	Integrated Resource Planning
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MISO	Midcontinent ISO
MWh	Megawatt hour
NREL	National Renewable Energy Laboratory
NYISO	New York ISO
O&M	Operation & Maintenance
PJM	Pennsylvania-New Jersey-Maryland (PJM) Interconnection
POI	Point of Interconnection
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PUC	Public Utilities Commission
RE	Renewable Energy
ReEDS	Regional Energy Deployment System
RFP	Request for Proposals
RTO	Regional Transmission Organization
SOS	Solar-Only Scenario
SPP	Southwest Power Pool
ST	Steam Turbine
TWh	Terawatt hour
VC	Variable Cost

EXECUTIVE SUMMARY

The United States faces an urgent challenge in deploying electricity supply quickly enough to meet growing electricity demand—including demand growth from data centers and artificial intelligence (AI)—while maintaining grid reliability and affordability. Nearly 1,500 GW of solar and wind and over 1,000 GW of battery storage remain stalled in interconnection queues, with median wait times increasing from less than two years in 2000–2007 to five years for projects built in 2023. This bottleneck, combined with extended lead times for critical grid equipment such as transformers and breakers, is preventing the U.S. from capitalizing on RE as a low-cost electricity supply option. Even if the current RE deployment rate of 30 GW/year doubles, projections indicate a shortfall of approximately 1,000 GW by 2035, compared to least-cost pathways identified by several studies.

A promising solution exists in leveraging existing grid infrastructure through interconnection sharing, that is, the addition of renewable energy (RE) and/or battery storage capacity at or near existing fossil plants to utilize their existing interconnection capacity. This concept, also known as Surplus Interconnection Service (SIS), was introduced by FERC Order 845 in 2018. Recent cost declines in renewables have made this strategy increasingly viable. In this study, we evaluated the potential to integrate RE by sharing grid access with existing fossil plants. To do this, we first assessed RE resource availability within a 6x6-mile buffer zone around existing fossil power plants, applying over 50 exclusion criteria to account for several practical constraints on deploying RE. Next, we compared the levelized cost of energy (LCOE) of local renewables to fossil plant operating costs for over 1,400 plants and identified opportunities where sharing grid access would reduce generation costs. Then, we modeled how much RE could integrate with existing interconnections while keeping curtailment below 5% and confirmed these results using dispatch simulations. The fourth step was to determine what share of the total renewable capacity needed in the future, based on a least-cost planning exercise, could be met through deployment at existing interconnections. To do this, we conducted a national generation capacity expansion study using the National Renewable Energy Lab (NREL) Regional Energy Deployment System (ReEDS) model, which simulates 134 sub-regions in the U.S., to identify the least-cost capacity mix of solar and wind. We then compared how much of this projected capacity could be met through deployment at existing interconnections. Our analysis reveals five key findings that demonstrate the transformative potential of interconnection sharing.

1. Substantial Hyperlocal RE Potential: Within just a 6x6-mile buffer zone around existing fossil power plants in the contiguous U.S., there exists over 15,400 GW of technically feasible RE potential. To ensure realistic developable potential, this assessment considered over 50 exclusion criteria, including physical site characteristics, protected areas, infrastructure density, and regulatory restrictions to estimate realistic development potential.

2. Economic Viability Has Arrived: For over 75% of the 700 GW of existing fossil interconnection capacity, the LCOE for local solar is now lower than the plants' variable costs. This economic advantage is projected to extend to nearly all existing fossil power plants by 2030 as RE costs continue to decline. Our analysis incorporated detailed unit-level data on fuel costs, operations and maintenance expenses, and local RE resource quality to determine economic crossover points.

3. Significant Integration Potential by 2030: Approximately 1,000 GW of solar and wind capacity could be economically integrated into existing thermal plant points of interconnection (POIs) by 2030. This finding emerges from hourly optimization analysis that considers interconnection capacity limits and maintains curtailment below 5% to ensure economic viability. The opportunity is particularly significant in PJM and MISO territories, where resource adequacy challenges are mounting due to rapid demand growth and planned fossil plant retirements. This potential integration could avoid approximately $85 billion in interconnection costs compared to developing projects at new POIs.

4. Alignment with a Least-Cost Power System: Leveraging existing interconnection could help deliver the majority of RE needs for a least-cost power system in 38 states by 2030. This assessment utilized the ReEDS model to optimize the least-cost generation mix across 134 zones in the contiguous U.S., accounting for current policies and projected technology cost declines. This approach provides a practical solution for states to meet their clean energy goals while minimizing infrastructure costs.

5. Immediate Opportunities with Underutilized Assets: Over 200 GW of U.S. fossil capacity currently operates at less than 15% capacity and faces operating costs approximately $20/MWh higher than intermediate and baseload fossil capacity. These are primarily gas combustion turbine peaker plants, which are critical for grid reliability during periods of high demand or low renewable generation, but operate infrequently. This minimally utilized interconnection capacity represents a prime opportunity for sharing while maintaining essential reliability services.

This grid access sharing strategy benefits all stakeholders: power plant owners diversify their portfolios and enhance revenue streams by increasing utilization of their interconnection capacity and maintaining their generators' capacity value; consumers gain access to lower-cost clean electricity, enhancing affordability; grid operators maintain reliability while accommodating low cost RE; RE developers achieve faster project realization with potentially lower transmission infrastructure costs; and local communities retain tax revenue and employment opportunities. Although adding RE at the interconnection of existing thermal power plants does not increase peak generation capacity in the power system, this could potentially be achieved by integrating storage with existing RE plants, thereby improving the utilization of their interconnection — a topic we will assess in forthcoming research.

However, realizing this opportunity requires coordinated policy and regulatory support. Key recommendations include:

- FERC should streamline surplus interconnection service frameworks and harmonize generator replacement rules across regions;
- ISOs/RTOs should integrate surplus interconnection considerations into long-term transmission planning and enhance transparency around opportunities;
- PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP);
- State legislators should mandate consideration of surplus interconnection in IRP;
- Load-serving entities should prioritize existing POIs for renewable development;
- Fossil asset owners should explore partnerships to monetize unused interconnection capacity.

With appropriate policy support from FERC, ISOs, and PUCs, the use of surplus interconnection service could become a mainstream strategy for accelerating clean energy deployment while maximizing the utilization of existing infrastructure—a critical pathway to meeting U.S. energy needs reliably and cost-effectively.

INTRODUCTION

The power grid has emerged as the primary bottleneck to meeting growing electricity demand with low-cost clean energy. Demand for electricity—and especially clean electricity—has soared, driven by electrification in various sectors, the rise of data centers for artificial intelligence (AI), and booming investment in clean tech and domestic manufacturing. Simultaneously, clean energy is becoming increasingly economically viable due to dramatic declines in the costs of renewables and battery storage, further supported by incentives from the Inflation Reduction Act (IRA). For example, utility-scale solar power purchase agreements (PPAs) reached a record-low price of $24/MWh for projects beginning commercial operation in 2023. Nearly half of the new PPAs signed that year qualify for the energy community tax credit (projects located in areas with significant fossil fuel employment or recent coal plant closures) and have achieved similar prices (1). Yet in the U.S. today, nearly 1,500 GW of solar and wind plus over 1,000 GW of battery storage remain stalled in the interconnection queue, where projects seeking to connect to the grid wait while they undergo a series of system impact studies to determine whether network upgrades are needed before the project can be brought online (2). The majority of these queued projects are ultimately withdrawn, primarily due to prohibitively high network upgrade costs. Moreover, the active capacity in the queue has been growing, translating to even longer interconnection wait times: while the typical duration from interconnection request to commercial operation averaged less than two years for projects built in 2000–2007, projects built in 2023 have a median wait of five years (2). Challenges associated with constructing the transmission upgrades exacerbate the issue, with lead times for transformers recently surging to two to four years (3).

These grid bottlenecks are holding back renewable energy (RE) deployment, which needs to be accelerated to meet the projected load growth at the lowest cost. At the national level, as shown in Figure 1, even in the optimistic case in which the current average rate of 30 GW/year is doubled (e.g., through streamlined interconnection processes), maintaining this pace until 2035 will likely fall short by 1,000 GW compared to the least-cost projections by several major studies. Some predictions indicate that AI data centers alone could require up to 500 TWh of electricity by 2030, absorbing almost all new RE additions if deployment continues at its current pace (4). In the absence of cleaner alternatives, this generation shortfall would have to be met by fossil generation, with the corresponding emissions and costs. In contrast, China is deploying RE at rates ten times higher than the U.S., reaping the benefits of low-cost energy for their consumers and industries. While 2024 is projected to be a record-setting year, with 45 GW of RE commencing commercial operation, additional efforts are required to close the gap (5).

PJM's resource adequacy risk

The Pennsylvania-New Jersey-Maryland (PJM) Interconnection, the largest grid operator in the U.S. by customers served, faces significant challenges in maintaining resource adequacy. Load forecasts show demand growth averaging 1.4% per year for the PJM footprint and up to 7% for zones with data center clusters, signifying unprecedented growth in electricity demand. At the same time, some 40 GW of fossil generation capacity (21% of PJM's currently installed capacity) is slated to retire by 2030, and the rate of new capacity additions has lagged, especially for RE and battery storage (6). This asymmetrical pace—in which resource retirements and load growth exceed the pace of new generation entry—could translate into a potential capacity shortfall of nearly 4 GW by 2029, escalating to over 8 GW by 2034 if current trends hold. This underscores the urgent need for accelerating the integration of new resources, and in particular RE and battery storage solutions, to meet future demand and support grid reliability.

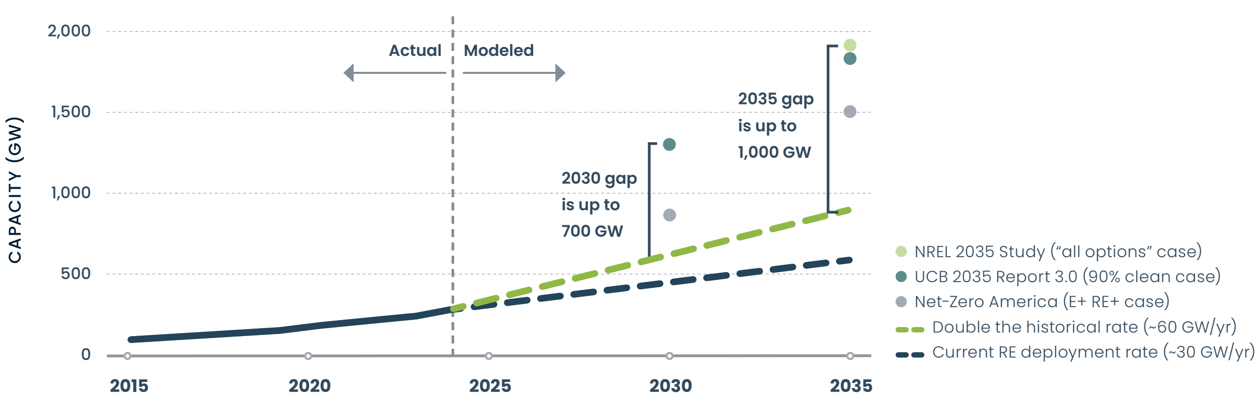

FIGURE 1. The U.S. is headed toward a significant shortfall in clean energy, projected to reach around 1,000 GW by 2035, even with a doubling of the current deployment rate. Actual values for 2015–2023, projected values for 2024, extrapolated values for 2024–2035, and modeled values for 2030 and 2035 from major studies (7–9).

A promising strategy for accelerating RE deployment is to leverage existing grid infrastructure through interconnection sharing. Also known as surplus interconnection service, repowering, cable pooling, or hybridization, this involves the expedited addition of RE and/or battery storage capacity at or in close proximity to existing power plants, allowing the RE capacity to share the existing grid access point without surpassing the original interconnection capacity limits, as shown in Figure 2. Importantly, surplus interconnection does not create additional peak capacity at the point of interconnection (POI) since total output remains limited by the original interconnection capacity. Rather, it enables the integration of new clean electricity generation that can utilize the existing interconnection capacity when the fossil plant is not operating at full output, which our analysis shows is the majority of hours, including many peak periods. The strategy would maximize the utilization of existing grid assets, accelerating interconnection by utilizing existing infrastructure rather than requiring new interconnection construction and extended study periods. Policy paves the way forward for interconnection sharing at existing facilities under FERC Order 845, which requires transmission providers to establish an expedited process for interconnection customers to utilize or transfer surplus interconnection service at existing facilities. While the subsequent analysis focuses on adding RE to operational fossil plants through surplus interconnection, the basic premise of leveraging existing grid infrastructure would likewise be valuable for retiring power plants through generator replacement, enabling new, low-cost RE and/or battery storage capacity to be added at the site of retiring power plants. A prime candidate for this is the nearly 70 GW of coal-fired capacity that is scheduled for retirement between 2024 and 2030 (10).

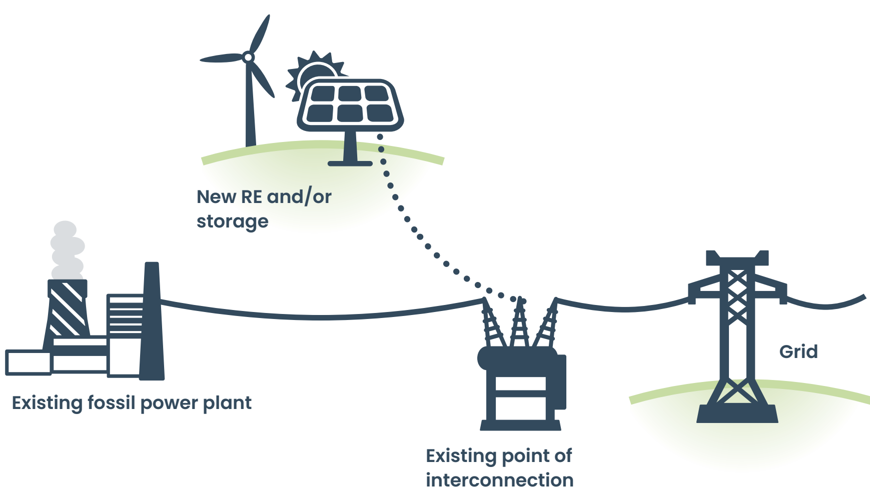

FIGURE 2. Schematic of RE and/or storage sharing the interconnection with existing fossil power plants.

The Growing Challenge of AI Infrastructure Energy Demand

The rapid expansion of AI infrastructure is creating unprecedented demands on the U.S. power grid. Morgan Stanley Research projects U.S. data center power consumption will grow from 160 terawatt-hours (TWh) in 2023 to 337 TWh by 2027, with AI-specific power demand growing at a 105% compound annual growth rate (4). By 2030, data center power consumption could reach 450 TWh, constituting 10.6% of total U.S. grid capacity. According to EPRI, U.S. data centers would increase from approximately 4% of total U.S. electricity consumption today to between 4.6% and 9% by 2030 (11).

Major technology companies are pursuing strategic partnerships with nuclear facilities to secure reliable clean power. Microsoft is funding the restoration of decommissioned nuclear facilities, while Amazon has acquired a nuclear-powered data center near the currently operating Susquehanna Nuclear facility. However, when large technology companies secure substantial portions of existing clean energy capacity, it reduces availability for other grid users, potentially increasing reliance on fossil fuels elsewhere if clean energy development cannot match growing demand.

Interconnection sharing offers a solution by enabling rapid integration of RE through existing POIs. By reducing project deployment times from 4–5 years to 1–2 years, this approach enables faster expansion of low-cost clean energy capacity rather than a redistribution of existing resources—which is crucial for maintaining U.S. technological leadership in AI development.

Clean energy cost declines and IRA incentives have substantially augmented the economic viability of the opportunity. Three factors in particular stand out in the IRA: Production Tax Credits (PTCs) for RE generation; a 10% bonus on PTC as well as an Investment Tax Credit (ITC) for RE projects located in qualifying energy communities (including areas with significant fossil fuel employment or recent coal plant closures); and an Energy Infrastructure Reinvestment (EIR) program that offers low-cost loans for communities to repower or repurpose existing energy infrastructure (12). These factors improve the economics of RE near existing fossil power plants relative to the existing plants' operating costs. When RE is available at these locations, system operators can economically dispatch the lower-cost renewable generation while adjusting fossil plant output according to market conditions, operational constraints, and reliability requirements—potentially reducing the overall cost of delivering power at the POI. This is demonstrated in Figure 3, which shows how renewables LCOE as well as PPA prices have declined in recent years, reaching a generation-weighted cost of $30.5/MWh with tax credits and $24/MWh for projects beginning commercial operation in 2023, respectively (1). This is either competitive or below the median variable costs of conventional generation sources, and RE costs are projected to continue to decline.

