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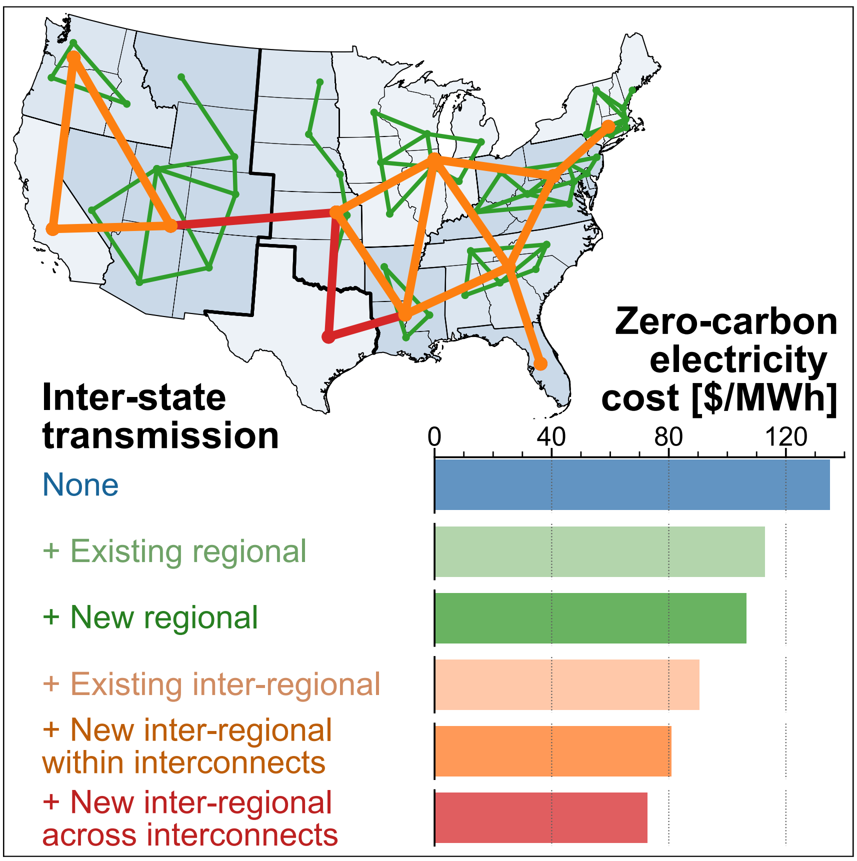
The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System



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HIGHLIGHTS

US electricity demand can be met with currently available zero-carbon technologies

Inter-regional coordination and transmission construction significantly reduce cost

Nuclear, if available, plays a smaller role than renewables at central cost projections

Nationally planned decarbonization is more efficient than state or regional approaches

Rapid decarbonization of electricity is a critical component of climate change mitigation. We model zero-carbon electricity systems for the continental US using technologies currently deployed at gigawatt-scale—solar, wind, existing hydropower, lithium-ion batteries, and transmission. Inter-state operational coordination reduces the cost of decarbonization; allowing new inter-state transmission reduces cost further. Nuclear power and long-duration energy storage have the potential to reduce system cost but are not necessary for decarbonization; all sensitivity cases deploy hundreds of gigawatts of new solar and wind.

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The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System

Patrick R. Brown[1,3,*] and Audun Botterud[2]

SUMMARY

Preventing global warming in excess of 1.5°C–2°C requires a transition to zero-carbon electricity systems by midcentury along with the widespread electrification of other sectors. Current state-level renewable portfolio standards and regional transmission arrangements do not capture the benefits of inter-regional transmission or coordination of planning and dispatch for renewable-energy integration. Here, using a co-optimized capacity-planning and dispatch model over 7 years of hourly operation, we show that inter-state coordination and transmission expansion reduce the system cost of electricity in a 100%-renewable US power system by 46% compared with a state-by-state approach, from 135 $/MWh to 73 $/MWh. Sensitivity analyses show that reductions in the cost of photovoltaics, wind, and lithium-ion batteries lead to the lowest electricity costs for systems in which transmission expansion is allowed, while cost reductions for nuclear power or long-duration energy storage lead to greater electricity cost reductions for isolated systems.

Context & Scale

Averting the worst effects of climate change requires decarbonizing the electricity sector as rapidly as possible. Given the urgency of action and the uncertainty inherent in new technology development, it is prudent to explore zero-carbon electricity systems limited to technologies currently being deployed at gigawatt-scale. Here, we model zero-carbon electricity systems for the continental US using solar photovoltaics, wind power, existing hydropower, lithium-ion batteries, and transmission, incorporating 7 years of hourly weather data from tens of thousands of available sites. New and existing long-distance transmission significantly reduces the system cost of electricity and the amount of energy storage required for reliable zero-carbon electricity. Streamlining the planning and permitting process for new transmission and coordinating decarbonization at the national (rather than state) level could enable a more efficient and rapid transition to a zero-carbon electricity system.

INTRODUCTION

Stabilizing global warming below 1.5°C–2°C necessitates reducing net anthropogenic greenhouse gas emissions to zero by the middle of this century.[1] Many analyses suggest that the electricity sector will need to decarbonize most rapidly, concomitant with electrification of other sectors.[2] Given the short time frame for power-system decarbonization and the long development times for new technologies and supply chains, there is a need for analyses demonstrating zero-carbon power-system pathways using technologies currently deployed at gigawatt-scale to prepare for the possibility that nascent technologies, including next-generation nuclear fission, carbon capture and long-term sequestration (CCS), and grid-connected hydrogen turbines or fuel cells, are delayed or unavailable at a large scale. Zero-carbon technologies currently deployed at gigawatt-scale in the United States (US) include onshore wind power (104 GW installed capacity at the end of 2019), nuclear power (103 GW), hydropower (80 GW), photovoltaics (36 GW), geothermal (3.8 GW), and concentrated solar thermal power (1.6 GW), and ancillary technologies including alternating-current (AC) and direct-current (DC) transmission, pumped-hydropower storage (PHS) (22 GW), and electrochemical batteries (1.0 GW).[3]

Modeling zero-carbon electricity systems for the US, particularly those relying on high penetrations of variable renewable energy (VRE, including wind and solar power) and storage, presents numerous challenges.[4,5] Large (continent-scale) geographic coverage is necessary to represent spatiotemporal correlation in weather systems and the long-range interconnected nature of the US electricity

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grid;[6–8] large (multi-year) temporal coverage is required to account for interannual weather variability and ensure resource adequacy during uncommon low-resource weather events;[8–11] fine ($\leq 1h$) temporal resolution is required to represent VRE variability and storage operation; and chronological time coupling is required to represent storage energy constraints, the combined capacity value of VRE and storage, and generator ramp rates in systems employing nuclear power.

Numerous optimization models[12,13] and a significant body of literature[4,5,14] address the optimal design of low- and zero-carbon electricity systems for the US. These models and studies can roughly be divided into two classes. One class employs high geographic resolution (10–100 zones), explicit representation of transmission investment and power flow, relatively low temporal resolution for capacity planning (typically tens to hundreds of "time slices"), and a multi-period sequential-investment framework, typically to model systems up to ~80% decarbonization.[15–20] The second class tends to employ low geographic resolution (often a single-zone "copper-plate" system), limited or no representation of transmission, high temporal resolution (hourly chronological time steps, often for a single year but sometimes over multiple years), and a single-period steady-state framework to model systems up to 100% decarbonization—in some cases for the entire US,[8,21] and in others for isolated sites,[10] states,[22] or regions.[23,24] MacDonald et al. partially bridge this divide,[25] combining hourly resolution with zonal transmission expansion, but do not exceed 80% decarbonization. Other studies explore zero-carbon systems for Europe,[26–29] including the recent work of Tröndle et al.,[30] which explores the impact of VRE siting policy and transmission availability on system cost (albeit for a single year at four-hour resolution). For the reasons noted above, both high temporal resolution and an explicit representation of transmission are necessary for accurately modeling low- and zero-carbon electricity systems for the US.

Here, we employ a linear optimization model with hourly resolution over 7 years of historical weather (2007–2013) to explore zero-carbon electricity systems for the US, co-optimizing capacity investments and hourly operation of generation, storage, and transmission to meet projected electricity demand in 2040. Transmission costs and constraints at the national scale are addressed using a hierarchical approach, first determining inter-state transmission investment within 11 regional planning areas (PAs), then optimizing inter-PA transmission investment and hourly flows for an interconnected US system. We find that a zero-carbon power system is feasible at the level of hourly system balancing using technologies deployed today (photovoltaics [PV], wind, transmission, Li-ion batteries, and hydropower) at all spatial scales considered, from isolated states to PAs to the interconnected US system. Inter-state and inter-regional coordination of capacity-planning and dispatch, as well as the construction of new inter-state transmission capacity, significantly reduce the cost of decarbonization. Sensitivity analyses show that, while flexible nuclear power and "long-duration" (low-energy-cost and low-self-discharge-rate) storage have the potential to reduce the cost of decarbonization, they are not required to reach a zero-carbon system and have less impact on system cost than continued reduction in the price of PV, wind, and Li-ion batteries when full transmission expansion is allowed.

