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Zero air pollution and zero carbon from all energy at low cost and without blackouts in variable weather throughout the U.S. with 100% wind-water-solar and storage

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ABSTRACT

This study analyzes 2050–2051 grid stability in the 50 U S. states and District of Columbia after their all-sector (electricity, transportation, buildings, industry) energy is transitioned to 100% clean, renewable Wind-Water-Solar (WWS) electricity and heat plus storage and demand response (thus to zero air pollution and zero carbon). Grid stability is analyzed in five regions; six isolated states (Texas, California, Florida, New York, Alaska, Hawaii); Texas interconnected with the Midwest, and the contiguous U.S. No blackouts occur, including during summer in California or winter in Texas. No batteries with over 4-h storage are needed. Concatenating 4-h batteries provides long-duration storage. Whereas transitioning more than doubles electricity use, it reduces total end-use energy demand by ~57% versus business-*as*-usual (BAU), contributing to the 63 (43–79)% and 86 (77–90)% lower annual private and social (private + health + climate) energy costs, respectively, than BAU. Costs per unit energy in California, New York, and Texas are 11%, 21%, and 27% lower, respectively, and in Florida are 1.5% higher, when these states are interconnected regionally rather than islanded. Transitioning may create ~4.7 million more permanent jobs than lost and requires only ~0.29% and 0.55% of new U.S. land for footprint and spacing, respectively, less than the 1.3% occupied by the fossil industry today.

1. Introduction

The United States is currently undergoing a slow but consistent transition to clean, renewable energy. We define clean, renewable energy as energy that is both clean (emits zero health- and climate-affecting air pollutants when consumed) and renewable (has a source that continuously replenishes the energy). We call energy sources that meet these criteria Wind-Water-Solar (WWS) sources. WWS electricity-generating technologies include onshore and offshore wind turbines (Wind); tidal turbines, wave devices, geothermal electric power plants, and hydroelectric power plants (Water); and rooftop/utility solar photovoltaics (PV) and concentrated solar power (CSP) plants (Solar) (Table 1). WWS heat-generating technologies include solar thermal and geothermal heat plants. WWS electricity must be transported by alternating current (AC), high-voltage AC (HVAC), and high-voltage direct current (HVDC) transmission lines and AC distribution lines (Table 1). WWS energy must also be stored in either electricity, heat, cold, or hydrogen storage media (Table 1). Finally, a transition to WWS requires equipment for transportation, industry, and buildings that runs on electricity. Such equipment includes electric and hydrogen fuel cell vehicles, heat pumps, induction cooktops, arc furnaces, resistance furnaces, lawn mowers, leaf blowers, chainsaws, and more (Table 1).

For this study, we consider only WWS energy since we believe that WWS technologies result in greater simultaneous reductions in air pollution, climate damage, and energy insecurity than do non-WWS technologies. We do not include fossil energy, bioenergy, non-hydrogen synthetic fuels, blue hydrogen, carbon capture, direct air capture, or nuclear energy, since each may result in a greater risk of air pollution, climate damage, and/or energy insecurity. The only hydrogen considered is green hydrogen (from WWS electricity). If we can solve all three problems at reasonable cost with WWS alone, we will not need miracle or controversial technologies to help.

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Table 1
Main generation, transmission, storage, efficiency, and use components of a 100% WWS system to provide energy for all purposes.

WWS Generation	WWS Storage	WWS Equipment
WWS electricity generation	Electricity storage	Building & district air/water heating
Onshore/offshore wind	Batteries	Electric heat pumps
Rooftop/utility photovoltaics	CSP storage	
Concentrated solar power	Pumped hydro storage	Building and district cooling
Geothermal electricity	Hydropower reservoirs	Electric heat pumps
Hydroelectricity	Flywheels	
Tidal & wave	Compressed air	Industrial heat
	Gravitational storage	Arc/induction/resistance furnaces
WWS heat generation		Dielectric/electron beam heaters
Solar thermal/CSP steam	District heat storage	Heat pumps/CSP steam
Geothermal heat	Water tanks	
	Boreholes	Hydrogen generation/compression
WWS Grid	Water pits	Electrolyzers/compressors
Transmission/distribution	Aquifers	
AC/HVAC/HVDC lines		Transportation vehicles
Distribution lines	District cold storage	Battery-electric
Grid management	Water tanks	Hydrogen fuel cell
Software	Ice	
Demand response	Aquifers	Some appliances/machines
		Induction cooktop
	Building heat storage	Electric leaf blower/lawn mower
	Water tanks	Heat pump dryer
	Thermal mass	
		Efficiency/reduced energy use
	Hydrogen storage	Insulate/weatherize buildings
	Hydrogen storage tanks	LED lights/efficient appliances
		Telecommute/public transit

CSP = concentrated solar power; AC = alternating current; HVAC = high-voltage alternating current; HVDC = high-voltage direct current; LED = light-emitting diode.

In 2020, WWS generators produced 19.2% of U.S. electricity, an increase from ~17% in 2019 [1]. Wind produced the majority (8.3% of all electricity) followed by water (hydroelectric and geothermal) (7.6%), and solar (3.3%). Of the WWS capacity additions since 2000, 45% were due to renewable portfolio standard (RPS) policies and the rest, which were in non-RPS markets, were due to voluntary green power markets, net-metered building PV, and utility purchases arising from the low cost of renewables [2].

The RPS laws fostering a transition include laws that have mandated a transition to 100% renewables. As of December 2021, 15 U S. states/districts/territories (California, Connecticut, Hawaii, Maine, Nevada, New Jersey, New Mexico, New York, Oregon, Puerto Rico, Rhode Island, Virginia, Washington D.C., Washington State, and Wisconsin) had enacted executive orders or laws requiring up to 100% renewables in the electric power sector [3]. Similarly, over 180 U S. cities had enacted such policies [4]. Business commitments have helped spur a transition in non-RPS markets. Over 340 international businesses have enacted policies requiring 100% renewable electricity or total energy for their global operations [5].

Future transition efforts to WWS will focus on buildings, transportation, and industry. By 2020, California's building code had required all new residential buildings to be zero net energy (ZNE) [7]. The annual consumed energy in a ZNE building is less than the on-site renewable energy generated. By the end of 2020, 41 cities in California had modified building codes to prevent the use of natural gas in new buildings, requiring them instead to run on electricity [6].

States are also phasing out fossil-fuel transportation. California and Massachusetts, for example, have banned the sale of new gasoline and diesel cars and small trucks by 2035 [8,9]. Simultaneously, electric vehicle sales are increasing throughout the U.S. Progress is similarly being made in industry. Not only are many companies self-mandating 100% renewables [5], but a rare-earth element mine in Texas, for example, will run on 100% renewables [10].

While the changes occurring so far are encouraging, they are not enough. Experts believe the world needs to transition all energy by 2035 to eliminate the seven million air pollution deaths that occur each year and to minimize climate damage [11]. Given that only ~4.5% of the infrastructure needed to power the U.S. entirely with WWS was in place in 2019/2020 (Table 3), it is imperative to speed up the transition to meet this goal.

On the other hand, some have blamed the growth in renewable electricity and its intermittency for the August 14–15, 2020, summer grid blackout in California and the February 14–18, 2021, winter blackout in Texas. WWS supplied close to 50% of California's electricity and 23% of Texas' electricity in 2020. Despite some blaming renewables, the heads of the California Public Utility Commission, California Independent System Operator, and California Energy Commission confirmed that “renewable energy did not cause the rotating outages” [12]. Instead, a variety of factors, including an unexpected unavailability of imports across the west, led to the blackouts. In fact, a proposed method to avert new failures was to “*shift* 80 MW *of (hydropower) electricity generation to the peak period*” [12], a technique previously proposed for use in a large-scale transition to WWS [13]. In the case of Texas, low temperatures caused natural gas, coal, nuclear, and wind electricity generators to fail, with natural gas being the largest source of electricity and failure [14]. A portion of frozen wind turbines had to be shut down because none had de-icing equipment.

Nevertheless, a substantial fear is that increasing WWS will increase blackouts. One purpose of this study is to evaluate this contention. To that end, this study analyzes the technical, economic, and grid stability attributes of a transition of all states and grid regions in the U.S. to 100% WWS energy and storage for all energy purposes. Although such a transition should be completed by 2035, with at least 80% by 2030, this study examines what a 100% WWS transition looks like in 2050, after further population growth and efficiency improvements have occurred.

Previous 100% clean, renewable energy roadmaps for individual U.S. states have been developed for New York, California, Washington State, and all 50 states [15–18]. The same group performed grid stability studies for California [19] and the 48 contiguous states [13,20–22]. Additional grid studies have examined near or at 100% renewable electricity or all energy in the U.S. [23–27]. One such study out of the U.S. National Renewable Energy Laboratory (NREL) [27] found that a 100% WWS U.S. electricity grid with no combustion turbines might cost ~4.8 ¢/kWh to keep the grid stable. This is less than the cost of electricity from a new natural gas plant. Several more studies have examined penetrations of up to 80% renewables. Even more have examined 100% renewable scenarios in other parts of the world and found such scenarios feasible at low cost [28–40].

Here, we expand upon our previous 50-state roadmap study [18] to develop new end-point roadmaps for each of the 50 U S. states and Washington D.C. to meet annual average load. We then expand upon our previous U.S. grid integration studies [13,20,21] to investigate meeting continuous load for two years (2050 and 2051) in six individual states (Alaska, California, Florida, Hawaii, New York, and Texas), five additional North American Electric Reliability Corporation (NERC) regions, Texas interconnected with the Midwest Reliability Organization (MRO) grid, and the contiguous United States (CONUS) as a well-interconnected grid (Table 2). We also examine, for the first time, whether the grids in California and Texas, which recently experienced blackouts, can run entirely on WWS energy and storage, both in isolation and when connected to larger grids. We further examine a new issue: whether long-duration battery storage is needed.

This study uses the latest 2018 Energy Information Administration (EIA) [41] end-use energy consumption data for the 50 states and D.C. rather than the 2012 data used in Ref. 18. The study also adopts updated future energy projections from EIA [42] plus more general techniques for determining rooftop solar availability [21,43]. In addition, it develops time-dependent heating load profiles for buildings in each state using the same weather-climate-air pollution model used to develop time-dependent wind and solar supply data [44]. The study further incorporates 2016–2020 electric load data from 13 U S. regions (Figs. 1 and S1) [45].

This study adopts a new and more detailed analysis of onshore wind resources [46] and of rooftop solar resources than before. It also accounts for end-use power demand reductions due to eliminating the energy needed to extract fossil fuels, which Ref. [18] did not do. It further assumes low-temperature heat will be obtained from heat pumps; Ref. [18] assumed mostly resistance heating. The study then assumes all high-temperature heat from industry will be obtained from electric furnaces and heaters (Table 1), or similar technologies, whereas the previous study assumed some hydrogen combustion in industry for heat. Both studies assume that green electrolytic hydrogen (produced from WWS electricity) will be used for long-distance, heavy transport. Finally, the present study accounts for new jobs to build electricity, heat, cold, and hydrogen storage and all-distance transmission and distribution, which the previous study did not.

2. Methodology

Note S2 of the Supplementary Information (SI) describes the methodology used here for developing year-2050 roadmaps to transition each of the 50 U S. states and D.C. to 100% WWS in order to meet annual average load among all energy sectors. It then describes the weather-climate-air pollution model used to predict time-dependent solar, wind, and wave resources and building heat and cold loads. Finally, it details the grid integration model used to meet continuous load every 30 s for two years (2050 and 2051) in states and regions. The main steps in the study are summarized briefly here, as follows:

(1) Project 2018 business-*as*-usual (BAU) end-use energy demand from EIA [41] to 2050 for each of six fuel types in each of four energy-use sectors for each state and D.C. with “BAU reference scenario” projections for the U.S. as a whole [42];
(2) Transition BAU load powered by each fuel type in each sector in 2050 to WWS electricity and heat load with factors in Table S2 and calculate the resulting reduction in energy demand, for each state and D.C.;
(3) Perform resource analyses and estimate mixes of wind-water-solar (WWS) electricity and heat generators to meet the annual-average end-use load among all energy sectors in each state and D.C.;
(4) Use a prognostic global weather-climate-air pollution model (GATOR-GCMOM [47–50], Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model), which accounts for competition among wind turbines for available kinetic energy, to estimate wind and solar radiation fields

Table 2
North American Reliability Corporation (NERC) grid regions as of February 2021 plus additional regions simulated here.

Region	NERC Region Name	States/Districts Mainly Within Each Region
WECC	Western Electricity Coordinating Council	Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington State, Wyoming
MRO	Midwest Reliability Organization	Iowa, Kansas, Minnesota, Nebraska, North Dakota, Oklahoma, South Dakota, Wisconsin
TRE	Texas Reliability Entity	Texas
RFC	Reliability First Corporation	Delaware, Indiana, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Washington D.C., West Virginia
SERC	Southeastern Electric Reliability Council	Alabama, Arkansas, Florida, Georgia, Illinois, Kentucky, Louisiana, Mississippi, Missouri, North Carolina, South Carolina, Tennessee, Virginia
NPCC	Northeast Power Coordinating Council	Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont
ASCC	Alaska System Coordinating Council	Alaska
HICC	Hawaiian Islands Coordinating Council	Hawaii
Region	Additional Region Name	States/Districts Within Each Region
CALI	California	California
FLA	Florida	Florida
NEWY	New York	New York
TXMRO	TRE + MRO	Iowa, Kansas, Minnesota, Nebraska, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin
CONUS	48 contiguous states + DC	48 contiguous states + DC

Some states appear partially in two NERC regions. They are assigned to the region with the larger areal coverage. Table S1 identifies the source of load data for each region.
“Total USA” is the sum of results from CONUS + ASCC + HICC.
CONUS also consists of the states in the WECC + MRO + TRE + RFC + SERC + NPCC regions.

Table 3
Nameplate capacity by WWS generator needed to meet 2050 (a) annual average and (b) continuous all-purpose end-use load plus transmission/distribution/maintenance losses, storage losses, and shedding losses for the sum of CONUS + ASCC + HICC results ("Total USA"). (c) Nameplate capacity already installed for the "Total USA." (d) Percent of 2050 end-use load plus losses supplied by the final nameplate capacity of each generator.

WWS Technology	(a) 2050 initial existing plus new nameplate capacity to meet annual-average load + losses (GW)	(b) 2050 final existing plus new nameplate capacity to meet continuous load + losses (GW)	(c) Nameplate capacity installed as of 2019 or 2020 (GW)	(d) Percent of 2050 WWS load + losses supplied by each generator
Onshore wind	974	1116	112.6	28.24
Offshore wind	573	855.6	0.042	16.37
Wave device	9.77	9.77	0	0.19
Geothermal electricity	7.65	7.65	3.85	0.46
Hydropower plant	88.8	88.8	88.8	2.97
Tidal turbine	1.28	1.28	0	0.022
Res. roof PV	688.3	686.8	13.91	9.05
Com/gov roof PV	622.6	870.2	8.74	11.47
Utility PV plant	1638	2211	36.26	30.77
Utility CSP plant	8.82	7.98	1.87	0.44
Solar thermal heat plant	0	0	0	0
Geothermal heat plant	0	0	0	0
Total all	**4613**	**5854**	**266**	**100**

"Annual average load + losses" is all-purpose end-use energy demand plus losses per year divided by 8760 h per year. "Initial" nameplate capacities (meeting annual-average demand) are nameplate capacities at the start of LOADMATCH simulations. "Final" nameplate capacities are those needed to match load plus losses after LOADMATCH simulations. Table S9 gives final nameplate capacities by state/region. Table S8 gives nameplate capacities already installed by state/region. Table S12 gives values in Column (d) by region.

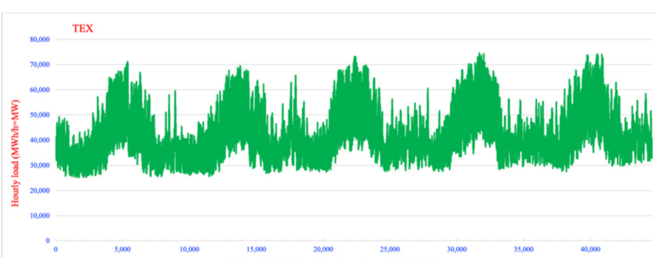

Fig. 1. Unmodified 2016–2020 hourly electric load (MWh/h = MW) for the Texas region [45]. Table S1 shows the average load by year.

and heat and cold loads in buildings every 30 s for two years in each state and D.C.;
(5) Group the 50 states and D.C. into the regions listed in Table 2, then use the LOADMATCH [13,20,21,44,51] grid integration model to match time-dependent WWS supply with demand, storage, and demand response every 30 s in 2050 and 2051 for each region;
(6) Calculate differences in BAU and WWS energy, health, and climate costs;
(7) Calculate land areas needed for new WWS energy generators;
(8) Calculate job changes resulting from a transition to WWS; and
(9) Discuss uncertainties.

Thus, three types of models are used for this study: a spreadsheet model (Steps 1–3, Note S2), a 3-D global weather-climate-air pollution model (Step 4, Note S3), and a grid integration model (Steps 5–8, Notes S4–S6). The SI discusses all three models in detail.

Briefly, LOADMATCH (Notes S4–S6) is a trial-and-error simulation model. It works by running multiple simulations for each state or grid region, one at a time. Each simulation marches forward one timestep at a time, just as the real world does, for any number of years for which sufficient input data are available. The main constraint during a simulation is that the summed electricity, heat, cold, and hydrogen load and losses, adjusted by demand response, must match energy supply and storage every timestep for an entire simulation period. If load is not met during any timestep, the simulation stops, inputs are adjusted (Note S4), and another simulation is run from the beginning. New simulations are run until load is met every time step of the simulation period. After load is met once, more simulations are performed with further-adjusted inputs based on user intuition and experience to generate a set of solutions that match load every timestep. The lowest cost solution in this set is then selected. Because LOADMATCH does not permit any load loss, it is designed to exceed the utility industry standard of load loss once every 10 years.

Unlike with an optimization model, which solves among all timesteps simultaneously, a trial-and-error model does not know what the weather will be during the next timestep. Because a trial-and-error model is non-iterative, it requires less than a minute for a 3-year simulation with a 30-s timestep. This is 1/500th to 1/100,000th the computer time of an optimization model for the same number of timesteps, regardless of computer architecture. The disadvantage of a trial-and-error model versus an optimization model is that the former does not find the least cost solution out of all possible solutions. Instead, it produces a set of viable solutions, from which the lowest-cost solution is selected.

3. Simulations and results

Fig. 2 shows two transition pathways between 2020 and 2050. In the first, 100% of all BAU energy is transitioned to WWS by 2035,

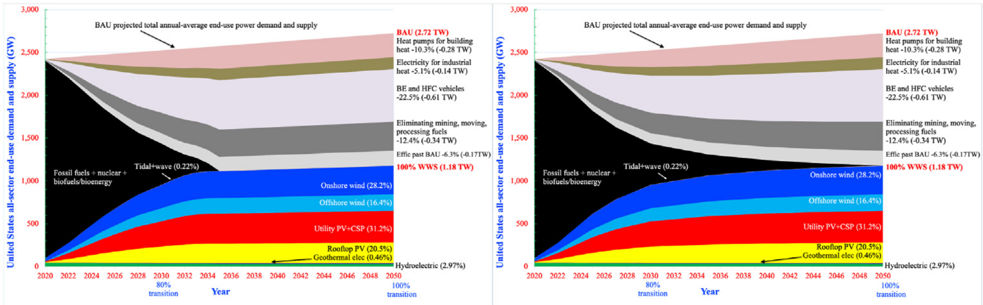

Fig. 2. Timeline for transitioning the United States to 100% WWS by 2035 (first panel) and 2050 (second panel), with 80% by 2030 in both cases. Five types of reductions in energy requirements occur along the way. Derived from totals in Table S3.

with 80%, by 2030. In the second, 100% is transitioned by 2050, with 80%, by 2030. The scenarios result in the same 2050 end-use energy requirements and WWS supply mixes, just different pathways to get there. Results here focus on the results in 2050.

The annual average end-use U.S. BAU loads in 2018 and 2050 are 2.40 and 2.72 TW, respectively (Fig. 2, Table S3). For comparison, the 2012 and 2050 U S. BAU loads from Ref. [18] were 2.37 and 2.62 TW, respectively. The slight difference in 2050 values is due mostly to the fact that the EIA projection of the 2012 data was to 2040 and a linear extrapolation was used thereafter, whereas the EIA projection here of the 2018 data is all the way to 2050.

As a result of electrifying or providing direct heat for all energy, transitioning from BAU to WWS in 2050 decreases all-purpose annual average end-use WWS power demand over the U.S. by ~56.7% to 1.18 TW (Fig. 2), with reductions ranging from 47.0% to 64.8% for individual states (Table S3). Of the mean U.S. decrease, ~37.9% points are due to the efficiency of WWS electricity over combustion; ~12.4 points are due to eliminating energy in the mining, transporting, and refining of fossil fuels and uranium; and ~6.4 points are due to end-use energy efficiency improvements and reduced energy use beyond those with BAU. Of the 37.9% decrease due to the efficiency of WWS, 22.5 points are due to the efficiency of WWS transport, 5.1 points are due to the efficiency of WWS electricity over combustion for industrial heat, and 10.3 points are due to the efficiency of electric heat pumps over combustion or electric resistance for building heat (Fig. 2). Thus, transitioning reduces end-use energy needs substantially.

Simultaneously, electrifying all energy increases electricity requirements. For example, in 2050, electricity may provide an estimated ~21.4% (582 GW) of BAU end-use annual average power among the 50 states. Upon electrifying all non-electricity sectors and providing the electricity with WWS in 2050, total electricity (and some direct heat) will provide almost 100% (1.18 TW) of the total annual-average end-use power (Fig. 2, Table S3). Thus, the 2050 WWS:BAU electricity consumption ratio is 2.03 [Table S3, Column (j)]. In other words, although WWS reduces total end-use load by 56.7% [Table S3, Column (i)], it increases the electricity load by 103% versus BAU. Thus, overall power needs decrease but electric power needs increase with WWS.

Next, GATOR-GCMOM was run on the global scale for 2050 and 2051 at 4° × 5° horizontal resolution under 2050–2051 climate conditions. The model calculated electricity production from onshore and offshore wind, rooftop and utility PV, and CSP; heat production from solar thermal collectors; and heat and cold loads for buildings, every 30 s for each U.S. state and D.C. The nameplate capacities in each state used in that model were those estimated to meet annual-average 2050 load in each state. The time-dependent WWS supplies and building heat and cold loads from GATOR-GCCMOM were then used in LOADMATCH.

LOADMATCH was run for each case in Table 2 with initial generator nameplate capacities and storage characteristics by state estimated to meet annual average WWS load. Table 3 provides the initial estimated nameplate capacities summed over the 50 states and D.C. If the first simulation did not result in a stable solution, inputs were adjusted each subsequent simulation until a zero-load-loss solution was found among all 30-s timesteps of each 2-year simulation. Success typically occurred within 10 simulation attempts. After one successful simulation, the model was run another 4–20 simulations with further adjustments to find lower-cost solutions. Thus, multiple zero-load loss solutions were found for each location, but only the lowest-cost solution is presented here.

Table S9 provides the final generator nameplate capacities for each state and region. Table 3 shows the same, but for the U.S. as a whole. Table S10 provides the ratio of final to first-guess generator nameplate capacities for each generator by region. Table S11 provides the final simulation-averaged capacity factors for each generator in each region. Table S12 provides the final energy supply in each region by generator type, before transmission, distribution, storage, or shedding losses. Table S13 provides the final storage peak charge rates, discharge rates, and capacities.

Tables 3 and S12 indicate that wind and solar dominate future U.S. energy production under the 100% WWS scenarios here. For the CONUS + HICC + ASCC domains (all 50 states and D.C.), 44.6% of all energy supplied may come from wind (28.2% onshore and 16.4% offshore), whereas 51.7% may come from solar (20.5% roof PV, 30.8% utility PV, and 0.44% CSP). Most of the rest may come from hydro (2.97%, all of which is assumed to exist today) and geothermal (0.46%), with the remainder from wave and tidal. The regions with the highest percentage of their 2050 estimated power produced from wind are ASCC (95%), NEWY (64.3%), HICC (64.0%), NPCC (53.9%), and TRE (52.4%) (Table S12). The region with the least wind generation is FLA (20.9%). The regions with the highest percentage from solar are FLA (78.8%), SERC (71.0%), RFC (64.3%), and CALI (58.5%). The region with the least solar generation is ASCC (1.01%).

3.1. Matching load with supply exactly

Figs. 3 and S2 show the full 2050 time series of WWS power generation versus load plus losses plus changes in storage plus shedding for each region. Supply exactly matches total demand (end-use load plus changes in storage plus transmission, distribution, and maintenance losses (TD&M) plus losses in and out of storage plus shedding losses) every 30 s in each region.

Table S15 and Fig. 4 show that, for "Total USA," ~12.7% of all energy produced is shed; ~6.26% is lost due to TD&M losses; and ~2.32% is lost during charging and discharging of storage. Shedding losses occur because the nameplate capacity required to meet continuous load for "Total USA" is ~26.9% higher than that required

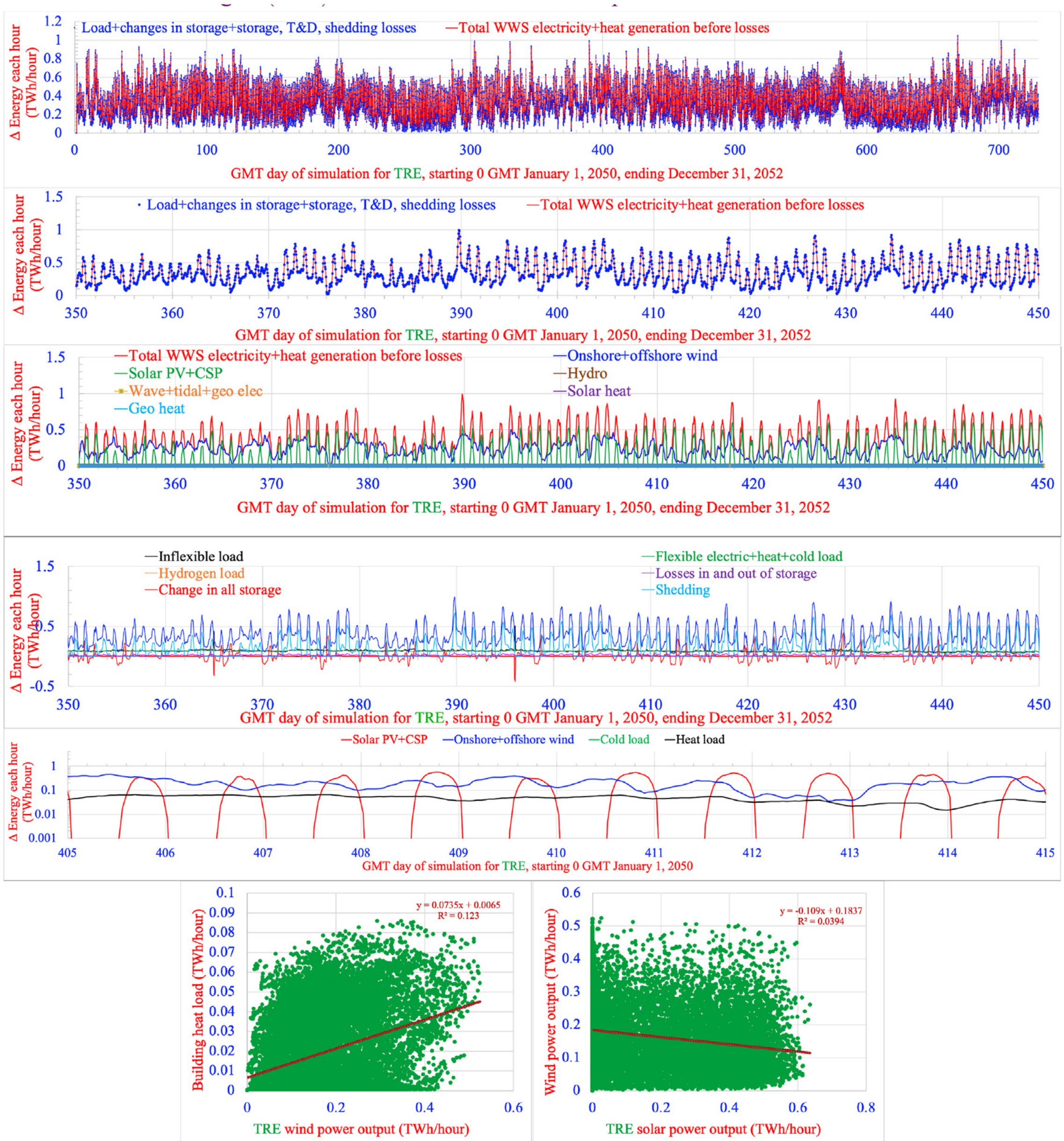

Fig. 3. 2050–2051 hourly time series showing the matching of all-energy demand with supply and storage for the isolated Texas grid (TRE). Also shown are correlation plots. First row: modeled time-dependent total WWS power generation versus load plus losses plus changes in storage plus shedding for the full two-year period. Second row: same as first row, but for a window of 100 days during winter. Third row: a breakdown of WWS power generation by source during the window. Fourth row: a breakdown of inflexible load; flexible electric, heat, and cold load; flexible hydrogen load; losses in and out of storage; transmission and distribution losses; changes in storage; and shedding during the window. Fifth row: A breakdown of solar PV + CSP electricity production, onshore plus offshore wind electricity production, building total cold load, and building total heat load as used in LOADMATCH during a 10-day window; Sixth row: correlation plots of building heat load versus wind power output and wind power output versus solar power output, obtained from all hourly-averaged data from GATOR-GCMOM, as used in LOADMATCH, during the simulation. Correlations are very strong for R = 0.8–1 (R^2 = 0.64–1); strong for R = 0.6–0.8 (R^2 = 0.36–0.64); moderate for R = 0.4–0.6 (R^2 = 0.16–0.36); weak for 0.2–0.4 (R^2 = 0.04–0.16); and very weak for 0–0.2 (R^2 = 0–0.04) [61]. The model was run at 30-s resolution. No load loss occurred during any 30-s interval. Results are shown hourly, so units are energy output (TWh/h = TW). Fig. S2 shows results for all regions.

to meet annual average load (Table 3). Oversizing is needed to meet peaks in load. However, oversizing results in some wasted (shed) energy. Some of the shedding is avoided because some excess electricity is used to produce heat, cold, and hydrogen that is either used immediately or stored (Note S6). When load is already met and electricity, heat, cold, and hydrogen storage are full, the excess electricity is shed. Because excess electricity that would otherwise be shed is used to produce at least some heat, cold, and green hydrogen, the overall waste and cost per unit energy of a WWS system that uses excess electricity in this way are less than of a system that sheds all excess electricity.

3.2. Are long-duration batteries needed?

What are battery storage capacity requirements to keep each region stable? For the “Total USA” (CONUS + ASCC + HICC), they are 15.7 TWh (Table S13). For the 50 states separated into eight grid regions (WECC, MRO, TRE, RFC, SERC, NPCC, ASCC, HICC), they are a combined 29.8 TWh. For the same regions, except MRO and TRE merged into TXMRO, they are a combined 26.3 TWh. For comparison, the U.S.-produced hydropower output in 2020 was 285 TWh. In 2050, the expected annual U.S. plus imported Canadian hydropower output in 2050 will be ~389 TWh/yr (Table S12), which

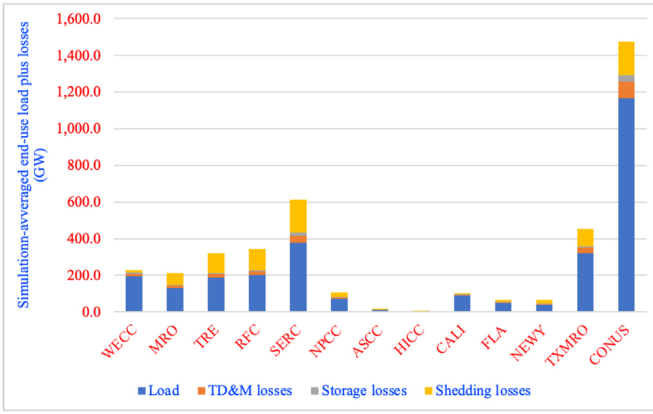

Fig. 4. Shares (GW) of simulation-averaged power produced by WWS used to meet end-use load, transmission, distribution, and maintenance (TD&M) losses, losses in and out of storage, and shedding losses. Table S15 provides exact values used in the figure. Table 2 defines the regions.

assumes no growth in hydro nameplate capacity between 2020 and 2050. As such, the 2050 annual hydro output is 13–25 times the battery storage capacity (or batteries would need to be cycled 13–25 times completely in one year to match hydropower storage. The number of full battery cycles per year range from 6 in Alaska to 228 in WECC (Table S14).

The United States has potential for up to 114 TWh of low-cost and 1400 TWh of low and high-cost pumped hydropower storage (PHS) capacity [52]. At 14-h of storage (Table S14), those capacities correspond to 8.1 TW and 100 TW of PHS peak discharge rate (generator nameplate capacity). The nameplate and storage capacities available are much greater than the 0.0596 TW/0.83 TWh of PHS proposed across the U.S. for this study (Table S13) or for Ref. [13], which assumed an increase in the peak discharge rate, but not of the storage capacity of U.S. hydropower. This study assumes the use of existing PHS plus PHS added between 2020 and 2050 based on pending licenses and preliminary permits. Instead of proposing almost all batteries to meet most storage needs, we could substitute them with PHS. In fact, the mean estimated cost of PHS per unit storage capacity between 2020 and 2050 is lower than that of batteries (Table S18). Also, PHS does not require chemical mining. However, permitting and building PHS takes longer and usually results in more community objection than do batteries. Given the need for a rapid transition and the greater ease of siting batteries, batteries are selected as the main option here. On the other hand, the growth of PHS beyond that proposed here would mean fewer batteries, facilitating the solution.

All batteries modeled are assumed to have 4-h storage at their peak discharge rate. To obtain longer storage, batteries are concatenated in series. In other words, if 8-h storage is needed, then one 4-h battery is depleted before a second 4-h battery is depleted. Minimizing storage time maximizes the flexibility of batteries both to meet peaks in demand (GW) and to store electricity for long periods (GWh). For example, suppose 100 batteries, each with 4-h storage and a peak discharge rate of 10 kW, are concatenated. This allows for either 400 h of storage at a peak discharge rate of 10 kW or 4 h of storage at a peak discharge rate of 1000 kW, or anything in between.

In sum, batteries with longer than 4-h storage are not needed to keep the grid stable. We similarly find that batteries with 1.94-h storage can keep the grids stable in all the regions (results not shown). However, for some regions, it is more efficient to have batteries with storage times at peak discharge of up to 62 h. Table S14, Column (e), shows the ratio of the assumed storage capacity (TWh) to the modeled maximum battery discharge rate (TW) during each simulation. This ratio is the ideal number of hours of storage at the peak discharge rate. The ratio ranges from 4 h for WECC to 62 h for NEWY, with most values below 25 h. The ratio indicates that, although 4-h batteries work fine, they result in, for all cases aside from WECC, peak discharge rates higher than necessary for the simulations performed. Thus, a longer storage time would ensure that the peak discharge rate of batteries is closer to what is needed. However, there is no technical disadvantage of having a higher peak discharge rate than necessary. Instead, there is an advantage since it allows for more flexibility to meet future growth in peak load.

This study suggests that long-duration (>62 h) storage for a single battery is never needed because we use storage for both its storage capacity and peak discharge rate, and the ratio of the storage capacity (TWh) to peak discharge rate (TW) is never >62 h (Table S14). This result contrasts with that of a recent study [53] that argues that long-duration (>100 h) battery storage is necessary for renewables to be cost competitive with BAU fuels. That study did not consider concatenating 4-h batteries to obtain long-duration storage. It also did not consider electrifying all energy sectors, demand response, or thermal energy storage.

Table S13 indicates that batteries dominate the peak discharge rate of electricity storage in all regions. The battery peak discharge rate for the "Total USA" (CONUS + ASCC + HICC) case is 3920 GW. For comparison, the peak discharge rate of hydropower is 88.8 GW; of pumped hydro is 59.6 GW; and of CSP is 8 GW. The battery peak discharge rate for all eight individual regions (WECC, MRO, TRE, RFC, SERC, NPCC, ASCC, HICC) is 7457 GW, which is higher than for "Total USA.". That for the eight regions, but with TRE and MRO merged into TXMRO, is 6587 GW. Thus, the greater the interconnection of regions, the less that battery storage is needed.

3.3. Energy, health, and climate costs

Energy social costs include the private plus health plus climate costs of energy. Both private and social costs of energy are provided here. The cost analysis here is a social cost analysis since policies are usually based on social (economic) costs rather than private (business) costs. A social cost analysis requires a social discount rate, not a private-individual discount rate, even for the private-market-cost portion of the total social cost. To maintain consistency with the fact that our analysis is a social cost analysis, we use a social discount rate of 2 (1–3)% for *all* costs, both private and economic, and for both WWS and BAU [21].

The WWS private cost per unit energy includes the costs of new electricity and heat generation (Table S17); short- and long-distance transmission and distribution (Table S17); heat, cold storage, and electricity storage (Table S18), and hydrogen production/compression/storage [21]. WWS energy private costs are assumed to equal WWS energy social costs, since in 2050, WWS generators, storage, and transmission will result in zero pollution emissions while in use. Also, their manufacture and decommissioning will be free of energy-related emissions. The health and climate costs of zero emissions are zero. Tables S20 and 3 provide annual energy, air pollution, and climate costs in the BAU and WWS cases for each state. BAU air pollution cost estimates are based on the projected number of air pollution deaths per year by state in 2050 due to energy (derived from values in Table S21) multiplied by a value of statistical life and cost factors for morbidity and non-health environmental impacts (Note S7). BAU climate costs are based on the social cost of carbon applied to estimated anthropogenic CO_2-equivalent emissions in 2050 by state (Table S21), as described in Note S7.

Table 4 indicates that the present-value of the upfront capital cost between 2020 and 2050 to transition a well-interconnected

CONUS grid plus Alaska and Hawaii ("Total USA") to WWS is $8.94 trillion (in USD 2020). This is the cost of electricity, heat, cold, and hydrogen generation and storage and all-distance transmission and distribution. It is the cost of the energy portion of the *Green New Deal* for the U.S. [21]. If the eight regions making up the 50 states (WECC, MRO, TRE, RFC, SERC, NPCC, ASCC, HICC) are isolated, the capital cost is $10.95 trillion. If all grid regions are isolated but TRE and MRO are merged to TXMRO, the capital cost of transitioning all 50 states (WECC, TXMRO, RFC, SERC, NPCC, ASCC, HICC) drops to $10.28 trillion. The 2050 WWS annual private energy cost (which equals the annual social energy cost) in the same three cases are $933 billion/yr, $1080 billion/yr, and $1030 billion/yr, respectively (Table 4).

Table 4 indicates that the upfront capital cost and annual private cost of energy for just the well-interconnected CONUS region are ~19% and ~14% lower, respectively, than the sum of such costs for each region (WECC, MRO, TRE, RFC, SERC, and NPCC) in isolation within CONUS. Similarly, the capital and annual costs of energy for the interconnected TXMRO region (TRE + MRO) are ~21% and ~15% lower, respectively, than the sum of such costs for TRE and MRO in isolation (Table 4). These results are consistent with previous studies that found that interconnecting larger and larger geographic regions smoothened power supply and/or reduced costs [51,54–58].

In the "Total USA" case, the 2050 BAU annual private energy cost is $2.5 trillion/yr, and the 2050 BAU annual social energy cost is $6.8 trillion/yr (Tables 4 and S20; Figs. 5 and S3). Thus, the private and social costs of WWS energy (both $933 billion/yr) are ~63% and ~86% lower, respectively, than those of BAU (Tables 4 and S20; Figs. 5 and S3). Across all cases, the WWS private and social costs are 43–79% and 77–90% lower, respectively, than those of BAU (Table 4; Fig. S3). The greatest private cost percentage decrease occurs in Hawaii, where energy prices are very high today due to

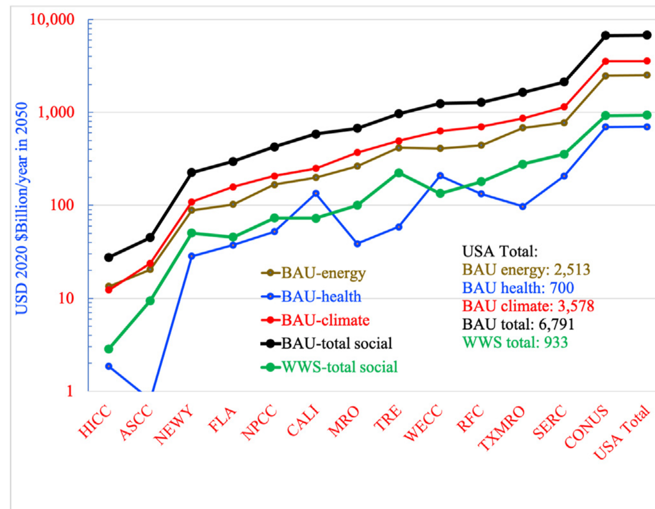

Fig. 5. BAU versus WWS social cost (energy plus health plus climate cost) of energy for each region simulated here.
Values are from Table 4. WWS social cost is just the energy cost. "USA Total" values are for CONUS + ASCC + HICC.

Table 4
2050 annual-average end-use (a) BAU load and (b) WWS load; (c) percentage difference between WWS and BAU loads; (d) 2020 mean capital cost of new WWS energy; mean levelized private costs (¢/kWh-all-energy-sectors, averaged between today and 2050) of all (e) BAU and (f) WWS energy; mean annual (g) WWS private (equals social) energy cost, (h) BAU private energy cost, (i) BAU health cost, (j) BAU climate cost, (k) BAU total social cost; percentage difference between (l) WWS and BAU private energy cost and (m) WWS and BAU social energy cost.

Region	(a) 2050 BAU Annual average end-use load (GW)	(b) 2050 WWS Annual average end-use load (GW)	(c) 2050 WWS minus BAU load= (b-a)/a (%)	(d) WWS mean capital cost ($tril 2020)	(e) BAU mean (¢/kWh-all energy)	(f) WWS mean (¢/kWh-all energy)	(g) WWS mean annual all-energy private cost = social cost = bfH ($bil/y)	(h) BAU mean annual all-energy private cost = aeH ($bil/y)	(i) BAU mean annual BAU health cost ($bil/y)	(j) BAU mean annual climate cost ($bil/y)	(k) BAU mean annual BAU total social cost = h + i + j ($bil/y)	(l) WWS minus BAU private energy cost= (g-h)/h (%)	(m) WWS minus BAU social energy cost= (g-k)/k (%)
WECC	472.0	195.5	−58.6	1.084	9.94	7.83	134.2	410.9	208.8	627.4	1247	−67.3	−89.2
MRO	292.3	131.7	−54.9	0.910	10.30	8.69	100.3	263.8	38.6	369.9	672.2	−62.0	−85.1
TRE	434.4	188.2	−56.7	2.345	10.96	13.58	223.9	417.1	58.6	492.4	968.1	−46.3	−76.9
RFC	476.6	200.7	−57.9	1.886	10.62	10.21	179.5	443.3	132.9	700.8	1277	−59.5	−85.9
SERC	830.7	378.8	−54.4	3.897	10.67	10.73	356.1	776.1	206.8	1144	2127	−54.1	−83.3
NPCC	187.3	71.8	−61.7	0.720	10.22	11.62	73.1	167.6	52.1	207.7	427.4	−56.4	−82.9
ASCC	23.2	10.0	−56.9	0.079	10.07	10.77	9.4	20.4	0.81	23.7	45.0	−53.9	−79.1
HICC	7.42	2.84	−61.8	0.028	20.73	11.52	2.9	13.5	1.85	12.3	27.6	−78.7	−89.6
CALI	218.6	88.2	−59.6	0.632	10.41	9.42	72.8	199.4	134.1	249.9	583.3	−63.5	−87.5
FLA	103.8	49.0	−52.8	0.472	11.26	10.57	45.4	102.4	37.4	157.9	297.7	−55.6	−84.7
NEWY	102.0	39.1	−61.7	0.521	9.88	14.68	50.3	88.3	28.3	109.3	225.9	−43.0	−77.7
TXMRO	**726.7**	**319.9**	**−56.0**	**2.584**	**10.69**	**9.90**	**277.3**	**680.8**	**97.2**	**862.3**	**1640**	**−59.3**	**−83.1**
TRE + MRO	**726.7**	**319.9**	**−56.0**	**3.255**	**10.69**	**11.57**	**324.2**	**680.8**	**97.2**	**862.3**	**1640**	**−52.4**	**−80.2**
CONUS	**2693**	**1167**	**−56.7**	**8.831**	**10.51**	**9.01**	**920.5**	**2479**	**698**	**3542**	**6718**	**−62.9**	**−86.3**
CONUS-6REG	**2693**	**1167**	**−56.7**	**10.84**	**10.51**	**10.44**	**1067**	**2479**	**698**	**3542**	**6718**	**−57.0**	**−84.1**
Total USA	2724	1179	−56.7	8.938	10.53	9.03	932.8	2513	700.4	3578	6791	−62.9	−86.3

All costs are in 2020 USD.
H = 8760 h per year.
TRE + MRO = linear sum of TRE and MRO.
CONUS-6REG = WECC + MRO + TRE + RFC + SERC + NPCC.
Total USA = CONUS + ASCC + HICC.
Energy costs are for new electricity, heat, cold, and hydrogen generation and storage (including heat pumps for district heating/cooling), and new all-distance transmission/distribution.
Tables S17–S20 give cost parameters. A social discount rate of 2 (1–3)% [21] is used.

the need to import fossil fuels. A transition to WWS in Hawaii reduces annual energy private costs by 79% and social costs by 90% (Table 4; Figs. 5 and S3).