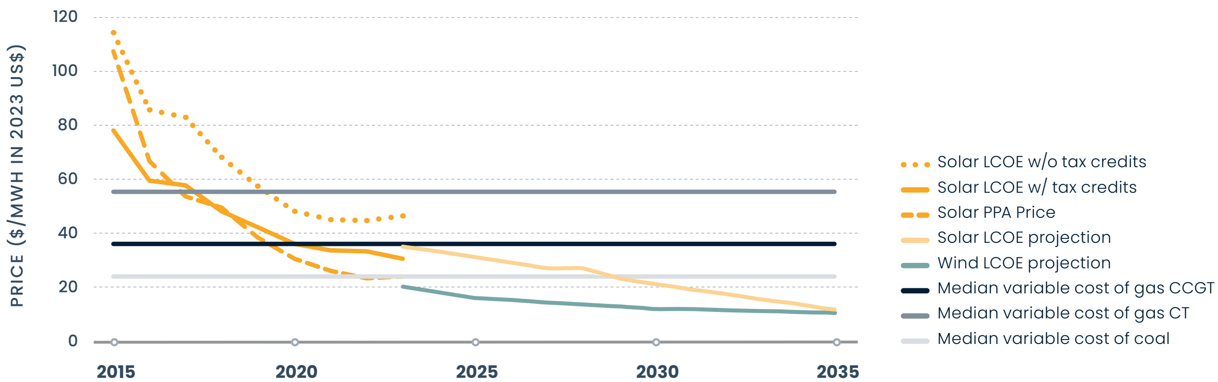

FIGURE 3. The costs of new solar and wind are passing below the variable operating costs of coal and gas plants, creating an opportunity to cost-effectively swap their generation with clean energy. Historical solar LCOE and PPA prices from (1), projected solar and wind LCOE from (13). Historical LCOE and PPA prices reflect the year in which commercial operation commenced.

Although the idea of interconnection sharing has been discussed for years, it was previously perceived as a limited case-by-case opportunity that required the highest RE resource quality (14–18). However, the falling costs of RE combined with recent policy developments have sparked new commercial interest in this solution, particularly for integrating solar at existing fossil power plants. These projects indicate that interconnection sharing offers significant advantages including faster deployment, avoided interconnection costs, improved infrastructure utilization, retained tax revenue and jobs in host communities, new revenue streams through portfolio diversification for fossil asset owners, and lower electricity costs and, thus, consumer bills. Overall, the strategy presents a promising, unifying pathway for accelerating clean energy deployment by engaging stakeholders who might otherwise resist the energy transition by aligning their economic interests with decarbonization efforts. Here, we build upon previous studies, using the latest data to quantify the opportunity of interconnection sharing, which—with appropriate policy and regulatory support—could become a mainstream strategy for rapidly integrating clean electricity sources at scale.

METHODS AND DATA SUMMARY

To estimate the technically feasible and economically viable RE integration potential by sharing grid access with existing fossil plants, we used the following steps.

First, we ***estimated the RE resource availability*** within the vicinity (within a 6x6-mile buffer zone around each power plant) that could share the existing grid access. In assessing solar PV and onshore wind resource availability, we considered over 50+ criteria to replicate the exclusion criteria typically used by developers, including physical constraints, environmental protections, local ordinances limiting RE deployment, and difficulty of deploying RE near urban areas. Even after accounting for these factors, we found that the combined solar and wind potential in the vicinity of more than 80% of fossil plants is more than five times greater than their current interconnection capacity.

The second step was ***to evaluate the economic viability of RE sharing grid access*** with existing fossil plants. ***We identified plants where the LCOE of local RE is lower than the operating costs (fuel costs and variable O&M costs) of fossil plants.*** In such cases, it would be economically beneficial for these plants to allow REs to access the grid, as this would enable them to save costs by prioritizing renewable generation over fossil-based electricity when available. This analysis involved collecting detailed data on the operating costs of over 1,400 power plants and estimating the local LCOE for REs near each of these plants. We also considered all the applicable tax incentives and savings in interconnection costs that arise from using the same interconnection.

The third step was to estimate for plants where the LCOE of local RE is lower than the operating costs of power plants, ***how much RE can be integrated to maximize the use of existing interconnection.*** For each of the plant locations, we estimated the optimal portfolio of solar and wind which maximizes interconnection usage (solar + wind generation) while limiting the curtailment to below 5%. We conducted dispatch simulation for a power plant using actual operating constraints and confirmed that technical operational limitations did not increase curtailment beyond the 5% threshold.

The fourth step was to ***determine what share of the total renewable capacity needed in the future, based on a least-cost planning exercise, could be met through deployment at existing interconnections.*** To do this, we conducted a national generation capacity expansion study using the NREL ReEDS model, which simulates 134 sub-regions in the U.S., to identify the least-cost capacity mix of solar and wind. We then compared how much of this projected capacity could be met through deployment at existing interconnections.

The following discussion offers more details on each of these steps.

1. Estimating Local Renewable Resource Availability

To assess the technical solar and wind potential near existing fossil power plants, we conducted a geospatial analysis integrating multiple high-resolution datasets. For each plant, we defined a 6x6-mile (10x10 km) buffer zone, representing the area within which RE projects could feasibly connect to existing interconnection infrastructure. We created a comprehensive exclusion dataset to exclude unsuitable areas for RE development, integrating land cover, protected areas, elevation, and slope data. Key data sources include:

- **Protected Areas:** U.S. Geological Survey's Protected Areas Database (PAD-US) to exclude national parks, wildlife refuges, and other conserved lands (23).
- **Elevation and Slope:** Copernicus Digital Elevation Model (30 m resolution) to exclude areas with high slopes and elevation (24).
- **Land Cover:** European Space Agency's WorldCover 10 m dataset to exclude urban areas, water bodies, wetlands, and dense forests, etc. (25).
- **Infrastructure Density:** We eliminated sites where built infrastructure exceeded 30% of the land area within a 6x6-mile buffer zone around existing power plants, recognizing that dense development patterns typically preclude cost-effective RE deployment.
- **Regulatory Restrictions:** Areas subject to local ordinances prohibiting wind development were excluded from wind potential calculations, reflecting current regulatory limitations (26).

For the remaining suitable areas within each buffer zone, we estimated technical solar and wind potential using standard conversion factors: 50 MW per square kilometer for solar PV and 6 MW per square kilometer for wind. These factors reflect typical utility-scale installation densities and provide an estimate of the maximum buildable RE capacity near each fossil plant.

2. Evaluating the Economic Viability of Renewable Energy Sharing Grid Access

Estimating power plant operating costs

We developed a detailed dataset of existing fossil power plants in the U.S. using data from the U.S. Energy Information Administration (EIA) Forms 860 and 923 for the year 2023 and 2022 (27, 28). This dataset includes information on plant location, capacity, fuel type, operational characteristics, heat rates, and variable operating costs. To enhance accuracy, especially for heat rates, we incorporated cleaned data from the NREL ReEDS database, which provides validated engineering assessments based on actual performance data (20). Fuel price data were collected from multiple EIA sources. For natural gas, we took the recent 7-year average incorporating state-level monthly natural gas prices for electric power (supplemented with monthly state-level prices at local distribution company delivery points, known as citygates, if power sector prices were not available) (29). As oil & gas steam turbines are either mostly gas-based or dual-use technologies, their fuel costs are similarly based on natural gas prices. For coal, we used the recent 7-year average incorporating quarterly prices based on coal shipments to the electric power sector by plant state (30). Ownership data for power plants were derived using the Environmental Protection Agency's Greenhouse Gas Reporting Program (GHGRP), supplemented by EIA Form 860 data (27,31).

Estimating local RE LCOE

We estimated hourly solar and wind generation profiles at each plant location using high-resolution meteorological data and a custom software tool developed for this study.

- **Custom Simulation Tool:** We developed a custom software tool that integrates established models (PySAM, PVWatts) with detailed system specifications to provide accurate hourly generation profiles for each site.
- **Solar Generation:** We utilized the ERA5 dataset from the European Centre for Medium-Range Weather Forecasts (ECMWF), providing hourly data on solar irradiance, air temperature, pressure, and wind speed at approximately 31 km resolution (32). We calculated three key solar irradiance measurements (Global Horizontal, Direct Normal, and Diffuse Horizontal) to model solar power generation. Using these measurements, we simulated the hourly output of a 1 MW solar farm equipped with single-axis tracking through the PVWatts model. To ensure accurate results, our simulation incorporated various technical parameters including the panels' tilt angles, directional orientation, system efficiency losses, and tracking system dynamics (33).

- **Wind Generation:** We utilized NASA's MERRA-2 dataset for wind speed, direction, pressure, and temperature at various altitudes (34). We employed the Python-based System Advisor Model (PySAM) to simulate wind power generation (35). The wind farm model simulates a detailed layout of 8 rows by 4, totaling 32 turbines, and accounts for wake effects and turbine interactions. Wind speeds are extrapolated to turbine hub heights, and adjusted for local terrain using high spatial resolution data from Global Wind Atlas.

These hourly generation profiles allowed us to estimate capacity factors for solar and wind at each plant location, accounting for temporal and spatial variations in resource quality.

Using the estimated capacity factors and cost parameters, we estimated the LCOE for solar and wind projects near each existing fossil power plant. Our cost and financial data were sourced from reputable industry and governmental reports to ensure accuracy:

- **Cost Data:** Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) come from NREL's Annual Technology Baseline (ATB) 2024 (13).
- **Financial Parameters:** Weighted Average Cost of Capital (WACC) is calculated based on typical industry debt-to-equity ratios and costs of capital, from NREL's ATB 2024 (13). Project Lifespan is assumed to be 30 years for both wind projects and solar PV projects, from NREL's ATB 2024 (13).
- **Regional Adjustments:** Capital Cost Multipliers were applied to account for regional variations in installation costs, using data from the U.S. EIA regional cost factors and the NREL ReEDS model (20).
- **Incentives:** We accounted for federal and state incentives, including the ITC and PTC as outlined in the IRA of 2022 (12). These incentives were applied according to eligibility criteria and phase-out schedules. We incorporated energy community designations to account for additional incentives available under the IRA. Energy communities are areas that have been economically affected by the decline of fossil fuel industries and are eligible for bonus tax credits to encourage RE development. We identified these areas using data from the National Energy Technology Laboratory's (NETL) Energy Communities interactive map and the Internal Revenue Service's (IRS) Notice 2023–29 (36, 37). This information was integrated into our dataset to adjust the LCOE of solar and wind for plants located within these designated areas.

We compared the estimated LCOE with the variable operating costs of individual units of the corresponding fossil plant, derived from fuel price data and heat rate metrics from EIA Forms 860 and 923 and ReEDS. If the LCOE was lower than the plant's variable costs, we considered the plant to have "crossed over," indicating a cost-effective opportunity for replacing fossil generation with renewable energy. This analysis was conducted annually from 2024 through 2030 to capture changes in technology costs, fuel prices, and policy incentives over time.

Interconnection cost savings

To quantify potential cost savings from utilizing existing interconnection infrastructure, we analyzed historical interconnection queue data from LBNL for projects from 2018 onwards across four Independent System Operators (ISOs): ISO-NE, MISO, PJM, and SPP (19). For each ISO, we calculated capacity-weighted average interconnection costs using only projects that completed their interconnection studies, finding costs that ranged from $71/kW in SPP to $107/kW in ISO-NE, with PJM at $83/kW and MISO at $85/kW (19). For regions outside these ISOs, we applied the mean interconnection cost from analyzed regions as a representative value.

The interconnection costs we analyzed include two significant components that could be largely avoided through co-location with existing fossil plants. The first component is POI costs, that is, the direct expenses associated with physically connecting to the grid, including construction of interconnection substations and transmission line extensions (spurlines or generation tie lines). The second component is network upgrade costs, that is, the broader system-wide upgrades required to accommodate new generation, often involving reconstruction of transmission lines and substantial grid modifications.

3. Estimating Renewable Energy Integration Potential to Maximize Use of Existing Interconnection Capacity

To determine the realistic integration potential of RE at existing POIs, we developed optimization models that maximize interconnection utilization while limiting curtailment and adhering to interconnection capacity limits. The model is formulated as follows:

Objective: $\text{Maximize} \quad \sum_{t=1}^{8760} (\text{solar\_generation}[t] + \text{wind\_generation}[t])$

With the following decision variables:

- Installed solar capacity, $\substack{:\text{solar\_cap} \\ :\text{wind\_cap}}$,
- Installed wind capacity, $\substack{:\text{solar\_cap} \\ :\text{wind\_cap}}$,

Subject to the following constraints:

- Interconnection Capacity Limit, ensures that generation does not exceed the plant's maximum interconnection capacity:
  $\text{solar\_generation}[t] + \text{wind\_generation}[t] \leq \text{interconnection\_max}$

- Curtailment Limit, limiting annual curtailment to 5% of total potential generation to maintain economic viability:

$$\sum_{t=1}^{8760}(\text{solar\_curtailment}[t] + \text{wind\_curtailment}[t]) \leq 0.05 \times \sum_{t=1}^{8760}(\text{potential\_generation}[t])$$

- Curtailment Calculation, where $\text{solar\_cf}[t]$ and $\text{wind\_cf}[t]$ and $\text{solar\_cf}[t]$ and $\text{wind\_cf}[t]$ are the hourly capacity factors for solar and wind, respectively:

$$\text{solar\_curtailment}[t] = \text{solar\_cap} \times \text{solar\_cf}[t] - \text{solar\_generation}[t]$$

$$\text{wind\_curtailment}[t] = \text{wind\_cap} \times \text{wind\_cf}[t] - \text{wind\_generation}[t]$$

For plants where wind energy was viable (capacity factors above a threshold of 30%, consistent with current projects), we optimized both solar and wind capacities. For others, we optimized solar capacity alone. The optimization was performed using hourly data over a full year for each plant, processing in parallel batches to manage computational demands.

Actionable RE integration potential

The actionable RE integration potential was then estimated based on the RE potential that was both technically and economically viable: for each unit where renewable costs fell below fossil operating costs ("cost crossover"), the plant-level technically viable RE was adjusted by the proportion of the unit's capacity to the plant's total capacity.

4. Determining the Share of Total Least-Cost Renewable Capacity That Can Be Met by Deployment at Existing Interconnections

To align the actionable RE integration with actual power system needs, we conducted a comparative analysis using the NREL ReEDS model (20). ReEDS is widely used by the U.S. Department of Energy and is considered an industry standard for projecting the optimal mix of generation technologies required to meet future electricity demand. By running ReEDS up to 2030, we obtained least-cost projections of the new capacity needed by technology—such as solar, wind, and gas—to meet the 2030 load, considering current U.S. policies and hourly load profiles. We aggregated the ReEDS-projected new capacity installations of RE (solar and wind) at the state level and similarly aggregated our estimated actionable RE integration potential from installing solar and wind near existing interconnections. This comparison allowed us to determine the percentage of the required renewable capacity in each state that could be met by integrating solar and wind near existing fossil plant interconnections. To ensure consistency with regional planning needs, we adjusted the actionable integration by capping it at the ReEDS-projected least-cost capacity portfolio for each state. If our integration potential exceeded the ReEDS estimate for a state, we limited it to the ReEDS requirement; if it was lower, we retained our original estimate.

RESULTS

Finding #1

The total hyperlocal RE technical potential near U.S. fossil plants exceeds 15,400 GW.

