UC Irvine
UC Irvine Previously Published Works

Title

Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar

Authors

Clack, Christopher TM
Qvist, Staffan A
Apt, Jay
et al.

Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar

Christopher T. M. Clack[a,b,1,2], Staffan A. Qvist[c], Jay Apt[d,e], Morgan Bazilian[f], Adam R. Brandt[g], Ken Caldeira[h], Steven J. Davis[i], Victor Diakov[j], Mark A. Handschy[b,k], Paul D. H. Hines[l], Paulina Jaramillo[d], Daniel M. Kammen[m,n,o], Jane C. S. Long[p,3], M. Granger Morgan[d], Adam Reed[q], Varun Sivaram[r], James Sweeney[s,t], George R. Tynan[u], David G. Victor[v,w], John P. Weyant[s,t], and Jay F. Whitacre[d]

[a]Earth System Research Laboratory, National Oceanic and Atmospheric Administration, Boulder, CO 80305; [b]Cooperative Institute for Research in Environmental Sciences, University of Colorado, Boulder, CO 80305; [c]Department of Physics and Astronomy, Uppsala University, 752 37 Uppsala, Sweden; [d]Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213; [e]Tepper School of Business, Carnegie Mellon University, Pittsburgh, PA 15213; [f]Center for Global Energy Policy, Columbia University, New York, NY 10027; [g]Department of Energy Resources Engineering, Stanford University, Stanford, CA 94305; [h]Department of Global Ecology, Carnegie Institution for Science, Stanford, CA 94305; [i]Department of Earth System Science, University of California, Irvine, CA 92697; [j]Omni Optimum, Evergreen, CO 80437; [k]Enduring Energy, LLC, Boulder, CO 80303; [l]Electrical Engineering and Complex Systems Center, University of Vermont, Burlington, VT 05405; [m]Energy and Resources Group, University of California, Berkeley, CA 94720; [n]Goldman School of Public Policy, University of California, Berkeley, CA 94720; [o]Renewable and Appropriate Energy Laboratory, University of California, Berkeley, CA 94720-3050; [p]Lawrence Livermore National Laboratory, Livermore, CA 94550; [q]Renewable and Sustainable Energy Institute, University of Colorado, Boulder, CO 80305; [r]Council on Foreign Relations, New York, NY 10065; [s]Precourt Energy Efficiency Center, Stanford University, Stanford, CA 94305-4206; [t]Management Science and Engineering Department, Huang Engineering Center, Stanford University, Stanford, CA 94305; [u]Department of Mechanical and Aerospace Engineering, Jacobs School of Engineering, University of California, San Diego, La Jolla, CA 92093; [v]School of Global Policy and Strategy, University of California, San Diego, La Jolla, CA 92093; and [w]Brookings Institution, Washington, DC 20036

A number of analyses, meta-analyses, and assessments, including those performed by the Intergovernmental Panel on Climate Change, the National Oceanic and Atmospheric Administration, the National Renewable Energy Laboratory, and the International Energy Agency, have concluded that deployment of a diverse portfolio of clean energy technologies makes a transition to a low-carbon-emission energy system both more feasible and less costly than other pathways. In contrast, Jacobson et al. [Jacobson MZ, Delucchi MA, Cameron MA, Frew BA (2015) Proc Natl Acad Sci USA 112(49):15060–15065] argue that it is feasible to provide "low-cost solutions to the grid reliability problem with 100% penetration of WWS [wind, water and solar power] across all energy sectors in the continental United States between 2050 and 2055", with only electricity and hydrogen as energy carriers. In this paper, we evaluate that study and find significant shortcomings in the analysis. In particular, we point out that this work used invalid modeling tools, contained modeling errors, and made implausible and inadequately supported assumptions. Policy makers should treat with caution any visions of a rapid, reliable, and low-cost transition to entire energy systems that relies almost exclusively on wind, solar, and hydroelectric power.

energy systems modeling | climate change | renewable energy | energy costs | grid stability

A number of studies, including a study by one of us, have concluded that an 80% decarbonization of the US electric grid could be achieved at reasonable cost (1, 2). The high level of decarbonization is facilitated by an optimally configured continental high-voltage transmission network. There seems to be some consensus that substantial amounts of greenhouse gas (GHG) emissions could be avoided with widespread deployment of solar and wind electric generation technologies along with supporting infrastructure.

Furthermore, it is not in question that it would be theoretically possible to build a reliable energy system excluding all bioenergy, nuclear energy, and fossil fuel sources. Given unlimited resources to build variable energy production facilities, while expanding the transmission grid and accompanying energy storage capacity enormously, one would eventually be able to meet any conceivable load. However, in developing a strategy to effectively mitigate global energy-related CO_2 emissions, it is critical that the scope of the challenge to achieve this in the real world is accurately defined and clearly communicated.

Wind and solar are variable energy sources, and some way must be found to address the issue of how to provide energy if their immediate output cannot continuously meet instantaneous demand. The main options are to (*i*) curtail load (i.e., modify or fail to satisfy demand) at times when energy is not available, (*ii*) deploy very large amounts of energy storage, or (*iii*) provide supplemental energy sources that can be dispatched when needed. It is not yet clear how much it is possible to curtail loads, especially over long durations, without incurring large economic costs. There are no electric storage systems available today that can

Significance

Previous analyses have found that the most feasible route to a low-carbon energy future is one that adopts a diverse portfolio of technologies. In contrast, Jacobson et al. (2015) consider whether the future primary energy sources for the United States could be narrowed to almost exclusively wind, solar, and hydroelectric power and suggest that this can be done at "low-cost" in a way that supplies all power with a probability of loss of load "that exceeds electric-utility-industry standards for reliability". We find that their analysis involves errors, inappropriate methods, and implausible assumptions. Their study does not provide credible evidence for rejecting the conclusions of previous analyses that point to the benefits of considering a broad portfolio of energy system options. A policy prescription that overpromises on the benefits of relying on a narrower portfolio of technologies options could be counterproductive, seriously impeding the move to a cost effective decarbonized energy system.

affordably and dependably store the vast amounts of energy needed over weeks to reliably satisfy demand using expanded wind and solar power generation alone. These facts have led many US and global energy system analyses (1–10) to recognize the importance of a broad portfolio of electricity generation technologies, including sources that can be dispatched when needed.

Faults with the Jacobson et al. Analyses

Jacobson et al. (11) along with additional colleagues in a companion article (12) attempt to show the feasibility of supplying all energy end uses (in the continental United States) with almost exclusively wind, water, and solar (WWS) power (no coal, natural gas, bioenergy, or nuclear power), while meeting all loads, at reasonable cost. Ref. 11 does include 1.5% generation from geothermal, tidal, and wave energy. Throughout the remainder of the paper, we denote the scenarios in ref. 11 as 100% wind, solar, and hydroelectric power for simplicity. Such a scenario may be a useful way to explore the hypothesis that it is possible to meet the challenges associated with reliably supplying energy across all sectors almost exclusively with large quantities of a narrow range of variable energy resources. However, there is a difference between presenting such visions as thought experiments and asserting, as the authors do, that rapid and complete conversion to an almost 100% wind, solar, and hydroelectric power system is feasible with little downside (12). It is important to understand the distinction between physical possibility and feasibility in the real world. To be clear, the specific aim of the work by Jacobson et al. (11) is to provide "low-cost solutions to the grid reliability problem with 100% penetration of WWS [wind, water and solar power] across all energy sectors in the continental United States between 2050 and 2055."

Relying on 100% wind, solar, and hydroelectric power could make climate mitigation more difficult and more expensive than it needs to be. For example, the analyses by Jacobson et al. (11, 12) exclude from consideration several commercially available technologies, such as nuclear and bioenergy, that could potentially contribute to decarbonization of the global energy system, while also helping assure high levels of reliability in the power grid. Furthermore, Jacobson et al. (11, 12) exclude carbon capture and storage technologies for fossil fuel generation. An additional option not considered in the 100% wind, solar, and hydroelectric studies is bioenergy coupled with carbon capture and storage to create negative emissions within the system, which could help with emissions targets. With all available technologies at our disposal, achieving an 80% reduction in GHG emissions from the electricity sector at reasonable costs is extremely challenging, even using a new continental-scale high-voltage trans-

mission grid. Decarbonizing the last 20% of the electricity sector as well as decarbonizing the rest of the economy that is difficult to electrify (e.g., cement manufacture and aviation) are even more challenging. These challenges are deepened by placing constraints on technological options.

In our view, to show that a proposed energy system is technically and economically feasible, a study must, at a minimum, show, through transparent inputs, outputs, analysis, and validated modeling (13), that the required technologies have been commercially proven at scale at a cost comparable with alternatives; that the technologies can, at scale, provide adequate and reliable energy; that the deployment rate required of such technologies and their associated infrastructure is plausible and commensurate with other historical examples in the energy sector; and that the deployment and operation of the technologies do not violate environmental regulations. We show that refs. 11 and 12 do not meet these criteria and, accordingly, do not show the technical, practical, or economic feasibility of a 100% wind, solar, and hydroelectric energy vision. As we detail below and in *SI Appendix*, ref. 11 contains modeling errors; incorrect, implausible, and/or inadequately supported assumptions; and the application of methods inappropriate to the task. In short, the analysis performed in ref. 11 does not support the claim that such a system would perform at reasonable cost and provide reliable power.

The vision proposed by the studies in refs. 11 and 12 narrows generation options but includes a wide range of currently uncosted innovations that would have to be deployed at large scale (e.g., replacement of our current aviation system with yet-to-be-developed hydrogen-powered planes). The system in ref. 11 assumes the availability of multiweek energy storage systems that are not yet proven at scale and deploys them at a capacity twice that of the entire United States' generating and storage capacity today. There would be underground thermal energy storage (UTES) systems deployed in nearly every community to provide services for every home, business, office building, hospital, school, and factory in the United States. However, the analysis does not include an accounting of the costs of the physical infrastructure (pipes and distribution lines) to support these systems. An analysis of district heating (14) showed that having existing infrastructure is key to effective deployment, because the high upfront costs of the infrastructure are prohibitive.

It is not difficult to match instantaneous energy demands for all purposes with variable electricity generation sources in real time as needed to assure reliable power supply if one assumes, as the authors of the ref. 11 do, that there exists a nationally integrated grid, that most loads can be flexibly shifted in time, that large amounts of multiweek and seasonal energy storage will be readily available at low cost, and that the entire economy can easily be electrified or made to use hydrogen. However, adequate support for the validity of these assumptions is lacking. Furthermore, the conclusions in ref. 11 rely heavily on free, nonmodeled hydroelectric capacity expansion (adding turbines that are unlikely to be feasible without major reconstruction of existing facilities) at current reservoirs without consideration of hydrological constraints or the need for additional supporting infrastructure (penstocks, tunnels, and space); massive scale-up of hydrogen production and use; unconstrained, nonmodeled transmission expansion with only rough cost estimates; and free time-shifting of loads at large scale in response to variable energy provision. None of these are going to be achieved without cost. Some assumed expansions, such as the hydroelectric power output, imply operating facilities way beyond existing constraints that have been established for important environmental reasons. Without these elements, the costs of the energy system in ref. 11 would be substantially higher than claimed.

In evaluating the 100% wind, solar, and hydroelectric power system (11), we focus on four major issues that are explored in

more detail below and in *SI Appendix*. (*i*) We note several modeling errors presented in ref. 11 that invalidate the results in the studies, particularly with respect to the amount of hydropower available and the demand response of flexible loads (*SI Appendix, section S1*). (*ii*) We examine poorly documented and implausible assumptions, including the cost and scalability of storage technologies, the use of hydrogen fuels, lifecycle assessments of technologies, cost of capital and capacity factors of existing technologies, and land use (*SI Appendix, section S2*). (*iii*) We discuss the studies' lack of electric power system modeling of transmission, reserve margins, and frequency response, despite claims of system reliability (*SI Appendix, section S3*). (*iv*) Finally, we argue that the climate/weather model used for estimates of wind and solar energy production has not shown the ability to accurately simulate wind speeds or solar insolation at the scales needed to assure the technical reliability of an energy system relying so heavily on intermittent energy sources (*SI Appendix, section S4*).