The time to pay back the cost of the WWS system is the capital cost of the system divided by the difference between the BAU and WWS annual private cost or social energy cost. For example, the mean time to pay back the cost of the infrastructure needed for the CONUS + ASCC + HICC simulations due to private energy cost savings from WWS is 5.7 years. The payback time due to social energy cost savings is 1.5 years. Thus, the cost of a WWS infrastructure is repaid rapidly due to energy, health, and climate cost savings. The amount paid back is through energy sales rather than subsidy.

For an estimated 2050 U S. population of ~374,257,000, the BAU and WWS annual private energy costs (across all energy sectors) per capita are $6710 and $2490/person/yr, respectively. In Texas alone (TRE), they are $10,600 and $5690/person/yr, respectively, but in TXMRO, they are $10,200 and $4150/person/yr, respectively. Thus, even with the large battery requirement (13.4 TWh, Table S13) of TRE in isolation, the annual energy cost per person in TRE with WWS is 54% less than that of BAU.

The social cost benefits across the U.S. found here are due to eliminating ~53,200 premature deaths per year, millions more illnesses per year, and 6.4 billion tonnes-CO_2e (carbon-dioxide-equivalent emissions) per year from energy-related emissions in 2050 (Table S21). Whereas the social cost of transitioning the U.S. in 2050 is $146 ($119-$257)/tonne-$CO_2$e-eliminated (where the range is among all regions simulated), the social cost of not transitioning is $1060 ($1020-$1300)/tonne-$CO_2$e-retained (in 2020 USD) (Table S21). Of the mean social cost, $392, $109, and $558/tonne–$CO_2$–retained are the energy, health, and climate costs of not transitioning, respectively (Table S21).

3.4. Land requirements

Footprint is the physical area on the top surface of soil or water needed for each energy device. It does not include areas of underground structures. Spacing is the area between some devices, such as wind turbines, wave devices, and tidal turbines, needed to minimize interference of the wake of one device with the operation of downwind devices. Offshore wind turbines, wave devices, tidal turbines, and rooftop PV take no new land; no new hydropower is added as part of these roadmaps; and geothermal additions are small. As such, over all 50 states plus Washington D.C., only 0.29% of land is needed for footprint of new utility PV and CSP generators and 0.55% of land is needed for spacing between new onshore wind turbines (Table S23). Thus, the total land needed for footprint plus spacing is 0.84% of U.S. land. The spacing area is multi-purpose spacing land. In fact, some of it can be used for utility PV, reducing total footprint plus spacing requirements. For comparison, ~1.3% of U.S. land today is used by the fossil fuel industry (Table 3.3 of Ref. [3]).

3.5. Changes in job numbers

This study also estimates the net job change due to replacing BAU with WWS generation, transmission, and storage. Note S9 provides the method of calculating employment. The estimate accounts for direct, indirect, and induced jobs. Direct jobs are jobs for project development, onsite construction, onsite operation, and onsite maintenance of the electricity generating facility. Indirect jobs are revenue and supply chain jobs. They include jobs associated with construction material and component suppliers; analysts and attorneys who assess project feasibility and negotiate agreements; banks financing the project; all equipment manufacturers; and manufacturers of blades and replacement parts. The number of indirect manufacturing jobs is included in the number of construction jobs. Induced jobs result from the reinvestment and spending of earnings from direct and indirect jobs. They include jobs resulting from increased business at local restaurants, hotels, and retail stores and for childcare providers, for example. Table S24 provides the resulting estimated number of construction and operation jobs per unit nameplate capacity or transmission line length for each energy-generating, storage, or transmission/distribution technology.

Transitioning to 100% WWS may create ~4.7 million more long-term, full-time jobs than lost among the 50 U S. states and DC (Table S25). Net job gains occur in all U.S. regions, but not in all states within each region. Only four states (Montana, New Mexico, North Dakota, and Wyoming) experience net job losses. Locations with fewer net job gains or net job losses are usually locations with high job losses in the fossil fuel industry. However, some states with high fossil fuel employment (e.g., Louisiana and Texas) have net job gains because of the large buildout of WWS infrastructure per capita needed in those states.

Job numbers here do not account for job changes due to the manufacture of electric appliances, vehicles, and machines instead of combustion appliances, vehicles, and machines. As such, accounting for those jobs may turn net job losses into net job gains in some states. Ironically, the more excess generation and storage needed in a state to meet continuous versus annual average load, the greater the net job creation in the state. The reason is that building additional generation and storage, in particular, creates jobs.

More net jobs are created in this study than in our previous 50-state study [18]. The main reason is that the present study includes jobs for electricity, heat, cold, and hydrogen storage needed; transmission (AC, HVAC, and HVDC) and distribution needed; and generation needed. The previous study included jobs only for energy generation.

3.6. Implications for Texas and California blackouts

A question arises as to whether the use of 100% WWS in the U.S. can avoid blackouts, such as those that occurred August 14–15, 2020, in California and February 14–18, 2021, in Texas. The Texas blackouts were caused by widespread natural gas, coal, nuclear, and wind turbine equipment failure. The present study does not consider equipment failure caused by extreme weather. Instead, it examines whether the Texas grid can stay stable if all fossil fuel and nuclear power are replaced by WWS, assuming de-icing equipment is added to wind turbines. The simulations here suggest that blackouts in California and Texas can be avoided at low cost in such cases with WWS. The main reasons are the significant demand reduction due to WWS (Table S3) and the ability of WWS supply plus storage and demand response to meet demand.

First, whereas a transition to WWS increases electricity requirements by 103% and 203% in California and Texas, respectively, it reduces total annual average end-use power demand in those states by 59.6% and 56.7%, respectively (Table S3). Most of these reductions are due to moving from natural gas air and water heaters for buildings to heat pump heaters, moving from combustion vehicles to electric vehicles, eliminating energy needed to mine conventional fuels, and end-use energy efficiency improvements.

The last reduction (efficiency improvements) is critical in Texas, where the 2018 BAU end-use load (Table S3) per capita was about 2.3 times that in California. Transitioning to WWS reduces not only the annual average load but also peaks in load. For example, the use of a heat pump, with a coefficient of performance (COP) of 3–5, instead of a natural gas air heater, while increasing electricity demand, reduces annual average and peak energy demand substantially. It also avoids the need for natural gas pipes or equipment, which risk freezing during winter, as occurred in Texas. For very cold winter and hot summer climates, ground-source heat pumps are recommended. These maintain high COPs, even when snow is on the ground. Air source heat pumps, which are more suitable for mild (less variable) climates, see their COP drop toward unity as the outside air temperature drops below the freezing point of water.

In order to meet its winter demand peaks, Texas also needs more wind turbines. The first correlation plot in Fig. 3 for TRE indicates a positive, albeit weak, positive correlation between wind power output and building heat load in Texas. The correlation is stronger in colder climates, as indicated not only in the correlation plots for all regions in Fig. S2 but also for many regions worldwide [44]. These are climate, rather than weather correlations. They indicate that, although individual weather events may give opposite results, heat loads correlate positively with wind power output when averaged over all weather events (climate). The positive climate correlation between demand for heat in buildings and wind power output suggests that increasing wind power output in Texas should help the state, on average, meet peak winter demand.

The second correlation plot in Figs. 3 and S2 suggest that, in U.S. regions, solar and wind are anticorrelated, thus complementary in nature. In other words, when the sun isn't shining during the day, the wind is blowing and vice versa. This correlation, found for large world regions and explained in Ref. [44], is supported here for U.S. regions.

An additional component of the WWS system that helps to meet winter peaks in Texas is seasonal heat storage. The main types of seasonal heat storage are underground thermal energy storage (UTES) technologies, namely borehole, water pit, and aquifer storage (Table 1). Since heat can be stored for multiple months in UTES storage, such storage reduces the burden on electric power generation and electricity storage for providing winter heat in a 100% WWS system.

A transition to 100% WWS also helps to reduce summer peak energy loads. Most air conditioning is already electrified, and air conditioners are like electric heat pumps, except that air conditioners do not run in reverse as heaters. As such, the COP of an air conditioner is similar to that of a heat pump in cooling mode. Thus, transitioning to heat pumps in California won't help meet peak summer loads except to the extent that new heat pumps are more efficient than older air conditioning units. However, additional end-use energy efficiency improvements, even in California, will help to reduce peaks in summer all-purpose demand. More important in California is the construction of offshore wind. Offshore wind speeds during summer in California are ~2 m/s faster than those during any other season [59]. Also, California offshore summer wind speeds are fastest during the late afternoon and early evening [59]. Blackouts are feared to occur when daytime solar output suddenly drops as the sun goes down. The addition of offshore wind will help to ameliorate this problem by supplying power after the sun goes down during summer.

To test the impacts of 100% WWS for all purposes on grid stability in Texas and California, simulations are run not only for the two states in isolation (TRE and CALI simulations, respectively), but also for cases where the states are interconnected within larger grids (TXMRO and WECC, respectively), and thirdly when they are interconnected within the CONUS grid as a whole. In all three situations, the grid remains stable continuously for two years (Fig. S2). Given that the Texas grid is currently isolated from other grids, testing the cost of energy when Texas is isolated versus interconnected is an important issue. California is already connected to the WECC grid, so simulations of California isolated from other states are less relevant than for Texas.

Costs per unit energy in Texas and California are 27.1% and 10.9% lower, respectively when these states are interconnected with the Midwest (MRO) and West (WECC) grids, respectively, than when the states are islanded (Table 4). Similarly, the cost per unit energy in New York is 20.8% lower when it is interconnected to the Northeast (NPCC) grid than when it is islanded (Table 4). The reason is largely because less shedding occurs when states are interconnected. The larger a region, the more likely the wind is blowing or the sun is shining somewhere and the more likely hydropower is available to fill in gaps in supply. For example, Table S15 indicates that, when TRE and MRO are isolated, an annual average sum of 170.8 GW is shed. However, when TRE and MRO are combined into TXMRO, total shedding drops to 93.9 GW. Less shedding means less nameplate capacity and storage needed, thus lower cost. Lower total cost occurs even though interconnecting regions increases transmission and distribution costs (Table S19).

Interconnecting does not always guarantee lower cost. The cost per unit energy of electricity in Florida, for example, is ~1.5% higher when the state is interconnected with the Southeast (SERC) grid than when the state is islanded (Table 4). The reason is that the SERC grid has poorer WWS resources than Florida, so Florida benefits SERC rather than the other way around. However, the cost difference is small.

The fact that the Texas and California grids stay stable with 100% WWS here does not guarantee stability under all other conditions. Our results have many uncertainties associated with them that create some risk of instability. These are described next.

3.7. Uncertainties

This study has many uncertainties. One is the assumption of a perfectly-interconnected transmission system in each region. The regions simulated here (Table 2) cover different spatial scales, from six isolated states (Alaska, California, Florida, Hawaii, New York, and Texas) to six multistate regions (WECC, MRO, RFC, SERC, NPCC, and TXMRO) to CONUS. In all cases, perfectly-interconnected transmission is assumed, but transmission and distribution costs and losses are accounted for (Table S17). Whereas the perfect-transmission assumption causes the greatest cost uncertainty with respect to the CONUS domain, it causes less uncertainty with respect to the regional and state domains since such domains are smaller and already well-interconnected. The fact that stable solutions are found for domains of all sizes indicates that this assumption has no impact on the ability of grids to stay stable, only on the cost of grid stability.

Another uncertainty is whether the time-dependent load and supply data are sufficiently representative of the real world in 2050 and whether they capture extreme weather events. First, the GATOR-GCMOM simulations account for 2050 climate, greenhouse gas, and natural and anthropogenic pollutant emission conditions upon a conversion to WWS. Second, since the model predicts the weather continuously worldwide, the simulations account statistically for extreme weather events. Third, all wind and solar supplies in GATOR-GCMOM are calculated with the same meteorology as are building heat and cold loads, and all are calculated at a resolution of 30 s.

A related uncertainty is whether a two-year simulation is sufficient to account for significant variations in weather and costs of energy. In previous analyses of U.S.-*as*-a-whole grid stability with LOADMATCH, simulations were run for six years [13]; five years [20], and three years [21]. Stable grids were found in all cases while accounting for variable and extreme weather. In all cases, like in this case, WWS costs were substantially lower than BAU costs. As such, it seems unlikely that a longer simulation period would make much difference in the main conclusions here.

A further uncertainty is whether the grid will stay stable in the real world even if the model indicates it will. Whereas the LOADMATCH model is designed to ensure zero loss of load, which is a stricter requirement than the industry standard of a loss of load once every ten years, the model examines only a finite set of conditions. In the real world, many more conditions arise. This could give rise to grid instability. However, we think that real grid planners will build a 100% WWS grid step by step and put sufficient safeguards in to ensure grid stability by the time 100% WWS is reached.

Yet another uncertainty is whether the models used here can replicate the real world. GATOR-GCMOM is a predictive model, and its meteorological, radiative, gas, and/or aerosol outputs have been compared with data in 34 peer-reviewed studies [21]. The model has also taken part in 14 intercomparisons with other models [21].

LOADMATCH, on the other hand, does not attempt to predict the future given a set of initial conditions. Instead, it provides a mix of generation and storage technologies that result in a stable grid given a set of constraints (e.g., time-series of demand and WWS supply, among other parameters). The key test to determine whether LOADMATCH is working correctly is to check if it conserves energy exactly. To that end, Tables S15 and S16 confirm exact energy conservation. They provide a summary and detailed budget, respectively, of energy demand, supply, losses, and changes in storage for each region simulated. For example, Table S15 shows that, for "Total USA," "End-use load plus losses" equals 1499 GW averaged over the simulation, and this exactly equals "Supply plus changes in storage." Of that total, 1179 GW is "annual average end-use load," which is the exact total shown in Table 4 for "Total USA."

A political, rather than modeling, uncertainty is whether the timeline proposed in the study, which is an 80% transition by 2030 and a 100% transition ideally by 2035 but no later than 2050 (Fig. 2), can be met. Whether it can depends on if U.S. policymakers will garner sufficient political will to complete a transition in the time needed and on whether manufacturing and deployment can be ramped up fast enough. Political will, itself, affects the speed of the buildout of generation, storage, and transmission. This study does not guarantee sufficient political will is available. Instead, it examines the consequences of a transition if sufficient political will is obtained.

4. Conclusions

In this study, grid stability in the presence of 100% clean, renewable (zero air pollution and zero carbon) energy for all purposes is examined in six isolated states (Alaska, California, Florida, Hawaii, New York, and Texas), six grid regions in the U.S., and the CONUS. The study finds that all states and regions can maintain grid stability (avoid blackouts), despite variable and extreme weather, while providing 100% of their all-purpose energy with WWS. The advantage of avoiding both air pollution and carbon is the elimination of about 53,200 U S. air-pollution-related deaths and millions more illnesses per year (Table S21) in 2050.

The private energy costs per unit energy in California, New York, and Texas are lower, but the costs in Florida are slightly higher, when these states are interconnected with the West, Northeast, Midwest, and Southeast grids, respectively, than when they are islanded. Similarly, annual costs in the well-interconnected CONUS are less than those summed among all isolated CONUS grid regions. Whereas interconnecting regions increases long-distance transmission costs, it reduces annual energy costs by reducing storage and excess generation nameplate capacity. The reductions in both also reduce shedding and land requirements. However, each state and region is large enough to provide its own reliable, low-cost electricity and heat for all energy purposes.

This study finds that a 100% WWS system can avoid winter blackouts, such as one that occurred in Texas during 2021, and summer blackouts, such as one that occurred in California in 2020. Part of the reason is due to a change in the demand structure arising from the transition to WWS. The rest is due to a change in the supply and storage structures. The costs of keeping the grid stable in Texas and California are lower when these states are interconnected with the Midwest (MRO) and West (WECC) grids, respectively, than when the states are islanded. Since Texas is currently isolated, interconnecting it with MRO could reduce its transition cost.

The results here indicate that no batteries with more than 4-h storage are needed. Long-duration electricity storage is obtained by concatenating batteries with 4-h storage. However, batteries with 8-h to 62-h storage may provide a more optimal ratio of peak storage capacity to peak discharge rate.

Because excess electricity that would otherwise be shed is used to produce heat, cold, and green hydrogen, the electricity waste and cost per unit energy in a system that uses excess WWS to produce heat, cold, and green hydrogen are less than those in a system that sheds all excess WWS.

The upfront capital cost of a 50-state U.S. transition is ~$8.9 trillion if the CONUS is well-interconnected and ~$10.95 trillion if the 50 states are divided into eight isolated grids. If TRE and MRO are merged to TXMRO, and if this plus the remaining seven grid regions are isolated, the capital cost is $10.3 trillion. The 2050 aggregate annual private and social energy costs of transitioning the U.S. to 100% WWS for all purposes are 63 (43–79)% and 86 (77–90)% lower, respectively, than not transitioning. Much of the private cost reduction is due to the substantial (57%) reduction in end-use energy requirements in the WWS case. The rest is due to the smaller reduction in the cost per unit energy. The social cost reduction is aided by the elimination of most health costs ($700 billion/yr) and climate costs ($3600 billion/yr) from U.S. emissions (Tables 4 and S20). Whereas the social cost of a transition is $146 ($119-$257)/tonne-$CO_2$e-eliminated, that of not transitioning is $1060 ($1015-$1300)/tonne-$CO_2$e-retained (Table S21).

Transitioning from BAU to WWS results in capital cost mean payback times of 5.7 and 1.5 years due to annual private and social energy cost savings, respectively. Thus, WWS pays for itself quickly. Subsidies are not needed for the payback but are crucial for speeding the transition.

A transition also creates 4.7 million more long-term, full-time jobs than lost across the U.S. and requires only ~0.29% and 0.55% of U.S. land area for footprint and spacing, respectively, for new energy technologies. The sum is less than the 1.3% occupied by the fossil fuel industry today.

The feasibility of transitioning individual U.S. regions and states in isolation, each with different WWS resources and weather conditions, suggests that small and large countries alike can transition as well. Indeed, this has been found in many previous studies [20,21,28–40]. Every country, though, has its own social, political, and economic challenges. Social and political forces may be the most difficult to overcome. However, if they are overcome, a transition will provide energy security for generations to come.

CRediT authorship contribution statement

Mark Z. Jacobson: Conceptualization, Methodology, Investigation, Software, Writing – review & editing, Visualization. **Anna-Katharina von Krauland:** Investigation, Writing – review & editing. **Stephen J. Coughlin:** Investigation, Review. **Frances C. Palmer:** Writing – review & editing, Visualization. **Miles M. Smith:** Writing – review & editing, Visualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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This research did not receive any funding from any source. The LOADMATCH model is available at https://github.com/mzjacobson/Public. Data going into the model are available in Ref. [60], in the time-series plots and tables in the Electronic Supplemental Information, and/or upon request from jacobson@stanford.edu.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2021.11.067.

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Supplementary Information

Zero Air Pollution and Zero Carbon From All Energy at Low Cost and Without Blackouts in Variable Weather Throughout the U.S. With 100% Wind-Water-Solar and Storage

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This supplementary information file contains some additional description of the models plus additional tables and figures to help explain more fully the methods and results found in this study.

Supporting Text

Note S1. Broader context

The United States is undergoing a transition to clean, renewable energy to reduce air pollution, climate-damaging pollutants, and energy insecurity. To minimize damage, all energy should ideally be transitioned by 2035. Whether this occurs will depend substantially on social and political factors. One potential barrier is the concern that a transition to intermittent wind and solar will cause blackouts. To analyze this issue, we examine the ability of all individual U.S. states and regions to avoid blackouts under realistic weather conditions that affect both energy demand and supply, when energy for all purposes originates from 100% clean, renewable (zero air pollution and zero carbon) Wind-Water-Solar (WWS) and storage. Two-year (2050-51) grid stability analyses for all U.S. regions and some individual states indicate that transitioning to WWS can keep the grid stable, even under variable weather conditions, at low-cost, everywhere. Whether grids are isolated or interconnected, annual energy costs are 63 (43-79)% lower and social costs (energy plus health plus climate) costs are 86 (77-90)% lower than in business-as-usual (BAU) cases. Costs per unit energy in California, New York, and Texas are 11%, 21%, and 27% lower, respectively, and costs in Florida are 1.5% higher, when these states are interconnected with the West, Northeast, Midwest, and Southeast grids, respectively, than when they are islanded. This result is relevant for Texas, whose grid is currently islanded.

An important issue is whether long-duration (100 hour to multi-month) electricity storage is needed. This study finds that no batteries with more than four hours of storage are needed. Instead, long-duration storage is obtained by concatenating batteries with four-hour storage. The new land footprint and spacing areas required for WWS systems are small relative to the land taken up by the fossil fuel industry. The transition may create millions more long-term, full-time jobs than lost and will eliminate not only carbon, but also air pollution, from energy. There is little downside to a transition.

Note S2. Methodology

This section describes the methodology for developing year-2050 roadmaps to transition each of the 50 U.S. states and D.C. to 100% WWS among all energy sectors in order to meet annual average load. It then describes the grid integration studies for regions and states to meet continuous load every 30 seconds for two years. The main steps in performing the analysis described here are as follows:

(1) Project 2018 business-as-usual (BAU) end-use energy demand to 2050 for six fuel types in each of four energy-use sectors, for each state and D.C.;
(2) Estimate the 2050 reduction in demand due to electrifying or providing direct heat for each fuel type in each sector and providing the electricity or heat with wind-water-solar (WWS), for each state and D.C.;
(3) Perform a resource analysis and estimate a mix of wind-water-solar (WWS) electricity and heat generators to meet the annual-average end-use load among all energy sectors in each state and D.C.;
(4) Use a prognostic global weather-climate-air pollution model (GATOR-GCMOM, Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model)), which accounts for competition among wind turbines for available kinetic energy, to estimate wind and solar radiation fields and heat and cold loads in buildings every 30 seconds for two years in each state and D.C.;
(5) Group the 50 states and D.C. into the regions listed in Table 1, then use the LOADMATCH grid integration model to match time-dependent WWS supply with demand, storage, and demand response every 30 seconds in 2050 and 2051 for each region;
(6) Calculate differences in BAU and WWS energy, health, and climate costs;
(7) Calculate land areas needed for new WWS energy generators;
(8) Calculate job changes resulting from a transition to WWS; and
(9) Discuss uncertainties.

Thus, three types of models are used for this study: a spreadsheet model (Steps 1-3), a 3-D global weather-climate-air pollution model (Step 4), and a grid model (Steps 5-8).

We start with 2018 business-as-usual (BAU) end-use energy consumption data for each of the 50 U.S. states and D.C. from EIA (2019). End-use energy is energy directly used by a consumer. It is the energy embodied in electricity, natural gas, gasoline, diesel, kerosene, and jet fuel that people use directly, including to extract and transport fuels themselves. It equals primary energy minus the energy lost in converting primary energy to end-use energy, including the energy lost during transmission and distribution. Primary energy is the energy naturally embodied in chemical bonds in raw fuels, such as coal, oil, natural gas, biomass, uranium, or renewable (e.g., hydroelectric, solar, wind) electricity, before the fuel or renewable electricity has been subjected to any conversion process.

For each state, the raw energy data include end-use energy in each the residential, commercial, transportation, and industrial sectors, and for each of six energy categories (oil, natural gas, coal, electricity, solar and geothermal heat, and wood and waste heat) in each sector. These data are projected for each fuel type in each sector in each state from 2018 to 2050 using "BAU reference scenario" projections for the U.S. as a whole (EIA, 2020). The reference scenario is one of moderate economic growth and accounts for policies, population growth, economic and energy growth, the growth of some renewable energy, modest energy efficiency measures, and reduced energy use.

The 2050 BAU energy for each fuel type in each sector and state is then transitioned to 2050 WWS electricity and heat using the factors in Table S2. Thus, for example, the source of residential and commercial building heat is converted from fossil fuel, wood, or waste heat to air- and ground-source heat pumps running on WWS electricity. Building cooling is also provided by heat pumps.

Liquid fuel (mostly gasoline and diesel) and natural gas vehicles are transitioned primarily to battery electric (BE) vehicles and some hydrogen fuel cell (HFC) vehicles, where the hydrogen is produced with WWS electricity (i.e., green hydrogen). BE vehicles are assumed to dominate short- and long-distance light-duty ground transportation, construction machines, agricultural equipment, short- and moderate-distance (<1,200 km) heavy-duty trucks, trains (except where powered by electric rails or overhead wires), ferries, speedboats, and ships; and short-haul (<1,500 km) aircraft. HFC vehicles are assumed to make up all long-distance, heavy payload transport by road, rail, water, and air, as well as heavy-duty air, water, and land military transportation machines (Katalenich, 2020).

High- and medium-temperature industrial processes are electrified with electric arc furnaces, induction furnaces, resistance furnaces, dielectric heaters, and electron beam heaters. Low-temperature heat for industry is assumed to be provided with electric heat pumps (Table 1).

Next, in each state, a mix of WWS resources is estimated to meet the all-sector annual-average end-use energy demand. The mix is determined after a WWS resource analysis is performed for each state, as described shortly, and after the technical potential of each WWS resource in each state is estimated, as follows.

For onshore wind, von Krauland et al. (2021) provides the upper nameplate capacities installable in each state, after eliminating areas that have land use restrictions and wind speeds below 5 m/s at 100 m above ground level. Upper limits of offshore wind resources for coastal states are estimated as the larger of values from Lopez et al. (2012) and 22.6 MW/km-shoreline (which assumes an installed power density of 7.16 MW/km^2 for offshore wind (Enevoldsen and Jacobson, 2021), turbines along 3.5% of the coast, and turbines 10-100 km from shore). Tidal and wave technical potentials are estimated as a function of coastline length using equations from Sections S5.5 and S5.6, respectively, of Jacobson et al. (2017).

Solar rooftop PV technical potentials are calculated here using the method in Section S5.2.2 of Jacobson et al. (2017). Table S6 shows the results by state. The U.S.-wide 2050 rooftop area suitable for PV (south facing/unshaded) over residential buildings and associated parking structures is ~5,255 km^2 and, for all other buildings (commercial, government, industrial), ~3,995 km^2. The associated technical potentials of solar PV are ~1.26 TW and ~0.96 TW nameplate capacity, respectively. The total suitable PV area of 9,250 km^2 and nameplate capacity of 2.2 TW for 2050 compare with previous estimates for 2015 of 8,130 km^2 and 1.1 TW, respectively (Gagnon et al., 2016). The slightly higher 2050 potential rooftop area here is due to the increase in building stock between 2015 and 2050. The lower nameplate capacity per unit area for 2015 from Gagnon et al. (2016) is due primarily to the use of a less efficient panel in 2015 than in the present study, which assumes a panel developed between today and 2050.

Utility PV, CSP, and geothermal electricity technical potential nameplate capacities by state are from Lopez et al. (2012). Geothermal electricity has technical potential in 13 states (AK, AZ, CA, CO, HI, ID, MT, NV, NM, OR, UT, WA, WY).

Hydropower state technical potentials are set to 2019 nameplate capacities already in the state plus the nameplate capacities of Canadian hydro currently imported into each state. In 2019, 11 states (CA, ME, MD, MA, MI, MN, NY, ND, OH, VT, and VA) imported Canadian hydropower (EIA, 2021c). The nameplate capacity providing such imports is estimated as 8.99 GW (see Table S8 footnote for a breakdown by state and the calculation method). With a U.S. total nameplate capacity in 2019 of 79.8 GW, the U.S. plus imported Canadian nameplate capacity is then 88.8 GW. Such pre-existing Canadian imports are considered here as part of U.S. hydropower nameplate capacity.

Next, nameplate capacities of a mix of WWS generators needed to meet annual average all-purpose load in each state are estimated. The penetration of each WWS electricity generator in each state is limited by the following constraints: (1) each generator type cannot produce more electricity in the state than the technical potential allows; (2) the land area taken up among all WWS land-based generators should be no more than a few percent of the land area of the state of interest; (3) the area of installed rooftop PV in each state must be less than the respective rooftop area suitable for PV (Table S6); (4) the nameplate capacity of conventional hydro is the same as in 2019; (5) the nameplate capacity of geothermal electricity is the larger of the geothermal electricity nameplate capacity in 2019 and 20% of geothermal electricity's technical potential; and (6) wind and solar, which are complementary in nature[44], are used in roughly equal proportions if possible.

The mix is calculated iteratively with the method in the accompanying spreadsheet (Jacobson and Delucchi, 2021). The calculation requires an initial estimate of the capacity factor (CF) of each generator in each state. Annual average CFs by state for onshore wind, utility PV, and hydropower are obtained from EIA (2021c) based on actual 2019 electricity generation and nameplate capacity data for each state. Rooftop PV CFs are estimated as 90% of utility PV CFs. Geothermal, tidal, and wave CFs are approximated as ~90.5%, ~24.65%, and 29.7%, respectively. These CFs are used only for a first estimate of nameplate capacity since GATOR-GCMOM calculates final CFs based on time- and space-dependent meteorological conditions.

The spreadsheet-estimated nameplate capacities of onshore and offshore wind electricity; rooftop and utility PV electricity; CSP electricity; and solar thermal heat supply are then input into the global weather-climate-air-pollution model, GATOR-GCMOM (Note S3) to predict power output by state from each generator every 30 seconds during 2050-2051. From the offshore wind predictions, time-dependent wave power estimates are derived. From modeled outdoor temperatures, heating and cooling loads in buildings are calculated every 30 seconds by state (Jacobson, 2021a).

The generator nameplate capacities and the time-dependent wind, solar, and wave power supplies and thermal loads from GATOR-GCMOM are then input into the LOADMATCH grid integration model (Notes S4-S6, Table S7). Geothermal electricity and heat supplies and tidal electricity supplies are assumed to be constant throughout a year. Hydroelectricity is consumed as needed but limited by the 2019 peak discharge rate (nameplate capacity) of hydropower and by the amount of water that gave the 2019 annual average hydropower output. Rainfall and runoff replenish hydropower reservoirs continuously during the year (Table S13, footnotes). LOADMATCH is used to match time-dependent (30-s resolution) electricity and heat loads and losses with supply, storage, and demand response during 2050-2051. Notes S4-S6 describe demand response.

The simulations discussed here (Table 1) cover different spatial scales, from six isolated states (Alaska, California, Florida, Hawaii, New York, and Texas) to six multistate regions (WECC, MRO, RFC, SERC, NPCC, and TXMRO) to CONUS. In all cases, perfectly-interconnected transmission is assumed. However, we account for transmission and distribution costs and losses (Table S17). Long-distance transmission costs increase when states are interconnected versus isolated. For the six individual states and NPCC in Table 1, no long-distance transmission is assumed because the distance across such entity is less than a typical HVDC transmission line length (1,000-2,000 km), or, as in the case of Alaska, the loads are too small. For the regions WECC, MRO, RFC, SERC, and TXMRO, 10% of all electricity consumed is assumed to be subject to long-distance transmission. For the CONUS, 20% is assumed to be subject to long-distance transmission. For California and New York, Canadian hydropower is included whether the state is interconnected to WECC or NPCC, respectively, or isolated.

Note S3. Description of GATOR-GCMOM and its Calculations

This note briefly summarizes the GATOR-GCMOM model and the main processes that it treats. GATOR-GCMOM is a three-dimension Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model (Jacobson, 2001; Jacobson et al., 2007; Jacobson and Archer, 2012; Jacobson and Jadhav, 2018). It simulates weather, climate, and air pollution on the global through urban scales. The main processes treated are as follows:

Gas processes (emissions, gas photochemistry, gas transport, gas-to-particle conversion, gas-cloud interactions, and gas removal);

Aerosol processes (size- and composition-resolved emissions, homogeneous nucleation, coagulation, condensation, dissolution, equilibrium and non-equilibrium chemistry, aerosol-cloud interactions, and aerosol removal);

Cloud processes (size- and composition-resolved aerosol particle activation into cloud drops, drop freezing; collision-coalescence, condensation/evaporation, dissolution, ice crystal formation, graupel formation, lightning formation, convection, and precipitation; drop breakup);

Transport processes (horizontal and vertical transport of individual gas, size- and composition-resolved aerosol particles, and size- and composition-resolved hydrometeor particles)

Radiative processes (spectral solar and thermal infrared radiation; heating rates; actinic fluxes; radiation through gases, aerosols, clouds, snow, sea ice, and ocean water);

Meteorological processes (wind, temperature, pressure, humidity, size- and composition-resolved clouds);

Surface processes (dry deposition of gases, sedimentation of aerosol and hydrometeor particles, dissolution of gases and particles into the oceans and surface water, soil moisture and energy balance, evapotranspiration, sea ice and snow formation and impacts; radiative transfer through snow, sea ice, and ocean water)

Ocean processes (2-D ocean transport and 3-D ocean diffusion and chemistry, phytoplankton, radiative transfer through the ocean)

GATOR-GCMOM simulates feedbacks among all these processes, in particular among meteorology, solar and thermal-infrared radiation, gases, aerosol particles, cloud particles, oceans, sea ice, snow, soil, and vegetation. Model predictions have been compared with data in 34 peer-reviewed studies. The model has also taken part in 14 model inter-comparisons (Jacobson et al., 2019).

The model is run here at $4^{\circ}\times5^{\circ}$ horizontal resolution and with 68 sigma-pressure-coordinate layers in the vertical, from the ground to 0.219 hPa (~60 km), with 15 layers in the bottom 0.95 km. The bottom five layers above the ground are at 30-m resolution; the next seven are at 50-m resolution, one is at 100-m resolution, and the last two are at 200-m resolution. Vertical resolution from 1 to 21 km is 500 m.

Onshore wind turbines, with nameplate capacity determined from the initial spreadsheet estimate of generators needed to meet 2050 end-use load, are placed in windy areas in each of the 50 U.S. states in GATOR-GCMOM. Offshore turbines are placed in coastal water in each state with a coastline (including states with a Great Lakes coastline). The wind turbine blades in the model cross five vertical model layers. Spatially-varying model-predicted wind speeds are used to calculate wind power output from each turbine every 30s. This calculation accounts for the reduction in the wind's kinetic energy and speed due to the competition among wind turbines for limited available kinetic energy (Jacobson and Archer, 2012).

Rooftop solar PV panels, utility PV panels, CSP plants, and solar thermal plants, with nameplate capacity determined from the initial estimate of generators needed to meet 2050 end-use load, are placed in urban areas (rooftop PV) and in southern parts of each state (utility PV, CSP, and solar thermal) in GATOR-GCMOM. The model calculates the temperature-dependence of PV output (Jacobson and Jadhav, 2018) and the reduction in sunlight to buildings and the ground due to the conversion of radiation to electricity by solar devices (Jacobson and Jadhav, 2018; Jacobson et al., 2019). It also accounts for (1) changes in air and ground temperature due to power extraction by solar and wind devices and subsequent electricity use (Jacobson and Jadhav, 2018; Jacobson et al., 2019); (2) impacts of time-dependent gas, aerosol, and cloud concentrations on solar radiation and wind fields (Jacobson et al., 2007); (3) radiation to rooftop PV panels at a fixed optimal tilt (Jacobson and Jadhav, 2018); and (4) radiation to utility PV panels, half of which are at an optimal tilt and the other half of which track the sun with single-axis horizontal tracking (Jacobson and Jadhav, 2018).

Finally, GATOR-GCMOM calculates a 30-s-resolution time series of building cooling and heating loads in each state for 2050 and 2051. The model predicts the ambient air temperature in each of multiple surface grid cells in each state and compares it with an ideal building interior temperature, set here to 294.261 K (70 ^{o}F). It then calculates how much heating or cooling energy is needed each 30 seconds to maintain the interior temperature among all buildings in the grid cell (assuming an average *U*-value and surface area for buildings and a given number of buildings in each grid cell) (Jacobson et al., 2021a). The time series loads among all grid cells in a state are then summed to obtain state values, which are output for use in LOADMATCH.

Note S4. Description of and Processes in the LOADMATCH Model

This note discusses the LOADMATCH model (Jacobson et al., 2015; 2018; 2019, 2021a,b) and its main processes. LOADMATCH is a trial-and-error simulation model written in Fortran. It works by running multiple simulations for each grid region, one at a time. Each simulation marches forward one timestep at a time, just as the real world does, for any number of years for which sufficient input data are available. In past studies, the model has been run for 1 to 6 years, but there is no technical or computational limit for the model running for hundreds or thousands of years given sufficient input data.

The main constraint during a simulation is that the summed electricity, heat, cold, and hydrogen load and losses, adjusted by demand response, must match energy supply and storage every timestep for an entire simulation period. If load is not met during any timestep, the simulation stops. Inputs (either the nameplate capacity of one or more generators; the peak charge rate, peak discharge rate, or peak capacity of storage; or characteristics of demand response) are then adjusted one at a time based on an examination of what caused the load mismatch (thus it is a "trial-and-error" model). Another simulation is then run from the beginning. New simulations are run until load is met every time step of the simulation period. After load is met once, additional simulations are performed with further-adjusted inputs based on user intuition and experience to generate a set of solutions that match load every timestep. The lowest cost solution in this set is then selected.

Unlike with an optimization model, which solves among all timesteps simultaneously, a trial-and-error model does not know what the weather will be during the next timestep. Because a trial-and-error model is non-iterative, it requires less than a minute for a 3-year simulation with a 30-s timestep. This is 1/500th to 1/100,000th the computer time of an optimization model for the same number of timesteps, regardless of computer architecture. The disadvantage of a trial-and-error model compared with an optimization model is that the former does not determine the least cost solution out of all possible solutions. Instead, it produces a set of viable solutions, from which the lowest-cost solution is selected.

Table S7 summarizes many of the processes treated in LOADMATCH. Model inputs are as follows:

(1) time-dependent electricity produced from onshore and offshore wind turbines, wave devices, tidal turbines, rooftop PV panels, utility PV plants, CSP plants, and geothermal plants;
(2) a hydropower plant peak discharge rate (nameplate capacity), which is set to the present-day nameplate capacity, a hydropower plant mean recharge rate (from rainfall), and a hydropower plant annual average electricity output;
(3) time-dependent geothermal heat and solar-thermal heat generation rates;
(4) specifications of hot-water and chilled-water sensible-heat thermal energy storage (HW-STES and CW-STES) (peak charge rate, peak discharge rate, peak storage capacity, losses into storage, and losses out of storage);
(5) specifications of underground thermal energy storage (UTES), including borehole, water pit, and aquifer storage;
(6) specifications of ice storage (ICE);
(7) specifications of electricity storage in pumped hydropower storage (PHS), phase-change materials coupled with CSP (CSP-PCM), and batteries;
(8) specifications of hydrogen (for use in transportation) electrolysis, compression, and storage equipment;
(9) specifications of electric heat pumps for air and water heating and cooling;
(10) specifications of a demand response system;
(11) specifications of losses along short- and long-distance transmission and distribution lines;
(12) time-dependent electricity, heat, cold, and hydrogen loads;
(13) specifications of scheduled and unscheduled maintenance downtimes for generators, storage, and transmission;

From model results, differences in energy, health, and climate costs and job creation and loss between BAU and WWS are estimated. Land requirements of WWS are also calculated. Calculations of cost require specifications of generator, storage, transmission, and distribution costs and air pollution and climate costs due to BAU fuels. Changes in job numbers require specifications of job data for generators, storage, and transmission/distribution. Land requirements require specification of the installed power density of generators.

For this study, both the nameplate capacity and installed capacity of hydropower are assumed to be equal. The nameplate capacity of a technology is the peak output (discharge) rate of the technology's generators or other devices producing electricity. The installed capacity for all technologies aside from hydropower equals the nameplate capacity. For hydropower, it is the smaller of the nameplate capacity and the upper limit of the annual average power produced by available water in a hydropower reservoir (Rahi and Kumar, 2016). Thus, for example, a hydropower plant may produce no more than 1 GW of annual average power (installed capacity) due to water limitations but have a much higher peak instantaneous electricity production rate of 10 GW (nameplate capacity) due to the construction of turbines to allow hydropower to meet peaks in grid electricity demand better.

Note S5. Time-Dependent Thermal and Electricity Load Profiles in LOADMATCH

This note discusses the development of time-dependent load profiles at 30-s time resolution for use in LOADMATCH. We start with the annual-average 2050 WWS energy loads for each sector in each state from Table S3. These loads are separated into (1) electricity and direct heat loads needed for low-temperature heating, (2) electric loads needed for cooling and refrigeration, (3) electricity loads needed to produce, compress, and store hydrogen for fuel cells used for transportation, and (4) all other electricity loads (including industrial heat loads), as described in Section S1.3.3 of Jacobson et al. (2019) and updated in Jacobson (2021). Each of these loads is then divided further into flexible and inflexible loads. Flexible loads include electricity and direct heat loads that can be used to fill cold and low-temperature heat storage (district heat storage or building water tank storage), electricity loads used to produce hydrogen (since all hydrogen can be stored), and remaining electricity and direct heat loads subject to demand response. Inflexible loads are all loads that are not flexible. Ten percent of thermal energy is assumed to be subject to district heating in each region.

Loads subject to demand response can be shifted forward in time a maximum of 8 hours. Loads subject to heat/cold storage can be met with such storage or with electricity, either currently available or stored. Inflexible loads must be met immediately with electricity that is currently available or stored.

In sum, total annual average cooling and low-temperature heating loads consist of flexible loads subject to storage, flexible loads subject to demand response, and inflexible loads. Such annual average cooling and heating loads for each state are converted to time-dependent cooling and heating loads using the time-dependent output from GATOR-GCMOM for each state (Note S3). State time series are summed in LOADMATCH among all states in each region. The results for 2050 and 2051 are then scaled by the ratio of the annual average cooling or low-temperature heating load required for a 100% WWS region from Table S5 to the annual average cooling or heating load from the regional 2050 or

2051 time series. This gives time-dependent 2050 and 2051 cooling and heating loads for each region that, when averaged over time, exactly match the estimated 2050 annual average loads.

Annual average 2050 and 2051 inflexible electric loads in each region are converted to time-dependent 2050 and 2051 inflexible electric loads for the region by scaling contemporary (2018 and 2019) time-dependent electric load data (Table S1) for the region to 2050 and 2051, respectively. Contemporary load data for 13 U.S. regions are available from EIA (2021a) (Table S1). Time-dependent loads from the 13 load regions are partitioned into each of the model regions defined in Table 1, as explained in the footnote to Tables S1. Thus, the 2050 and 2051 inflexible time-series loads for each region are obtained by multiplying the 2018 and 2019 time-series electric loads, respectively, for the region by the ratio of the annual average 2050 inflexible load for the region (Table S5) to the annual average load from the 2018 or 2019 time-dependent profiles, given in Table S1.

Finally, all remaining loads (all non-heating, non-cooling flexible loads), which include most electric loads for transportation (for electric and hydrogen fuel cell vehicles) and for high-temperature industrial heat, are assumed to be distributed evenly during the year.

For transportation, this assumption is roughly justified by the fact that, between 2016-2019, the minimum and maximum monthly U.S. gasoline supplies were 7.76% and 8.73%, respectively, of the annual supply (EIA, 2021d), with the highest consumption during the summer and the lowest during the winter. Both gasoline vehicle (GV) and battery-electric vehicle (BEV) ranges drop with lower temperature, with BEV ranges dropping more. For example, gasoline-vehicle fuel mileage is about 15-24% lower at 20 ^oF (-6.67 ^oC) than at 77 ^oF (25 ^oC) (U.S. DOE, 2021), whereas BEF range is ~40% lower between those two temperatures (Geotab, 2020). Since gasoline consumption is greater during summer than winter, this implies that the summer-winter difference in BEV electricity consumption will be less than the summer-winter difference in gasoline consumption, justifying a relatively even spread during the year of electricity consumption with BEVs.

85% of vehicle electric load (for either battery-electric or hydrogen fuel cell vehicles) and 70% of high-temperature industrial heat load are assumed to be subject to demand response or storage. As such, these loads can be shifted forward in time if necessary.

Note S6. Order of Operation in LOADMATCH

In this section, the order of operations in LOADMATCH, including how the model treats excess generation over demand and excess demand over generation, is summarized. The first situation discussed is one in which the current (instantaneous) supply of WWS electricity or heat exceeds the current electricity or heat load. The total load, whether for electricity or heat, consists of flexible and inflexible loads. Whereas flexible loads may be shifted forward in time with demand response, inflexible loads must be met immediately. If WWS instantaneous electricity or heat supply exceeds the instantaneous inflexible electricity or heat load, then the supply is used to satisfy that load. The excess WWS is then used to satisfy as much current flexible electric or heat load as possible. If any excess electricity exists after inflexible and current flexible loads are met, the excess electricity is sent to fill electricity storage or used to produce heat, cold, or hydrogen, which is either stored or used immediately.

Electricity storage is filled first. Excess CSP high-temperature heat goes to CSP thermal energy storage in a phase-change material. If CSP storage is full, remaining high-temperature heat produces electricity that is used, along with excess electricity from other sources, to charge battery storage followed by pumped hydropower storage, cold water storage, ice storage, hot water tank storage, and underground thermal energy storage. Remaining excess electricity is used to produce hydrogen. Any residual after that is shed.