To quantify the potential for leveraging the interconnection of existing fossil plants, we first estimated the total resource potential of solar and wind near existing fossil power plants. While previous studies assessed the RE potential over a large radius, i.e., around 28 miles (45 km) (18), to make a robust case that there is sufficient local RE that can share existing POIs, we used a considerably tighter buffer zone of 6x6 miles around the existing power plant, reflective of commercial activity in the U.S. today. In practice, this means that the maximum generator tie line distance between the RE facility and the existing POI would be less than 6 miles (10 km), which also simplifies the siting and permitting of the tie line. Within each buffer zone, we assessed the potential for RE development of each 100x100 ft (30x30m) parcel of land through high-resolution satellite imagery and applying several exclusion criteria (for more details, see Methods). We find that the total hyperlocal RE potential within the 6x6-mile buffer zone around the 1,400 existing fossil power plants in the contiguous U.S. is over 15,400 GW.

Estimating Deployable Hyper-Local Renewable Energy Potential by Considering Multiple Exclusions

Increasingly, siting challenges are holding back RE deployment. To arrive at a realistic estimate of deployable potential, we sought to replicate the criteria that RE project developers typically use to select suitable land for deployment considering these challenges. We applied more than 50 exclusion criteria, grouped into four main categories:

1. **Physical Site Characteristics:** We excluded areas based on incompatible land cover types (including urban development, water bodies, forests, and mangroves), excessive slope gradients, and elevation constraints that would preclude RE development.
2. **Protected Areas:** All locations with environmental protection status or development restrictions were removed from consideration.
3. **Infrastructure Density:** We eliminated sites where built infrastructure exceeded 30% of the land area within a 6x6-mile buffer zone around existing power plants, recognizing that dense development patterns typically preclude cost-effective RE deployment.
4. **Regulatory Restrictions:** Areas subject to local ordinances prohibiting wind development were excluded from wind potential calculations, reflecting current regulatory limitations.

Out of a total of 1,404 power plants, 155 plants are entirely excluded due to having more than 30% built infrastructure within a 6x6-mile buffer zone, including plants such as peaker plants in the Los Angeles Basin. We also excluded areas where local prohibitions prevent RE deployment, impacting approximately 5% of the plants in our analysis.

After applying these exclusions, of the remaining 1,220 plants, 1,099 have renewable potential more than five times greater than their current interconnection capacity, indicating significant opportunities to increase the utilization of existing interconnections to rapidly deploy new low-cost energy sources. The magnitude of this potential suggests ample availability of suitable contiguous land parcels for utility-scale development within these buffer zones.

From this total, we next evaluated the technical and economic viability to quantify the actionable RE integration potential as well as the RE needs for a least-cost power system, as shown in Figure 4.

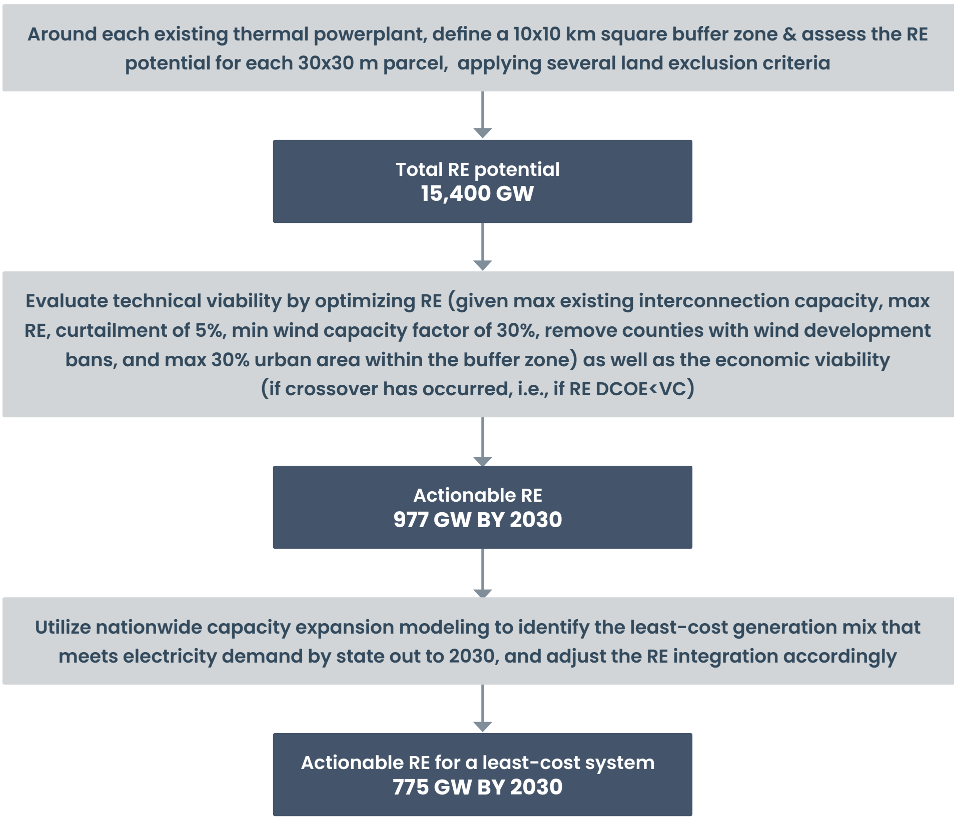

FIGURE 4. Summary of methods and results.

FINDING #2

For over 75% of existing fossil power plants, the RE LCOE is lower than their current variable cost.

Despite this tremendous potential, the RE integration potential at existing interconnections is likely far lower due to several constraints. For interconnection sharing to be economically viable, "crossover" must have occurred, meaning that the LCOE of local RE must be lower than the variable cost (VC) of the existing fossil plants, particularly those operating at high capacity. The VC is calculated by adding the fuel cost (based on the 7-year historical average of state-level costs for coal or gas, from the EIA) and the variable operation and maintenance (O&M) costs (from ReEDS; for more details, see Methods). This analysis is conducted at the unit level for the 4600 units across the 1,400 fossil plants in the U.S., recognizing as a limitation that fuel type and prime mover may vary across units within the same plant.

As shown in panels (a) and (b) of Figure 5, we find that in solar energy, crossover has occurred for 75% of the 700 GW of existing fossil interconnection, and in wind energy, crossover has occurred for 80% of the 700 GW of existing fossil interconnection in the U.S. today. Crossover is projected by 2030 for nearly all existing fossil plants as RE costs decline further, as shown in panels (c) and (d) of Figure 5. The annual cumulative interconnection capacity of existing fossil plants that have "crossed over" can be seen in panels (e) and (f) of Figure 5, projecting, on average, the crossover of 8 GW of wind and 30 GW of solar per year up to 2030.

This economic crossover triggers a shift in the conventional operational paradigm: once the local RE LCOE falls below the VC of fossil generation, renewable generation should be prioritized when available, factoring in the operational constraints of existing plants (e.g., ramp rates or minimum run rates). In this approach, fossil assets effectively become backup resources, operating only when renewable generation is insufficient to meet demand or during extreme events, such as severe weather or contingencies, where grid reliability is critical. By prioritizing renewable generation during solar and wind hours while maintaining fossil capacity for gaps in renewable generation, power plant owners can realize significant savings.

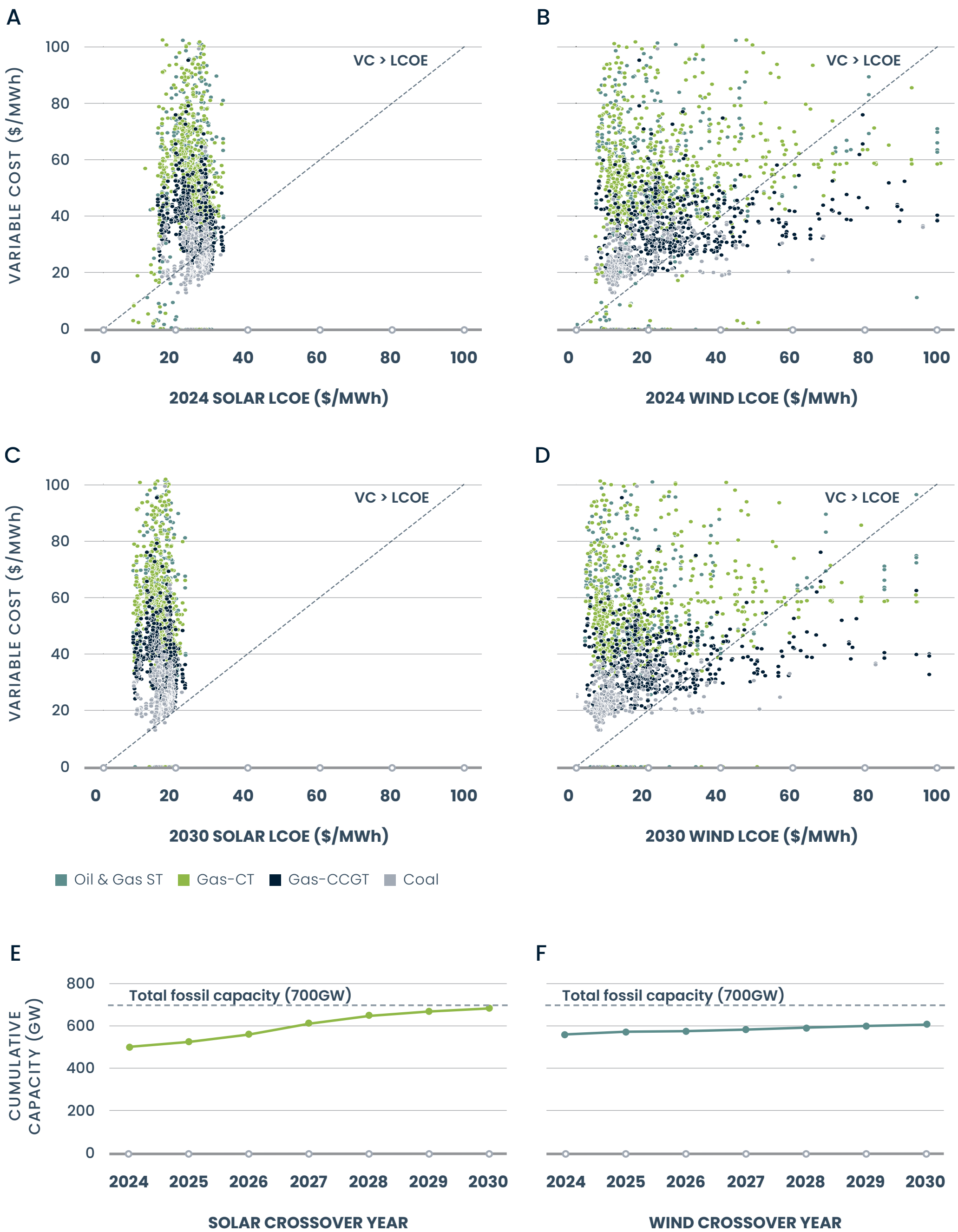

FIGURE 5. **RE cost crossover has occurred for over 75% of existing fossil interconnection in the U.S. today. (A-D):** Cost of local solar and wind compared to the VC (fuel cost plus variable O&M) of existing fossil power plants, in 2024 and 2030. Crossover occurs when the local RE LCOE is lower than the unit-level variable cost of existing fossil power plants. **(E-F):** The cumulative interconnection capacity of existing fossil plants where crossover has occurred, as a function of year, for both solar and wind.

FINDING #3

By 2030, approximately 1,000 GW of solar and wind will be economically viable for integration into existing fossil interconnection

We next optimized the solar and wind capacity that is not only economically viable but also technically viable, for potential integration at each existing fossil plant. To do so, we took hyperlocal hourly annual solar and wind profiles at each existing fossil plant and maximized annual RE generation (solar + wind), subject to constraints including an interconnection capacity limit (to ensure that instantaneous RE generation does not exceed the existing interconnection capacity) and an annual curtailment that is no higher than 5% (to maintain economic viability). We additionally excluded the plant if built-up area exceeds 30% of the area within the 6x6-mile buffer zone around the plant, as this indicates significant cost implications and potential challenges in land acquisition for RE development. The quality of local RE was benchmarked against projects now under development in the area. While solar resources are generally comparable, we applied an exclusion criterion for wind, considering only local potential with a minimum capacity factor of 30%. This ensures that integrating RE projects near existing fossil plants would not compromise on quality or cost, compared to connecting RE via dedicated grid expansions. In addition to these technical and economic constraints, wind development was excluded in counties with existing moratoriums.

The RE potential that is both technically and economically viable comprises the 836 GW of actionable RE potential near existing fossil plants today, which increases to 977 GW by 2030 as the costs of new RE decline. If integrated, this actionable RE potential could nearly double the U.S. generation capacity. The evolution of the actionable RE integration between 2024–2030 can be viewed by ISO/RTO in Figure 6, highlighting significant opportunity in PJM and MISO. The opportunity in PJM is particularly pressing, as surging electricity demand is straining resource adequacy, increasing the risk of a multi-GW capacity shortfall over the next five to ten years. This underscores the potential of interconnection sharing—both with existing fossil assets and at retiring facilities—to help accelerate new resource integration, meet projected load growth, and support grid reliability.

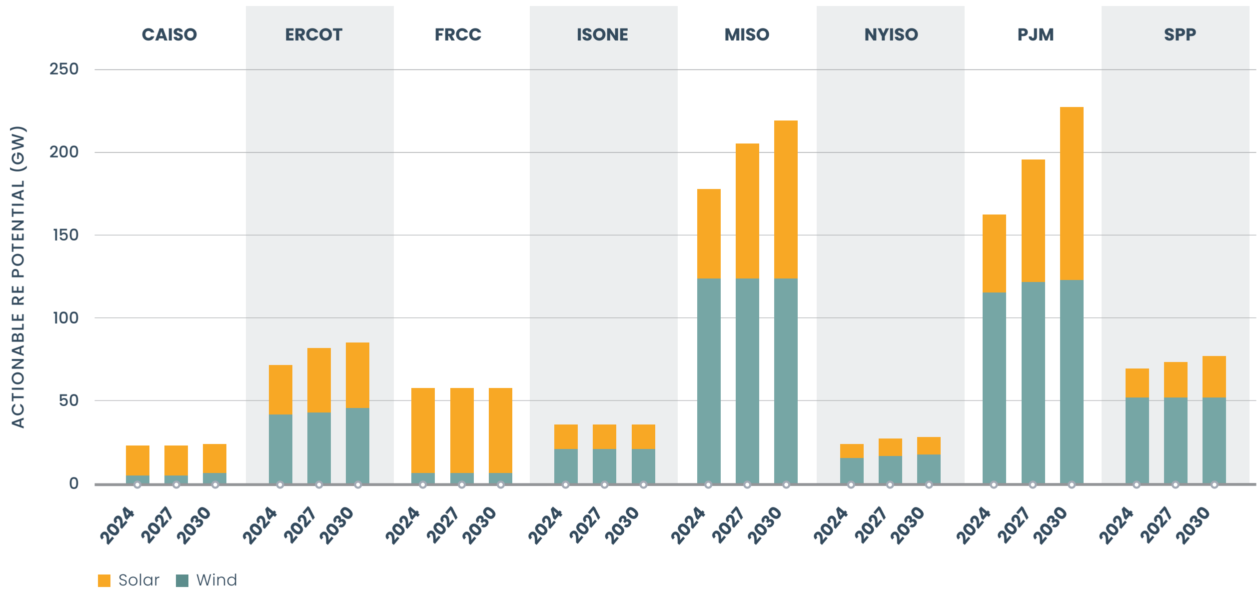

FIGURE 6. **Opportunity for integrating RE at existing interconnection is significant in PJM and MISO, followed by ERCOT, SPP, and FRCC.**

Fully deploying this actionable RE potential would require an unprecedented effort, currently hindered by practical barriers such as siting and permitting, equipment procurement, labor availability for installation, and financing, etc. Addressing each of these barriers individually is crucial to substantially accelerate RE deployment. Another outstanding question regarding realistic integration of actionable RE potential pertains to the breakdown by type of RE, and specifically, solar versus wind. Within the past five years, onshore wind has added an average of 10 GW/year in capacity, while solar has nearly doubled that at 18 GW/year. Moreover, annual capacity additions for onshore wind have been trending downward, while solar has been trending upward, reflecting solar's relative ease in siting, permitting, and installation, compared to wind (38).

Given these deployment trends and the significant role of fuel prices in determining economic viability, we examined two key scenarios: one that includes both solar and wind integration potential, and another focused solely on solar deployment. We analyzed these scenarios across a range of state-specific fuel prices to understand how price volatility affects integration potential over time.

