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Can Wind and Solar Replace Coal in Texas?

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Can wind and solar replace coal in Texas?

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Abstract

Texas has seen a rapid decline in coal use in recent years, but still burns more coal and emits more carbon dioxide and sulfur dioxide than any other state. Coal's share of power generation in the Electric Reliability Council of Texas (ERCOT) system that covers most of the state fell to 20 percent in 2019, while wind grew to 20 percent and solar to 2 percent. Here, we investigate the potential for new wind and solar projects already proposed in the ERCOT interconnection queue as of June 2020 to replace the coal power that remained in 2019. The Wind Integration National Data Set (WIND) Toolkit is used to simulate the output of each wind project, and the System Advisor Model to simulate solar output, for 3 years of meteorological conditions. Mixed integer cost-optimization modeling finds that a portfolio of just 72 of the 108 wind projects and 42 of the 262 solar projects in the queue would be sufficient to replace most coal generation in ERCOT, leaving 10 percent of coal output uncovered and generating larger surpluses at other times. The complementary timing of solar and wind in Texas, with sunshine peaking midday and winds peaking overnight in the west and on summer evenings near the coast, enables these high levels of displacement to be achieved. In fact, the wind and solar portfolio would outproduce retired coal on summer afternoons when demand peaks, leaving small gaps in evenings and shoulder seasons when demand is lower.

Keywords: Electric Reliability Council of Texas (ERCOT), Electricity generation, Complementarity, Mixed integer optimization, Cost analysis, Interconnection queue, Emissions, Wind, Utility-scale solar, Duck curve

Introduction

The United States is undergoing a rapid shift away from coal for the generation of electricity. After providing more than half of the U.S. power supply until as recently as 2006, coal's market share plunged to 24% by 2019 (Energy Information Administration, 2020b). Meanwhile, wind and solar soared from less than 1% of supply in 2006 to a combined 9% in 2019. Natural gas garnered the rest of coal's lost market share, rising by 18 percentage points over that time span.

Despite their decline, coal-fired power plants remain major emitters of carbon dioxide and nitrogen oxides and the dominant emitters of sulfur dioxide in the United States. Thus, accelerating their retirements can benefit climate, air quality, and health. Legislation in at least eight states and two U.S. territories requires 100 percent

carbon-free electricity by target dates ranging from 2040 to 2050 (National Conference of State Legislatures, 2021). Although nuclear and hydropower have historically been the leading sources of carbon-free electricity, high costs of new plants and retirements of old ones make it unlikely that their output will grow this decade. That leaves wind and solar power as the least-cost and fastest-growing sources of new carbon-free electricity (Energy Information Administration, 2020b; Lazard, 2020). Costs of wind and solar power have plummeted over the past decade thanks to learning-by-doing as deployments have grown (Kavak et al., 2018; Lazard, 2020; Nemet, 2019). However, the variable nature of their output raises questions as to how reliably wind and solar can displace fossil power plants.

Texas provides a proving ground for the replacement of coal with wind and solar. Texas power plants consume more coal and natural gas and emit more carbon dioxide than those in any other state (Energy Information Administration, 2019). However, Texas also generates more wind power than any other state and has a rapidly

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growing solar industry. Since the state has no mandate for clean electricity, market forces dictate the competition between these sources of power.

Most of the state's power grid is managed by the Electric Reliability Council of Texas (ERCOT), which has only limited connectivity with other power grids in the United States and Mexico. Thus, any decline in fossil fuel generation in ERCOT must be replaced primarily with alternative sources of power within its domain. In 2019, the generation mix in ERCOT was 47% natural gas, 20% coal, 20% wind, 11% nuclear, and 2% solar and other sources (ERCOT, 2021a). Developers have proposed hundreds of new wind and solar farms (ERCOT, 2020c), but ERCOT's 2025 capacity and demand report forecasts that far fewer will be built (ERCOT, 2020d). ERCOT drew national attention during winter storm Uri in February 2021, when outages at natural gas, coal, wind, and nuclear plants caused widespread blackouts (Doss-Gollin et al., 2021; ERCOT, 2021b; Everhart & Molnar, 2021; Storrow, 2021).

Several previous studies have examined challenges and opportunities for shifting from fossil to variable renewable resources in ERCOT. Zarnikau (2011) chronicled early successes integrating wind into ERCOT. Du and Rubin (2018) analyzed how additions of transmission capacity to west Texas have enabled more wind power to be transmitted to urban centers in the eastern half of the state. Deetjen et al. (2016) and (2017) modeled how additions of wind and solar may shift the timing and flexibility of output that is needed from other resources. Deetjen et al. (2018) modeled the optimal siting of new wind and solar farms and transmission capacity to provide about one-third of ERCOT's power supply. Several studies have modeled the scale-ups of wind, solar, and storage that would be needed to replace coal- and gas-fired electricity in ERCOT, but did not consider how siting wind and solar across locations with complementary timing of generation could reduce storage needs (M. Leonard et al., 2018; M. D. Leonard et al., 2020; Michaelides, 2019). None of these studies modeled specific wind and solar projects in the interconnection queue and their ability to displace coal.

Previous work has shown that wind and solar power are generated at complementary times, with west Texas winds blowing most strongly at night, south Texas sea breezes peaking on summer afternoons, and solar power peaking midday (Slusarewicz & Cohan, 2018). Other work has shown that coal-fired power plants in Texas contribute not only to climate change but also to air pollution responsible for several hundred premature deaths each year (Strasert et al., 2019). However, the extent to which electricity from those coal plants could be replaced by new wind and solar power deserves attention.

Here, we compute the half-hourly power generation that could be produced by each wind and solar project in the ERCOT interconnection queue as of June 2020 (ERCOT, 2020c). We then conduct mixed integer optimization modeling to identify least-cost combinations of proposed projects that could replace coal-fired power generation in ERCOT.

Methods

The following subsections describe our methods for (1) characterizing conditions in ERCOT; (2) simulating the output of wind and solar projects in the interconnection queue; (3) estimating the costs of wind and solar projects; and (4) optimizing a least-cost set of projects that could replace existing coal output with a specified percent of slack.

ERCOT coal and market conditions

For ERCOT market conditions and coal power output, we focus exclusively on the year 2019, since it was the only full year of data available at the time of this analysis after several large coal plants closed in 2018. Coal plants that continued operating in 2019 are shown in Fig. 1. Power generation by resource type on a 15-min basis was obtained from the ERCOT Fuel Mix Report (ERCOT, 2021a). Hourly power demand (load) in each of eight weather regions (Fig. 2) was taken from ERCOT hourly load data archives (ERCOT, 2020b). Real-time market electricity prices in each of the eight load zone hubs were taken from ERCOT market price archives on a 15-min basis (ERCOT, 2020a).

Wind and solar projects in the ERCOT interconnection queue

Data on wind and solar projects in the interconnection queue were obtained from ERCOT's Generator Interconnection Status (GIS) Report for June 2020 (ERCOT, 2020c). The report provides the status, capacity, and location of every project seeking to connect to the ERCOT grid. The report tallied 108 wind and 262 solar projects, including 10 wind repower projects, totaling over 24,500 MW of proposed wind capacity and 58,000 MW of solar on an alternating current (AC) basis (Fig. 3). By comparison, the ERCOT grid had 25,000 MW of existing wind capacity and just 3300 MW of utility-scale solar as of July 2020. Most projects in the interconnection queue have completed neither a full interconnection study (FIS) nor an interconnection agreement (IA) (Fig. 4), and thus their likelihood of construction remains in doubt. An FIS typically takes 40 to 300 days and assesses how a project would affect the transmission system. After an FIS has been accepted by ERCOT, the interconnecting entity and