Analytical Approach

Renewable-Energy Supply Curves

Modeling the expansion of PV and wind capacity requires assessing the available land area for new deployment. We develop supply curves of available land area for PV and wind development, excluding water bodies,[31] national parks,[32] urban

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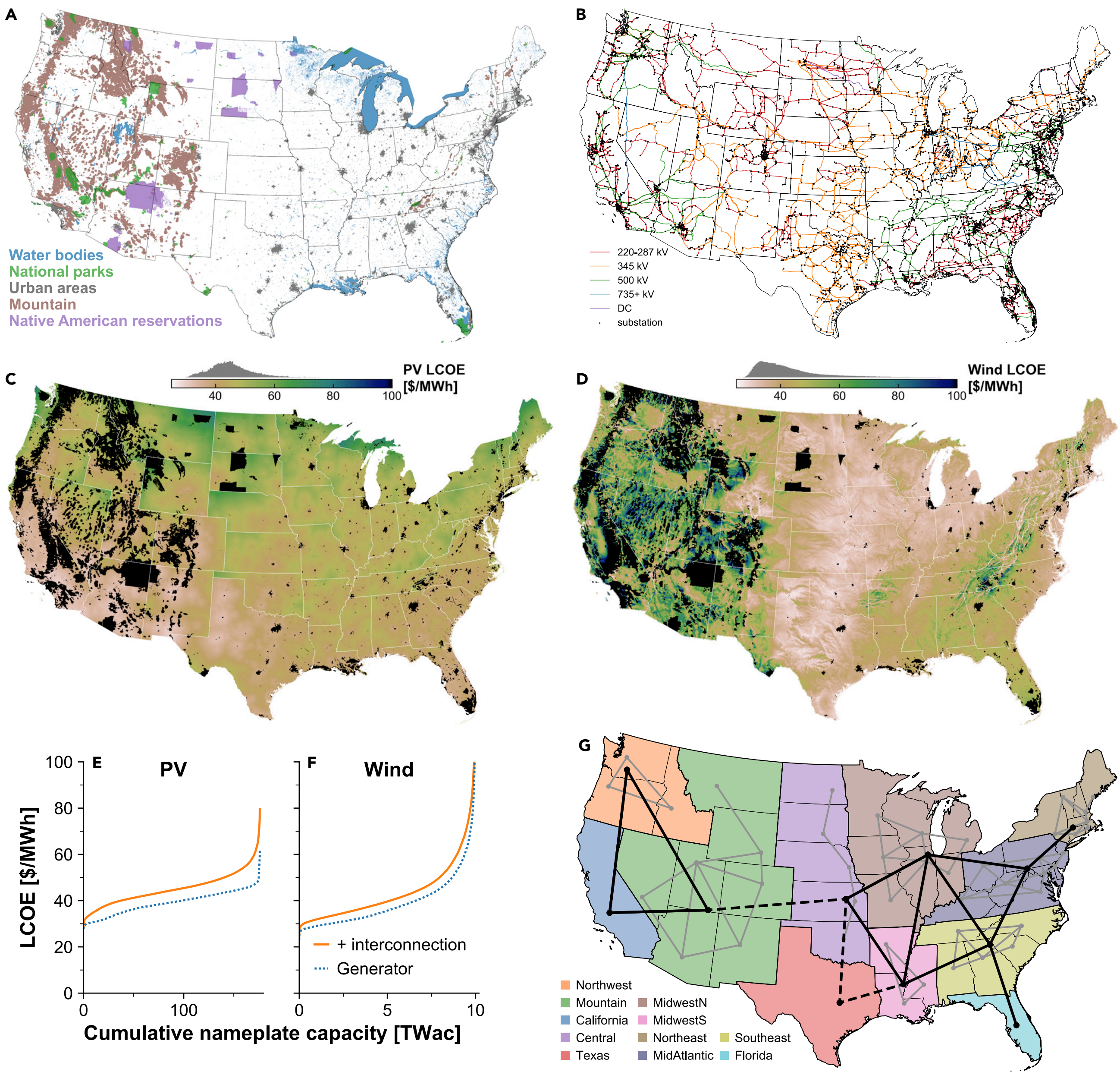

Figure 1. Geospatial Input Assumptions for VRE Availability and Power System Topology for the Continental US.

(A) Land exclusions.[31–35] Excluded areas are indicated by colored areas; white areas are assumed to be available for solar and wind deployment.

(B) Existing transmission lines (colored lines) and transmission substations (black circles).[76] Interconnection costs are calculated based on the distance from solar and wind sites to substations and the distance from substations to urban boundaries in (A), as described in the Supplemental Information.

(C and D) Maps of the LCOE for 41,990 PV sites (C) and 416,859 wind sites (D), including the site-specific cost of interconnection to in-state substations.

(E and F) Supply curves of PV sites (E) and wind sites (F) sorted by site-specific LCOE, excluding (blue dotted lines) and including (orange solid lines) interconnection costs.

(G) PA boundaries and transmission system topology assumed for the capacity-planning model in this study. Inter-state intra-PA transmission is denoted by gray lines; inter-PA transmission is denoted by black lines. Solid lines denote AC connections; dashed lines denote DC connections. All costs in (C)–(F) and in the remainder of this work are in 2017 US dollars.

areas,[33] mountain ranges,[34] and Native American territories[35] from development (Figure 1A) and quantifying the interconnection cost of "spur lines" to connect to existing transmission infrastructure (Figure 1B).

The hourly capacity factor (CF) of horizontal 1-axis-tracking PV over 2007–2013 is simulated using satellite data from the National Solar Radiation Database (NSRDB)[36,37] for 41,990 sites across the continental US; the hourly CF of wind is simulated using climate reanalysis data from the WIND Toolkit and manufacturer power curve data for the Gamesa:G126/2500 turbine at 100-meter height for 416,859 sites. Figures 1C and 1D show maps of the calculated levelized cost of electricity (LCOE) across the modeled sites assuming 2030 "mid" cost projections from the 2019 NREL Annual Technology Baseline (ATB),[38] and Figures 1E and 1F show the cumulative available capacity sorted by LCOE, applying areal power densities representative of current installations. Further details are provided in the Supplemental Information (Note S2).

Capacity-Planning Model

The capacity-planning model minimizes the sum of annualized capital costs and hourly operational costs over 7 years of hourly operation using 2007–2013 weather data, subject to constraints on hourly demand balance, hourly VRE availability, available PV and wind capacities, storage energy balance, transmission flows, and hydropower availability. Using the "steady-state" framework discussed above, we include long-lived "brownfield" hydropower and transmission assets while treating all other generators as "greenfield" assets, and we do not consider limits on annual capacity deployment. The model improves upon previous work by combining hourly resolution, interannual variability (across 7 years in central cases and up to 21 years in the Supplemental Information [Note S5.2]), explicit modeling of transmission flows, and site-specific VRE interconnection costs with an extensive sensitivity analysis over more than 370 independent cases. Details regarding the model formulation, assumptions, and input data are provided in the Supplemental Information (Note S3), with open-source computer code available in the associated repository.

Hourly electricity demand projections by state are obtained from the NREL Electrification Futures Study, using the 2040 "reference" electrification scenario with "slow" technology advancement.[39,40] Cost and performance assumptions for generation and storage technologies are provided in Table 1; we use 2030 "mid" cost projections from the 2019 NREL ATB unless noted otherwise, reflecting the fact that most capacity in the modeled demand year of 2040 will be installed in years prior to 2040. Cost and performance assumptions for transmission are taken from the NREL ReEDS model[15] and are provided in Table S3; existing transmission capacity is assumed to be available at no cost. PV and wind sites are aggregated into five LCOE classes within each zone to reduce the model size. No existing ("brownfield") VRE capacity is included, given that most installations are likely to be repowered by 2040. The power and energy costs of Li-ion battery systems are disaggregated,[41,42] allowing the model to optimize the duration (energy-to-power ratio) of storage within each modeled zone. Existing reservoir and run-of-river (ROR) hydropower facilities are included, using monthly historical generation from 2007–2013.[3,43,44] Existing hydropower is considered to be fully paid off, with zero capex cost; no new hydropower construction is allowed.

