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Future cost-competitive electricity systems and their impact on US CO_2 emissions

Alexander E. MacDonald[1*†], Christopher T. M. Clack[1,2*†], Anneliese Alexander[1,2], Adam Dunbar[1], James Wilczak[1] and Yuanfu Xie[1]

Carbon dioxide emissions from electricity generation are a major cause of anthropogenic climate change. The deployment of wind and solar power reduces these emissions, but is subject to the variability of the weather. In the present study, we calculate the cost-optimized configuration of variable electrical power generators using weather data with high spatial (13-km) and temporal (60-min) resolution over the contiguous US. Our results show that when using future anticipated costs for wind and solar, carbon dioxide emissions from the US electricity sector can be reduced by up to 80% relative to 1990 levels, without an increase in the levelized cost of electricity. The reductions are possible with current technologies and without electrical storage. Wind and solar power increase their share of electricity production as the system grows to encompass large-scale weather patterns. This reduction in carbon emissions is achieved by moving away from a regionally divided electricity sector to a national system enabled by high-voltage direct-current transmission.

Carbon dioxide (CO_2) release from burning fossil fuels is a major contributor to climate change[1]. Without significant action to curb these emissions, humans and the natural world will face increasing penalties[2–5]. In contrast with the negative effects of CO_2 emissions are the benefits of cheap energy; electricity in particular is strongly linked to advanced national economies and high living standards[6]. Any solution to mitigate CO_2 must be economical for it to succeed.

Wind and solar power have very low life-cycle CO_2 emissions[7]. Integrating large amounts of wind and solar would decrease CO_2 emissions drastically; however, they are dependent on the weather. The variability of the weather has led to the assumption that all weather-dependent renewable energy technologies need to be supported by backup fossil fuel generation or storage on a significant basis, causing costs to soar[8]. Paradoxically, the variability of the weather can provide the answer to its perceived problems.

Because Earth's mid-latitude weather systems cover large geographic areas, the average variability of weather decreases as size increases[9]; if wind or solar power are not available in a small area, they are more likely to be available somewhere in a larger area. Even more importantly, access to electricity over a large region allows locations with rich wind and solar resources to supply cheap power to distant markets. The key enabling technology for the large geographic domains favoured for wind and solar power is a network of high-voltage direct-current (HVDC) transmission lines. Electrical storage can also reduce the intermittency of wind and solar, but at a higher cost than HVDC transmission lines.

Our study targets the contiguous US electricity sector to find cost-optimal networks of wind and solar generators that fulfil the requirements of an electrical power system. We show that the US can reduce CO_2 emissions from the electricity sector by 33–78% at approximately the same cost of electricity as in 2012. In recent years, similar tools have been developed that deal with electrical power ystem optimization, for example, MARKAL, NEMS, WEM, ReEDS, SWITCH, US-REGEN and ReNOT (refs 10–18). Our National Electricity with Weather System (NEWS) model differs from these models in its use of weather data with high temporal and spatial resolution, broad geographic areas, and extended time periods. Further, it co-optimizes dispatch, transmission and capacity expansion, allowing cost savings from geographic diversity, load smoothing, transmission expansion, reserve pooling and decreased energy density requirements. We integrate complex weather data over continental-scale geography while still handling the salient features of an electrical power system. NEWS implicitly computes the security-constrained unit commitment and economic dispatch, explicitly determines the planning reserves, load-following reserves and calculates the hourly transmission power flow, the capacity expansion of generators as well as transmission expansion. These constraints can be found in Supplementary Information Section 1.6.

Several studies have appeared over the past few years examining very high penetration levels of variable generation (close to 100%); these studies model renewable energy domination of the electricity sector. Two of these use subsets of the US, both spatially and temporally[19,20]. To get very high penetrations of variable generation they either constrain the fossil fuels or assume low-cost storage. Further, transmission is assumed to be perfect, an assumption that we do not make. A further study[21] considers the entire contiguous US is considered, but with large amounts of spatial aggregation along with a longer time series. However, the longer time series is simplified by utilizing only a small subset of those data. Also, they cost-optimize predetermined resource sites to balance the load. Aside from the resource data, the critical difference in these models compared with NEWS is the co-optimized structure of the NEWS model, which solves for the minimum total system cost, including both generation and transmission simultaneously.