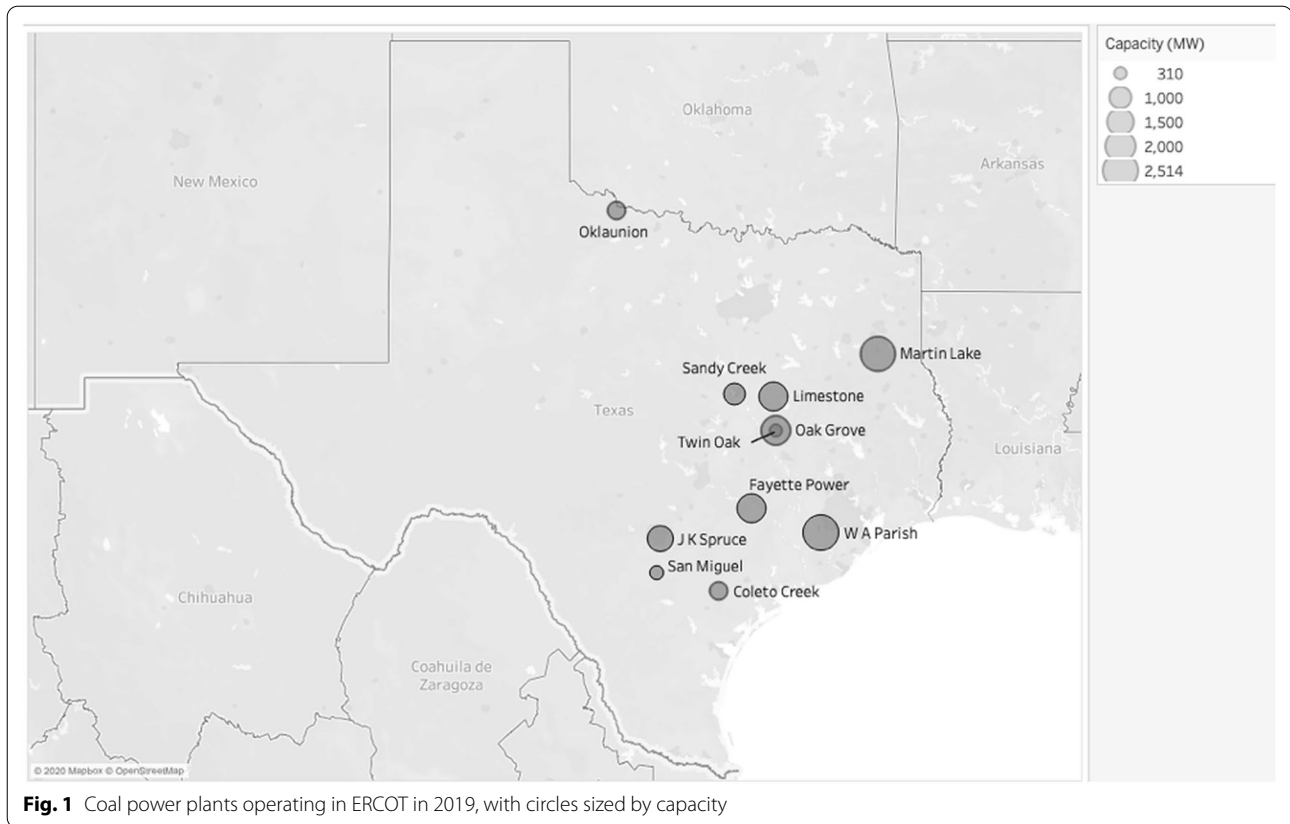


Fig. 1 Coal power plants operating in ERCOT in 2019, with circles sized by capacity

transmission service provider have 180 days to negotiate an IA (ERCOT, 2012).

Tracking the projects from the June 2020 GIS report, the most recent available at the time of our analysis, to the April 2021 report that became available during revisions, shows that 19 wind and 21 solar projects gained approval for energization, synchronization, and/or operation, while 18 wind projects and 41 solar projects were canceled or became inactive (Table 1). Over a longer span, from the December 2018 report to April 2021, 1.7 times as many projects were canceled or deactivated as gained approval, and a large fraction remained under active consideration (Table 1). This reinforces our framing of the ERCOT queue as a pool of projects with an uncertain likelihood of construction. Data compiled by Lawrence Berkeley National Laboratory provide insights into interconnection queues nationally (Rand et al., 2021).

Wind power output

Wind power output was simulated using the National Renewable Energy Laboratory's (NREL) Wind Integration National Data Set (WIND) Toolkit (Draxl et al., 2015; King et al., 2014) for the years 2009, 2010, and 2011. Data for 2019 were unavailable at the time of

this analysis. The WIND Toolkit applies the Weather Research and Forecasting (WRF) meteorological model over the continental United States to simulate wind speeds with 5-min temporal resolution, and converts those wind speeds to power output by assuming site-appropriate power curves for turbines with 100-m hub height. Meteorological and power estimates were validated by King et al. (2014) and Draxl et al. (2015).

We applied the WIND Toolkit at every point in a grid covering ERCOT with 0.25-degree resolution (approximately 900 points, 28 km apart north–south and roughly 24 km apart east–west). Results were then aggregated on a county-level basis. In counties with more than one grid point, wind projects were assumed to be sited at the point with the highest overall capacity factor, since wind speeds vary within counties (Pryor et al., 2020) and wind farms tend to be sited at the windiest available locations. Spatial averaging within counties would reduce wind capacity factor estimates by three percentage points, with the biggest differences in large counties. Output was scaled by the capacity of each project within a county and aggregated on a half-hourly basis. Degradations in output due to curtailments, equipment malfunctions, and maintenance were not considered.

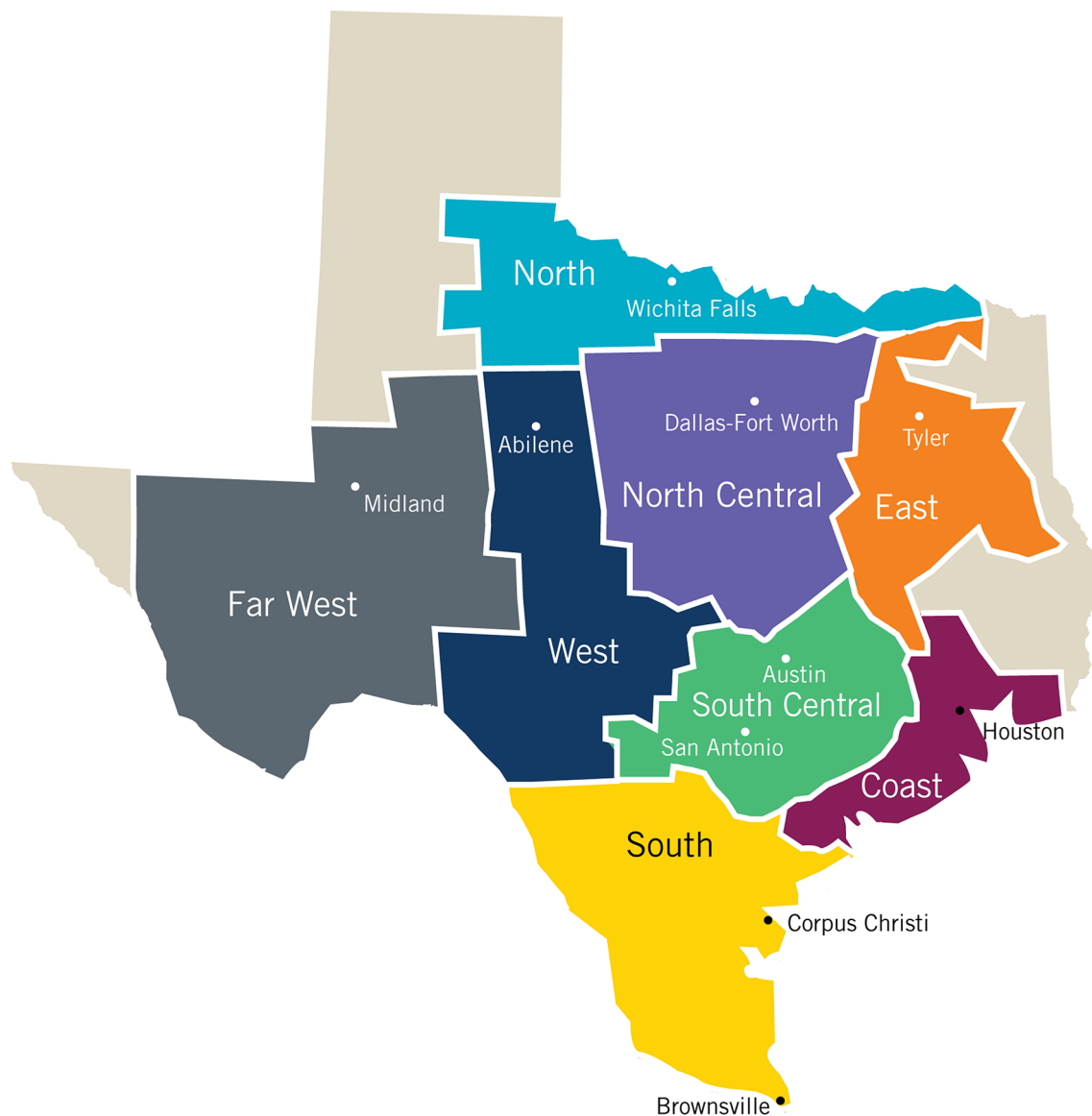


Fig. 2 ERCOT weather zones (<http://www.ercot.com/news/mediakit/maps>)

Solar power output

Solar power output was simulated based on meteorological data from the NREL National Solar Radiation Database (NSRDB) for the years 2009, 2010, and 2011. This database uses satellite inputs from Geostationary Operational Environmental Satellites (GOES) and accounts for cloud properties, aerosols, and water vapor to calculate surface radiation (Sengupta et al., 2015). Meteorological data were input to NREL's

System Advisor Model (SAM) (Blair et al., 2018) to compute half-hourly capacity factors for each solar project, using SAM version 2020.2.29. We adopted the SAM solar farm configuration from Slusarewicz and Cohan (2018), including their assumption of single-axis tracking, as is most prevalent at U.S. solar farms (Bolinger et al., 2019). However, here we assumed a DC-to-AC inverter loading ratio of 1.3, based on the average value for U.S. solar projects that came

(See figure on next page.)