Sensitivity analysis

To assess the robustness of our findings, we conducted sensitivity analyses using state-specific historical fuel price volatility. For each state, we established three scenarios based on 7-year fuel price data: a base case using the state's average price, and low and high cases set at one standard deviation below and above that state's mean. Natural gas prices in the base case ranged from \$2.41 to \$7.54/MMBtu (mean: \$4.26/MMBtu), with the low scenario ranging from \$1.02 to \$6.75/MMBtu (mean: \$2.40/MMBtu) and the high scenario from \$3.74 to \$10.00/MMBtu (mean: \$6.11/MMBtu). Similarly, for coal, base case prices varied from \$1.25 to \$8.07/MMBtu (mean: \$2.56/MMBtu), with the low scenario ranging from \$1.20 to \$5.45/MMBtu (mean: \$2.15/MMBtu) and the high scenario from \$1.31 to \$10.70/MMBtu (mean: \$2.98/MMBtu).

As shown in Figure 7, while state-level fuel price variations significantly influence the total RE integration potential, the opportunity remains substantial across all scenarios. In 2024, the integration potential ranges from 564 GW in the low fuel price case to 932 GW in the high fuel price case, with the base case at 837 GW. This range evolves to 681–979 GW by 2027, with base case at 921 GW and reaches 829–990 GW by 2030, with base case at 977 GW. Notably, the minimum potential grows consistently across years—from 564 GW to 829 GW—demonstrating that even in states with persistently low fuel prices, declining renewable costs drive increasing the economic viability of RE integration.

This state-level sensitivity analysis reinforces the fundamental strength of leveraging existing interconnection for renewable integration. Even in states with consistently low fuel prices, the potential for over 800 GW of RE capacity integration by 2030 represents a transformative opportunity. The convergence of integration potential across scenarios over time, illustrated in Figure 7, underscores how declining renewable costs progressively reduce the impact of state-level fuel price volatility on the economic case for RE integration. The narrowing range between scenarios—from 368 GW in 2024 to 161 GW in 2030—further demonstrates the increasing robustness of the RE integration opportunity as technology costs decline.

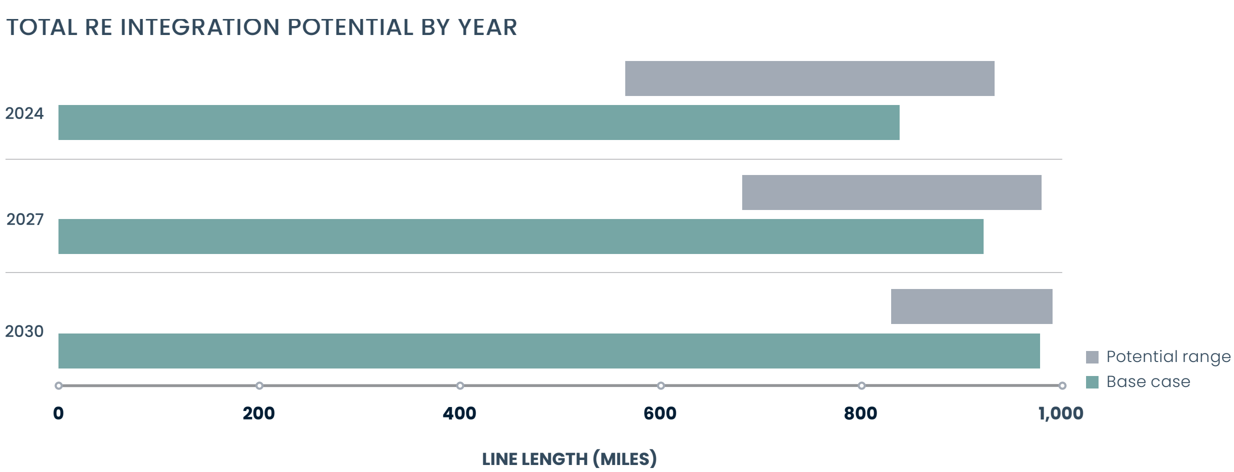

FIGURE 7. Total RE integration potential across different fuel price scenarios (2024–2030). The range between high and low scenarios narrows from 368 GW in 2024 to 161 GW in 2030, demonstrating increasing resilience to fuel price variations.

To align more closely with current renewable deployment trends, we conducted a Solar-Only Scenario (SOS) analysis, reflecting the generally lower siting and permitting barriers faced by solar projects compared to wind. As seen in Figure 8, in the SOS base case, the integration potential begins at 499 GW in 2024, grows to 614 GW by 2027, and reaches 693 GW by 2030. This potential shows significant sensitivity to fuel price variations, particularly in earlier years. Under high fuel prices (one standard deviation above state means), the potential increases to 608 GW in 2024, 681 GW in 2027, and 700 GW in 2030. Conversely, with low fuel prices (one standard deviation below state means), the potential starts at 281 GW in 2024, rises to 384 GW by 2027, and reaches 567 GW by 2030.

The impact of fuel price variations on solar integration potential demonstrates a clear pattern of convergence over time, as also shown in Figure 8. The potential range is widest in 2024, spanning 327 GW (from 281 GW to 608 GW), but narrows substantially to 297 GW by 2027 (from 384 GW to 681 GW) and further contracts to 134 GW by 2030 (from 567 GW to 700 GW). This convergence pattern mirrors our findings from the combined solar and wind analysis, suggesting that while near-term solar deployment opportunities are significantly influenced by fuel price fluctuations, the long-term integration potential becomes increasingly robust as solar costs continue to decline. Even in the most conservative scenario, with persistently low fuel prices, the potential for solar integration reaches 567 GW by 2030, representing a substantial opportunity for clean energy deployment.

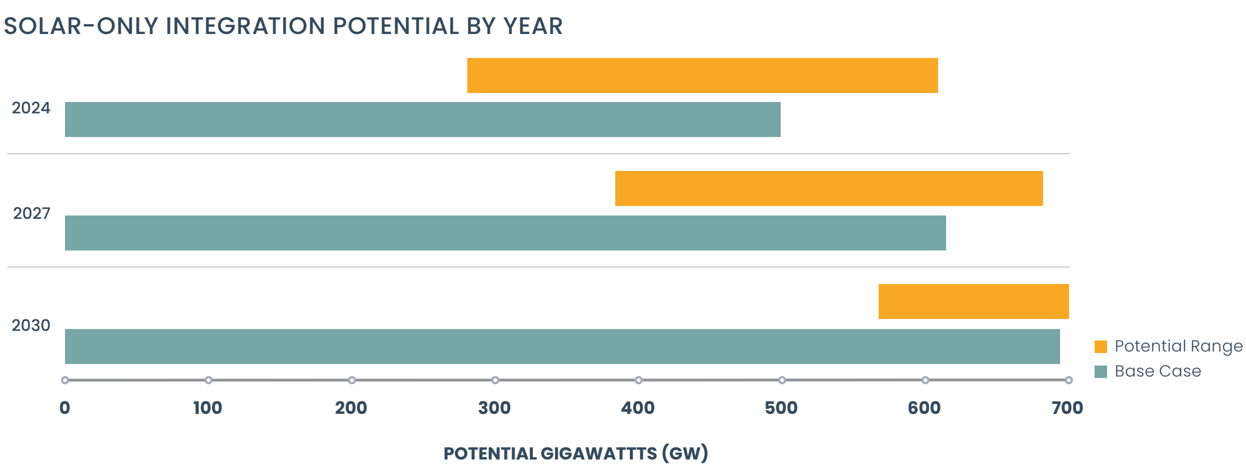

FIGURE 8. Solar-only integration potential across different fuel price scenarios (2024–2030). Similar to total RE, the range between scenarios contracts from 327 GW in 2024 to 134 GW in 2030, showing increasing economic viability over time.

Interconnection cost savings

Utilizing existing interconnection significantly reduces integration costs, including those for network upgrades, which have risen substantially in recent years, ranging from $71-107/kW by ISO (19). Integrating the identified 1134 GW of renewable capacity at existing POIs by 2030 could save approximately $85 billion compared to developing these projects at new POIs. These savings come from minimizing direct interconnection infrastructure investments and avoiding network upgrades by leveraging the existing system, leading to a significant reduction in overall system costs.

Operational feasibility

To assess the operational feasibility of integrating RE capacity at existing POIs and account for operational constraints of existing plants (e.g., ramp rates or minimum run rates), we conducted a detailed hourly dispatch simulation for an exemplary CCGT, California's La Paloma Plant (1048 MW), with an additional 1048 MWAC of solar capacity at the same POI. The combined solar and gas system was modeled to deliver flat block power daily, which is the most rigorous ramping and unit commitment scenario, requiring the CCGT plant to cycle each day within operational constraints that are aligned with CAISO's model parameters. The analysis indicates that integrating solar capacity alongside the CCGT at the existing POI is technically feasible and fully adheres to operational constraints—including ramping, technical minimum levels, and minimum up and down times— and maintains solar curtailment at only ~5%. Further investigation is necessary to evaluate the long-term impacts of daily cycling on CCGT equipment durability.

FINDING #4

Leveraging existing interconnection can help deliver a least-cost power system in over 35 states

Although approximately 1000 GW of actionable RE integration is assessed on a hyperlocal plant level, from a broader system perspective, the RE required for a least-cost system is likely to differ. To evaluate this, we used the widely adopted high-resolution transmission and generation capacity expansion model, ReEDS (20), which optimizes the least-cost generation mix that meets the projected electricity demand for each of the model's 134 zones in the contiguous U.S., accounting for current policy (such as IRA incentives), as well as future technology cost declines. We compared the resulting least-cost renewable capacity needs for 2030 with our estimated interconnection sharing potential at the state level in order to ensure alignment with least-cost system requirements while identifying states where interconnection sharing could substantially support renewable deployment targets. Where actionable RE through interconnection sharing exceeds the least-cost requirement for a state, we constrained it to that requirement, whereas in states where our estimated potential falls below the least-cost requirement, we maintained our original estimate, as it represents the realistic ceiling for interconnection sharing in that region. After applying these adjustments across all states, our analysis indicates that by 2030, interconnection sharing could be economically viable for the integration of 775 GW of renewables, helping to deliver the majority of RE needs for a least-cost power system in 38 states, as shown in Figure 9.

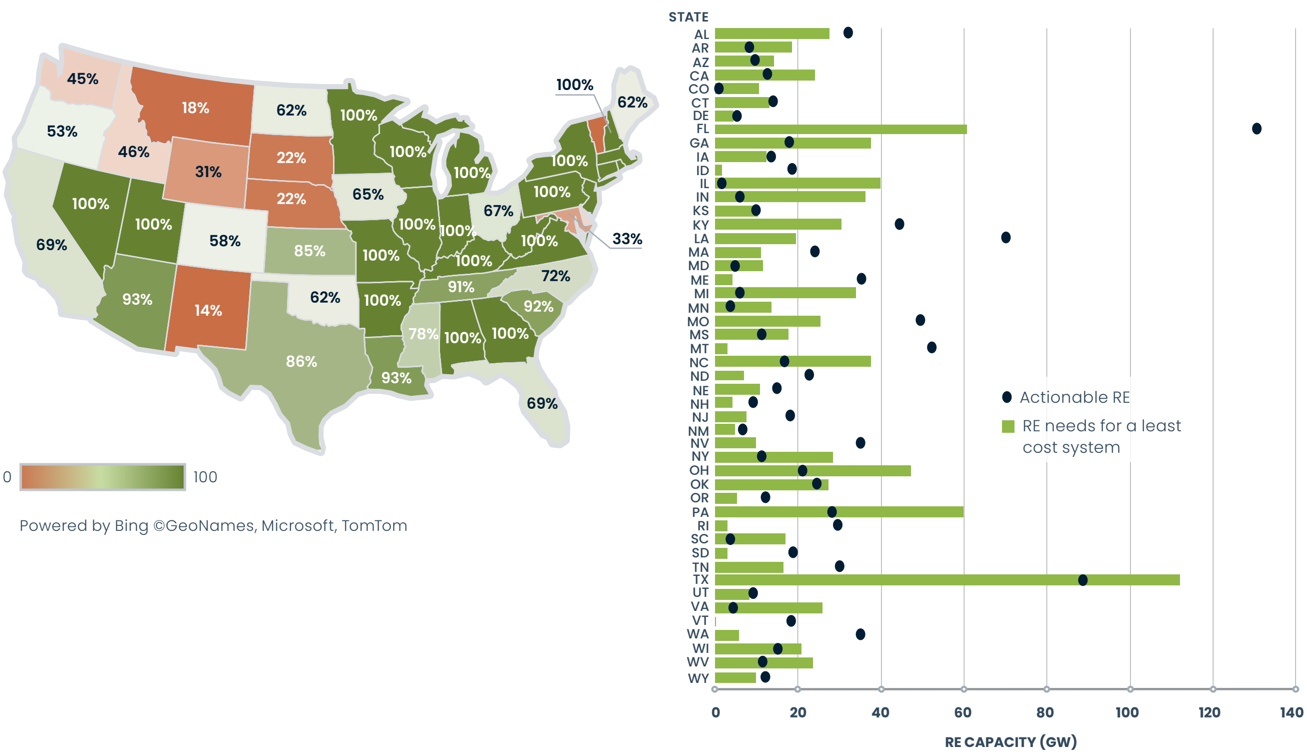

FIGURE 9. Leveraging the interconnection of existing fossil plants can help deliver a least-cost power system in most states. (a) Percentage showing the proportion of interconnection sharing in meeting the state's RE needs for a least-cost system in 2030. (b) State-by-state breakdown of actionable RE versus the RE requirements.

Peak demand can be met even with RE capacity sharing interconnection with thermal plants

There are concerns that connecting multiple resources behind a single shared POI could limit the combined output, as these resources might need to reduce generation in order to avoid exceeding the existing interconnection limit. If this curtailment were not properly accounted for in resource adequacy or operational models, it could lead to shortages during peak demand periods.

For this scenario to occur, gas plants would need to run at maximum capacity during peak hours while significant solar generation also tried to feed into the grid, triggering curtailment orders. However, our 2035 simulation shows a different reality. We find that at the system-wide peak load of over 900 GW, which happens at 4:00 PM in September, gas generation contributes just 115 GW, and the majority of peak demand is met by solar, batteries, wind, and other resources. Moreover, during the highest gas generation period, where gas generation exceeds 300 GW, solar generation is zero, further illustrating that gas and solar peaks are naturally complementary. Therefore, even substantial solar capacity installed behind the meter at gas plants would not impact the system's ability to meet peak demand, since gas and solar generation peaks do not coincide. This evidence demonstrates that sharing interconnection capacity between gas and solar does not meaningfully constrain the system's ability to meet peak demand.

FINDING #5

More than 200 GW of existing fossil capacity in the U.S. is minimally utilized and has high operating costs

The greatest immediate opportunity for interconnection sharing lies with existing fossil plants that are expensive to operate (with high variable costs) and/or minimally utilized (with low capacity factors). For instance, in 2023, over 200 GW of U.S. fossil capacity did not use their interconnection for over 85% of the hours in a year. The majority of this fossil capacity consists of peaker plants, run only to meet periods of peak residual demand. These peaker plants are typically natural gas-fired combustion turbines (CTs) as well as oil and gas steam turbines (STs) with higher heat rates and thus lower efficiencies compared to baseload fossil generation, namely natural gas-fired combined cycle gas turbines (CCGTs). At the same time, most of this underutilized 200 GW of fossil capacity has operating costs that are, on average, approximately $20/MWh higher than those of intermediate and baseload fossil plants, which run at higher capacity factors, as seen in Figure 10. On a broader scale, the utilization of fossil plants and their interconnection capacity would decline as RE penetration increases.