Nuclear power represents a special case when compared with other currently deployed technologies; while nuclear power produced roughly 20% of US electricity in 2019, only a single unit has been built in the US in the last 24 years.[3,43] There are two operational power-generating carbon-capture plants worldwide at the time of this writing, with a

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Table 1. Cost and Performance Assumptions for Generation and Storage Technologies

Technology	Qualifier	Capex Cost (Power)	Capex Cost (Energy)	Lifetime	WACC (Real)	FOM Cost (Power)	FOM Cost (Energy)	Ramp Rate	Minimum Generation
		[$/kWac]	[$/kWh]	[Years]	[%]	[$/kWac-yr]	[$/kWh-yr]	[%/h]	[% capacity]
PV	2018	1,442	-	25	4.2	26	-	100	0
PV	2030 "Mid"	1,118	-	25	4.2	13	-	100	0
PV	2030 "Low"	733	-	25	4.2	9	-	100	0
Wind	2018	1,623	-	25	4.2	44	-	100	0
Wind	2030 "Mid"	1,262	-	25	4.2	39	-	100	0
Wind	2030 "Low"	1,134	-	25	4.2	34	-	100	0
Nuclear	Noflex	6,180*	-	25	4.5	101	-	0	100
Nuclear	Midflex	6,180*	-	25	4.5	101	-	25	50
Nuclear	Fullflex	6,180*	-	25	4.5	101	-	25	0
Nuclear	Existing	0	-	-	-	234	-	5	85
Hydro	Reservoir	-	-	-	-	36	-	100	10
Hydro	Run-of-River	-	-	-	-	36	-	0	100
CCGT	2030 "Mid"	850	-	25	4.5	11	-	50	0
OCGT	2030 "Mid"	849	-	25	4.5	12	-	100	0
Li-Ion	2018	287	300	15	4.2	6	7	100	0
Li-Ion	2030 "Mid"	158	165	15	4.2	3	4	100	0
Li-Ion	2030 "Low"	95	99	15	4.2	2	2	100	0
LDES		1,757	5–50*	25	4.2	16	0	100	0
PHS	Existing	0	0	-	-	16	0	100	0

All monetary quantities are in 2017 US dollars and are taken, where possible, from the NREL Annual Technology Baseline (ATB).[38] Capital expenditure (capex) costs for nuclear power and long-duration energy storage (LDES), marked with a "*", vary across sensitivity cases and are noted in Figure 4 for cases in which they are included. LDES cost and performance assumptions are derived from estimates for PHS. Reservoir and run-of-river hydropower are included in all simulations, but no capacity additions are allowed. Figures 2 and 3 and the "default" row in Figure 4 include only PV "2030 mid," wind "2030 mid," Li-ion "2030 mid," and transmission as new investment options; other rows in Figure 4 include the additional technologies listed here where noted. Additional cost and performance assumptions are given in Tables S10 and S11. Abbreviations are defined in the Supplemental Information (Note S1).

combined capacity of 0.35 GW; both utilize the captured CO_2 for enhanced oil recovery,[45] and cannot be classified as zero-carbon given the sub-100% CO_2-capture efficiency of CCS. While offshore wind is currently deployed at gigawatt-scale in Europe, the deployed US capacity is 0.03 GW at the time of this writing.[3] Given our focus on technologies currently being deployed at gigawatt-scale in the US, only PV, wind, Li-ion batteries, existing hydropower, and transmission are included in the base case; nuclear power is considered separately in the sensitivity analysis described below, while offshore wind and carbon capture are excluded given their sub-gigawatt capacity. Geothermal and CSP currently demonstrate relatively limited regional availability and deployment, and are thus excluded to reduce the model size and computation time (computational details are provided in Supplemental Information section S4). Three additional sources of flexibility are considered in the sensitivity analysis: flexible nuclear, long-duration energy storage (LDES, with cost assumptions and technical parameters derived from PHS), and load shedding during periods of peak net demand.

Table 2. Regional Coordination and Transmission Assumptions

Scenario	Zones	Independent Simulations	Coordination Boundary	Existing Inter-State Transmission?	New Inter-State Transmission?
States	States	48	State	No	No
PA – AC	States	11	PA	Within each PA	No
PA + AC	States	11	PA	Within each PA	AC between states within PA
USA – AC – DC	PAs	1	USA	Between adjacent PAs	AC between states within PA No new AC/DC between PAs
USA + AC – DC	PAs	1	USA	Between adjacent PAs	AC between states within PA New AC between synchronous PAs
USA + AC + DC	PAs	1	USA	Between adjacent PAs	AC between states within PA New AC between synchronous PAs New DC between asynchronous PAs

The transmission system topology for the "PA" and "USA" scenarios is shown in Figure 1G. Each PA contains between 1 and 8 states. "+" and "–" symbols in scenario names indicate whether new transmission of the indicated type (AC or DC) is allowed (+) or disallowed (–) between the constituent zones (states for PA scenarios, PAs for USA scenarios). There are three groups of synchronous PAs: the western interconnect (Northwest, Mountain, and California), the eastern interconnect (Central, MidwestN, MidwestS, Northeast, MidAtlantic, Southeast, Florida), and Texas; AC transmission is included between PAs within the same synchronous interconnect, while DC transmission is only included between interconnects.

Regional Coordination and Transmission Scenarios

In this work, "coordination" is defined to include all of the functions that would be performed by a cost-minimizing centrally-planned electric system operator within an isolated coordination area: generation and transmission capacity planning and procurement, balancing of supply and demand through hourly dispatch, and (in the relevant sensitivity cases discussed below) procurement of operating reserves. We consider three different boundaries for regional coordination: individual states, multi-state PAs, and the interconnected US system. Two "PA" and three "USA" scenarios are considered, differing in their allowance of new transmission construction. The "States" and "PA" scenarios entail independent optimizations of each state or PA, balancing hourly supply and demand using only generation assets sited within the borders of the relevant state or PA, while the "USA" scenarios entail a single optimization of the full 11-PA system. These six scenarios are summarized in Table 2.

While existing transmission capacity is most closely approximated by the "USA – AC – DC" scenario, this scenario does include new intra-PA inter-state transmission to balance VRE generation with demand within the PA. Independent system operators (ISOs) currently coordinate extensively between states within their service territory, while inter-ISO coordination is comparatively more difficult;[46] coordination of generation capacity-planning and day-ahead unit commitment between ISOs is limited, and wheeling charges disincentivize inter-regional power flows. The names and boundaries of the 11 PAs considered here, in addition to the assumed intra-PA inter-state grid topology and inter-PA topology, are shown in Figure 1G. To accommodate our high temporal resolution (>60,000 chronological hourly timesteps over 7 years), the 11 PAs used here are larger in size and smaller in number than the ~70 balancing authorities of the continental US.[47]

Limitations

Before describing our results, we first note several limitations in our analysis. We do not model sub-hourly resource variability (although the hourly operating reserves cases suggest that doing so would not substantially increase costs); transmission is modeled in a highly aggregated fashion, without AC or DC optimal power flow; we do not include connections to Canada or Mexico, offshore wind, geothermal,

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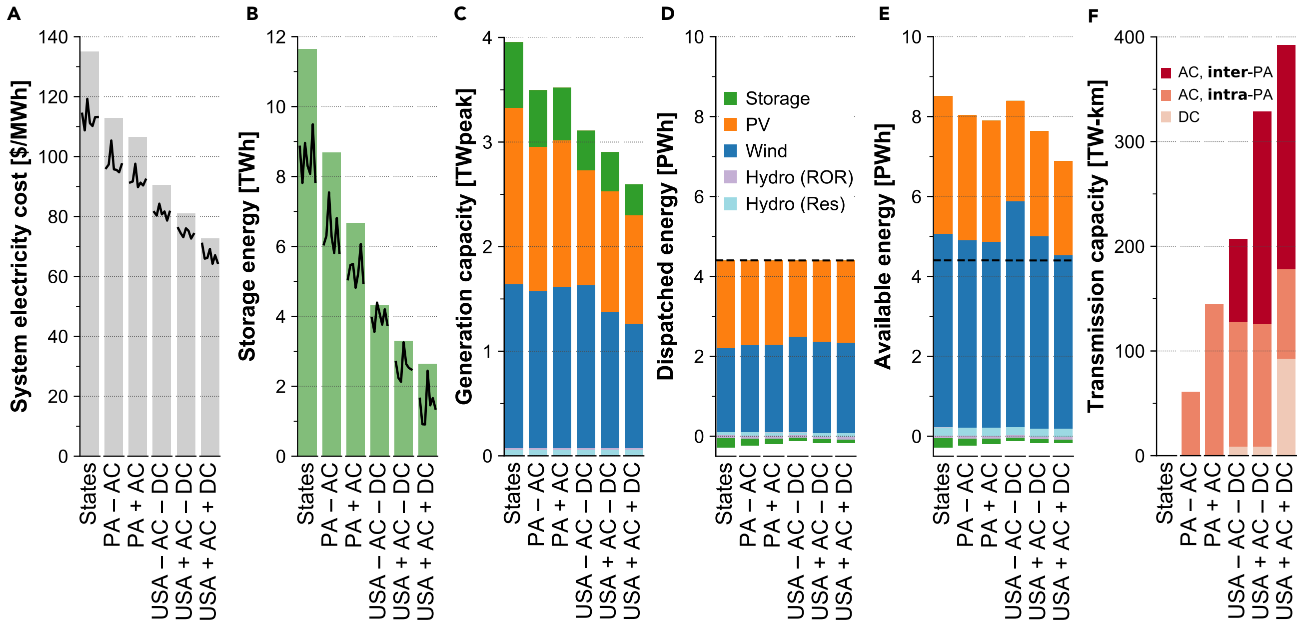