Fig. 3 Wind (top) and solar (bottom) projects in the ERCOT interconnection queue as of June 2020, aggregated by county (ERCOT, 2020c)

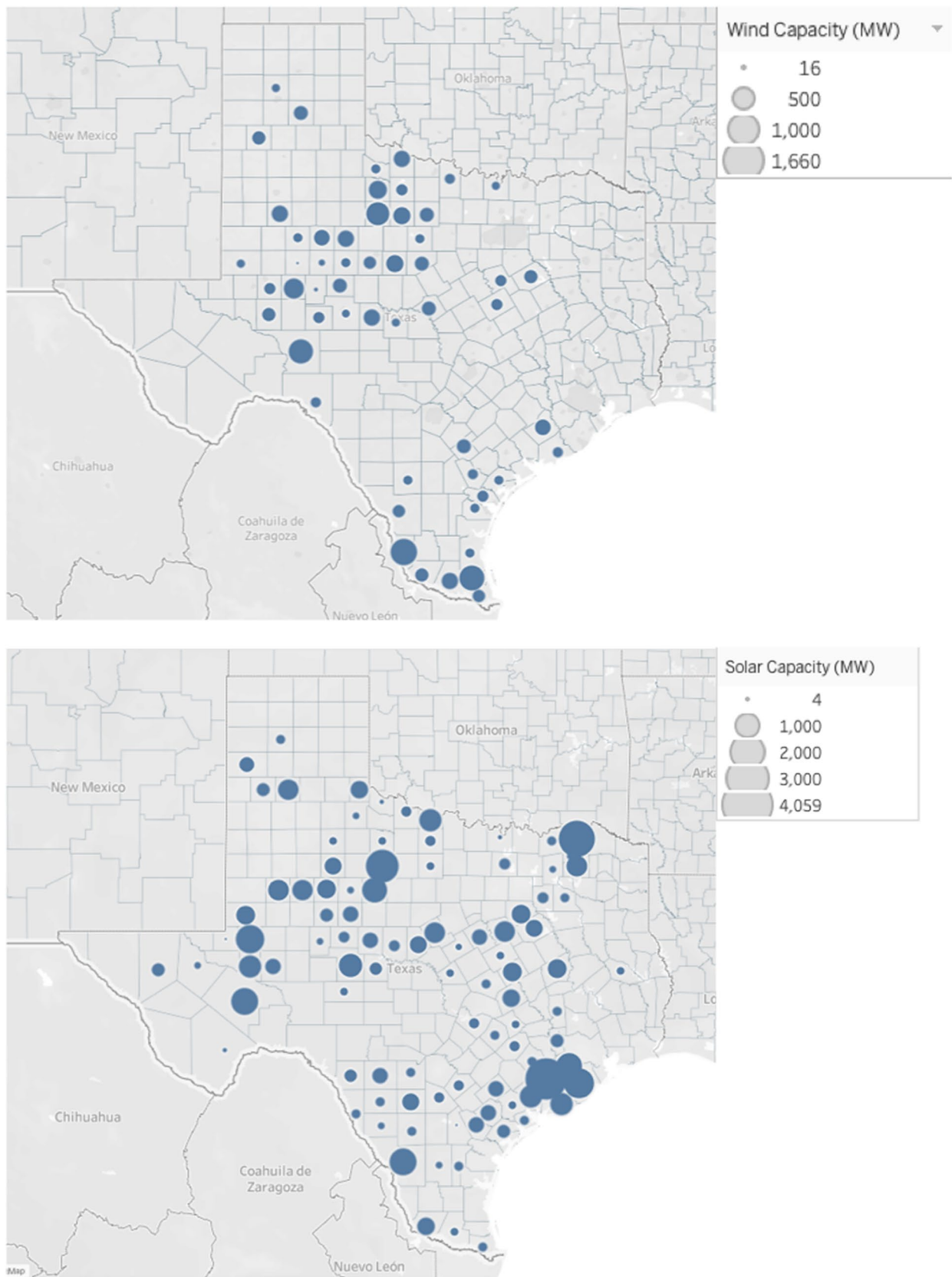


Fig. 3 (See legend on previous page.)

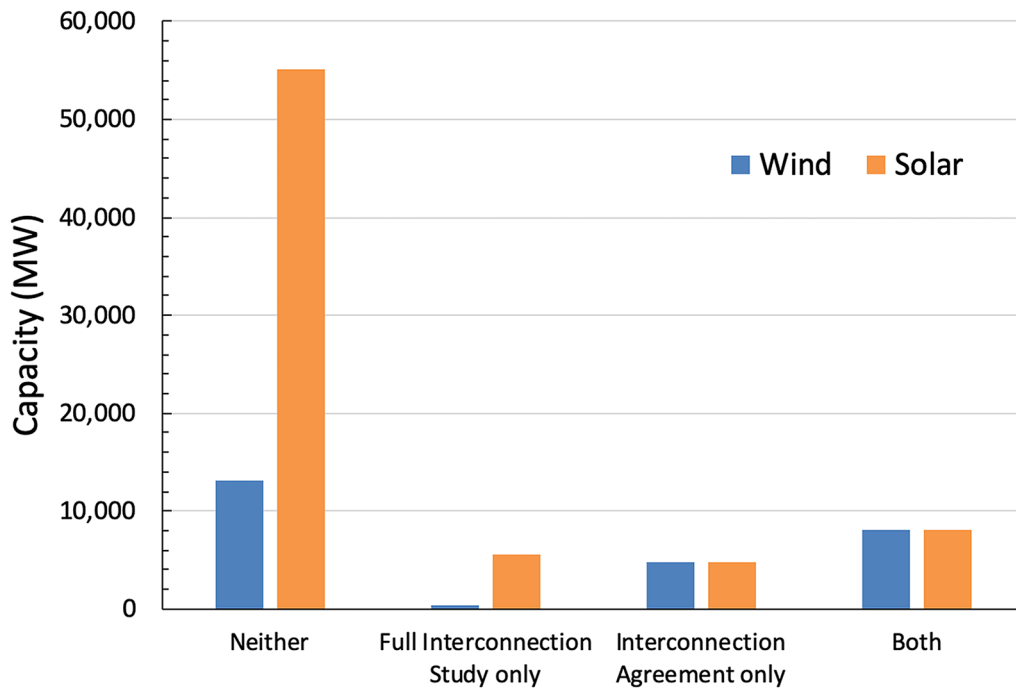


Fig. 4 Status of wind and solar projects in the ERCOT interconnection queue as of June 2020, indicating whether the full interconnection study (FIS) and interconnection agreement (IA) had been completed (ERCOT, 2020c)

Table 1 Wind and solar projects in the December 2018 and June 2020 interconnection queues, categorized by their status in April 2021

	Remained under review	Already approved ^a	Became approved ^b	Deactivated or canceled	Total
December 2018, wind	27	6	45	63	143
December 2018, solar	64	1	30	65	160
June 2020, wind	51	20	19	17	108
June 2020, solar	193	7	21	41	262

^a Already approved for energization, synchronization, and/or operation in initial report

^b Became approved for energization, synchronization, and/or operation between initial report and April 2021

online in 2019 (Bolinger et al., 2020), rather than the 1.0 assumed by Slusarewicz and Cohan. The 1.3 ratio means that 1.3 MW_{DC} of solar panels are installed for each 1.0 MW_{AC} capacity that can be supplied to the grid. All capacity, capacity factor, and cost data in this paper are reported on an AC basis.

Solar power capacity factors were simulated on the same 0.25-degree resolution grid of points used for wind. However, for counties with more than one grid point, we averaged solar capacity factors across those grid points, since variability within a county is typically small and not determinative of the siting of solar farms. Output was scaled by the capacity of each proposed project.