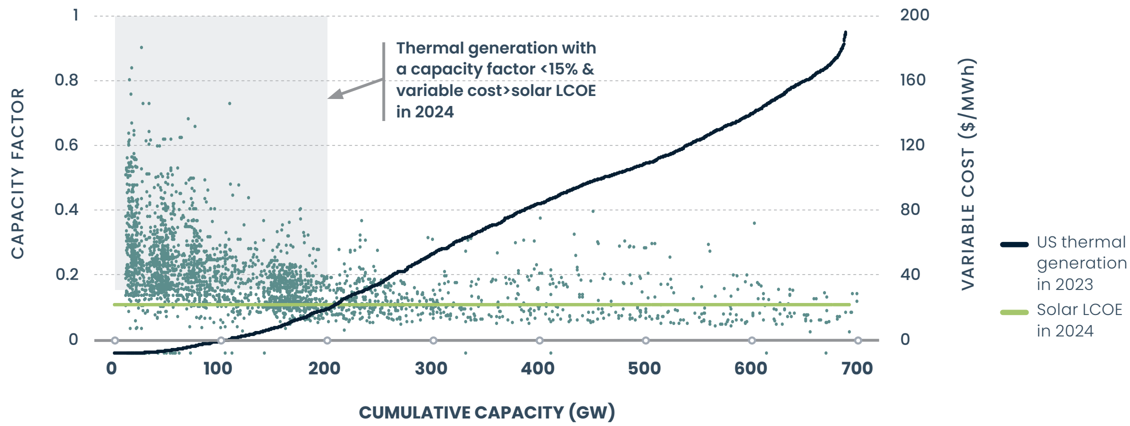

FIGURE 10. **More than 200 GW of fossil capacity has a capacity factor below 15% and faces operating costs higher than the cost of new RE.** The supply curve shows the capacity factor versus the cumulative installed capacity of U.S. fossil plants, overlaid with the plants' operating costs from 2023 (composed of variable O&M plus fuel costs).

The high operating costs of these plants are partly due to their age, which further exacerbates their inefficiencies. In the U.S., coal-fired plants average over 43 years old, while oil-fired units average 42 years—likely beyond or at least approaching the lifespan envisioned in their original design specifications (21). As these plants age, they require more fuel per unit of electricity generated, leading to higher costs and reduced efficiency. Additionally, they occupy increasingly valuable POIs at a time when new RE projects face significant delays in securing grid access. This represents an opportunity to improve grid utilization through interconnection sharing, enabling the efficient integration of low-cost clean energy sources while maintaining the reliability services provided by existing generators.

DISCUSSION

The technically feasible and economically viable opportunity for low-cost solar and wind to share interconnection with existing fossil plants totals around 1,000 GW by 2030, with the potential to nearly double U.S. generation capacity. This strategy benefits all stakeholders involved, as seen in Figure 11. First, it helps to rapidly deliver clean and low-cost electricity for consumers and the economy. From a power system perspective, integrating additional RE while retaining conventional fossil assets ensures the availability of sufficient generation capacity to serve rapid load growth while supporting grid reliability. This strategy diversifies the portfolios and revenue streams of power plant owners, and delivers net savings when lower-cost RE is used instead of conventional fossil generation during RE generation hours. Meanwhile, RE developers benefit from faster project realization, IRA incentives, and lower infrastructure costs due to avoided expenditure on interconnection equipment such as breakers and transformers. Further, this approach drives substantial investment and reduced pollution in energy communities, generating local tax revenue and providing employment opportunities to those who may otherwise experience a progressive decline as conventional fossil assets are scaled back.

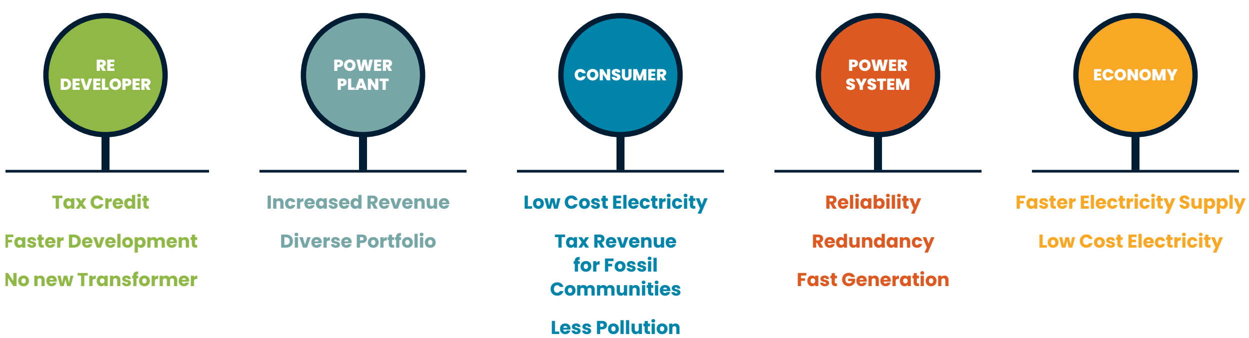

FIGURE 11. Interconnection sharing offers multiple benefits for various stakeholders.

Policy recommendations to accelerate RE deployment at existing interconnection

Although FERC Order 845 lays the groundwork for leveraging surplus interconnection, additional policy and regulatory support is required to make this a mainstream strategy for rapidly scaling RE integration. Surplus interconnection presents a significant opportunity, but it also deviates from the conventional interconnection process. While this process has undergone substantial reform in recent years, it still generally involves an interconnection customer (i.e., a RE project developer) submitting a request to the transmission provider and joining the queue of interested projects. These projects must undergo a series of system impact and facility studies to determine what, if any, network upgrades are needed before the project can be brought online. The interconnection customer bears the costs of these studies and the required network upgrades. In recent years, the queue has grown significantly due to factors such as the rise in distributed energy projects, increased interest in developing RE with the support of tax credits, and an outdated process that has not kept pace with demand. If a project clears these hurdles, the interconnection customer signs an agreement with the transmission provider, stipulating the terms of operation. By contrast, a customer seeking interconnection at an existing POI would follow a very different process.

Background on FERC Order 845

Issued April 2018, FERC Order 845 (via Section IV.C.3) requires transmission providers to establish an expedited process for interconnection customers to utilize or transfer Surplus Interconnection Service (SIS) at existing generating facilities, ensuring that the total interconnection service (and combined generating output) at the POI remains unchanged and no network upgrades are required (22). While priority for SIS use is given to the existing interconnection customer or its affiliates, it can be transferred to another interconnection customer. The required studies for SIS include reactive power, short circuit/fault duty, stability analyses, and, if necessary, steady-state (thermal/voltage) analyses. Nearly all U.S. regions comply with Order 845, except ERCOT (which is not under FERC jurisdiction) and NYISO (which was granted an independent entity variation). Generally, the SIS process significantly shortens the interconnection timeline, compared to the recent average of 4–5 years for projects requiring new interconnection. However, surplus interconnection is tied to the continued existence of the original customer's service. Additionally, the process for adding new generation at retiring plant sites— referred to as "generator replacement service"—varies widely by region.

Today, three main barriers hinder the full realization of actionable RE potential: (1) limited awareness or motivation among existing interconnection rights holders to capitalize on the large availability of economically viable RE potential near existing fossil plants, (2) current IRP and transmission planning processes do not factor in RE deployment at existing interconnections, and (3) existing grid interconnection rules offer limited or insufficient support for interconnection sharing.

To address these barriers, policy recommendations for key entities include:

Federal Energy Regulatory Commission (FERC):

- **Streamline Surplus Interconnection Service (SIS):** Ensure a consistent surplus interconnection service framework, removing overly restrictive study assumptions, improving process functionality, and including a streamlined procedure for SIS customers to be able to permanently retain interconnection rights following the retirement of the original interconnection customer.
- **Harmonize Generator Replacement Rules:** Ensure a consistent generator replacement framework across all U.S. regions that enables the fast-tracking of new energy projects at the site of retiring facilities, for example based on MISO's existing model.
- **Create Standardized Agreements:** Consider requiring transmission operators to develop and implement pro-forma agreements (e.g., Monitoring and Consent, Conversion) to clarify and expedite interconnection transactions, reducing administrative complexities across RTOs.
- **Optimize Interconnection Rights:** Allocate existing interconnection rights efficiently to lower costs and protect consumer interests. Develop a regulatory pathway that ensures fair compensation for current rights holders while establishing a system for efficient grid access allocation that promotes improved utilization, cost reduction, and competition.
- **Enhance Transparency:** Introduce open processes for transferring interconnection rights to prevent capacity hoarding, including the potential creation of a clearinghouse, which would addressing concerns over "capacity squatting" and enable fair access to interconnection capacity.

ISOs/RTOs:

- **Streamline SIS:** Ensure a consistent surplus interconnection service framework, removing overly restrictive study assumptions, improving process functionality, and including a streamlined procedure for SIS customers to be able to retain interconnection rights following the retirement of the original interconnection customer.

- **Enhance Generator Replacement Rules:** Ensure a consistent generator replacement framework compatible with neighboring regions that enables the fast-tracking of new energy projects at the site of retiring facilities, for example based on MISO's existing model. Make sure this is harmonized to allow for continuation of interconnection service for SIS customers following the retirement of the original interconnection customer.
- **Integrate SIS and Generator Replacement in Long-Term Transmission Planning:** Consider renewable resources at existing POIs in the scenario planning under Order 1920.
- **Enhance Transparency:** Establish data portals and/or perform studies that highlight surplus interconnection opportunities to guide developers and load-serving entities in project planning.
- **Facilitate Adoption:** Consider developing a clearinghouse to enable market participants to offer surplus interconnection capacity to others, facilitating bilateral agreements.
- **Standardize Contractual Agreements with Interconnection Customers:** Consider developing standardized contractual agreements to establish the terms of operation of shared interconnection, particularly with surplus interconnection customers.

Public Utility Commissions (PUCs):

- **Integrate SIS in IRPs and RFPs:** Require utilities to include surplus interconnection and generation replacement capacity options in IRP and RFPs to prioritize cost-effective renewable deployment that can leverage existing infrastructure.
- **Assess Existing Interconnection Potential:** Direct utilities to study clean energy potential at existing fossil plants, promoting rapid RE deployment and cost savings by avoiding additional interconnection and transmission expenses.

State Legislators:

- **Mandate SIS and Generator Replacement in Planning:** Pass legislation requiring that PUCs assess surplus interconnection and generation replacement capacity as part of generation planning processes, improving grid resilience and accelerating renewable deployment for consumer benefit.
- **Address Siting and Workforce Development:** Allocate funding to communities with fossil infrastructure to conduct studies on local siting as well as the economic, environmental, and community benefitsof utilizing existing interconnection, and support workforce reskilling

programs to transition labor from retiring plants to new clean energy roles.

Load-Serving Entities:

- **Prioritize Existing Interconnection in Resource Planning:** Assess surplus interconnection and generation replacement capacity opportunities in resource planning and Renewable Portfolio Standard (RPS) compliance, focusing on renewable development at existing POIs to minimize infrastructure costs and increase speed of interconnection.
- **Conduct Cost-Savings Studies:** Analyze and communicate potential savings from integrating renewable energy at existing sites, demonstrating reduced costs through avoided interconnection and transmission needs.
- **Partner with Legacy Generators:** Collaborate with legacy generators to co-develop renewable and storage projects at existing interconnection, using shared interconnection agreements to share benefits and meet clean energy goals effectively.
- **Incentivize Utility Interconnection Sharing:** One potential challenge in deploying renewable energy (RE) at surplus POIs is that, in many cases, interconnection rights are owned by regulated utilities. These utilities are neither RE developers nor owners of any RE assets. RE developers could compensate such utilities for sharing the interconnection rights with their plants. However, electricity regulators must encourage this practice by providing utilities with incentives to share interconnection rights, ultimately lowering costs for all consumers.

Generators with Interconnection Rights:

- **Monetize Interconnection Capacity:** Explore opportunities to monetize unused interconnection capacity, either through direct sale or auction, thereby creating new revenue streams and supporting renewable deployment.
- **Partner with Renewable Developers:** Develop partnerships with RE and storage developers to utilize surplus interconnection rights, providing access to existing infrastructure while supporting grid reliability and clean energy growth.

FUTURE WORK

Exploring the Potential of an Integrated Renewable, Repower (Surplus Interconnection), and Reconductoring (RRR) Strategy for Rapid and Extensive Deployment of Low-Cost Electricity

There can be several possible extensions of this work, including first, evaluating the additional storage and RE deployment potential by sharing grid access with existing RE plants, which currently have a capacity of about 250 GW. There is potential to add 4–6 hours of storage at a similar capacity (250 GW), thereby adding significant new firm capacity to the U.S. grid while creating opportunities for an additional 250–500 GW of RE deployment that can share the same interconnection. Several RE projects are already adopting such strategies.

The U.S. has one of the world's largest transmission networks, with hundreds of thousands of miles of high-voltage transmission line crisscrossing the country, and vast amounts of economical RE potential exist in their vicinity. However, in 2023, the country added only around 60 miles of new high-voltage transmission lines, contributing to a five-year total of just 2,500-3,000 miles. The grid primarily uses wires based on technology that is more than 100 years old. Our research has shown that the U.S. can double its transmission capacity and meet over 80% of its transmission needs by rewiring the grid with commercially available advanced conductors (i.e., reconductoring) that can carry twice the amount of electricity.(39) This upgrade can be completed much faster and more economically than building brand-new lines, bypassing the lengthy permitting processes required for new infrastructure.

With reconductoring, which can potentially double grid capacity, the interconnection capacity of the existing power generation infrastructure (exceeding 1,000 GW) can be significantly increased (up to doubled). This would enable more interconnections, leveraging existing infrastructure while reducing costs and timelines. Thus, combining a focus on RE, re-powering (surplus interconnection), and a reconductoring strategy can pave the way for low-cost, clean energy abundance.

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APPENDIX

Additional Figures

FIGURE S1. **Fossil capacity where VC > solar LCOE in 2024, by state. No urban area exclusion criterion.**

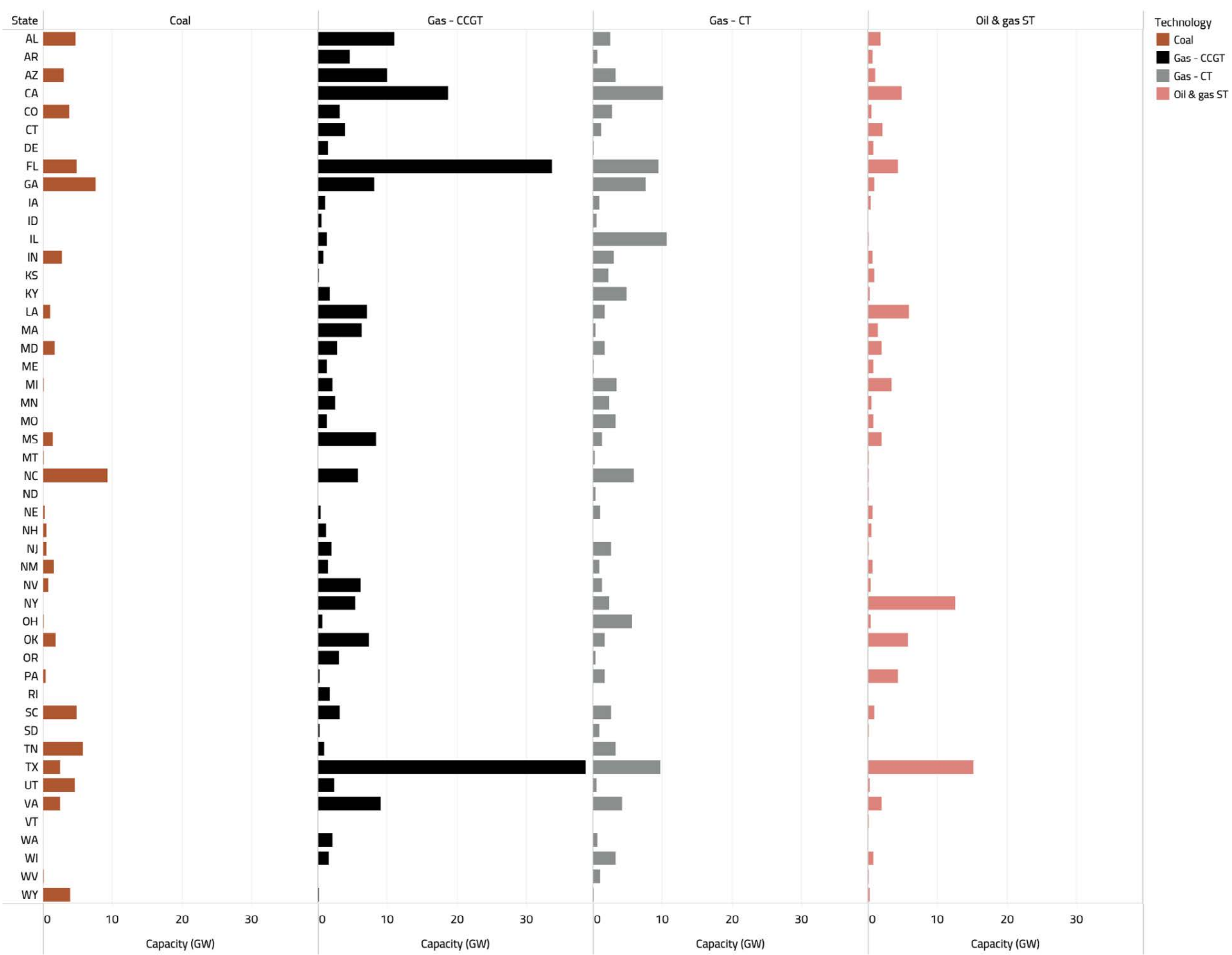

FIGURE S2. Fossil capacity where VC > solar LCOE in 2024, by major utility. No urban area exclusion criterion.