Figure 2. Cost, Capacity, and Annual Operation of Optimized Zero-Carbon Power Systems

Results are shown for isolated states ("States"); isolated PAs without ("PA – AC") and with ("PA + AC") new inter-state AC transmission; and the full-US system without new inter-PA transmission ("USA – AC – DC"), with new inter-PA AC transmission ("USA + AC – DC"), and with new inter-PA AC and DC transmission ("USA + AC + DC"). New DC transmission capacity is only allowed between nodes connected by dashed lines in Figure 1G.

(A) Average SCOE, given by the optimized value of the objective function divided by the summed hourly system demand. Gray bars denote optimized solutions for the full 2007–2013 period; black lines denote optimized individual yearly solutions for the 7 years between 2007 and 2013, with 2007 on the left and 2013 on the right.

(B) Installed energy capacity of storage. As in (A), green bars denote solutions optimized for the full 2007–2013 period and black lines denote individual yearly solutions for the 7 years between 2007 and 2013.

(C) Installed power capacity of generation and storage optimized for the full 2007–2013 period.

(D) Annual dispatched energy for systems optimized for the full 2007–2013 period. Bars start from a negative value that corresponds to the energy used to charge storage, in addition to storage and transmission losses. The sum of dispatched energy from storage and dispatched energy from hydropower, wind, and PV equals the annual demand, denoted by the black dashed line.

(E) Annual available energy for systems optimized for the full 2007–2013 period, with annual demand denoted by the black dashed line. As in (D), bars start from a negative value to account for storage charging and losses from storage and transmission. The available energy from wind and PV is given by the 7-year average CF multiplied by the installed capacity. The available energy from reservoir hydropower is given by historical generation over 2007–2013, assuming no spilled power.

(F) Installed inter-state transmission capacity. Bars include both existing and new-build transmission capacity. Interconnection "spur lines" associated with PV and wind sites are not included. Intra-PA transmission for the "USA" scenarios is calculated using the method described in the Supplemental Information (Note S3.2.1).

CSP, demand response (outside of the bounding "$9000/MWh load shedding" sensitivity case discussed below), unit commitment for nuclear or CCGT, security constraints, or nonlinearities arising from wind wake effects and storage degradation. Our approach can be characterized as "perfect hindsight," showing that historical demand profiles (scaled up to account for demand growth and electrification) can be met under historical weather conditions; we do not model forecast uncertainty in VRE availability or demand, or the impact of climate change on weather patterns. We also do not address issues of system inertia or transient stability (although recent work shows that PV,[48] wind,[49] and batteries[50] can provide such services). These areas should be considered in future work. Including additional generation technologies or demand response would decrease estimated electricity costs, while modeling optimal power flow, security constraints, inertia, or unit commitment would tend to increase costs.[51]

RESULTS

Impacts of Regional Coordination and Transmission

Figure 2 shows the system cost of electricity (SCOE, defined as the total annualized capex and operational costs of generation, storage, and transmission divided by the yearly system-wide demand; distribution and administration costs are not included), installed capacity, and dispatched and available energy for the six central zero-carbon scenarios described in Table 2. Zero-carbon systems are feasible with today's VRE and storage technologies in all scenarios, even for the "States" scenario requiring each state to balance hourly electricity supply and demand from generators within its own borders. Yet as regional coordination increases along the horizontal axis, the SCOE and installed generation and storage capacity decrease substantially. Benefits are derived both from increasing coordination without installing new transmission capacity (the SCOE decreases by 22 \$/MWh from "States" to "PA – AC" and by 16 \$/MWh from "PA + AC" to "USA – AC – DC") and from allowing new transmission installations at the same level of coordination (in the "USA" scenarios, allowing new AC transmission reduces the SCOE by 10 \$/MWh, and allowing new DC transmission across the three asynchronous interconnects reduces SCOE by a further 8 \$/MWh).

The decline in storage deployment is even more pronounced: The "USA + AC + DC" case deploys 40% of the storage used in the "PA + AC" case and 23% of the storage used in the "States" case. Projected average 2040 electricity demand is 0.50TW, so the installed energy capacity of storage (Figure 2B) divided by average demand equates to roughly 23 hours in the "States" case, 13 hours in the "PA + AC" case, and 5.3 hours in the "USA + AC + DC" case. Inter-state transmission capacity (including both intra-PA and inter-PA capacity) increases by roughly 90% between the "USA – AC – DC" and "USA + AC + DC" cases.

These results corroborate previous studies showing that a single weather year is insufficient for modeling zero-carbon systems with high reliability.[8–11] The 7-year simulations over 2007–2013 always entail higher SCOE (Figure 2A) and typically employ larger storage capacity (Figure 2B) than simulations over individual weather years, even the "worst" years, although interannual weather variability is smaller at the continent scale than at the scale of states or PAs (Note S5). Because the worst year varies across states (Figure S19) and storage deployment tends to be sized for the worst year (where "worst" roughly indicates the severity and duration of synchronized low-availability periods for wind, PV, and hydropower), the gap between the optimal 7-year and 1-year storage capacities (and SCOE) is larger for the geographically-isolated "States" and "PA" scenarios than for the "USA" scenarios.

Given the currently available technologies modeled here, the intermittency of VRE is primarily managed by sizing VRE capacity to provide sufficient generation during the lowest-resource times (cloudy winters for PV and calm summers for wind) and curtailing generation to match demand during other times.[22,52] Increased regional coordination and transmission reduce the necessary capacity and the incidence of curtailment (Figures 2D and 2E). As shown in Figure 3, storage duration (defined by the energy-to-power ratio of the optimized storage capacity in a given zone) is lower in the "USA + AC + DC" scenario than in the "USA – AC – DC" scenario. Construction of new transmission capacity thus has two primary benefits—it allows increased VRE deployment at higher-quality sites, reducing the capacity investment required to produce a given amount of energy (Figure 2C); it also reduces VRE intermittency by integrating generation from distant sites spanning different cloud and weather systems,[6,7] thus reducing the amount and duration of storage required (Figures 2B, 3C, and 3G).