Heat and cold storage are filled by using excess electricity to power an air source or ground source heat pump to move heat or cold from the air, water, or ground to the thermal storage medium. Hydrogen storage is filled by using electricity in an electrolyzer to produce hydrogen and in a compressor to compress the hydrogen, which is then moved to a storage tank.

If any excess direct geothermal or solar heat exists after it is used to satisfy inflexible and flexible heat loads, the remainder is used to fill either district heat storage (water tank and underground heat storage) or building water tank heat storage.

The second situation is one in which current load exceeds WWS electricity or heat supply. When current inflexible plus flexible electricity load exceeds the current WWS electricity supply from the grid, the first step is to use electricity storage (CSP, battery, pumped hydro, and hydropower storage, in that order) to fill in the gap in supply. The electricity is used to supply the inflexible load first, followed by the flexible load.

If electricity storage becomes depleted and flexible load persists, demand response is used to shift the flexible load to a future hour.

If the inflexible plus flexible heat load subject to storage exceeds WWS direct heat supply, then stored district heat (in water tanks and underground storage) is used to satisfy district heat loads subject to storage, and building heat storage (in hot water tanks) is used to satisfy building water heat loads. If stored heat becomes exhausted, then any remaining low-temperature air or water heat load becomes either an inflexible load (85%), which must be met immediately with electricity, or a flexible load (15%), which can either be met with electricity or shifted forward in time with demand response and turned into an inflexible load.

Similarly, if the inflexible plus flexible cold load subject to storage exceeds cold storage (in ice or water), excess cold load becomes either an inflexible load (85%), which must be met immediately with electricity, or a flexible load (15%), which can be met with electricity or shifted forward in time with demand response and turned into an inflexible load.

Finally, if the current hydrogen load depletes hydrogen storage, the remaining hydrogen load becomes an inflexible electrical load that must be met immediately with current electricity.

In any of the cases above, if electricity is not available to meet the remaining inflexible load, the simulation stops and must be restarted after increasing nameplate capacities of generation and/or storage.

Because the model does not permit load loss at any time, it is designed to exceed the utility industry standard of load loss once every 10 years.

Note S7. Calculation of Air Pollution and Climate Costs

BAU air pollution cost estimates are based on the projected number of air pollution deaths per year due to energy in 2050 by state multiplied by a value of statistical life and cost factors for morbidity and non-health environmental impacts. Column (a) of Table S21 gives the estimated total number of air pollution deaths by state in 2050. These values were obtained by multiplying 2010-12 state air pollution deaths from Jacobson et al. (2015) by the ratio of the total number of 2050 air pollution mortalities per year in the U.S. from Jacobson et al. (2019), 53,199 (36,394-73,614) deaths per year, to the total 2010-12 number of deaths across the U.S. from Jacobson et al. (2015) 62,381/yr (19,363/yr-115,723/yr). The estimated number of U.S. deaths in 2050 from Jacobson et al. (2019) was derived from WHO (2017) air pollution mortality data for the United States for 2016, then projected to 2050 using Equation S35 of Jacobson et al. (2019).

Multiplying the total numbers of 2050 air pollution deaths per year from Table S21 by 90% (the estimated percentage of total air pollution mortalities that are due to energy) gives the estimated numbers of deaths per year due to energy. Multiplying those numbers by a statistical cost of life of $11.56 ($7.21-$17.03) million/mortality (2020 USD) and a multiplier of 1.15 for morbidity and another multiplier of 1.1 for non-health impacts (Jacobson et al., 2019) gives the 2050 annual BAU health cost by state in Table S20.

BAU climate costs are estimated based on the social cost of carbon applied to estimated anthropogenic CO_2-equivalent emissions in 2050 from Table S21. The social cost of carbon in 2050 is estimated as $548 ($315-$1,188)/metric tonne-$CO_2$ (in 2020 USD), which is slightly updated from values in Jacobson et al. (2019), which were in 2013 USD.

Note S8. Calculation of Land Requirements

Footprint is the physical area on the top surface of soil or water needed for each energy device. It does not include areas of underground structures. Spacing is the area between some devices, such as wind turbines, wave devices, and tidal turbines, needed to minimize interference of the wake of one turbine with downwind turbines. Spacing area can be used for multiple purposes, including rangeland, ranching land, industrial land (e.g., installing solar panels), open space, or open water. Table S22 provides estimated footprint and spacing areas per megawatt of nameplate capacity of WWS electricity and heat generation technologies considered here.

Applying the footprint and spacing areas per megawatt nameplate capacity from Table S22 to the new nameplate capacities needed to provide grid stability (obtained by subtracting the existing nameplate capacities in Table S8 from the existing plus new nameplate capacities in Table S9) gives the total land footprint and spacing areas required for each state and region shown in Table S23.

New land footprint arises only for new solar PV plants, CSP plants, onshore wind turbines, geothermal plants, and solar thermal plants. Offshore wind, wave, and tidal generators are in water, so they don't take up new land, and rooftop PV does not take up new land. The footprint area of a wind turbine is relatively trivial (primarily the area of the tower and of exposed cement above the ground surface).

The total new land area for footprint (before removing the fossil fuel infrastructure) required with 100% WWS is about 0.29% of the U.S. land area (Table S23), almost all for utility PV and CSP. WWS has no footprint associated with mining fuels to run the equipment, but both WWS and BAU energy infrastructures require one-time mining for raw materials for new plus repaired equipment construction.

The only spacing area over land needed in a 100% WWS world is between onshore wind turbines. Table S23 indicates that the spacing area for onshore wind to power the U.S. is about 0.55% of U.S. land area.

Together, the new land footprint and spacing areas for 100% WWS across all energy sectors are 0.84% of U.S. land area, and most of this land area is multi-purpose spacing land.

Note S9. Calculation of Job Changes

A final metric discussed relevant to policy decision-making is net job creation and loss. Table S24 provides estimated numbers of permanent, full-time construction and operation jobs per megawatt of new nameplate capacity or kilometer of new transmission line for several electricity-generating and storage technologies and for transmission and distribution expansion. The total number of jobs produced in a region equals the new nameplate capacity of each electricity generator or storage device or the number of kilometers of new transmission/distribution lines multiplied by the respective value in the table.

The jobs per unit nameplate capacity in the table were derived for the United States primarily from the Jobs and Economic Development Impact (JEDI) models (NREL, 2019). These models estimate the number of construction and operation jobs plus earnings due to building an electric power generator or transmission line. The models treat direct jobs, indirect jobs, and induced jobs. Values are the same as in Jacobson et al. (2019), except that new values for constructing and operating heat pumps for district heat were added and HVDC job numbers were updated. Transmission/distribution job numbers came from Jacobson et al. (2017).

Direct jobs are jobs for project development, onsite construction, onsite operation, and onsite maintenance of the electricity generating facility. Indirect jobs are revenue and supply chain jobs. They include jobs associated with construction material and component suppliers; analysts and attorneys who assess project feasibility and negotiate agreements; banks financing the project; all equipment manufacturers; and manufacturers of blades and replacement parts. The number of indirect manufacturing jobs is included in the number of construction jobs. Induced jobs result from the reinvestment and spending of earnings from direct and indirect jobs. They include jobs resulting from increased business at local restaurants, hotels, and retail stores and for childcare providers, for example. Changes in jobs due to changes in energy prices are not included. Energy price changes may trigger changes in factor allocations among capital, energy input, and labor that result in changes in the number of jobs.

Specific output from the JEDI models for each new electric power generator includes temporary construction jobs, permanent operation jobs, and earnings, all per unit nameplate capacity. A temporary construction job is defined as a full-time equivalent job required for building infrastructure for one year. A full-time equivalent (FTE) job is a job that provides 2,080 hours per year of work. Permanent operation jobs are full-time jobs that last as long as the energy facility lasts and that are needed to manage, operate, and maintain an energy generation facility. In a 100% WWS system, permanent jobs are effectively indefinite because, once a plant is decommissioned, another one must be built to replace it. The new plant requires additional construction and operation jobs.

The number of temporary construction jobs is converted to a number of permanent construction jobs as follows. One permanent construction job is defined as the number of consecutive one-year construction jobs for L years to replace $1/L$ of the total nameplate capacity of an energy device every year, all divided by L years, where L is the average facility life. In other words, suppose 40 GW of nameplate capacity of an energy technology must be installed over 40 years, which is also the lifetime of the technology. Also, suppose the installation of 1 MW creates 40 one-year construction jobs (direct, indirect, and induced jobs). In that case, 1 GW of wind is installed each year and 40,000 one-year construction jobs are required each year. Thus, over 40 years, 1.6 million one-year jobs are required. This is equivalent to 40,000 40-year jobs. After the technology life of 40 years, 40,000 more 1-year jobs are needed continuously each year in the future. As such, the 40,000 construction jobs are permanent jobs.

Jobs losses due to a transition to WWS include losses in the mining, transport, processing, and use of fossil fuels, biofuels, bioenergy, and uranium. Jobs will also be lost in the BAU electricity generation industry and in the manufacturing of appliances that use combustion fuels. In addition, when comparing the number of jobs in a BAU versus WWS system, jobs are lost due to *not* constructing BAU electricity generation plants, petroleum refineries, and oil and gas pipelines.

Table S25 estimates the number of permanent, full-time jobs created and lost due to a transition in the 50 states and D.C. to 100% WWS by 2050. The job creation accounts for new direct, indirect, and induced jobs in the electricity, heat, cold, and hydrogen generation, storage, and transmission (including HVDC transmission) industries. It also accounts for the building of heat pumps to supply district heating and cooling. However it does not account for changes in jobs in the production of electric appliances, vehicles, and machines or in increasing building energy efficiency. Construction jobs are for new WWS devices only. Operation jobs are for new and existing devices.

The job losses in Table S25 are due to eliminating jobs for mining, transporting, processing, and using fossil fuels, biofuels, and uranium. Fossil-fuel jobs due to non-energy uses of petroleum, such as lubricants, asphalt, petrochemical feedstock, and petroleum coke, are retained. For transportation sectors, the jobs lost are those due to transporting fossil fuels (e.g., through truck, train, barge, ship, or pipeline); the jobs not lost are those for transporting other goods. The table does not account for jobs lost in the manufacture of combustion appliances, including automobiles, ships, or industrial machines.

Table S25 indicates that transitioning to 100% WWS may create about 4.7 million more long-term, full-time jobs than lost among the 50 U.S. states and D.C.. Net job gains occur in all U.S. regions, but not in all states within each region. Only four states (Montana, New Mexico, North Dakota, and Wyoming) experience net job losses. Locations with fewer net job gains or net job losses are usually locations with high job losses in the fossil fuel industry. However, some states with high fossil fuel employment (e.g., Louisiana and Texas) have net job gains because of the large buildout of WWS infrastructure per capita in those states.

Supporting Tables

Table S1. The regions and states/district within each region for which contemporary hourly load data were obtained for 2018-2019 from EIA (2021a). Some states appear partially in two regions. They are assigned to the region with the larger areal coverage. This assumption has little impact since the changes in load rather than the magnitude of load are then scaled to 2050. Because the load regions in this table do not exactly overlap the North American Reliability Council (NERC) and other grid regions given in Table 1, loads from the regions in this table are partitioned into the regions given in Table 1, as described in the footnote below.

			Annual Average Load (GW)				
Region	Region Name	States/District in Region	2016	2017	2018	2019	2020
CAL	California	CA	32.25	30.72	31.49	30.19	30.57
CAR	Carolinas	NC, SC	25.12	27.06	25.24	25.12	24.09
CENT	Central	KS, NE, ND, OK, SD	29.52	31.79	31.28	30.84	29.90
FLA	Florida	FL	27.27	19.21	27.63	27.55	27.91
MIDA	Mid-Atlantic	DC, DE, KY, MD, NJ, OH, PA, VA, WV	91.92	98.45	93.81	91.36	87.71
MIDW	Midwest	AR, IL, IN, IA, LA, MI, MN, MO, WI	80.66	85.05	83.06	80.79	77.35
NE	New England	CT, ME, MA, NH, RI, VT	14.30	14.42	14.08	13.50	13.16
NW	Northwest	CO, ID, MT, NV, OR, UT, WA, WY	38.53	43.82	39.68	39.98	38.94
NY	New York	NY	18.31	17.92	18.39	17.79	17.10
SE	Southeast	AL, GA, MS	27.47	28.27	27.94	27.76	26.42
SW	Southwest	AZ, NM	12.14	10.37	11.65	11.92	12.44
TEN	Tennessee	TN	18.29	20.88	18.67	18.19	17.45
TEX	Texas	TX	40.03	40.89	43.04	43.79	43.38
CONUS	Contiguous US	Sum of regions above	455.79	468.86	465.96	458.78	446.41

Time dependent load data for these "load regions" are partitioned into time-dependent load data for the "grid regions" in Table 1 as follows:

WECC=CAL+NW+SW
MRO=CENT+(3/9)MIDW
TRE=TEX
RFC=(7/9)MIDA+(2/9)MIDW
SERC=CAR+FLA+SE+TEN+(4/9)MIDW+(2/9)MIDA
NPCC=NE+NY
ASCC=NW
HICC=CAL
CALI=CAL
FLA=FLA
NEWY=NY
TXMRO=TEX+CENT+(3/9)MIDW
CONUS=CAL+CAR+CENT+FLA+MIDA+MIDW+NE+NW+NY+SE+SW+TEN+TEX

Table S2. Factors to multiply BAU end-use energy consumption by in each of four energy sectors to obtain equivalent WWS end-use energy consumption. The factors are the ratio of BAU work-output/energy-input to WWS work-output/energy-input, by fuel and sector.

	Residential		Comm./Govt.		Industrial		Transportation	
Fuel	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra Effic-iency
Oil	0.2[a]	0.84	0.2[a]	0.95	0.78[e]	0.98	0.21/.52[f]	0.96
Natural gas	0.2[a]	0.81	0.2[a]	1	0.78[e]	0.98	0.21/.52[g]	0.88
Coal	0.2[a]	1	0.2[a]	1	0.78[e]	0.97	--	--
Electricity	1[b]	0.77	1[b]	0.78	1[b]	0.92	1[b]	1
Heat for sale	0.25[c]	1.0	0.25[c]	1	0.25[c]	1	--	--
WWS heat	1[d]	1	1[d]	1	1.0[d]	1	--	--
Biofuels/waste	0.2[a]	0.87	0.2[a]	1	0.78[e]	1	0.21/[h]	0.96

Residential loads include electricity and heat consumed by households, excluding transportation.

Comm./Govt. loads include electricity and heat consumed by commercial and public buildings, excluding transportation.

Industrial loads include energy consumed by all industries, including iron, steel, and cement; chemicals and petrochemicals; non-ferrous metals; non-metallic minerals; transport equipment; machinery; mining (excluding fuels, which are treated under transport); food and tobacco; paper, pulp, and print; wood and wood products; construction; and textile and leather.

Transportation loads include energy consumed during any type of transport by road, rail, domestic and international aviation and navigation, or by pipeline, and by agricultural and industrial use of highways. For pipelines, the energy required is for the support and operation of the pipelines. The transportation category excludes fuel used for agricultural machines, fuel for fishing vessels, and fuel delivered to international ships, since those are included under the agriculture/forestry/fishing category.

Elec:fuel ratio (electricity-to-fuel ratio) is the ratio of the energy input of end-use WWS electricity to energy input of BAU fuel needed for the same work output. For example, a value of 0.5 means that the WWS device consumed half the end-use energy as did the BAU device to perform the same work.

Extra efficiency is the effect of the additional efficiency and energy reduction measures in the WWS system beyond those in the BAU system and are based on the assumption of moderate economic growth. For example, in the case of natural gas, oil, and biofuels for residential air and water heating, it is the additional efficiency due to better insulation of pipes and weatherizing homes. For residential electricity, it is due to more efficient light bulbs and appliances. In the industrial sector, it is due to faster implementation of more energy efficient technologies than in the BAU case. The improvements are calculated as the product of (a) the ratio of energy use, by fuel and energy sector, of the EIA's *high efficiency all scenarios* (HEAS) case and their *reference* (BAU) case and (b) additional estimates of slight efficiency improvements beyond those in the HEAS case (Jacobson et al., 2019).

Oil includes end-use energy embodied in oil products, including refinery gas, ethane, liquefied petroleum gas, motor gasoline (excluding biofuels), aviation gasoline, gasoline-type jet fuel, kerosene-type jet fuel, other kerosene, gas oil, diesel oil, fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes, petroleum coke, and other oil products. Does not include oil used to generate electricity.

Natural gas includes end-use energy embodied in natural gas. Does not include natural gas used to generate electricity.

Coal includes end-use energy embodied in hard coal, brown coal, anthracite, coking coal, other bituminous coal, sub-bituminous coal, lignite, patent fuel, coke oven coke, gas coke, coal tar, brown coal briquettes, gas works gas, coke oven gas, blast furnace gas, other recovered gases, peat, and peat products. Does not include coal used to generate electricity.

Electricity includes end-use energy embodied in electricity produced by any source.

Heat for sale is end-use energy embodied in any heat produced for sale. This includes mostly waste heat from the combustion of fossil fuels, but it also includes some heat produced by electric heat pumps and boilers.

WWS heat is end-use energy in the heat produced from geothermal heat reservoirs and solar hot water heaters.

Biofuels and waste include end-use energy for heat and transportation from solid biomass, liquid biofuels, biogas, biogasoline, biodiesel, bio jet kerosene, charcoal, industrial waste, and municipal waste.

[a]The ratio 0.2 assumes electric heat pumps (mean coefficient of performance, COP, of 4, with a range of 3.2 to 5.2) replace oil, gas, coal, biofuel, and waste combustion heaters (COP=0.803) for low temperature air and water heating in buildings. The ratio is calculated by dividing the COP of BAU heaters by that of heat pumps. The mean heat pump COP of 4 assumes 60% of heat pumps are air-source at the low end of the range (COP=3.2) and 40% are ground source at the high end of the range (COP=5.2). The COP of combustion heaters assumes 98% have a COP of 0.8 and 2% have a COP of 0.95.

[b]Since *electricity* is already end-use energy, there is no reduction in end-use energy (only in primary energy) from using WWS technologies to produce electricity.

[c]Since *heat for sale* is low-temperature heat, it will be replaced by heat from electric heat pumps (mean COP=4) giving an electricity-to-fuel ratio of 0.25 (=1/4). Heat for sale is also low-temperature heat in the industrial sector, so it is replaced in that sector with heat pumps as well.

[d]Since *WWS heat* is already from WWS resources, there is no reduction in end-use or primary energy upon a transition to 100% WWS for this source.

[e]The ratio 0.78 for industrial heat processes assumes a mixture of electric resistance furnaces, arc furnaces, induction furnaces, and dielectric heaters replace oil, gas, coal, biofuels, and waste combustion heaters for medium and high-temperature heating processes (above 100 ºC). It also assumes that heat pumps replace those fuels for low-temperature heating processes. The electricity-to-fuel ratio for high-temperature replacement is 0.88 (=0.854/0.97), where 0.854 is the mean COP for natural gas, coal, or oil boilers and 0.97 is that for electric resistance furnaces. The COP for fossil fuel boilers assumes 80% have a COP of 0.8 and 20% have a COP of 107%, which can occur because some industrial boilers recapture waste heat and latent heat of condensation, and the COP is based on the lower heating value). The electricity-to-fuel ratio for heat pumps replacing low-temperature industrial heat processes is 0.21 (=0.854/4), where 0.854 was just defined and 4 is the mean COP of a heat pump. It is assumed that 15% of industrial heat will be with heat pumps (electricity-to-fuel ratio of 0.21)and 85% with high-temperature replacements (0.88), giving a mean replacement ratio of 0.78. The industrial sector electricity-to-fuel ratio and extra efficiency measure factors are applied only after industrial sector BAU energy used for mining and processing fossil fuels, biofuels, bioenergy, and uranium (industry "own use") has been removed from each fuel sector. The amount of industry own use is scaled from United States values from Jacobson et al. (2019) for each fuel sector.

[f]The electricity-to-fuel ratio for a battery-electric (BE) vehicle is 0.21; that for a hydrogen fuel cell (HFC) vehicle is 0.52. The ratio for BE vehicles is calculated assuming 85% of vehicles have a ratio of 0.19 and 15% have a ratio of 0.31. The 0.19 ratio is calculated as the ratio of the low tank-to-wheel efficiency of internal combustion engine (ICE) vehicles (0.17) to the high plug-to-wheel efficiency of a BE vehicle (0.89). The 0.31 value is calculated as the high efficiency of an ICE vehicle (0.2) divided by the low efficiency of a BE vehicle (0.64). The 0.52 ratio for HFC vehicles is calculated assuming 85% of vehicles have a ratio of 0.46 and 15% have a ratio of 0.87. The 0.46 value is the low tank-to-wheel efficiency of an ICE vehicle (0.17) divided by the high efficiency of an HFC vehicle (0.37). The 0.87 value is the high efficiency of an ICE vehicle (0.20) divided by the low efficiency of an HFC vehicle (0.23). 2% of BAU energy in the form of *oil* in the *transportation* sector is used to transport fossil fuels, biofuels, bioenergy, and uranium. That BAU energy is eliminated in a 100% WWS world. Of the remaining end-use fuel from oil used for transportation, 76% is replaced with electricity (the rest is replaced with electrolytic hydrogen). The 76% is multiplied by the electricity-to-fuel ratio for BE vehicles to determine the WWS electricity used for BE transportation replacing oil and 24% is multiplied by the electricity-to-fuel ratio for HFC transportation replacing oil.

[g]About 80% of *natural gas* energy in the transportation sector is used to transport fossil fuels, biofuels, bioenergy, and uranium (e.g., through pipelines or other means). That BAU energy is eliminated in a 100% WWS world. Of the remainder, 95% is electrified with BE vehicles and 5% is electrified with HFC vehicles.

[h]It is assumed that 100% of *biofuels and waste* currently used in transportation will be electrified in 2050 thus will have the electricity-to-fuel ratio of a BE vehicle.

Table S3. 1st row of each state: 2018 annually-averaged end-use load (GW) and percentage of the load by sector. 2nd row: estimated 2050 total annually-averaged end-use load (GW) and percentage of the total load by sector if conventional fossil-fuel, nuclear, and biofuel use continues to 2050 under a BAU trajectory. 3rd row: estimated 2050 total end-use load (GW) and percentage of total load by sector if 100% of BAU end-use all-purpose delivered load in 2050 is instead provided by WWS. Column (i) shows the percentage reductions in total 2050 BAU load due to switching from BAU to WWS, including the effects of (f) energy use reduction due to the higher work to energy ratio of electricity over combustion, (g) eliminating energy use for the upstream mining, transporting, and/or refining of coal, oil, gas, biofuels, bioenergy, and uranium, and (h) policy-driven increases in end-use efficiency beyond those in the BAU case. Column (j) is the ratio of electricity load (=all energy load) in the 2050 WWS case to the electricity load in the 2050 BAU case. Whereas Column (j) shows that electricity consumption increases in the WWS versus BAU cases, Column (i) shows that all energy decreases.

State/district	Scenario	(a) Total annual average end-use load (GW)	(b) Resid-ential % of total end-use load	(c) Com-mercial % of total end-use load	(d) Indus-try % of total end-use load	(e) Trans-port % of total end-use load	(f) % change end-use load w/WWS due to higher work: energy ratio	(g) % change end-use load w/WWS due to elim-inating upstream	(h) % change end-use load w/WWS due to effic-iency beyond BAU	(i) Overall % change in end-use load with WWS	(j) WWS :BAU elec-tricity load
Alabama	BAU 2018	46.0	11.4	8.8	44.0	35.8					
	BAU 2050	53.8	10.9	9.1	51.0	29.0					
	WWS 2050	27.0	13.9	10.9	61.1	14.1	-31.05	-12.98	-5.78	-49.80	2.05
Alaska	BAU 2018	18.5	6.8	7.5	55.1	30.5					
	BAU 2050	23.2	4.7	6.3	66.9	22.1					
	WWS 2050	9.99	3.5	5.5	77.5	13.6	-33.99	-19.80	-3.09	-56.88	10.73
Arizona	BAU 2018	32.0	19.0	16.5	12.0	52.5					
	BAU 2050	34.2	20.0	18.8	15.8	45.5					
	WWS 2050	15.2	29.2	25.8	19.0	25.9	-39.26	-7.24	-9.00	-55.50	1.24
Arkansas	BAU 2018	26.1	14.5	13.7	34.7	37.1					
	BAU 2050	29.9	13.5	13.9	42.7	29.9					
	WWS 2050	13.9	16.5	13.4	53.7	16.4	-36.19	-11.35	-5.96	-53.50	1.92
California	BAU 2018	201.9	14.6	13.0	20.0	52.5					
	BAU 2050	218.6	14.0	14.2	27.1	44.7					
	WWS 2050	88.2	16.7	18.9	35.0	29.5	-43.59	-9.45	-6.60	-59.64	2.03
Colorado	BAU 2018	36.8	21.0	13.6	25.8	39.6					
	BAU 2050	41.0	18.5	14.5	34.0	33.0					
	WWS 2050	16.7	17.6	17.9	43.4	21.1	-40.80	-11.51	-6.88	-59.19	1.96
Connecticut	BAU 2018	19.2	30.2	21.2	8.1	40.6					
	BAU 2050	19.4	26.3	24.2	11.6	38.0					
	WWS 2050	7.3	27.8	27.6	16.7	27.9	-48.83	-5.19	-8.45	-62.48	1.60
DC	BAU 2018	3.0	26.1	53.0	1.0	19.9					
	BAU 2050	3.7	22.0	51.9	1.1	25.1					
	WWS 2050	1.9	18.2	55.4	1.1	25.2	-32.88	-2.62	-11.53	-47.03	0.98
Delaware	BAU 2018	6.3	19.7	18.7	22.6	39.0					
	BAU 2050	7.0	18.0	19.7	30.2	32.1					
	WWS 2050	3.0	22.1	21.7	36.5	19.7	-40.26	-10.06	-7.12	-57.44	1.70
Florida	BAU 2018	97.3	16.9	15.5	12.3	55.4					
	BAU 2050	103.8	18.8	17.7	16.0	47.4					
	WWS 2050	49.0	29.8	24.1	19.8	26.3	-38.65	-5.36	-8.76	-52.77	1.38
Georgia	BAU 2018	64.7	18.3	12.7	26.7	42.3					
	BAU 2050	72.0	17.8	13.8	33.2	35.2					
	WWS 2050	34.5	20.7	17.2	42.8	19.3	-36.46	-8.21	-7.47	-52.13	1.68
Hawaii	BAU 2018	7.43	8.1	11.8	8.2	71.9					
	BAU 2050	7.42	9.7	13.8	11.5	65.0					
	WWS 2050	2.84	18.8	19.3	16.7	45.3	-49.96	-4.93	-6.89	-61.77	1.53
Idaho	BAU 2018	13.3	19.2	12.7	27.3	40.8					

	BAU 2050	14.6	16.8	13.5	34.9	34.8					
	WWS 2050	6.3	17.9	15.1	46.9	20.1	-39.40	-10.89	-6.66	-56.95	1.80
Illinois	BAU 2018	93.6	23.0	16.1	24.8	36.1					
	BAU 2050	102.4	20.8	17.0	31.1	31.1					
	WWS 2050	41.7	18.0	18.6	42.9	20.6	-42.69	-9.48	-7.12	-59.29	1.95
Indiana	BAU 2018	66.0	15.3	10.0	43.8	31.0					
	BAU 2050	75.5	13.4	10.1	51.6	24.8					
	WWS 2050	35.0	13.2	10.3	62.5	14.0	-34.50	-13.53	-5.56	-53.58	2.28
Iowa	BAU 2018	43.4	12.0	9.3	55.3	23.4					
	BAU 2050	52.4	9.6	8.9	63.4	18.2					
	WWS 2050	26.1	8.0	7.7	75.3	9.1	-31.22	-14.73	-4.31	-50.26	3.43
Kansas	BAU 2018	26.1	16.8	13.4	33.2	36.6					
	BAU 2050	30.6	14.4	13.5	41.2	30.8					
	WWS 2050	13.0	14.8	17.0	51.9	16.3	-36.04	-15.35	-6.34	-57.73	2.11
Kentucky	BAU 2018	37.0	15.1	11.0	29.0	45.0					
	BAU 2050	41.2	14.3	11.8	36.6	37.4					
	WWS 2050	18.2	18.3	14.6	45.6	21.4	-37.23	-11.94	-6.66	-55.82	1.62
Louisiana	BAU 2018	103.6	5.0	4.2	67.2	23.7					
	BAU 2050	141.2	4.1	3.7	73.8	18.4					
	WWS 2050	63.5	5.8	4.9	81.2	8.0	-25.65	-25.75	-3.65	-55.05	4.57
Maine	BAU 2018	11.0	25.0	14.5	26.9	33.6					
	BAU 2050	11.2	18.2	16.2	35.7	29.8					
	WWS 2050	5.0	15.3	14.7	52.6	17.5	-42.97	-6.20	-6.09	-55.26	2.69
Maryland	BAU 2018	30.5	24.1	22.5	6.5	46.9					
	BAU 2050	32.4	23.2	25.0	8.1	43.7					
	WWS 2050	13.3	28.2	31.2	11.2	29.4	-44.26	-5.71	-9.11	-59.08	1.36
Massachusetts	BAU 2018	36.7	27.7	22.4	8.0	41.9					
	BAU 2050	37.6	24.5	25.5	11.4	38.6					
	WWS 2050	14.1	23.9	31.0	16.5	28.5	-49.03	-4.83	-8.48	-62.34	1.60
Michigan	BAU 2018	71.0	25.9	16.7	21.3	36.1					
	BAU 2050	75.4	22.9	18.3	27.3	31.5					
	WWS 2050	29.8	19.7	20.3	39.8	20.2	-44.71	-8.27	-7.47	-60.46	1.95
Minnesota	BAU 2018	46.2	20.2	16.0	30.2	33.6					
	BAU 2050	51.4	17.2	16.6	38.1	28.1					
	WWS 2050	22.0	15.4	16.7	51.2	16.7	-40.28	-10.57	-6.34	-57.19	2.17
Mississippi	BAU 2018	29.1	11.3	9.2	30.8	48.7					
	BAU 2050	33.2	10.9	9.7	38.7	40.8					
	WWS 2050	14.7	15.1	12.8	49.9	22.2	-36.74	-13.16	-6.01	-55.90	2.00
Missouri	BAU 2018	41.0	23.0	16.3	15.3	45.4					
	BAU 2050	43.3	22.2	18.3	20.1	39.4					
	WWS 2050	18.2	26.2	23.2	26.2	24.4	-42.62	-7.14	-8.30	-58.07	1.52
Montana	BAU 2018	9.8	21.5	17.2	21.1	40.2					
	BAU 2050	10.5	18.1	18.5	28.1	35.2					
	WWS 2050	4.0	18.7	20.0	38.5	22.9	-44.27	-10.49	-6.69	-61.45	1.86
Nebraska	BAU 2018	22.7	13.3	11.3	44.0	31.4					
	BAU 2050	26.3	11.6	11.4	51.6	25.4					
	WWS 2050	12.8	10.8	11.1	65.2	12.9	-34.49	-11.72	-5.17	-51.38	2.83
Nevada	BAU 2018	17.1	19.3	17.0	18.9	44.9					
	BAU 2050	18.5	18.9	18.6	24.4	38.2					
	WWS 2050	7.9	23.1	22.5	31.2	23.1	-40.73	-9.00	-7.93	-57.66	1.36
New Hampshire	BAU 2018	8.1	30.6	17.2	9.8	42.3					
	BAU 2050	7.8	24.9	20.7	14.6	39.8					
	WWS 2050	2.9	25.3	24.2	22.0	28.5	-50.12	-4.82	-8.02	-62.96	1.76
New Jersey	BAU 2018	55.9	24.0	20.4	7.5	48.1					
	BAU 2050	57.5	22.9	23.2	10.8	43.1					
	WWS 2050	20.9	23.2	29.4	14.9	32.5	-50.67	-4.70	-8.25	-63.62	1.73
New Mexico	BAU 2018	17.5	14.6	12.4	29.3	43.8					
	BAU 2050	19.8	12.3	12.9	38.4	36.4					
	WWS 2050	8.0	12.7	16.1	48.9	22.3	-39.89	-13.84	-5.88	-59.61	2.21
New York	BAU 2018	97.0	29.7	23.9	7.9	38.6					
	BAU 2050	102.0	26.2	26.4	10.5	36.9					

	WWS 2050	39.1	23.0	30.5	15.5	31.0	-48.52	-4.50	-8.64	-61.66	1.55
North Carolina	BAU 2018	55.6	19.4	15.8	20.3	44.6					
	BAU 2050	60.4	19.3	17.5	26.0	37.2					
	WWS 2050	28.6	25.0	22.0	32.3	20.7	-37.33	-7.10	-8.27	-52.70	1.42
North Dakota	BAU 2018	16.7	7.9	8.9	55.4	27.9					
	BAU 2050	19.4	6.7	8.9	59.5	24.8					
	WWS 2050	9.1	7.2	10.2	71.6	10.9	-29.86	-18.62	-4.84	-53.32	2.98
Ohio	BAU 2018	86.9	21.5	15.0	28.0	35.5					
	BAU 2050	95.6	19.5	15.9	34.5	30.0					
	WWS 2050	40.5	18.9	17.4	45.8	17.9	-40.00	-10.53	-7.08	-57.61	1.81
Oklahoma	BAU 2018	41.7	13.1	10.5	37.5	38.8					
	BAU 2050	50.4	11.4	10.4	45.8	32.3					
	WWS 2050	21.4	13.9	13.2	56.4	16.6	-34.21	-17.50	-5.78	-57.49	2.28
Oregon	BAU 2018	24.2	19.5	14.4	22.8	43.3					
	BAU 2050	26.3	17.9	15.7	29.5	36.9					
	WWS 2050	11.8	20.6	19.0	39.0	21.4	-39.32	-8.52	-7.40	-55.25	1.61
Pennsylvania	BAU 2018	95.3	21.1	13.1	33.1	32.8					
	BAU 2050	106.4	17.8	13.6	40.0	28.5					
	WWS 2050	46.0	17.1	14.3	51.2	17.4	-37.87	-12.39	-6.47	-56.72	2.04
Rhode Island	BAU 2018	5.2	32.0	19.5	8.7	39.8					
	BAU 2050	5.3	27.7	22.4	12.7	37.2					
	WWS 2050	1.9	26.7	28.9	17.7	26.7	-48.41	-6.41	-8.74	-63.56	1.67
South Carolina	BAU 2018	35.1	14.2	11.0	28.7	46.1					
	BAU 2050	38.9	14.5	12.0	35.8	37.7					
	WWS 2050	18.8	19.3	14.9	45.2	20.5	-35.94	-8.62	-6.99	-51.56	1.57
South Dakota	BAU 2018	10.3	13.2	11.0	43.4	32.4					
	BAU 2050	12.1	11.1	11.0	51.4	26.5					
	WWS 2050	5.9	11.0	11.9	64.3	12.9	-33.65	-12.39	-5.09	-51.13	3.19
Tennessee	BAU 2018	48.4	16.9	14.1	24.3	44.8					
	BAU 2050	52.9	16.8	15.5	30.3	37.4					
	WWS 2050	24.5	21.2	19.4	38.4	21.0	-38.00	-8.31	-7.45	-53.76	1.64
Texas	BAU 2018	346.1	7.7	7.4	50.7	34.2					
	BAU 2050	434.4	6.9	7.1	60.7	25.3					
	WWS 2050	188.2	9.7	9.7	65.7	14.9	-31.30	-20.97	-4.41	-56.69	3.03
Utah	BAU 2018	20.0	19.0	15.7	20.6	44.8					
	BAU 2050	21.8	17.4	16.8	26.8	38.9					
	WWS 2050	8.5	17.7	20.8	36.3	25.1	-43.14	-10.78	-7.09	-61.02	1.78
Vermont	BAU 2018	4.3	35.8	19.4	9.3	35.5					
	BAU 2050	4.0	28.2	23.5	14.3	34.0					
	WWS 2050	1.4	27.4	25.7	21.2	25.7	-51.51	-5.20	-8.04	-64.75	1.66
Virginia	BAU 2018	53.7	18.5	18.4	18.4	44.6					
	BAU 2050	57.6	18.1	20.6	23.0	38.4					
	WWS 2050	26.3	22.0	25.7	29.8	22.5	-39.64	-6.56	-8.16	-54.35	1.52
Washington	BAU 2018	46.8	18.1	13.5	19.8	48.6					
	BAU 2050	50.0	17.2	15.0	25.9	41.9					
	WWS 2050	21.6	20.5	18.5	36.1	25.0	-41.79	-7.75	-7.34	-56.87	1.64
West Virginia	BAU 2018	19.6	14.1	10.4	42.6	33.0					
	BAU 2050	23.3	12.0	10.2	50.3	27.5					
	WWS 2050	10.2	14.1	11.0	61.0	14.0	-32.77	-17.60	-5.72	-56.09	1.96
Wisconsin	BAU 2018	45.2	21.4	15.4	29.6	33.6					
	BAU 2050	49.7	18.2	16.3	37.7	27.8					
	WWS 2050	21.5	15.8	16.9	50.5	16.8	-40.46	-9.71	-6.56	-56.73	2.05
Wyoming	BAU 2018	13.5	7.7	7.7	55.5	29.1					
	BAU 2050	16.7	5.8	7.3	63.0	23.9					
	WWS 2050	7.3	5.4	7.8	75.2	11.6	-30.55	-21.33	-4.34	-56.22	2.91
Total USA	**BAU 2018**	**2,404**	**16.7**	**13.2**	**30.5**	**39.6**					
	BAU 2050	**2,724**	**14.9**	**13.8**	**38.5**	**32.8**					
	WWS 2050	**1,179**	**16.6**	**16.4**	**47.3**	**19.6**	**-37.92**	**-12.43**	**-6.35**	**-56.70**	**2.03**

2018 BAU values are from EIA (2019). These values are projected to 2050 using EIA (2020) "reference scenario" projections, as described in the text. The EIA projections account for policies, population growth, modest economic and energy growth, some modest renewable energy additions, and modest energy efficiency measures and reduced energy use in each sector. The transportation load includes, among other loads, energy produced in each state for aircraft and shipping. 2050 WWS values are estimated from 2050 BAU values assuming electrification of end-uses and effects of additional energy-efficiency measures beyond those in the BAU case, as described in the text.

Table S4. 2050 annual average end-use electric plus heat load (GW) by sector and region after energy in all sectors has been converted to WWS. Instantaneous loads can be higher or lower than annual average loads. Values for each region equal the sum over all state values from Table S3 in each region, where Table 1 defines the regions.

Region	Total	Residential	Commercial	Industry	Transport
WECC	195.5	35.55	36.94	72.82	50.20
MRO	131.7	16.45	17.38	79.16	18.72
TRE	188.2	18.24	18.21	123.7	28.04
RFC	200.7	37.12	36.38	87.84	39.38
SERC	378.8	71.04	62.77	173.2	71.80
NPCC	71.78	16.79	20.70	13.52	20.77
ASCC	9.99	0.35	0.55	7.74	1.36
HICC	2.84	0.53	0.55	0.47	1.28
CALI	88.25	14.70	16.65	30.85	26.05
FLA	49.04	14.63	11.80	9.71	12.91
NEWY	39.11	8.98	11.94	6.06	12.12
TXMRO	319.9	34.68	35.59	202.8	46.76
CONUS	1,167	195.2	192.4	550.2	228.9
Total USA	1,179	196.1	193.5	558.4	231.5

Total USA is for all 50 states plus Washington D.C.=CONUS+ASCC+HICC. Total values for each region are summed from the state values in each region given in Table S3. Sector values in each region are obtained by multiplying the total WWS 2050 value for each state by the percentage of the total in each sector, given in Table S3, and summing the result over all states in a region.

Table S5. Annual average WWS all-sector inflexible and flexible loads (GW) for 2050 by region. "Total load" is the sum of "inflexible load" and "flexible load." "Flexible load" is the sum of "cold load subject to storage," "low-temperature heat load subject to storage," "load for H_2" production, compression, and storage (accounting for leaks as well), and "all other loads subject to demand response (DR)." Annual average loads are distributed in time at 30-s resolution, as described in the text. Instantaneous loads, either flexible or inflexible, can be much higher or lower than annual average loads. Also shown is the annual hydrogen mass needed in each region, estimated as the H_2 load multiplied by 8,760 h/yr and divided by 59.01 kWh/kg-H_2. Table 1 defines the regions.

Region	Total end-use load (GW)	Inflex-ible load (GW)	Flex-ible load (GW)	Cold load subject to storage (GW)	Low-tem-perature heat load subject to storage (GW)	Load for H_2 (GW)	All other loads sub-ject to DR (GW)	H_2 needed (Tg-H_2/yr)
WECC	195.5	97.6	97.9	0.41	8.18	21.5	67.8	3.19
MRO	131.7	66.7	65.0	0.40	4.06	8.10	52.5	1.20
TRE	188.2	91.3	96.8	0.95	4.49	12.2	79.2	1.81
RFC	200.7	103.9	96.8	0.63	8.39	16.2	71.6	2.41
SERC	378.8	194.6	184	2.35	15.3	30.8	135.7	4.58
NPCC	71.8	38.1	33.7	0.15	4.03	7.34	22.2	1.09
ASCC	9.99	4.63	5.4	0.019	0.14	0.60	4.60	0.088
HICC	2.84	1.19	1.65	0.10	0.066	0.57	0.92	0.084
CALI	88.2	42.5	45.7	0.22	3.50	11.1	30.9	1.64
FLA	49.0	25.3	23.8	1.66	2.91	5.62	13.6	0.83
NEWY	39.1	20.6	18.5	0.11	2.23	3.83	12.3	0.57
TXMRO	319.9	158.0	161.8	1.26	8.58	20.3	131.7	3.01
CONUS	1,167	592.6	574.1	4.16	44.6	96.2	429.0	14.28
Total USA	1,179	598.4	581.1	4.28	44.8	97.4	434.6	14.45

CONUS=WECC+MRO+TRE+RFC+SERC+NPCC
Total USA is for all 50 states + DC=CONUS+ASCC+HICC

Table S6. Rooftop areas suitable for solar PV panels and the potential nameplate capacity of suitable rooftop areas, for the 50 U.S. states and Washington DC. Residential values include rooftops over associated residential parking areas. Commercial/government values include institutional buildings (e.g., schools) and industrial buildings. About 54.6% and 91.1% of potential residential and commercial/government rooftop areas, respectively, are proposed to be installed by 2050 based on the final nameplate capacities for all 50 states and Washington DC provided in Table 3 of the main text. The methodology for determining suitable rooftop area is described in Jacobson et al. (2017) and summarized in the footnote below.

State/District	Residential rooftop area suitable for PVs in 2050 (km^2)	Potential nameplate capacity of suitable area in 2050 ($MW_{dc\text{-}peak}$)	Commercial/govt. roof-top area suitable for PVs in 2050 (km^2)	Potential nameplate capacity of suitable area in 2050 ($MW_{dc\text{-}peak}$)	State/District	Residential rooftop area suitable for PVs in 2050 (km^2)	Potential nameplate capacity of suitable area in 2050 ($MW_{dc\text{-}peak}$)	Commercial/govt. rooftop area suitable for PVs in 2050 (km^2)	Potential nameplate capacity of suitable area in 2050 ($MW_{dc\text{-}peak}$)
Alabama	125	29,885	80	19,076	Montana	29	6,955	33	7,822
Alaska	9	2,061	19	4,445	Nebraska	48	11,497	47	11,193
Arizona	137	32,788	99	23,719	Nevada	67	15,924	59	14,058
Arkansas	84	20,114	58	13,844	New Hampshire	25	6,028	21	5,014
California	352	84,196	254	60,681	New Jersey	45	10,865	32	7,719
Colorado	112	26,841	94	22,430	New Mexico	62	14,710	50	12,025
Connecticut	27	6,492	21	5,023	New York	157	37,566	132	31,532
DC, Washington	2	398	1	207	North Carolina	236	56,495	167	39,982
Delaware	10	2,505	8	1,893	North Dakota	18	4,190	22	5,172
Florida	273	65,332	161	38,554	Ohio	178	42,628	141	33,668
Georgia	230	55,001	155	37,086	Oklahoma	108	25,847	77	18,446
Hawaii	19	4,512	11	2,538	Oregon	82	19,621	84	20,121
Idaho	50	11,914	56	13,418	Pennsylvania	166	39,710	136	32,428
Illinois	122	29,182	96	22,873	Rhode Island	7	1,694	5	1,283
Indiana	124	29,650	97	23,123	South Carolina	130	31,102	90	21,426
Iowa	68	16,154	59	14,230	South Dakota	25	5,902	26	6,122
Kansas	68	16,374	60	14,249	Tennessee	161	38,432	111	26,629
Kentucky	100	23,866	70	16,733	Texas	597	142,808	397	94,945
Louisiana	108	25,810	70	16,677	Utah	64	15,296	56	13,432
Maine	33	7,994	27	6,550	Vermont	13	3,208	10	2,450
Maryland	55	13,246	40	9,640	Virginia	152	36,291	115	27,429
Massachusetts	44	10,537	34	8,192	Washington St.	93	22,242	102	24,495
Michigan	146	34,926	135	32,274	West Virginia	36	8,655	25	6,081
Minnesota	116	27,676	100	23,848	Wisconsin	112	26,834	90	21,449
Mississippi	84	20,205	50	12,065	Wyoming	15	3,578	15	3,533
Missouri	130	31,057	99	23,603					
					Total USA	**5,255**	**1,256,793**	**3,995**	**955,430**

Rooftops considered include those over residential buildings (excluding parking), residential parking, commercial/government/institutional buildings (including parking), and industrial buildings (including parking). Residential rooftops and residential parking rooftop areas are then combined into residential rooftop values reported here and commercial/government/institutional building rooftops and industrial building rooftops are combined into commercial/government values reported here.