The NEWS model is intended to be a hybrid capacity expansion and production cost model. The hybrid approach allows for cost reductions because the capacity expansion is decided in parallel with the dispatch of the generators instead of in serial. Supplementary Information Section 1 provides more

[1]Earth System Research Laboratory, NOAA, 325 Broadway, Boulder, Colorado 80305, USA. [2]Cooperative Institute for Research in Environmental Sciences, University of Colorado, Boulder, Colorado 80305, USA. †Joint first authors. *e-mail: alexander.e.macdonald@noaa.gov; christopher.clack@noaa.gov

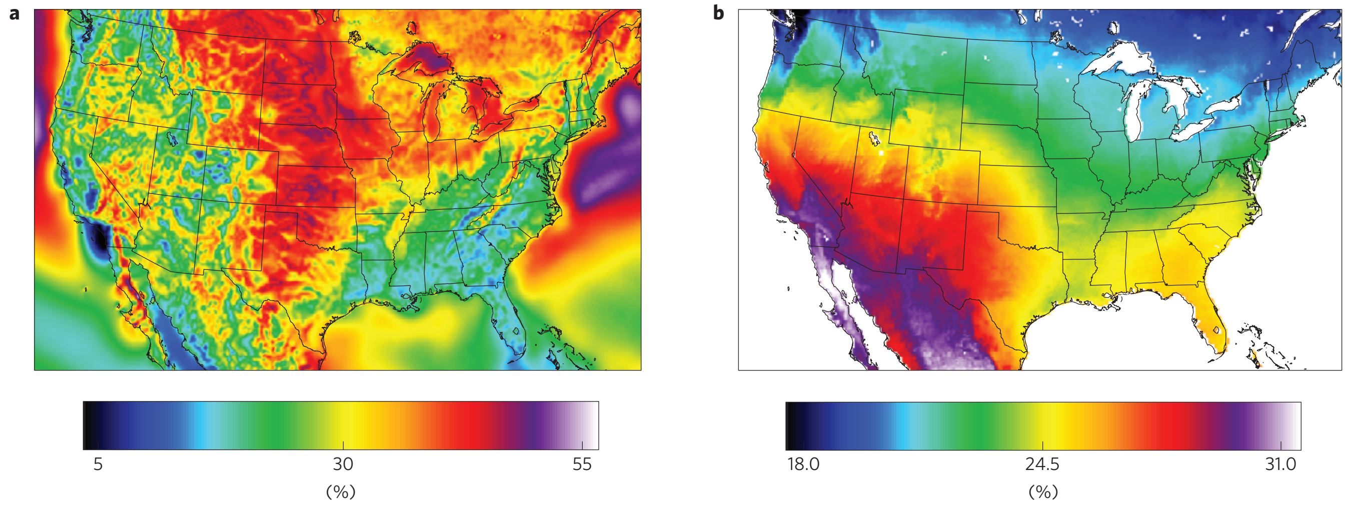

Figure 1 | The wind and solar PV power potential over the contiguous US. a,**b**, Wind at 90 m above ground level (**a**) and solar PV resource potential (**b**) over the US using the high-resolution weather data and power-modelling algorithms for 2006–2008. The potential is presented as the expected percentage of installed capacity power (capacity factor). Black/blue represents very low resource potential whereas red/violet indicate very good resource potential for that technology. The range of values is different for wind and solar PV. The description of the wind and solar PV power modelling is given in Supplementary Information Section 1.1.2.

details on the mathematics of the optimization. Further discussion of the optimization technique can also be found in ref. 22. The study uses hourly wind speed and solar irradiance for the years 2006–2008 using an advanced weather assimilation model on a 13-km grid[23]. The weather assimilation model extrapolates extensive weather observations over a uniformly spaced grid utilizing mathematical operators consistent with atmospheric dynamics and physics. We convert the weather data into electrical power output for wind turbines and solar photovoltaic (PV) panels with sophisticated power-modelling algorithms to mimic current technology behaviour (see Supplementary Information Section 1 for the methods).