Costs

Costs were assumed to scale linearly with the capacity of proposed projects. Capital costs for new solar farms, and operation and maintenance costs for both wind and solar farms, were taken from the 2020 NREL Annual Technology Baseline (NREL, 2020), using the “moderate

Table 2 Estimated unsubsidized costs of new wind and solar farms in ERCOT (in 2018 dollars)

	Capital cost (\$/kW)	O&M cost (\$/kW-year)	Total Annualized Cost (\$/kW-year)
Wind	\$1,287	\$42.14	\$118.48
Solar	\$1,302	\$15.25	\$92.50

scenario” for facilities beginning commercial operation in 2021 (Table 2). Capital costs for wind farms were taken from the weighted average cost of wind farms installed in ERCOT in 2019 (Wiser et al., 2020), since that study provided the latest available region-specific data for wind.

Costs were converted to year 2018 dollars based on the U.S. consumer price index. We assumed a real after-tax weighted average cost of capital of 4.3% and a 30-year capital recovery period, consistent with EIA Annual Energy Outlook 2020 (Energy Information Administration, 2020a); that corresponds to a capital recovery factor of 5.93%. Total annualized costs were computed by multiplying capital costs by the capital recovery factor and adding it to operation and maintenance costs, resulting in the equation:

$$y = \$118.48w_c + \$92.50s_c \quad (1)$$

where y is the annualized cost in Year 2018 dollars, and w_c and s_c are the kilowatts of wind and solar capacity built. Tax credits and subsidies were ignored in these calculations, despite the current availability of a production tax credit for wind and an investment tax credit for solar, because the future availability of those credits is uncertain. Note that while we assume that the annualized costs per kilowatt of capacity are spatially uniform, spatial variations in capacity factors will lead to more output per unit of capacity and thus lower levelized costs per megawatt-hour at sites with better wind and solar conditions.

We do not explicitly model transmission costs. However, all projects in the queue have identified an interconnection point to the existing grid. Our solar cost estimates include the costs of local transmission substation upgrades (NREL, 2020), and our wind cost estimates include electrical interconnection costs (Form EIA-860). That omits costs to expand the high-voltage transmission system, which can range from zero to a few hundred dollars per megawatt of new generation capacity depending on where projects are built and the adequacy of the existing system (Andrade & Baldick, 2017). We also neglect changes in transmission congestion costs and associated curtailments. Consideration of these factors may lead projects to be built closer to load, where capacity factors may be lower than in our optimization.

Optimization modeling

We apply a Mixed Integer Program (MIP) to conduct our analyses. The advantages of mixed integer programming relative to other optimization methods for solving this type of problem are discussed by Pereira et al. (2016). A more formal presentation of the equations is provided in the supplemental information and summarized here. The integer decision variables are the binary choices of whether to build or not build each

of the wind or solar projects listed in the June 2020 ERCOT GIS Report. There are 108 wind and 262 solar projects, and thus 370 binary decision variables. Power output of the wind and solar projects is computed as described above. Wind and solar output estimates for each half-hour in 2009–2011 are compared to actual coal power output for the corresponding date and time of day in 2019. As noted earlier, lack of WIND Toolkit data for 2019, and sharp reductions in coal capacity prior to 2019, prompted our choice of mismatched years. Transmission constraints and line losses are ignored, and no storage is assumed to be added. Line losses averaged 5 percent for ERCOT in 2019, much of it for local distribution that would be little changed in our scenarios (EPA, 2020).

For each combination of wind and solar build decisions, we compute the amount of coal generation that would be left unreplaced (“slack”) within each half-hour period if all coal plants are retired and the selected wind and solar projects are built (Eq. 2):

$$slack_t = \max((coal_t - w_t - s_t), 0) \quad (2)$$

Note that $slack_t$ is the difference between the output of 2019 coal plants ($coal_t$) and the output of the selected new wind (w_t) and solar (s_t) projects during each corresponding half-hour t . The max function neglects surpluses of wind and solar in the computation of $slack_t$. Thus, the presence of surpluses does not influence the optimization in selecting a least-cost portfolio of projects, but is considered later in analyzing the output of that portfolio. Analysis was conducted both for wind and solar averaged over 2009–2011, and for each of those years individually, to explore the impact of meteorological variability.

We set a constraint that the aggregate amount of slack must be held below a specified percentage of annual coal output (Eq. 3):

$$\frac{\sum_t slack_t}{\sum_t coal_t} \leq p \quad (3)$$

The objective is to minimize the annualized costs of new wind and solar projects (computed via Table 2) while holding total slack below p . The coal-fired power to be displaced, $coal_t$, was highest during the summer, when output peaked during the afternoon; wintertime output exhibited a bimodal distribution with morning and evening peaks (Fig. 5).

The MIP was solved using Gurobi Optimizer 9.0.1. Computational time for each value of p was typically under 20 min on a 2018 MacBook Pro with a 1.4 GHz Intel Core i5 Processor. Gurobi is commercial software, available via no-cost academic license or for purchase.

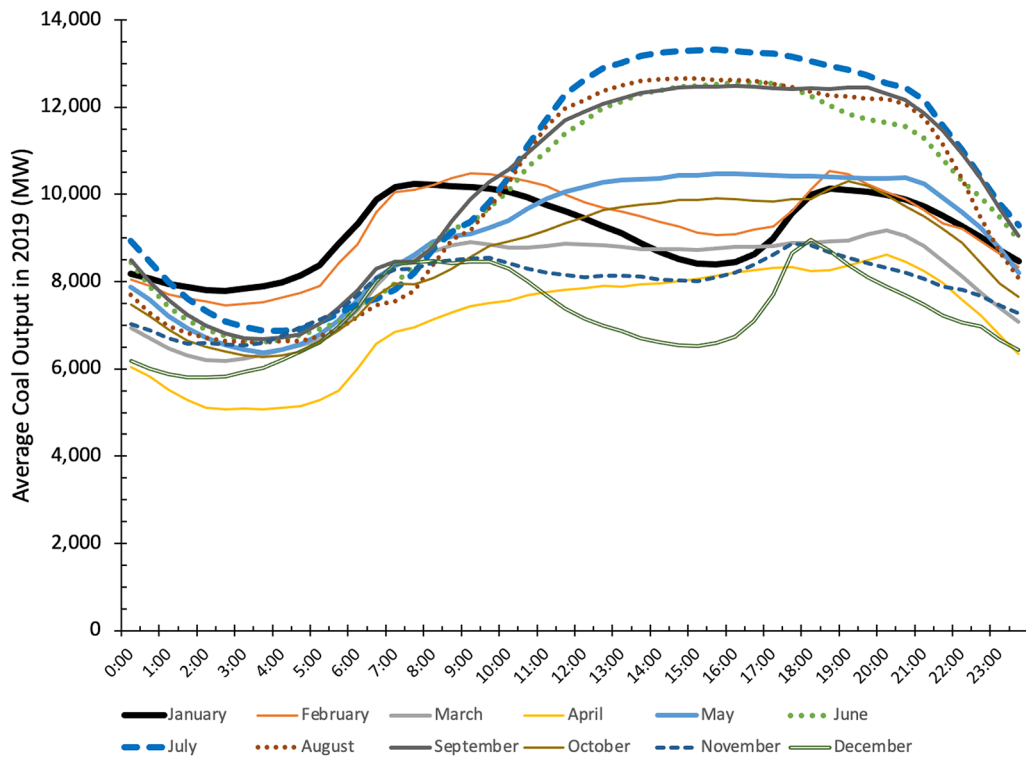


Fig. 5 Average coal-fired power generation by half-hour during each month of 2019 (ERCOT, 2021a)

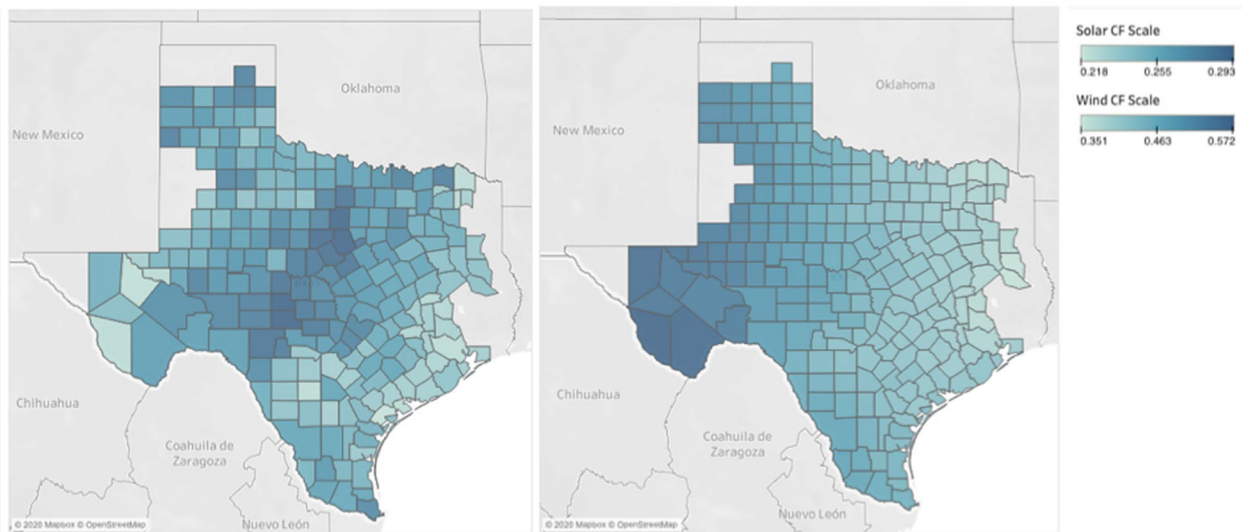


Fig. 6 Average capacity factors for wind (left) and solar (right), for each county in ERCOT, computed by the WIND Toolkit for wind and System Advisor Model for solar under 2009–2011 meteorology