Modeling Errors

As we detail in *SI Appendix, section S1*, ref. 11 includes several modeling mistakes that call into question the conclusions of the study. For example, the numbers given in the supporting information of ref. 11 imply that maximum output from hydroelectric facilities cannot exceed 145.26 GW (*SI Appendix, section S1.1*), about 50% more than exists in the United States today (15), but figure 4B of ref. 11 (Fig. 1) shows hydroelectric output exceeding 1,300 GW. Similarly, as detailed in *SI Appendix, section S1.2*, the total amount of load labeled as flexible in the figures of ref. 11 is much greater than the amount of flexible load represented in their supporting tabular data. In fact, the flexible load used by LOAD-MATCH is more than double the maximum possible value from table 1 of ref. 11. The maximum possible from table 1 of ref. 11 is given as 1,064.16 GW, whereas figure 3 of ref. 11 shows that flexible load (in green) used up to 1,944 GW (on day 912.6). Indeed, in all of the figures in ref. 11 that show flexible load, the restrictions enumerated in table 1 of ref. 11 are not satisfied.

In the analysis in ref. 11, the flexible loads can be accumulated in 8-h blocks, which raises a serious issue of extreme excess industrial/commercial/residential capacity to use the high power for short periods of time. Under these assumptions, there would need to be oversized facilities on both the demand and generation sides to compensate for their respective variabilities. These errors are critical, because the conclusions reached in ref. 11 depend on the availability of large amounts of dispatchable energy and a large degree of flexibility in demand. Ref. 11 also includes a scenario where zero demand response is allowed, and it shows that there is almost no cost changes and that the grid is still stable. Thus, there can be no cost associated with demand response (on either the supply or the consumption side); otherwise, there would be substantial changes in final costs caused by the complete reconfiguring of the US economy schedule.

Implausible Assumptions

The conclusions contained in ref. 11 rely on a number of unproven technologies and poorly substantiated assumptions as detailed in *SI Appendix, section S2*. In summary, the reliability of the proposed 100% wind, solar, and hydroelectric power system depends centrally on a large installed capacity of several different energy storage systems (11), collectively allowing their model to flexibly reshape energy demand to match the output of variable electricity generation technologies. The study (11) assumes a total of 2,604 GW[4] of storage charging capacity, more than double the entire current capacity of all power plants in the United States (16). The energy storage capacity consists almost entirely of two technologies that remain unproven at any scale: 514.6 TWh of UTES (the largest UTES facility today is 0.0041 TWh) (additional discussion is in *SI Appendix, section S2.1*) and 13.26 TWh of phase change materials (PCMs; effectively in research and demonstration phase) (additional discussion is in *SI Appendix, section S2.2*) coupled to concentrating solar thermal power (CSP). To give an idea of scale, the 100% wind, solar, and hydroelectric power system proposed in ref. 11 envisions UTES systems deployed in nearly every community for nearly every home, business, office building, hospital, school, and factory in the United States, although only a handful exist today.

Although both PCM and UTES are promising resources, neither technology has reached the level of technological maturity to be confidently used as the main underpinning technology in a study aiming to show the technical reliability and feasibility of an energy system. The relative immaturity of these technologies cannot be reconciled with the authors' assertion that the solutions proposed in ref. 11 and companion papers are ready to be implemented today at scale at low cost and that there are no technological or economical hurdles to the proposed system.[5]

The 100% wind, solar, and hydroelectric power system study (11) also makes unsupported assumptions about widespread adoption of hydrogen as an energy carrier, including the conversion of the aviation and steel industries to hydrogen and the ability to store in hydrogen an amount of energy equivalent to more than 1 month of current US electricity consumption. Furthermore, in figure S6 of ref. 11, hydrogen is being produced at a peak rate consuming nearly 2,000 GW of electricity, nearly twice the current US electricity-generating capacity. As detailed in *SI Appendix, section S2.3*, the costs and feasibility of this transition to a hydrogen economy are not appropriately accounted for by ref. 11. To show the scale of the additional capacities that are demanded in refs. 11 and 12, we plot them along with the electricity generation capacity in 2015 in Fig. 2. The data used for Fig. 2 can be found in Datasets S1 and S2.

Refs. 11 and 12 cite each other about the values of capacity. For example, ref. 12, which supposedly includes information for all 50 states, reports table S2 in ref. 11 as the source of the numbers. Then, ref. 11, which only includes information for the capacity in the 48 contiguous states, cites table 2 in ref. 12 as the source of the values. The values in the two papers do not agree, presumably because of the difference in the number of states included, and therefore, it is unclear how each reference can be the source of the values for the other one. Additionally, ref. 11 assumes that 63% of all energy-intensive industrial demand is
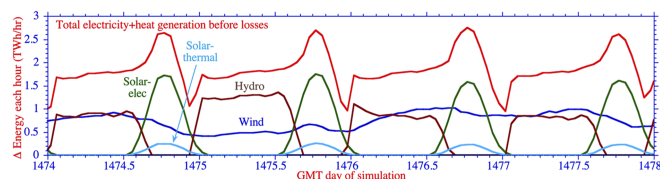

Fig. 1. This figure (figure 4B from ref. 11) shows hydropower supply rates peaking at nearly 1,300 GW, despite the fact that the proposal calls for less than 150 GW hydropower capacity. This discrepancy indicates a major error in their analysis. Modified from ref. 11.

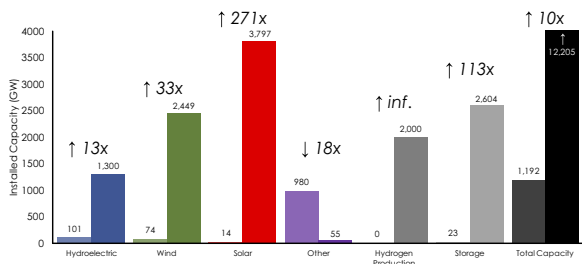SUSTAINABILITY SCIENCE

ENVIRONMENTAL SCIENCES

Fig. 2. Installed capacity values for 2015 (left column in each pair) and those used in the studies in refs. 11 and 12 (right column in each pair). These 100% wind, solar, and hydroelectric studies propose installing technologies at a scale equivalent to (or substantially greater than) the entire capacity of the existing electricity generation infrastructure. The other category includes coal, natural gas, and nuclear, all of which are removed by 2050.

flexible: able to reschedule all energy inputs within an 8-h window. As discussed in *SI Appendix,* section S2.4, and the National Research Council's "Real Prospects for Energy Efficiency in the United States," (17) it is infeasible for many industrial energy demands to be rapidly curtailed.

Similarly, ref. 11 assumes that the capacity factor (i.e., actual electricity generation divided by the theoretically maximum potential generation obtained by operating continuously at full nameplate capacity) for existing energy technologies will increase dramatically in the future. As described in *SI Appendix,* section S2.5, the authors of ref. 11 anticipate that individual hydropower facilities will increase generation by over 30%. They explain this by saying, "[i]ncreasing the capacity factor is feasible because existing dams currently provide much less than their maximum capacity, primarily due to an oversupply of energy available from fossil fuel sources, resulting in less demand for hydroelectricity" (12). From ref. 12, it is stated that hydroelectric and geothermal capacity factors increase, because "[f]or geothermal and hydropower, which are less variable on short time scales than wind and solar, the capacity-factor multipliers in our analysis are slightly greater than 100% on account of these being used more steadily in a 100% WWS system than in the base year." In addition to being inconsistent with their statement that hydropower is "used only as a last resort" (11), this explanation shows a fundamental misunderstanding of the operation of electricity markets and the factors determining hydroelectric supply. With near-zero marginal costs (free "fuel"), hydroelectric generators will essentially run whenever they are available; in those instances where they participate in merchant markets, they underbid fossil generators that must at least recover their coal or natural gas costs. The primary factor limiting hydroelectric capacity factor is water supply and environmental constraints, not lack of demand. Furthermore, there seems to be a mistake with the hydroelectric capacity factor adjustment: from EIA, it should only go up to 42%, not 52.5%.[6]

To illustrate the implausibility of the assumed increase in hydroelectric net generation (dispatched from the plants to the electricity grid) in the face of limited water supply, we plot in Fig. 3 the last 25 y of generation from hydropower in the United States along with the average for the studies in refs. 11 and 12. The data used for Fig. 3 can be found in Datasets S1 and S2. Average future generation assumed by refs. 11 and 12 is 13% higher than the highest peak year in the last 25 y and 85% higher than the minimum year in the last 25 y. Therefore, in addition to needing 1,300 GW of peak power from 150 GW of capacity, there also needs to be an extra 120 TWh of hydroelectric gener-

ation on top of the 280 TWh available. Additional difficulties in raising hydropower capacity factors are described in *SI Appendix,* section S2.5.

Most of the technologies considered in ref. 11 have high capital costs but relatively low operating costs. As a result, the cost of capital is a primary cost driver in the vision contained in ref. 11. As discussed in *SI Appendix,* section S2.7, the baseline value for cost of capital in ref. 11 is one-half to one-third of that used by most other studies. The 100% wind, solar, and hydroelectric energy system studies (11, 12) provide little evidence that the low cost of capital assumed in their study could be obtained by real investors in the capital markets. Using more realistic discount rates of 6–9% per year instead of the 3–4.5% used in ref. 11 could double the estimate of a cost of 11 cents/kWh of electricity to 22 cents/kWh, even before adding in the unaccounted for capital costs described above. One possible explanation of the lower discount rates used could be that they forecast lower (or negative) growth in domestic product. In the case of lower growth, there would likely be lower interest rates; however, that lower growth may also lead to lower energy demand and investment.

One of the global leaders of solar PV and wind energy installation in recent years is Germany, which through its "Energiewende," is attempting to shift toward an 80% renewables energy system. Germany, therefore, presents a suitable example against which to benchmark the feasibility of the plan set out in ref. 11 for the United States. In *SI Appendix,* section S2.8, we describe how ref. 11 assumes that the United States will build out new solar, wind, and hydroelectric facilities at a sustained rate that, on a per-unit gross domestic product basis, is 16 times greater than the average deployment rate in Germany's Energiewende initiative during the years 2007–2014 and over 6 times greater than Germany achieved in the peak year of 2011 (*SI Appendix,* Fig. S4).

In Fig. 4, we display another metric on the scale of expansion. It shows the rate of installation as watts per year per capita. Using this metric, we can compare the scale of capacity expansion in ref. 11 with historical data. Fig. 4 shows that the plans proposed in refs. 11 and 12 would require a sustained installation rate that is over 14 times the US average over the last 55 y and over 6 times the peak rate. For the sake of comparison, Fig. 4 includes the estimated rate for a solution that decarbonizes the US electric grid by 78% by 2030 (1), historical German data, and historical Chinese data. We note that ref. 1 considered large-scale storage but excluded it based on preliminary results showing that it was not cost-effective compared with a national transmission system. The data used for Fig. 4 can be found in Datasets S1 and S2. Sustaining public support for this scale of investment (and this scale of deployment of new wind turbines, power lines, etc.) could prove challenging. One of the reasons that this buildout may prove difficult is that the 100%
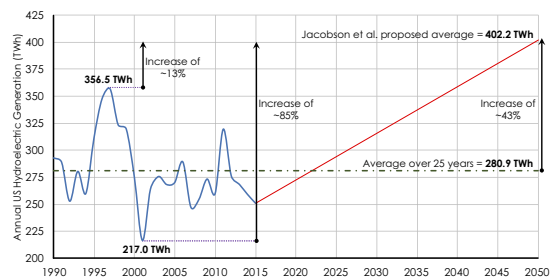
Fig. 3. Historical and proposed hydroelectric generation per year. The historical data (www.eia.gov/todayinenergy/detail.php?id=2650) show generation averaging 280.9 TWh/yr; generation proposed in ref. 11 is 402.2 TWh, 13% higher than the 25-y historical maximum of 356.5 TWh (1997) and 85% higher than the historical minimum of 217 TWh (2001).

---

[6]Excel spreadsheets from refs. 11 and 12, Tab EIA capacity factors 2011–2075 are at web.stanford.edu/group/efmh/jacobson/Articles/I/USStates.xlsx.