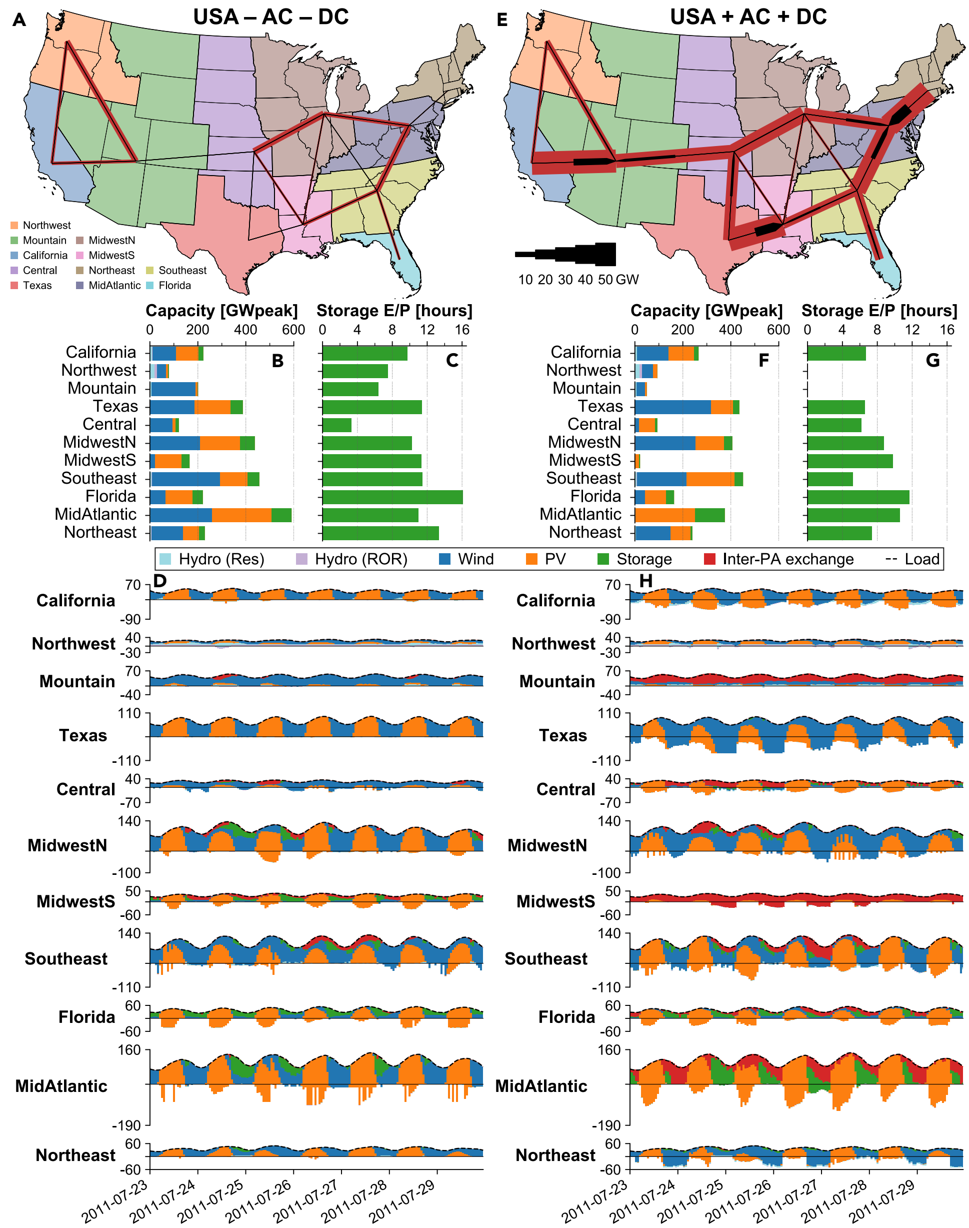

Figure 3. Capacity and Operation of Optimized Zero-Carbon Systems Disaggregated by PA for the "USA – AC – DC" (Left) and "USA + AC + DC" (Right) Scenarios

Power capacity and dispatch are optimized for the full 2007–2013 period.

(A and E) Installed inter-PA transmission capacity (red) and average hourly power flow (black), with capacity and flow indicated by line thickness. Each link shows the average flow in both directions, with the average flow into a node shown by the thickness of the black line on the side of the link closest to that node.

(B and F) Installed power capacity of generation and storage disaggregated by PA.

(C and G) Energy/power ratio of storage for each PA. Storage energy in GWh is given by the product of storage power in (B and F) and energy/power ratio in (C and G).

(D and H) Hourly dispatch by PA for the week from 2011-07-23-00:00 to 2011-07-29-23:00, shown in US central standard time. Negative values indicate charging of storage or power flow out of the PA; red areas indicate transmission power flow into the PA. Curtailment of wind and PV and spillage of reservoir hydropower are not shown.

Alternative Technology Assumptions

While the analysis described thus far indicates the feasibility of zero-carbon systems and the value of inter-regional coordination and transmission, the assumed future technology costs and demand levels are far from certain. It is also possible that technologies excluded thus far—including nuclear power and long-duration storage—could be economically viable in the future. Figure 4 presents the results of a sensitivity analysis across 48 different cases (41 zero-carbon cases and 7 "no-policy" cases), taking the "USA + AC + DC" scenario described above as the base case. Numerical and methodological assumptions for the alternative cases are provided in Table 1 and in Note S3.2.5.

Three zero-carbon cases result in a SCOE that is at least 10 $/MWh cheaper than the default case: "2030low VRE&S prices" (-17 $/MWh difference with the default case), "LDES ($5/kWh)" (-13 $/MWh), and "fullflex nuclear_$4000/kW" (-12 $/MWh). In addition to the "States" and "PA" scenarios described above, eight cases produce a SCOE that is at least 10 $/MWh more expensive than the default case: "2018 VRE&S prices," "no new AC or DC" (the same scenario as "USA – AC – DC" described above), "WTKclass2" (representing a higher-specific-power wind turbine model), "5× Li-ion cost," "Vestas:V110/2000" (another higher-specific-power wind turbine model), "0.1× VRE available," "5× interconnection cost," and "6% WACC." Combining changes from multiple sensitivity cases would lead to greater differences from the default case.

New Nuclear

The impact of nuclear is sensitive to cost and technical assumptions. At a capex cost of $12,000/kW$_{ac}$—roughly the estimated cost of the Georgia Vogtle nuclear plant expansion, still incomplete at the time of this writing[53]—no new nuclear capacity is installed ("noflex nuclear_$12000/kW"). At the 2030 ATB cost projection of $6,180/kW$_{ac}$, between 70 GW ("noflex nuclear_$6180/kW") and 190 GW ("fullflex nuclear_$6180/kW") of nuclear capacity is installed depending on the flexibility assumptions, but the system cost is only reduced by 0.2–2 $/MWh compared with the default case without nuclear. System cost reductions greater than 5 $/MWh are only observed once the nuclear capex cost drops to $5,000/kW$_{ac}$, roughly 10% below the ATB cost projection for 2050. "Fullflex" nuclear at $4,000/kW$_{ac}$ does significantly reduce the SCOE (-12 $/MWh) but to a lesser extent than achieving the 2030 "low" cost projections for PV, wind, and Li-ion batteries (-17 $/MWh). While the impact of nuclear at central cost projections is low, nuclear and VRE can coexist, even in the "noflex" nuclear cases: VRE generators are highly rampable within their temporal availability limits, so when paired with inflexible nuclear, VRE and storage perform load-following to complement nuclear baseload.

VRE Availability / Wind Turbine

Results are relatively robust to assumptions regarding the available land area for VRE development and regional cost variability: uniformly reducing the available land area by 80% ("0.2× VRE available") only raises the SCOE by 2 $/MWh, and applying regional cost scalers from the EIA Annual Energy Outlook 2020[54] raises the SCOE by 1 $/MWh. VRE prices are comparatively much more important, along with technical assumptions regarding wind power: utilizing the power curve for the high-specific-power "WTKclass2" model increases the SCOE by ~16 $/MWh relative to the low-specific-power Gamesa:G126/2500 (used as the default) or Leitwind:LTW90/1000 models. These results corroborate previous studies reporting an increased value for low-specific-power wind turbines at lower wind penetrations.[55,56] Additional details on wind modeling are provided in the Supplemental Information (Note S2).