The total rooftop area for each type of building is the product of the floor area per capita, the population, an overhang multiplier, and a pitch (slope) multiplier, divided by the average number of stories (Jacobson et al., 2017). The floor area per capita depends on the fraction of the state's population that is urban versus rural (Iowa State University, 2021) and some other factors. The potential rooftop or canopy area over residential parking spaces in each state is computed as a function of the number of passenger cars per person, the number of parking spaces per car, the average parking space area per car, the percentage of parking spaces that are covered, and the percentage of covered spaces with exposed roof (Jacobson et al., 2017).

The rooftop area suitable for PV is the fraction of roof area that is south facing (in the Northern Hemisphere) or flat and non-shaded. The fraction is calculated as a function of the following parameters in each state: average building height (the greater the average height, the greater the variation in height, and the more likely buildings shade one-another); average rooftop area (the greater the area, the more likely some significant portion of the area is unshaded); the percentage of rooftop area that is flat (the entire area of a flat roof is often suitable for PV); and the average slope of pitched roofs (the steeper the roof, the less suitable it is for PVs if it is pitched away from the sun) (Jacobson et al.,

2017).
The potential nameplate capacity of PV is the suitable area multiplied by a maximum possible installed power density of PV in 2050, estimate at 239 W/m^2.

Table S7. Several of the processes treated in the LOADMATCH model simulations for matching demand with supply, storage, and demand response.

Parameter	Is the process treated?
Onshore and offshore wind electricity	Yes
Residential, commercial/government rooftop PV electricity	Yes
Utility PV electricity	Yes
CSP electricity	Yes
Geothermal electricity	Yes
Tidal and wave electricity	Yes
Direct solar and geothermal heat	Yes
Battery storage	Yes
CSP storage	Yes
Pumped hydropower storage	Yes
Existing hydropower dam storage	Yes
Added hydropower turbines	No
Heat storage (water tanks, underground)	Yes
Cold storage (water tanks, ice)	Yes
Hydrogen storage in tanks	Yes
Hydrogen fuel cell vehicles for long-distance, heavy transport	Yes
Battery-electric vehicles for all other transport	Yes
District heating	Yes
Electric heat pumps for building cooling and air/water heating	Yes
Electric furnaces and heat pumps for industrial heat	Yes
Wind, PV, CSP, solar heat, wave supply calculated in GATOR-GCMOM	Yes
Building heat and cold loads calculated in GATOR-GCMOM	Yes
Array losses due to wind turbines competing for kinetic energy	Yes
Losses from T&D, storage, shedding, downtime	Yes
Perfect transmission interconnections	Yes
Costs of all generation, all storage, short- and long-distance T&D	Yes
Avoided cost of air pollution damage	Yes
Avoided cost of climate damage	Yes
Land footprint and spacing requirements	Yes
Changes in job numbers	Yes

Table S8. 2019 or 2020 existing nameplate capacity (GW) by WWS generator in each state of each region and for each region as a whole. Initial nameplate capacities for wave, tidal, solar thermal, and geothermal heat are assumed to be zero.

Region	On-shore wind (2020)	Off-shore wind (2020)	Resi-dential roof PV (2019)	Com /gov roof PV (2019)	Utility PV (2019)	CSP with storage (2020)	Geo-ther-mal elec-tricity (2019)	Hydro (2019)
WECC Total	**24.30**	**0**	**8.07**	**4.20**	**18.84**	**1.80**	**3.80**	**51.43**
Arizona	0.27	0	1.03	0.46	1.91	0.25	0	2.72
California	6.69	0	5.81	3.32	11.79	1.36	2.81	11.34
Colorado	4.56	0	0.26	0.12	0.61	0	0	0.67
Idaho	0.97	0	0.04	0.01	0.24	0	0.02	2.69
Montana	0.88	0	0.01	0.01	0.02	0	0	2.70
Nevada	0.15	0	0.34	0.08	2.17	0.19	0.83	1.05
New Mexico	2.04	0	0.12	0.06	0.67	0	0.02	0.08
Oregon	3.43	0	0.09	0.07	0.40	0	0.04	8.43
Utah	0.39	0	0.22	0.06	0.92	0	0.08	0.26
Washington St.	3.11	0	0.15	0.02	0.02	0	0	21.18
Wyoming	1.82	0	0.01	0	0.09	0	0	0.30
MRO total	**38.13**	**0**	**0.14**	**0.16**	**1.02**	**0**	**0**	**5.84**
Iowa	10.80	0	0.04	0.07	0.01	0	0	0.13
Kansas	6.51	0	0.02	0.01	0.01	0	0	0.01
Minnesota	4.05	0	0.05	0.04	0.90	0	0	1.71
Nebraska	2.36	0	0.01	0	0.02	0	0	0.33
North Dakota	3.64	0	0	0	0	0	0	0.65
Oklahoma	8.17	0	0.01	0	0.03	0	0	0.82
South Dakota	1.85	0	0	0	0	0	0	1.65
Wisconsin	0.75	0	0.03	0.03	0.04	0	0	0.54
TRE (Texas)	**30.90**	**0**	**0.31**	**0.07**	**2.44**	**0**	**0**	**0.71**
RFC total	**8.19**	**0**	**1.87**	**1.78**	**1.76**	**0**	**0**	**2.95**
DC, Washington	0	0	0.03	0.03	0	0	0	0
Delaware	0	0	0.06	0.03	0.04	0	0	0
Indiana	2.46	0	0.04	0.05	0.25	0	0	0.10
Maryland	0.19	0	0.58	0.23	0.32	0	0	0.55
Michigan	2.46	0	0.05	0.02	0.10	0	0	0.86
New Jersey	0.01	0	0.83	1.12	0.86	0	0	0.01
Ohio	0.86	0	0.06	0.11	0.11	0	0	0.13
Pennsylvania	1.46	0	0.22	0.18	0.08	0	0	0.92
West Virginia	0.74	0	0.01	0	0	0	0	0.37
SERC total	**7.30**	**0.01**	**1.14**	**0.41**	**10.24**	**0.08**	**0**	**15.07**
Alabama	0	0	0	0	0.20	0	0	3.32
Arkansas	0	0	0.02	0.02	0.11	0	0	1.32
Florida	0	0	0.40	0.08	2.07	0.08	0	0.04
Georgia	0	0	0.01	0.01	1.53	0	0	1.96
Illinois	5.86	0	0.09	0.07	0.04	0	0	0.04
Kentucky	0	0	0.01	0	0.03	0	0	1.10
Louisiana	0	0	0.14	0	0	0	0	0.19
Mississippi	0	0	0.05	0.02	0.22	0	0	0
Missouri	1.20	0	0.11	0.09	0.06	0	0	0.51
North Carolina	0.21	0	0.09	0.04	4.52	0	0	1.89
South Carolina	0	0	0.17	0.04	0.66	0	0	1.37
Tennessee	0.03	0	0	0	0.18	0	0	2.50
Virginia	0	0.01	0.07	0.04	0.63	0	0	0.83
NPCC total	**3.45**	**0.03**	**1.97**	**2.00**	**1.69**	**0**	**0**	**12.28**
Connecticut	0.01	0	0.30	0.20	0.14	0	0	0.12
Maine	0.92	0	0.03	0.02	0.01	0	0	1.45
Massachusetts	0.12	0	0.64	0.87	0.86	0	0	0.27
New Hampshire	0.21	0	0.06	0.04	0	0	0	0.51
New York	1.99	0	0.83	0.69	0.49	0	0	6.99

Rhode Island	0.05	0.03	0.02	0.12	0.08	0	0	0
Vermont	0.15	0	0.08	0.05	0.12	0	0	2.93
ASCC (Alaska)	**0.06**	**0**	**0**	**0**	**0**	**0**	**0**	**0.48**
HICC (Hawaii)	**0.23**	**0**	**0.40**	**0.12**	**0.27**	**0**	**0.05**	**0.03**
CALI (California)	**6.69**	**0**	**5.81**	**3.32**	**11.79**	**1.36**	**2.81**	**11.34**
FLA (Florida)	**0**	**0**	**0.40**	**0.08**	**2.07**	**0.08**	**0**	**0.04**
NEWY (New York)	**1.99**	**0**	**0.83**	**0.69**	**0.49**	**0**	**0**	**6.99**
TXMRO	**69.03**	**0**	**0.45**	**0.23**	**3.47**	**0**	**0**	**6.55**
Iowa	10.80	0	0.04	0.07	0.01	0	0	0.13
Kansas	6.51	0	0.02	0.01	0.01	0	0	0.01
Minnesota	4.05	0	0.05	0.04	0.90	0	0	1.71
Nebraska	2.36	0	0.01	0	0.02	0	0	0.33
North Dakota	3.64	0	0	0	0	0	0	0.65
Oklahoma	8.17	0	0.01	0	0.03	0	0	0.82
South Dakota	1.85	0	0	0	0	0	0	1.65
Texas	30.90	0	0.31	0.07	2.44	0	0	0.71
Wisconsin	0.75	0	0.03	0.03	0.04	0	0	0.54
CONUS	**112.27**	**0.04**	**13.50**	**8.62**	**35.99**	**1.87**	**3.80**	**88.27**
Alabama	0	0	0	0	0.20	0	0	3.32
Arizona	0.27	0	1.03	0.46	1.91	0.25	0	2.72
Arkansas	0	0	0.02	0.02	0.11	0	0	1.32
California	6.69	0	5.81	3.32	11.79	1.36	2.81	11.34
Colorado	4.56	0	0.26	0.12	0.61	0	0	0.67
Connecticut	0.01	0	0.30	0.20	0.14	0	0	0.12
DC, Washington	0	0	0.03	0.03	0	0	0	0
Delaware	0	0	0.06	0.03	0.04	0	0	0
Florida	0	0	0.40	0.08	2.07	0.08	0	0.04
Georgia	0	0	0.01	0.01	1.53	0	0	1.96
Idaho	0.97	0	0.04	0.01	0.24	0	0.02	2.69
Illinois	5.86	0	0.09	0.07	0.04	0	0	0.04
Indiana	2.46	0	0.04	0.05	0.25	0	0	0.10
Iowa	10.80	0	0.04	0.07	0.01	0	0	0.13
Kansas	6.51	0	0.02	0.01	0.01	0	0	0.01
Kentucky	0	0	0.01	0	0.03	0	0	1.10
Louisiana	0	0	0.14	0	0	0	0	0.19
Maine	0.92	0	0.03	0.02	0.01	0	0	1.45
Maryland	0.19	0	0.58	0.23	0.32	0	0	0.55
Massachusetts	0.12	0	0.64	0.87	0.86	0	0	0.27
Michigan	2.46	0	0.05	0.02	0.10	0	0	0.86
Minnesota	4.05	0	0.05	0.04	0.90	0	0	1.71
Mississippi	0	0	0.05	0.02	0.22	0	0	0
Missouri	1.20	0	0.11	0.09	0.06	0	0	0.51
Montana	0.88	0	0.01	0.01	0.02	0	0	2.70
Nebraska	2.36	0	0.01	0	0.02	0	0	0.33
Nevada	0.15	0	0.34	0.08	2.17	0.19	0.83	1.05
New Hampshire	0.21	0	0.06	0.04	0.	0	0	0.51
New Jersey	0.01	0	0.83	1.12	0.86	0	0	0.01
New Mexico	2.04	0	0.12	0.06	0.67	0	0.02	0.08
New York	1.99	0	0.83	0.69	0.49	0	0	6.99
North Carolina	0.21	0	0.09	0.04	4.52	0	0	1.89
North Dakota	3.64	0	0.	0.	0.	0	0	0.65
Ohio	0.86	0	0.06	0.11	0.11	0	0	0.13
Oklahoma	8.17	0	0.01	0.	0.03	0	0	0.82
Oregon	3.43	0	0.09	0.07	0.40	0	0.04	8.43
Pennsylvania	1.46	0	0.22	0.18	0.08	0	0	0.92
Rhode Island	0.05	0.03	0.02	0.12	0.08	0	0	0
South Carolina	0	0	0.17	0.04	0.66	0	0	1.37
South Dakota	1.85	0	0.	0.	0.	0	0	1.65
Tennessee	0.03	0	0.	0.	0.18	0	0	2.50
Texas	30.90	0	0.31	0.07	2.44	0	0	0.71
Utah	0.39	0	0.22	0.06	0.92	0	0.08	0.26
Vermont	0.15	0	0.08	0.05	0.12	0	0	2.93

Virginia	0	0.01	0.07	0.04	0.63	0	0	0.83
Washington St.	3.11	0	0.15	0.02	0.02	0	0	21.18
West Virginia	0.74	0	0.01	0.	0.	0	0	0.37
Wisconsin	0.75	0	0.03	0.03	0.04	0	0	0.54
Wyoming	1.82	0	0.01	0.	0.09	0	0	0.30
Total USA	**112.57**	**0.042**	**13.91**	**8.74**	**36.26**	**1.87**	**3.85**	**88.78**

Total USA=CONUS+ASCC+HICC

Onshore wind is for Q3 of 2020 (DOE, 2020), except for California, which is for Q1 of 2021 (CAISO, 2020). Only two small offshore wind farms were operating in the U.S in 2020.

Residential roof PV, commercial/government roof PV (which includes industrial roof PV), utility PV, and geothermal electricity are for 2019 (EIA, 2021c).

CSP is for 2020 (NREL, 2020).

Hydropower nameplate capacity built in the U.S. totaled 79,787 MW in 2019 (EIA, 2021c). Because 11 states imported hydropower from Canada in 2019, an additional nameplate capacity of 8,988 MW built in Canada was assigned to 11 states as follows: 1,269.3 MW to California; 739 MW to Maine; 3.4 MW to Maryland; 2.2 MW to Massachusetts; 503 MW to Michigan; 1,498.7 MW to Minnesota; 2,299.1 MW to New York; 68.5 MW to North Dakota; 3.4 MW to Ohio; 2,598.1 MW to Vermont; and 3.4 MW to Virginia. These nameplate capacities were obtained by determining the Canadian province that each state's imported hydroelectricity originated from (Canada Energy Regulator, 2020), then multiplying the total imported Canadian electricity per year to the state from EIA (2021c) by the fraction of the province's electricity that is hydroelectricity (Statistics Canada, 2020), then dividing the result by the number of hours in a year and the mean capacity factor of Canadian hydro, 54% (Hughes, 2018).

Table S9. Final 2050 total (existing plus new) nameplate capacity (GW) by generator needed in each state of each region and for each region as a whole to supply 100% of all load plus losses continuously with WWS across all energy sectors in each region (as determined by LOADMATCH). Nameplate capacity equals the maximum possible instantaneous discharge rate. The nameplate capacity for each generator in each region multiplied by the mean capacity factor for the generator in the region (Table S11) gives the simulation-averaged power output from the generator in the region (Table S12).

Region	On-shore wind	Off-shore wind	Res-ident-ial roof PV	Com /gov roof PV	Util-ity PV	CSP with stor-age	Geo-ther-mal elec-tricity	Hydr o	Wav e	Tid al	Solar ther-mal	Geo-ther-mal heat
WECC Total	**155.53**	**69.77**	**91.75**	**144.9**	**232.5**	**3.11**	**6.73**	**51.43**	**1.09**	**0.15**	**0**	**0**
Arizona	10.95	0	8.90	17.43	25.11	0.35	0.21	2.72	0	0	0	0
California	44.30	64.42	48.44	43.24	118.9	2.07	3.32	11.34	0.87	0.06	0	0
Colorado	21.76	0	0	16.71	23.40	0.12	0.23	0.67	0	0	0	0
Idaho	9.11	0	0	4.00	4.01	0	0.44	2.69	0	0	0	0
Montana	4.49	0	0	2.95	2.93	0	0.17	2.70	0	0	0	0
Nevada	7.35	0	0	8.75	9.16	0.17	1.15	1.05	0	0	0	0
New Mexico	7.31	0	0	8.98	9.62	0.20	0.33	0.08	0	0	0	0
Oregon	6.22	2.40	5.01	13.88	5.60	0	0.46	8.43	0.08	0.03	0	0
Utah	13.20	0	3.55	9.60	9.98	0.21	0.33	0.26	0	0	0	0
Washington St.	18.98	2.95	5.92	16.66	6.57	0	0.06	21.18	0.13	0.06	0	0
Wyoming	11.85	0	2.45	2.73	17.21	0	0.03	0.30	0	0	0	0
MRO total	**210.49**	**17.97**	**73.27**	**101.4**	**295.8**	**0**	**0**	**5.84**	**0.46**	**0**	**0**	**0**
Iowa	45.12	0	10.12	10.57	119.0	0	0	0.13	0	0	0	0
Kansas	21.88	0	7.24	6.80	43.83	0	0	0.01	0	0	0	0
Minnesota	33.16	9.36	18.08	25.17	24.39	0	0	1.71	0.23	0	0	0
Nebraska	19.66	0	7.75	12.87	25.07	0	0	0.33	0	0	0	0
North Dakota	14.80	0	2.86	5.98	13.55	0	0	0.65	0	0	0	0
Oklahoma	32.37	0	11.62	21.01	32.73	0	0	0.82	0	0	0	0
South Dakota	9.88	0	2.18	7.08	6.08	0	0	1.65	0	0	0	0
Wisconsin	33.62	8.61	13.42	11.89	31.13	0	0	0.54	0.23	0	0	0
TRE (Texas)	**339.3**	**187.3**	**176.5**	**140.0**	**327.2**	**10.45**	**0**	**0.71**	**2.04**	**0.06**	**0**	**0**
RFC total	**188.7**	**123.8**	**106.2**	**181.4**	**890.1**	**0**	**0**	**2.95**	**1.95**	**0.13**	**0**	**0**
DC, Washington	0.01	8.64	0.17	0.18	0	0	0	0	0	0	0	0
Delaware	0.97	5.83	1.46	3.13	8.28	0	0	0	0.03	0.01	0	0
Indiana	39.36	3.25	19.07	33.86	174.7	0	0	0.10	0.31	0	0	0
Maryland	12.32	17.37	7.68	15.87	24.19	0	0	0.55	0.14	0.06	0	0
Michigan	35.52	13.84	22.54	37.18	97.11	0	0	0.86	0.32	0.01	0	0
New Jersey	9.44	51.14	5.74	9.13	52.45	0	0	0.01	0.23	0.04	0	0
Ohio	37.10	12.38	27.04	50.28	189.2	0	0	0.13	0.44	0	0	0
Pennsylvania	48.62	11.35	16.77	21.16	304.6	0	0	0.92	0.49	0.01	0	0
West Virginia	5.31	0	5.74	10.60	39.58	0	0	0.37	0	0	0	0
SERC total	**216.5**	**454.2**	**429.2**	**277.2**	**1,405**	**0.065**	**0**	**15.07**	**3.23**	**0.47**	**0**	**0**
Alabama	4.57	3.74	29.27	17.27	150.8	0	0	3.32	0.27	0.02	0	0
Arkansas	2.42	0	19.99	12.62	69.76	0	0	1.32	0	0	0	0
Florida	17.93	95.41	54.94	32.71	120.3	0.065	0	0.04	0.53	0.11	0	0
Georgia	6.16	79.90	52.08	33.09	34.26	0	0	1.96	0.37	0.05	0	0
Illinois	50.87	12.06	26.53	19.41	233.9	0	0	0.04	0.43	0	0	0
Kentucky	7.71	0	23.39	15.13	116.8	0	0	1.10	0	0	0	0
Louisiana	22.97	174.81	23.00	12.08	285.8	0	0	0.19	0.68	0.10	0	0
Mississippi	5.34	6.27	20.15	9.95	110.4	0	0	0	0.16	0.01	0	0
Missouri	18.87	0	30.42	21.37	68.34	0	0	0.51	0	0	0	0
North Carolina	22.84	25.94	47.84	35.82	41.60	0	0	1.89	0.30	0.06	0	0
South Carolina	7.43	26.63	29.90	19.24	34.57	0	0	1.37	0.20	0.05	0	0
Tennessee	34.65	0	37.17	23.96	100.7	0	0	2.50	0	0	0	0
Virginia	14.76	29.48	34.53	24.50	37.65	0	0	0.83	0.28	0.06	0	0
NPCC total	**24.91**	**125.31**	**39.63**	**28.25**	**182.1**	**0**	**0**	**12.28**	**0.70**	**0.18**	**0**	**0**
Connecticut	1.30	15.78	3.76	2.73	23.26	0	0	0.12	0.08	0.02	0	0
Maine	2.01	7.25	3.43	1.47	11.70	0	0	1.45	0.05	0.06	0	0
Massachusetts	8.28	26.57	5.79	4.16	38.33	0	0	0.27	0.15	0.04	0	0

New Hampshire	1.14	3.91	3.24	1.82	5.98	0	0	0.51	0.03	0.01	0	0
New York	11.69	67.34	22.39	17.19	96.05	0	0	6.99	0.37	0.05	0	0
Rhode Island	0.35	4.45	0.91	0.61	6.53	0	0	0	0.02	0.01	0	0
Vermont	0.13	0	0.10	0.27	0.26	0	0	2.93	0	0	0	0
ASCC (Alaska)	**21.62**	**2.78**	**0.20**	**0.07**	**1.00**	**0**	**0.39**	**0.48**	**0.27**	**0.27**	**0**	**0**
HICC (Hawaii)	**2.984**	**3.16**	**1.33**	**1.28**	**3.84**	**0.12**	**0.52**	**0.03**	**0.03**	**0.03**	**0**	**0**
CALI (California)	**44.30**	**64.42**	**48.44**	**43.24**	**125.2**	**2.07**	**3.32**	**11.34**	**0.87**	**0.06**	**0**	**0**
FLA (Florida)	**10.46**	**58.71**	**34.79**	**27.26**	**158.6**	**0.13**	**0**	**0.04**	**0.53**	**0.11**	**0**	**0**
NEWY (New York)	**19.48**	**97.95**	**22.39**	**24.07**	**53.36**	**0**	**0**	**6.99**	**0.37**	**0.05**	**0**	**0**
TXMRO	**420.88**	**159.34**	**161.50**	**137.6**	**721.0**	**5.50**	**0**	**6.55**	**2.50**	**0.06**	**0**	**0**
Iowa	43.16	0.00	10.12	7.04	162.9	0	0	0.13	0	0	0	0
Kansas	20.92	0.00	7.24	4.53	59.98	0	0	0.01	0	0	0	0
Minnesota	31.72	11.44	18.08	16.78	33.37	0	0	1.71	0.23	0	0	0
Nebraska	18.81	0.00	7.75	8.58	34.30	0	0	0.33	0	0	0	0
North Dakota	14.16	0.00	2.86	3.99	18.55	0	0	0.65	0	0	0	0
Oklahoma	30.96	0.00	11.62	14.01	44.79	0	0	0.82	0	0	0	0
South Dakota	9.45	0.00	2.18	4.72	8.32	0	0	1.65	0	0	0	0
Texas	219.54	137.37	88.23	69.98	316.3	5.50	0	0.71	2.04	0.06	0	0
Wisconsin	32.15	10.53	13.42	7.93	42.59	0	0	0.54	0.23	0	0	0
CONUS	**1,091**	**849.6**	**685.2**	**868.8**	**2,206**	**7.86**	**6.73**	**88.27**	**9.47**	**0.98**	**0**	**0**
Alabama	4.38	2.87	19.51	20.15	92.55	0	0	3.32	0.27	0.02	0	0
Arizona	12.59	0	8.90	24.40	17.84	0.31	0.21	2.72	0	0	0	0
Arkansas	2.32	0	13.33	14.72	42.81	0	0	1.32	0	0	0	0
California	50.95	96.63	48.44	60.54	84.49	1.86	3.32	11.34	0.87	0.06	0	0
Colorado	25.03	0	8.33	23.40	16.63	0.10	0.23	0.67	0	0	0	0
Connecticut	2.50	10.76	3.76	3.82	17.44	0	0	0.12	0.08	0.02	0	0
DC, Washington	0.01	6.48	0.17	0.11	0	0	0	0	0	0	0	0
Delaware	1.12	4.38	1.46	1.90	6.21	0	0	0	0.03	0.01	0	0
Florida	17.18	73.39	36.63	38.17	73.81	0.12	0	0.04	0.53	0.11	0	0
Georgia	5.90	61.46	34.72	38.60	21.02	0	0	1.96	0.37	0.05	0	0
Idaho	10.48	0	1.43	5.61	2.85	0	0.44	2.69	00	0	0	0
Illinois	48.75	9.28	17.68	22.64	143.6	0	0	0.04	0.43	0	0	0
Indiana	45.27	2.44	19.07	20.61	131.	0	0	0.10	0.31	0	0	0
Iowa	45.12	0	10.12	9.86	84.56	0	0	0.13	0	0	0	0
Kansas	21.88	0	7.24	6.35	31.14	0	0	0.01	0	0	0	0
Kentucky	7.39	0	15.59	17.66	71.70	0	0	1.10	0	0	0	0
Louisiana	22.02	134.47	15.33	14.10	175.4	0	0	0.19	0.68	0.10	0	0
Maine	3.85	4.94	3.43	2.06	8.78	0	0	1.45	0.05	0.06	0	0
Maryland	14.17	13.03	7.68	9.66	18.14	0	0	0.55	0.14	0.06	0	0
Massachusetts	15.86	18.12	5.79	5.82	28.75	0	0	0.27	0.15	0.04	0	0
Michigan	40.85	10.38	22.54	22.63	72.83	0	0	0.86	0.32	0.01	0	0
Minnesota	33.16	15.60	18.08	23.50	17.33	0	0	1.71	0.23	0	0	0
Mississippi	5.12	4.82	13.44	11.61	67.71	0	0	0	0.16	0.01	0	0
Missouri	18.08	0	20.28	24.94	41.93	0	0	0.51	0	0	0	0
Montana	5.16	0	1.05	4.13	2.08	0	0.17	2.70	0	0	0	0
Nebraska	19.66	0	7.75	12.01	17.81	0	0	0.33	0	0	0	0
Nevada	8.46	0	3.25	12.25	6.51	0.15	1.15	1.05	0	0	0	0
New Hampshire	2.19	2.67	3.24	2.54	4.48	0	0	0.51	0.03	0.01	0	0
New Jersey	10.86	38.36	5.74	5.56	39.34	0	0	0.01	0.23	0.04	0	0
New Mexico	8.40	0	3.41	12.57	6.83	0.18	0.33	0.08	0	0	0	0
New York	22.41	45.91	22.39	24.07	72.04	0	0	6.99	0.37	0.05	0	0
North Carolina	21.89	19.95	31.89	41.79	25.53	0	0	1.89	0.30	0.06	0	0
North Dakota	14.80	0	2.86	5.59	9.63	0	0	0.65	0	0	0	0
Ohio	42.66	9.29	27.04	30.61	141.9	0	0	0.13	0.44	0	0	0
Oklahoma	32.37	0	11.62	19.61	23.26	0	0	0.82	0	0	0	0
Oregon	7.15	3.60	5.01	19.43	3.98	0	0.46	8.43	0.08	0.03	0	0
Pennsylvania	55.91	8.51	16.77	12.88	228.5	0	0	0.92	0.49	0.01	0	0
Rhode Island	0.68	3.04	0.91	0.85	4.90	0	0	0	0.02	0.01	0	0
South Carolina	7.12	20.49	19.94	22.45	21.21	0	0	1.37	0.20	0.05	0	0
South Dakota	9.88	0	2.18	6.61	4.32	0	0	1.65	0	0	0	0
Tennessee	33.21	0	24.78	27.95	61.80	0	0	2.50	0	0	0	0
Texas	229.51	187.32	88.23	97.97	164.2	4.95	0	0.71	2.04	0.06	0	0

Utah	15.19	0	3.55	13.44	7.09	0.19	0.33	0.26	0	0	0	0
Vermont	0.24	0	0.10	0.37	0.19	0	0	2.93	0	0	0	0
Virginia	14.14	22.68	23.02	28.58	23.10	0	0	0.83	0.28	0.06	0	0
Washington St.	21.83	4.42	5.92	23.33	4.67	0	0.06	21.18	0.13	0.06	0	0
West Virginia	6.11	0	5.74	6.45	29.68	0	0	0.37	0	0	0	0
Wisconsin	33.62	14.35	13.42	11.10	22.12	0	0	0.54	0.23	0	0	0
Wyoming	13.63	0	2.45	3.82	12.23	0	0.03	0.30	0	0	0	0
Total USA	**1,116**	**855.6**	**686.8**	**870.2**	**2,211**	**7.98**	**7.65**	**88.78**	**9.77**	**1.28**	**0**	**0**

Total USA=CONUS+ASCC+HICC

Table S10. LOADMATCH capacity adjustment factors (CAFs), which show the ratio of the final nameplate capacity of a generator to meet load continuously, after running LOADMATCH, to the pre-LOADMATCH initial nameplate capacity estimated herein to meet load in the annual average. Thus, a CAF less than 1.0 means that the LOADMATCH-stabilized grid meeting hourly demand requires less than the nameplate capacity needed to meet annual average load (which is our initial, pre-LOADMATCH nameplate-capacity assumption).

Region	(a) Onshore wind CAF	(b) Off-shore wind CAF	(c) Res. Roof PV CAF	(d) Com./Gov Roof PV CAF	(e) Utility PV CAF	(f) CSP CAF	(g) Solar Thermal CAF
WECC	1	1	1	1	1.9	1	0
MRO	1.15	0.9	1	1.5	1.9	0	0
TRE	1.7	1.5	2	2	2.69	1.9	0
RFC	1	2	1	2.3	1.8	0	0
SERC	1.2	1.95	1.5	1.2	2.2	0.5	0
NPCC	0.6	2.2	1	1	1.8	0	0
ASCC	0.9	0.5	0.5	0.5	0.5	0	0
HICC	1.9	2.4	0.5	0.7	2	1.4	0
CALI	1	1	1	1	2	1	0
FLA	0.7	1.2	0.95	1	2.9	1	0
NEWY	1	3.2	1	1.4	1	0	0
TXMRO	1.1	1.1	1	1	2.6	1	0
CONUS	1.15	1.5	1	1.4	1.35	0.9	0

All generators not on this list have a CAF=1. Table S9 provides final nameplate capacities accounting for the CAFs. The initial estimated nameplate capacity of each generator in each state or region equals the final nameplate capacity divided by the CAF of the generator in the region that the state resides or of the region itself, respectively. The CAFs are also used to adjust the time-dependent wind and solar supplies provided from GATOR-GCMOM to LOADMATCH. Such supplies are calculated based on the initial nameplate capacities fed into LOADMATCH. The supplies must be multiplied by the CAFs to be consistent with the new nameplate capacities. Table 1 lists the states in each region.

Table S11. Simulation-averaged 2050-2051 capacity factors (percentage of nameplate capacity produced as electricity before transmission, distribution or maintenance losses) by region in this study. The mean capacity factors in this table equal the simulation-averaged power supplied by each generator in each region from Table S12 divided by the final nameplate capacity of each generator in each region from Table S9.

Region	On-shore wind	Off-shore wind	Rooftop PV	Utility PV	CSP with storage	Geo-thermal elec-tricity	Hydropower	Wave	Tidal	Solar thermal	Geo-thermal heat
WECC	0.369	0.297	0.224	0.263	0.95	0.903	0.488	0.298	0.247	0	0
MRO	0.466	0.418	0.205	0.224	0	0	0.591	0.297	0	0	0
TRE	0.354	0.252	0.21	0.233	0.78	0	0.45	0.298	0.248	0	0
RFC	0.38	0.395	0.182	0.19	0	0	0.553	0.299	0.247	0	0
SERC	0.286	0.235	0.19	0.213	0.81	0	0.469	0.299	0.247	0	0
NPCC	0.367	0.391	0.161	0.17	0	0	0.622	0.298	0.247	0	0
ASCC	0.709	0.637	0.139	0.143	0	0.899	0.459	0.297	0.246	0	0
HICC	0.595	0.577	0.212	0.228	0.76	0.898	0.447	0.294	0.246	0	0
CALI	0.343	0.293	0.246	0.286	0.98	0.902	0.484	0.297	0.246	0	0
FLA	0.199	0.193	0.212	0.235	0.81	0	0.545	0.297	0.247	0	0
NEWY	0.354	0.352	0.173	0.183	0	0	0.73	0.297	0.246	0	0
TXMRO	0.409	0.275	0.208	0.228	0.78	0	0.576	0.298	0.248	0	0
CONUS	0.372	0.284	0.197	0.208	0.84	0.903	0.501	0.298	0.247	0	0
Total USA	0.379	0.286	0.197	0.208	0.834	0.902	0.501	0.298	0.247	0	0

Capacity factors of offshore and onshore wind turbines account for array losses (extraction of kinetic energy by turbines). In all cases, capacity factors are before transmission, distribution, maintenance, storage, and shedding losses, which are summarized for each region in Tables S15 and S16. T&D loss rates are given in Table S17. The symbol "--" indicates no installation of the technology. Rooftop PV panels are fixed-tilt at the optimal tilt angle of the country they reside in; utility PV panels are half fixed optimal tilt and half single-axis horizontal tracking (Jacobson and Jadhav, 2018). Total USA=weighted average of CONUS, HICC, and ASCC.

Table S12. LOADMATCH 2050-2051 simulation-averaged all-sector projected WWS end-use power supplied (which equals power consumed plus power lost due to transmission, distribution, and maintenance losses; storage losses; and shedding losses), by region and percentage of such supply met by each generator. Simulation-average power supply (GW) equals the simulation total energy supply (GWh/yr) divided by the number of hours of simulation. The percentages for each region add to 100%. Multiply each percentage by the 2050 total supply to obtain the GW supply by each generator. Divide the GW supply from each generator by its capacity factor (Table S11) to obtain the final 2050 nameplate capacity of each generator needed to meet the supply (Table S9). The 2050 total WWS supply is also obtained from Column (f) of Table S15.

Region	Annual average total WWS supply (GW)	On-shore wind (%)	Off-shore wind (%)	Roof PV (%)	Utility PV (%)	CSP with stor-age (%)	Geoth ermal elec-tricity (%)	Hydro power (%)	Wave (%)	Tidal (%)	Solar ther-mal heat (%)	Geo-ther-mal heat (%)
WECC	226.8	25.32	9.13	23.35	26.99	1.30	2.68	11.07	0.14	0.016	0	0
MRO	211.2	46.45	3.56	16.95	31.34	0	0	1.63	0.07	0	0	0
TRE	319.2	37.66	14.77	20.87	23.85	2.56	0	0.10	0.19	0.005	0	0
RFC	343.8	20.82	14.21	15.20	49.11	0	0	0.48	0.17	0.009	0	0
SERC	610.4	10.14	17.52	21.98	49.02	0.01	0	1.16	0.16	0.019	0	0
NPCC	107.9	8.47	45.38	10.16	28.69	0	0	7.08	0.19	0.041	0	0
ASCC	18.0	85.17	9.84	0.21	0.80	0	1.96	1.21	0.45	0.367	0	0
HICC	5.6	31.63	32.41	9.87	15.60	1.59	8.37	0.27	0.14	0.123	0	0
CALI	103.1	14.72	18.28	21.86	34.66	1.98	2.91	5.32	0.25	0.014	0	0
FLA	64.1	3.25	17.65	20.53	58.09	0.16	0	0.04	0.25	0.042	0	0
NEWY	64.4	10.70	53.57	12.47	15.15	0	0	7.92	0.17	0.017	0	0
TXMRO	451.4	38.18	9.71	13.77	36.38	0.95	0	0.84	0.17	0.003	0	0
CONUS	1,474	27.54	16.39	20.81	31.20	0.45	0.41	3.00	0.19	0.017	0	0
Total USA	1,497	28.24	16.37	20.52	30.77	0.44	0.46	2.97	0.19	0.022	0	0

Total USA=CONUS+ASCC+HICC

Table S13. Aggregate (among all states in each region) maximum instantaneous charge rates, maximum instantaneous discharge rates, and maximum energy storage capacities of the different types of electricity storage (PHS, CSP-PCM, batteries, hydropower), cold storage (CW-STES, ICE), and heat storage (HW-STES, UTES) technologies treated here, by region. Table S14 gives the maximum number of hours of storage at the maximum discharge rate. The product of the maximum discharge rate and hours of storage gives the maximum energy storage capacity. The maximum storage capacities are either of electricity for the electricity storage options or of thermal energy for the hot and cold storage options.

	WECC			**MRO**			**TRE**			**RFC**		
Storage technology	Max charge rate GW	Max dis-charge rate GW	Max storage capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max storage capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max storage capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max storage capac-ity TWh
PHS	31.60	31.60	0.44	7.06	7.06	0.10	0.10	0.10	0.0014	6.16	6.16	0.086
CSP-elec.	3.11	3.11	--	0	0	--	10.45	10.45	--	0	0	--
CSP-PCM	5.01	--	0.070	0	--	0	16.85	--	0.24	0	--	0
Batteries	247	247	0.988	570	570	2.28	3,350	3,350	13.4	1,130	1,130	4.52
Hydropower	23.35	51.43	204.57	3.36	5.84	29.41	0.31	0.71	2.72	1.59	2.95	13.92
CW-STES	0.17	0.17	0.0023	0.16	0.16	0.0022	0.38	0.38	0.0053	0.25	0.25	0.0035
ICE	0.25	0.25	0.0035	0.24	0.24	0.0033	0.57	0.57	0.0080	0.38	0.38	0.0053
HW-STES	26.87	26.87	0.21	12.24	12.24	0.10	20.57	20.57	0.16	26.19	26.19	0.21
UTES-heat	0	26.87	12.90	0	12.24	0.29	0	20.57	0.49	0	26.19	3.14
UTES-elec.	26.87	--	--	12.24	--	--	20.57	--	--	26.19	--	--
	SERC			**NPCC**			**ASCC**			**HICC**		
PHS	10.81	10.81	0.151	3.74	3.74	0.052	0.10	0.10	0.0014	0.10	0.10	0.0014
CSP-elec.	0.065	0.065	--	0	0	--	0	0	--	0.12	0.12	--
CSP-PCM	0.10	--	0.0015	0	--	0	0	--	0	0.19	--	0.0026
Batteries	1,370	1,370	5.48	580	580	2.32	188	188	0.752	22.3	22.3	0.089
Hydropower	6.88	15.07	60.29	7.43	12.28	65.10	0.21	0.48	1.86	0.015	0.034	0.128
CW-STES	0.94	0.94	0.013	0.061	0.061	0.0009	0.0075	0.0075	0.0001	0.039	0.039	0.0006
ICE	1.41	1.41	0.020	0.091	0.091	0.0013	0.0112	0.0112	0.0002	0.059	0.059	0.0008
HW-STES	59.04	59.04	0.47	10.86	10.86	0.087	0.30	0.30	0.0024	0.23	2.26	0.018
UTES-heat	0	59.04	28.34	0	10.86	2.61	0	0.30	0.01	0	2.26	0.054
UTES-elec.	59.04	--	--	10.86	--	--	0.30	--	--	0.23	--	--
	CALI			**FLA**			**NEWY**			**TXMRO**		
PHS	8.29	8.29	0.12	0.10	0.10	0.0014	1.88	1.88	0.026	7.06	7.06	0.099
CSP-elec.	2.07	2.07	--	0.13	0.13	--	0	0	--	5.50	5.50	--
CSP-PCM	3.34	--	0.047	0.21	--	0.0029	0	--	0	8.87	--	0.12
Batteries	507	507	2.028	262	262	1.048	600	600	2.4	3,050	3,050	12.2
Hydropower	5.33	11.34	46.66	0.023	0.044	0.202	4.97	6.99	43.50	3.67	6.55	32.12
CW-STES	0.09	0.09	0.0013	0.67	0.67	0.009	0.045	0.045	0.0006	0.51	0.51	0.01
ICE	0.13	0.13	0.0019	1.00	1.00	0.014	0.068	0.068	0.0009	0.76	0.76	0.01
HW-STES	13.72	13.72	0.11	21.59	21.59	0.17	6.59	6.59	0.05	30.98	30.98	0.25
UTES-heat	0	13.72	6.58	0	21.59	10.36	0	6.59	0.16	0	30.98	2.23
UTES-elec.	13.72	--	--	21.59	--	--	6.59	--	--	30.98	--	--
	CONUS			**Total USA**								
PHS	59.37	59.37	0.83	59.57	59.57	0.83						
CSP-elec.	7.86	7.86	--	7.98	7.98	--						
CSP-PCM	12.68	--	0.18	12.87	--	0.18						
Batteries	3,710	3,710	14.84	3,920	3,920	15.68						
Hydropower	42.92	88.27	376.00	43.15	88.78	378.0						
CW-STES	1.66	1.66	0.023	1.71	1.71	0.024						
ICE	2.50	2.50	0.035	2.57	2.57	0.036						

HW-STES	142.05	142.05	1.14	142.6	144.6	1.16
UTES-heat	0	142.05	37.50	0	144.6	37.56
UTES-elec.	142.05	--	--	142.6	--	--

Total USA=CONUS+ASCC+HICC

PHS=pumped hydropower storage; PCM=Phase-change materials; CSP=concentrated solar power; CW-STES=Chilled-water sensible heat thermal energy storage; HW-STES=Hot water sensible heat thermal energy storage; and UTES=Underground thermal energy storage (either boreholes, water pits, or aquifers). The peak energy storage capacity equals the maximum discharge rate multiplied by the maximum number of hours of storage at the maximum discharge rate. Table S14 gives maximum storage times at the maximum discharge rate.

Pumped hydro storage is estimated as the existing (in 2020) nameplate capacity plus the nameplate capacity of pending licenses and of preliminary permits by state (in 2020) (FERC, 2021). If a region has no existing or pending pumped hydro, a minimum of 100 MW is imposed to account for the addition of pumped hydro between 2021 and 2050.

Heat captured in a working fluid by a CSP solar collector can be either used immediately to produce electricity by evaporating water and running it through a steam turbine connected to a generator, stored in a phase-change material, or both. The maximum direct CSP electricity production rate (CSP-elec) equals the maximum electricity discharge rate, which equals the nameplate capacity of the generator. The maximum charge rate of CSP phase-change material storage (CSP-PCM) is set to 1.612 multiplied by the maximum electricity discharge rate, which allows more energy to be collected than discharged directly as electricity. Thus, since the high-temperature working fluid in the CSP plant can be used to produce electricity and charge storage at the same time, the maximum overall electricity production plus storage charge rate of energy is 2.612 multiplied by the maximum discharge rate. This ratio is also the ratio of the mirror size with storage versus without storage. This ratio can be up to 3.2 in existing CSP plants (footnote to Table S17). The maximum energy storage capacity equals the maximum electricity discharge rate multiplied by the maximum number of hours of storage at full discharge, set to 22.6 hours, or 1.612 multiplied by the 14 hours required for CSP storage to charge when charging at its maximum rate.

Hydropower's maximum discharge rate in 2050 is its 2019 nameplate capacity. Hydropower can be recharged only naturally by rainfall and runoff, and its annual-average recharge rate approximately equals its 2019 annual energy output (TWh/yr) divided by the number of hours per year. Hydro is recharged each time step at this recharge rate. The maximum hydropower energy storage capacity available in all reservoirs is also assumed to equal hydro's 2019 annual energy output. Whereas the present table gives hydro's maximum storage capacity, its output from storage during a given time step is limited by the smallest among three factors: the current energy available in the reservoir, the peak hydro discharge rate multiplied by the time step, and the energy needed during the time step to keep the grid stable.

The CW-STES peak discharge rate is set equal to 40% of the annual average cold load (for air conditioning and refrigeration) subject to storage, which is given in Table S5 for each region. The ICE storage discharge rate is set to 60% of the same annual average cold load subject to storage. The peak charge rate is set equal to the peak discharge rate. The exception is Hawaii, where it is 10% of the discharge rate. Heat pumps are used to produce both cold water and ice. Table S18 (footnotes) provides the cost of the heat pumps per kW-electricity consumed to charge storage.

The HW-STES peak discharge rate is set equal to the maximum instantaneous heat load subject to storage during any 30-second period of the two-year simulation. The values have been converted to electricity assuming the heat needed for storage is produced by heat pumps (with a coefficient of performance of 4) running on electricity. Table S18 (footnotes) provides the cost of the heat pumps per kW-electricity consumed to charge storage. Because peak discharge rates are based on maximum rather than the annual average loads, they are higher than the annual-average low-temperature heat loads subject to storage in Table S5. The peak charge rate is set equal to the peak discharge rate. The exception is Hawaii, where it is 10% of the discharge rate.