Clack et al.
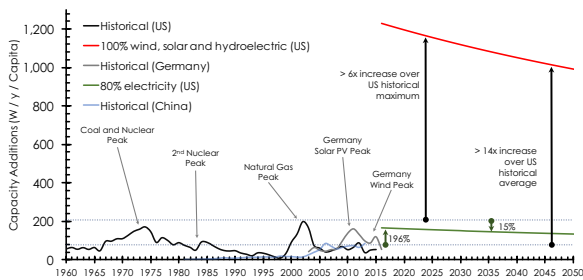
Fig. 4. The historical rates of installed electric-generating capacity per capita (watts per year per capita) for China (blue), Germany (gray), and the United States (black) are shown with the estimated values for the US proposals from the works by Jacobson et al. (11, 12) (red) and MacDonald et al. (1) (green). It shows that the 100% wind, solar, and hydropower power plan requires installation of new capacity at a rate more than an order of magnitude greater than that previously recorded in China, Germany, or the United States. The rate would have to be continued indefinitely because of replacing generation as it aged.

wind, solar, and hydroelectric system relies on energy sources with relatively low areal power density (additional details are in *SI Appendix,* section S2.9). According to NREL, average power density achieved in land-based wind farms is about 3 W/m^2, with a range of 1–11.2 W/m^2 (although at larger deployment scales, power densities would likely be lower) (18). At the average power densities, the scale of wind power envisioned in ref. 11 would require nearly 500,000 km^2 (134,000–1,500,000 km^2), which is roughly 6% of the continental United States and >1,500 m^2 of land for wind turbines for each American. Much of this land could be dual use, but the challenges associated with this level of scale-up should not be underestimated. The proposed transition in ref. 11 requires unprecedented rates of technology deployment. For example, increased pressure on materials, elevated commodity prices, and high demand for wind power installations produced elevated prices for wind power deployment between 2002 and 2008 (19, 20).

The rejection of many potential sources of low-carbon emission energy is based on an analysis presented by Jacobson in ref. 21. A full discussion of that paper is beyond the scope of our evaluation. However, one flaw is its failure to use other numbers already published in detailed studies on lifecycle GHG emissions, land use requirements, and human mortality of energy production technologies. Rather than using the results of the many detailed studies available from large international bodies, such as those surveyed by the Intergovernmental Panel on Climate Change, ref. 20 presents assessments that, in many cases, differ in method and granularity to produce results that differ markedly from those generally accepted in scientific and technical communities.

Selective assessments of lifecycle emissions can be used to favor or disfavor specific technologies. As an example, the lifecycle GHG emissions for nuclear power generation in ref. 21 include the emissions of the background fossil-based power system during an assumed planning and construction period for up to 19 y per nuclear plant.[7] Added to these emissions, the effects of a nuclear war, which is assumed to periodically reoccur on a 30-y cycle, are included in the analysis of emissions and mortality of civilian nuclear power.[8] In contrast, those same authors do not consider emissions for the fossil-based power system associated with construction and permitting delays for offshore

wind farms (or the transmission infrastructure needed to connect these farms), which have already been a challenge in the development of US offshore wind resources. Although there is extensive experience outside of the United States with developing offshore wind resources, very few offshore wind facilities have been permitted in US territorial waters. The 100% wind, solar, and hydroelectric power system (11) envisions more than 150,000 5-MW turbines permitted and built offshore without delays.

Insufficient Power System Modeling

The study of a 100% wind, solar, and hydroelectric power system (11) purports to report the results of a "grid integration model." It is important to understand the limitations of the study with regard to what is usually meant by grid integration. Reliable operation of the grid involves myriad challenges beyond just matching total generation to total load. Its role in cascading failures and blackouts illustrates the important role of the transmission system (22). Reliable grid operation is further complicated by its ac nature, with real and reactive power flows and the need to closely maintain a constant frequency (23). Margins for generator failures must be provided through operational and planning reserves (24). The solution proposed by refs. 11 and 12 involves fundamental shifts in aspects of grid architecture that are critical to reliable operation. Wind generation, largely located far from load centers, will require new transmission. Solar generation and onsite storage connected to the distribution grid replace capability currently connected to the more centralized transmission grid. Rotating machines with substantial inertia that is critical for frequency stability are supplanted by asynchronous wind and solar generators.

Although a grid integration study is detailed and complex, the grid model of ref. 11 is spatially 0D; all loads, generation (sited before the LOADMATCH runs and placed precisely where existing generation resides), and storage are summed in a single place. Therefore, those authors do not perform any modeling or analysis of transmission. As a result, their analysis ignores transmission capacity expansion, power flow, and the logistics of transmission constraints (*SI Appendix,* section S2.6). Similarly, those authors do not account for operating reserves, a fundamental constraint necessary for the electric grid. Indeed, LOADMATCH used in ref. 11 is a simplified representation of electric power system operations that does not capture requirements for frequency regulation to ensure operating reliability (additional details are in *SI Appendix,* section S3).

Furthermore, the model is fully deterministic, implying perfect foresight about the electricity demand and the variability of wind and solar energy resources and neglecting the effect of forecast errors on reserve requirements (25). In a system where variable renewable resources make up over 95% of the US energy supply, renewable energy forecast errors would be a significant source of uncertainty in the daily operation of power systems. The LOADMATCH model does not show the technical ability of the proposed system from ref. 11 to operate reliably given the magnitude of the architectural changes to the grid and the degree of uncertainty imposed by renewable resources.

Inadequate Scrutiny of Input Climate Model

The climate model used to generate weather data in the work in ref. 11 has never been adequately evaluated. For example, results from this model have not been made available to the Climate Model Intercomparison Project (26) or opened to public inspection in ways similar to the results of major reanalysis projects (27). As detailed in *SI Appendix,* section S4, the fragmentary results that have been made available show poor correlation with reality in terms of resolution and accuracy. Because the conclusions from ref. 11 depend on the weather data used, their conclusions cannot be considered to be adequate without an appropriate evaluation of the weather data used.

---

[7]The five sources cited in ref. 12 give construction time estimates of 5–8 y.

[8]In the almost 60 y of civilian nuclear power (two of the assumed war cycles), there have been no nuclear exchanges. The existence of nuclear weapons does not depend on civil power production from uranium.

Conclusions

Many previous studies of deep decarbonization of electric power illustrate that much can be done with wind and solar power but that it is extremely difficult to achieve complete decarbonization of the energy system, even when using every current technology and tool available, including energy efficiency and wind, hydroelectric, and solar energy as well as carbon capture and storage, bioenergy, and nuclear energy (1–6, 8–10). In contrast, ref. 11 asserts that it is cost-effective to fully decarbonize the US energy system primarily using just three inherently variable generating technologies: solar PV, solar CSP, and wind, to supply more than 95% of total energy in the proposal presented in ref. 11. Such an extraordinarily constrained conclusion demands a standard of proof that ref. 11 does not meet.

The scenarios of ref. 11 can, at best, be described as a poorly executed exploration of an interesting hypothesis. The study's numerous shortcomings and errors render it unreliable as a guide about the likely cost, technical reliability, or feasibility of a 100% wind, solar, and hydroelectric power system. It is one thing to explore the potential use of technologies in a clearly caveated hypothetical analysis; it is quite another to claim that a model using these technologies at an unprecedented scale conclusively shows the feasibility and reliability of the modeled energy system implemented by midcentury.

From the information given by ref. 11, it is clear that both hydroelectric power and flexible load have been modeled in erroneous ways and that these errors alone invalidate the study and its results. The study of 100% wind, solar, and hydroelectric power systems (11) extrapolates from a few small-scale installations of relatively immature energy storage technologies to assume ubiquitous adoption of high-temperature PCMs for storage at concentrating solar power plants; UTES for heating, cooling, and refrigeration for almost every building in the United States; and widespread use of hydrogen to fuel airplanes, rail, shipping, and most energy-intensive industrial processes. For the critical variable characteristics of wind and solar resources, the study in ref. 11 relies on a climate model that has not been independently scrutinized.

The authors of ref. 11 claim to have shown that their proposed system would be low cost and that there are no economic barriers to the implementation of their vision (12). However, the modeling errors described above, the speculative nature of the terawatt-scale storage technologies envisioned, the theoretical nature of the solutions proposed to handle critical stability aspects of the system, and a number of unsupported assumptions, including a cost of capital that is one-third to one-half lower than that used in practice in the real world, undermine that claim. Their LOADMATCH model does not consider aspects of transmission power flow, operating reserves, or frequency regulation that would typically be represented in a grid model aimed at assessing reliability. Furthermore, as detailed above and in *SI Appendix*, a large number of costs and barriers have not been considered in ref. 11.

Many researchers have been examining energy system transitions for a long time. Previous detailed studies have generally found that energy system transitions are extremely difficult and that a broad portfolio of technological options eases that transition. If one reaches a new conclusion by not addressing factors considered by others, making a large set of unsupported assumptions, using simpler models that do not consider important features, and then performing an analysis that contains critical mistakes, the anomalous conclusion cannot be heralded as a new discovery. The conclusions reached by the study contained in ref. 11 about the performance and cost of a system of "100% penetration of intermittent wind, water and solar for all purposes" are not supported by adequate and realistic analysis and do not provide a reliable guide to whether and at what cost such a transition might be achieved. In contrast, the weight of the evidence suggests that a broad portfolio of energy options will help facilitate an affordable transition to a near-zero emission energy system.

SI Appendix

SI Appendix contains the details of this evaluation. Datasets S1 and S2 contain data and calculations used to produce the figures. Within the spreadsheet are the data sources and collation of data.

1. MacDonald AE, Clack CTM, Alexander A, Dunbar A, Wilczak J, Xie Y (2016) Future cost-competitive electricity systems and their impact on US CO₂ emissions. *Nat Clim Chang* 6:526–531.
2. NREL (2012) *Renewable Electricity Futures Study* (National Renewable Energy Laboratory, Golden, CO), Tech Rep NREL/TP-6A20-52409.
3. Deep Decarbonization Pathways Project (2015) *Pathways to Deep Decarbonization* (Sustainable Development Solutions Network and Institute for Sustainable Development and International Relations, Paris).
4. Fawcett AA, Clarke LE, Weyant JP, eds, The EMF24 study on U.S. technology and climate policy strategies. *The Energy Journal*. Available at https://web.stanford.edu/group/emf-research/docs/emf24/EMF_24.pdf. Accessed June 1, 2017.
5. Krey V, Luderer G, Clarke L, Kriegler E (2014) Getting from here to there – energy technology transformation pathways in the EMF27 scenarios. *Clim Change* 123:369–382.
6. Williams JH, et al. (2012) The technology path to deep greenhouse gas emissions cuts by 2050: The pivotal role of electricity. *Science* 335:53–59.
7. Mileva A, Johnston J, Nelson JH, Kammen DM (2016) Power system balancing for deep decarbonization of the electricity sector. *Appl Energy* 162:1001–1009.
8. IEA (2015) *Energy Technology Perspectives 2015*: Mobilising innovation to accelerate climate action (International Energy Agency, Paris).
9. Energy and Research Partnership (2015) *Managing Flexibility Whilst Decarbonising the GB Electricity System* (Energy Research Partnership, London).
10. IPCC (2014) *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, eds Pachauri RK, Meyer LA (IPCC, Geneva).
11. Jacobson MZ, Delucchi MA, Cameron MA, Frew BA (2015) Low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes. *Proc Natl Acad Sci USA* 112:15060–15065.
12. Jacobson MZ, et al. (2015) 100% clean and renewable wind, water, and sunlight (WWS) all-sector energy roadmaps for the 50 United States. *Energy Environ Sci* 8:2093–2117.
13. Pfenninger S, DeCarolis J, Hirth L, Quoilin S, Staffell I (2017) The importance of open data and software: Is energy research lagging behind? *Energ Policy* 101:211–215.
14. Reed A, McCartney JS (2015) The sun also rises: Prospects for solar district heating in the United States. *Albany Law J Sci Technol* 25:165–211.
15. EIA (2014) *Electric Power Annual* (US Energy Information Administration, Washington, DC), Table 4.3.
16. Blackwell R (2016) Can the world convert to total renewable energy by 2050? *The Globe and Mail*. Available at https://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/can-the-world-convert-to-total-renewable-energy-by-2050/article27989205/. Accessed June 1, 2017.
17. National Academy of Sciences, National Academy of Engineering, and National Research Council (2010) *Real Prospects for Energy Efficiency in the United States* (National Academies Press, Washington, DC).
18. Denholm P, Hand M, Jackson M, Ong S (2009) *Land-Use Requirements of Modern Wind Power Plants in the United States* (National Renewable Energy Laboratory, Golden, CO), Tech Rep NREL/TP-6A2-45834.
19. Blanco MI (2009) The economics of wind energy. *Renew Sustain Energ Rev* 13:1372–1382.
20. Bolinger M, Wiser R (2011) *Understanding Trends in Wind Turbine Prices Over the Past Decade* (Lawrence Berkeley National Laboratory, Berkeley, CA), Rep LBNL-5119E.
21. Jacobson MZ (2009) Review of solutions to global warming, air pollution, and energy security. *Energy Environ Sci* 2:148–173.
22. Dobson I, Carreras BA, Lynch VE, Newman DE (2007) Complex systems analysis of series of blackouts: Cascading failure, critical points, and self-organization. *Chaos* 17:026103.
23. Backhaus S, Chertkov M (2013) Getting a grip on the electrical grid. *Phys Today* 66:42–48.
24. Hirst E, Kirby B (1996) *Electric-Power Ancillary Services* (Oak Ridge National Laboratory, Oak Ridge, TN), Tech Rep ORNL/CON-426.
25. Mauch B, Apt J, Carvalho PMS, Jaramillo P (2013) What day-ahead reserves are needed in electric grids with high levels of wind power?. *Environ Res Lett* 8:034013.
26. Taylor KE, Stouffer RJ, Meehl GA (2012) An Overview of CMIP5 and the experiment design. *Bull Am Meteorol Soc* 93:485–498.
27. Dee D, Fasullo J, Shea D, Walsh J, NCAR Staff (2016) *The Climate Data Guide: Atmospheric Reanalysis: Overview & Comparison Tables* (National Center for Atmospheric Research, Boulder, CO). Available at https://climatedataguide.ucar.edu/climate-data/atmospheric-reanalysis-overview-comparison-tables. Accessed June 1, 2017.