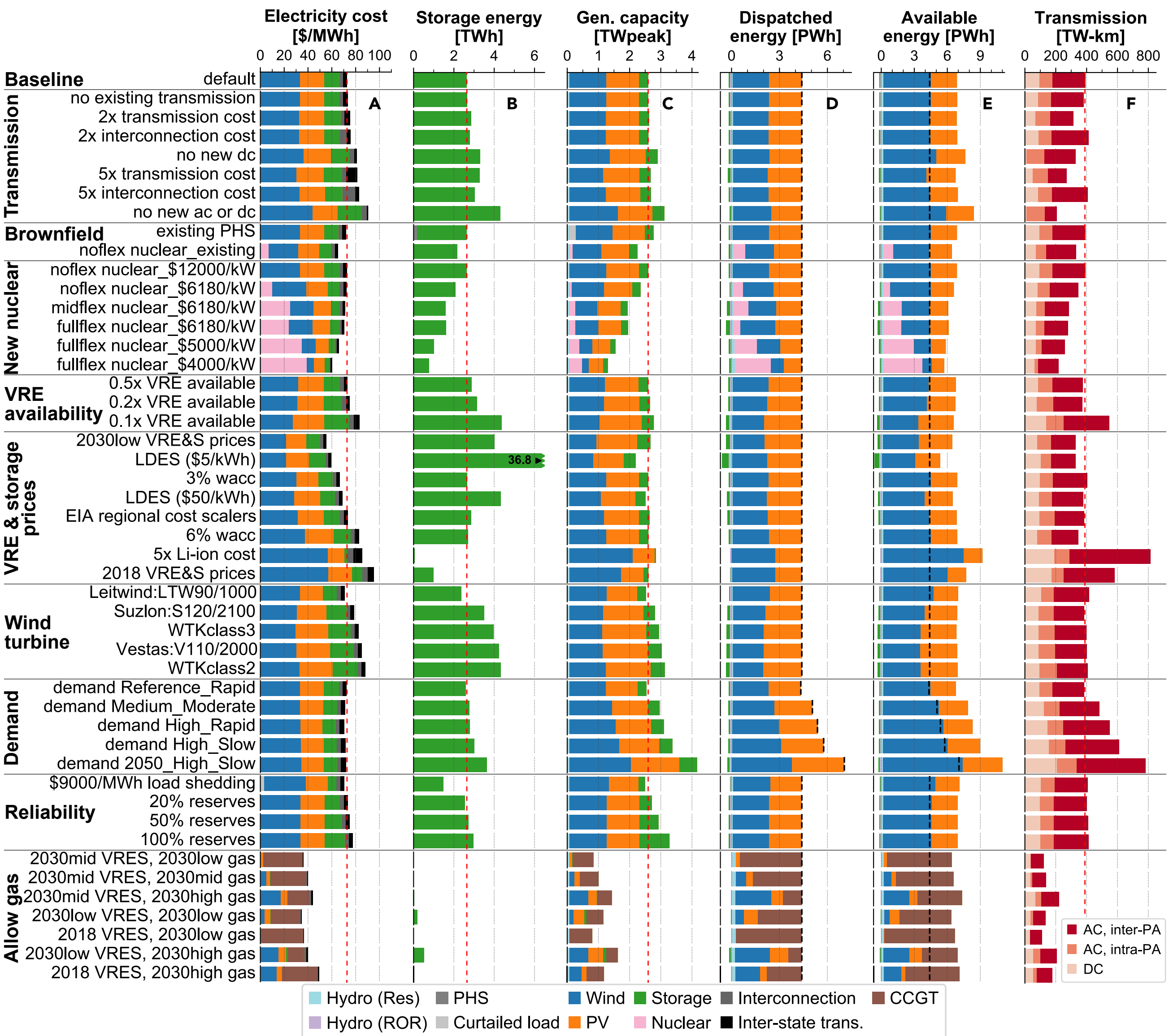

Figure 4. Sensitivity of Cost, Capacity, and Annual Operation to a Range of Assumptions

All results are for the interconnected US system; default assumptions correspond to the scenario labeled "USA + AC + DC" in Figure 2.

(A) Average SCOE

(B) Installed storage energy capacity

(C) Installed power capacity of storage and generation

(D) Annual dispatched energy

(E) Annual available energy

(F) Installed transmission capacity.

Plotting conventions follow Figure 2, but only results for the full 2007–2013 period are shown here. Panel (A) disaggregates the SCOE into contributions from different sources; here, "Inter-state trans." includes the cost of new intra-PA and inter-PA transmission, while "Interconnection" includes site-specific interconnection costs for PV and wind. The dotted red line in (A), (B), (C), and (F) indicates the value for the "default" case as a guide to the eye, and the dotted black line in (D) and (E) indicates the yearly electricity demand. Low, medium, and high gas prices for "Allow gas" rows are 3.40, 4.11, and 5.82 $/MMBtu, respectively (3.22, 3.90, and 5.52 $/GJ); complete details on other different sensitivity cases are provided in Table 1 and in the Supplemental Information (Note S3.2.5). Social costs associated with emissions of greenhouse gases and particulate matter in the "Allow gas" cases are not included.

VRE & Storage Prices / Transmission

Regional scope is still more important than VRE/storage cost assumptions: assuming constant VRE and storage costs for the full-US "USA + AC + DC" scenario ("2018 VRES prices" in Figure 4) results in a SCOE that is 11 $/MWh *lower* than assuming the baseline projected 2030 "mid" cost reductions for the transmission-constrained "PA + AC" scenario (Figure 2A). Reductions in the cost of either PV or storage tend to increase the deployment of PV and storage at the expense of wind and inter-PA transmission, while reductions in the cost of either wind or transmission tend to have the opposite effect (Note S6.1). Even in the "5× transmission cost" case there are substantial transmission additions: optimized inter-PA transmission capacity in this case increases 30% over the "no new AC or DC" ("USA – AC – DC") case, reducing the SCOE by 6 $/MWh.

Demand

The SCOE is relatively insensitive to the assumed electricity demand. While significantly more generation capacity and storage are built in the high-demand cases ("Demand" in Figure 4), the increased capex cost is levelized over an increased electricity demand, such that the SCOE of all alternative demand scenarios is roughly equivalent to the baseline SCOE. Given the greater degree of electrification of heating and transportation in the high-demand cases, these cases represent a greater reduction in economy-wide emissions than the baseline case and may enable increased flexibility from price-responsive demand (not considered here).

Reliability

Results are also relatively insensitive to changes in the reliability assumptions. Implementing load shedding at a cost of $9,000/MWh ("$9000/MWh load shedding," matching the scarcity price currently used in the ERCOT system) reduces the SCOE by 2 $/MWh, resulting in load shedding equivalent to 0.10 days of average system-wide demand per year (Figure S25). Results for individual states and PAs are much more sensitive to assumptions regarding load shedding, as shown in the Supplemental Information (Note S6.3). Implementing an hourly operating reserve margin requirement, which can be met by curtailed VRE or by energy held in storage, also has relatively little impact on cost: SCOE increases by 0.7 $/MWh, 2 $/MWh, and 5 $/MWh in the "20% reserves," "50% reserves," and "100% reserves" cases, where the reserve level indicates the percentage of hourly demand for which operating reserves must be procured.

Alternative Assumptions for Regional Coordination and Transmission

The sensitivity analysis shown in Figure 4 applies to the "USA + AC + DC" scenario allowing transmission expansion between all adjacent PAs. Figure 5 shows the SCOE for a subset of sensitivity cases for each of the six coordination and transmission scenarios described in Table 2. In each case, costs increase monotonically as inter-regional coordination and the ability to deploy new transmission capacity are reduced. In general, cost differences across sensitivity cases are accentuated in the transmission-constrained "States" and "PA" scenarios. While the directionality of most trends across sensitivity cases is similar within each of the six coordination and transmission scenarios, low-cost flexible nuclear and long-duration storage reduce the SCOE to a much larger extent in the "States" and "PA" scenarios than in the "USA" scenarios and, when available, reduce the relative benefits of inter-regional coordination and transmission. While the "2030low VRE&S prices" case gives the lowest SCOE in the "USA + AC + DC" and "USA + AC – DC" scenarios (and accordingly gives the lowest SCOE across all sensitivity-case/transmission-