Results and discussion

Capacity factors

Our county-level analysis based on the WIND Toolkit found that annual capacity factors can top 50% in portions of central Texas and the Texas Panhandle (Fig. 6a). Winds tend to be slower in east and south Texas, except in the southernmost counties near the coast. Our results are consistent with wind capacity factors observed at recently-built wind farms built in Texas, which have averaged 42% and topped 50% at some sites (Wiser et al., 2020), and slightly higher than estimates from Kumler et al. (2019).

County-level analysis of solar capacity factors with SAM showed values ranging from 28% in eastern Texas to 36% in the sunnier western portions of the state

(Fig. 6b). Note that solar capacity factors are lower than wind capacity factors on an annual basis but are also less spatially variable (Fig. 6a). Our results are consistent with capacity factors reported for recent solar projects (Bolinger et al., 2020), but roughly one-third higher than studies (Kumler et al., 2019; Slusarewicz & Cohan, 2018) that neglected the 1.3 DC-to-AC inverter loading ratio that is typical of recent projects (Bolinger et al., 2020).

Since our focus here is on replacing the time-varying output of coal plants throughout the year, temporal variations in wind and solar output are crucial to identifying sites whose output is complementary. During the winter, winds blow most strongly at night throughout Texas, with western regions outperforming other regions at night and coastal regions outperforming

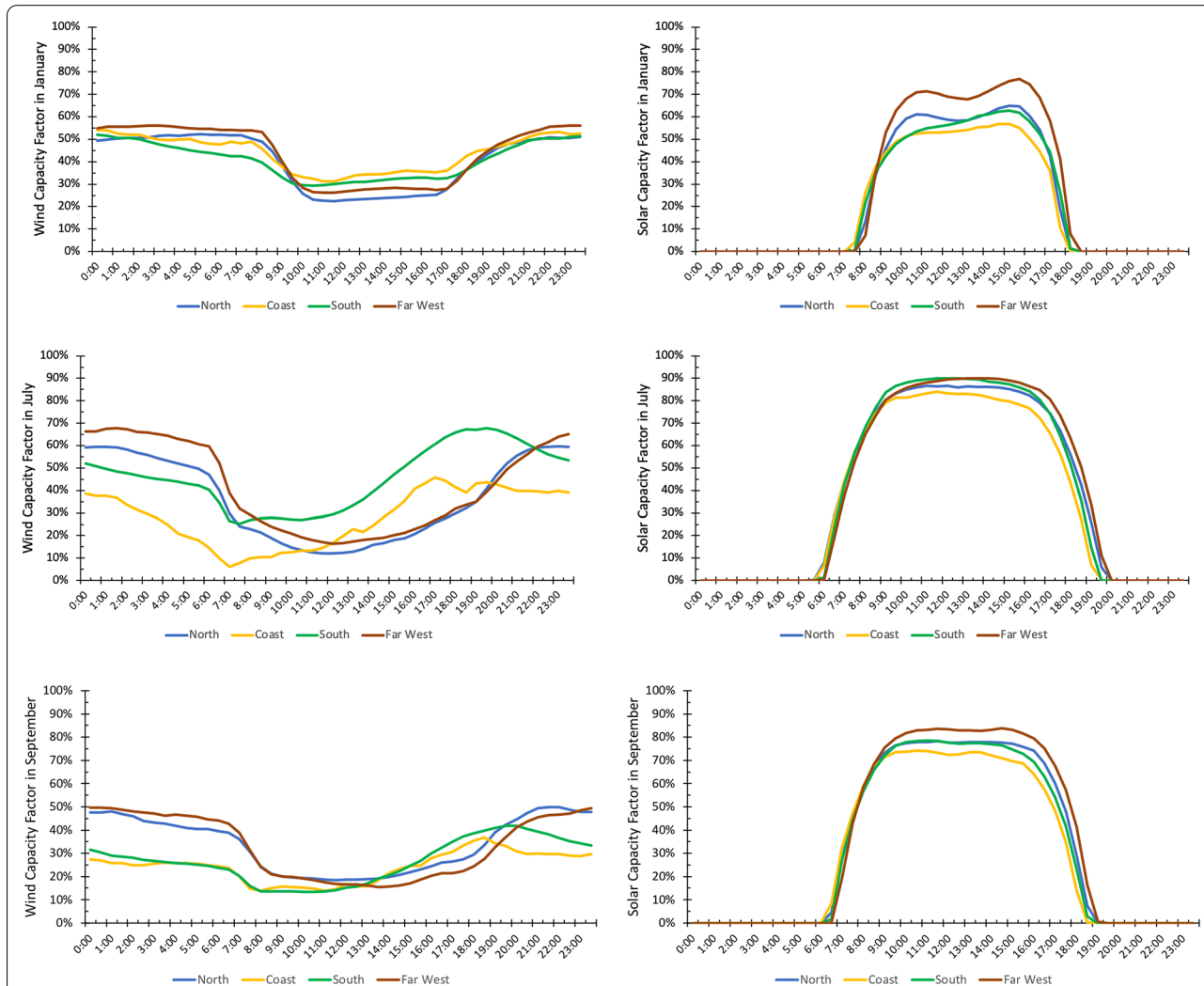


Fig. 7 Average regional capacity factor of wind (left) and solar (right) sites in ERCOT interconnection queue in peak demand months of January (top), July (middle), and September (bottom), based on half-hourly output from the WIND Toolkit for wind and System Advisor Model for solar under 2009–2011 meteorology

other regions during the afternoon (Figs. 2 and 7). During the summer, diurnal patterns of wind output are far more spatially variable, peaking at night in inland regions and during the afternoon and evening in southern and coastal weather zones (Figs. 2 and 7). Wind output is weakest in September (Fig. 7). Southern and coastal winds peak during summer afternoons and evenings (Fig. 7) when demand and coal output tend to be high, but interior regions yield higher annual wind capacity factors (Fig. 6).

Diurnal patterns of solar output are more consistent than wind across regions, peaking during daytime hours and with higher capacity factors during the summer as expected (Fig. 7). Solar output is shifted by nearly an hour from east to west due to timing of sunrise and sunset. Due in part to the inverter loading ratio, solar farms across Texas can achieve capacity factors above 50% throughout most daytime hours during the winter, and above 80% during the summer. The complementarity of wind and solar is readily apparent in Fig. 7, with the inversely correlated patterns during the winter and the mix of nighttime peaks from inland wind, daytime peaks from solar, and evening peaks from southern and coastal wind during the summer, consistent with Slusarewicz and Cohan (2018). For image clarity, only the north, coast, south, and far west weather regions are plotted in Fig. 7.

Diurnal patterns in the unplotted regions—north central, south central, and west—resemble patterns in the similarly-named plotted regions—north, south, and far west, respectively. The east region has no wind projects in the ERCOT queue, and its solar output resembles coastal solar (Fig. 6).

Optimization modeling

Building all 108 wind and 262 solar projects in the ERCOT interconnection queue and closing all coal plants would leave a slack (p) of 3.5% of the 2019 coal load uncovered, based on meteorological conditions in 2009–2011. Wind and solar would exceed coal output at other times, since a total of 83 GW of new renewable power capacity would replace 15 GW of coal. This would result in a net surplus averaging more than 180,000 GWh per year (21 GW of power) and an aggregate cost for new wind and solar of \$8.28 billion per year, based on the cost estimates in Table 2. It seems implausible that all wind and solar projects in the queue would be built, since their output together with existing non-coal supply would exceed demand much of the year. Furthermore, a large fraction of projects in the ERCOT queue historically has not been built (Table 1) (Rand et al., 2021).