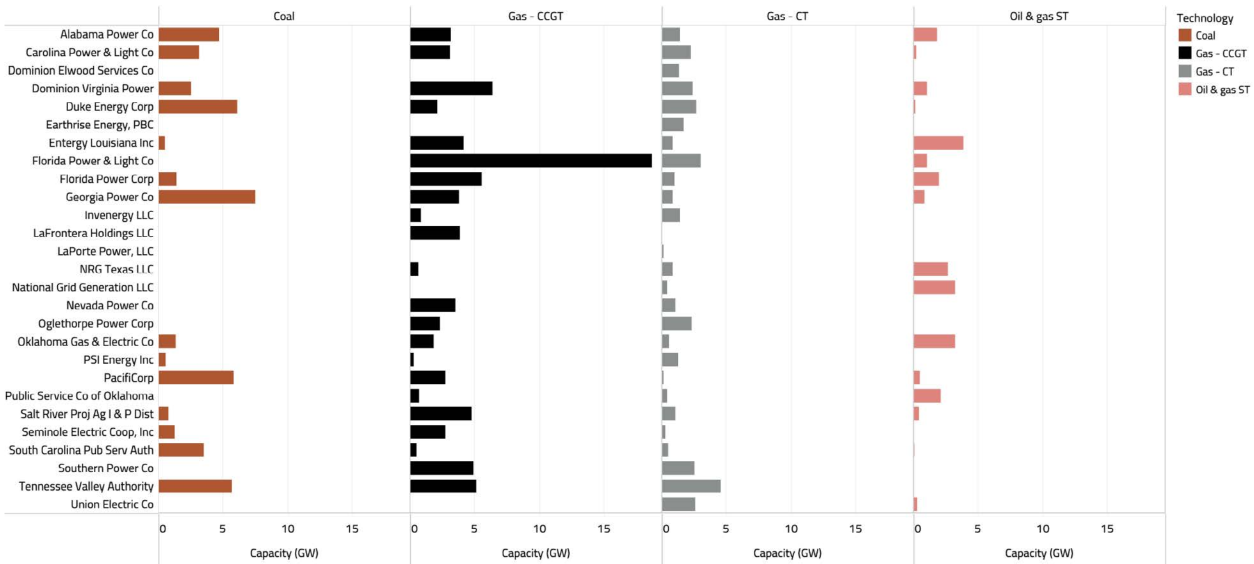

FIGURE S3. Fossil capacity where VC > $50/MWh (i.e., at least 2x the LCOE of local RE), by state. No urban area exclusion criterion.

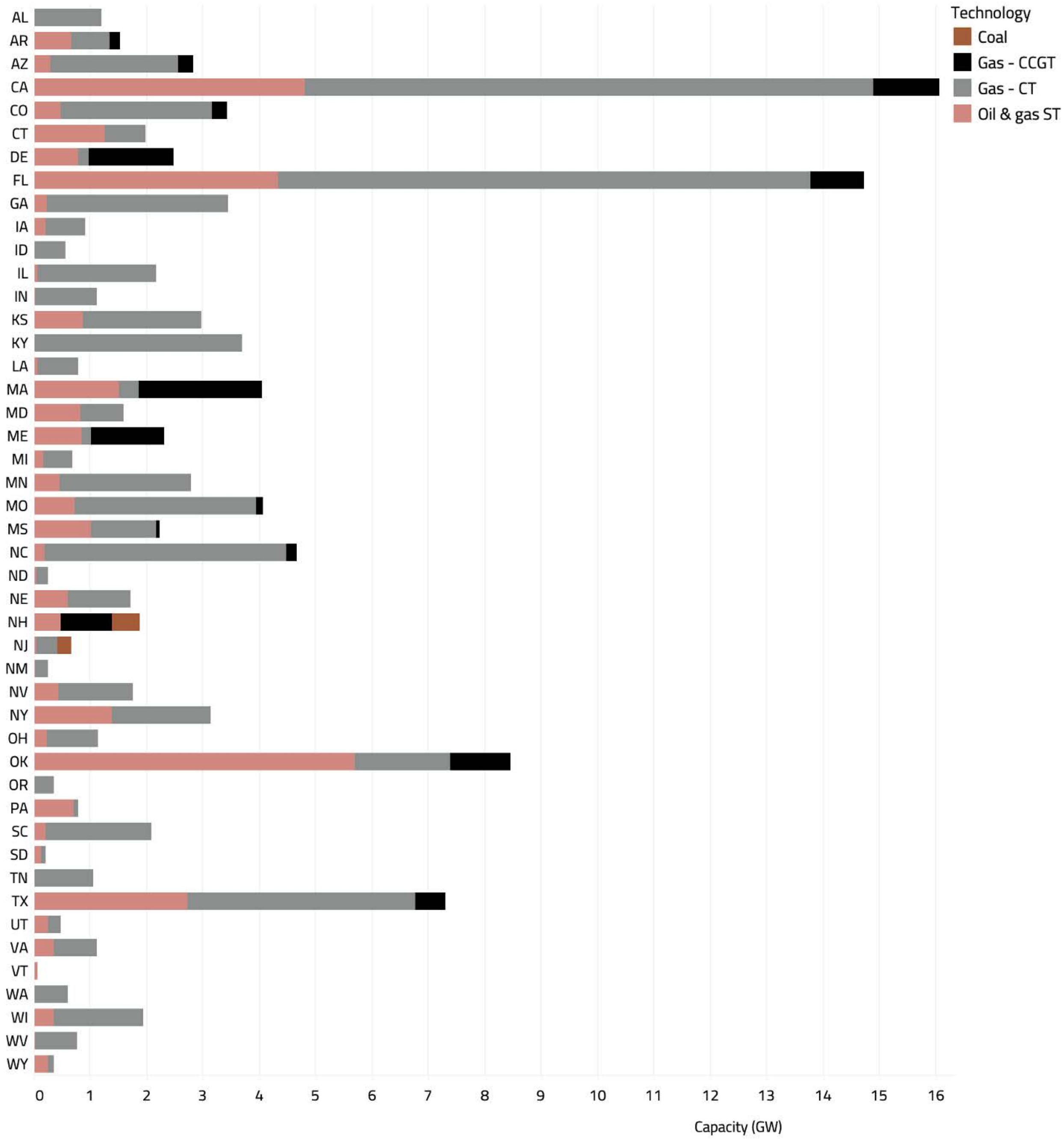

FIGURE S4. Fossil capacity where VC > $50/MWh (i.e., at least 2x the LCOE of local RE), by major utility. No urban area exclusion criterion.

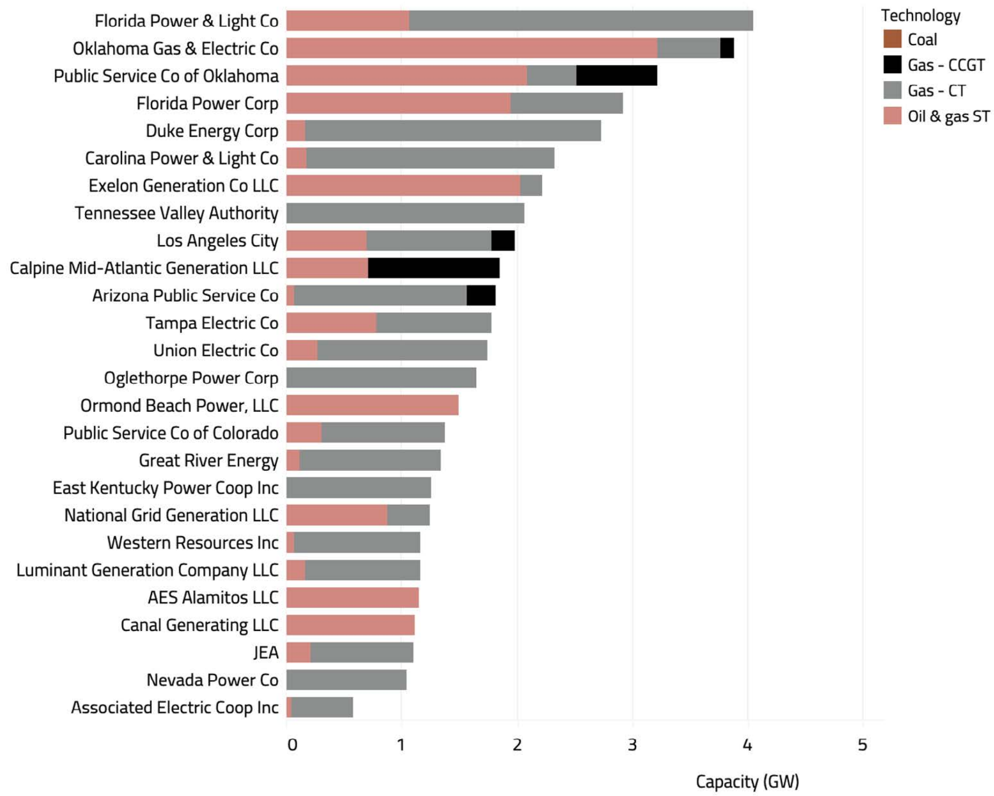

FIGURE S5. Fossil capacity where VC > $50/MWh (i.e., at least 2x the LCOE of local RE), by parent company. No urban area exclusion criterion. Unknown parent companies are not listed.

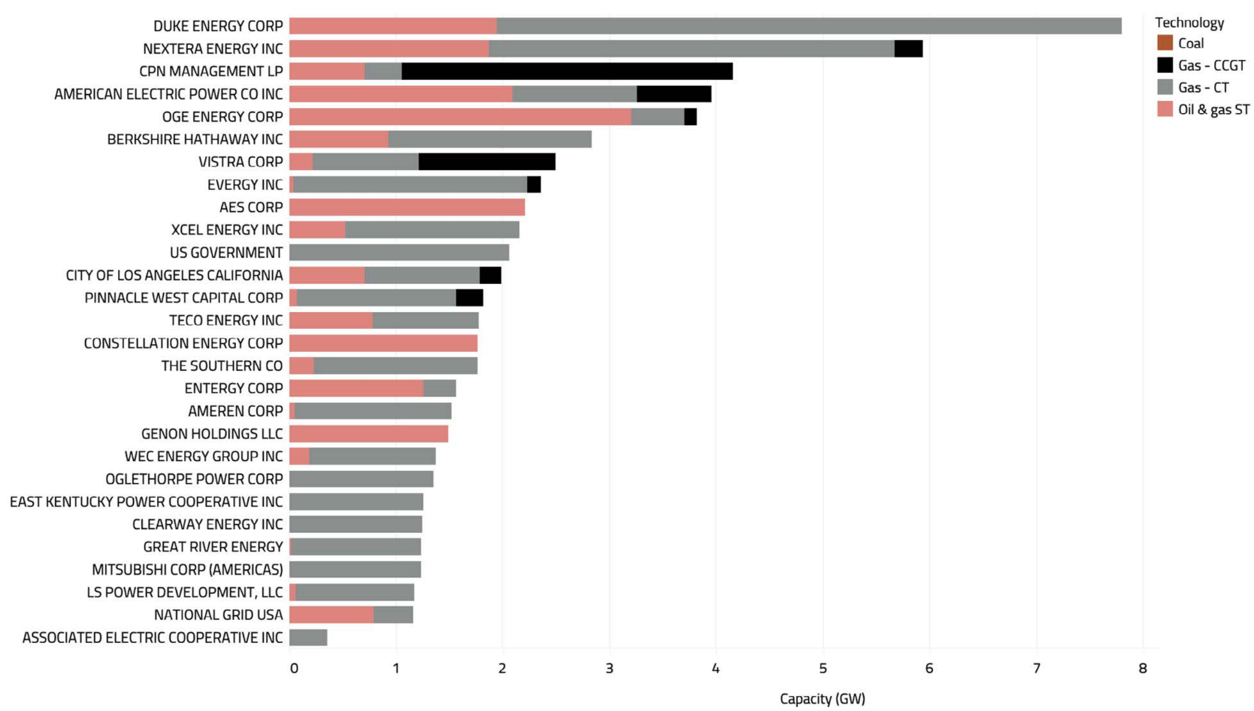

FIGURE S6. Fossil capacity not using its interconnection >85% of the time (i.e., a capacity factor < 15%), by state, based on 2023 data.

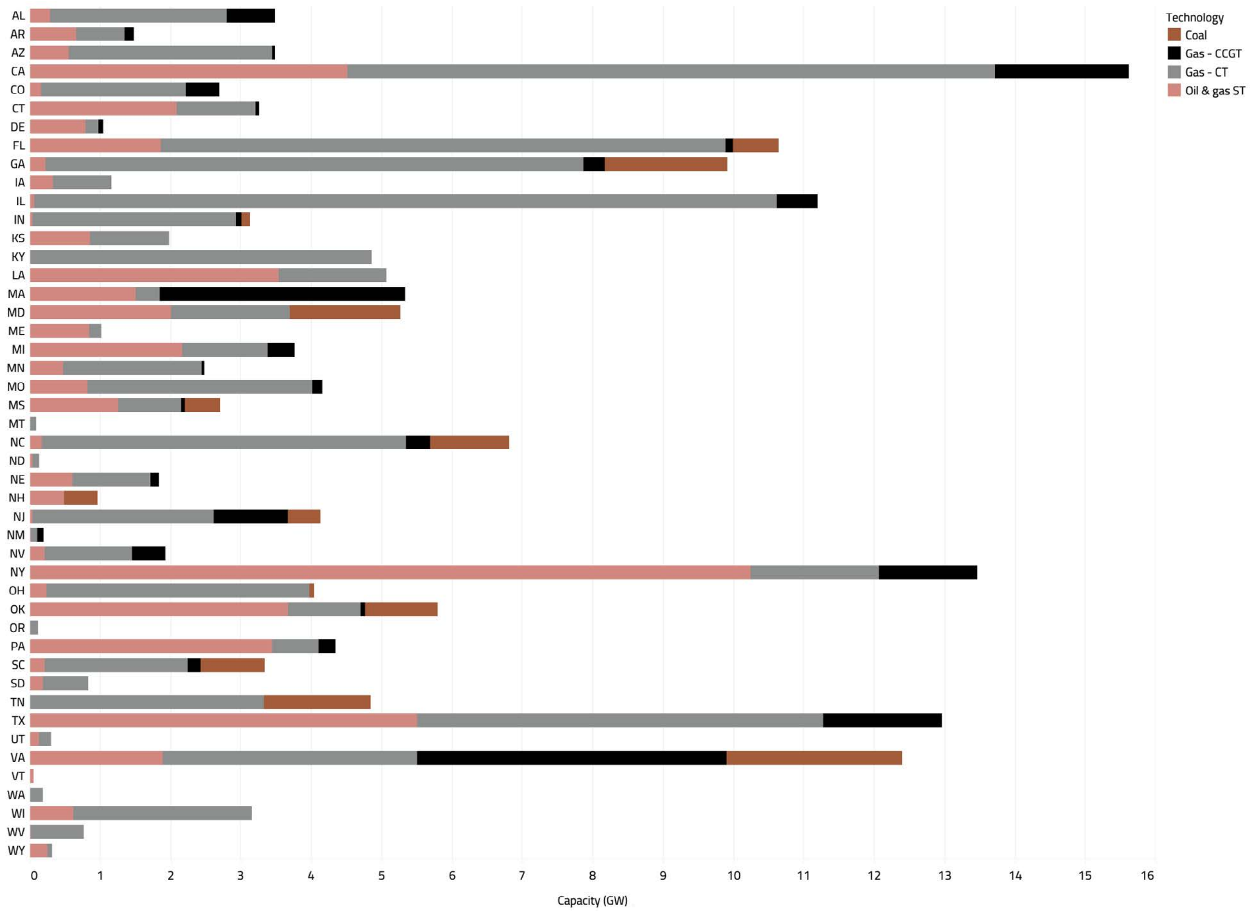

FIGURE S7. Fossil capacity not using its interconnection > 85% of the time (i.e., a capacity factor < 15%), by major utility, based on 2023 data.