UTES heat stored in underground soil (borehole storage) or water (water pit or aquifer storage) can be charged with either solar or geothermal heat or excess electricity (assuming the electricity produces heat with an electric heat pump at a coefficient of performance of 4). The maximum charge rate of heat (converted to equivalent electricity) to UTES storage (UTES-heat) is set to the nameplate capacity of solar thermal collectors divided by the coefficient of performance of a heat pump=4). When no solar thermal collectors are used, such as in all simulations here, the maximum charge rate for UTES-heat is zero, and UTES is charged only with excess grid electricity running heat pumps. The maximum charge rate of UTES storage using excess grid electricity (UTES-elec.) is set equal to the maximum instantaneous heat load subject to storage during any 30-second period of the two-year simulation. The exception is Hawaii, where it is set to 10% of this value. The maximum UTES heat discharge rate is set equal to the maximum instantaneous heat load subject to storage. The maximum charge rate, discharge rate, and capacity of UTES storage are all in units of equivalent electricity that would give heat at a coefficient of performance of 4. Table S18 (footnotes) provides the cost of the heat pumps per kW-electricity consumed to charge storage with electricity.

Table S14. Maximum number of days of storage at the maximum discharge rate (given in Table S13 for each region) of (a) underground thermal energy storage (UTES) and (b) hydrogen (H_2) storage. (c) Battery full cycles per year; (d) the maximum discharge rate during any time interval of the simulation; and (e) the number of hours of battery storage actually needed for the simulation, which equals the ratio of the storage capacity of batteries (TWh) from Table S13 divided by the maximum discharge rate during any time interval of the simulation (TW) from Column (d). The maximum discharge rate actually occurring is always less than or equal to the maximum discharge rate allowed in Table S13. (f) HVDC line length in each region; (g) HVDC line capacity in each region; and (h) fraction of non-roof PV and non-shed energy that is subject to HVDC transmission in each region.

Region	(a) UTES (day)	(b) H_2 (day)	(c) Battery full cycles per year	(d) Max battery discharge rate occurring during simulation (TW)	(e) Ratio of max storage capacity (TWh) to max battery discharge rate (TW) during simu-lation (hours)	(f) HVDC line length (km)	(g) HVDC line capacity (MW)	(h) Fraction of non-roof PV/non-shed energy subject to HVDC
WECC	20	30	228	0.247	4.0	3,292	31,379	0.1
MRO	1	20	62	0.133	17.2	2,382	22,077	0.1
TRE	1	5	12	0.747	17.9	0	0	0
RFC	5	5	66	0.202	22.3	2,230	35,191	0.1
SERC	20	10	130	0.389	14.1	2,370	57,056	0.1
NPCC	10	35	32	0.067	34.6	0	0	0
ASCC	1	5	6	0.015	49.7	0	0	0
HICC	1	32	11	0.003	25.7	0	0	0
CALI	20	40	63	0.081	24.9	0	0	0
FLA	20	25	124	0.079	13.3	0	0	0
NEWY	1	60	16	0.039	62.0	0	0	0
TXMRO	3	4	31	0.606	20.1	2,707	58,213	0.1
CONUS	11	24	100	0.97	15.3	3,024	389,717	0.2

The maximum discharge rate multiplied by the number of hours of storage equals the maximum storage capacity in Table S13. For all regions, the maximum number of hours of CSP storage at the maximum discharge rate is 22.6 h; those for PHS, cold water storage (CW-STES), and ICE storage are 14 h; that for hot water storage (HW-STES) is 8 h; and that for battery storage is 4 h.

The product of Columns (f), (g) and $400/MW-km (Jacobson et al., 2017) gives the capital cost of HVDC transmission.

Table S15. Budget of simulation-averaged end-use power demand met, energy lost, WWS energy supplied, and changes in storage, during the 2-year (17,507.4875 hour) simulations for all regions and summed for the U.S. as a whole (CONUS+ASCC+HICC). All units are GW averaged over the simulation and are derived from the data in Table S16 by dividing values from the table in units of TWh per simulation by the number of hours of simulation. Figure S1 shows the time series of matching demand with supply and changes in storage for each region. TD&M losses are transmission, distribution, and maintenance losses. Wind turbine array losses are already accounted for in the "WWS supply before losses" numbers," since wind supply values come from GATOR-GCMOM, which accounts for such losses.

Region	(a) Annual average end-use load (GW)	(b) TD&M losses (GW)	(c) Storage losses (GW)	(d) Shedding losses (GW)	(e) End-use load+ losses =a+b+ c+d (GW)	(f) WWS supply before losses (GW)	(g) Changes in storage (GW)	(h) Supply+ changes in storage =f+g (GW)
WECC	195.5	13.83	6.02	11.8	227.2	226.8	0.34	227.2
MRO	131.7	13.69	2.82	63.0	211.2	211.2	-0.04	211.2
TRE	188.2	19.94	3.27	107.8	319.1	319.1	-0.003	319.1
RFC	200.7	22.65	6.67	113.9	343.9	343.8	0.07	343.9
SERC	378.8	37.73	15.05	180.2	611.7	610.5	1.25	611.7
NPCC	71.78	7.43	2.33	26.3	107.9	107.9	0.02	107.9
ASCC	9.99	1.35	0.10	6.56	18.00	18.00	-0.005	18.00
HICC	2.84	0.39	0.04	2.35	5.61	5.62	-0.003	5.61
CALI	88.25	6.38	3.06	5.49	103.2	103.1	0.05	103.2
FLA	49.04	4.02	3.02	8.33	64.41	64.12	0.29	64.41
NEWY	39.11	4.35	1.05	19.89	64.39	64.44	-0.05	64.39
TXMRO	319.9	30.13	7.56	93.94	451.5	451.4	0.06	451.5
CONUS	1,167	92.12	34.71	181.8	1,475	1,474	1.54	1,475
Total USA	1,179	93.86	34.84	190.67	1,499	1,497	1.53	1,499

Total USA=CONUS+ASCC+HICC

Table S16. Budget of simulation-total end-use energy demand met, energy lost, WWS energy supplied, and changes in storage, during the 2-year (17,507.4875 hour) simulations for all regions and summed for the U.S. as a whole (CONUS+ASCC+HICC). All units are TWh over the simulation. Divide by the number of hours of simulation to obtain simulation-averaged power values, which are provided in Table S15 for key parameters. Figure S1 shows the time series of matching demand with supply and changes in storage for each region.

	WECC	MRO	TRE	RFC	SERC
A1. Total end use demand	**3,423**	**2,306**	**3,294**	**3,514**	**6,631**
Electricity for electricity inflexible demand	1,728	1,174	1,613	1,832	3,454
Electricity for electricity, heat, cold storage + DR	1,318	990	1,468	1,397	2,637
Electricity for H_2 direct use + H_2 storage	377	142	213	284	540
A2. Total end use demand	**3,423**	**2,306**	**3,294**	**3,514**	**6,631**
Electricity for direct use, electricity storage, + H_2	3,295	2,236	3,215	3,373	6,378
Low-T heat load met by heat storage	127	69	75	140	246
Cold load met by cold storage	0.91	0.84	3.66	1.58	7.26
A3. Total end use demand	**3,423**	**2,306**	**3,294**	**3,514**	**6,631**
Electricity for direct use, electricity storage, DR	2,896	2,086	2,986	3,071	5,782
Electricity for H_2 direct use + H_2 storage	377	142	213	284	540
Electricity + heat for heat subject to storage	143	71	79	147	269
Electricity for cold load subject to storage	7.26	6.97	16.61	11.06	41.12
B. Total losses	**554**	**1,391**	**2,293**	**2,507**	**4,078**
Transmission, distribution, maintenance losses	242	240	349	397	661
Losses CSP storage	0.25	0	0.47	0.00	0.01
Losses PHS storage	2.96	0.0014	0.0000	0.0076	0.0077
Losses battery storage	50	31.3	34.78	66.1	158.1
Losses CW-STES + ICE storage	0	0.2	0.66	0.3	1.3
Losses HW-STES storage	16	12.7	13	20.6	28.7
Losses UTES storage	36	5.2	8	29.8	75.4
Losses from shedding	207	1,102	1,887	1,994	3,154
Net end-use demand plus losses (A1 + B)	***3,977***	***3,697***	***5,587***	***6,021***	***10,709***
C. Total WWS supply before T&D losses	**3,971**	**3,698**	**5,587**	**6,020**	**10,687**
Onshore + offshore wind electricity	1,368	1,849	2,930	2,109	2,956
Rooftop + utility PV+ CSP electricity	2,051	1,786	2,641	3,871	7,589
Hydropower electricity	439.7	60.4	5.6	28.6	123.8
Wave electricity	5.67	2.39	10.67	10.23	16.90
Geothermal electricity	106.402	0	0	0	0
Tidal electricity	0.6511	0	0.259	0.558	2.016
Solar heat	0	0	0	0	0
Geothermal heat	0	0	0	0	0
D. Net taken from (+) or added to (-) storage	**5.9215**	**-0.6666**	**-0.046**	**1.154**	**21.8576**
CSP storage	-0.007	0	0.098	0	0.0007
PHS storage	-0.0442	-0.0099	-0.0001	-0.0086	-0.0151
Battery storage	-0.0985	-0.228	-0.6462	-0.452	-0.3131
CW-STES+ICE storage	-0.0006	-0.0006	-0.0005	-0.0009	-0.0031
HW-STES storage	0.1403	-0.0098	0.1481	-0.0046	0.3435
UTES storage	7.4357	-0.0294	0.1943	1.7868	22.5206
H_2 storage	-1.5042	-0.389	0.1604	-0.1667	-0.6759
Energy supplied plus taken from storage (C+D)	***3,977***	***3,697***	***5,587***	***6,021***	***10,709***

	NPCC	ASCC	HICC	CALI	FLA
A1. Total end use demand	**1,257**	**175**	**49.7**	**1,545**	**859**
Electricity for electricity inflexible demand	670	81	21.7	750	463

Electricity for electricity, heat, cold storage + DR	459	83	18.1	601	297
Electricity for H_2 direct use + H_2 storage	128	10	9.9	193	98
A2. Total end use demand	**1,257**	**175**	**49.7**	**1,545**	**859**
Electricity for direct use, electricity storage, + H_2	1,187	173	47.9	1,486	803
Low-T heat load met by heat storage	69	2	1.0	59	51
Cold load met by cold storage	0.30	0.14	0.80	0.46	4.56
A3. Total end use demand	**1,257**	**175**	**49.7**	**1,545**	**859**
Electricity for direct use, electricity storage, DR	1,055	162	36.9	1,286	680
Electricity for H_2 direct use + H_2 storage	128	10	9.9	193	98
Electricity + heat for heat subject to storage	71	2	1.2	61	51
Electricity for cold load subject to storage	2.66	0.33	1.73	3.91	29.11
B. Total losses	**632**	**140**	**49**	**261**	**269**
Transmission, distribution, maintenance losses	130	24	6.79	112	70
Losses CSP storage	0	0	0.0024	0.16	0.01
Losses PHS storage	0.0006	0.0003	0	0.0531	0.0000
Losses battery storage	16	1.08	0	28.2	28.88
Losses CW-STES + ICE storage	0	0.03	0	0.1	0.82
Losses HW-STES storage	10	0.43	0	7.2	5.59
Losses UTES storage	14	0.14	0	17.8	17.51
Losses from shedding	461	115	41.1	96.1	145.9
Net end-use demand plus losses (A1 + B)	***1,889***	***315***	***98.3***	***1,806.3***	***1,127.7***
C. Total WWS supply before T&D losses	**1,888**	**315**	**98.3**	**1,805**	**1,123**
Onshore + offshore wind electricity	1,017	299	63.0	596	235
Rooftop + utility PV+ CSP electricity	733	3	26.6	1,056	884
Hydropower electricity	133.6	3.8	0.3	96.1	0.4
Wave electricity	3.64	1.42	0.13	4.55	2.78
Geothermal electricity	0	6.1664	8.23	52.477	0
Tidal electricity	0.772	1.156	0.121	0.261	0.469
Solar heat	0	0	0	0	0
Geothermal heat	0	0	0	0	0
D. Net taken from (+) or added to (-) storage	**0.3399**	**-0.0834**	**-0.0471**	**0.8047**	**5.0525**
CSP storage	0	0	-0.0003	-0.0047	0.0015
PHS storage	-0.0052	-0.0001	-0.0001	-0.0116	-0.0001
Battery storage	-0.2296	-0.0752	-0.0089	-0.2028	-0.0636
CW-STES+ICE storage	-0.0002	0	-0.0001	-0.0003	-0.0022
HW-STES storage	0.0105	-0.0001	0.0112	0.0431	0.1189
UTES storage	1.162	-0.0007	-0.0054	2.0382	3.2758
H_2 storage	-0.5976	-0.0072	-0.0434	-1.0572	1.7223
Energy supplied plus taken from storage (C+D)	***1,889***	***315***	***98.3***	***1,806.3***	***1,127.7***

	NEWY	TXMRO	CONUS	Total USA
A1. Total end use demand	**685**	**5,600**	**20,424**	**20,649**
Electricity for electricity inflexible demand	366	2,790	10,497	10,600
Electricity for electricity, heat, cold storage + DR	252	2,455	8,243	8,344
Electricity for H_2 direct use + H_2 storage	67	355	1,684	1,705
A2. Total end use demand	**685**	**5,600**	**20,424**	**20,649**
Electricity for direct use, electricity storage, + H_2	650	5,455	19,715	19,935
Low-T heat load met by heat storage	35	142	701	704
Cold load met by cold storage	0.21	2.82	8.60	9.55
A3. Total end use demand	**685**	**5,600**	**20,424**	**20,649**
Electricity for direct use, electricity storage, DR	577	5,073	17,885	18,084

Electricity for H_2 direct use + H_2 storage	67	355	1,684	1,705
Electricity + heat for heat subject to storage	39	150	782	785
Electricity for cold load subject to storage	1.98	22.11	72.86	74.91
B. Total losses	**443**	**2,304**	**5,403**	**5,591**
Transmission, distribution, maintenance losses	76	527	1,613	1,643
Losses CSP storage	0	0.34	0.54	0.54
Losses PHS storage	0.0006	0.02	0.40	0.41
Losses battery storage	8	83	328	329
Losses CW-STES + ICE storage	0.04	0.51	1.55	1.72
Losses HW-STES storage	6.19	22	92	93
Losses UTES storage	3.68	26	185	185
Losses from shedding	348	1,645	3,182	3,338
Net end-use demand plus losses (A1 + B)	***1,127***	***7,904***	***25,827***	***26,240***
C. Total WWS supply before T&D losses	**1,128**	**7,903**	**25,800**	**26,213**
Onshore + offshore wind electricity	725	3,785	11,333	11,695
Rooftop + utility PV+ CSP electricity	312	4,039	13,533	13,562
Hydropower electricity	89.3	66	774	778
Wave electricity	1.94	13	49	51
Geothermal electricity	0.00	0	106.402	121
Tidal electricity	0.20	0.259	4.257	5.534
Solar heat	0	0	0	0
Geothermal heat	0	0	0	0
D. Net taken from (+) or added to (-) storage	**-0.8047**	**0.9835**	**26.9233**	**26.7928**
CSP storage	0	0.0651	-0.0145	-0.0148
PHS storage	-0.0026	-0.0099	-0.0831	-0.0833
Battery storage	-0.24	-1.1814	-1.1853	-1.2694
CW-STES+ICE storage	-0.0002	-0.0017	-0.0056	-0.0057
HW-STES storage	0	0.2148	0.8931	0.9042
UTES storage	-0.0158	1.9596	32.6525	32.6464
H_2 storage	-0.5461	-0.063	-5.3338	-5.3844
Energy supplied plus taken from storage (C+D)	***1,127***	***7,904***	***25,827***	***26,240***

End-use demands in A1, A2, A3 should be identical. Transmission/distribution/maintenance loss rates are given in Table S17. Round-trip storage efficiencies are given in Table S18. Generated electricity is shed when it exceeds the sum of electricity demand, cold storage capacity, heat storage capacity, and H_2 storage capacity.

Onshore and offshore wind turbines in GATOR-GCMOM, used to calculate wind power output for use in LOADMATCH, are assumed to be Senvion (formerly Repower) 5 MW turbines with 126-m diameter blades, 100 m hub heights, a cut-in wind speed of 3.5 m/s, and a cut-out wind speed of 30 m/s.

Rooftop PV panels in GATOR-GCMOM were modeled as fixed-tilt panels at the optimal tilt angle of the country they resided in; utility PV panels were modeled as half fixed optimal tilt and half single-axis horizontal tracking. All panels were assumed to have a nameplate capacity of 390 W and a panel area of 1.629668 m^2, which gives a 2050 panel efficiency (Watts of power output per Watt of solar radiation incident on the panel) of 23.9%, which is an increase from the 2015 value of 20.1%.

Each CSP plant before storage is assumed to have the mirror and land characteristics of the Ivanpah solar plant, which has 646,457 m^2 of mirrors and 2.17 km^2 of land per 100 MW nameplate capacity and a CSP efficiency (fraction of incident solar radiation that is converted to electricity) of 15.796%, calculated as the product of the reflection efficiency of 55% and the steam plant efficiency of 28.72%. The efficiency of the CSP hot fluid collection (energy in fluid divided by incident radiation) is 34%.

Total USA=CONUS+ASCC+HICC.

Table S17. Parameters for determining costs of energy from electricity and heat generators.

	Capital cost new installations ($million/MW)	O&M Cost ($/kW/yr)	Decom-missioning cost (% of capital cost)	Lifetime (years)	TDM losses (% of energy generated)
Onshore wind	1.02 (0.85-1.18)	37.5 (35-40)	1.25 (1.2-1.3)	30 (25-35)	7.5 (5-10)
Offshore wind	1.96 (1.49-2.44)	80 (60-100)	2 (2-2)	30 (25-35)	7.5 (5-10)
Residential PV	1.93 (1.76-1.10)	27.5 (25-30)	0.75 (0.5-1)	44 (41-47)	1.5 (1-2)
Commercial/government PV	1.29 (0.93-1.66)	16.5 (13-20)	0.75 (0.5-1)	46 (43-49)	1.5 (1-2)
Utility-scale PV	0.75 (0.67-0.84)	19.5 (16.5-22.5)	0.75 (0.5-1)	48.5 (45-52)	7.5 (5-10)
CSP with storage[a]	4.58 (3.59-5.57)	50 (40-60)	1.25 (1-1.5)	45 (40-50)	7.5 (5-10)
Geothermal for electricity	4.63 (3.97-5.29)	45 (36-54)	2.5 (2-3)	45 (40-50)	7.5 (5-10)
Hydropower	2.78 (2.36-3.20)	15.5 (15-16)	2.5 (2-3)	85 (70-100)	7.5 (5-10)
Wave	4.10 (2.82-5.39)	175 (100-250)	2 (2-2)	45 (40-50)	7.5 (5-10)
Tidal	3.65 (2.93-4.38)	125 (50-200)	2.5 (2-3)	45 (40-50)	7.5 (5-10)
Solar thermal for heat	1.17 (1.06-1.29)	50 (40-60)	1.25 (1-1.5)	35 (30-40)	3 (2-4)
Geothermal for heat	4.63 (3.97-5.29)	45 (36-54)	2 (1-3)	45 (40-50)	7.5 (5-10)

Capital costs (per MW of nameplate capacity) are an average of 2020 and 2050 values. 2050 costs are derived and sourced in Jacobson and Delucchi (2021), which uses the same methodology as in Jacobson et al. (2019). For comparison the capital costs of onshore wind and utility-scale PV from Lazard (2020) for 2020 are $1.05-1.45 million/MW and $0.825-0.925 million/MW, respectively.

O&M=Operation and maintenance. TDM=transmission/distribution/maintenance. TDM losses are a percentage of all energy produced by the generator and are an average over short and long-distance (high-voltage direct current) lines.

Short-distance transmission costs are $0.0105 (0.01-0.011)/kWh. Distribution costs are $0.02375 (0.023-0.0245)/kWh. Long-distance transmission costs are $0.0089 (0.0042-0.010)/kWh (in USD 2020) (Jacobson et al., 2017, but brought up to USD 2020), which assumes 1,500 to 2,000 km HVDC lines, a capacity factor usage of the lines of ~50% and a capital cost of ~$400 (300-460)/MWtr-km. Table S14 gives the total HVDC line length and capacity and the fraction of all non-rooftop-PV and non-shed electricity generated that is subject to HVDC transmission by region.

The discount rate used for generation, storage, transmission/distribution, and social costs is a social discount rate of 2 (1-3)%.

[a]The capital cost of CSP with storage includes the cost of extra mirrors and land but excludes costs of phase-change material and storage tanks, which are given in Table S18. The cost of CSP with storage depends on the ratio of the CSP storage maximum charge rate plus direct electricity use rate (which equals the maximum discharge rate) to the CSP maximum discharge rate. For this table, for the purpose of benchmarking the "CSP with storage" cost, we use a ratio of 3.2:1. (In other words, if 3.2 units of sunlight come in, a maximum of 2.2 units can go to storage and a maximum of 1 unit can be discharged directly as electricity at the same time.) The ratio for "CSP no storage" is 1:1. In our actual simulations and cost calculations, we assume a ratio of 2.612:1 for CSP with storage (footnote to Table S13) and find the cost for this assumed ratio by interpolating between the "CSP with storage" benchmark value and the "CSP no storage" value in this table.

Table S18. Present value of mean 2020 to 2050 lifecycle costs of new storage capacity and round-trip efficiencies of the storage technologies treated here.

Storage technology	Present-value of lifecycle cost of new storage ($/kWh—electricity or equivalent electricity, in the case of cold and heat storage)			Round-trip charge/store/ discharge efficiency (%)
	Middle	Low	High	
Electricity				
PHS	14	12	16	80
CSP-PCM	20	15	23	55, 28.72, 99
LI Batteries	60	30	90	89.5
Cold				
CW-STES	12	0.4	40	84.7
ICE	100	40	160	82.5
Heat				
HW-STES	12	0.4	40	83
UTES	1.6	0.4	4	56

PHS=pumped hydropower storage; CSP-PCM=concentrated solar power with phase change material for storage; LI Batteries=lithium ion batteries; CW-STES=cold water sensible-heat thermal energy storage; ICE=ice storage; HW-STES=hot water sensible-heat thermal energy storage; UTES=underground thermal energy storage (modeled as borehole).

All values reflect averages between 2020 and 2050. From Jacobson et al. (2019), except as follows.

PHS efficiency is the ratio of electricity delivered to the sum of electricity delivered and electricity used to pump the water. The 2020-2050 mean PHS round-trip efficiency estimated here (80%) can be compared with the U.S.-average value in 2019 of 79% (EIA, 2021a).

The CSP-PCM cost is for the PCM material and storage tanks. In the model, only the heat captured by the working fluid due to reflection of sunlight off of CSP mirrors can be stored. The three CSP-PCM efficiencies are as follows. 55% of incoming sunlight is reflected to the central tower, where it is absorbed by the working fluid (the remaining 45% of sunlight is lost to reflection and absorption by the CSP mirrors); without storage, 28.72% of heat absorbed by the working fluid is converted to electricity (the remaining 71.28% of heat is lost); and with storage, 99% of heat received by the working fluid that goes into storage is recovered and available to the steam turbine after storage (Mancini, 2006) and, of that, 28.72% is converted to electricity. Thus, the overall efficiency of CSP without storage is 15.785% and that with storage is 15.638%.

Irvine and Rinaldo (2020) project LI battery cell costs for Tesla batteries to be ~$25/kWh by 2035. We estimate that the total system cost for an installed battery pack will be more than twice this, ~$60/kWh, by 2035 and take this as the mean between 2020 and 2050. For LI battery storage, the 2020-2050 mean round-trip efficiency is taken as the roundtrip efficiency of a 2021 Tesla Powerpack with four hours of storage (Tesla, 2021). Battery efficiency is the ratio of electricity delivered to electricity put into the battery.

CW-STES, ICE, HW-STES, and UTES costs were updated to reflect average values between 2020 and 2050 rather than values in 2016, which they were previously based on. UTES costs were also updated with data from Denmark (Jacobson, 2020, p. 65). In addition, the thermal energy storage (CW-STES, ICE, HW-STEES, and UTES) costs in $/kW-th were multiplied by the mean coefficient of performance (COP) of heat pumps used here (=4 kWh-th/kWh/electricity) to give the costs in $/kW-equivalent electricity. The reason is that all energy in this study is carried in units of electricity, and heat pumps are assumed to provide heat or cold for thermal storage media. Thus, storage capacities are limited to the electricity needed to produce a larger amount of heat or cold. Since the storage size for heat or coal as equivalent electricity is smaller than the storage size of the heat or cold itself, the storage cost per unit equivalent electricity must be proportionately larger (by a factor of COP) for costs to be calculated consistently. The cost of heat pumps is assumed to be $160 (132-188)/kW-electricity, or $40 (33-47)/kW-th, based on data for large heat pumps (> 500 tons) projected to between 2020 and 2050. CW-STES and HW-STES efficiencies are the ratios of the energy returned as cooling and heating, respectively, after storage, to the electricity input into storage. The UTES efficiency is the fraction of heated fluid entering underground storage that is ultimately returned during the year (either short or long term) as air or water heat for a building.

Storage costs per unit energy generated are the product of the maximum energy storage capacity (Table S13) and the lifecycle-averaged capital cost of storage per unit maximum energy storage capacity (this table), annualized with the same discount rate as for power generators (Table S17), but with average 2020 to 2050 storage lifetimes of 17 (12 to 22) years for batteries and 32.5 (25 to 40) years all other storage, all divided by the annual average end-use load met. At least one stationary storage battery (lithium-iron-phosphate) is warrantied up to 15,000 cycles (or 15 years) (Sonnen, 2021). 15,000 cycles is equivalent to one cycle per day (365 cycles per year) for 41.1 years, so this battery may last much longer than the 15 year warranty. As such, the 17-year mean battery life here is likely underestimated.

Table S19. Summary of 2050 WWS mean capital costs of new electricity plus heat generators; electricity, heat, cold, and hydrogen storage (including heat pumps to supply district heating and cooling), and all-distance transmission/distribution ($ trillion in 2020 USD) and mean levelized private costs of energy (LCOE) (USD ¢/kWh-all-energy or ¢/kWh-electricity-replacing-BAU-electricity) averaged over each simulation for each region. Also shown is the energy consumed per year in each case and the resulting aggregate annual energy cost to the region.

	WECC	MRO	TRE	RFC	SERC	NPCC	ASCC
Capital cost new generators only ($tril)	0.799	0.706	1.502	1.536	3.351	0.513	0.033
Cap cost generators-storage-H_2-HVDC ($tril)	**1.084**	**0.910**	**2.345**	**1.886**	**3.897**	**0.720**	**0.079**
Components of total LCOE (¢/kWh-all-energy)							
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.062	0.047	0.000	0.046	0.042	0.000	0.000
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generators	3.257	3.895	5.802	5.179	6.037	5.517	2.811
Additional hydro turbines	0	0	0	0	0	0	0
Solar thermal collectors	0	0	0	0	0	0	0
LI battery storage	0.294	1.008	4.145	1.311	0.842	1.881	4.380
CSP-PCM + PHS storage	0.005	0.000	0.016	0.000	0.000	0.000	0.001
CW-STES + ICE storage	0.001	0.002	0.003	0.002	0.004	0.001	0.001
HW-STES storage	0.009	0.006	0.007	0.008	0.010	0.009	0.002
UTES storage	0.069	0.002	0.003	0.016	0.078	0.038	0.001
Heat pumps for filling district heating/cooling	0.038	0.026	0.030	0.036	0.043	0.042	0.008
H_2 production/compression/storage	0.675	0.284	0.152	0.190	0.252	0.704	0.140
Total LCOE (¢/kWh-all-energy)	**7.834**	**8.693**	**13.583**	**10.212**	**10.733**	**11.619**	**10.768**
LCOE (¢/kWh-replacing BAU electricity)	7.037	8.373	13.391	9.958	10.346	10.825	10.618
GW annual avg. end-use demand (Table S4)	195.5	131.7	188.2	200.7	378.8	71.8	10.0
TWh/y end-use demand (GW x 8,760 h/y)	1,713	1,154	1,648	1,758	3,318	629	88
Annual energy cost ($billion/yr)	**134.2**	**100.3**	**223.9**	**179.5**	**356.1**	**73.1**	**9.4**
	HICC	CALI	FLA	NEWY	TXMRO	CONUS	Total USA
Capital cost new generators only ($tril)	0.018	0.393	0.348	0.323	1.734	6.784	6.835
Cap cost generators-storage-H_2-HVDC ($tril)	**0.028**	**0.632**	**0.472**	**0.521**	**2.584**	**8.831**	**8.938**
Components of total LCOE (¢/kWh-all-energy)							
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.000	0.000	0.000	0.000	0.057	0.118	0.116
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generators	4.853	3.556	4.898	6.571	4.009	4.214	4.204
Additional hydro turbines	0	0	0	0	0	0	0
Solar thermal collectors	0	0	0	0	0	0	0
LI battery storage	1.829	1.337	1.244	3.572	2.220	0.740	0.774
CSP-PCM + PHS storage	0.017	0.007	0.001	0.000	0.005	0.002	0.002
CW-STES + ICE storage	0.021	0.002	0.020	0.002	0.002	0.002	0.002
HW-STES storage	0.050	0.010	0.028	0.011	0.006	0.008	0.008
UTES storage	0.020	0.078	0.221	0.004	0.007	0.034	0.033
Heat pumps for filling district heating/cooling	0.022	0.043	0.122	0.047	0.027	0.034	0.034
H_2 production/compression/storage	1.281	0.957	0.616	1.045	0.139	0.431	0.430
Total LCOE (¢/kWh-all-energy)	**11.52**	**9.415**	**10.57**	**14.68**	**9.898**	**9.007**	**9.028**
LCOE (¢/kWh-replacing BAU electricity)	10.14	8.327	9.587	13.57	9.715	8.492	8.514
GW annual avg. end-use demand (Table S4)	2.8	88.2	49.0	39.1	319.9	1,167	1,179.5
TWh/y end-use demand (GW x 8,760 h/y)	25	773	430	343	2,802	10,220	10,332
Annual energy cost ($billion/yr)	**2.9**	**72.8**	**45.4**	**50.3**	**277.3**	**920.5**	**932.8**

The LCOEs are derived from capital costs, annual O&M, and end-of-life decommissioning costs that vary by technology (Table S17) and that are a function of lifetime (Table S17) and a social discount rate for an intergenerational project of 2.0 (1-3)%, all divided by the total annualized end-use demand met, given in the present table.

Capital cost of generators-storage-H_2-HVDC ($trillion) is the capital cost of new electricity and heat generators; electricity, heat, cold, and hydrogen storage; hydrogen electrolyzers and compressors; and long-distance (HVDC) transmission.

Since the total end-use load includes heat, cold, hydrogen, and electricity loads (all energy), the "electricity generator" cost, for example, is a cost per unit all energy rather than per unit electricity alone. The 'Total LCOE' gives the overall cost of energy, and the 'Electricity LCOE' gives the cost of energy for the electricity portion of load replacing BAU electricity end use. It is the total LCOE less the costs for UTES and HW-STES storage, H_2, and less the portion of long-distance transmission associated with H_2.

Short-distance transmission costs are $0.0105 (0.01-0.011)/kWh.

Distribution costs are $0.02375 (0.023-0.0245)/kWh.

Long-distance transmission costs are $0.0089 (0.0042-0.010)/kWh (in USD 2020) (Jacobson et al., 2017, but brought up to USD 2020), which assumes 1,500 to 2,000 km HVDC lines, a capacity factor usage of the lines of ~50% and a capital cost of ~$400 (300-460)/MWtr-km. Table S14 gives the total HVDC line length and capacity and the fraction of all non-rooftop-PV and non-shed electricity generated that is subject to HVDC transmission by region. Storage costs are derived as described in Table S18.

H_2 costs are derived as in Note S38 and Note S43 of Jacobson et al. (2019). These costs exclude electricity costs, which are included separately in the present table.

Total USA=CONUS+ASCC+HICC

Table S20. 2050 regional and state annual-average end-use (a) BAU load and (b) WWS load; (c) percentage difference between WWS and BAU load; (d) present value of the mean total capital cost for new WWS electricity, heat, cold, and hydrogen generation and storage and all-distance transmission and distribution; mean levelized private costs of all (e) BAU and (f) WWS energy (¢/kWh-all-energy-sectors, averaged between today and 2050); (g) mean WWS private (equals social) energy cost per year, (h) mean BAU private energy cost per year, (i) mean BAU health cost per year, (j) mean BAU climate cost per year, (k) BAU total social cost per year; (l) percentage difference between WWS and BAU private energy cost; and (m) percentage difference between WWS and BAU social energy cost. All costs are in 2020 USD. H=8760 hours per year.

Region	(a)[1] 2050 BAU Annual average end-use load (GW)	(b)[1] 2050 WWS Annual average end-use load (GW)	(c) 2050 WWS minus BAU load = (b-a)/a (%)	(d)[2] WWS mean total capital cost ($tril 2020)	(e)[3] BAU mean private energy cost (¢/kWh -all energy)	(f)[4] WWS mean private energy cost (¢/kWh -all energy)	(g)[5] WWS mean annual all-energy private and social cost = bfH ($bil/y)	(h)[5] BAU mean annual all-energy private cost = aeH ($bil/y)	(i)[6] BAU mean annual BAU health cost ($bil/y)	(j)[7] BAU mean annual climate cost ($bil/y)	(k) BAU mean annual BAU total social cost =h+i+j ($bil/y)	(l) WWS minus BAU private energy cost = (g-h)/h (%)	(m) WWS minus BAU social energy cost = (g-k)/k (%)
WECC Total	**472.0**	**195.5**	**-58.6**	**1.084**	**9.94**	**7.83**	**134.2**	**410.9**	**208.8**	**627.4**	**1,247**	**-67.3**	**-89.2**
Arizona	34.3	15.2	-55.5	0.089	9.94	7.83	10.5	29.8	21.7	59.7	111	-64.9	-90.6
California	218.6	88.2	-59.6	0.517	9.94	7.83	60.6	190.3	134.1	249.9	574	-68.2	-89.5
Colorado	41.0	16.7	-59.2	0.098	9.94	7.83	11.5	35.7	9.6	60.7	106	-67.8	-89.2
Idaho	14.6	6.3	-56.9	0.030	9.94	7.83	4.3	12.7	3.3	12.9	29	-66.1	-85.0
Montana	10.5	4.0	-61.4	0.018	9.94	7.83	2.8	9.1	1.7	21.1	32	-69.6	-91.3
Nevada	18.6	7.9	-57.7	0.042	9.94	7.83	5.4	16.1	8.2	25.2	50	-66.6	-89.1
New Mexico	19.8	8.0	-59.6	0.044	9.94	7.83	5.5	17.2	3.6	33.9	55	-68.2	-90.0
Oregon	26.3	11.8	-55.2	0.058	9.94	7.83	8.1	22.9	5.9	26.7	55	-64.7	-85.4
Utah	21.8	8.5	-61.0	0.053	9.94	7.83	5.8	19.0	8.6	40.5	68	-69.3	-91.4
Washington St.	50.0	21.6	-56.9	0.092	9.94	7.83	14.8	43.5	11.6	54.5	110	-66.0	-86.5
Wyoming	16.7	7.3	-56.2	0.042	9.94	7.83	5.0	14.6	0.6	42.3	57	-65.5	-91.2
MRO total	**292.3**	**131.7**	**-54.9**	**0.910**	**10.30**	**8.69**	**100.3**	**263.8**	**38.6**	**369.9**	**672**	**-62.0**	**-85.1**
Iowa	52.4	26.1	-50.3	0.198	10.30	8.69	19.9	47.3	5.8	53.2	106	-58.0	-81.3
Kansas	30.7	13.0	-57.7	0.091	10.30	8.69	9.9	27.7	3.8	40.3	72	-64.3	-86.3
Minnesota	51.4	22.0	-57.2	0.168	10.30	8.69	16.8	46.4	8.0	61.3	116	-63.9	-85.5
Nebraska	26.3	12.8	-51.4	0.088	10.30	8.69	9.7	23.7	2.8	33.3	60	-59.0	-83.7
North Dakota	19.4	9.1	-53.3	0.049	10.30	8.69	6.9	17.5	0.7	39.1	57	-60.6	-88.0
Oklahoma	50.4	21.4	-57.5	0.132	10.30	8.69	16.3	45.5	6.8	64.6	117	-64.1	-86.0
South Dakota	12.1	5.9	-51.1	0.035	10.30	8.69	4.5	10.9	1.0	10.1	22	-58.7	-79.5
Wisconsin	49.7	21.5	-56.7	0.149	10.30	8.69	16.4	44.8	9.8	68.0	123	-63.5	-86.7
TRE (Texas)	**434.4**	**188.2**	**-56.7**	**2.345**	**10.96**	**13.58**	**223.9**	**417.1**	**58.6**	**492.4**	**968**	**-46.3**	**-76.9**
RFC total	**476.6**	**200.7**	**-57.9**	**1.886**	**10.62**	**10.21**	**179.5**	**443.3**	**132.9**	**700.8**	**1,277**	**-59.5**	**-85.9**
DC, Wash.	3.7	2.0	-47.0	0.021	10.62	10.21	1.7	3.4	1.9	1.8	7	-49.0	-75.6
Delaware	7.0	3.0	-57.4	0.031	10.62	10.21	2.7	6.5	2.4	8.5	17	-59.1	-84.8
Indiana	75.5	35.0	-53.6	0.318	10.62	10.21	31.3	70.2	18.7	122.6	211	-55.4	-85.2
Maryland	32.4	13.3	-59.1	0.122	10.62	10.21	11.9	30.1	14.3	36.0	80	-60.6	-85.3
Michigan	75.4	29.8	-60.5	0.279	10.62	10.21	26.7	70.1	17.7	105.8	194	-62.0	-86.2
New Jersey	57.5	20.9	-63.6	0.206	10.62	10.21	18.7	53.5	14.8	70.4	139	-65.0	-86.5
Ohio	95.6	40.5	-57.6	0.393	10.62	10.21	36.2	88.9	30.1	142.4	261	-59.2	-86.1
Pennsylvania	106.4	46.0	-56.7	0.441	10.62	10.21	41.2	98.9	30.3	150.0	279	-58.4	-85.3
West Virginia	23.3	10.2	-56.1	0.077	10.62	10.21	9.2	21.7	2.7	63.2	88	-57.8	-89.6
SERC total	**830.7**	**378.8**	**-54.4**	**3.897**	**10.67**	**10.73**	**356.1**	**776.1**	**206.8**	**1,144**	**2,127**	**-54.1**	**-83.3**
Alabama	53.8	27.0	-49.8	0.244	10.67	10.73	25.4	50.2	10.1	75.5	136	-49.5	-81.3
Arkansas	29.9	13.9	-53.5	0.130	10.67	10.73	13.1	27.9	4.9	44.5	77	-53.2	-83.1
Florida	103.8	49.0	-52.8	0.515	10.67	10.73	46.1	97.0	37.4	157.9	292	-52.5	-84.2

Georgia	72.0	34.5	-52.1	0.382	10.67	10.73	32.4	67.3	25.8	91.9	185	-51.8	-82.5
Illinois	102.4	41.7	-59.3	0.383	10.67	10.73	39.2	95.7	28.0	140.2	264	-59.0	-85.1
Kentucky	41.3	18.2	-55.8	0.187	10.67	10.73	17.1	38.5	9.4	79.2	127	-55.5	-86.5
Louisiana	141.2	63.5	-55.0	0.736	10.67	10.73	59.7	131.9	7.8	157.8	297	-54.8	-79.9
Mississippi	33.2	14.7	-55.9	0.174	10.67	10.73	13.8	31.0	5.3	47.0	83	-55.6	-83.5
Missouri	43.3	18.2	-58.1	0.181	10.67	10.73	17.1	40.5	11.9	85.3	138	-57.8	-87.6
North Carolina	60.4	28.6	-52.7	0.283	10.67	10.73	26.9	56.5	21.4	80.2	158	-52.4	-83.0
South Carolina	38.9	18.8	-51.6	0.196	10.67	10.73	17.7	36.3	12.7	48.0	97	-51.3	-81.7
Tennessee	52.9	24.5	-53.8	0.249	10.67	10.73	23.0	49.4	16.8	68.0	134	-53.5	-82.9
Virginia	57.6	26.3	-54.4	0.238	10.67	10.73	24.7	53.8	15.3	68.2	137	-54.1	-82.0
NPCC total	**187.3**	**71.8**	**-61.7**	**0.720**	**10.22**	**11.62**	**73.1**	**167.6**	**52.1**	**207.7**	**427**	**-56.4**	**-82.9**
Connecticut	19.4	7.3	-62.5	0.081	10.22	11.62	7.4	17.4	6.8	23.2	47.5	-57.3	-84.4
Maine	11.2	5.0	-55.3	0.047	10.22	11.62	5.1	10.0	1.4	10.7	22.2	-49.1	-77.0
Massachusetts	37.6	14.1	-62.3	0.144	10.22	11.62	14.4	33.6	11.3	44.1	89.1	-57.2	-83.8
New Hampshire	7.8	2.9	-63.0	0.030	10.22	11.62	2.9	7.0	1.9	9.3	18.2	-57.9	-83.9
New York	102.0	39.1	-61.7	0.391	10.22	11.62	39.8	91.3	28.3	109.3	228.9	-56.4	-82.6
Rhode Island	5.3	1.9	-63.6	0.022	10.22	11.62	2.0	4.8	1.7	7.0	13.4	-58.6	-85.3
Vermont	4.0	1.4	-64.7	0.004	10.22	11.62	1.4	3.6	0.6	4.0	8.2	-59.9	-82.5
ASCC (Alaska)	**23.2**	**9.99**	**-56.9**	**0.079**	**10.07**	**10.77**	**9.4**	**20.4**	**0.8**	**23.7**	**45.0**	**-53.9**	**-79.1**
HICC (Hawaii)	**7.42**	**2.84**	**-61.8**	**0.028**	**20.73**	**11.52**	**2.9**	**13.5**	**1.9**	**12.3**	**27.6**	**-78.7**	**-89.6**
CALI (Calif.)	**218.6**	**88.2**	**-59.6**	**0.632**	**10.41**	**9.42**	**72.8**	**199.4**	**134.1**	**249.9**	**583**	**-63.5**	**-87.5**
FLA (Florida)	**103.8**	**49.0**	**-52.8**	**0.472**	**11.26**	**10.57**	**45.4**	**102.4**	**37.4**	**157.9**	**298**	**-55.6**	**-84.7**
NEWY (NY)	**102.0**	**39.1**	**-61.7**	**0.521**	**9.88**	**14.68**	**50.3**	**88.3**	**28.3**	**109.3**	**226**	**-43.0**	**-77.7**
TXMRO	**726.7**	**319.9**	**-56.0**	**2.584**	**10.69**	**9.90**	**277.3**	**680.8**	**97.2**	**862.3**	**1,640**	**-59.3**	**-83.1**
Iowa	52.4	26.1	-50.3	0.253	10.69	9.90	22.6	49.1	5.8	53.2	108	-54.0	-79.1
Kansas	30.7	13.0	-57.7	0.114	10.69	9.90	11.2	28.7	3.8	40.3	73	-60.9	-84.6
Minnesota	51.4	22.0	-57.2	0.191	10.69	9.90	19.1	48.1	8.0	61.3	117	-60.4	-83.8
Nebraska	26.3	12.8	-51.4	0.103	10.69	9.90	11.1	24.6	2.8	33.3	61	-55.0	-81.7
North Dakota	19.4	9.1	-53.3	0.059	10.69	9.90	7.9	18.2	0.7	39.1	58	-56.8	-86.5
Oklahoma	50.4	21.4	-57.5	0.154	10.69	9.90	18.6	47.2	6.8	64.6	119	-60.7	-84.3
South Dakota	12.1	5.9	-51.1	0.040	10.69	9.90	5.1	11.4	1.0	10.1	22	-54.8	-77.1
Texas	434.4	188.2	-56.7	1.491	10.69	9.90	163.1	407.0	58.6	492.4	958	-59.9	-83.0
Wisconsin	49.7	21.5	-56.7	0.179	10.69	9.90	18.6	46.5	9.8	68.0	124	-60.0	-85.0
CONUS	**2,693**	**1,167**	**-56.7**	**8.831**	**10.51**	**9.01**	**920.5**	**2,479**	**697.7**	**3,542**	**6,718**	**-62.9**	**-86.3**
Alabama	53.8	27.0	-49.8	0.192	10.51	9.01	21.3	49.5	10.1	75.5	135	-57.0	-84.2
Arizona	34.3	15.2	-55.5	0.099	10.51	9.01	12.0	31.5	21.7	59.7	113	-61.9	-89.4
Arkansas	29.9	13.9	-53.5	0.103	10.51	9.01	11.0	27.5	4.9	44.5	77	-60.1	-85.7
California	218.6	88.2	-59.6	0.609	10.51	9.01	69.6	201.2	134.1	249.9	585	-65.4	-88.1
Colorado	41.0	16.7	-59.2	0.109	10.51	9.01	13.2	37.7	9.6	60.7	108	-65.0	-87.8
Connecticut	19.4	7.3	-62.5	0.061	10.51	9.01	5.7	17.9	6.8	23.2	48	-67.8	-88.0
DC, Wash.	3.7	2.0	-47.0	0.017	10.51	9.01	1.5	3.4	1.9	1.8	7	-54.6	-78.4
Delaware	7.0	3.0	-57.4	0.025	10.51	9.01	2.3	6.4	2.4	8.5	17	-63.5	-86.6
Florida	103.8	49.0	-52.8	0.423	10.51	9.01	38.7	95.6	37.4	157.9	291	-59.5	-86.7
Georgia	72.0	34.5	-52.1	0.320	10.51	9.01	27.2	66.3	25.8	91.9	184	-59.0	-85.2
Idaho	14.6	6.3	-56.9	0.034	10.51	9.01	4.9	13.4	3.3	12.9	30	-63.1	-83.2
Illinois	102.4	41.7	-59.3	0.308	10.51	9.01	32.9	94.3	28.0	140.2	262	-65.1	-87.5
Indiana	75.5	35.0	-53.6	0.273	10.51	9.01	27.6	69.5	18.7	122.6	211	-60.2	-86.9
Iowa	52.4	26.1	-50.3	0.176	10.51	9.01	20.6	48.2	5.8	53.2	107	-57.4	-80.8
Kansas	30.7	13.0	-57.7	0.084	10.51	9.01	10.2	28.2	3.8	40.3	72	-63.8	-85.9
Kentucky	41.3	18.2	-55.8	0.146	10.51	9.01	14.4	38.0	9.4	79.2	127	-62.1	-88.6
Louisiana	141.2	63.5	-55.0	0.580	10.51	9.01	50.1	129.9	7.8	157.8	296	-61.5	-83.1
Maine	11.2	5.0	-55.3	0.038	10.51	9.01	4.0	10.3	1.4	10.7	22	-61.6	-82.4
Maryland	32.4	13.3	-59.1	0.103	10.51	9.01	10.5	29.8	14.3	36.0	80	-64.9	-86.9
Massachusetts	37.6	14.1	-62.3	0.114	10.51	9.01	11.2	34.6	11.3	44.1	90	-67.7	-87.6
Michigan	75.4	29.8	-60.5	0.240	10.51	9.01	23.5	69.4	17.7	105.8	193	-66.1	-87.8
Minnesota	51.4	22.0	-57.2	0.177	10.51	9.01	17.4	47.3	8.0	61.3	117	-63.3	-85.1

Mississippi	33.2	14.7	-55.9	0.133	10.51	9.01	11.6	30.6	5.3	47.0	83	-62.2	-86.0
Missouri	43.3	18.2	-58.1	0.152	10.51	9.01	14.3	39.9	11.9	85.3	137	-64.0	-89.5
Montana	10.5	4.0	-61.4	0.021	10.51	9.01	3.2	9.6	1.7	21.1	32	-66.9	-90.2
Nebraska	26.3	12.8	-51.4	0.084	10.51	9.01	10.1	24.2	2.8	33.3	60	-58.3	-83.2
Nevada	18.6	7.9	-57.7	0.048	10.51	9.01	6.2	17.1	8.2	25.2	50	-63.7	-87.7
New Hampshire	7.8	2.9	-63.0	0.025	10.51	9.01	2.3	7.2	1.9	9.3	18	-68.3	-87.7
New Jersey	57.5	20.9	-63.6	0.168	10.51	9.01	16.5	52.9	14.8	70.4	138	-68.8	-88.1
New Mexico	19.8	8.0	-59.6	0.050	10.51	9.01	6.3	18.2	3.6	33.9	56	-65.4	-88.7
New York	102.0	39.1	-61.7	0.307	10.51	9.01	30.9	93.9	28.3	109.3	231	-67.1	-86.7
North Carolina	60.4	28.6	-52.7	0.244	10.51	9.01	22.5	55.6	21.4	80.2	157	-59.5	-85.7
North Dakota	19.4	9.1	-53.3	0.047	10.51	9.01	7.1	17.9	0.7	39.1	58	-60.0	-87.6
Ohio	95.6	40.5	-57.6	0.332	10.51	9.01	32.0	87.9	30.1	142.4	260	-63.7	-87.7
Oklahoma	50.4	21.4	-57.5	0.127	10.51	9.01	16.9	46.4	6.8	64.6	118	-63.6	-85.6
Oregon	26.3	11.8	-55.2	0.071	10.51	9.01	9.3	24.2	5.9	26.7	57	-61.6	-83.6
Pennsylvania	106.4	46.0	-56.7	0.375	10.51	9.01	36.3	97.9	30.3	150.0	278	-62.9	-86.9
Rhode Island	5.3	1.9	-63.6	0.016	10.51	9.01	1.5	4.9	1.7	7.0	14	-68.8	-88.7
South Carolina	38.9	18.8	-51.6	0.164	10.51	9.01	14.9	35.8	12.7	48.0	96	-58.5	-84.6
South Dakota	12.1	5.9	-51.1	0.035	10.51	9.01	4.7	11.2	1.0	10.1	22	-58.1	-79.0
Tennessee	52.9	24.5	-53.8	0.207	10.51	9.01	19.3	48.7	16.8	68.0	134	-60.4	-85.5
Texas	434.4	188.2	-56.7	1.349	10.51	9.01	148.5	399.8	58.6	492.4	951	-62.9	-84.4
Utah	21.8	8.5	-61.0	0.060	10.51	9.01	6.7	20.1	8.6	40.5	69	-66.6	-90.3
Vermont	4.0	1.4	-64.7	0.003	10.51	9.01	1.1	3.7	0.6	4.0	8	-69.8	-86.6
Virginia	57.6	26.3	-54.4	0.204	10.51	9.01	20.7	53.0	15.3	68.2	137	-60.9	-84.8
Washington St.	50.0	21.6	-56.9	0.111	10.51	9.01	17.0	46.0	11.6	54.5	112	-63.0	-84.8
West Virginia	23.3	10.2	-56.1	0.065	10.51	9.01	8.1	21.5	2.7	63.2	87	-62.3	-90.8
Wisconsin	49.7	21.5	-56.7	0.157	10.51	9.01	17.0	45.7	9.8	68.0	124	-62.9	-86.3
Wyoming	16.7	7.3	-56.2	0.044	10.51	9.01	5.8	15.4	0.6	42.3	58	-62.5	-90.1
Total USA[8]	**2,724**	**1,179**	**-56.7**	**8.94**	**10.53**	**9.03**	**932.8**	**2,513**	**700.4**	**3,578**	**6,791**	**-62.9**	**-86.3**

[1]From Table S3.