Supporting Information for the paper "Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar"

Christopher T. M. Clack[1,2,3*], Staffan A. Qvist[4], Jay Apt[5,6], Morgan Bazilian[7], Adam Brandt[8], Ken Caldeira[9], Steven J. Davis[10], Victor Diakov[11], Mark Handschy[2,12], Paul Hines[13], Paulina Jaramillo[5], Daniel M. Kammen[14-16], Jane C. S. Long[17], M. Granger Morgan[5], Adam Reed[18], Varun Sivaram[19], James Sweeney[20,21], George R. Tynan[22], David G. Victor[23,24], John P. Weyant[20,21], and Jay F. Whitacre[5]

[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; [3]Now at Vibrant Clean Energy, LLC, Boulder, CO, USA; [4]Department of Physics and Astronomy, Uppsala University, Lagerhyddsvagen 1, Uppsala, Sweden; [5]Department of Engineering and Public Policy, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213, USA; [6]Tepper School of Business, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213, USA; [7]Center for Global Energy Policy, Columbia University, New York, NY, USA; [8]Department of Energy Resources Engineering, Stanford University, 367 Panama Street, Stanford, CA 94305, USA; [9]Department of Global Ecology, Carnegie Institution for Science, 260 Panama Street, Stanford, CA 94305, USA; [10]Department of Earth System Science, University of California, Irvine, Croul Hall, Irvine, CA 92697, USA; [11]Omni Optimum, Evergreen, Colorado, USA; [12]Enduring Energy, LLC, Boulder, CO, USA; [13]University of Vermont, Electrical Engineering and Complex Systems Center, Burlington, VT, 05405, USA; [14]Energy and Resources Group, University of California, 310 Barrows Hall, Berkeley, CA 94720 USA; [15]Goldman School of Public Policy, University of California, 2607 Hearst Ave, Berkeley, CA 94720, USA; [16]Renewable and Appropriate Energy Laboratory, University of California, 310 Barrows Hall, Berkeley, CA 94720-3050, USA; [17]Lawrence Livermore National Laboratory, Livermore, CA, USA (retired); [18]Renewable and Sustainable Energy Institute, University of Colorado, Boulder, Colorado 80305, USA; [19]Council on Foreign Relations, 58 E 68th St, New York, NY 10065, USA; [20]Precourt Energy Efficiency Center, Stanford University, 473 Via Ortega, Stanford, CA 94305-4206, USA; [21]Management Science and Engineering Department, Stanford University, Huang Engineering Center, 475 Via Ortega, Stanford, CA 94305, United States; [22]Department of Mechanical and Aerospace Engineering, Jacobs School of Engineering, UC San Diego, Voigt Drive, La Jolla, CA 92093, USA; [23]School of Global Policy & Strategy, UC San Diego, La Jolla, CA 92093, USA; [24]Brookings Institution, 1775 Massachusetts Ave, NW, Washington DC 20036

The following document contains the supporting information for the paper "Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar". In section S1, we examine important modeling errors that call into question the results in the studies. In section S2, we examine poorly documented and unsupported assumptions, including the cost and scalability of storage technologies and the use of hydrogen fuels, which underpin the energy system reliant on 100% wind, solar and hydroelectric power. In section S3, we focus on the studies' claims about the operational reliability of an electric power system, which are based on a model of load matching that does not fully capture the realistic operations of power systems. In section S4, we argue that the climate/weather model used for estimates of wind and solar energy production has not been sufficiently vetted and has not demonstrated the ability to accurately simulate wind speeds or solar insolation at the scales needed to assure the reliability of an energy system heavily reliant on variable energy sources.

www.pnas.org/cgi/doi/10.1073/pnas.XXXXXXXXXX

PNAS | **May 8, 2017** | vol. XXX | no. XX | **1–13**

S1: Modeling Errors

A primary concern with the analysis of ref. [11] is the presence of errors in the modeling of the proposed energy system. Errors arise with the treatment of hydroelectric output and also concern assumptions about the flexibility of major electricity loads. These errors are important because the flexibility of supply (notably hydropower) and demand are essential for understanding the reliability of electricity supply in an almost 100% wind, solar and hydroelectric power system (as with the main manuscript we shorten to 100% wind, solar and hydroelectric for simplicity).

S1.1: Hydroelectric Capacity. The analysis in ref. [11] relies on much more hydroelectric capacity than can reasonably be expected to be available. In ref. [11], the total installed hydroelectric power capacity in the U.S. system, as defined in Table S2 of its supporting information (SI), is 87.48 GW. In addition to this, Table S1 of its SI defines the maximum discharge rate for new pumped hydroelectric capacity (assuming that all of this is completely new capacity and not existing capacity with added pumping) to be 57.68 GW[1]. Thus, assuming that conventional hydroelectric generation and "pumped" hydroelectric power production capacity is separate, the total maximum theoretical output of all hydroelectric capacity postulated in ref. [11] is 145.16 GW.
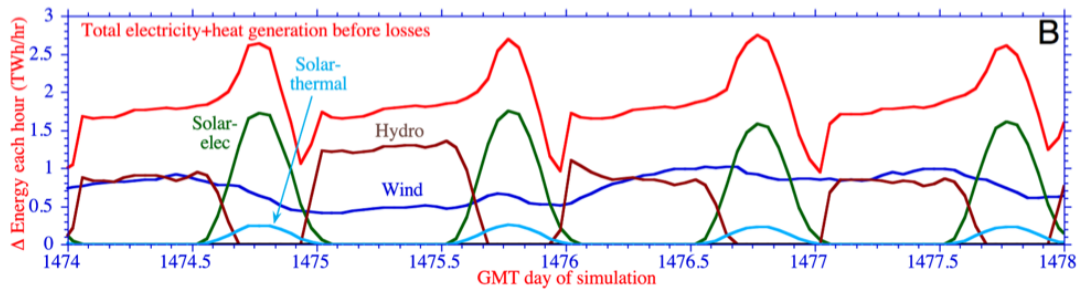

Fig. S1. Panel B of Figure 4 of ref. [11]

Figure S1 (which corresponds to Panel B of Figure 4 in ref. [11]), shows the power supplied by different sources in TWh/hr, which is effectively the average power for each hour in the unit of TW, for a period of four days in January of 2055. Readers of ref. [11] are given only a few snapshots of the modeling results, but as an example, for half of the simulated day of 15th of January 2055, hydropower is depicted as supplying ∼84% of total system load, averaging 1.3 TW (1,300 GW) over a period of 13 hours, or approximately 9 times the theoretical maximum instantaneous output of all installed conventional hydropower and pumped storage combined. It is not feasible for an installed hydropower capacity of 87.48 to 145.16 GW (depending on whether pumped hydro is included in these figures in the hydro output or in non-underground thermal energy storage output) to produce 1,300 GW for hours at a time. It is worth noting that 1,300 GW is more than the current combined generating capacity of all the U.S. power plants. Furthermore, this error is not limited to a single figure in ref. [11]. The hydroelectric production profiles depicted throughout the dispatch figures reported in both the paper and its supplemental information routinely show hydroelectric output far exceeding the maximum installed capacity as well. Both Figures S4 and S5 of its SI, for example, depict hydroelectric generation rates exceeding 700 GW. This error is so substantial that we hope there is another explanation for the large amounts of hydropower output depicted in these figures. In [12] the authors state that "We constrain hydropower to existing capacity in each state except in the case of Alaska." Then in [11] the authors state values from [12] are used.

One possible explanation for the errors in the hydroelectric modeling is that the authors assumed they could build capacity in hydroelectric plants for free within the LOADMATCH model. If this were the case then, using their values from Table S2 [11] ($2,820 / kW), we estimate that the cost for 1,200 GW extra capacity would be $3.38 trillion. Table 2 from [11] states total cost for new generators would be $13.9 trillion. Therefore, the additional cost of the hydroelectric power plants would be an additional 24% of the cost of the entire 100% wind, solar and hydroelectric power system. Furthermore, in ref. [12] the authors state that "we do however assume that nationally most good hydropower sites already have been developed." So presumably new sites are necessary. The hydroelectric power plants that exist today do not have the space required to expand their capacity by 10-15 times. Indeed, the extra piping needed to supply water to these turbines would cause considerable engineering issues due to the age of the plants and the river flows. A report from IRENA[2] shows that around the world the average cost of hydroelectric is $3,500 / kW (see Fig 4.5 the IRENA report); of that cost, $911 / kW is for the reservoir. If the

---

[1] It is stated in ref. [11] that "PHS is limited to its present penetration plus preliminary and pending permits as of 2015". According to current Federal Energy Regulatory Commission (FERC) data [27], the total sum of pending and preliminary permits for PHS in the U.S. is 26.99 GW, and the existing capacity in PHS is 21.6 GW [28], which gives the actual total potential PHS according to the definition of ref. [11] as 48.59 GW, or 9.1 GW less than what is assumed in ref. [11]. FERC data for ref. [11] was accessed in December 2014, while FERC data from October 2015 was accessed for this evaluation, which means a change in the FERC data may be a source for this discrepancy.

[2] IRENA report found here: http://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf

---

[*] To whom correspondence should be addressed. E-mail: christopher@vibrantcleanenergy.com

hydroelectric capacity for the 100% wind, solar and hydroelectric power system was built in situ for current locations, the other costs would still apply (you need pipes, penstocks, power houses, etc.). If that is the case the cost of the new hydroelectric capacity would be $2,589 / kW, reducing the additional cost to $3.1 trillion instead of the $3.38 trillion we estimated above.

Achievable peak hydropower output is likely to be significantly smaller than the theoretical maximum assumed by the authors in ref. [11] (145.16 GW), and certainly less than shown in its figures (i.e. 700 or 1,300 GW). This is because the total output of hydroelectric facilities is limited by overall river flows and further constrained by environmental considerations and other priorities for water use (e.g., navigation, irrigation, protection of endangered species and recreation). These constraints currently prevent all hydroelectric capacity from running at peak capacity simultaneously (see, e.g., Figure S5 from ref. [1]). In addition, a portion of U.S. hydropower facilities are "run-of-river" facilities without the ability to store water for on-demand power production behind the dams, and still more facilities have minimum and maximum flow rates imposed for environmental reasons that restrict their operating flexibility. Recent years have seen major environmental initiatives to restrict hydropower output and even remove dams; the courts and political processes have been receptive to these efforts and all indications point to even more restrictions in future.