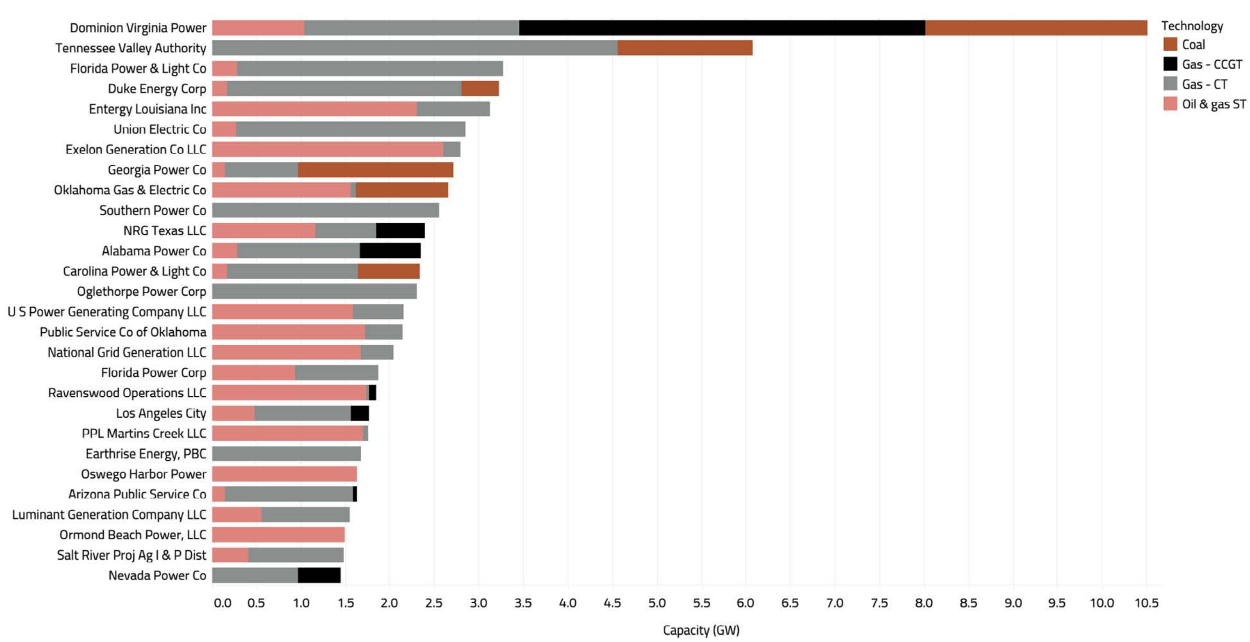

FIGURE S8. Fossil capacity not using its interconnection >85% of the time (i.e. a capacity factor <15%) by parent company, based on 2023 data. Unknown parent companies are not listed.

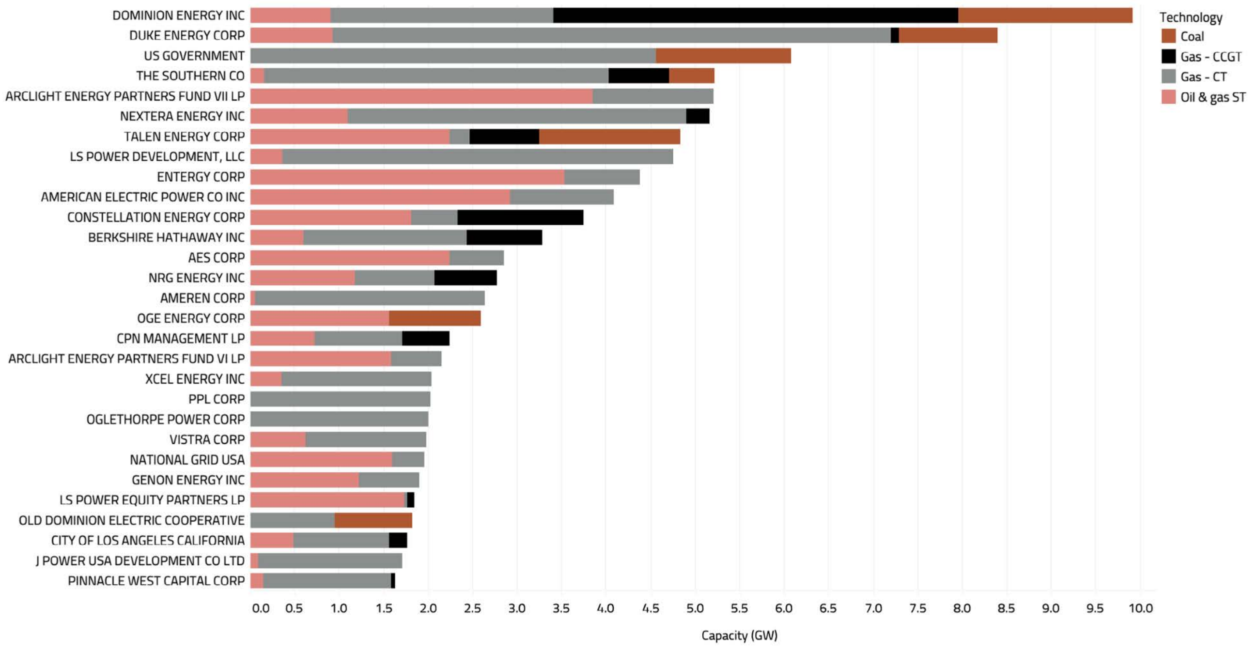

FIGURE S9. Evolution of actionable RE potential for all transmission planning regions.

TABLE S1. Average heat rates, by technology.

TECHNOLOGY	AVERAGE HEAT RATE, BASED ON 2023 DATA (BTU/KWH)
Coal	10,957
Natural gas - CCGT	7,948
Natural gas - CT	13,309
Oil & gas ST	15,279

Supplementary Text #1: Real-world case studies

Catalyst Energy Partners "acquires, invests, and develops North American thermal electric power plants and associated transmission infrastructure by adding renewable energy generation and energy storage to meet the needs of a rapidly growing national market for firm renewable power."

Their flagship project is Wolf Hills Solar, a 262 MW utility-scale solar project under development adjacent to the Wolf Hills Generating Station in Washington County, Virginia. The Wolf Hills Generating Station is an operating gas-fired power plant consisting of five simple-cycle gas turbines, rated at 57 MW each, for a total nameplate capacity of 285 MW. Like many other peak power plants, this plant is typically operated for only 1–5% of the hours in a year, yet is considered critical for grid reliability. This means that its interconnection and associated transmission infrastructure are unused over 95% of the time, creating an opportunity—particularly during solar hours—to interconnect additional renewable capacity, which in turn could avoid the need and associated time required to develop new grid infrastructure. As a result, the Wolf Hills Solar project is expected to see lower environmental impact and a faster time to commercial operations, projected at 3.5 years—from the time of the first community engagement (Q1 2024) to the commercial date of operation (Q3 2027).

The cost of producing power at Wolf Hills Solar is expected to be below the current market prices in Southwest Virginia, which can reduce reliance on inefficient generators that may inflate consumers' electric bills. The project is projected to generate over $20 million in local tax revenue over its lifetime (~35 years). The project has also garnered support from local landowners seeking to diversify their income, as well as local corporations looking to source carbon-free electricity to power their operations. During construction, the project will create approximately 300 full-time jobs, and during operation, the plant will employ three full-time power plant operators.

Earthrise Energy is an "independent power producer… that acquires, owns, and operates legacy fossil fuel assets and repurposes the transmission infrastructure for renewable energy development projects, bringing them online faster than typical greenfield renewable energy projects." The company manages 1.7 GW of gas-fired generation capacity and is developing over 1.5 GW of solar projects, primarily in the MISO and PJM market areas.

One example from Earthrise Energy's portfolio is in Gibson City, Illinois. The Gibson City Energy Center (GCEC) is a 237 MW highly flexible natural gas peaking plant that was acquired by Earthrise Energy in December 2021. Earthrise Energy plans to develop two solar farms and connect them to the GCEC. The first stage, GCEC — Solar I will be a 135 MW solar PV farm covering approximately 1,300 acres in the eastern portion of McLean County, within five miles of the natural gas plant in Gibson City, as seen in Figure S10. The second stage, GCEC — Solar II will be another 135 MW solar PV farm covering approximately 1,300 acres in the southern portion of Ford County, a few miles northwest of the natural gas plant in Gibson City. The lifetime of both projects is projected to be 30–35 years. GCEC - Solar I alone is projected to generate $24–27 million in economic benefits, including local property taxes, over the project lifetime.

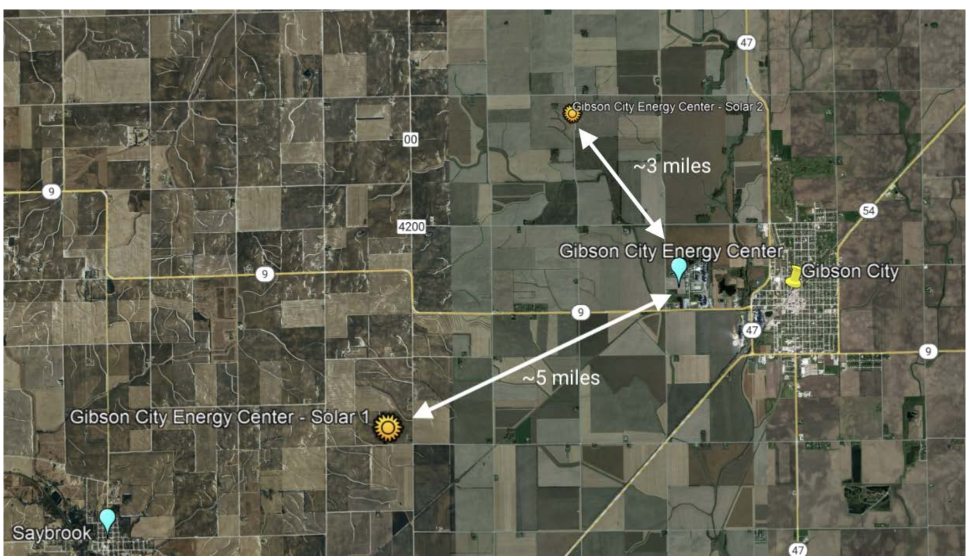

FIGURE S10. Both GCEC - Solar I and GCEC - Solar II are located within five miles of the gas-fired GCEC.

Earthrise is also developing similar projects throughout the state of Illinois, at the Shelby County Energy Center Hub, Tilton Energy Hub, Crete Energy Venture Hub, and Lincoln Generating Clean Energy Hub. An overview of some of these projects can be found in Table S1.

Island Green Power (IGP) is a utility-scale solar and battery plant developer. Their completed projects total over 1 GW and span the United Kingdom (UK), Spain, Italy, Australia, and New Zealand. In the UK, IGP is developing two notable solar projects that are utilizing the interconnection of former and existing power plants: the Cottam Solar Project and the West Burton Solar Project.

The Cottam Solar Project is named after its grid connection point, the existing 400kV National Grid substation at the former Cottam Power Station. The Cottam Power Station was a 2,000 MW coal-fired power plant that was closed in September 2019 after over five decades of operation. Also at the site is the Cottam Development Centre, a 445 MW natural gas-fired power plant that was commissioned in 1999. The Cottam Solar Project seeks to leverage the opportunity of spare grid connection capacity (in Europe, "interconnection" typically refers to cross-border transmission infrastructure, rather than the grid connection of power plants) by proposing to add 600 MW of solar capacity. This solar capacity would be distributed over several land parcels in close proximity to the substation, within a radius of approximately 20 kilometers, covering some 2,800 acres in total. These land parcels, which have confirmed agreements with the relevant landowners, were selected after thorough evaluation on the existing use and quality of the land, potential environmental or heritage designations, and visibility of the site from local areas. Cable corridors near existing roads would connect the generated solar power with the substation. The project will also include a 600 MW battery energy storage system.

Not far from the Cottam Power Station, IGP is also developing the similar, slightly smaller, West Burton Solar Project. The project is also named after its grid connection point, the existing 400kV National Grid substation at the West Burton Power Station. West Burton A was a 2,000 MW coal-fired power plant that was closed in 2023 after nearly six decades of operation. West Burton B is an existing 1,270 MW combined cycle gas turbine (CCGT) power plant that was commissioned in 2013. Also at the site is a 49 MW battery energy storage system that was added in 2018. The West Burton Solar Project would similarly leverage the spare grid connection capacity and add 480 MW of solar PV capacity, within a radius of approximately 20km and covering some 2,550 acres in total.

TABLE S2. Summary of domestic case studies.

EXISTING/FORMER POWER PLANT	EXISTING/ FORMER CAPACITY	NEW POWER PLANT	NEW CAPACITY	DEVELOPER	PROJECT DESCRIPTION	LOCATION	DATE IN-SERVICE	ECONOMIC IMPACT	SOURCE(S)
Wolf Hills Generating Station (WHGS) (gas)	285 MW	Wolf Hills Solar Plant	262 MW	Catalyst Energy Partners	The solar PV would provide primary generation; gas would serve as a backup or supplement, providing firm power when needed (e.g., periods of low solar/high demand).	Washington County, Virginia	Q3 2027	$386.9 million capital investment, supporting 300 full-time jobs during construction. The project is expected to generate $20 million in tax revenue during its lifetime.	wolfhillsolar.com
Gibson City Energy Center (GCEC) (gas)	237 MW	GCEC - Solar I	135 MW	Earthrise Energy	Earthrise Energy bought the gas plant in 2021 and plans to develop two solar farms nearby. Each solar farm will be sited on ~1,300 acres of land leased from private landowners. Both solar projects will leverage the existing transmission infrastructure at the natural gas plant.	McLean County, Illinois (MISO)	Q1 2026	GCEC - Solar I alone is projected to generate between $24-27 million in economic benefits, including local property taxes during the lifetime of the project (30-35 years).	earthriseenergy.com
Gibson City Energy Center (GCEC) (gas)	237 MW	GCEC - Solar II	135 MW	Earthrise Energy	Earthrise Energy bought the gas plant in 2021 and plans to develop two solar farms nearby. Each solar farm will be sited on ~1,300 acres of land leased from private landowners. Both solar projects will leverage the existing transmission infrastructure at the natural gas plant.	Ford County, Illinois (MISO)	Q1 2026	GCEC - Solar I alone is projected to generate between $24-27 million in economic benefits, including local property taxes during the lifetime of the project (30-35 years).	earthriseenergy.com
Shelby County Energy Center (SCEC) (gas)	352 MW	Northwest Solar	150 MW	Earthrise Energy	Earthrise Energy bought the gas plant in 2021 and plans to develop two solar farms nearby. Northwest solar will be sited on ~2,000 acres of land and Glacier Moraine Solar will be sited on ~2,900 acres of land, leased from private landowners, east of the SCEC. Both solar projects will leverage the existing transmission infrastructure at the natural gas plant.	Cumberland County, Illinois (MISO)	Q4 2026	-	earthriseenergy.com
Shelby County Energy Center (SCEC) (gas)	352 MW	Glacier Moraine Solar	210 MW	Earthrise Energy	Earthrise Energy bought the gas plant in 2021 and plans to develop two solar farms nearby. Northwest solar will be sited on ~2,000 acres of land and Glacier Moraine Solar will be sited on ~2,900 acres of land, leased from private landowners, east of the SCEC. Both solar projects will leverage the existing transmission infrastructure at the natural gas plant.	Cumberland County, Illinois (MISO)	Q3 2027	-	earthriseenergy.com
Lincoln Generating Facility (LGF) (gas)	656 MW	Lincoln 1	300 MW	Earthrise Energy	Earthrise Energy acquired the gas plant in September 2022 and plans to develop three solar farms nearby.	Will County, Illinois (PJM)	Q4 2026	-	earthriseenergy.com
Lincoln Generating Facility (LGF) (gas)	656 MW	Lincoln 2	200 MW	Earthrise Energy	Earthrise Energy acquired the gas plant in September 2022 and plans to develop three solar farms nearby.	Will County, Illinois (PJM)	Q2 2027	-	earthriseenergy.com
Lincoln Generating Facility (LGF) (gas)	656 MW	Lincoln 3	100 MW	Earthrise Energy	Earthrise Energy acquired the gas plant in September 2022 and plans to develop three solar farms nearby.	Will County, Illinois (PJM)	Q3 2027	-	earthriseenergy.com

TABLE S3. Summary of international case studies.