[2]Capital cost of generators-storage-H_2-HVDC ($trillion) is the capital cost of new electricity and heat generators; electricity, heat, cold, and hydrogen storage; hydrogen electrolyzers and compressors; and long-distance (HVDC) transmission.

[3]This is the BAU electricity-sector cost of energy per unit energy. It is assumed to equal the BAU all-energy cost of energy per unit energy.

[4]The WWS cost per unit energy is for all energy, which is almost all electricity (plus a small amount of direct heat)

[5]The annual private cost of WWS or BAU energy equals the cost per unit energy from Column (f) or (g), respectively, multiplied by the energy consumed per year, which equals the end-use load from Column (b) or (a), respectively, multiplied by 8,760 hours per year.

[6]The 2050 annual BAU health cost equals the number of total air pollution mortalities per year in 2050 from Table S21, Column (a), multiplied by 90% (the estimated percentage of total air pollution mortalities that are due to energy) and by a statistical cost of life of $11.56 ($7.21-$17.03) million/mortality (2020 USD) and a multiplier of 1.15 for morbidity and another multiplier of 1.1 for non-health impacts (Jacobson et al., 2019).

[7]The 2050 annual BAU climate cost equals the 2050 CO_2e emissions from Table S21, Column (b), multiplied by the social cost of carbon in 2050 of $548 ($315-$1,188)/metric tonne-$CO_2$ (in 2020 USD), which is updated from values in Jacobson et al. (2019), which were in 2013 USD.

[8]Total USA=CONUS+ASCC+HICC

Table S21. Regional and state (a) estimated air pollution mortalities per year in 2050-2051 due to anthropogenic sources (90% of which are energy); (b) carbon-equivalent emissions (CO_2e) in the BAU case; (c) cost per tonne-CO_2e of eliminating CO_2e with WWS; (d) BAU energy cost per tonne-CO_2e emitted; (e) BAU health cost per tonne-CO_2e emitted; (f) BAU climate cost per tonne-CO_2e emitted; (g) BAU total social cost per tonne-CO_2e emitted; (h) BAU health cost per unit all-BAU-energy produced; and (i) BAU climate cost per unit-all-BAU-energy produced.

Region/state	(a)[1] 2050 (Deaths/ y)	(b)[2] 2050 BAU CO_2e (Mtonne/ y)	(c)[3] 2050 WWS ($/ tonne-$CO_2e$-elim-inated)	(d)[4] 2050 BAU energy cost ($/ tonne-$CO_2e$-emitted)	(e)[4] 2050 BAU health cost ($/ tonne-$CO_2e$-emitted)	(f)[4] 2050 BAU climate cost ($/ tonne-$CO_2e$-emitted)	(g)[4] 2050 BAU social cost = d+e+f ($/ tonne-$CO_2e$-emitted)	(h)[5] 2050 BAU health cost (¢/kWh)	(i)[5] 2050 BAU climate cost (¢/kWh)
WECC Total	**15,867**	**1,124**	**119.4**	**366**	**185.8**	**558**	**1,110**	**5.05**	**15.2**
Arizona	1,650	107	97.9	279	203.3	558	1,041	7.24	19.9
California	10,191	448	135.3	425	299.4	558	1,283	7.00	13.0
Colorado	725	109	105.7	329	87.9	558	975	2.66	16.9
Idaho	248	23	187.1	551	141.4	559	1,251	2.55	10.1
Montana	131	38	73.2	241	45.5	558	844	1.88	23.0
Nevada	623	45	119.4	358	181.7	559	1,098	5.05	15.5
New Mexico	276	61	90.1	283	59.8	558	901	2.10	19.6
Oregon	445	48	168.8	478	122.3	558	1,159	2.54	11.6
Utah	653	73	80.4	262	118.4	558	938	4.50	21.2
Washington St.	879	98	151.4	445	118.3	558	1,122	2.64	12.5
Wyoming	46	76	66.4	192	7.9	558	759	0.41	28.8
MRO total	**2,931**	**663**	**151.4**	**398**	**58.3**	**558**	**1,015**	**1.51**	**14.4**
Iowa	441	95	208.4	496	61.2	558	1,116	1.27	11.6
Kansas	289	72	136.6	383	52.8	558	994	1.42	15.0
Minnesota	608	110	152.7	423	73.0	558	1,054	1.78	13.6
Nebraska	210	60	163.6	399	46.4	558	1,003	1.20	14.4
North Dakota	51	70	98.4	250	9.5	558	817	0.39	23.0
Oklahoma	513	116	140.9	393	58.3	558	1,009	1.53	14.6
South Dakota	74	18	249.6	605	54.0	558	1,217	0.92	9.5
Wisconsin	745	122	134.3	368	80.4	558	1,006	2.25	15.6
TRE (Texas)	**4,438**	**882**	**253.8**	**473**	**66.4**	**558**	**1,098**	**1.54**	**12.9**
RFC total	**10,101**	**1,255**	**143.0**	**353**	**105.9**	**558**	**1,017**	3.18	16.8
DC, Washington	144	3	534.7	1,049	583.1	558	2,191	5.90	5.7
Delaware	186	15	173.3	423	160.0	558	1,142	4.01	14.0
Indiana	1,423	220	142.8	320	85.2	558	964	2.83	18.5
Maryland	1,086	64	183.9	467	221.9	558	1,247	5.04	12.7
Michigan	1,346	189	140.8	370	93.4	558	1,022	2.68	16.0
New Jersey	1,124	126	148.4	424	117.4	558	1,100	2.94	14.0
Ohio	2,284	255	142.1	348	117.8	558	1,025	3.59	17.0
Pennsylvania	2,302	269	153.2	368	112.7	558	1,039	3.25	16.1
West Virginia	206	113	80.8	191	24.0	558	774	1.33	31.0
SERC total	**15,700**	**2,048**	**173.8**	**379**	**100.9**	**558**	**1,038**	**2.84**	**15.7**
Alabama	768	135	187.7	372	74.9	558	1,005	2.15	16.0
Arkansas	370	80	163.8	350	61.0	558	969	1.86	17.0
Florida	2,839	283	163.0	343	132.2	558	1,034	4.11	17.4
Georgia	1,958	165	196.8	409	156.7	558	1,124	4.09	14.6
Illinois	2,125	251	156.2	381	111.5	558	1,051	3.12	15.6
Kentucky	712	142	120.8	272	66.0	558	896	2.59	21.9
Louisiana	589	283	211.1	467	27.6	558	1,052	0.63	12.8

Mississippi	399	84	163.8	369	62.6	558	990	1.81	16.1
Missouri	902	153	111.8	265	77.7	558	901	3.13	22.5
North Carolina	1,627	144	187.1	393	149.3	558	1,101	4.05	15.2
South Carolina	965	86	206.1	423	147.9	558	1,129	3.73	14.1
Tennessee	1,279	122	188.7	406	138.0	558	1,102	3.63	14.7
Virginia	1,167	122	202.4	441	125.6	558	1,124	3.04	13.5
NPCC total	**3,958**	**372**	**196.4**	**451**	**140.0**	**558**	**1,149**	3.17	12.7
Connecticut	520	42	177.9	417	164.4	558	1,139	4.03	13.7
Maine	109	19	265.8	523	74.7	558	1,156	1.46	10.9
Massachusetts	858	79	182.2	426	142.9	559	1,127	3.43	13.4
New Hampshire	146	17	175.5	417	115.0	558	1,090	2.82	13.7
New York	2,153	196	203.4	467	144.8	558	1,170	3.17	12.2
Rhode Island	126	12	157.9	381	133.6	559	1,073	3.58	15.0
Vermont	46	7	198.6	495	82.9	558	1,136	1.71	11.5
ASCC (Alaska)	**61**	**43**	**221.6**	**480**	**19.1**	**558**	**1,058**	**0.40**	**11.7**
HICC (Hawaii)	**141**	**22**	**130.2**	**613**	**84.2**	**558**	**1,255**	**2.85**	**18.9**
CALI (California)	**10,191**	**448**	**162.6**	**445**	**299.4**	**558**	**1,303**	**7.00**	**13.0**
FLA (Florida)	**2,839**	**283**	**160.6**	**362**	**132.2**	**558**	**1,053**	**4.11**	**17.4**
NEWY (New York)	**2,153**	**196**	**257.0**	**451**	**144.8**	**558**	**1,154**	**3.17**	**12.2**
TXMRO	**7,369**	**1,544**	**179.6**	**441**	**62.9**	**558**	**1,062**	**1.53**	**13.5**
Iowa	441	95	237.3	515	61.2	558	1,135	1.27	11.6
Kansas	289	72	155.5	397	52.8	558	1,008	1.42	15.0
Minnesota	608	110	173.8	439	73.0	558	1,070	1.78	13.6
Nebraska	210	60	186.2	414	46.4	558	1,019	1.20	14.4
North Dakota	51	70	112.0	259	9.5	558	827	0.39	23.0
Oklahoma	513	116	160.4	408	58.3	558	1,024	1.53	14.6
South Dakota	74	18	284.2	628	54.0	558	1,240	0.92	9.5
Texas	4,438	882	185.0	461	66.4	558	1,086	1.54	12.9
Wisconsin	745	122	152.9	382	80.4	558	1,020	2.25	15.6
CONUS	**52,995**	**6,344**	**145.1**	**391**	**110.0**	**558**	**1,059**	**2.96**	**15.0**
Alabama	768	135	157.5	366	74.9	558	999	2.15	16.0
Arizona	1,650	107	112.5	295	203.3	558	1,057	7.24	19.9
Arkansas	370	80	137.4	345	61.0	558	964	1.86	17.0
California	10,191	448	155.5	449	299.4	558	1,307	7.00	13.0
Colorado	725	109	121.5	347	87.9	558	994	2.66	16.9
Connecticut	520	42	137.9	429	164.4	558	1,151	4.03	13.7
DC, Washington	144	3	471.7	1,038	583.1	558	2,180	5.90	5.7
Delaware	186	15	152.9	419	160.0	558	1,137	4.01	14.0
Florida	2,839	283	136.8	338	132.2	558	1,029	4.11	17.4
Georgia	1,958	165	165.2	403	156.7	558	1,118	4.09	14.6
Idaho	248	23	215.1	583	141.4	559	1,283	2.55	10.1
Illinois	2,125	251	131.1	375	111.5	558	1,045	3.12	15.6
Indiana	1,423	220	125.9	316	85.2	558	960	2.83	18.5
Iowa	441	95	215.9	506	61.2	558	1,126	1.27	11.6
Kansas	289	72	141.5	390	52.8	558	1,001	1.42	15.0
Kentucky	712	142	101.4	268	66.0	558	892	2.59	21.9
Louisiana	589	283	177.1	460	27.6	558	1,046	0.63	12.8
Maine	109	19	206.1	537	74.7	558	1,170	1.46	10.9
Maryland	1,086	64	162.2	462	221.9	558	1,243	5.04	12.7
Massachusetts	858	79	141.3	438	142.9	559	1,139	3.43	13.4
Michigan	1,346	189	124.2	366	93.4	558	1,018	2.68	16.0
Minnesota	608	110	158.2	431	73.0	558	1,062	1.78	13.6
Mississippi	399	84	137.5	364	62.6	558	985	1.81	16.1
Missouri	902	153	93.8	261	77.7	558	897	3.13	22.5
Montana	131	38	84.1	254	45.5	558	858	1.88	23.0
Nebraska	210	60	169.5	407	46.4	558	1,011	1.20	14.4

Nevada	623	45	137.2	378	181.7	559	1,118	5.05	15.5
New Hampshire	146	17	136.0	429	115.0	558	1,102	2.82	13.7
New Jersey	1,124	126	130.9	420	117.4	558	1,096	2.94	14.0
New Mexico	276	61	103.6	299	59.8	558	917	2.10	19.6
New York	2,153	196	157.7	480	144.8	558	1,183	3.17	12.2
North Carolina	1,627	144	157.0	387	149.3	558	1,095	4.05	15.2
North Dakota	51	70	102.0	255	9.5	558	822	0.39	23.0
Ohio	2,284	255	125.3	345	117.8	558	1,021	3.59	17.0
Oklahoma	513	116	146.0	401	58.3	558	1,017	1.53	14.6
Oregon	445	48	194.1	506	122.3	558	1,186	2.54	11.6
Pennsylvania	2,302	269	135.1	364	112.7	558	1,035	3.25	16.1
Rhode Island	126	12	122.4	392	133.6	559	1,084	3.58	15.0
South Carolina	965	86	173.0	417	147.9	558	1,123	3.73	14.1
South Dakota	74	18	258.6	617	54.0	558	1,229	0.92	9.5
Tennessee	1,279	122	158.3	400	138.0	558	1,096	3.63	14.7
Texas	4,438	882	168.3	453	66.4	558	1,078	1.54	12.9
Utah	653	73	92.4	277	118.4	558	953	4.50	21.2
Vermont	46	7	153.9	509	82.9	558	1,150	1.71	11.5
Virginia	1,167	122	169.9	434	125.6	558	1,118	3.04	13.5
Washington St.	879	98	174.1	471	118.3	558	1,148	2.64	12.5
West Virginia	206	113	71.3	189	24.0	558	772	1.33	31.0
Wisconsin	745	122	139.2	375	80.4	558	1,014	2.25	15.6
Wyoming	46	76	76.4	203	7.9	558	770	0.41	28.8
Total USA[6]	**53,197**	**6,408**	**145.6**	**392**	**109.3**	**558**	**1,060**	**2.94**	**15.0**

[1]2050 state mortalities due to air pollution are scaled from 2010-12 state values from Jacobson et al. (2015) using the ratio of the total 2050 air pollution mortalities for the U.S. from Jacobson et al. (2019) 53,199/yr (36,394/yr-73,614/yr) to the total 2010-12 number of deaths across the U.S. from Jacobson et al. (2015) 62,381 (19,363-115,723) deaths/year. The estimated number of U.S. deaths in 2050 from Jacobson et al. (2019) was derived from WHO (2017) air pollution mortality data for the United States for 2016, then projected to 2050 using Equation S35 of Jacobson et al. (2019).

[2]CO_2e=CO_2-equivalent emissions. This accounts for the emissions of CO_2 plus the emissions of other greenhouse gases multiplied by their global warming potentials.

[3]Calculated as the WWS private energy and total social cost from Table S20, Column (g) divided by the CO_2e emissions from Column (b) of the present table.

[4]Columns (d)-(g) are calculated as the BAU private energy, health, climate, and total social costs from Table S20, Columns (h)-(k), respectively, each divided by the CO_2e emissions from Column (b) of the present table.

[5]Columns (h)-(i) are calculated as the BAU health and climate costs from Table S20, Columns (i)-(j), respectively, each divided by the BAU end-use load from Table S20, Column (a) and by 8760 hours per year.

[6]Total USA=CONUS+ASCC+HICC

Table S22. Footprint and spacing areas per MW of nameplate capacity and installed power densities for WWS electricity or heat generation technologies.

WWS technology	Footprint (m^2/MW)	Spacing (km^2/MW)	Installed power density (MW/km^2)
Onshore wind	3.22	0.0505	19.8
Offshore wind	3.22	0.139	7.2
Wave device	700	0.033	30.3
Geothermal plant	3,290	0	304
Hydropower plant	502,380	0	2.0
Tidal turbine	290	0.004	250
Residential roof PV	5,230	0	191.2
Commercial/govt. roof PV	5,230	0	191.2
Solar PV plant	12,220	0	81.8
Utility CSP plant	29,350	0	34.1
Solar thermal for heat	1,430	0	700

From Jacobson et al. (2019). Spacing areas for onshore and offshore wind are based on data from Enevoldsen and Jacobson (2021). The installed power density is the inverse of the spacing except, if spacing is zero, it is the inverse of the footprint.

Table S23. Footprint areas for *new* utility PV farms, CSP plants, solar thermal plants for heat, geothermal plants for electricity and heat, and hydropower plants and spacing areas for new onshore wind turbines, for each state within each grid region and for the grid region as a whole.

Region/State	Region land area (km^2)	Footprint Area (km^2)	Spacing area (km^2)	Footprint area as percentage of region land area (%)	Spacing area as a percentage of region land area (%)
WECC Total	**3,042,090**	**2,659**	**6,627**	**0.09**	**0.22**
Arizona	294,312	287	539	0.10	0.18
California	403,882	1,332	1,899	0.33	0.47
Colorado	268,627	283	869	0.11	0.32
Idaho	214,314	47	411	0.02	0.19
Montana	376,979	36	182	0.01	0.05
Nevada	284,448	86	364	0.03	0.13
New Mexico	314,309	116	266	0.04	0.08
Oregon	248,631	65	141	0.03	0.06
Utah	212,751	118	647	0.06	0.30
Washington St.	172,348	80	802	0.05	0.47
Wyoming	251,489	209	507	0.08	0.20
MRO total	**1,455,586**	**3,602**	**8,704**	**0.25**	**0.60**
Iowa	144,701	1,454	1,733	1.00	1.20
Kansas	211,900	536	776	0.25	0.37
Minnesota	206,189	287	1,470	0.14	0.71
Nebraska	199,099	306	874	0.15	0.44
North Dakota	178,647	166	564	0.09	0.32
Oklahoma	177,847	400	1,222	0.22	0.69
South Dakota	196,540	74	406	0.04	0.21
Wisconsin	140,663	380	1,660	0.27	1.18
TRE (Texas)	**678,051**	**4,275**	**15,573**	**0.63**	**2.30**
RFC total	**574,269**	**10,855**	**9,113**	**1.89**	**1.59**
DC, Washington	177	0	0.32	0	0.18
Delaware	5,060	101	49	1.99	0.97
Indiana	92,895	2,132	1,863	2.29	2.01
Maryland	25,314	292	612	1.15	2.42
Michigan	147,121	1,185	1,670	0.81	1.13
New Jersey	19,211	631	476	3.28	2.48
Ohio	106,056	2,310	1,830	2.18	1.73
Pennsylvania	116,074	3,722	2,381	3.21	2.05
West Virginia	62,361	484	231	0.78	0.37
SERC total	**1,628,956**	**17,042**	**10,566**	**1.05**	**0.65**
Alabama	131,426	1,841	231	1.40	0.18
Arkansas	134,856	851	122	0.63	0.09
Florida	139,670	1,444	905	1.03	0.65
Georgia	149,976	400	311	0.27	0.21
Illinois	143,961	2,858	2,273	1.99	1.58
Kentucky	102,896	1,427	389	1.39	0.38
Louisiana	112,825	3,492	1,160	3.10	1.03
Mississippi	121,488	1,346	270	1.11	0.22
Missouri	178,414	834	892	0.47	0.50
North Carolina	126,161	453	1,143	0.36	0.91
South Carolina	77,983	414	375	0.53	0.48
Tennessee	106,752	1,228	1,749	1.15	1.64
Virginia	102,548	452	745	0.44	0.73
NPCC total	**284,957**	**2,205**	**1,083**	**0.77**	**0.38**
Connecticut	12,548	283	66	2.25	0.52

Maine	79,931	143	55	0.18	0.07
Massachusetts	20,306	458	412	2.25	2.03
New Hampshire	23,227	73	47	0.31	0.20
New York	122,283	1,168	490	0.96	0.40
Rhode Island	2,706	79	16	2.92	0.58
Vermont	23,956	2	-1	0.01	-0.01
ASCC (Alaska)	**1,481,347**	**14**	**1,088**	**0.0009**	**0.07**
HICC (Hawaii)	**16,635**	**49**	**139**	**0.29**	**0.84**
CALI (California)	**403,882**	**1,408**	**1,899**	**0.35**	**0.47**
FLA (Florida)	**139,670**	**1,914**	**528**	**1.37**	**0.38**
NEWY (New York)	**122,283**	**646**	**883**	**0.53**	**0.72**
TXMRO	**2,133,637**	**8,930**	**17,768**	**0.42**	**0.83**
Iowa	144,701	1,990	1,634	1.38	1.13
Kansas	211,900	733	728	0.35	0.34
Minnesota	206,189	397	1,397	0.19	0.68
Nebraska	199,099	419	830	0.21	0.42
North Dakota	178,647	227	531	0.13	0.30
Oklahoma	177,847	547	1,151	0.31	0.65
South Dakota	196,540	102	384	0.05	0.20
Texas	678,051	3,996	9,526	0.59	1.40
Wisconsin	140,663	520	1,586	0.37	1.13
CONUS	**7,663,909**	**26,701**	**49,428**	**0.35**	**0.64**
Alabama	131,426	1,129	221	0.86	0.17
Arizona	294,312	197	622	0.07	0.21
Arkansas	134,856	522	117	0.39	0.09
California	403,882	905	2,235	0.22	0.55
Colorado	268,627	200	1,034	0.07	0.38
Connecticut	12,548	212	126	1.69	1.00
DC, Washington	177	0	0	0.00	0.20
Delaware	5,060	75	56	1.49	1.11
Florida	139,670	878	868	0.63	0.62
Georgia	149,976	238	298	0.16	0.20
Idaho	214,314	33	480	0.02	0.22
Illinois	143,961	1,754	2,166	1.22	1.50
Indiana	92,895	1,598	2,162	1.72	2.33
Iowa	144,701	1,033	1,733	0.71	1.20
Kansas	211,900	380	776	0.18	0.37
Kentucky	102,896	876	373	0.85	0.36
Louisiana	112,825	2,143	1,112	1.90	0.99
Maine	79,931	107	148	0.13	0.19
Maryland	25,314	218	706	0.86	2.79
Massachusetts	20,306	341	795	1.68	3.92
Michigan	147,121	889	1,939	0.60	1.32
Minnesota	206,189	201	1,470	0.10	0.71
Mississippi	121,488	825	258	0.68	0.21
Missouri	178,414	512	853	0.29	0.48
Montana	376,979	26	216	0.01	0.06
Nebraska	199,099	217	874	0.11	0.44
Nevada	284,448	53	419	0.02	0.15
New Hampshire	23,227	55	100	0.24	0.43
New Jersey	19,211	470	548	2.45	2.85
New Mexico	314,309	82	322	0.03	0.10
New York	122,283	874	1,031	0.72	0.84
North Carolina	126,161	257	1,095	0.20	0.87
North Dakota	178,647	118	564	0.07	0.32
Ohio	106,056	1,732	2,111	1.63	1.99

Oklahoma	177,847	284	1,222	0.16	0.69
Oregon	248,631	45	188	0.02	0.08
Pennsylvania	116,074	2,791	2,750	2.40	2.37
Rhode Island	2,706	59	32	2.18	1.18
South Carolina	77,983	251	360	0.32	0.46
South Dakota	196,540	53	406	0.03	0.21
Tennessee	106,752	753	1,676	0.71	1.57
Texas	678,051	2,122	10,030	0.31	1.48
Utah	212,751	82	747	0.04	0.35
Vermont	23,956	1	5	0.00	0.02
Virginia	102,548	275	714	0.27	0.70
Washington St.	172,348	57	945	0.03	0.55
West Virginia	62,361	363	271	0.58	0.43
Wisconsin	140,663	270	1,660	0.19	1.18
Wyoming	251,489	148	597	0.06	0.24
Total USA	**9,161,891**	**26,764**	**50,655**	**0.29**	**0.55**

Spacing areas are areas between wind turbines needed to avoid interference of the wake of one turbine with the next. Such spacing area can be used for multiple purposes, including farmland, rangeland, open space, or utility PV. Footprint areas are the physical land areas, water surface areas, or sea floor surface areas removed from use for any other purpose by an energy technology. Rooftop PV is not included in the footprint calculation because it does not take up new land. Conventional hydro new footprint is zero because no new dams are proposed as part of these roadmaps. Offshore wind, wave, and tidal are not included because they don't take up new land. Table S22 gives the installed power densities. Areas are given both as an absolute area and as a percentage of the region land area, which excludes inland or coastal water bodies. For comparison, the total area and land area of Earth are 510.1 and 144.6 million km^2, respectively. Total USA=CONUS+ASCC+HICC.

Table S24. Estimated mean number of long-term, full-time construction and operation jobs per MW nameplate capacity of different electric power sources and storage types in the United States. A full-time job is a job that requires 2,080 hours per year of work. The job numbers include direct, indirect, and induced jobs.

Electric power generator	Construction Jobs/MW or Jobs/km	Operation Jobs/MW or Jobs/km
Onshore wind electricity	0.24	0.37
Offshore wind electricity	0.31	0.63
Wave electricity	0.15	0.57
Geothermal electricity	0.71	0.46
Hydropower electricity	0.14	0.30
Tidal electricity	0.16	0.61
Residential rooftop PV	0.88	0.32
Commercial/government rooftop PV	0.65	0.16
Utility PV electricity	0.24	0.85
CSP electricity	0.31	0.86
Solar thermal for heat	0.71	0.85
Geothermal heat	0.14	0.46
Pumped hydro storage (PHS)	0.77	0.3
CSP storage (CSP-PCM)	0.62	0.3
Battery storage	0.092	0.2
Chilled-water storage (CW-STES)	0.15	0.3
Ice storage (ICE)	0.15	0.3
Hot water storage (HW-STES)	0.15	0.3
Underground heat storage (UTES)	0.15	0.3
Producing heat pumps for district heat	0.15	0.3
Producing and storing hydrogen	0.32	0.3
AC transmission (jobs/km)	0.073	0.062
AC distribution (jobs/km)	0.033	0.028
HVDC transmission (jobs/km)	0.094	0.080

Taken from Jacobson et al. (2019), except "producing heat pumps for district heat" values are estimated here and HVDC transmission job numbers were slightly updated. Values for solar thermal for heat and geothermal heat were taken from values for utility PV and geothermal electricity, respectively. Values for transmission were derived in Jacobson et al. (2017). Jobs for battery construction and operation were estimated low to account for economies of scale and automation of battery manufacturing. Please see Note S9 for more details.

Table S25. Changes in the Numbers of Long-Term, Full-Time Jobs

Estimated long-term, full-time jobs created and lost due to transitioning from BAU energy to WWS across all energy sectors. The job creation accounts for new direct, indirect, and induced jobs in the electricity, heat, cold, and hydrogen generation, storage, and transmission (including HVDC transmission) industries. It also accounts for the building of heat pumps to supply district heating and cooling. However it does not account for changes in jobs in the production of electric appliances, vehicles, and machines or in increasing building energy efficiency. Construction jobs are for new WWS devices only. Operation jobs are for new and existing devices. The losses are due to eliminating jobs for mining, transporting, processing, and using fossil fuels, biofuels, and uranium. Fossil-fuel jobs due to non-energy uses of petroleum, such as lubricants, asphalt, petrochemical feedstock, and petroleum coke, are retained. For transportation sectors, the jobs lost are those due to transporting fossil fuels (e.g., through truck, train, barge, ship, or pipeline); the jobs not lost are those for transporting other goods. The table does not account for jobs lost in the manufacture of combustion appliances, including automobiles, ships, or industrial machines.

Region/State	(a) Construction jobs produced	(b) Operation jobs produced	(c) Total jobs produced =a+b	(d) Total jobs lost	(e) Net change in jobs =c-d
WECC Total	**463,806**	**510,741**	**974,547**	**500,351**	**474,196**
Arizona	42,132	43,242	85,374	15,330	70,044
California	200,238	243,110	443,349	140,586	302,763
Colorado	44,553	44,235	88,788	71,400	17,388
Idaho	13,392	13,429	26,820	6,808	20,012
Montana	9,100	8,922	18,021	23,178	-5,157
Nevada	20,622	25,607	46,228	6,698	39,530
New Mexico	20,965	20,546	41,512	65,058	-23,546
Oregon	27,553	25,302	52,856	14,160	38,696
Utah	23,374	23,090	46,464	28,988	17,476
Washington St.	41,541	38,199	79,739	48,972	30,767
Wyoming	20,337	25,060	45,396	79,173	-33,777
MRO total	**474,470**	**517,868**	**992,338**	**416,321**	**576,017**
Iowa	107,130	141,964	249,094	59,511	189,583
Kansas	51,072	62,933	114,005	40,672	73,333
Minnesota	79,526	74,419	153,945	50,685	103,260
Nebraska	47,034	46,617	93,651	31,771	61,880
North Dakota	28,242	30,427	58,668	77,630	-18,962
Oklahoma	71,378	70,889	142,267	110,757	31,510
South Dakota	20,165	18,854	39,019	15,299	23,720
Wisconsin	69,923	71,765	141,688	29,996	111,692
TRE (Texas)	**937,314**	**1,243,441**	**2,180,755**	**610,892**	**1,569,863**
RFC total	**968,075**	**1,090,095**	**2,058,170**	**507,619**	**1,550,551**
DC, Washington	6,130	5,235	11,366	6,075	5,291
Delaware	14,652	14,607	29,259	10,396	18,863
Indiana	174,084	201,205	375,288	63,846	311,442
Maryland	57,478	52,677	110,155	9,261	100,894
Michigan	142,653	143,039	285,692	43,354	242,338
New Jersey	85,010	91,755	176,766	32,625	144,141
Ohio	205,154	223,816	428,971	106,968	322,003
Pennsylvania	235,402	306,696	542,098	172,319	369,779
West Virginia	47,511	51,065	98,576	62,775	35,801
SERC total	**1,751,700**	**1,836,718**	**3,588,418**	**681,903**	**2,906,515**
Alabama	132,799	153,838	286,637	46,300	240,337
Arkansas	72,584	77,051	149,635	34,706	114,929
Florida	204,276	198,310	402,586	46,249	356,337
Georgia	144,205	112,970	257,175	37,099	220,076
Illinois	194,590	244,254	438,844	95,450	343,394
Kentucky	101,563	117,961	219,524	37,727	181,797

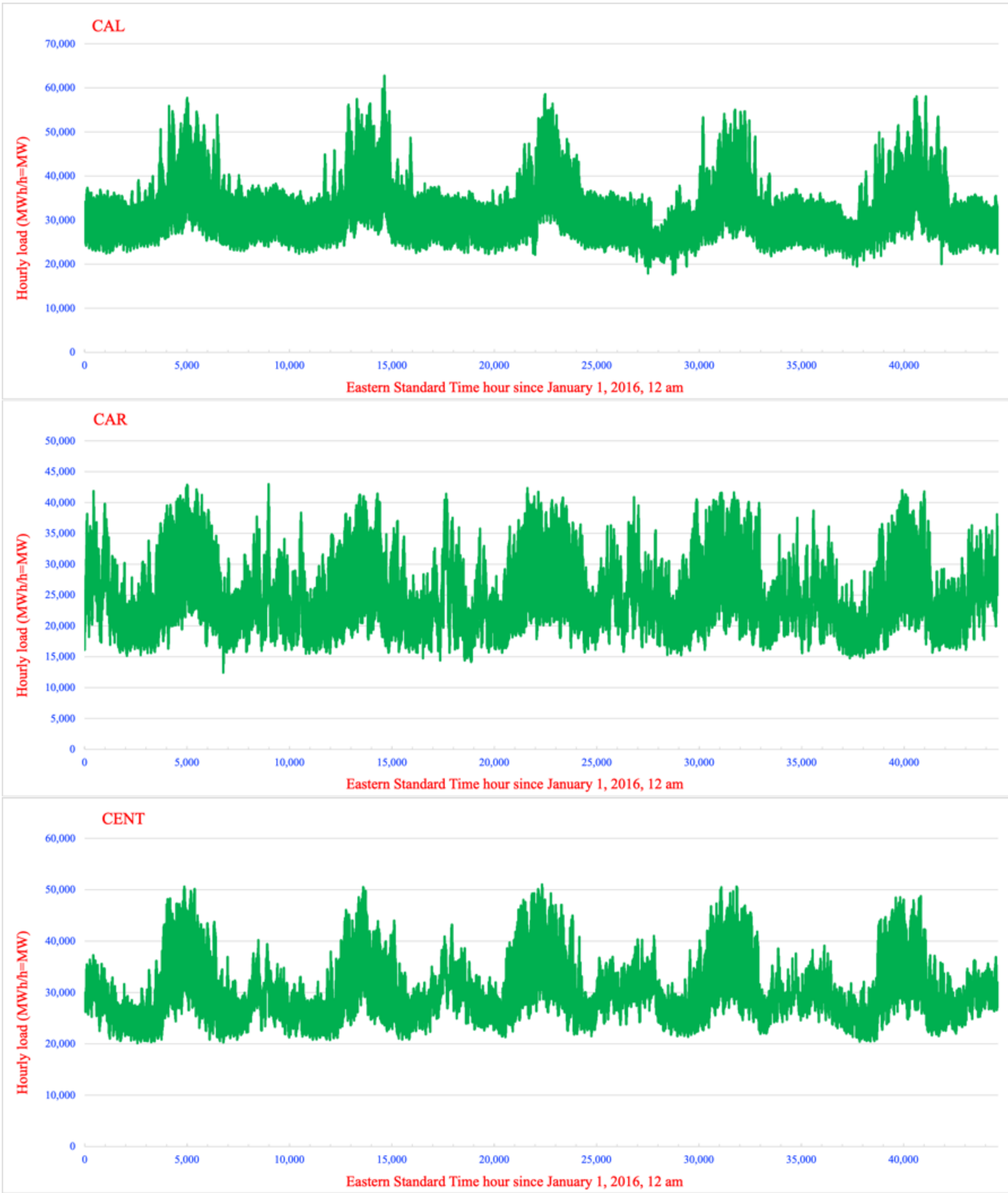
Louisiana	274,336	339,916	614,253	219,344	394,909
Mississippi	90,540	110,222	200,762	38,565	162,197
Missouri	94,169	90,079	184,248	21,377	162,871
North Carolina	126,772	107,408	234,180	27,294	206,886
South Carolina	85,291	71,559	156,850	20,518	136,332
Tennessee	125,553	127,271	252,824	28,168	224,656
Virginia	105,022	85,878	190,900	29,106	161,794
NPCC total	**293,847**	**333,278**	**627,125**	**77,406**	**549,719**
Connecticut	32,901	37,909	70,810	8,225	62,585
Maine	21,454	23,914	45,367	10,447	34,920
Massachusetts	57,996	68,528	126,524	9,925	116,599
New Hampshire	13,794	13,706	27,500	12,841	14,659
New York	154,887	172,364	327,250	30,686	296,564
Rhode Island	9,370	11,023	20,393	2,275	18,118
Vermont	3,446	5,834	9,280	3,007	6,273
ASCC (Alaska)	**31,161**	**51,681**	**82,843**	**36,338**	**46,505**
HICC (Hawaii)	**11,265**	**14,490**	**25,755**	**9,176**	**16,579**
CALI (California)	**252,141**	**328,448**	**580,590**	**140,586**	**440,004**
FLA (Florida)	**198,321**	**240,438**	**438,759**	**46,249**	**392,510**
NEWY (New York)	**184,021**	**208,540**	**392,562**	**30,686**	**361,876**
TXMRO	**1,163,156**	**1,536,818**	**2,699,974**	**1,027,213**	**1,672,761**
Iowa	130,973	199,736	330,710	59,511	271,199
Kansas	60,777	88,004	148,782	40,672	108,110
Minnesota	87,028	102,946	189,973	50,685	139,288
Nebraska	52,932	66,286	119,218	31,771	87,447
North Dakota	32,407	43,327	75,733	77,630	-1,897
Oklahoma	80,020	100,966	180,986	110,757	70,229
South Dakota	21,867	26,380	48,247	15,299	32,948
Texas	616,602	807,382	1,423,984	610,892	813,092
Wisconsin	80,550	101,792	182,341	29,996	152,345
CONUS	**3,555,947**	**3,868,176**	**7,424,123**	**2,794,492**	**4,629,631**
Alabama	93,006	105,725	198,731	46,300	152,431
Arizona	47,131	42,903	90,034	15,330	74,704
Arkansas	52,001	53,346	105,347	34,706	70,641
California	227,346	249,898	477,244	140,586	336,658
Colorado	50,280	46,227	96,507	71,400	25,107
Connecticut	24,504	28,719	53,223	8,225	44,998
DC, Washington	3,924	4,631	8,555	6,075	2,480
Delaware	10,257	11,525	21,782	10,396	11,386
Florida	148,819	151,283	300,102	46,249	253,853
Georgia	109,082	92,259	201,341	37,099	164,242
Idaho	15,658	15,061	30,719	6,808	23,911
Illinois	136,984	172,040	309,025	95,450	213,575
Indiana	123,900	152,922	276,823	63,846	212,977
Iowa	84,804	111,813	196,617	59,511	137,106
Kansas	41,332	50,689	92,021	40,672	51,349
Kentucky	71,795	80,612	152,407	37,727	114,680
Louisiana	191,446	250,173	441,618	219,344	222,274
Maine	16,503	18,484	34,987	10,447	24,540
Maryland	40,133	41,672	81,804	9,261	72,543
Massachusetts	43,662	52,960	96,621	9,925	86,696
Michigan	101,911	110,799	212,710	43,354	169,356
Minnesota	69,868	64,038	133,906	50,685	83,221
Mississippi	63,165	75,038	138,203	38,565	99,638
Missouri	70,021	65,306	135,327	21,377	113,950
Montana	10,566	9,932	20,498	23,178	-2,680

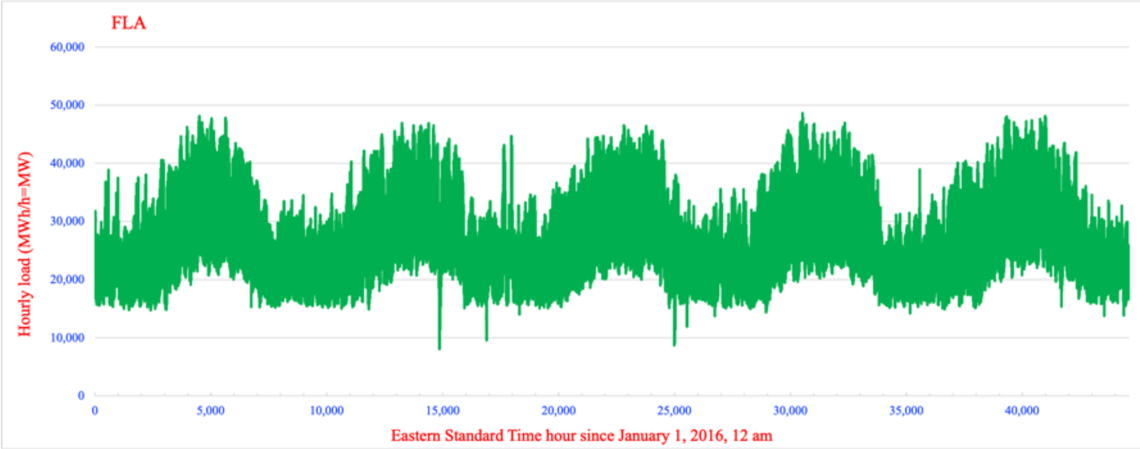
Nebraska	39,188	38,347	77,536	31,771	45,765
Nevada	23,663	25,005	48,667	6,698	41,969
New Hampshire	11,266	10,655	21,921	12,841	9,080
New Jersey	58,212	72,983	131,195	32,625	98,570
New Mexico	24,033	21,475	45,508	65,058	-19,550
New York	116,359	128,515	244,875	30,686	214,189
North Carolina	97,368	83,418	180,785	27,294	153,491
North Dakota	23,241	25,468	48,709	77,630	-28,921
Ohio	145,294	169,768	315,061	106,968	208,093
Oklahoma	59,421	59,266	118,688	110,757	7,931
Oregon	33,410	29,202	62,612	14,160	48,452
Pennsylvania	167,798	232,728	400,526	172,319	228,207
Rhode Island	7,000	8,521	15,521	2,275	13,246
South Carolina	64,107	55,579	119,686	20,518	99,168
South Dakota	17,079	16,175	33,254	15,299	17,955
Tennessee	92,536	92,079	184,615	28,168	156,447
Texas	454,295	476,235	930,530	610,892	319,638
Utah	26,842	24,142	50,983	28,988	21,995
Vermont	2,438	4,150	6,588	3,007	3,581
Virginia	79,223	67,733	146,956	29,106	117,850
Washington St.	50,712	45,794	96,506	48,972	47,534
West Virginia	33,227	38,108	71,335	62,775	8,560
Wisconsin	60,040	60,551	120,592	29,996	90,596
Wyoming	21,099	24,225	45,324	79,173	-33,849
Total USA	**3,598,373**	**3,934,347**	**7,532,721**	**2,840,006**	**4,692,715**

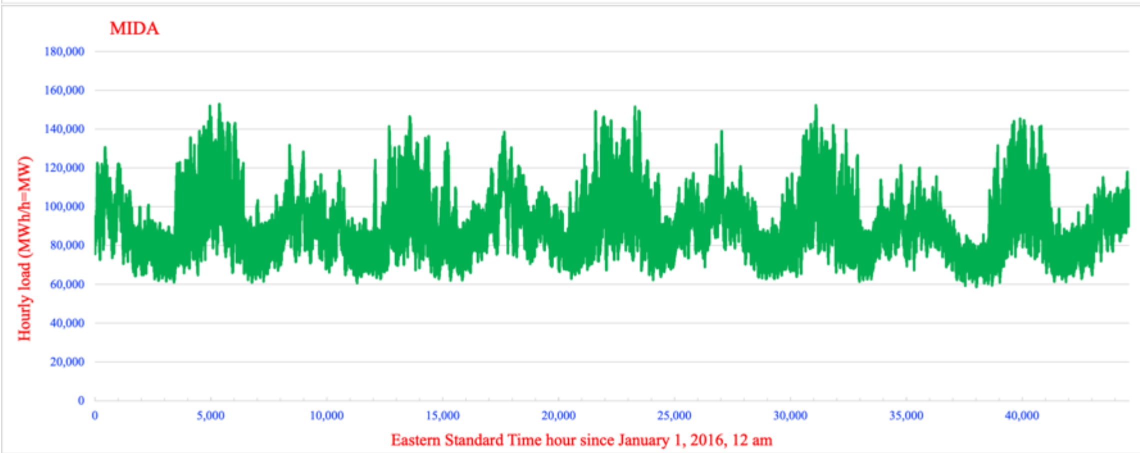
Total USA=CONUS+ASCC+HICC
Job creation calculations are detailed in Jacobson and Delucchi (2021). Job losses are largely from Jacobson et al. (2019), except as modified in Jacobson and Delucchi (2021).