To demonstrate the point regarding maximal output from U.S. hydroelectric power, we plot the average power from the entire U.S. hydroelectric fleet[3] for each month for the years 2006–2016 (up to September 2016) in Fig. S2. Figure S2 shows an annual cycle (which is driven by the hydrological cycle). The maximum monthly power output from the combined U.S. hydroelectric fleet (∼101.6 GW) is shown to be ∼44.8 GW. Thus, the peak month in the last decade had a monthly capacity factor of 44.1%. In contrast, Fig. 2 in ref. [11] shows that hydroelectricity provided in month 12 of the simulation totaled ∼150-175 TWh of electricity. Assuming the mean value of this range (162.5 TWh), such generation would represent an average hourly power output for the month of 218.4 GW. That is over twice the installed capacity of hydroelectricity in 2015 generating electricity constantly for an entire month. Moreover, 162.5 TWh is ∼40% of the allocated hydroelectric energy allowed by [11][4]. Therefore, the water would need to have been stored from earlier in the year. Indeed, Fig. 2 in ref. [11] shows precisely that; no hydroelectricity production from months 2 to 6 for the first year of the simulation (a common pattern followed for the other years). However, these early months of the year have substantial production in the current electric grid because of the hydrological cycle, irrigation needs, and reservoir restrictions. This is illustrated by Fig. S2 and Fig. S5 from ref. [1].
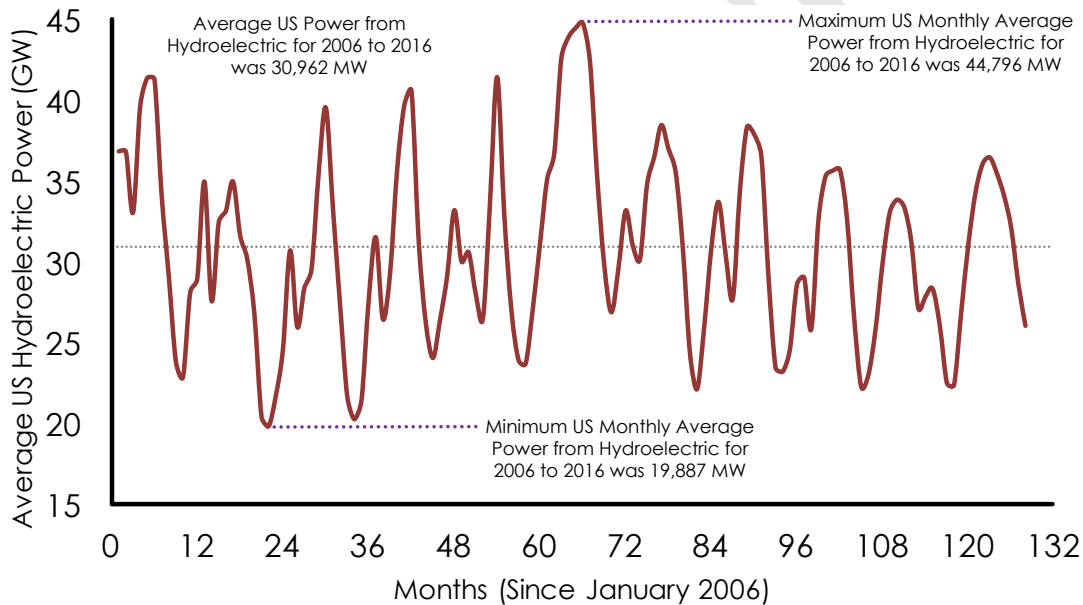
Fig. S2. The average power output from all the U.S. hydroelectric plants for 2006 through August 2016. The annual cycle from hydrology can be seen throughout the plot. The last five years are water constrained and the power output suffers as a result. The peak average monthly power is 44,796 MW for Spring 2011 (months 62-66). The minimum was 19,887 MW for late fall 2007. The average monthly value for the decade was 30,962 MW, or 30.5% of installed capacity.

S1.2: Flexible Demand. The analysis of a 100% wind, solar and hydroelectric power system [11] contains errors in the handling of flexible demand. The total amount of load that is labeled as flexible in the dispatch figures is inconsistent with the flexible load that is reported in the paper.

First, if one takes the total percentage of load that is flexible or coupled with TES or used for hydrogen production from Table 1 column (4) bottom row from [11] there would be 67.66% of the total load being flexible. That means there can only be a maximum of 1064.16 GW that can somehow be manipulated for load reshaping.

Deeper inspection of Table 1 column (4) in ref. [11] shows that the categories of transportation, on-site transportation in industry and high-temperature chemical or electrical processes within industry (Hi-T/chem/elec) have some fraction of

---

[3]data obtained from EIA: https://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01

[4]see its Table 2 and divide hydropower electricity by six for yearly values (2413/6 = 402.2 TWh).

load categorized as "flexible". For transportation it is labeled as 85% flexible (F), coupled to TES (S) **or** used for hydrogen production (H) [F, S, H]; while on-site transportation is labeled as 85% (F); and Hi-T/chem/elec is labeled as 70% (F, H). All other categories are only flexible with TES or hydrogen production (S, H). Using these values, and assuming **all** these loads can be exclusively flexible (F) then there would be 683.8 GW that is assigned to this category of flexible load. That is a value of 43.5% of the total load.

If instead one was to read Table 1 column (5) in ref. [11], which further decomposes the flexible loads with TES (F, S) [separated from (H)], it can be seen that 108.9 GW is available for (F, S) from transport, 4.31 GW is available for (F) from on-site transportation and 390.44 GW is available for (F) from Hi-T/chem/elec. This results in a maximum available flexible (F) loads of 503.65 GW or 32.0% of the total load.

Thus we have three values possible for "flexible" loads: an absolute maximum of 1064.16 GW (67.7% of total load) assuming that some things were mislabeled and the LOADMATCH model could make everything flexible rather than going to TES or hydrogen production; a maximum of 683.8 GW (43.5% of total load) if the labeling is correct in Table 1 in ref. [11] and we assume all flexible load, TES, and hydrogen production are interchangeable; or a maximum of 503.65 GW (32.0% of total load) if column (5) values are taken as correct.

Looking at Fig. 3 from [11] at the point representing day 912.6 there is a flexible load (green) value of 1,900 GW of a possible 2,400 TW of total load. This represents a flexible load of 79% a value that is far higher than any of the possible values from Table 1 in ref. [11] and is double the value of total flexible load allowed according to that table. In fact, each day in Fig. 3 of ref. [11] appears to break the 67.7% value for flexible load. This is further confirmed by Fig. 4 of ref. [11], where each day flexible load gets as high as 77% of the total load. In fact every single figure that shows the "flexible" load appears to break either the 67.7% value or the maximum capacity of flexible load of 1064.16 GW.

The only way this scale of flexible load would be feasible is if the fraction of demand from transport and industrial loads during these days is at least twice as large as the average shares reported in Table 1 of ref. [11], and if all of these loads are considered flexible (as opposed to being part of the separately labeled UTES output). The authors of ref. [11] do not provide evidence to justify this implausible scale of load flexibility. The idling capital-intensive industrial facilities when intermittent energy sources are unable to meet demand represents a large cost that is not included in ref. [11].

It should be noted that LOADMATCH models generation from wind and solar *a priori* and then aggregates them together. It does not determine the capacity of generation endogenously. The model is essentially one-dimensional; all loads, generation and storage are considered in a single place though time. Thus, the sensitivity analysis performed in ref. [11] ultimately relies only on changes in storage and demand response (and erroneous hydropower capacity) on a trial and error basis. The authors of ref. [11] assert in Table S3 and Fig. S14 that having zero demand response (DR) does not change the cost of energy and energy is supplied reliably. If this were to be true, what is the purpose of the flexible load in the model? The flexible load appears to shift demand to the end of the eight-hour blocks and is used substantially more in winter than summer. How can a considerably shifted demand profile (and associated economy) cost practically the same as an inelastic one? If ref. [11] included a transmission and capacity expansion model, it would become apparent that supplying these huge fluctuations in demand would create congestion and other issues within the grid. The lack of sensitivity to DR is particularly worrisome because it is the highest priority item in the LOADMATCH model after inflexible load and it is utilized so ubiquitously in the base case scenario.

S2: Implausible Assumptions

The 100% wind, solar and hydroelectric power system in ref. [11] includes only 18 GW of PCM-ice storage; just 30% of the total flexible cooling and refrigeration demand. Therefore, the vast majority of storage underlying the extremely high flexibility of air conditioning and refrigeration needs in the study must consist of UTES. It should be noted that the cost of retrofitting all heating, cooling, and refrigeration to be compatible with UTES or ice-PCM is not included in the analysis in ref. [11].

S2.1: Underground Thermal Energy Storage (UTES). Underground thermal energy storage systems using geothermal boreholes to store heat in the soil, as used in ref. [11], have to date been employed at a relatively small scale in only a handful of projects [29]. The largest UTES borehole storage system in the world appears to be a project in Crailsheim, Germany, which supplies seasonal thermal storage for 260 homes and two community buildings, and has a total storage capacity of 0.0041 TWh [30]. The UTES used in ref. [11] is specifically "patterned by" an even smaller borehole ground heating system which supplies Drake Landing, a master planned community of 52 custom-designed solar homes in Alberta, Canada. Both the Crailsheim and Drake Landing projects are supplemented by heating from conventional fossil-fueled heating systems.

The plan of the 100% wind, solar and hydroelectric power system [11] extrapolates from these small-scale demonstration projects to propose the ubiquitous deployment of UTES at every home, business, office building, hospital, school, and factory in the United States. The performance (and cost) of UTES systems is highly dependent on the underlying geology of the site, such as the thermal properties of the soil and the absence of any groundwater flow (which if present, will remove stored heat over time). In addition, the projects cited as the basis for the UTES systems appearing in ref. [11] supply only heating, yet the the study envisions 85% of residential air conditioning, 95% of commercial and industrial air conditioning, and 50% of commercial and industrial refrigeration being coupled with UTES and/or ice-based PCM storage systems.

UTES systems depend on heat pumps and/or liquid circulating pumps to deposit into and extract heat from the ground. The most efficient geothermal heat pumps available consume about one unit of electricity for every four to five units of heating or cooling they supply. So while much more efficient than electrical heating or cooling, UTES systems still consume electricity on demand whenever they supply heating or cooling needs (this is in addition to the energy needed to charge the system in the first place). It does not appear that this on-demand electricity consumption is modeled in ref. [11].

The supplemental material for ref. [11] reports a wide span of costs for underground thermal energy storage ranging from $0.071 to $1.71 / kWh$_{th}$, (with the higher estimate 24-times the lower) but does not adequately justify these numbers. One of the provided references consists of presentation slides by the company Rehau [30] in which no directly applicable cost data are provided. The other reference is a conference contribution [31] on simulating heat transfer rates from a CHP-coupled UTES system. Reliable cost figures cannot be obtained from the analysis in ref. [31]. With 515 TWh of UTES underlying the proposed balancing of U.S. thermal energy needs, the cost estimates reported for the 100% wind, solar and hydroelectrcic power system [11] imply a total cost ranging from a low of $37 billion to a high of $900 billion. However, the known capital costs for the Drake Landing system suggest a UTES installation cost of at least $1.8 trillion for the 100% wind, solar and hydroelectric power system[5], double the high-end estimate reported in ref. [11]. In addition, this estimated cost excludes the cost of the requisite heating and cooling systems inside homes, businesses, and industrial facilities capable of making use of stored energy in UTES systems. Moreover, the handful of existing UTES systems that form the basis for extensive use in ref. [11] are all installed during the new construction of specifically-designed communities or feed into established district heating systems, and none of them appear to feature the capability of providing cooling or refrigeration. Costs to retrofit existing homes and buildings with heat pumps capable of interfacing with UTES systems and install UTES boreholes and insulating layers beneath existing structures are unlikely to be as affordable as new construction. Thus, the actual costs of deploying UTES ubiquitously at virtually all buildings in the United States, as the 100% wind, solar and hydroelectric power system requires [11], are likely to be much larger.

S2.2: Energy Storage in Phase-Change Materials (PCM). The use of phase change materials in high temperature storage applications is entirely unproven at scale and is still effectively in the research and demonstration stage [33]. To date, only a handful of concentrating solar power projects have been built worldwide with any thermal storage, and these systems exclusively employ more mature (and costly) molten salt storage systems [34]. Phase-change materials, so called due to their ability to store heat by transitioning from a solid to liquid state, include paraffin wax and certain salts. Employing these materials for high-temperature thermal energy storage could yield much higher energy densities and potentially lower costs than molten salt storage. But doing so requires solving a number of practical challenges before the technologies will be ready for commercial adoption, including designing methods to overcome the poor thermal conductivity of phase change materials; solving corrosion, material degradation and thermal stress-related durability problems; and developing cost-effective mass production methods [33–36]. In the 100% wind, solar and hydroelectric power system study [11], the PCM-CSP systems are cited as having a 99% round-trip energy efficiency (Table S1 of ref. [11]) - with the implication that much of this is for electrical power. However, the study [37] cited in ref. [11] refers to the energetic efficiency, and assumes that all usable heat can be exploited. The assumption of a very high round trip efficiency greatly (favorably) impacts the levelized cost of stored electricity assessment.