Our MIP optimization modeling identified combinations of wind and solar projects that would hold slack from coal below various thresholds p . Note that

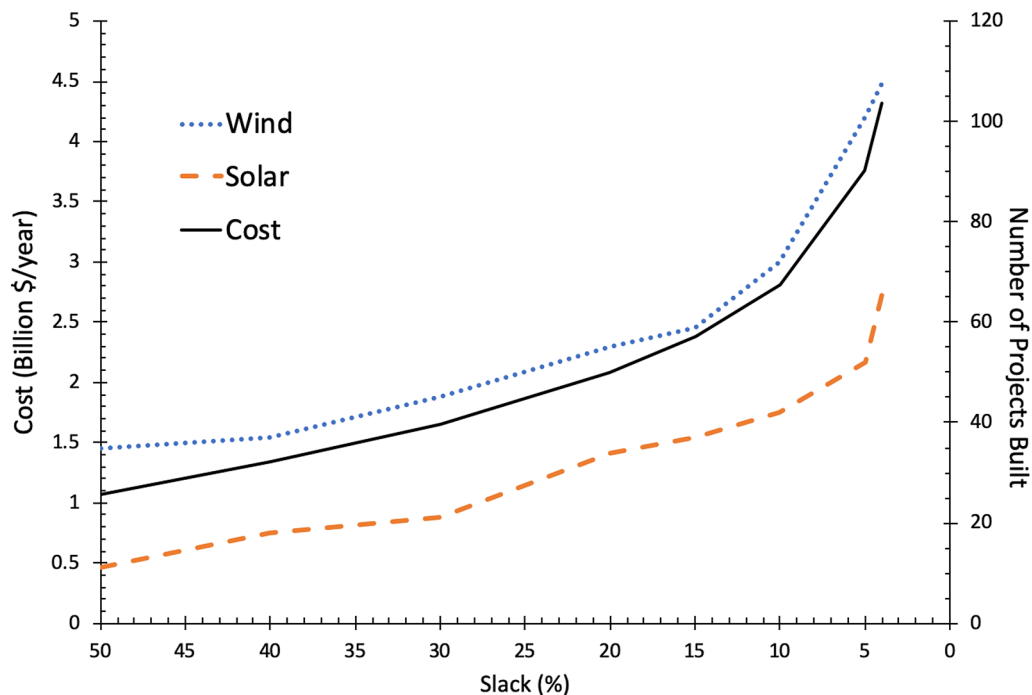


Fig. 8 Annual cost (black, in Year 2018 USD) and number of wind (blue) and solar (orange) sites from the interconnection queue optimized to replace coal with each percentage of slack

calculations of slack (Eq. 2) neglect surplus at times when new wind and solar output exceed coal. Plotting aggregate annualized costs of new wind and solar projects as a function of slack shows that costs increase almost linearly until slack is ratcheted down to near 10% (Fig. 8). Costs accelerate nonlinearly beyond that point, as less productive wind and solar projects must be added and remaining slack is mostly at dark and non-windy times. Thus, we focus the remainder of our analysis on a scenario with 10% slack, i.e., 90% of 2019 coal output is covered, and surpluses may occur at other times.

Least-cost displacement of 90% of coal output (10% slack) would require the construction of 72 of the 108 wind projects, and just 42 of the 262 solar projects from the interconnection queue (Figs. 8 and 9). That corresponds to 15,798 MW of new wind capacity and 10,156 MW of new solar capacity. The unsubsidized annualized cost of those projects is \$2.81 billion, or just one-third of the aggregate cost of all projects in the queue. Although building these wind and solar projects and eliminating coal would leave 7,785 GWh of slack to be covered by other sources annually, it would yield 27,431 GWh of annual surpluses at other times. Thus, demand for natural gas or other resources would be reduced overall, and new storage or other resources are needed only if the timing or location of output is problematic, as we examine in subsequent discussion.

Levelized costs for the wind and solar projects were computed by dividing annualized costs by average annual output under 2009–2011 meteorology. Projected

unsubsidized costs range from \$24.19 to \$38.26 per MWh for wind and from \$29.29 to \$38.11 per MWh for solar, with wind projects cheaper in most cases. Wind and solar projects selected in the 10% slack scenario tended to have lower levelized costs than unselected projects, with some exceptions driven by the need for complementary output (Fig. 10).

Figure 11 shows power output under a scenario of eliminating all coal (white boxes) and adding wind (light blue) and solar (light orange) output from the 10% slack scenario in January and July. Other components of Fig. 11 display the output of each other power source in the 2019 ERCOT fuel mix (ERCOT, 2021a). Overall power output under our scenario (heavy black line) would at most times be higher than actual output in 2019 (red line). During January, surpluses would occur during daylight hours when solar output is strong, and slack would occur most prominently in the hours immediately before sunrise and after sunset. In July, new wind and solar output closely match coal, with slight surpluses in the morning and late afternoon and slack after sunset. In each case, slack occurs when demand is well below the annual peaks, easing the burden of replacing it with other resources.

A fuller picture of how replacement of coal with new wind and solar would shift the burden on other resources is shown in Fig. 12, which plots the amount of year 2019 load not covered by coal (red) or by the new wind and solar that would be added to replace coal in the 10% slack scenario (black). In most months, replacing coal with new wind and solar reduces the residual load to be

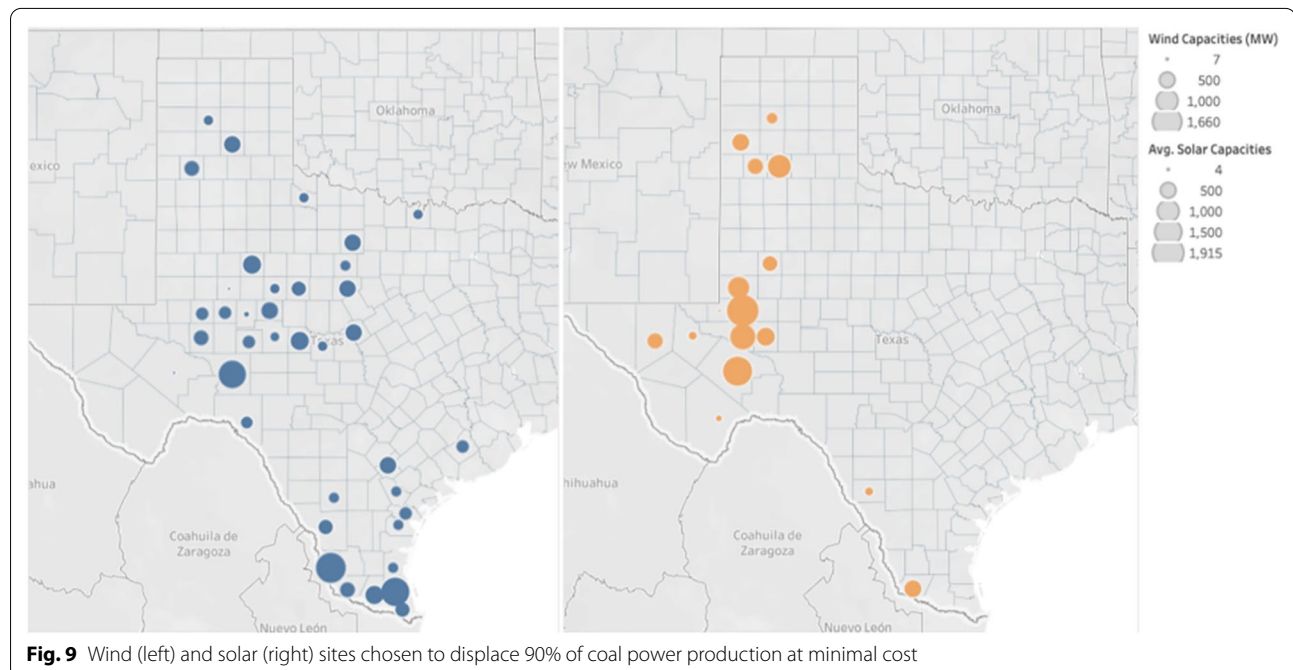


Fig. 9 Wind (left) and solar (right) sites chosen to displace 90% of coal power production at minimal cost