Figure 1 shows the wind and solar PV resource potential over the US. It demonstrates the high level of detail contained in the weather and power data sets; there are ~152,000 spatial grid points in the data set. The panels in Fig. 1 show the temporal averages for 2006–2008; the data set contains ~27,000 hourly time steps. Figure 1a highlights that the locations across the US that have a high wind resource potential are predominantly away from densely populated regions, whereas Fig. 1b shows that the best solar PV resources are located in the desert southwest. The wind power data set is described in more detail in ref. 24. We did not explicitly treat wake effect interactions between wind turbines because the number of wind turbines is a dependent variable within the optimization and doing so would have made the problem intractable. The resulting distribution of wind turbines across the US does not extract more than 0.5 W m^{-2} on average from their grid cells.

Because weather is a major driver of electrical power use, we compiled the concurrent electricity demand for each market area and each hour of 2006–2008 (ref. 25). It is recognized that electrical power system dispatch includes timescales shorter than one hour, and that sub-hourly variability of wind and solar PV can be significant. However, the current NEWS model cannot address these high-frequency fluctuations because current data sets of electricity demand, as well as output from weather assimilation models, are not available at higher temporal resolution for the geographic scales we are modelling. Furthermore, the geographic scales considered in the present study effectively eliminate sub-hourly variability due to aggregation[26].

We selected 2030 as the reference year to create a cost-minimized electrical power system, and included a 14% increase in electricity demand above our baseline years of 2006–2008. The main reason for choosing a reference year of 2030 is that the cost estimates for all of the technologies become increasingly uncertain at longer time horizons. The increase in electricity demand is found by tracking GDP growth and contraction to 2011, then estimating a 0.7% growth per annum, in line with EIA estimates[27]. Supplementary Fig. 4 shows the aggregated hourly US electricity demand. Cost estimates for generators are continually evolving, so to provide rigorous estimates we compiled cost projections from numerous studies available at the time of the simulation runs and constructed three 2030 scenarios that span a range of future costs. The reader can refer to Supplementary Information Section 1.4 (Supplementary Fig. 6 and Supplementary Table 3) for a detailed description of the cost estimates used. The first was the high-cost renewable and low-cost natural gas (HRLG) scenario, which is similar to costs in 2012. The second was the low-cost renewable and high-cost gas (LRHG) scenario, in which the US achieves future expected cost reductions for renewable energy and faces increased demand for natural gas. Finally, we took the average of those two estimates to create the mid-cost renewable and mid-cost natural gas (MRMG) scenario. We assume that generator and transmission purchase costs are fully amortized over thirty years with a real discount rate of 6.6%. The costs are socialized equally among all of the different geographic regions of the contiguous US. Further, there are no increased capacity payments in the model because the purchases are simply assumed to be all debt repaid over the thirty years.

The study focused on three main generation technologies; wind turbines, solar PV, and natural gas combined cycle turbines, while one simulation also included coal plants. Natural gas is an effective complement to wind and solar PV because it has lower greenhouse gas emissions than other fossil fuels, and has the advantage of being able to rapidly change power output. Starting from nuclear, hydroelectric (no pumped hydroelectric is considered), wind, and solar PV plants that existed in 2012, our optimization model designs a new cost-optimal electrical power system for the entire contiguous US. The solution comprises wind, solar PV, natural gas, nuclear and hydroelectric generators. It also includes an HVDC transmission network that can transmit electricity over long distances, which high-voltage alternating current (HVAC) cannot do. In addition, HVDC is more efficient and cheaper than HVAC (ref. 28). Our model's key constraint is that it must provide electrical