Phase-Change Materials (PCM) storage coupled to CSP plants represent 88% of all proposed electricity storage capacity in ref. [11], at a reported cost of $10 to $20 / kWh$_{th}$. As high-temp PCM for CSP applications remains pre-commercial, there is no reliable data for the current cost of PCM storage. The reference cited by ref. [11] is not a current technology cost, but

---

[5]Future projected cost estimates (which are significantly lower than actual costs) for the Drake Landing type UTES are given in Table 3 of ref. [32]. Excluding costs for collectors and their installations, and noting that in 2007, $1 CAD≈$1 USD, implies a system cost of $3.5 billion (2015) per TWh, or $1.8 trillion for the scale of UTES systems proposed in ref. [11].

rather the \$15 / kWh$_{th}$ cost target proposed by the US Department of Energy SunShot program, which states that achieving these goals will require a combination of evolutionary and revolutionary technological changes [38]. A technical report by the IEA and IRENA [33] reports a much wider range of €10-50 / kWh$_{th}$ for PCM (about \$11-55 / kWh$_{th}$), and this range is inclusive of more affordable low-temperature applications; such as inclusion of PCM in building materials. Whether high-temp PCM for CSP plants is commercially successful, and at what cost, remains speculative, and if costs fall to the higher range reported by IEA/IRENA, PCM storage for CSP could cost upwards of \$729 billion to install, or more than 3.5-times as much as assumed in ref. [11].

S2.3: Ease of Transition to a Hydrogen Economy. The 100% wind, solar and hydroelectric power system proposed in ref. [11] relies upon unsupported assumptions about the very widespread adoption of hydrogen production and consumption, which supplies nearly half of all transportation energy needs and 11% of the energy-intensive industrial processes (i.e. aluminum and steel production, chemical manufacturing). Moreover, the authors of ref. [11] postulate the availability of hydrogen storage giving the proposed system the ability to store the equivalent of more than a month of current U.S. electricity consumption. The authors of ref. [11] provide no information in ref. [11] (or its supplemental material) on how air, shipping, rail or long-haul freight transportation sectors or various energy-intensive industrial processes would use hydrogen. There is a long history of imagining a transition to hydrogen fuels in transportation, notably aircrafts. So far, little progress has been made because existing infrastructures readily "lock out" radical new systems such as hydrogen [39]. While early demonstrations of some of these hydrogen fuel applications (for example, commuter rail in Germany and heavy trucks in California) exist and much work has been done suggesting that hydrogen aircraft might be technically feasible in the future, the technical challenges and economic costs of such widespread applications of hydrogen as a fuel are not addressed in ref. [11].

In addition, it appears from the modeling results shown in ref. [11] that no physical limitations have been placed on the rate of hydrogen production in the system. In Figure S6 of its SI, it is shown that a hydrogen charge rate (power going to hydrogen production) of almost 2 TW is achieved, nearly double the total current installed generating capacity of the United States. The actual capacity for hydrogen production is never explicitly presented in ref. [11] and is not appropriately accounted for in the cost estimates[6]. The authors of ref. [11] provide no information regarding the hydrogen production equipment (electrolysis, etc.) that would enable a hydrogen production rate of at least 2 TW, as shown in the dispatch figures (see the lowermost panel of their Figure S6; shown here below in Figure S3).
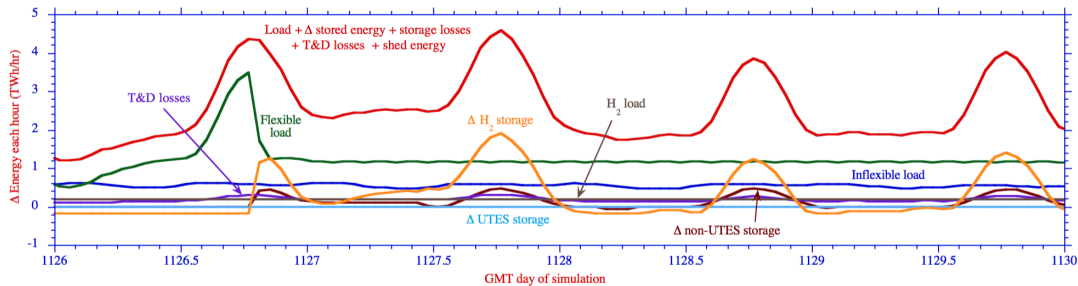

Fig. S3. Lowermost panel of Figure S6 of ref. [11]

For cost estimates of the hydrogen production system, the authors of ref. [11] cite their own previous work [41], which reports average costs of hydrogen production as 4 cents / kWh-to-H$_2$ for the electrolyzer, compressor, storage equipment, and water (with a range of 1.96-6.05 cent / kWh). Calculating costs in this way, as a simple levelized cost per kWh, is inappropriate for circumstances like those in ref. [11] where peak production is much higher than average production. The cost estimates presented in ref. [41] assume the electrolyzers operate with a 95% capacity factor (e.g. they produce at 95% of their maximum rated capacity on average throughout their economic life). But, according to the dispatch figures in ref. [11], the maximum production rate for hydrogen is about 2,000 GW; 11 times higher than the 180.2 GW average production given in Table 1 of the same paper. Thus, the capacity factor of electrolysis equipment in the 100% wind, solar and hydroelectric power system would be roughly 9%, or an order of magnitude less than the utilization rate assumed in ref. [41]. Consequently, the costs for electrolyzers necessary to produce hydrogen at a rate of 2,000 GW are at least 10-25 times[7] higher than those reported by ref. [11], with the capital cost for these components totaling approximately \$2 trillion. Additional variable costs associated with water consumption and other variable operations and maintenance should be explicitly reported as well. In short, the total costs of hydrogen production required by the 100% wind, solar and hydroelectric power system in ref. [11] do not represent the scale of hydrogen production and utilization implied by the dispatch of hydrogen represented in the LOADMATCH simulations.

The electrification of the entire economy in the manner proposed in ref. [11, 12] would also require significant capital beyond what is suggested. For example, it is proposed that air travel would be fueled by hydrogen, as would substantial portions of other modes of transport and industrial processes. However, the technologies required to use hydrogen fuels do not exist for a variety of the applications envisioned and are very expensive for those applications that have been demonstrated. While the

---

[6]The DOE cost reduction target for high volume production of electrolyzers is \$320 / kW, so 2 TW of hydrogen electrolyzer capacity would be in excess of \$600 billion, ignoring all of the costs of the infrastructure to store, distribute and dispense the fuel [40].

[7]The higher value refers to the high value for capital cost of electrolyzers from ref. [41]. Only the lower value was used in ref. [11].

costs of hydrogen storage are included in the study, the costs of retrofitting large swaths of the transportation and industrial sectors to run on hydrogen fuel - or even the costs to develop these technologies in the first place - are not accounted for in the analysis. These costs would be substantial and could potentially motivate a completely different approach to producing fuels for transportation, particularly aviation.

S2.4: Flexibility of Demand. In addition to the errors related to the flexible demand, there are problems with assumptions of that flexible demand. Indeed, 63% of all energy-intensive industrial demand is assumed to be flexible, able to freely reschedule all energy inputs within an eight-hour window (this is in addition to the use of hydrogen, discussed in the previous subsection). Some industrial producers do participate in demand response programs currently and temporarily reduce or interrupt demand during periods of supply shortages for short periods of time [42]. However, the authors of ref. [11] provide no explanation or justification as to how (and why) industrial producers would be able or willing to schedule their production around variable renewable energy output on a daily basis, nor do the authors quantify the resulting economic impacts of doing this.

In short, the reliability of the 100% wind, solar and hydroelectric power system postulated in ref. [11] relies on reshaping energy demand to become extremely flexible such that demand can be made to conform to the variable output of renewable energy; rather than energy supplies being shaped to match patterns of demand, as is the mandate of the current U.S. energy system. Although such a system is theoretically possible, the authors of ref. [11] provide no evidence that this system is practical or reliable and do not adequately account for its deployment or operational costs.

S2.5: Capacity Factors for Existing Generation Technologies. The economic analysis in ref. [11] depends on assumptions about the ability to increase the capacity factor of existing generation technologies. In Table 2, note f of ref. [11], the capacity factor of geothermal power plants is given as 92.1%. That is much greater than the capacity factor of existing U.S. geothermal power plants of 73.6% in 2013 or 74% in 2014 [43]. There is only a brief discussion in [12] with regards to why these capacity factors increase. Similarly, combined U.S. and Canadian hydropower is assumed to increase its capacity factor from ∼39% to 52.5%, but the authors of ref. [11] do not present analysis justifying this assumption or explaining the cost associated with increasing this capacity factor [12] other than an erroneous connection to EIA data that states hydroelectric could increase to 42% capacity factor. Because running existing units at much higher capacity factors reduces the need for other generation and storage devices, these assumptions reduce the estimated costs reported in ref. [11].

Figure 3 of the present paper shows that the 100% wind, solar and hydroelectric power system in ref. [11] consumes 43% more annual hydroelectric energy than in recent history. This extra energy will be needed at different times, in addition to current activities at hydroelectric power plants. Presumably, the changes needed to be made would cause water levels to rise and fall quite dramatically throughout the year. The additional water needed for the increased energy is not accounted for in either [11] or [12]. The authors of ref. [11, 12] state that the reservoir sizes do not increase, but this cannot be the case because more power is being drawn and therefore the head level will decrease rapidly, lowing power output.

To demonstrate the difficulty of getting the energy needed, consider Hoover Dam. It has a capacity of 2.1 GW. If we assume there needs to be 10x capacity nationally, this would rise to 21 GW. Currently there are nineteen turbines in the power plant. The power produced by a hydroelectric plant is

$$P = E * D * F * g * h,$$

where P is the power (W), E is the efficiency (%), D is the density of water (kg/m^3), F is the flow rate (m^3/s), g is gravitational acceleration (m/s^2) and h is the head height (m). If we assume Hoover Dam has a head height of 180m and an efficiency of 80%. We can see the maximum flow rate today should be

$$F_{max} = \frac{2.08 * 10^9}{0.8 * 1000 * 9.81 * 180} = 1472.4 \ \text{m}^3/\text{s}.$$

The average capacity factor (1947–2008) of Hoover Dam has been 23.05%[8]. Therefore, the total volume of water used on an average year is 10.7 km^3 (or 54.7% of Lake Mead's active capacity). In 2015, the capacity factor was 19.8%[9], illustrating the lower water availability for hydroelectric power in much of the U.S. in recent years. Since, the authors of ref. [11] assume an increase of 43% from historical average values (see our Fig. 3), then Hoover Dam must produce 43% more electricity for a total of 6.01 TWh[10]. Using the calculation above, the increase in electricity production would require an additional 4.6 km^3 of water. Thus, on average Hoover Dam would be required to use 78.2% of the active capacity of Lake Mead.

The calculation above is simply one of water use. It is clear that more water would need to be passed through the turbines at hydroelectric power plants, regardless of the capacity. The additional need for water is not explained in [11] or [12]. Further, to compound the issues, the higher capacity is used to generate more power when necessary. This extra power results in more water moving downstream. From the calculations above, for Hoover Dam to have 21 GW capacity the maximum flow rate would be 14,724 m^3/s, which is greater than the capacity of the spillways at Hoover Dam. The extra water will cause issues downstream for all the other uses of the water, particularly irrigation. At other times, the power plants will be shutdown to store the water, presumably leaving the river to dry up downstream.

---

[8]data from: http://www.usbr.gov/lc/hooverdam/faqs/powerfaq.html

[9]Data from: http://www.usbr.gov/lc/region/g4000/24mo/2015/DEC15.pdf

[10]Average electricity generation for 1947 to 2008 was 4.2 TWh; 2015 was 3.6 TWh.

S2.6: Electricity Transmission. The authors of ref. [12] state: "We assume that 30% to 45% of total WWS generation (all generators except offshore wind) is sent through the new onshore long-distance grid and that 15% to 25% of offshore wind generation is sent through the extended-transmission offshore grid". Presumably the same values are used in ref. [11], since no other information is given. Again, no modeling, motivation, or reference relating to any of these assumed values is given.