EXISTING/ FORMER POWER PLANT	EXISTING/FORMER POWER PLANT CAPACITY	NEW POWER PLANT	NEW POWER PLANT CAPACITY	DEVELOPER	PROJECT DESCRIPTION	LOCATION	DATE IN-SERVICE	ECONOMIC IMPACT	SOURCE(S)
Cottam Power Station	2,000 MW decommissioned coal-fired capacity; 445 MW of existing gas-fired capacity	Cottam Solar Project	600 MW	Island Green Power	Sites for these solar projects were chosen in order to utilize the existing grid connection infrastructure left behind by retired coal-fired power plants. The project will also include a 600 MW battery energy storage system.	Retford, United Kingdom	Late 2020s	-	cottamsolar.co.uk/
West Burton Power Station	2,000 MW decommissioned coal-fired capacity; 1,270 MW of existing gas-fired capacity	West Burton Solar Project	480 MW			Retford, United Kingdom		-	westburton-solar.co.uk/

SUPPLEMENTARY TEXT #2

Hourly dispatch analysis for La Paloma gas power plant in California

The La Paloma Generating Project (LPGP) is a 1,048 MW natural gas-fired CCGT facility located in Kern County, supplying to the PG&E system. It consists of four combustion turbine generators, four heat recovery steam generators and exhaust stacks, and two to four steam turbines.[1]

Actual dispatch in 2023:

As shown in Figures S11 and S12, in 2023, LPGP operated with an annual capacity factor of 26% (annual generation of 2,394 GWh), cycling nearly every day and often shutting down during periods of high solar generation, typically between 9 a.m. and 1 or 2 p.m. For several days, the plant remained entirely offline.

1 Please refer here for details: https://www.energy.ca.gov/powerplant/combined-cycle/la-paloma-generating-plant

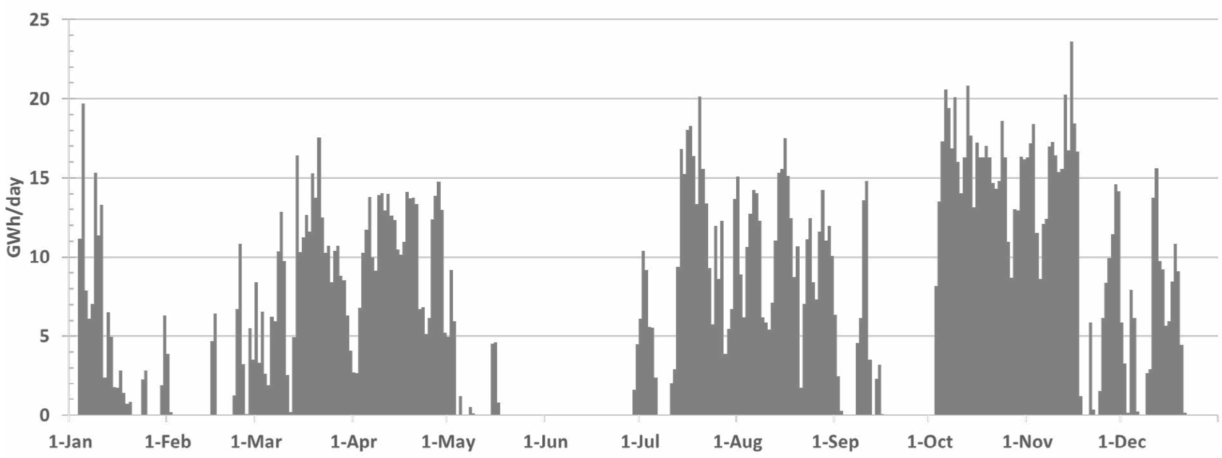

FIGURE S11. Daily electricity generation from La Paloma Generating Project (1048 MW CCGT) in 2023 (Actual). During several days, the plant did not turn on, as indicated by zero energy production.

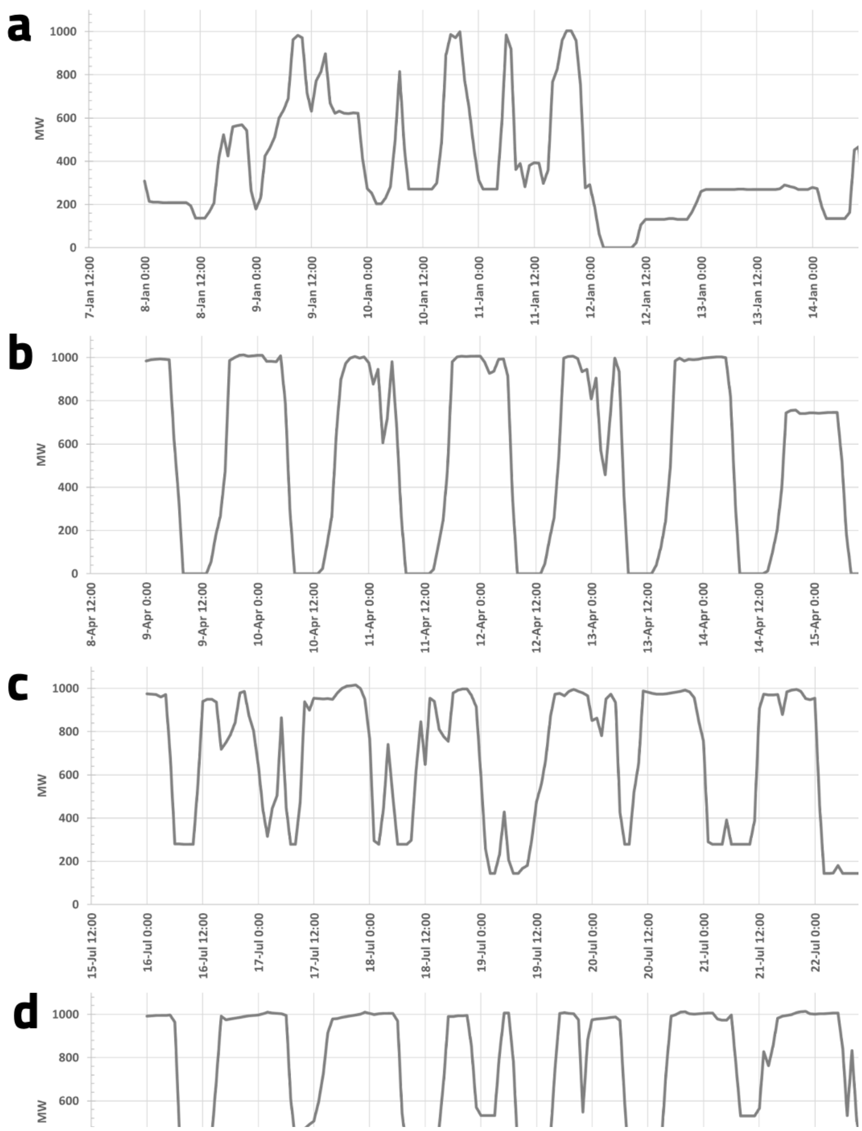

FIGURE S12. Actual hourly dispatch from La Paloma Generation Project (1048 MW CCGT) in 2023. Figure S12a shows dispatch during the week of January 8, 2023. Figure S12b shows the week of April 9, 2023, Figure S12c shows the week of July 16, and Figure S12d shows the week of October 8.

Simulated dispatch after adding 1048 MWAC of solar capacity at the same interconnection:

We simulated the hourly dispatch of the LPGP after integrating 1048 MWAC of solar capacity at the same POI. This solar capacity, with an inverter loading ratio (ILR) of 1.3, equates to approximately 1362 MW DC. The combined solar and gas power plant system was modeled to deliver a flat-block power profile daily, requiring the CCGT plant to cycle each day while adhering to technical constraints, including minimum generation levels, ramp rates, and minimum up and down times.

Although the actual 2023 dispatch was substantially lower than the flat-block profile, this approach allowed us to examine the operational feasibility of the combined system for an extreme ramping and unit commitment scenario. The need for daily cycling effectively sets an upper limit on RE curtailment and the level of RE that could be economically integrated at the same POI. If the plant were dispatched for fewer hours, RE curtailment would likely decrease due to reduced ramping and cycling.

The simulations, conducted in PLEXOS, utilized the same operational and cost parameters for LPGP as those in CAISO's IRP 25 MMT Stochastic PLEXOS model. CAISO's database reported maximum achievable ramp rates that were significantly higher than the actual hourly ramps delivered by the plant. Therefore, to adopt a conservative approach and ensure the gas plant's ability to manage ramping requirements introduced by solar integration, we limited maximum ramp rates to the values observed in 2023.

Table S4 provides an annual comparison of CCGT operations, along with a summary of solar generation and curtailment. To maintain continuous gas plant generation during non-solar hours and achieve flat block power, the solar + gas system experiences nearly double the starts and stops compared to its 2023 gas-only operations. This increase in cycling raises the start and shutdown cost per MWh for the solar + gas system, although the impact remains moderate as most starts are hot or warm. Heat rate losses due to part-load operation are also found to be comparable to gas-only levels. To keep gas plant ramp rates within 2023 levels, a moderate solar curtailment (~5%) is necessary, predominantly occurring during shoulder periods (early or late solar hours, around 8 a.m. or 6-7 p.m.) when the gas plant ramps down to its technical minimum or shuts down before ramping up to meet evening demand (see Figure S13).

This preliminary simulation analysis indicates that even in the most conservative scenario—providing flat block power, where the gas power plant is committed daily—solar capacity, rated at the interconnection capacity (AC), could be integrated at the same POI. However, the long-term impacts of such cycling on the CCGT equipment, including potential wear and tear and reduced turbine lifespan due to frequent starts and stops, warrant further investigation.

*Figure S13 displays the hourly dispatch for the 1048 MW CCGT combined with 1048 MW*AC solar capacity at the La Paloma interconnection, assuming the same interconnection capacity of 1048 MW as previously established.

TABLE S4. Annual Comparison of CCGT power plant operations - 2023 actual (gas-only) and Gas + 1048 MW Solar flat block.

	GAS-ONLY (2023 ACTUAL)	SOLAR + GAS FLAT BLOCK (SIMULATED)
Gas capacity (MW)	1,048 MW	1,048 MW
Solar capacity (MW)	-	1,048 MW AC
Annual gas generation (GWh)	2,394 GWh	6,210 GWh
Gas marginal cost $/MWh	31.9	31.9
Solar generation (GWh)	-	2,946 GWh
Solar curtailment %	-	5.6%
Solar LCOE $/MWh (incl. IRA incentives)	XX	XX
Maximum CCGT ramp-up rate	629 MW/hr	628 MW/hr
Maximum CCGT ramp-down rate	-528 MW/hr	-519 MW/hr
# of hours per CCGT unit with zero output (shutdown)	5,790	2,206
# of CCGT starts and shutdowns per unit in a year	149 (estimated from actual dispatch; several cold starts)	297 (all hot / warm)
Start and shutdown cost ($/MWh)	5.0 (simulated)	6.7*
# of hours of each CCGT unit at technical minimum level	504 (simulated)	840
Heat rate loss due to part-load operation $/MWh	1.8 (simulated)	1.7*

* *Assuming the same unit commitment as in 2023, cost will be lower for the optimized unit commitment for flat-block.*

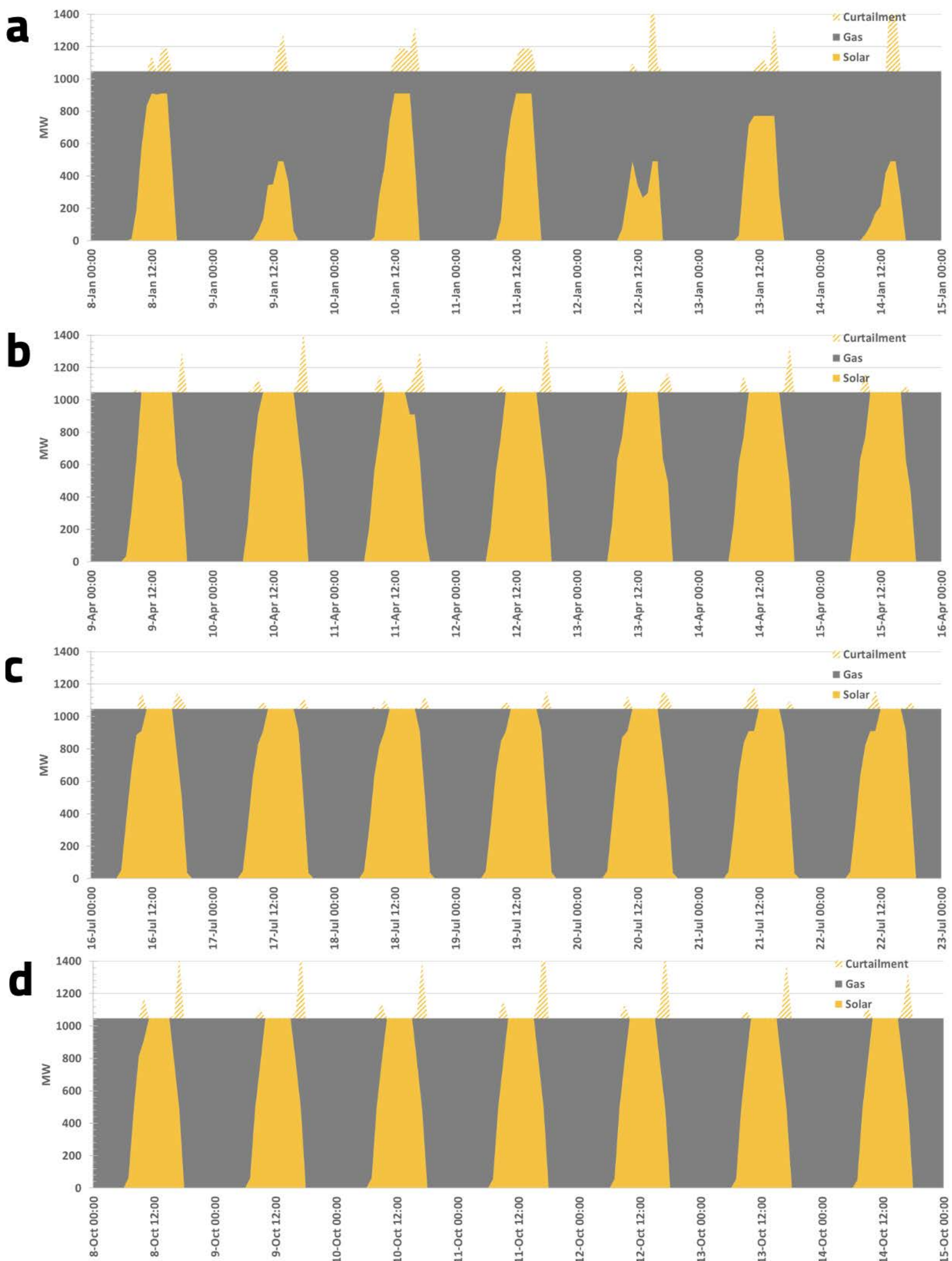

FIGURE S13. Simulated hourly dispatch from La Paloma Generating Project (1048 MW CCGT + 1048 MWAC Solar) for delivering flat block power. Figure S13aa shows dispatch during the week of January 8. Figure S13b shows the week of April 9, Figure S13c shows the week of July 16, and Figure S13d shows the week of October 8.

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