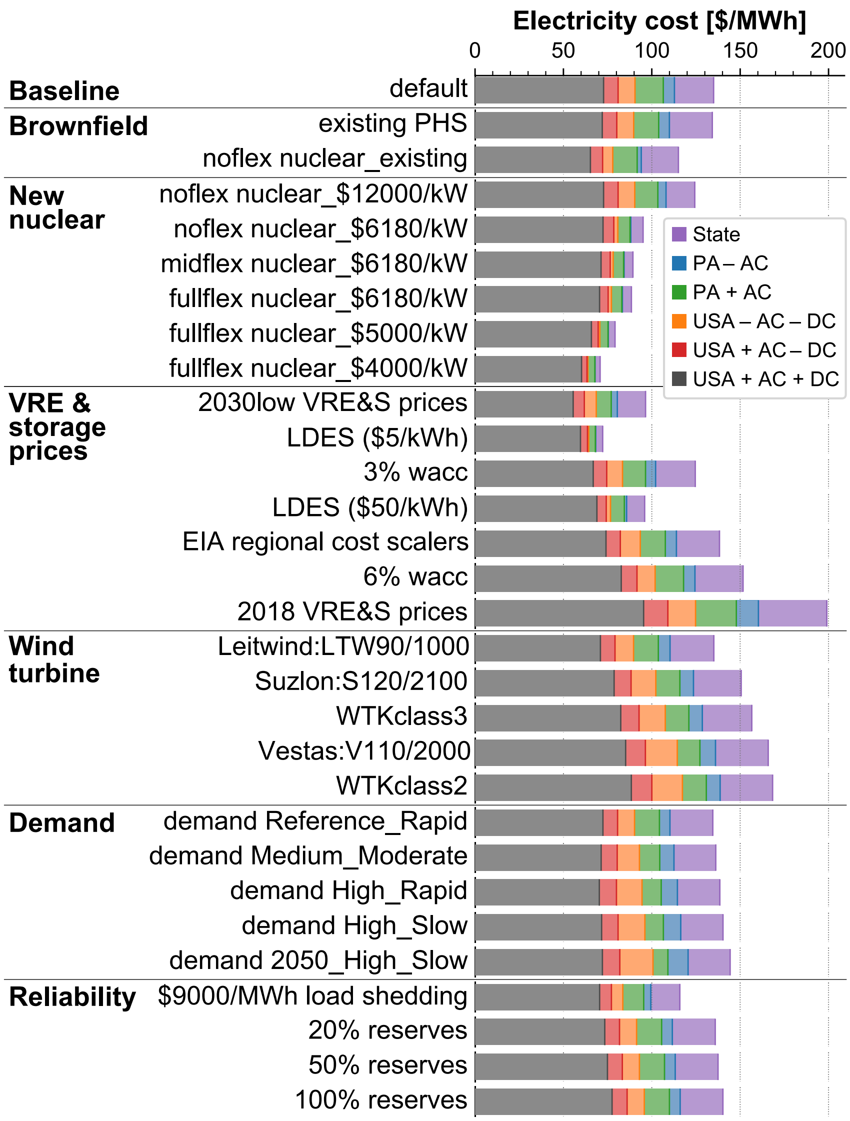

Figure 5. Sensitivity of Electricity Cost to Technical Assumptions under Different Scenarios for Regional Coordination and Transmission

Regional coordination and transmission scenarios are described in Table 2. Sensitivity cases represent a subset of the cases included in Figure 4 and are described in Note S3.2.5. The dark gray "USA + AC + DC" bars reproduce the total SCOE shown in Figure 4A.

scenario pairs considered in this study), "LDES ($5/kWh)" and "fullflex nuclear_$4000/kW" give lower costs in the "PA" and "States" scenarios.

These results emphasize that there are multiple potentially viable paths to a zero-carbon system at costs below those presented in Figure 2 under default assumptions: low-cost renewables and Li-ion batteries coupled with new transmission construction give the lowest cost, but if either are unavailable, the development of low-cost flexible nuclear or low-cost long-duration storage would provide an alternative at only moderately higher cost. Electricity costs would be further reduced if all technology options (low-cost renewables, Li-ion batteries, nuclear, LDES, and transmission) were available.

Additional sensitivity cases and results are discussed in the Supplemental Information (Note S6), including the impact of interannual weather variability over longer periods and alternative assumptions for nuclear power and load shedding.

"No-Policy" Decarbonization

The discussion thus far has focused on zero-carbon electricity systems. To illustrate the trajectory of electricity cost between a "no-policy" case (unconstrained carbon emissions) and zero carbon, we here allow investment in combined-cycle gas turbines (CCGT) and open-cycle gas turbines (OCGT). The "Allow gas" rows in Figure 4 demonstrate the characteristics of the optimized system in the no-policy case with three different natural gas price assumptions: 3.40, 4.11, and 5.82 \$/MMBtu (or 3.22, 3.90, and 5.52 \$/GJ) for the "low," "mid," and "high" cases, taken from the NREL ATB for 2030.[38] Using 2030 "mid" prices for all technologies results in 31% of demand being met by non-fossil resources (Figure 4D). As noted in other studies,[25,57] the economic level of decarbonization in a no-policy case is highly sensitive to assumptions regarding the capex cost of VRE and fuel price of natural gas: "no-policy" decarbonization ranges from 6% in the "2018 VRES, 2030 low gas" scenario to 81% in the "2030 low VRES, 2030 high gas" scenario.

From "No-Policy" to "Zero-Carbon"

Figure 6 bridges the gap between the no-policy and zero-carbon cases by applying an escalating clean-energy standard (CES, equivalent to a renewable portfolio standard [RPS] in this nuclear-free case) in each of the isolated states (blue bars), isolated PAs (green bars), and the interconnected US system (orange and red bars). The current implementation of most RPS policies lies between our "States" and "PA" scenarios; some states allow out-of-state generation capacity to contribute to the state's RPS if generation is delivered to the state, while other states have quotas or benefits for in-state generation siting.[58] Other studies have noted that system cost increases nonlinearly as decarbonization approaches 100%;[10,19,24] while our results support this finding, the cost increase is much smaller for an interconnected US system than for isolated systems. Achieving 95%, 99%, and 100% decarbonization adds 24 \$/MWh, 44 \$/MWh, and 93 \$/MWh, respectively, to the no-policy SCOE when the CES is applied at the level of isolated states, compared with 10 \$/MWh, 18 \$/MWh, and 33 \$/MWh when applied to the full US allowing new inter-PA transmission capacity. For context, 33 \$/MWh was roughly the difference in retail electricity price between Michigan and Oklahoma in 2018.[59] As noted in Figure 4A, achieving low-cost targets for VRE and Li-ion, LDES, or nuclear would reduce the electricity cost premium for 100% decarbonization relative to the middle "no-policy" case to 16 \$/MWh, 20 \$/MWh, or 20 \$/MWh, respectively.

DISCUSSION

Curtailment

It is notable that the level of curtailment—defined as the total nameplate capacity times hourly availability of each generator minus annual demand, shown by the gap between the black dotted line and the sum of the colored bars in Figure 4E—is roughly the same between the zero-carbon and no-policy cases. Given that peak demand nationwide is ~1.6 × mean demand,[40] a system reliant on fully dispatchable generation would feature ~37% ($1-1/1.6$) curtailment. This level of curtailment is observed across most of the zero-carbon and no-policy sensitivity cases considered in Figure 4 (with the exception of the "LDES (\$5/kWh)" and "fullflex nuclear" cases, which exhibit 20%–30% curtailment, and the "no new AC or DC" and "5× Li-ion cost" cases, which exhibit ~50% curtailment). Just as natural gas peaking capacity lies idle during off-peak periods (with most open-cycle gas peakers

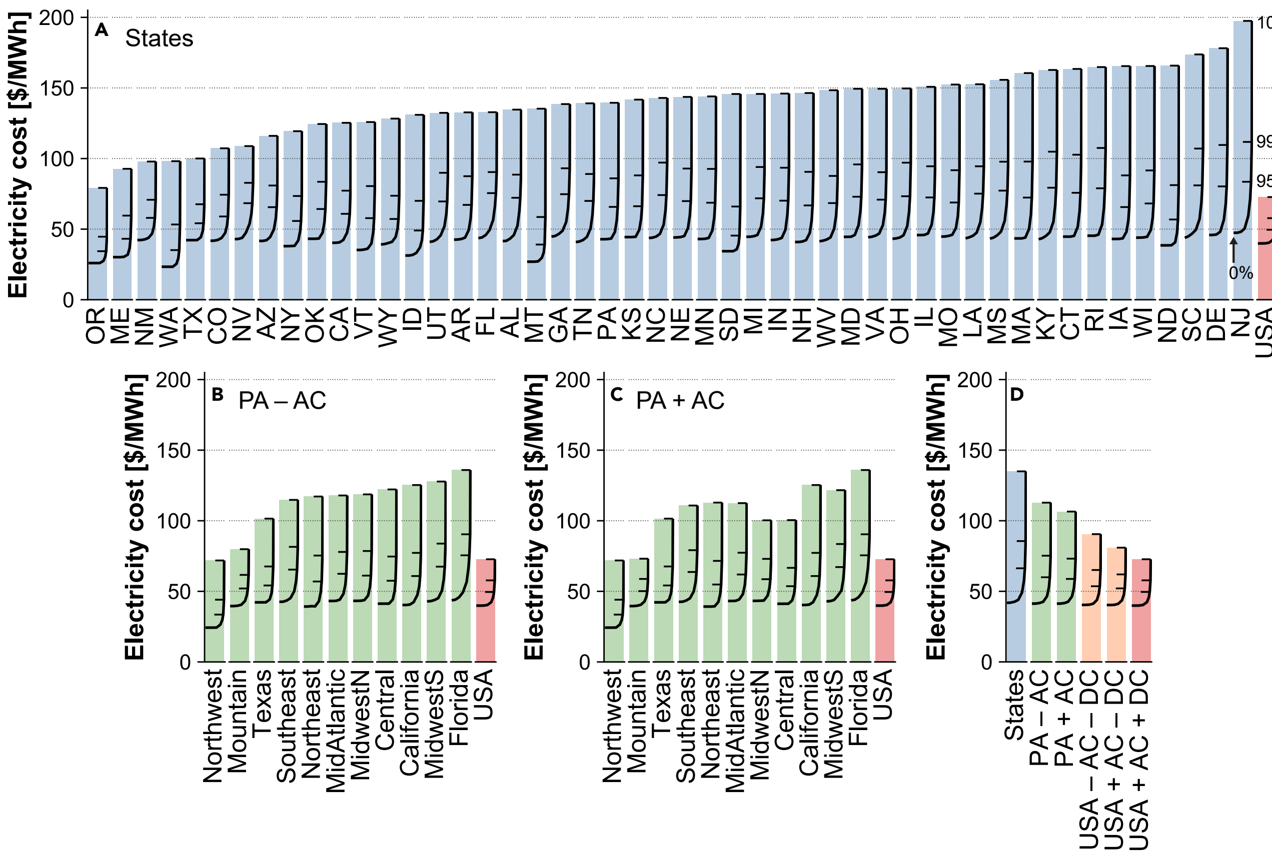

Figure 6. System Cost of Electricity As a Function of Clean-Energy Standard (CES) *En Route* to 100%