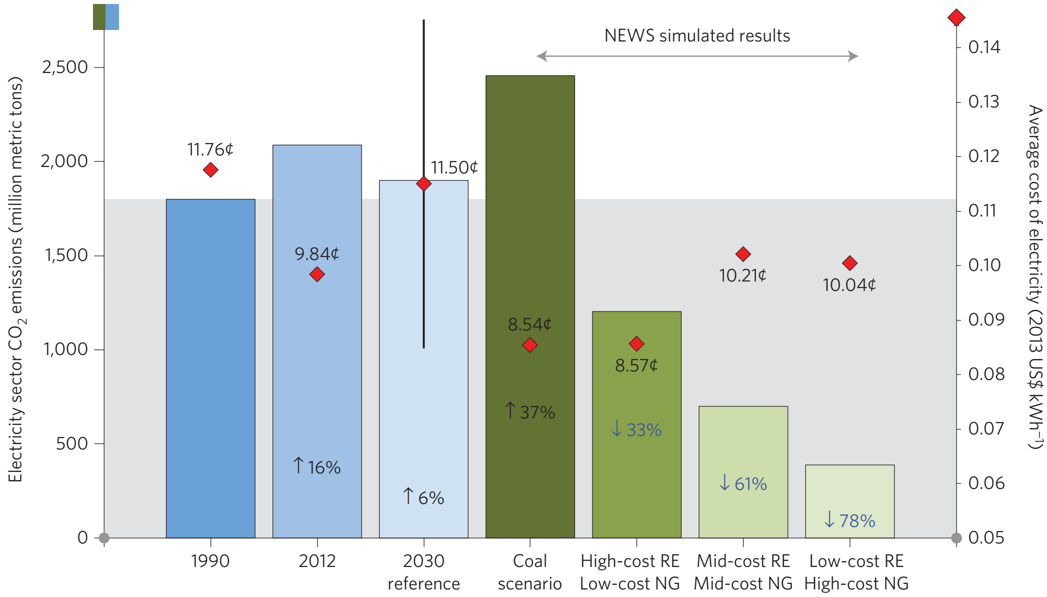

Figure 2 | The US electricity sector CO_2 emissions (left axis, bars) and levelized cost of electricity (right axis, diamonds). The blue bars are for historical data and an International Energy Agency projection to 2030 (ref. 6). The green bars represent results from our optimization model (the values are the average of the three years of simulations). The coal scenario is identical to the HRLG scenario, but with the inclusion of coal plants. The red diamonds represent the levelized cost of electricity per kilowatt-hour (kWh) to consumers in 2013US$. The percentages show the change of CO_2 emissions relative to 1990 levels.

power for every hour to every market while operating within current technology limits (see Supplementary Information Section 1 for methods).

The IEA World Energy Outlook (WEO) 2013 estimates that the levelized cost of electricity (LCOE), in 2013US$, to US customers will be 11.5¢, with a range between 8.5¢ and 14.5¢, per kWh by 2030, and CO_2 emissions will be 6% higher than in 1990 (ref. 6). The EIA Annual Energy Outlook (AEO) 2015 also estimates that the LCOE to US customers will be 11.5¢ per kWh (ref. 29). The LCOE to US customers includes the generation, transmission, distribution, O&M and fuel costs. The same applies to results from the NEWS model. Although our study focused on three main technologies, coal at present plays a major role in electricity generation in the US. In Fig. 2 we show results from optimization model runs that included coal (without carbon capture and sequestration (CCS)); CO_2 emissions were 37% higher than 1990 levels and the LCOE was 8.5¢ kWh^{-1} (ref. 29). The cost of electricity for comparison is estimated using the optimization model output and assuming that the split of costs remains the same as at present—that is, 68% for generation and transmission and 32% for distribution. The costs of nuclear and hydroelectric generation are 6¢ kWh^{-1} and 2¢ kWh^{-1}, respectively. Although somewhat less expensive than the other NEWS solutions, the coal scenario does not mitigate CO_2 emissions. Any proposed solution to mitigate CO_2 emissions cannot have substantial coal without CCS. Storage was considered and available in the optimization model; however, in preliminary simulations it was not selected in national solutions at a cost of US$1.50 per watt installed (more can be found in Supplementary Information Section 1.4). Therefore, for simplicity we removed it from the model. All other generation technologies were excluded from the optimization on the basis of cost projections that make them non-cost-competitive, or because of their current lack of large-scale commercial availability; including geothermal, concentrating solar power, and marine-hydro-kinetics. Further, the NEWS scenarios do not model fossil fuel generator stranded assets. However, we note that there is a significant turnover of fossil fuel generators on decadal timescales and, in particular, large numbers of coal plants are at present being retired for age, economic or environmental reasons.