Building a power system dependent on renewable resources will require a substantial expansion of long-distance transmission capacity to access higher-quality resources and transmit power to load centers, particularly for the onshore wind resource that is relatively far away from major load centers. In addition, the U.S. power system today remains balkanized into three weakly coupled electricity grids (or interconnections). Freely assuming that power could move back and forth between these systems at the continental scale, as the authors of ref. [11] implicitly do, is not feasible today, and enabling such power exchanges would require a continent-spanning set of high-voltage power lines and associated AC-DC-AC interconnection points [1]. Furthermore, refs [1] and [44] showed that explicitly considering transmission expansion alters how the generating capacity is distributed across the United States, diversifying the resource and reducing the need for storage dramatically. A detailed study by the National Renewable Energy Laboratory [2] concluded that for renewable energy to supply 90% of U.S. electricity alone (not all energy needs, as in ref. [11]) would require doubling existing installed U.S. long-distance transmission capacity (an increase of 200 million MW-miles of high-voltage transmission lines[11]) as well as adding 80 GW of new AC-DC-AC intertie capacity between the U.S. grids. Informed people can disagree about whether the scenarios presented by refs [1] and [2] would be feasible given constraints on building electric transmission lines. However, long-distance transmission needed to accommodate the 100% wind, solar and hydroelectric power system set out in ref. [11, 12] would be even larger and costlier.

S2.7: Cost of Capital. The analysis of the 100% wind, solar and hydroelectric power system in ref. [11] relies on exceptionally low discount rates (ranging from 1.5% to 4.5% with a baseline value of 3%) to calculate the levelized cost of energy. Since the wind, solar and hydroelectric technologies are capital cost intensive (there are no fuel costs), the discount rate is decisive for the economic analysis. Reducing the discount rate by a factor of two reduces the projected cost of capital by an even greater amount. The IPCC baseline discount rate for calculating the cost from wind and solar investments is 8% [10]; the PRIMES model used by the European Union sets the discount rate at 9% for the power sector [46]; the National Renewable Energy Laboratory (NREL) estimates the after-tax inflation-adjusted U.S. discount rate at 6.5% for on-shore wind [47]; the NEWS model used a real discount rate of 6.6% [1]; while the International Renewable Energy Agency (IRENA) [48] estimates a span between 5.5% and 12.6%, with a baseline of 10%. Rates can be significantly higher for technology investments seen as riskier, which includes offshore wind, tidal and wave [49].

Assuming the investments needed to reach a 100% wind, solar and hydroelectric power system envisioned in ref. [11, 12] would be made by private firms, it is instructive to look at what firms pay for access to capital - a rate revealed in the corporate debt markets. Low-risk firms such as well-managed regulated electric utilities have debt costs similar to the numbers assumed in the energy studies described above and about double the rate assumed in ref. [11]. Higher risk firms, such as those that populate the residential solar market, have much higher rates. In other research, scholars have shown how more realistic assumptions about capital costs can have a radical impact on patterns of investment when cutting emissions of greenhouse gases - shifting investment away from higher risk speculative technologies and toward lower risk opportunities while raising the overall cost of mitigation substantially [50].

It is also worth noting that according to the cost assumptions in Table 5 of ref. [12], excluded options (such as nuclear power and fossil fueled sources with carbon capture and storage) are lower cost than the offshore wind, solar with CSP, CSP with storage, rooftop solar and wave / tidal power considered in ref. [11]. This means the costs associated with the 100% wind, solar and hydroelectric power system from ref. [11, 12] are greater than a more diversified low-carbon energy system.

S2.8: Scale of Buildout and Pace of Change. Increasing annual production of wind, solar and hydroelectric technologies in the U.S. will likely be possible at substantially higher GDP-normalized rates than in Germany, owing to the more advantageous conditions for both wind and solar power in many areas of the U.S. compared with Germany (which is reflected in the higher capacity factors achieved in existing wind and solar power in the United States). However, the rates at which ref. [11] plans to add wind, solar and hydroelectric production capability (measured in the amount of energy produced per year) are an order of magnitude greater than the rates achieved in the German Energiewende, as depicted in Figure S4 below.

The continuous rates of addition of wind, solar and hydroelectric energy production in ref. [11][12] are 13 times higher than the GDP-normalized average rate achieved in the last seven years of the Energiewende in Germany (2007-2014). In fact, the average GDP-normalized rates required by ref. [11] year after year are six times higher than that achieved in the single fastest year of wind, solar and hydroelectric installation achieved to date in the German Energiewende (see Fig. S4). We use this metric because it also accounts for the capacity factor differences between generator types. It demonstrates the amount of extra energy that is needed each year from these new technologies.

Another metric that is helpful in illustrating the scale that the authors of ref. [11] are proposing is the amount of capacity per capita that must be added each year until 2050. This metric can be compared to rates in other countries. We show historical data for China, Germany, and the U.S. in Fig. 4. In addition, we show the 100% wind, solar and hydroelectric power system proposed values [11] and the computed values for [1]. Figure 4 shows that the authors of ref. [11] are suggesting a pathway that involves installing capacity at a rate that is 14.5 times greater than the U.S. historical average and 6.2 times

---

[11]In ref. [45], Table ES-8, p. 26: "Existing total transmission capacity in the contiguous United States is estimated at 150-200 million MW-miles".

[12]The best estimate of the energy-production-averaged operational lifetime of the proposed system presented in ref. [11] is ~26.7 years (using EIA estimates for operational lifetime of each technology), which also defines the rate at which the entire system (on average) may need to be replaced (~3.7% of the total system each year).
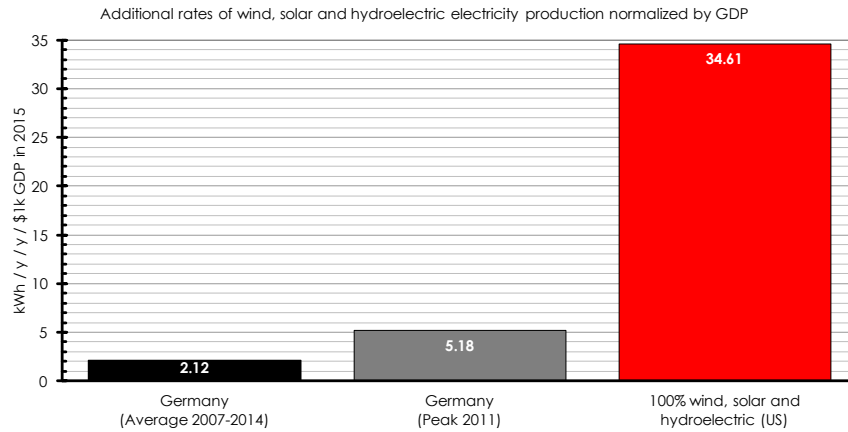
Additional rates of wind, solar and hydroelectric electricity production normalized by GDP

Fig. S4. GDP-normalized wind, solar and hydroelectric power addition rates of Germany (data from ref. [51]) and the rates implied for the 100% wind, solar and hydroelectric power system from ref. [11].

greater than the historical peak. The rate would have to be continued indefinitely because as 2050 is reached all units installed before 2020 would need to be replaced. From the "LRHG" scenario from ref. [1], it can be seen there is a requirement of increased capacity installations, but a rate lower than the historical peak within the United States.

A third metric of interest is the installation rate per year per $GDP. To do the analysis, estimations of GDP must be used. It is assumed that US GDP will grow at 2.08% per annum out to 2050[13]. In Fig. S5, we display historical rates for the United States, China, and Germany along with estimates for the 100% wind, solar and hydroelectric power system proposed in ref. [11] and the 80% carbon-free electricity system shown in ref. [1]. The 100% wind, solar and hydroelectric power system requires installation rates at twice the U.S. historical average (7.8 kW / y / $GDP). The rates would be on a level not seen since the 1970s in the U.S. and rival rates seen in China in the past few decades; where the economy was rapidly expanding. The average annual GDP growth rate of China for 1980 to 2015 was 9.77%[14], nearly five times the estimated GDP growth rate estimated for the US from 2016 to 2050. For comparison, the average installation rate (15.5 kW / y / $GDP) of the 100% wind, solar and hydroelectric power system is roughly seven times the average installation rate for the United States between 1980 and 2015 (2.3 kW / y / $GDP).
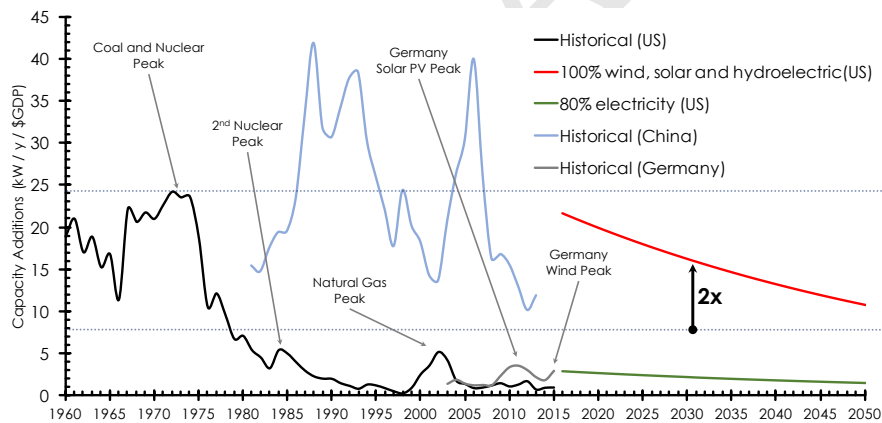

Fig. S5. Installed capacity per year per $ GDP. Historical data for the United States, China and Germany are shown along with the estimates for the 100% wind, solar and hydroelectric power system proposal [11] and the 80% carbon-free electricity system shown in ref. [1]. The 100% wind, solar and hydroelectric power system study requires installation rates at twice the historical average. China has a high rate due to the rapid expansion of their economy. The average annual GDP growth rate for 1980 to 2015 for China was 9.77%; nearly five times the estimate annual growth rate of the United States from 2016 to 2050. The average installation rate of the Jacobson et al. proposal is roughly seven times the average installation rate for the United States between 1980 and 2015.

It is clear that decarbonizing energy production using any combination of methods will be a huge challenge on many levels (economical, technological, societal). This is one of the most important reasons, as mentioned in the introduction of the present paper, why energy analysts and climate scientists across the globe propose to not exclude any potential technologies that could make the challenge more tractable. The implied premature decommissioning of existing (and under-construction) low emissions technology also add to the challenge in a very direct way. Over 60% of low-emission electricity production in the U.S. today is from nuclear power stations, many of which (including new plants nearing completion today) are to be prematurely

---

[13]US GDP growth rate of 2.08% is calculated from projections obtained from OECD: https://data.oecd.org/gdp/gdp-long-term-forecast.htm

[14]Data from: http://data.worldbank.org/indicator/NY.GDP.MKTP.KD.ZG?end=2015&locations=CN&start=1980

decommissioned in the 100% wind, solar and hydroelectric power system plan. The costs of decommissioning these plants, including the opportunity cost, were not accounted for in ref. [11].

S2.9: Land-use issues. Adding to the difficulty in the constrained 100% wind, solar and hydroelectric power system approach is the fact that the main energy sources (wind and solar) have a comparatively low areal energy density. According to NREL, the current best-estimate for land use of onshore wind farms is 0.33 km^2 / MW ($= \sim$3 W / m^2, when including spacing) [52], which for the 100% wind, solar and hydroelectric power system proposal [11] translates to half a million square kilometers. To put this number in perspective, this is more than twice the total area of all urban areas in the U.S. combined[15] [53]. Added to this, an additional 100,000 square kilometers of land would be used for large-scale centralized solar PV and CSP plants [54], an area roughly the size of Kentucky. In the 100% wind, solar and hydroelectric power system plan [11], during a build-out period of 20-25 years (the assumed lifespan of wind turbines), over 65 km^2 of new U.S. land per day would have to be designated for energy production facilities. While this could theoretically be done, and indeed much of the land for wind turbines could remain dual-use (for instance for agriculture), the challenge of this undertaking should not be understated. In a system where a higher power density technologies are allowed to contribute, the land use requirements (and any associated scale-up challenges) for decarbonization of the energy system could be reduced dramatically.

---

[15]The Census Bureau method for estimating urban area includes urbanized areas with at least 50,000 people and urban clusters with 2,500-50,000 people but excludes portions of extended cities that are essentially rural in character and lands in rural residential uses.

Clack *et al.*

S3: Insufficient Power System Modeling

The most fundamental elements missing from the LOADMATCH model used by authors of ref. [11] are: the ability to model frequency regulation and compute transmission power flows and associated reliability; the ability to show how much transmission would be needed, its costs, and where the transmission would need to be placed; the inclusion of operating reserves necessary to ensure reliability in the face of unexpected failures of generators or transmission lines, demand contingencies and renewable energy forecast errors.