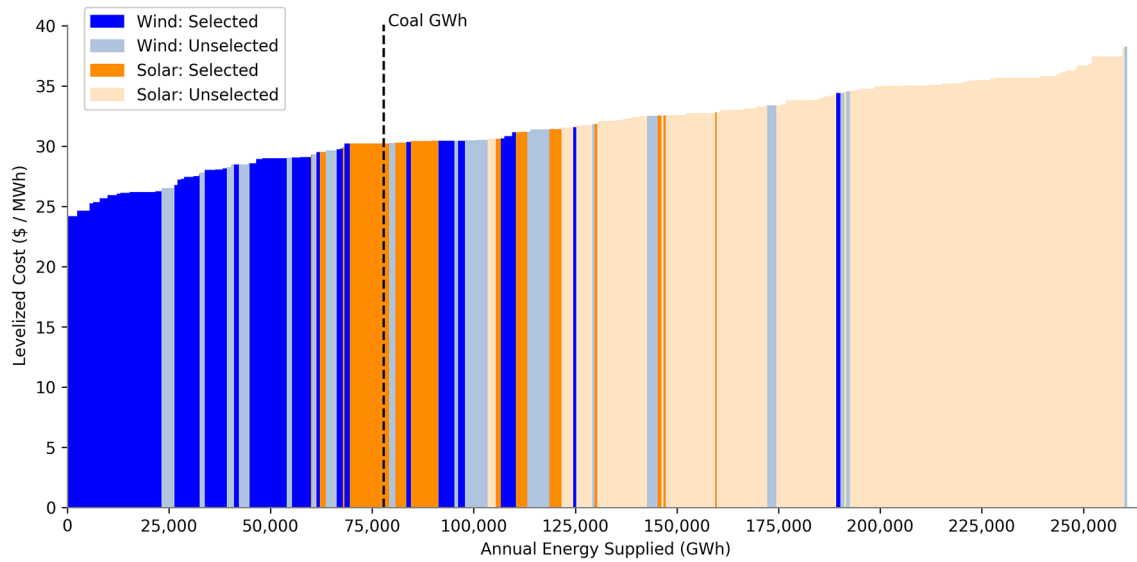


Fig. 10 Levelized unsubsidized costs of selected (dark) and unselected (light) wind (blue) and solar (orange) projects in the 10% slack optimization, plotted in least-cost order

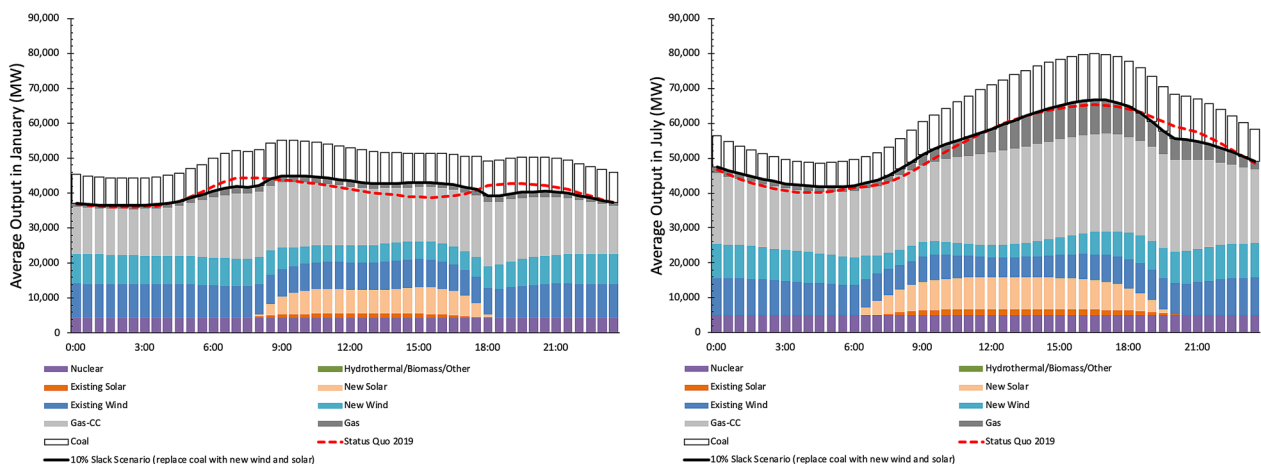


Fig. 11 ERCOT average daily fuel mix under the 10% slack scenario, with new wind (light blue) and solar (light orange) added and all coal (white boxes) removed, resulting in output shown by the heavy black line, compared to actual generation in 2019 (red line) for January (left) and July (right)

covered by gas and other resources (i.e., black curve is beneath red curve). Only September has substantial net slack, as winds are relatively weak. However, a mild “duck curve” (Jones-Albertus, 2017) emerges in winter and spring months, with minimal load mid-day when solar is strong and a need to ramp up other resources as the sun sets (Fig. 12). In the summer months, the scenario reduces peak net load in the afternoon, but slack emerges in the evening.

Even though our wind and solar scenario provides more power overall than the existing coal fleet,

including surpluses on most afternoons, it is important to examine occasional lulls in wind and solar output that might be difficult for other resources to cover. The portfolio is modeled to have a 43% average capacity factor overall under 2009–2011 meteorology, so we set 20% as a threshold for defining lulls in output (Table 3). Output fell below that threshold on 8.8% of all half hours in our modeling, including 2% of half hours with capacity factor below 10%. During summer 2011, a season of record heat and drought, capacity factors remained consistently above 30% from 10 a.m. to 6 p.m.

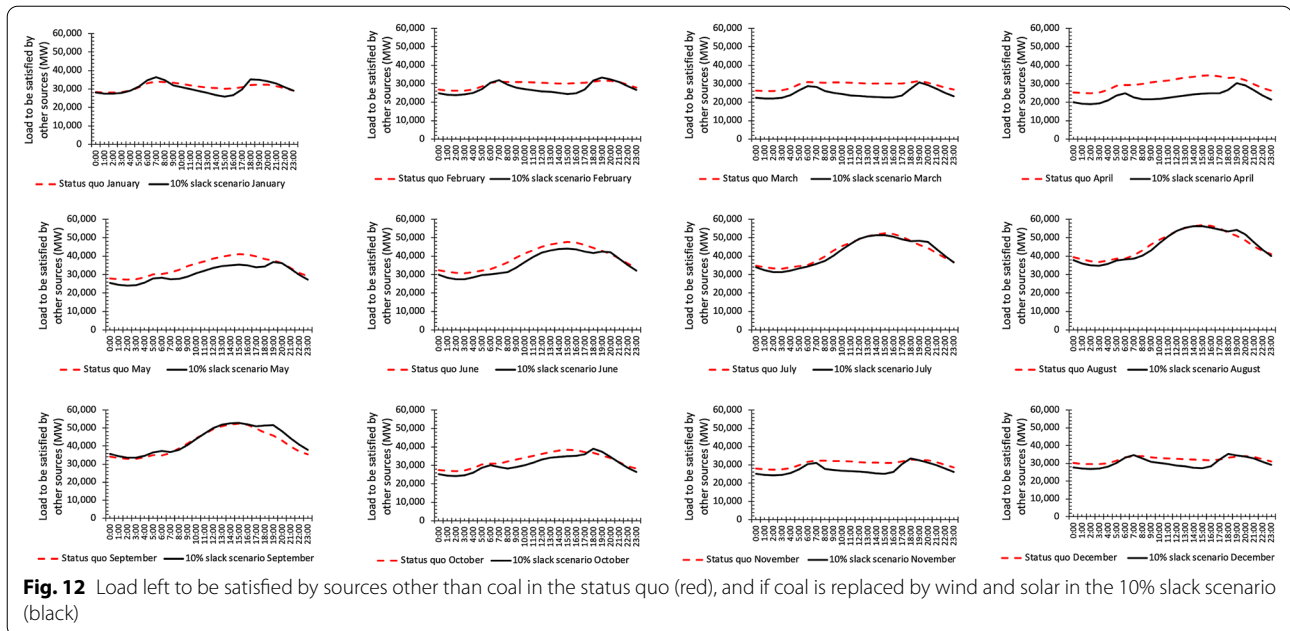


Table 3 Frequency of low output from the wind and solar scenario in 2009–2011, and the average and maximum load during those times

Capacity factor	Frequency	Average load (MW)	Max load (MW)
< 5.00%	0.4%	31,172	46,058
5–10%	1.6%	32,008	48,553
10–20%	6.8%	32,940	60,303
> 20.00%	91.2%	36,882	68,318

every day. Most lulls in renewable output come on fall and spring nights, when power demand tends to be low. In fact, the maximum load in 2009–2011 at times when renewable output would have been below 10% was 20 GW lower than the overall maximum load (Table 3). If this pattern of low load during the deepest lulls in wind and solar holds true, then other existing power sources, including the 5 GW of nuclear and 49 GW of natural gas that was operational as of summer 2021 (ERCOT, 2021c), could cover those lulls even if all 15 GW of coal is retired, unless there are new record weather extremes or equipment malfunctions such as those that caused the February 2021 blackouts. It should be noted that coal has often failed to perform during extreme events, including 38% that was offline in February 2021 (Storow, 2021).