Figure 2 indicates that, with current technologies, CO_2 emissions would be reduced by 33%, 61% and 78% relative to 1990 levels according to the HRLG, MRMG and LRHG scenarios, respectively. With a LCOE at 8.6¢, 10.2¢ and 10.0¢ kWh^{-1}, the three scenarios are below the 2030 reference LCOE of 11.5¢ kWh^{-1}, estimated by both the WEO 2013 and AEO 2015. Therefore, with existing technologies, the US electricity sector can substantially reduce its CO_2 emissions by 2030 without an increase in the LCOE, assuming learning curve cost reductions in wind and solar PV and the facilitation of a national HVDC transmission grid overlay. Using the LRHG scenarios (2006–2008), US power consumers could save an estimated US$47.2 billion annually with a national electrical power system versus a regionally divided one (~1.1¢ kWh^{-1}). This amounts to almost three times the cost of the HVDC transmission per year.

The model-produced electrical power system is a complex amalgam of variable and conventional generators, HVDC transmission lines and varying electrical load. Another component of the optimization model is that it simultaneously computes the locations of each generator and the capacity of each HVDC transmission line, dispatches each generator every hour at each location, and calculates the power flow (with losses) within the HVDC transmission network. The HVDC transmission network is a web of lines that connects 32 nodes, allowing power to flow between each region. The siting of the generators is bounded by numerous constraints, and care was taken to incorporate these restrictions within the model. For example, the nuclear and hydroelectric power plants are placed where they existed in 2012, the optimization can select to build natural gas and coal plants only where a fossil fuel plant existed in 2012 (to ensure the necessary infrastructure exists), and wind and solar PV plants cannot be built on protected lands, within urban areas or on steep slopes. See Supplementary Information Section 2.2 for details.

The selected locations of the wind and solar PV plants in the cost-optimized solutions are geographically dispersed over the entire contiguous US (Fig. 3). The electrical power system shown in Fig. 3 is for the LRHG scenario using data year 2007. It includes 523 gigawatts (GW) of wind (22 MW offshore, seen