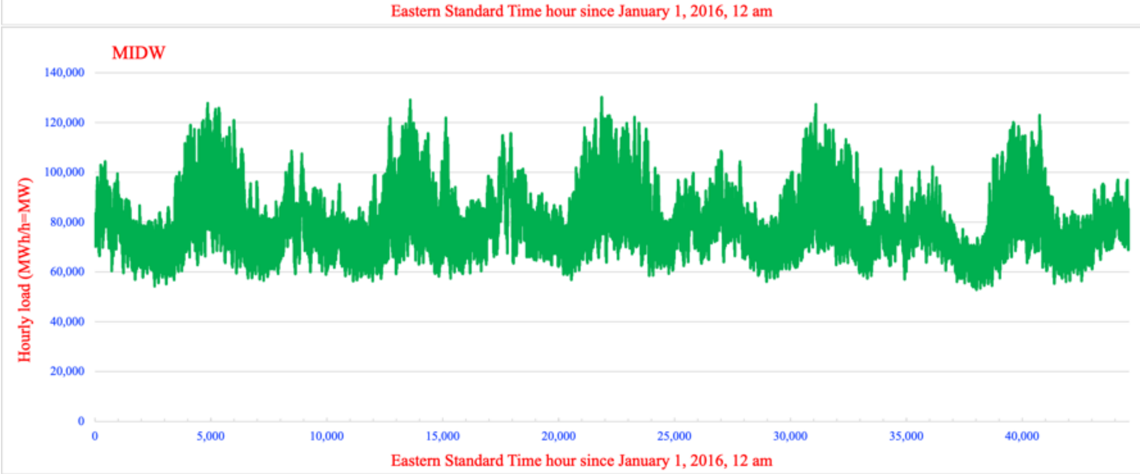
Supporting Figures

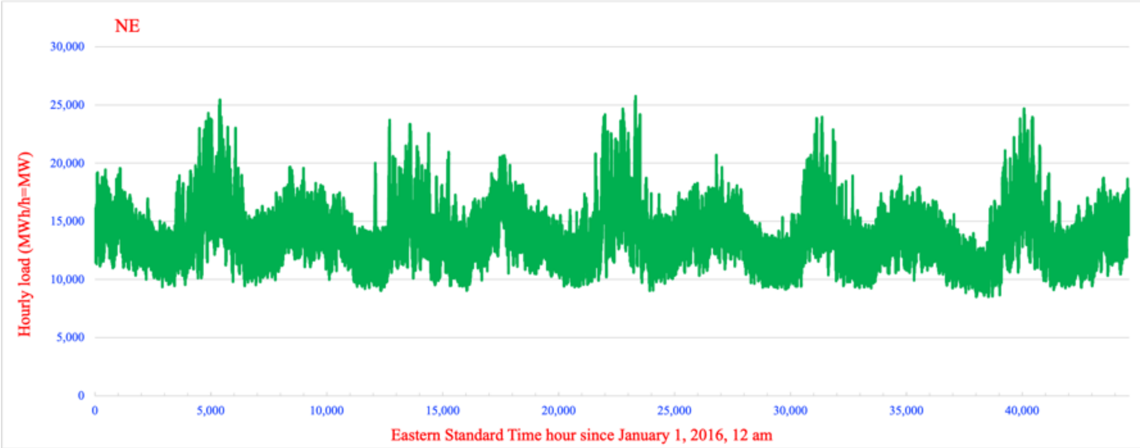
Figure S1. Unmodified 2016-2020 hourly electric load (MWh/h=MW) for each of the load regions listed in Table S1, which also shows the annual average load for each region each year. Data are from EIA (2021a).

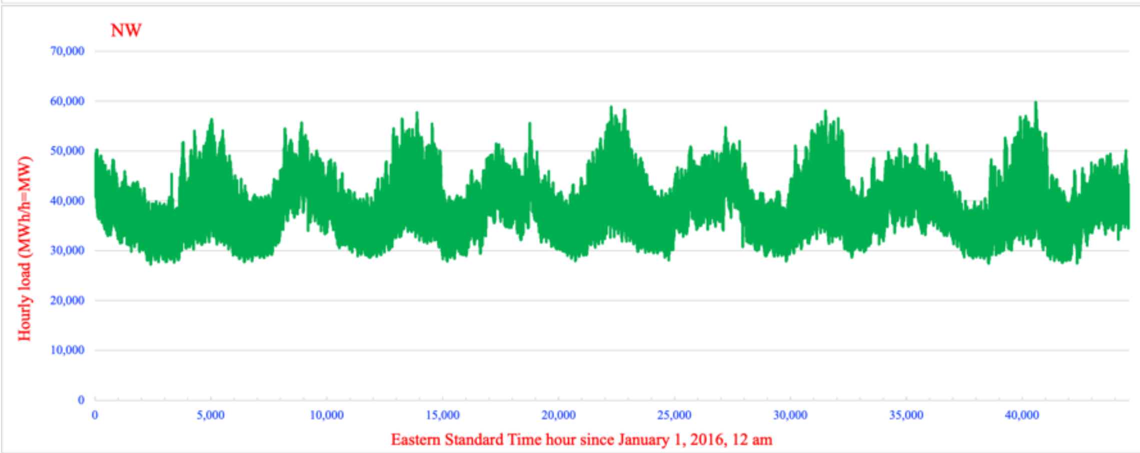


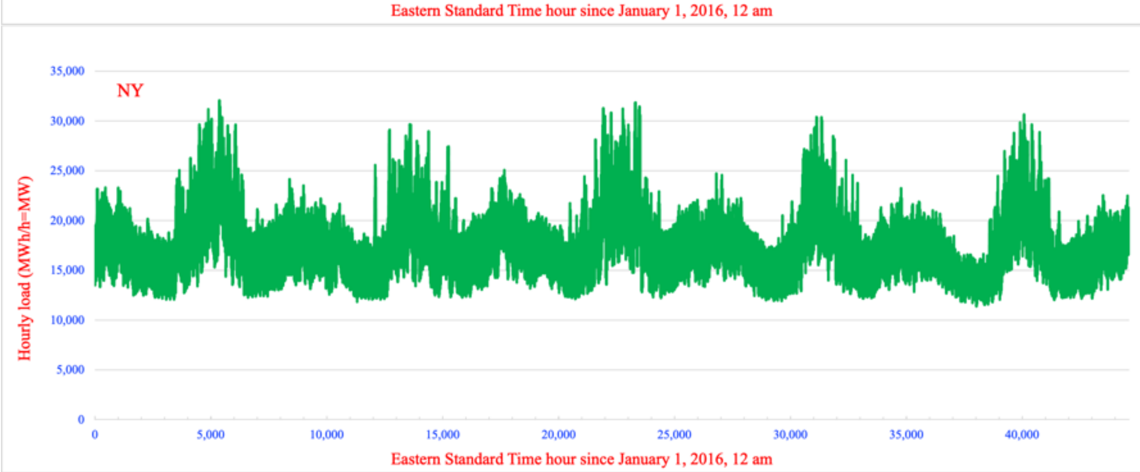

FLA
Hourly load (MWh/h=MW)
60,000
50,000
40,000
30,000
20,000
10,000
0
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am

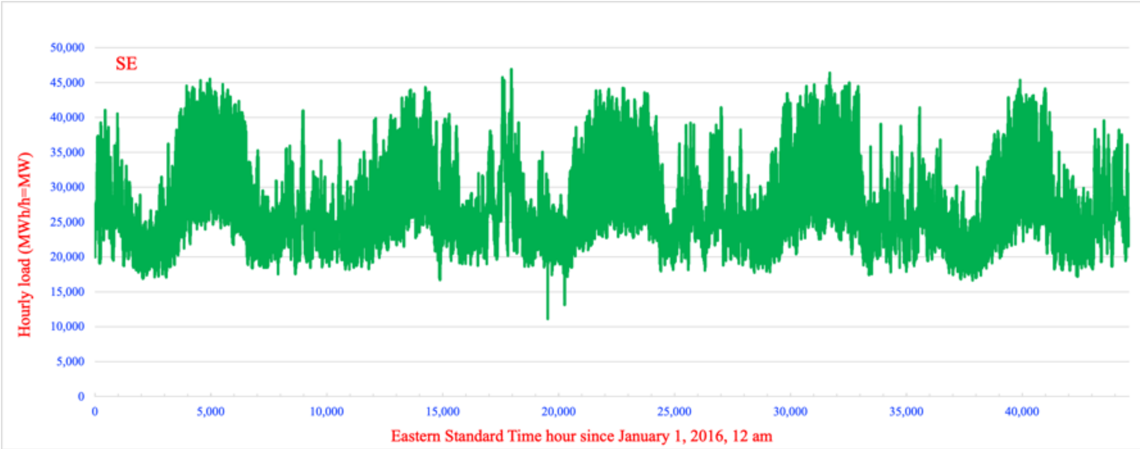

MIDA
Hourly load (MWh/h=MW)
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am

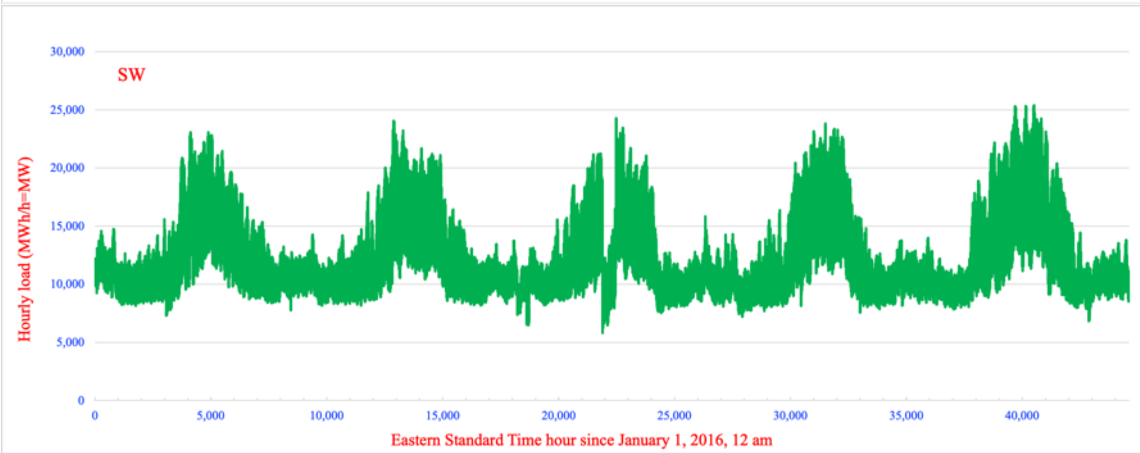

MIDW
Hourly load (MWh/h=MW)
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am

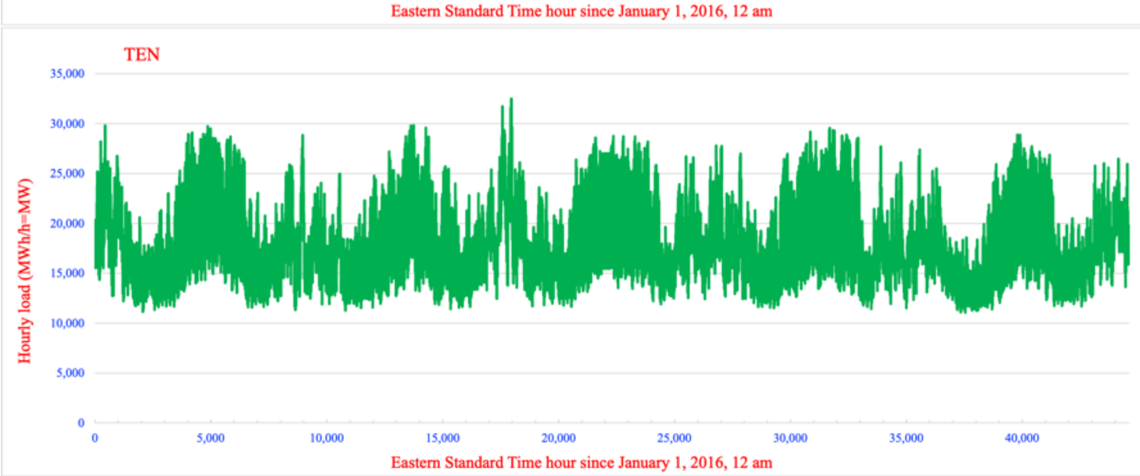

NE
Hourly load (MWh/h=MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am

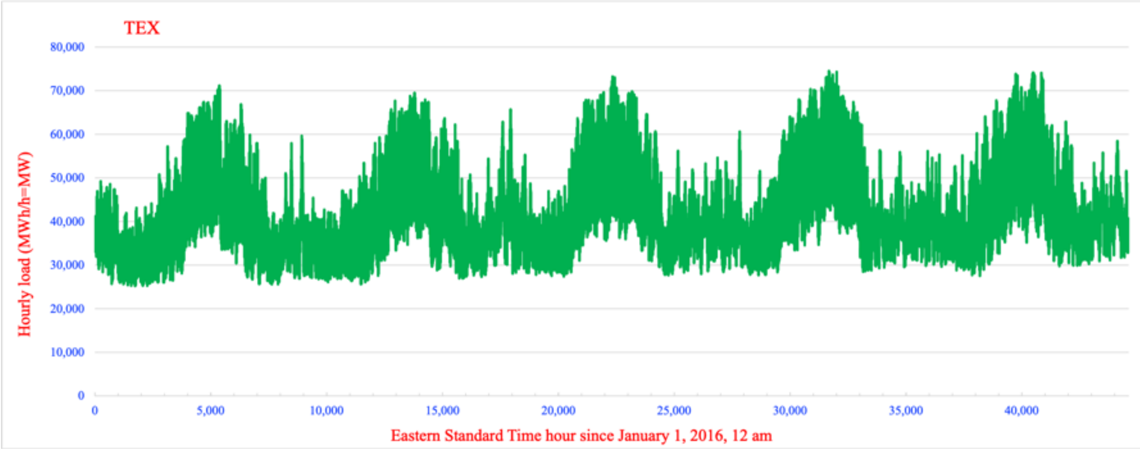

NW
Hourly load (MWh/h=MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am


NY
Hourly load (MWh/h=MW)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am


SE
Hourly load (MWh/h=MW)
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
45,000
50,000
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am


SW
Hourly load (MWh/h=MW)
0
5,000
10,000
15,000
20,000
25,000
30,000
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am


TEN
Hourly load (MWh/h=MW)
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am


TEX
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Hourly load (MWh/h=MW)
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am

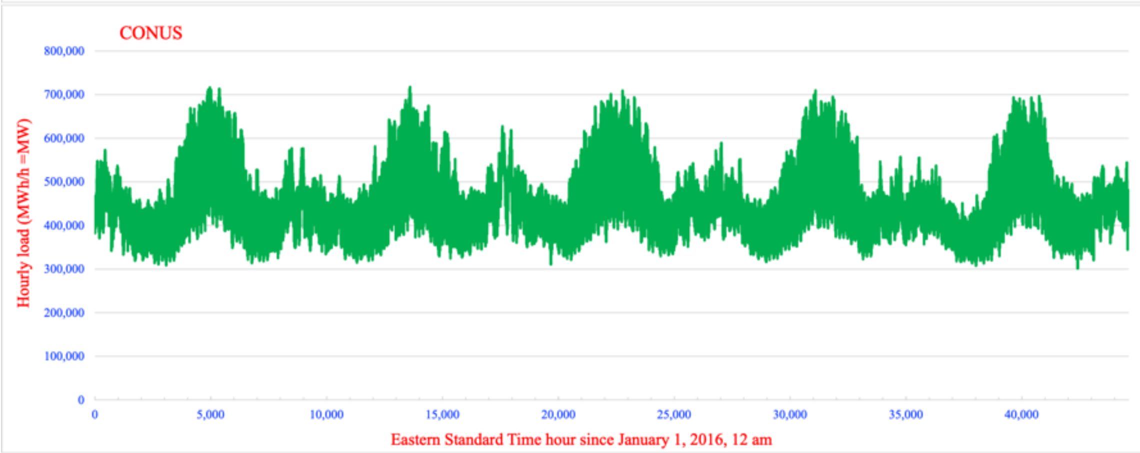
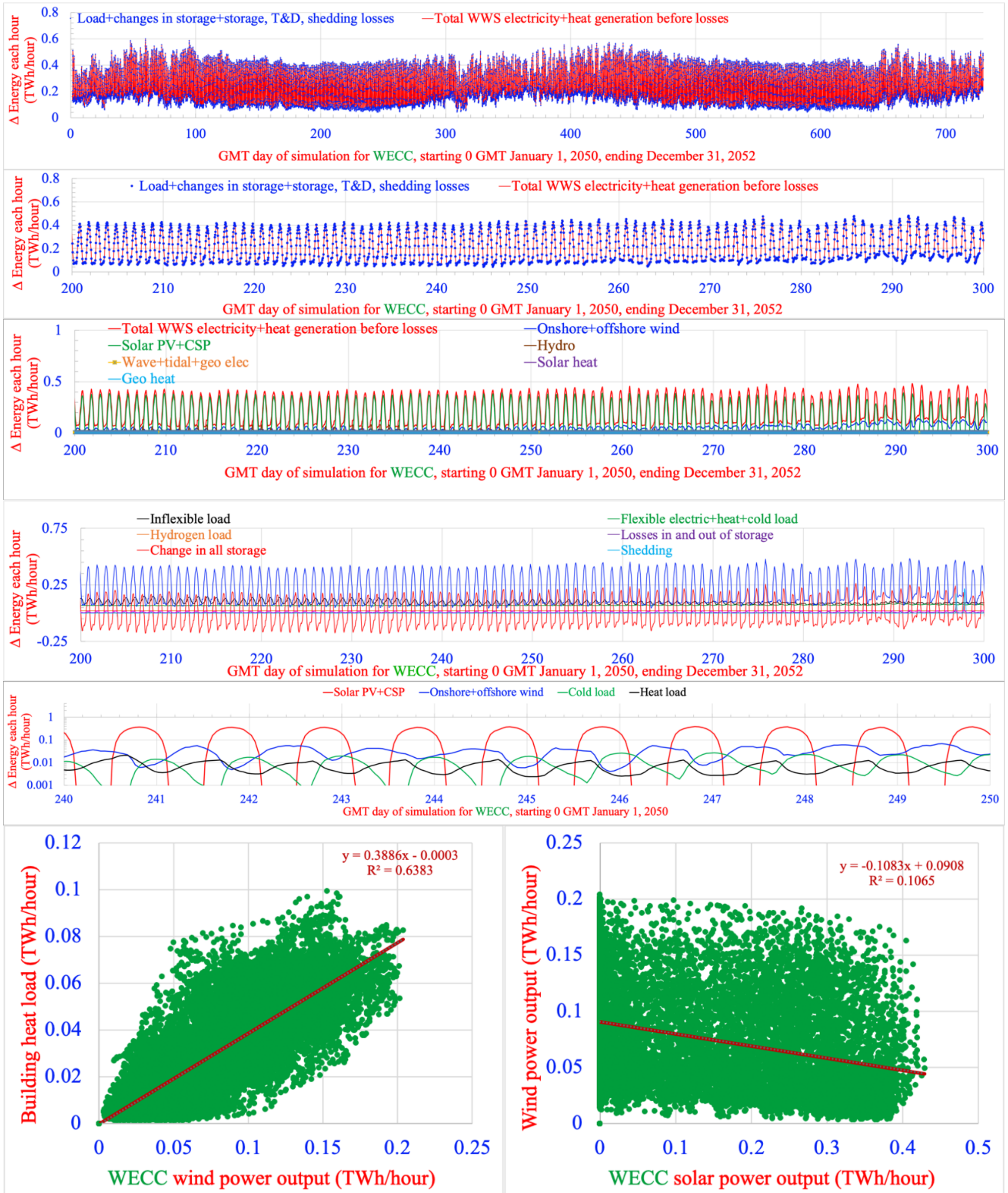

CONUS
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Hourly load (MWh/h=MW)
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
Eastern Standard Time hour since January 1, 2016, 12 am

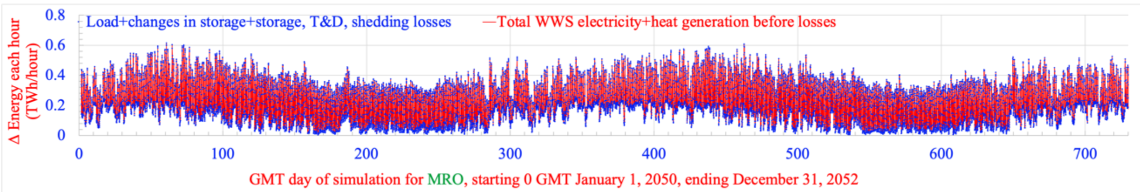
Figure S2. 2050-2051 hourly time series showing the matching of all-energy demand with supply and storage for the regions defined in Table 1. First row: modeled time-dependent total WWS power generation versus load plus losses plus changes in storage plus shedding for the full two-year simulation period. Second row: same as first row, but for a window of 100 days during the simulation. The window is during winter in MRO, TRE, RFC, NPCC, ASCC, NEWY, and CONUS and summer in WECC, SERC, HICC, CALI, and FLA. Third row: a breakdown of WWS power generation by source during the window. Fourth row: a breakdown of inflexible load; flexible electric, heat, and cold load; flexible hydrogen load; losses in and out of storage; transmission and distribution losses; changes in storage; and shedding during the window. Fifth row: A breakdown of solar PV+CSP electricity production, onshore plus offshore wind electricity production, building total cold load, and building total heat load, summed over each region, as used in LOADMATCH, during a 10-day window; Sixth row: correlation plots of building heat load versus wind power output and wind power output versus solar power output, obtained from all hourly-averaged data from GATOR-GCMOM, as used in LOADMATCH, during each simulation. Correlations are very strong for R=0.8-1 (R^2=0.64-1); strong for R=0.6-0.8 (R^2=0.36-0.64); moderate for R=0.4-0.6 (R^2=0.16-0.36); weak for 0.2-0.4 (R^2=0.04-0.16); and very weak for 0-0.2 (R^2=0-0.04) (Evans, 1996). The model was run at 30-s resolution. Results are shown hourly, so units are energy output (TWh) per hour increment, thus also in units of power (TW) averaged over the hour. No load loss occurred during any 30-s interval. Raw GATOR-GCMOM results for solar, wind, heat load, and cold load were provided and fed into LOADMATCH at 30-s time increments. LOADMATCH modified the magnitudes, but not time series, of GATOR-GCMOM results, as described in the main text.

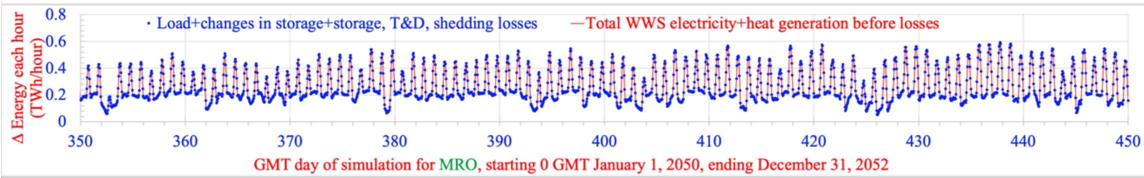
WECC

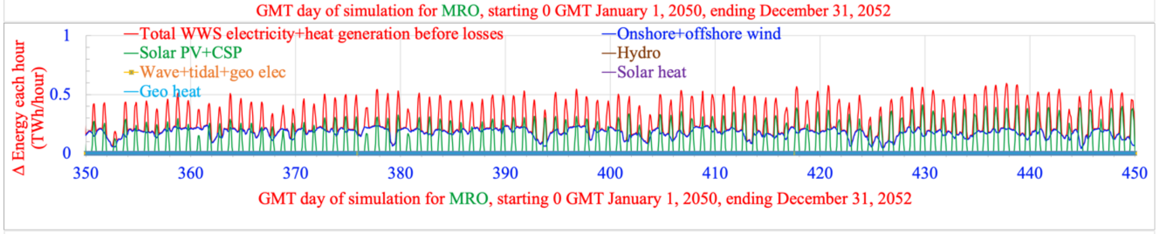


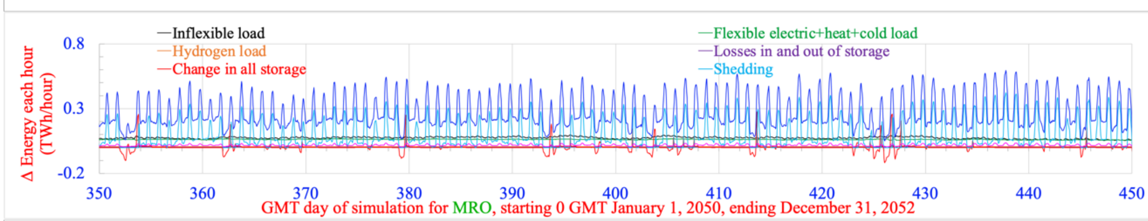
Δ Energy each hour (TWh/hour)
Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
GMT day of simulation for WECC, starting 0 GMT January 1, 2050, ending December 31, 2052
Δ Energy each hour (TWh/hour)
Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
GMT day of simulation for WECC, starting 0 GMT January 1, 2050, ending December 31, 2052
Δ Energy each hour (TWh/hour)
Total WWS electricity+heat generation before losses
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
GMT day of simulation for WECC, starting 0 GMT January 1, 2050, ending December 31, 2052
Δ Energy each hour (TWh/hour)
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
GMT day of simulation for WECC, starting 0 GMT January 1, 2050, ending December 31, 2052
Δ Energy each hour (TWh/hour)
Solar PV+CSP
Onshore+offshore wind
Cold load
Heat load
GMT day of simulation for WECC, starting 0 GMT January 1, 2050
Building heat load (TWh/hour)
y = 0.3886x - 0.0003
R² = 0.6383
WECC wind power output (TWh/hour)
Wind power output (TWh/hour)
y = -0.1083x + 0.0908
R² = 0.1065
WECC solar power output (TWh/hour)

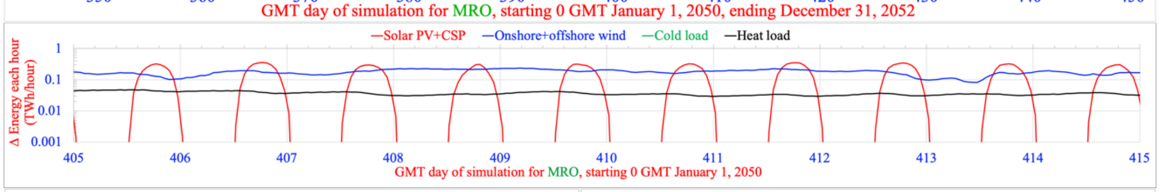
MRO

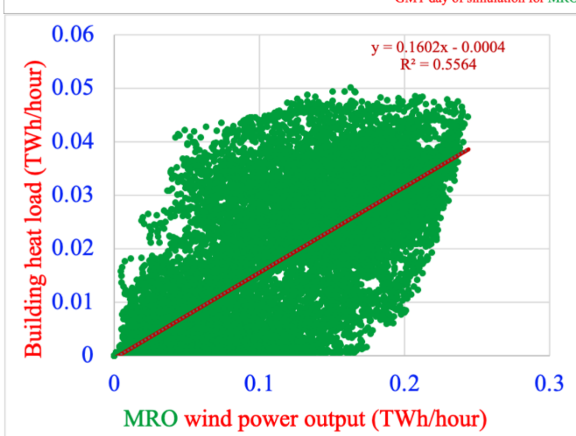

Load+changes in storage+storage, T&D, shedding losses
—Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
0
0.2
0.4
0.6
0.8
0
100
200
300
400
500
600
700
GMT day of simulation for MRO, starting 0 GMT January 1, 2050, ending December 31, 2052

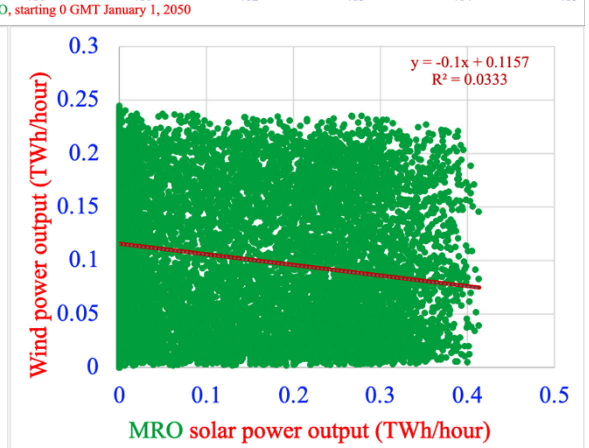

Load+changes in storage+storage, T&D, shedding losses
—Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
0
0.2
0.4
0.6
0.8
350
360
370
380
390
400
410
420
430
440
450
GMT day of simulation for MRO, starting 0 GMT January 1, 2050, ending December 31, 2052


—Total WWS electricity+heat generation before losses
—Onshore+offshore wind
—Solar PV+CSP
—Hydro
Wave+tidal+geo elec
—Solar heat
—Geo heat
Δ Energy each hour (TWh/hour)
0
0.5
1
350
360
370
380
390
400
410
420
430
440
450
GMT day of simulation for MRO, starting 0 GMT January 1, 2050, ending December 31, 2052

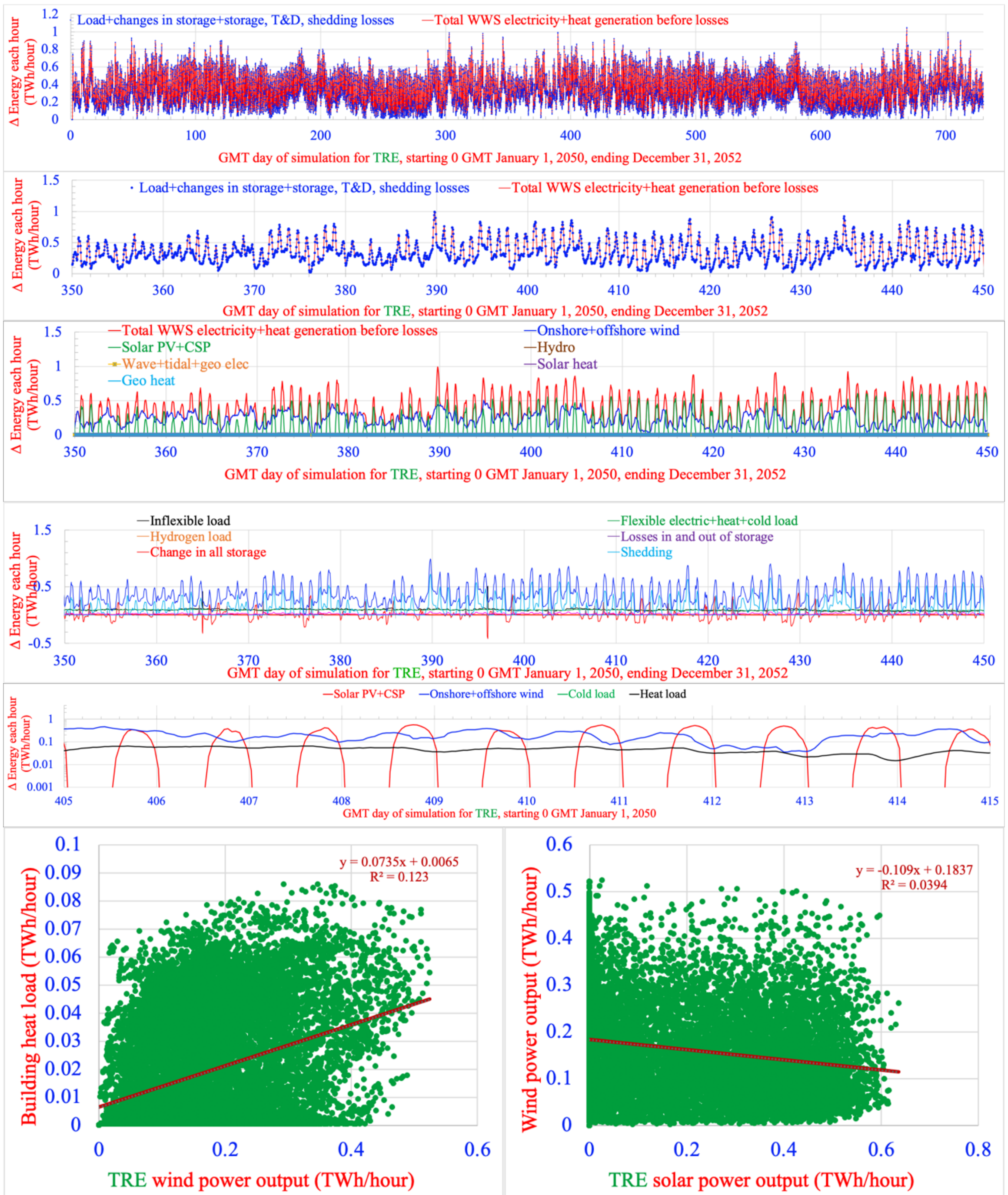

—Inflexible load
—Flexible electric+heat+cold load
—Hydrogen load
—Losses in and out of storage
—Change in all storage
—Shedding
Δ Energy each hour (TWh/hour)
-0.2
0.3
0.8
350
360
370
380
390
400
410
420
430
440
450
GMT day of simulation for MRO, starting 0 GMT January 1, 2050, ending December 31, 2052


—Solar PV+CSP
—Onshore+offshore wind
—Cold load
—Heat load
Δ Energy each hour (TWh/hour)
0.001
0.01
0.1
1
405
406
407
408
409
410
411
412
413
414
415
GMT day of simulation for MRO, starting 0 GMT January 1, 2050

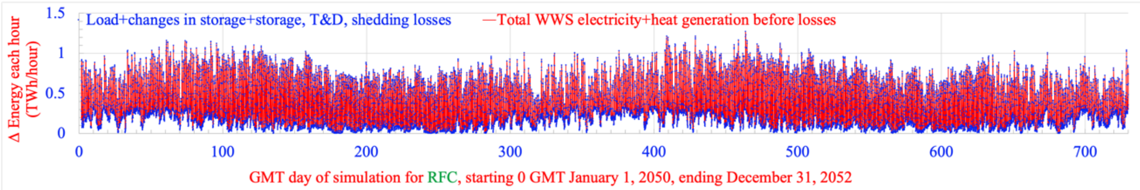

y = 0.1602x - 0.0004
R² = 0.5564
Building heat load (TWh/hour)
0
0.01
0.02
0.03
0.04
0.05
0.06
0
0.1
0.2
0.3
MRO wind power output (TWh/hour)

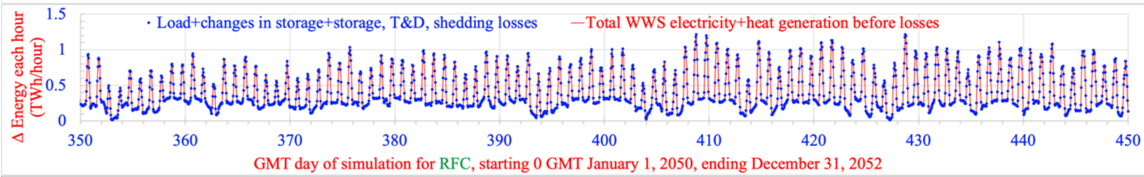

y = -0.1x + 0.1157
R² = 0.0333
Wind power output (TWh/hour)
0
0.05
0.1
0.15
0.2
0.25
0.3
0
0.1
0.2
0.3
0.4
0.5
MRO solar power output (TWh/hour)

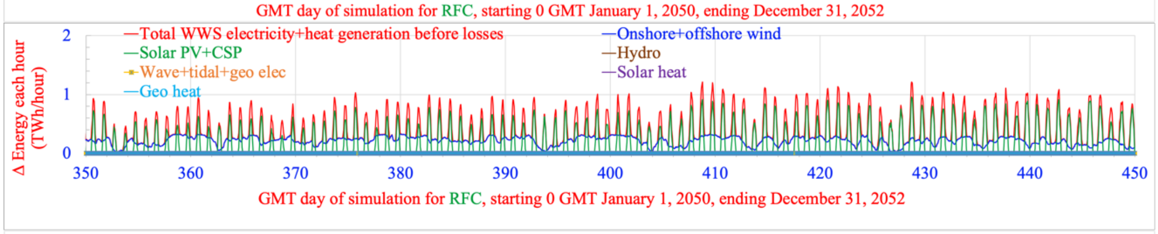
TRE

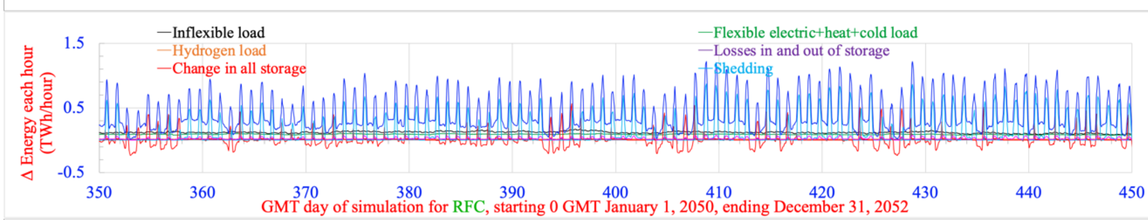

Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for TRE, starting 0 GMT January 1, 2050, ending December 31, 2052
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Cold load
Heat load
GMT day of simulation for TRE, starting 0 GMT January 1, 2050
y = 0.0735x + 0.0065
R² = 0.123
Building heat load (TWh/hour)
TRE wind power output (TWh/hour)
y = -0.109x + 0.1837
R² = 0.0394
Wind power output (TWh/hour)
TRE solar power output (TWh/hour)

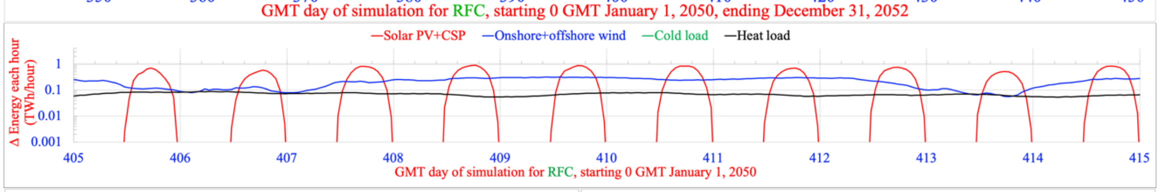
RFC

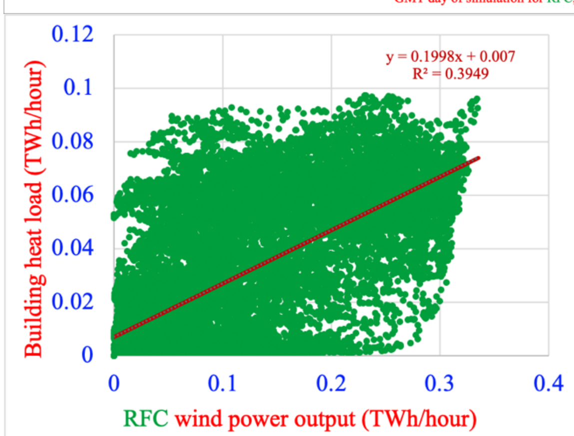

Load+changes in storage+storage, T&D, shedding losses
—Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for RFC, starting 0 GMT January 1, 2050, ending December 31, 2052

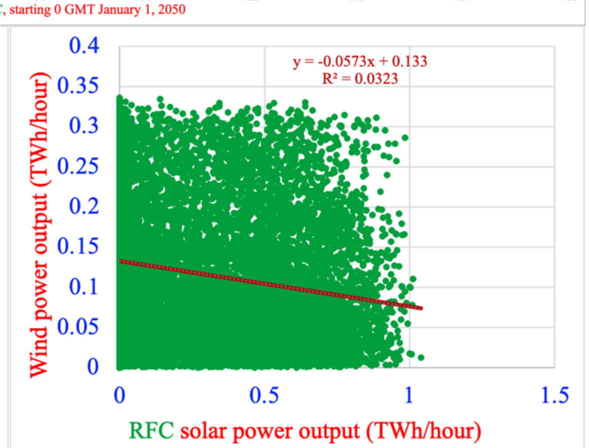

Load+changes in storage+storage, T&D, shedding losses
—Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for RFC, starting 0 GMT January 1, 2050, ending December 31, 2052


—Total WWS electricity+heat generation before losses
—Onshore+offshore wind
—Solar PV+CSP
—Hydro
Wave+tidal+geo elec
—Solar heat
—Geo heat
Δ Energy each hour (TWh/hour)
GMT day of simulation for RFC, starting 0 GMT January 1, 2050, ending December 31, 2052

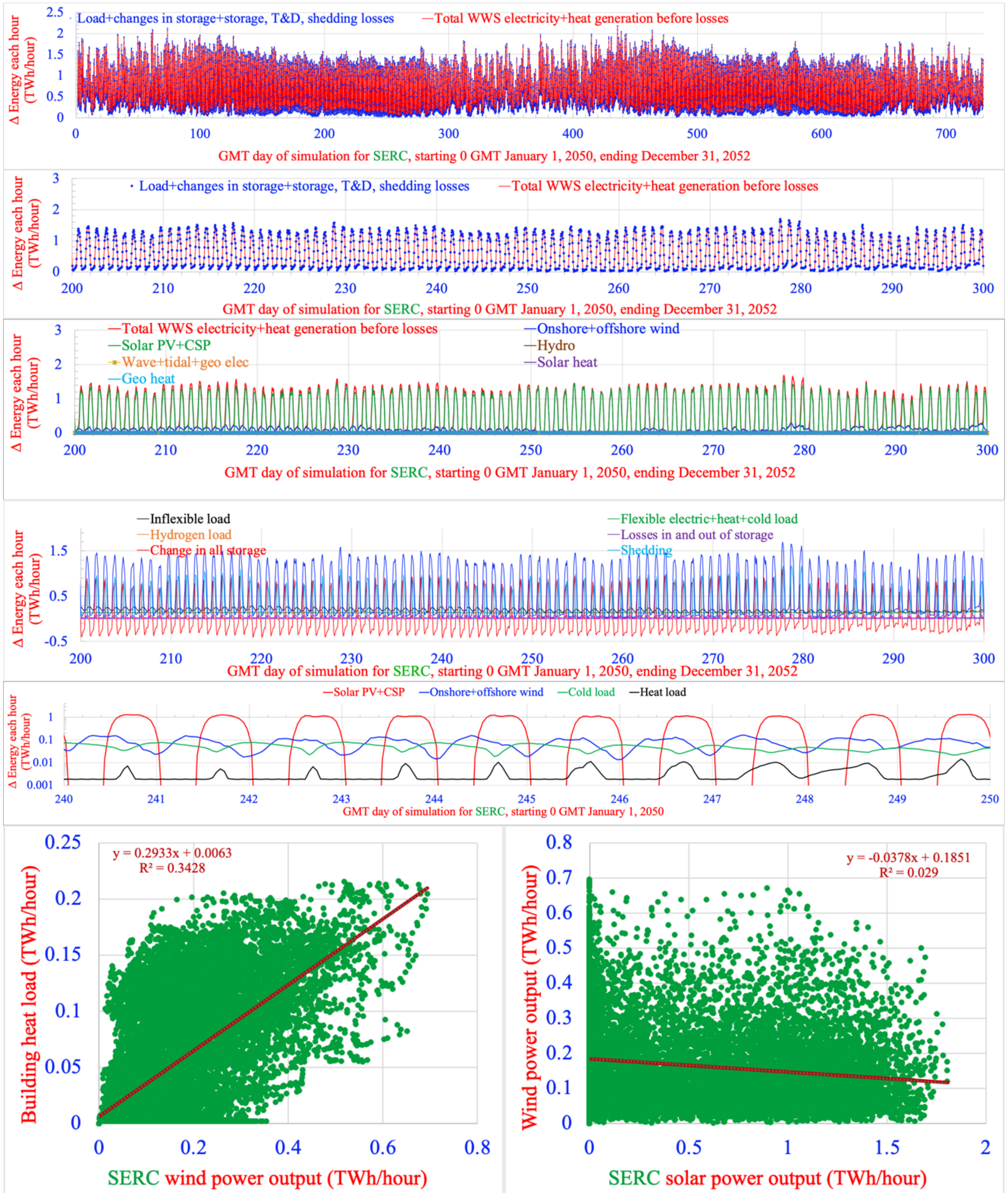

—Inflexible load
—Flexible electric+heat+cold load
—Hydrogen load
—Losses in and out of storage
—Change in all storage
Shedding
Δ Energy each hour (TWh/hour)
GMT day of simulation for RFC, starting 0 GMT January 1, 2050, ending December 31, 2052