Another challenge in replacing coal with wind and solar is the need for other sources to ramp up when renewables output falls abruptly (Jones-Albertus,

2017). The complementary nature of wind and solar power in Texas mitigates but does not eliminate abrupt declines. In our scenario, renewable capacity factor fell by at least 20 percentage points (i.e., 5.2 GW) in an hour on 16.6% of all evenings. However, such rapid fall-offs are modeled to occur on only 1.4% of evenings in the summer, when sea breezes compensate for the setting sun.

Regional transmission

Since our optimization ignored transmission constraints, it favored solar projects in the westernmost, sunniest portions of ERCOT (Figs. 6 and 9). Meanwhile, the optimization chose a more diverse set of wind projects, blending central and western sites, where annual capacity factors are highest with complementary southern and coastal sites. By contrast, most coal power plants are located in eastern and central Texas (Fig. 1). To quantify coal output by zone, we used Acid Rain Program data for plant-level gross coal load (EPA, 2021) to apportion net coal output data for 2019, which ERCOT provides data only on a systemwide basis (ERCOT, 2021a). As shown in Fig. 13, replacing coal with our wind and solar 10% slack scenario would produce more energy in the west, far west, south, and north zones, but less energy in the north central, coast, and south central zones, where load is highest. Thus, more power would need to be transmitted from windy and sunny areas to urban regions. Quantification of needs for new transmission capacity is beyond the scope of this study and deserves further research.

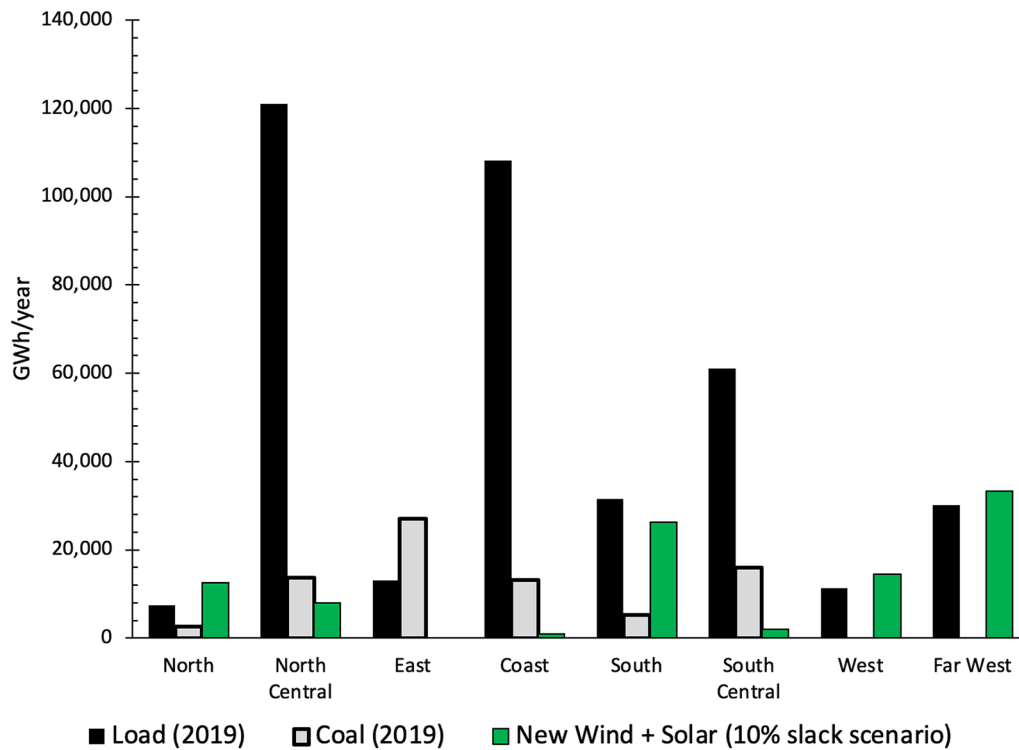


Fig. 13 Overall load and coal output in 2019 compared to wind and solar output added in the 10% slack scenario, aggregated by ERCOT weather zone

Interannual variability

The optimizations described above were conducted based on meteorology from 2009 to 2011. To explore interannual variability, we repeated the 10% slack optimizations with 2 years of meteorological data, and then examined how they would have performed under the third (withheld) year of data. This analysis showed only slight variability in the wind and solar projects that would be selected. Scenarios optimized to leave 10% slack in the two training years would leave 7.5–11.9% slack in the third (“test”) year (Table 4). This indicates that the effects of interannual variability in meteorology on our optimization are modest, at least within 3 years considered here. Longer term studies have found that interannual

variability in wind output, though significant, is far smaller than synoptic variability (Pryor et al., 2018, 2020).

Conclusions

Retirements of coal-fired power plants in ERCOT could avert the several hundred deaths (Henneman et al., 2019; Strasert et al., 2019) and hundreds of millions of tons of pollution that they now cause each year. This study demonstrates that a mere subset of wind and solar projects already in the interconnection queue are sufficient to replace all the output from those plants under two key conditions—adequate transmission, and reliable and flexible operation of existing resources. Our scenario entails the construction of less than half

Table 4 Slack that would be left in the test year from wind and solar projects optimized to leave 10% slack in the training years

Test year	Training years	Slack in test year	Solar sites	Wind sites	Cost (Billion \$)
2009	2010–11	11.9%	42	71	2.75
2010	2009, 11	11.1%	39	72	2.77
2011	2009–10	7.5%	44	74	2.91

as much wind and solar capacity as a coal replacement scenario developed by Michaelides (2019), which ignored opportunities to minimize costs by siting projects in locations with complementary timing of wind and solar output.

Simply put, it's not always windy and not always sunny, but it's almost always windy or sunny somewhere in Texas. Lulls of simultaneously weak winds and darkness occur mainly during hours (evening) and months when demand is at moderate rather than peak levels, easing the burden on other resources that would supplement wind and solar if coal is retired. Still, a reliable power supply will depend on adequate transmission, other resources operating reliably and flexibly, and all resources being adequately weatherized to perform as intended through extreme events.

Actual development will not follow the specifics of our optimization. New projects will continue to be added to the interconnection queue as others are built or canceled (Rand et al., 2021). Developers will choose projects based on profitability, availability of transmission, and other factors, not on propensity to replace coal. Profitability depends on time-varying prices for electricity, tax policies, and other factors that were not considered here.

Robust transmission is essential to replacing coal with wind and solar. This study treated the entire ERCOT grid as one region, with transmission occurring throughout the state with the same line losses as in the status quo and without congestion bottlenecks or curtailments of wind and solar output. By focusing on actual projects within the interconnection queue, we ensured that tie-in points to the grid have indeed been identified. However, further research should explore the expansions in high-voltage transmission capacity that may be needed to bring power from those tie-in points to consumers. In particular, what's needed is transmission from windy and sunny regions in the west and south to urban regions in the east. Transmission needs could be reduced by siting more projects in the eastern half of the state, where dozens of solar farms have already been proposed (Fig. 3). Although our optimization shunned eastern solar projects in favor of sunnier sites in the west, their capacity factors are projected to be only around one-fifth lower than selected projects (Fig. 6), with leveled costs correspondingly higher (Fig. 10). Thus, in the absence of expanded transmission capacity, eastern solar projects could win favor for their proximity to urban regions and legacy coal sites.

Further research should study interannual variability in meteorology beyond 3 years considered here. Research should also explore opportunities for storage

to balance the variability of wind and solar output, avert curtailments, and provide power during evenings and extreme events (Denholm & Mai, 2019; Solomon et al., 2020; Ziegler et al., 2019).

Abbreviations

EIA: U.S. Energy Information Administration; EPA: U.S. Environmental Protection Agency; ERCOT: Electric Reliability Council of Texas; NREL: National Renewable Energy Laboratory; SAM: System Advisor Model; WIND: Wind Integration National Data Set.

Supplementary Information

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Additional file 1. Optimization model.

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Authors' contributions

Richard Morse conducted the optimization modeling, wrote the initial draft of the manuscript, and helped revise the manuscript. Sarah Salvatore plotted results of the analysis. Joanna H. Slusarewicz assisted with modeling of wind and solar output. Daniel Cohan was the principal investigator for this project, guiding its direction and contributing to the writing and revising of the manuscript.

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Availability of data and materials

The System Advisor Model and WIND Toolkit are available free of charge from NREL. All ERCOT data are also publicly available. Results and code for our analysis are available at <https://github.com/rmorse7/Can-wind-and-solar-replace-coal-in-Texas>.

Declarations

Competing interests

The authors declare that they have no competing interests.

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