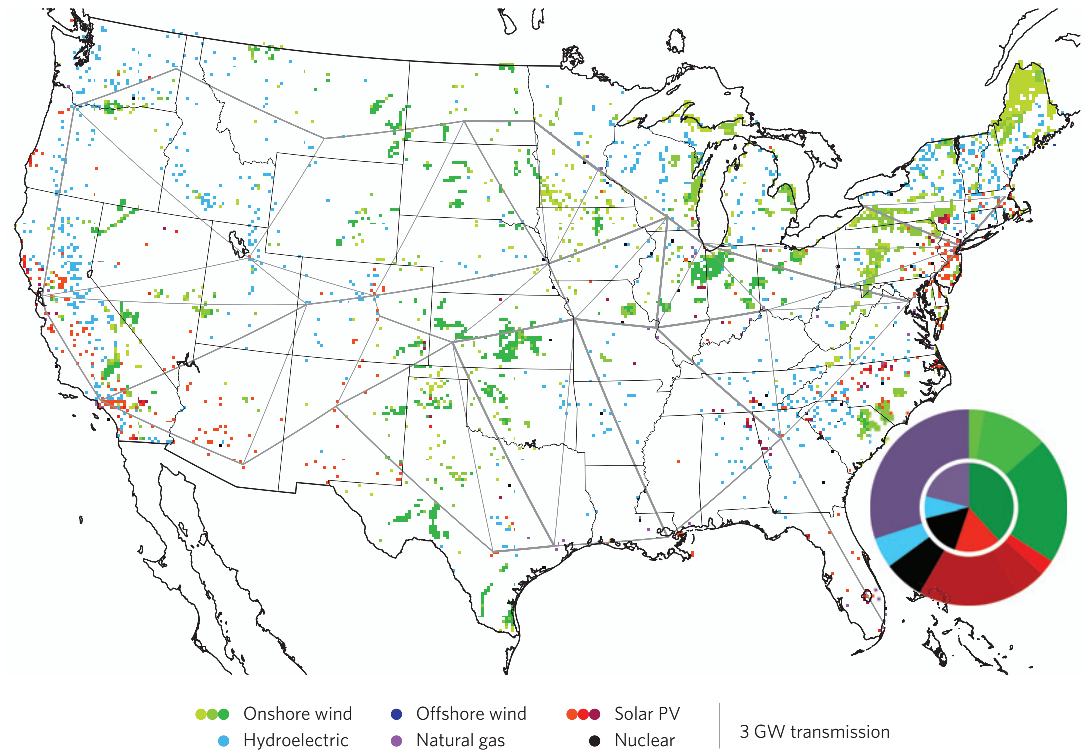

Figure 3 | Cost-optimized single electrical power system for the contiguous US, using data year 2007. The colours indicate that a model grid cell has a technology sited within it. Onshore wind and solar PV are split into three bins to designate the density of installations. For wind the bins are: less than 0.5 W m^{-2}; between 0.5 W m^{-2} and 1.5 W m^{-2}; above 1.5 W m^{-2}. For solar the bins are: less than 5 W m^{-2}; between 5 W m^{-2} and 10 W m^{-2}; above 10 W m^{-2}. The grey lines show the HVDC transmission network. The outer pie chart represents the installed capacity, whereas the inner pie chart shows the electricity demand met by each technology.

halfway down the Maine coastline), 371 GW of solar PV, 461 GW of natural gas, 100 GW of nuclear, and 74 GW of hydroelectric, for a total of 1,529 GW installed capacity. The very small amount of offshore wind (22 MW) demonstrates the cost efficiency of HVDC transmission to be able to transmit the power from the high plains to the coast rather than building wind turbines offshore. Compared with 2012 that represents a total increase in capacity of 31%. Natural gas capacity falls by 25 GW, whereas wind and solar PV rise by 463 GW (a factor of eight) and 368 GW (a factor of 62), respectively[27]. The inner pie chart in Fig. 3 shows that wind provides the dominant share of electricity at 38%, natural gas contributes 21%, solar PV 17%, and the remainder is fulfilled by nuclear and hydroelectric (16% and 8%, respectively). In other words, natural gas reduces its contribution by 9% relative to 2012, whereas wind and solar PV substantially increase their share to replace the other fossil fuels and displace some natural gas. The reader is encouraged to compare this result with those found in Supplementary Information Section 2 for all the other scenario runs.

The land taken out of its current uses and converted into power production is 6,570 km^2 (460 km^2 for wind and 6,110 km^2 for solar PV), or 0.08% of the contiguous US. The HVDC transmission network provides the access to these distant areas at a share of 4% of the cost of the electricity. A further benefit from this scenario is a significant drop of 65% in water consumption for electricity generation relative to 2012, predominantly because fewer steam turbines and cooling towers are needed[30]. More detailed results are presented in the Supplementary Information Section 2.

In the current US electricity sector there is no single electrical power system; there are three large connected regions known as interconnects, which are further divided into balancing authority areas (BAAs) that are designed to maintain supply and demand of electricity within their respective areas. Small, self-contained areas will diminish the efficacy of power generation from wind and solar PV because the local resources will be more correlated in time than geographically separated sites. In Fig. 4a the dependency on electrical power system size can be observed. As the size of the connected system grows, the amount of wind and solar PV generation increases. Moreover, the cost of electricity decreases as the area increases, because the system has access to more remote, rich resources and the correlation between connected sites weakens. The amounts by which the wind and solar PV installations grow and the costs decrease vary by scenario, but the trend persists in each. It is worth mentioning that, even in the single connected electrical power system, there can be thirty-two asynchronous subsystems that are connected by the HVDC. The HVDC reduces the potential of whole electrical power system blackouts because the entire system does not need to operate at the exact same frequency. Therefore, when faults occur, regions of the electrical power system can be isolated from the remainder.

Natural gas is a commodity and its cost to the electricity sector fluctuates continuously. During the decade of 2004–2014 the average monthly cost of natural gas for electricity has been as low as US\$2.81 and as high as US\$12.41 per million British thermal units (MM Btu). One MM Btu is equivalent to 1.054615 GJ. (ref. 31). Because the NEWS model minimizes the total system cost, the deployment of wind and solar PV in our model is linked to the cost of natural gas; as it increases so does the installed capacity of wind and solar PV. There is always a critical cost of natural gas where the system rapidly installs more wind and solar PV. Figure 4a,b can be used together to estimate the additional amounts of carbon-emission-free generation that could be economically deployed in 2030 for the same LCOE if a national HVDC-enabled system were implemented. For example, for ~11¢ kWh^{-1} there is ~75% carbon-emissions-free generation for the mid renewable costs in the