—Solar PV+CSP
—Onshore+offshore wind
—Cold load
—Heat load
Δ Energy each hour (TWh/hour)
GMT day of simulation for RFC, starting 0 GMT January 1, 2050


y = 0.1998x + 0.007
R² = 0.3949
Building heat load (TWh/hour)
RFC wind power output (TWh/hour)

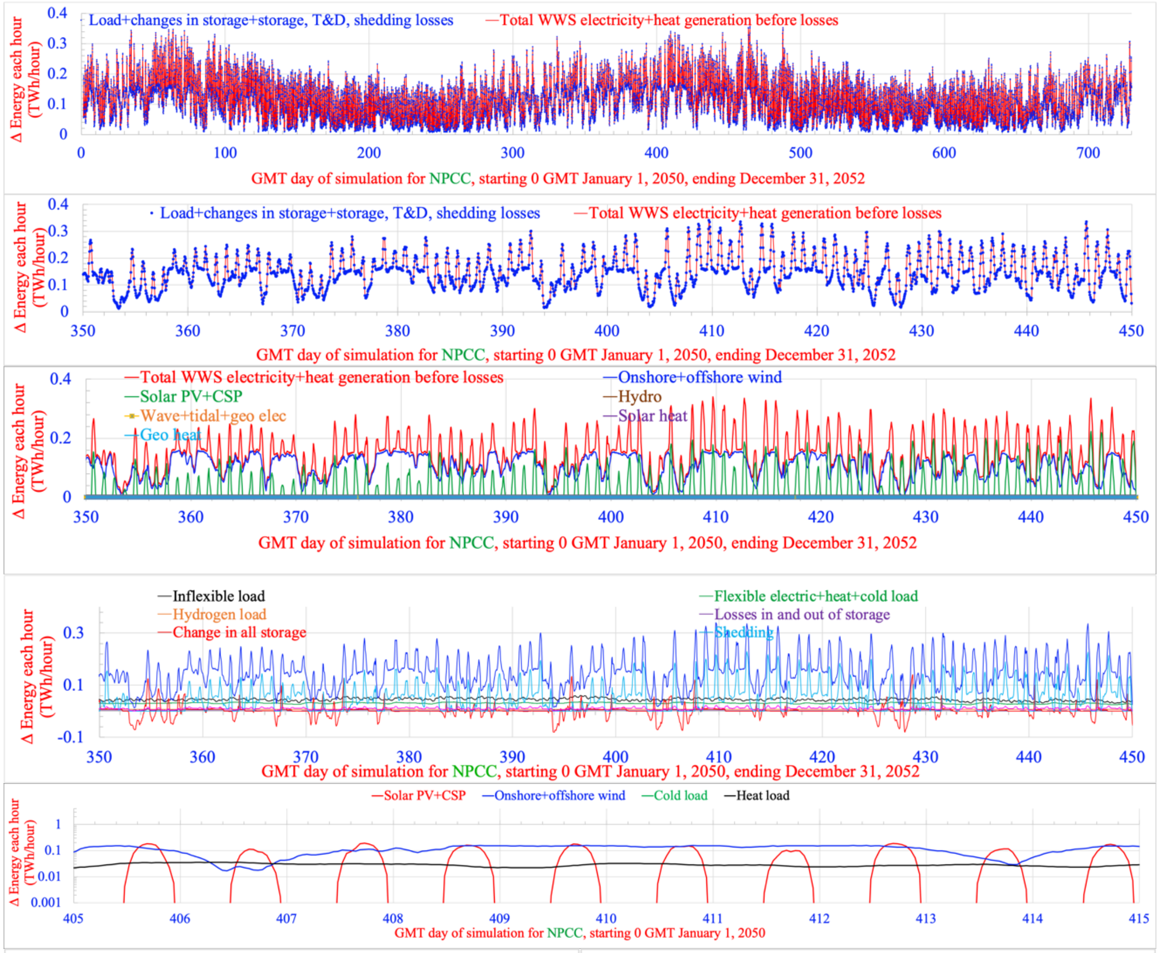

y = -0.0573x + 0.133
R² = 0.0323
Wind power output (TWh/hour)
RFC solar power output (TWh/hour)

SERC

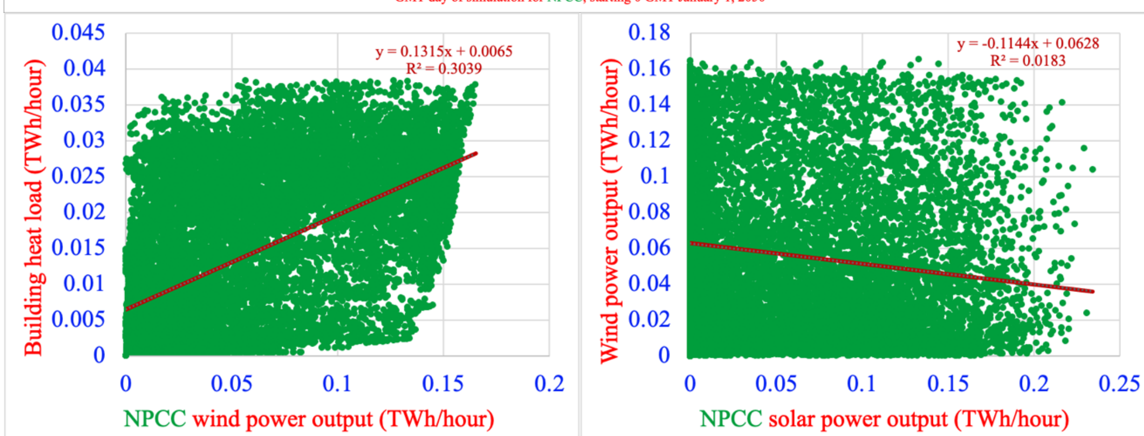


Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for SERC, starting 0 GMT January 1, 2050, ending December 31, 2052
Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for SERC, starting 0 GMT January 1, 2050, ending December 31, 2052
Total WWS electricity+heat generation before losses
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Δ Energy each hour (TWh/hour)
GMT day of simulation for SERC, starting 0 GMT January 1, 2050, ending December 31, 2052
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Δ Energy each hour (TWh/hour)
GMT day of simulation for SERC, starting 0 GMT January 1, 2050, ending December 31, 2052
Solar PV+CSP
Onshore+offshore wind
Cold load
Heat load
Δ Energy each hour (TWh/hour)
GMT day of simulation for SERC, starting 0 GMT January 1, 2050
y = 0.2933x + 0.0063
R² = 0.3428
Building heat load (TWh/hour)
SERC wind power output (TWh/hour)
y = -0.0378x + 0.1851
R² = 0.029
Wind power output (TWh/hour)
SERC solar power output (TWh/hour)

NPCC

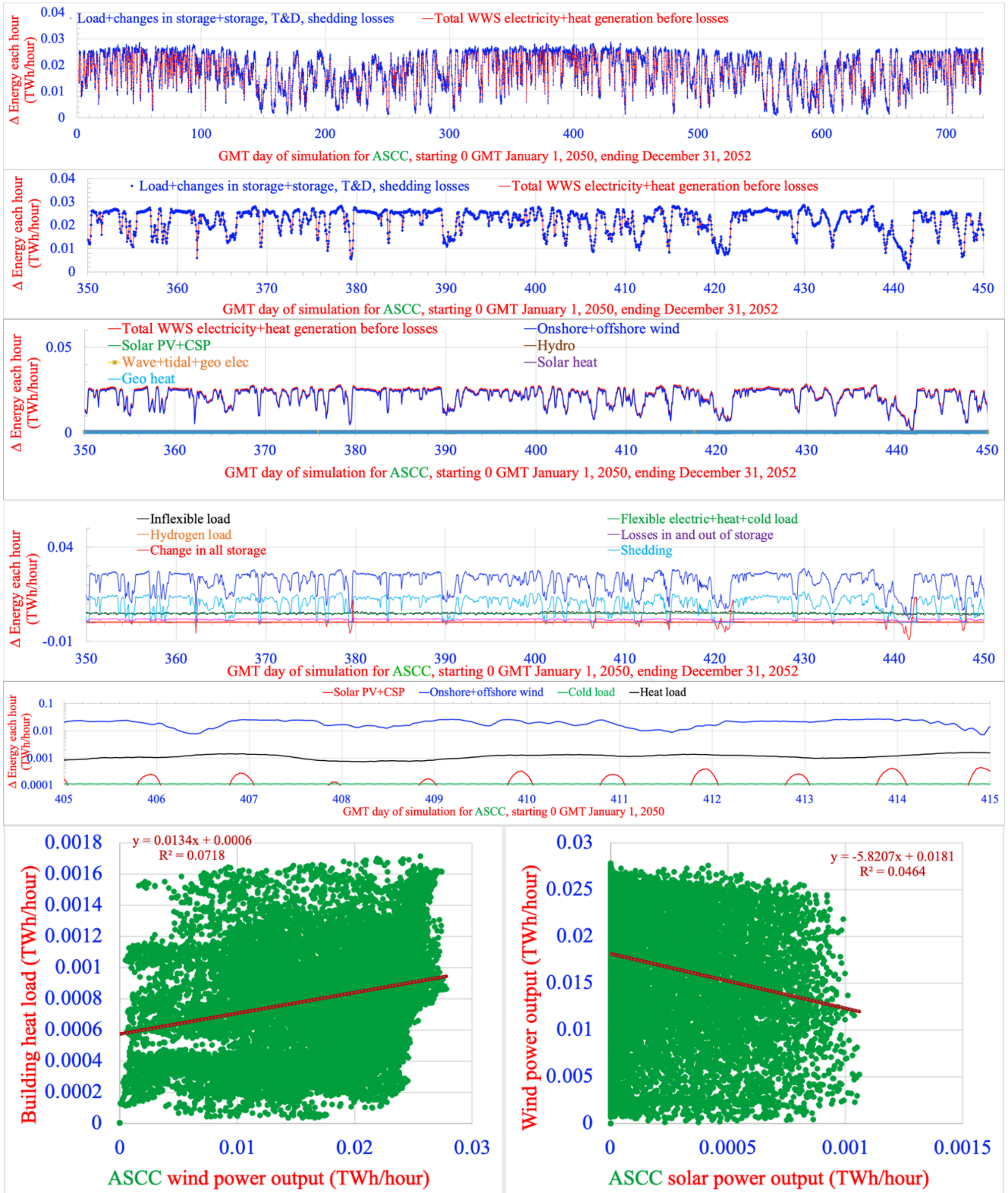


Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for NPCC, starting 0 GMT January 1, 2050, ending December 31, 2052
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Cold load
Heat load
GMT day of simulation for NPCC, starting 0 GMT January 1, 2050

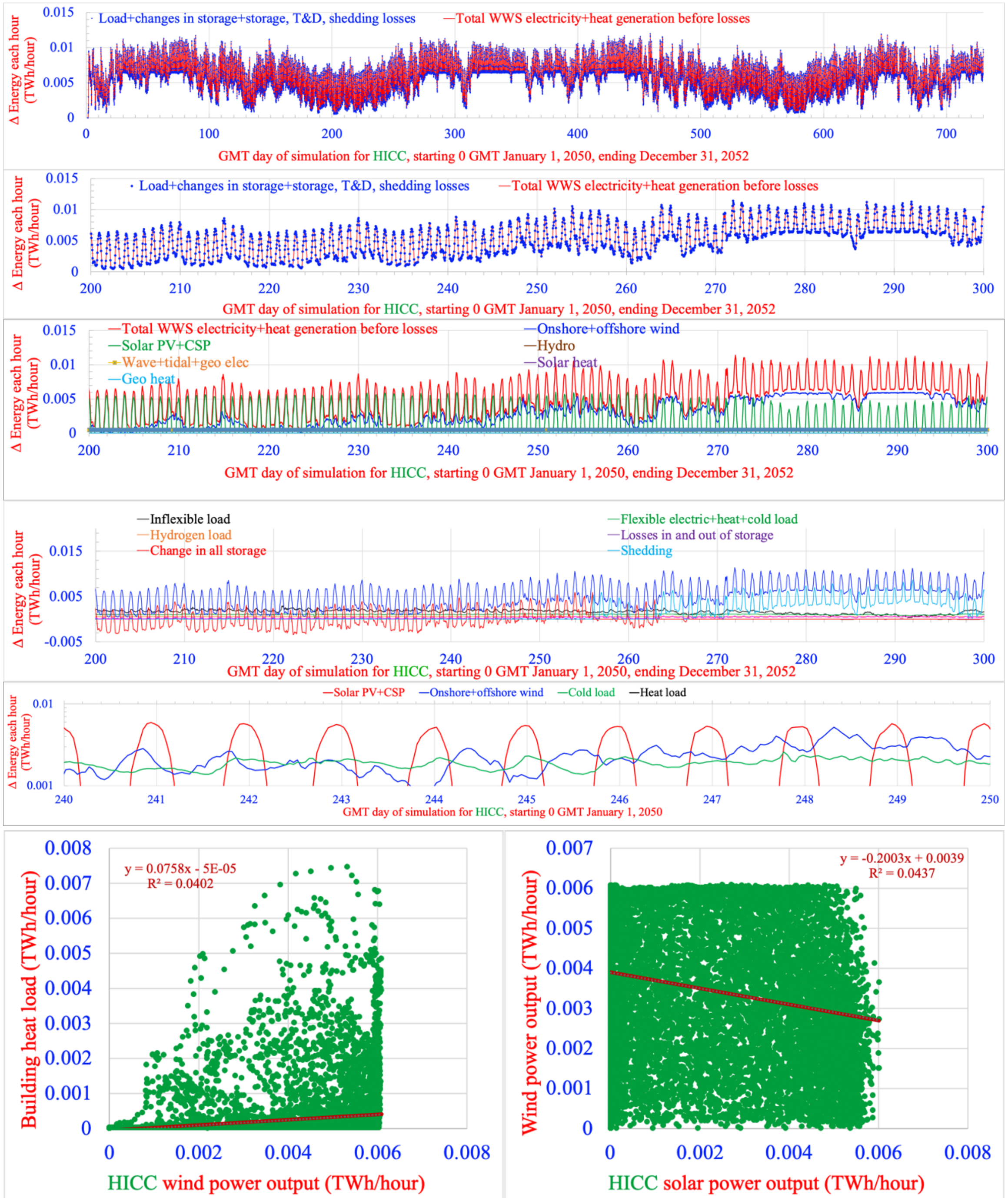


y = 0.1315x + 0.0065
R² = 0.3039
Building heat load (TWh/hour)
NPCC wind power output (TWh/hour)
y = -0.1144x + 0.0628
R² = 0.0183
Wind power output (TWh/hour)
NPCC solar power output (TWh/hour)

ASCC

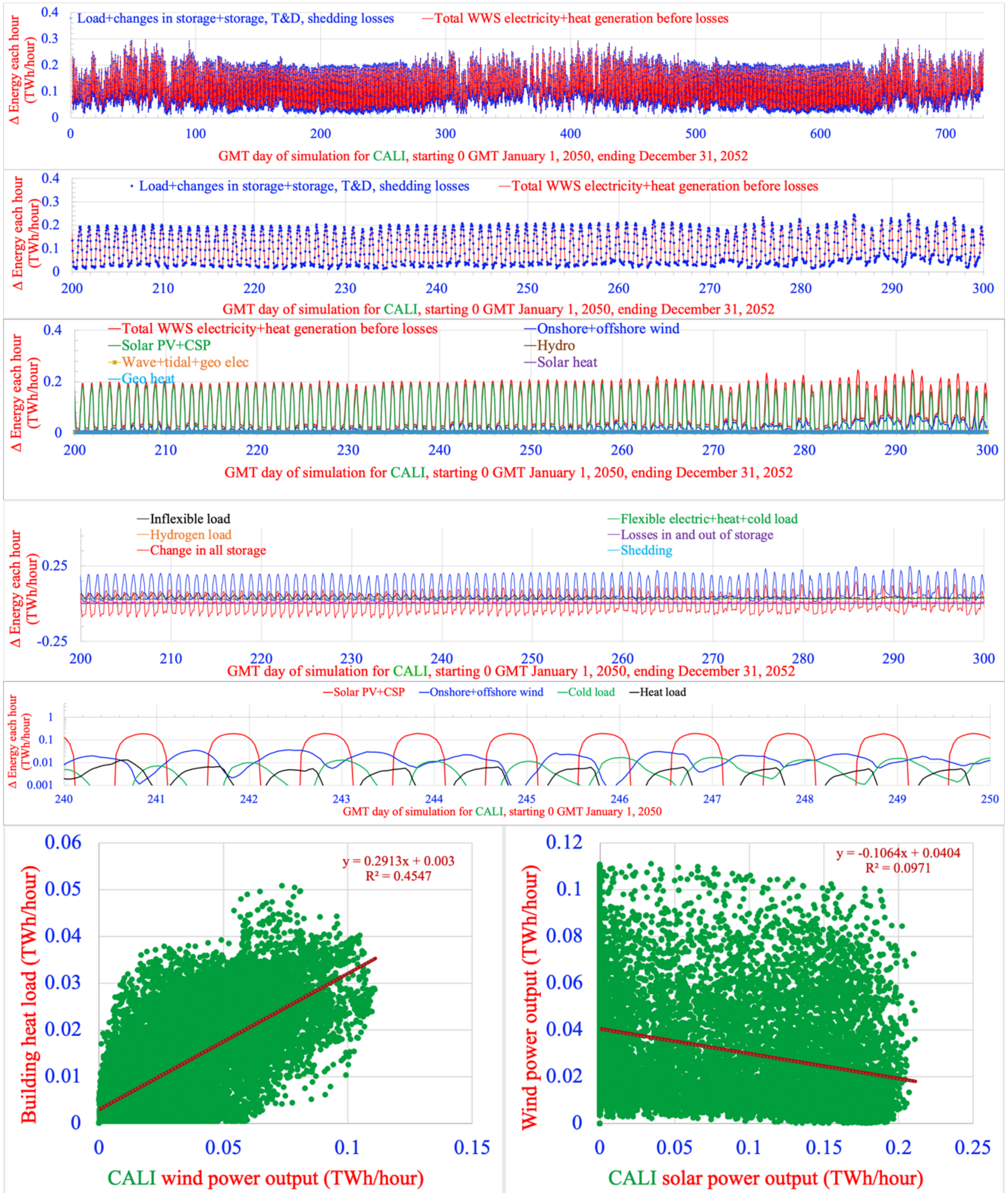

Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for ASCC, starting 0 GMT January 1, 2050, ending December 31, 2052
Total WWS electricity+heat generation before losses
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Solar PV+CSP
Onshore+offshore wind
Cold load
Heat load
GMT day of simulation for ASCC, starting 0 GMT January 1, 2050
y = 0.0134x + 0.0006
R² = 0.0718
Building heat load (TWh/hour)
ASCC wind power output (TWh/hour)
y = -5.8207x + 0.0181
R² = 0.0464
Wind power output (TWh/hour)
ASCC solar power output (TWh/hour)

HICC



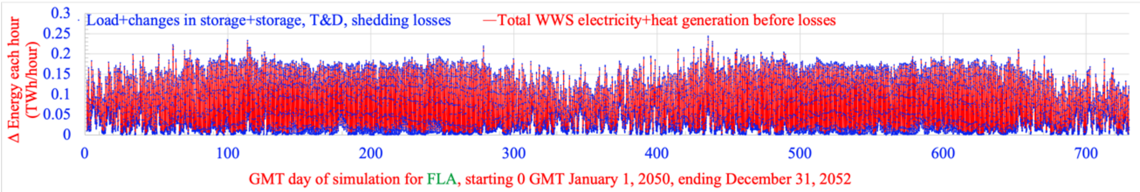
Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for HICC, starting 0 GMT January 1, 2050, ending December 31, 2052
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Cold load
Heat load
GMT day of simulation for HICC, starting 0 GMT January 1, 2050
y = 0.0758x - 5E-05
R² = 0.0402
Building heat load (TWh/hour)
HICC wind power output (TWh/hour)
y = -0.2003x + 0.0039
R² = 0.0437
Wind power output (TWh/hour)
HICC solar power output (TWh/hour)

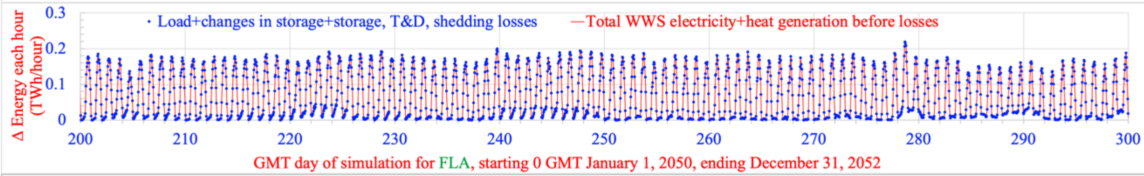
CALI

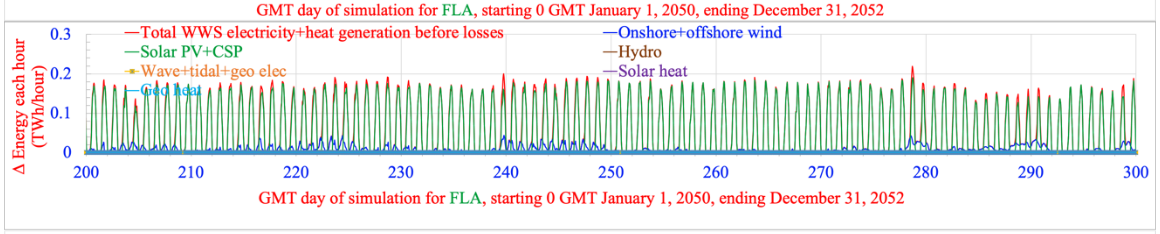


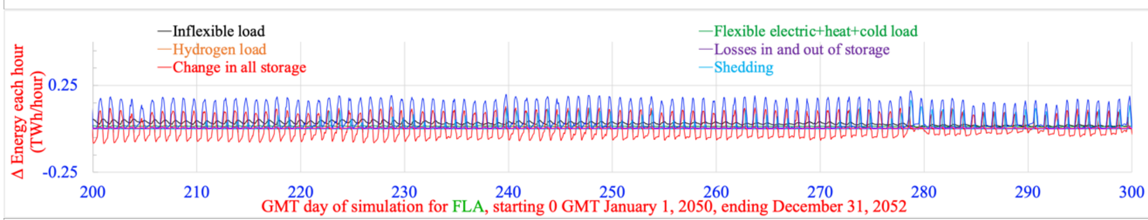
Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for CALI, starting 0 GMT January 1, 2050, ending December 31, 2052
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Hydrogen load
Change in all storage
Flexible electric+heat+cold load
Losses in and out of storage
Shedding
Cold load
Heat load
GMT day of simulation for CALI, starting 0 GMT January 1, 2050
y = 0.2913x + 0.003
R² = 0.4547
Building heat load (TWh/hour)
CALI wind power output (TWh/hour)
y = -0.1064x + 0.0404
R² = 0.0971
Wind power output (TWh/hour)
CALI solar power output (TWh/hour)

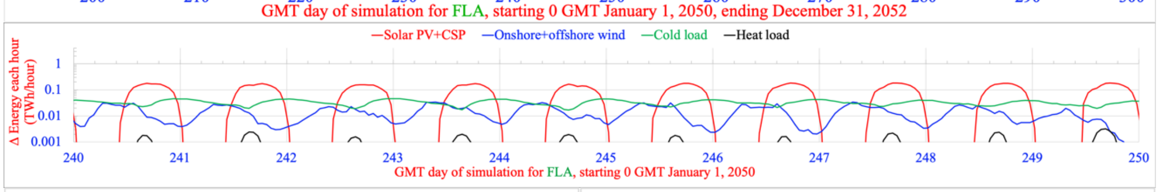
FLA

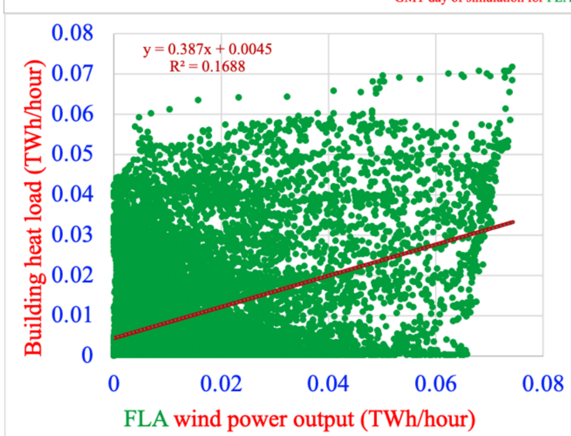

Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for FLA, starting 0 GMT January 1, 2050, ending December 31, 2052

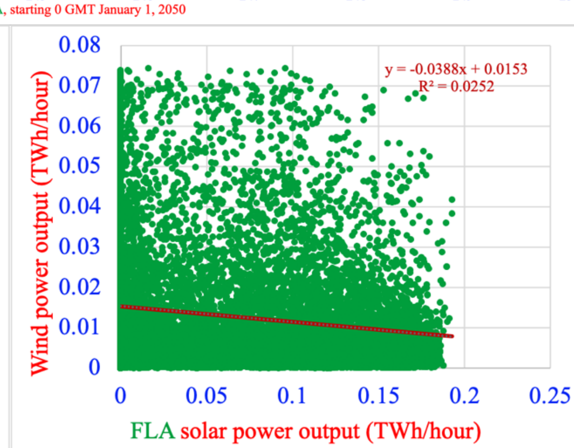

Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for FLA, starting 0 GMT January 1, 2050, ending December 31, 2052


Total WWS electricity+heat generation before losses
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Δ Energy each hour (TWh/hour)
GMT day of simulation for FLA, starting 0 GMT January 1, 2050, ending December 31, 2052

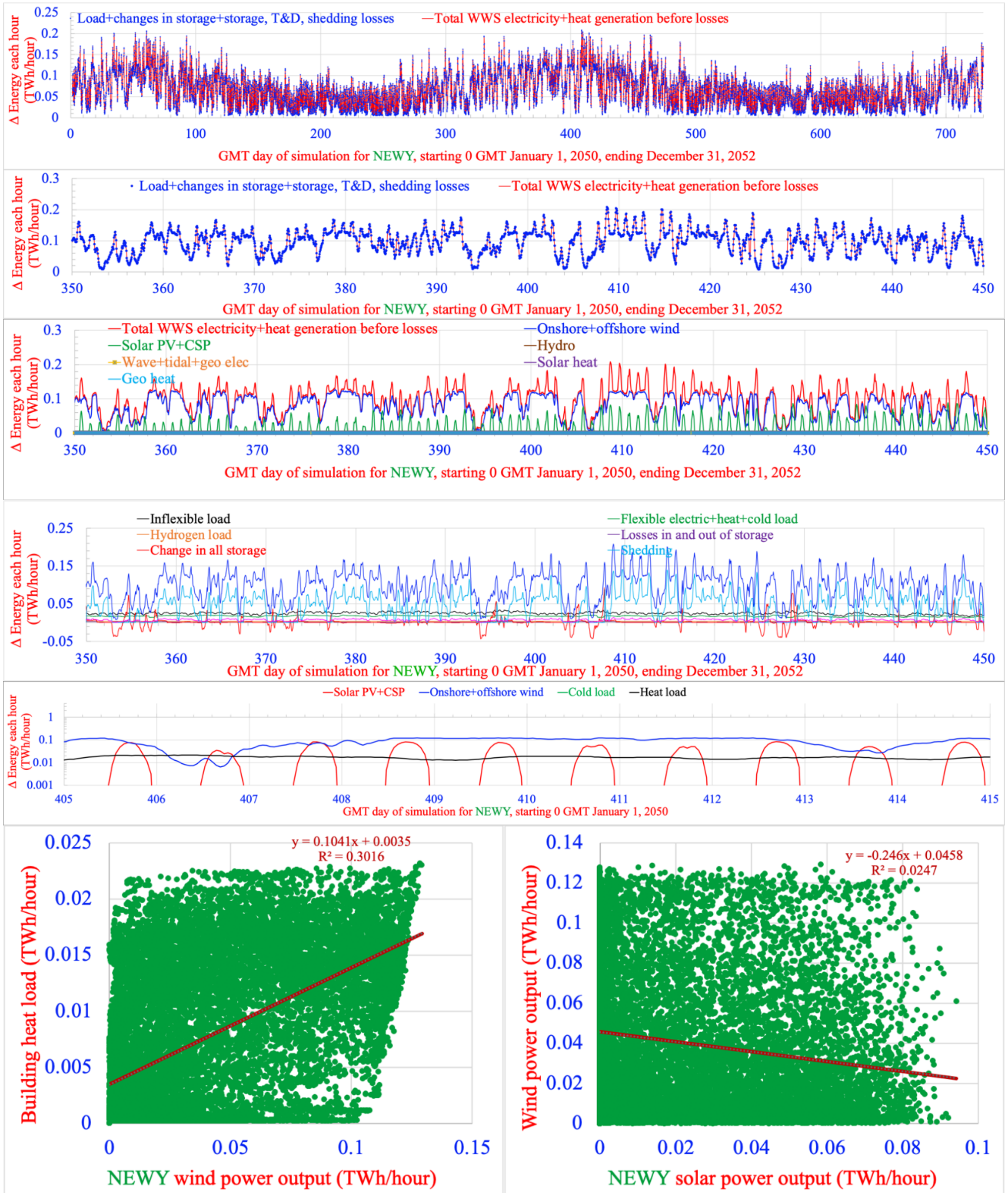

Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Δ Energy each hour (TWh/hour)
GMT day of simulation for FLA, starting 0 GMT January 1, 2050, ending December 31, 2052


Solar PV+CSP
Onshore+offshore wind
Cold load
Heat load
Δ Energy each hour (TWh/hour)
GMT day of simulation for FLA, starting 0 GMT January 1, 2050

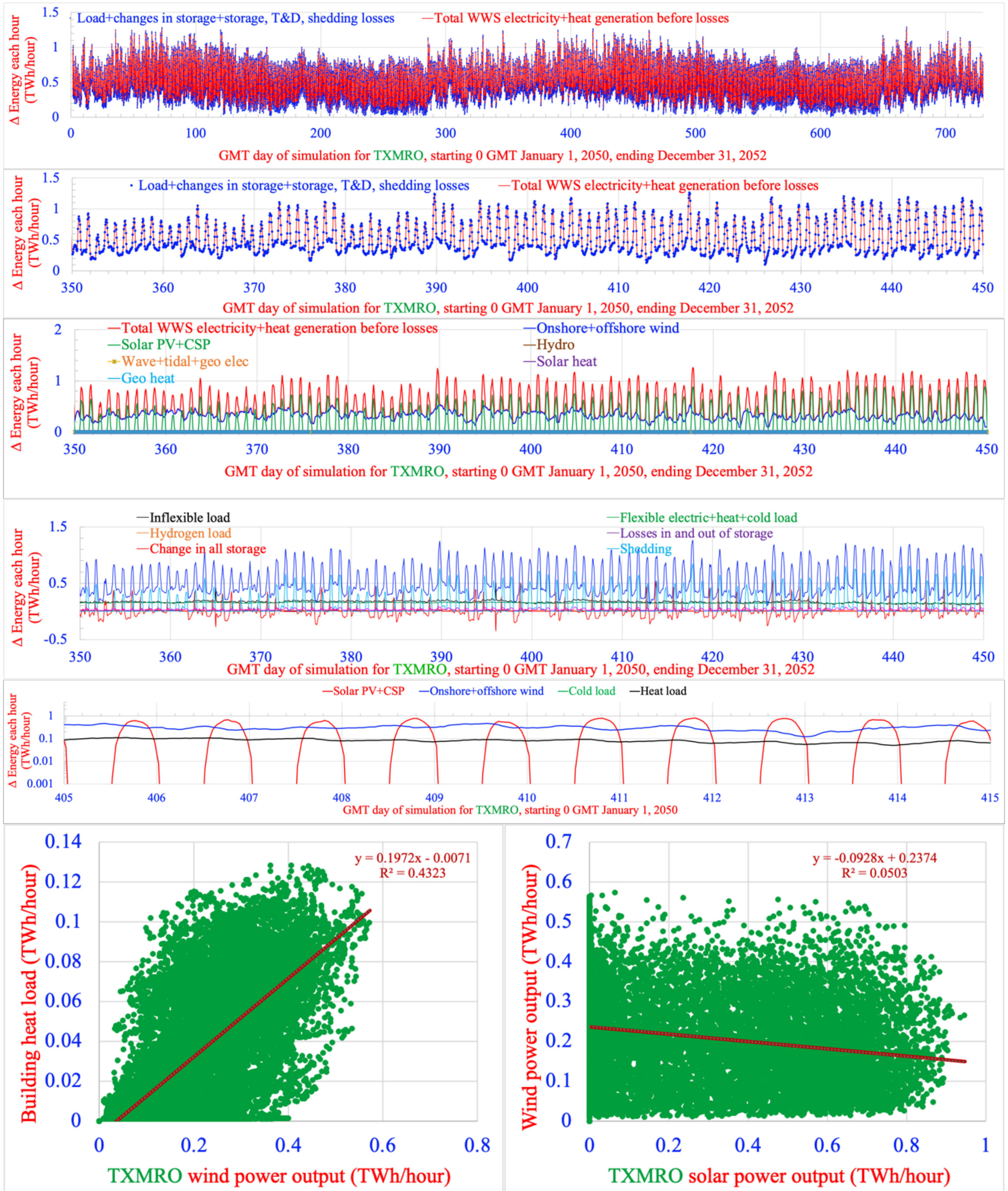

y = 0.387x + 0.0045
R² = 0.1688
Building heat load (TWh/hour)
FLA wind power output (TWh/hour)


y = -0.0388x + 0.0153
R² = 0.0252
Wind power output (TWh/hour)
FLA solar power output (TWh/hour)

NEWY


Load+changes in storage+storage, T&D, shedding losses
—Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for NEWY, starting 0 GMT January 1, 2050, ending December 31, 2052
· Load+changes in storage+storage, T&D, shedding losses
—Total WWS electricity+heat generation before losses
GMT day of simulation for NEWY, starting 0 GMT January 1, 2050, ending December 31, 2052
—Total WWS electricity+heat generation before losses
—Onshore+offshore wind
—Solar PV+CSP
—Hydro
Wave+tidal+geo elec
—Solar heat
—Geo heat
GMT day of simulation for NEWY, starting 0 GMT January 1, 2050, ending December 31, 2052
—Inflexible load
—Flexible electric+heat+cold load
—Hydrogen load
—Losses in and out of storage
—Change in all storage
Shedding
GMT day of simulation for NEWY, starting 0 GMT January 1, 2050, ending December 31, 2052
—Solar PV+CSP
—Onshore+offshore wind
—Cold load
—Heat load
GMT day of simulation for NEWY, starting 0 GMT January 1, 2050
y = 0.1041x + 0.0035
R² = 0.3016
Building heat load (TWh/hour)
NEWY wind power output (TWh/hour)
y = -0.246x + 0.0458
R² = 0.0247
Wind power output (TWh/hour)
NEWY solar power output (TWh/hour)

TXMRO


Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for TXMRO, starting 0 GMT January 1, 2050, ending December 31, 2052
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Cold load
Heat load
GMT day of simulation for TXMRO, starting 0 GMT January 1, 2050
y = 0.1972x - 0.0071
R² = 0.4323
Building heat load (TWh/hour)
TXMRO wind power output (TWh/hour)
y = -0.0928x + 0.2374
R² = 0.0503
Wind power output (TWh/hour)
TXMRO solar power output (TWh/hour)

CONUS

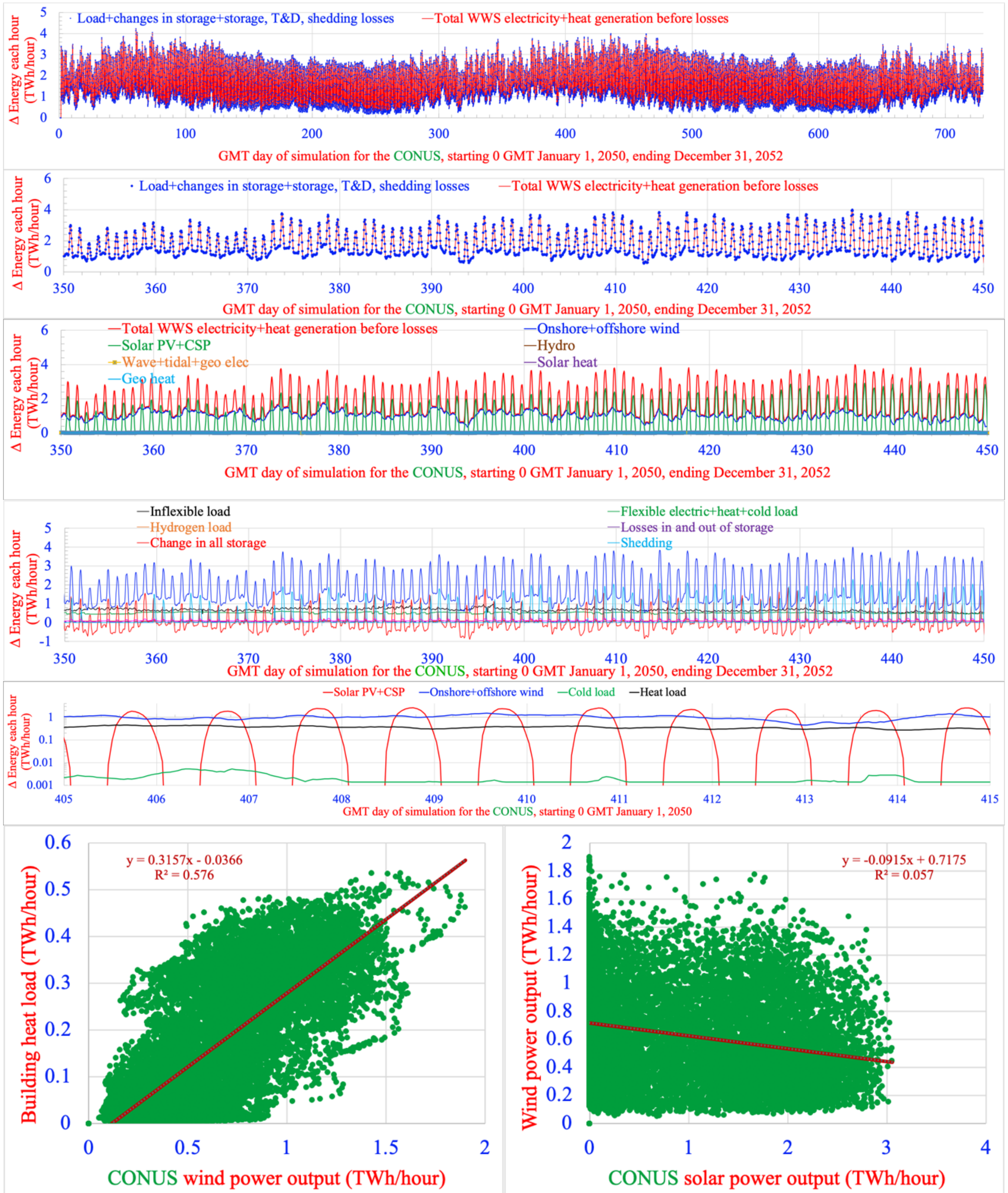
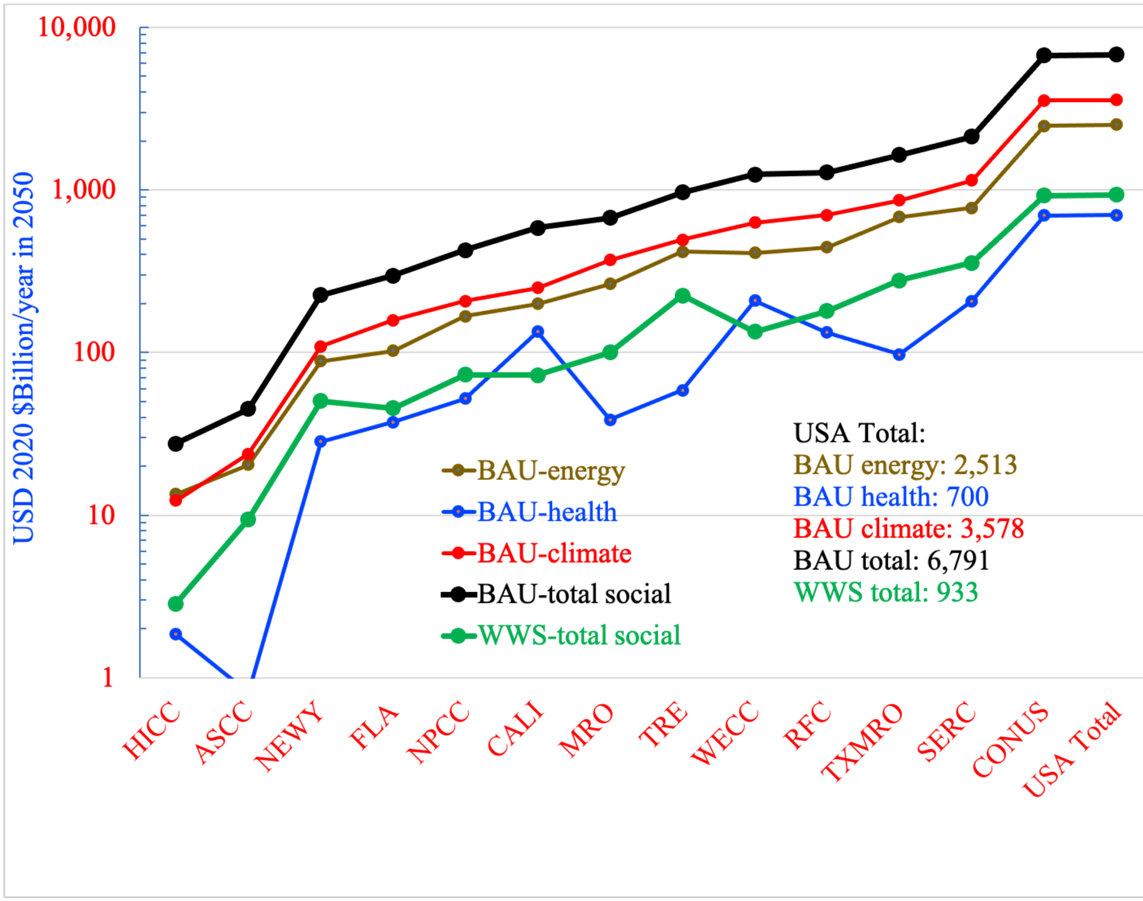

Load+changes in storage+storage, T&D, shedding losses
Total WWS electricity+heat generation before losses
Δ Energy each hour (TWh/hour)
GMT day of simulation for the CONUS, starting 0 GMT January 1, 2050, ending December 31, 2052
Total WWS electricity+heat generation before losses
Onshore+offshore wind
Solar PV+CSP
Hydro
Wave+tidal+geo elec
Solar heat
Geo heat
Inflexible load
Flexible electric+heat+cold load
Hydrogen load
Losses in and out of storage
Change in all storage
Shedding
Solar PV+CSP
Onshore+offshore wind
Cold load
Heat load
GMT day of simulation for the CONUS, starting 0 GMT January 1, 2050
y = 0.3157x - 0.0366
R² = 0.576
Building heat load (TWh/hour)
CONUS wind power output (TWh/hour)
y = -0.0915x + 0.7175
R² = 0.057
Wind power output (TWh/hour)
CONUS solar power output (TWh/hour)

Figure S3. BAU versus WWS annual social cost of energy. The social cost of energy equals the energy plus health plus climate costs of energy. Data are obtained from Tables 3 and S20.



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