Colored bars indicate the SCOE for zero-carbon (100% CES) systems. Each bar is overlaid with a subplot (black lines) indicating the SCOE for systems allowing natural gas generation and employing an escalating CES, with 0% CES on the left of each bar and 100% CES on the right of each bar. The three horizontal ticks in each bar indicate the SCOE at 95%, 99%, and 100% CES, as shown in the "NJ" bar in (A). The SCOE of the interconnected US system allowing construction of new inter-state and inter-PA transmission is shown on the right of each subplot in red for context.

(A) SCOE for each of the 48 states in the continental US if each state were to meet its hourly electricity demand within its own borders (corresponding to scenario "States" in [D] and Figure 2), sorted by SCOE at 100% CES.

(B) SCOE for each of the isolated PAs without new inter-state transmission ("PA − AC" in [D] and Figure 2), sorted by SCOE at 100% CES.

(C) SCOE for each of the isolated PAs allowing new inter-state transmission ("PA + AC" in [D] and Figure 2), in the same order as (B).

(D) Combined SCOE across all isolated states (blue), isolated PAs (green), and the interconnected US system (orange and red). Colored bars in this plot indicate the same values as in Figure 2A. Social costs associated with emissions of greenhouse gases and particulate matter in the sub-100% CES cases are not included.

exhibiting capacity factors <10%, or >90% "curtailment"), [60] some VRE capacity lies idle during high-resource low-demand periods in a cost-optimized system (albeit without fuel-based cost savings). Including demand response through flexible charging of electric vehicles or other forms of inter-sector coupling (not modeled here) could significantly reduce the curtailment of zero-marginal-cost VRE.

It is also notable that curtailment is higher in the "USA – AC – DC" scenario than in the "PA + AC" scenario (Figure 2E), even though wind and solar capacity is higher in "PA + AC" (Figure 2C). As the "USA" scenarios have access to higher-quality wind and solar sites, more energy can be generated from less capacity, thus reducing cost while increasing curtailment. While curtailment is a feature of a cost-minimized system, it does lead to market-design implications and would increase the importance of capacity markets and/or scarcity pricing for cost recovery.

Expanding Transmission versus Generation Capacity

The roughly 90% increase in transmission capacity in the cost-optimized "USA + AC + DC" scenario compared with the "USA – AC – DC" scenario (Figure 2F) is in line with other studies showing roughly a doubling in installed transmission capacity to be cost-optimal for electricity decarbonization in the USA[61] and the EU.[29,30] While large, the relative expansion in transmission capacity is considerably smaller than the expansion in wind (~10×) and PV (~28×) capacity in the default case or the ~3× expansion in nuclear capacity in the most-aggressive nuclear case (Figure 4C).[3] Note also that the ~90% increase in transmission capacity [TW-km] does not necessarily imply a similar increase in transmission-line-miles; a double-circuit 500kV line can carry roughly 7.5× the power of a single-circuit 230kV line over a given distance.[62]

MacDonald et al. also present the benefits of nationwide transmission expansion for decarbonization; as MacDonald et al. utilize a "no-policy" scenario reaching ~80% decarbonization, they report lower benefits from inter-regional transmission than are observed in our 100%-decarbonized scenarios.[25] The 13 $/MWh reduction in SCOE observed here for the "LDES ($5/kWh)" case is roughly in line with the 10–20 $/MWh reduction in SCOE from LDES observed by Dowling et al.[63] for a full-US model without transmission constraints. Shaner et al.[8] report that hourly US electricity demand over 36 years could be met by a 50/50 wind/solar resource mix with an available-energy/demand ratio of ~1.3× and storage equivalent to 4 days of mean demand; this result is in line with our "LDES ($5/kWh)" case (Figure 4), which employs 3 days of storage and an available-energy/demand ratio of 1.2×. Other studies over small geographic areas report a larger role for LDES[10] and nuclear power[24] in zero-carbon systems; as shown in Figure 5, we also find that nuclear and LDES significantly reduce the SCOE in isolated and transmission-constrained zero-carbon systems, but their impact is diminished when new transmission deployment is fully allowed.

Conclusions and Policy Implications

The results described here suggest that a zero-carbon electricity system for the US based on VRE and storage is feasible at 1-hour resolution over many years of operation, accounting for the costs and constraints of transmission and land availability, using technologies currently being deployed at gigawatt-scale. Moreover, we demonstrate that, while decarbonization of the electricity system is feasible at the level of individual states and regions, it can be accomplished at a significantly lower cost when implemented at the national level.

Even in the absence of new inter-regional transmission, inter-state coordination of generation capacity planning and dispatch reduces system cost substantially in decarbonized electricity systems. Historical experience with the western Energy Imbalance Market (EIM) shows that inter-regional coordination of real-time dispatch alone can reduce operational costs, renewable curtailment, and CO_2 emissions;[64] this work shows that as the geographic and operational bounds of coordination are expanded, even further benefits can be realized. Relaxing in-state siting requirements for renewable portfolio standards would deliver similar benefits.[65] While increased coordination delivers system-wide cost reductions, the relinquishing of local operational control alongside the potential for locally increased electricity prices in low-priced regions upon coordination with higher-priced regions can lead to localized opposition.[66]

While this study demonstrates that transmission expansion is a cost-effective enabler of electricity system decarbonization, transmission construction—particularly inter-state and inter-regional transmission—faces multiple challenges in the US. Transmission lines typically require permits from multiple federal agencies and from each state and local jurisdiction within their path;[67] the multi-party benefits of transmission make cost allocation difficult;[68] and like any type of energy infrastructure, transmission can engender local opposition.[69] There are a number of strategies for streamlining the planning, permitting, and construction of new inter-state transmission to overcome such barriers: increasing utilization of existing transmission rights-of-way through reconductoring of existing lines, increasing line voltage, or adding additional circuits;[70] converting existing AC transmission corridors to DC;[71] implementing federally identified transmission corridors;[72] and building social acceptance through public engagement[73] or community ownership[74,75] could accelerate and reduce the cost of transmission expansion and power-system decarbonization. While innovation in long-duration energy storage and nuclear power has the potential to reduce system costs, all zero-carbon systems modeled here deploy substantial capacities of wind and PV (>670 GW in all cases and >2,200 GW in the base case), demonstrating the importance of near-term deployment of available technologies in the pursuit of urgent climate targets.

EXPERIMENTAL PROCEDURES

Resource Availability

Lead Contact

Requests for further information should be directed to the Lead Contact, Patrick R. Brown (prbrown@alum.mit.edu).

Materials Availability

No materials were used in this study.

Data and code availability

Computer code, input data, and results are available as a Zenodo repository at https://doi.org/10.5281/zenodo.4268878.

Full experimental procedures are given in the Supplemental Information.

SUPPLEMENTAL INFORMATION

Supplemental Information can be found online at https://doi.org/10.1016/j.joule.2020.11.013.

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AUTHOR CONTRIBUTIONS

P.R.B. conceived the study, built the model, collected data, performed the analysis, and wrote the manuscript. A.B. provided guidance on model design and technical assumptions and edited the manuscript.

DECLARATION OF INTERESTS

Both authors are affiliated with the MIT Energy Initiative, which receives funding from a variety of external sources, including oil and gas producers, utility companies, renewable energy companies, private philanthropic organizations, and environmental non-profits, listed at http://energy.mit.edu/membership/#current-members. P.R.B. is also at the National Renewable Energy Laboratory, and A.B. is also at Argonne National Laboratory. None of these organizations were involved with the development of the work reported here. The authors declare no other competing financial interests.

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