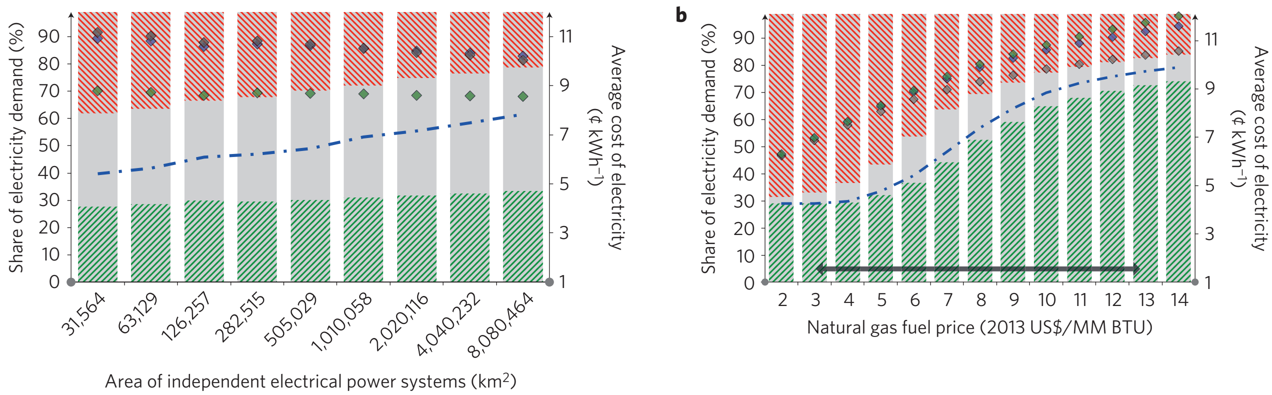

Figure 4 | Sensitivity to geographic scale and natural gas price. a,**b**, Influence of area (**a**) and natural gas cost (**b**) on the amount of carbon-emission-free generation. The green-hashed area represents the carbon-emissions-free generation of the HRLG scenario, whereas the grey area shows extra carbon-emissions-free generation created in the LRHG scenario. The blue dot-dashed line is the midrange (MRMG) value of the share of demand met by non-fossil fuel generation. The grey, blue and green diamonds show the LRHG, MRMG and HRLG cost scenarios LCOE to customers, respectively. The values shown are the three-year averages. The shaded arrow in **b** denotes natural gas costs to electricity utilities over the past decade (2004–2014).

national system (from Fig. 4b, columns for US$12–13 per million British thermal units (MM BTU)), but only ~40% with systems on the scale of the 2012 BAAs (from Fig. 4a, 63,129 km^2 column).

The formidable challenges associated with a large transformation of the US electrical power system by the 2030s include: the integration of variable generators; changes to the existing regulatory, commercial and legal system; and investments in a HVDC network and new power plants. Importantly, if the electricity sector is decarbonized, there are good prospects that electrical vehicles, heat pumps, and other electricity-based technologies can similarly reduce CO_2 across the entire energy sector. Although it would be a difficult transition, the challenges are not dissimilar to previous US projects for the creation of national markets, such as the transcontinental railroads of the nineteenth century, and the interstate highway system of the twentieth century.

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Author contributions
A.E.M. developed the original concept. C.T.M.C. wrote the majority of the paper along with help from all the other authors. C.T.M.C. produced all the figures and associated data. C.T.M.C. devised, ran and computed the results for all of the experiments, created and developed the mathematical optimization along with the associated software, and wrote the Supplementary Information. C.T.M.C. also finalized the spatial, load and transmission data sets for the optimization routine. A.A. created the initial spatial availability and electrical load data sets, and compiled the original weather data sets. A.D. computed the costs for each technology. J.W. verified the weather data and assisted extensively with editing the paper. Y.X. helped with the initial optimization approach and verified the mathematical approach. All authors contributed to data review and consistency checks.

Additional information
Supplementary information is available in the online version of the paper. Reprints and permissions information is available online at www.nature.com/reprints. Correspondence and requests for materials should be addressed to A.E.M. or C.T.M.C.

Competing financial interests
The authors declare no competing financial interests.