The reliability and stability of power grids require frequency regulation resources, yet LOADMATCH does not have the capability to simulate these requirements. Instead, in ref. [12], the authors assert, "Frequency regulation of the grid can be provided by ramping up/down hydroelectric, stored CSP or pumped hydro; ramping down other WWS generators and storing the electricity in heat, cold, or hydrogen instead of curtailing; and using demand response". Ref. [12] does not cite analysis or demonstration of the viability of this approach. In addition, the authors present ref. [11] as a "grid integration" study, but do not mention frequency regulation in the main text. Inspection of the supplemental information of that paper reveals that frequency regulation was not modeled at all. While studies evaluating high penetration of renewables at a national level do not usually include frequency regulation, the authors of ref. [11] make the unique statement that frequency response can be provided, even though they did not analyze the viability of the statement.

While it is likely that future power systems could depend to a greater extent on synthetic inertia from asynchronous generators like wind and solar photovoltaic (PV) or management of loads or thermal storage, these techniques remain unproven at scale. Given current technologies, power system operators in isolated regions with high penetrations of wind and/or solar PV limit the instantaneous production of power from these asynchronous generation sources to 50-75% of total generation in order to preserve sufficient physical inertia to manage grid frequency [42, 55]. The issue of system inertia stability is an important and likely solvable challenge, but the models used in the 100% wind, solar and hydroelectric power system study [11] do not confront this challenge, which is critical to demonstrating the reliability of a system with high penetration of variable renewables. With 87.95% of annual energy supplied in 2050 by wind and solar PV on average in the 100% wind, solar and hydroelectric power system, these resources would, for much of the time, constitute 100% of instantaneous power generation; 100% power generation by variable generation for extended periods is beyond anything that has been proven technically feasible for the stability of an isolated grid. Only 7.4% of installed capacity (corresponding to a theoretical maximum of ∼28% of estimated average load) in the proposed power system is capable of providing conventional inertia for frequency regulation, and of this capacity, 95% consists of hydroelectric and concentrating solar thermal power (CSP), the availability of which varies significantly on a seasonal basis.

An important gap in the analysis of ref. [11] is that it does not provide evidence that the proposed system can maintain sufficient frequency regulation to preserve power system stability. The designers of power markets have known for decades that there is a need for improved markets that reward ancillary services that contribute to grid reliability [56]. Yet, to date, these markets remain erratic; even the market that have made the greatest strides, the PJM ancillary services market, have a largely unfinished agenda.

In addition to not addressing the challenges associated with maintaining frequency regulation in a system with very high penetrations of variable and asynchronous generation, the LOADMATCH model does not provide the provision of operating reserves necessary to maintain reliability in the case of unplanned outages of transmission lines and generation or storage facilities and errors in forecasted wind and solar output and demand. Studies of existing wind and solar projects and experience in power systems with growing shares of variable renewable resources demonstrate that solar and wind energy forecast errors can be significant: for example, errors related to variable output caused by cloud cover and other meteorological conditions that have been documented at coastal and inland solar PV and CSP plants in California [57–59]. Again, this omission is substantial, given that the envisioned power system relies overwhelmingly on wind and solar energy generation with deterministic, but chaotic, output.

Further, the authors of ref. [11] state that the LOADMATCH model "assumes a fully interconnected grid" that does not include any transmission constraints. Those authors state that "the impact of transmission congestion on reliability is not modeled explicitly", and simply assume that there is unlimited transmission availability and that if "congestion is an issue at the baseline level of long-distance transmission, increasing the transmission capacity will relieve congestion with only a modest increase in cost". This is a striking set of assumptions given that it has proven extremely difficult to site vital transmission lines, notably near urban areas (where loads are concentrated).

We note that if hydroelectric power were expanded to the level implied by the numbers we find in [11], and there was an infinite super-grid that covered the whole of the contiguous U.S., then the frequency regulation problem would be substantially reduced. Hydroelectric turbines can do a large amount of fast ramping and contain significant inertia. If large amounts of hydroelectric power is coupled with advanced wind/solar frequency response systems and advanced demand response the most recent literature suggests that the frequency regulation issue is solvable.

S4: Inadequate Scrutiny of the Climate Model that is Employed

Instead of employing actual data from meteorological datasets, the authors of ref. [11] use time-dependent variable wind and solar resources (every 30 seconds for 6 years) predicted with a 3D global climate/weather model called GATOR-GCMOM. As the wind and solar resource values produced by GATOR-GCMOM are the core inputs to the energy production simulation employed by LOADMATCH, the performance, resolution, and accuracy of GATOR-GCMOM in predicting local wind speeds and solar resource levels are central to the conclusions reached in ref. [11, 12].

S4.1: Inadequate Evaluation of Climate Model Results. The authors of ref. [11] refer us to [60–62] for assessment of the appropriateness of the GATOR-GCMOM model for its present purpose. Referring to a model with a slightly different name (GATOR-GCMM), the authors of the ref. [60] report normalized gross wind-speed errors for their non-nested model of 46.1% with a bias of -35.7% for the domain surrounding San Francisco, California, which is the only domain evaluated. No broader evaluation of wind or solar intensity fields is provided in ref. [60]. In ref. [61], the only evaluation of modeled wind or solar fields is a single supplemental figure (Fig. S2 in that work) illustrating some first order correspondence between global wind fields over the ocean as projected by the model and as inferred from satellite imagery. No quantitative analysis is provided but visual inspection of the figure indicates factor of two errors in annual mean wind speeds in many locations. One can presume that errors are larger on shorter time scales. Further, no assessment is provided of reliability of the model to project winds speeds or solar intensity over land. In ref. [62], the only evaluation of the modeled wind or solar fields is the assessment of its ability to simulate peak winds in three hurricanes after the model has been run in assimilation mode. No evaluation of general wind or solar intensity fields is provided in ref. [62].

Unlike widely used major climate models, users of the GATOR-GCMOM model have never participated in any of the major international climate model inter-comparison projects (e.g., CMIP5 [63]) and thus, the validity of this model has not been assessed by the IPCC (e.g., [26, 64]). The authors of ref. [11] have not demonstrated that the weather data is suitable for estimating resource potential for either solar or wind power. There has been no peer reviewed evaluation of this model regarding its performance in predicting the statistics of wind speeds and associated temporal and spatial correlations. There has been no published evaluation of the model regarding its performance in predicting downward solar radiation near the Earth surface and its associated spatial and temporal correlations. Further, there has been no evaluation of model performance regarding correlation between wind speed and insolation. These quantities are central to the conclusions reached in ref. [11].

S4.2: Questions about Adequacy of Model Resolution. In contrast to the use of 30-second time steps in the matching of load and generation, the spatial resolution of the weather data is coarse. At the finest resolution ($2°$ x $2.5°$), the grid cells are $\sim$220 km on a side. Thus, any wind turbines and solar panels within a single grid cell will be homogenous with respect to power output. It is well known that wind farms are not correlated with each other at a 30-second period over several hundreds of kilometers [65]. Further, the depiction of the terrain at those resolutions is not useful for monitoring wind speed acceleration over slopes. For example, the authors of ref. [1] utilized 13-km resolution data assimilation that blends actual observation data (about 25,000 per hour) and a background field to estimate the resource each hour [66–68].

Assumptions made by the authors of ref. [11] about wind turbine competition for kinetic energy are also problematic. Since many wind turbines are within the tens of thousands of square kilometer area represented by each model grid cell, the wakes of the turbines cannot be resolved and thus information about how they interact is lacking. Thus, estimates of power generated per wind turbine in ref. [11] is questionable.

S4.3: Representation of Correlations and Anti-correlations between Load and Weather. The load data used in the model by the authors of ref. [11] is not closely based on actual load data. Assumptions are made about the conversion of industries, heating, and transportation using yearly values. This is then temporally disaggregated into 30-second bins. Further, the load data are not related to the weather that is being supplied as the resource. Therefore, in the study [11], a main driver of electricity (and energy) use does not exhibit the observed correlations (and anti-correlations) with electricity (and energy) supply. In addition, it is assumed that all non-flexible loads behave exactly as the aggregated electricity demand did in 2006 and 2007, something there is insufficient evidence provided for.

References.

1. MacDonald AE, Clack CTM, Alexander A, Dunbar A, Wilczak J, Xie Y (2016) Future cost-competitive electricity systems and their impact on US CO_2 emissions. *Nature Climate Change* 6:526–531.
2. NREL (2012) Renewable Electricity Futures Study (NREL/TP-6A20-52409), (National Renewable Energy Laboratory), Technical report.
3. UNDDP (2015) Pathways to deep decarbonization 2015 report (United Nations Deep Decarbonization Pathways Project), (SDSN - IDDRI), Technical report.
4. EMF (2014) The EMF24 Study on U.S. Technology and Climate Policy Strategies (Energy Modeling Forum). *Special issue of The Energy Journal* 35:1–229.
5. Krey V, Luderer G, Clarke L, Kriegler E (2013) Getting from here to there – energy technology transformation pathways in the EMF27 scenarios. *Climatic Change* 123(3-4):369–382.
6. Williams JH et al. (2012) The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. *Science* 335(6064):53–59.
7. Mileva A, Johnston J, Nelson JH, Kammen DM (2016) Power system balancing for deep decarbonization of the electricity sector. *Applied Energy* 162:1001–1009.
8. IEA (2015) Energy Technology Perspectives 2015, (International Energy Agency), Technical report.
9. Energy Research and Partnership (2015) Managing Flexibility Whilst Decarbonising the GB Electricity System, Technical report.
10. IPCC and Working and Group and III (2014) Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.
11. Jacobson MZ, Delucchi MA, Cameron MA, Frew BA (2015) Low-Cost Solution to the Grid Reliability Problem with 100% Penetration of Intermittent Wind, Water, and Solar for All Purposes. *Proceedings of the National Academy of Sciences of the United States of America* 112(49):15060–15065.
12. Jacobson MZ et al. (2015) 100% clean and renewable wind, water, and sunlight (WWS) all-sector energy roadmaps for the 50 United States. *Energy & Environmental Science* 8(7):2093–2117.
13. Pfenninger S, DeCarolis J, Hirth L, Quoilin S, Staffell I (2017) The Importance of open data and software: is energy research lagging behind? *Energy Policy* 101:211–215.
14. Reed A, McCartney JS (2015) The Sun Also Rises: Prospects for Solar District Heating in the United States. *Albany Law Journal of Science and Technology* 25:165–211.
15. Energy Information Agency (2014) EIA Electricity Data, Table 4.3. Existing Capacity by Energy Source, 2014 (Megawatts).
16. The Globe and Mail (2016) Can the world convert to total renewable energy by 2050?
17. Denholm P, Hand M, Jackson M, Ong S (2009) Land-use requirements of modern wind power plants in the United States, (National Renewable Energy Laboratory), Technical report.
18. Isabel BM (2009) The economics of wind energy. *Renewable and Sustainable Energy Reviews* 13(6-7):1372–1382.
19. Bolinger M, Wiser R (2011) Understanding Trends in Wind Turbine Prices Over the Past Decade, (Lawrence Berkeley National Laboratory, Berkeley, CA), Technical report.
20. Jacobson MZ (2009) Review of solutions to global warming, air pollution, and energy security. *Energy Environ. Sci.* 2(2):148–173.
21. Dobson I, Carreras BA, Lynch VE, Newman DE (2007) Complex systems analysis of series of blackouts: Cascading failure, critical points, and self-organization. *Chaos* 17(2).
22. Backhaus S, Chertkov M (2013) Getting a grip on the electrical grid. *Physics Today* 66(5):42–48.
23. Hirst E, Kirby B (1996) Electric-Power Ancillary Services, (Oak Ridge National Laboratory, Oak Ridge, TN), Technical report.
24. Mauch B, Apt J, Carvalho PMS, Jaramillo P (2013) What day-ahead reserves are needed in electric grids with high levels of wind power? *Environ. Res. Lett.* 8(3):034013.
25. Taylor KE, Stouffer RJ, Meehl GA (2012) An Overview of CMIP5 and the Experiment Design. *Bulletin of the American Meteorological Society* 93(4):485–498.
26. Dee D, Fasullo J, Shea D, Walsh J, NCAR Staff (2016) The Climate Data Guide Atmospheric Reanalysis Overview & Comparison Tables.
27. US, FERC (2016) Pumped storage projects (http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp).
28. Oak Ridge National Laboratory (2015), 2014 hydropower market report.
29. Wamboldt J (2009) Central solar heating plants with seasonal storage for residential applications in canada. *Queens University, Canada (thesis)*.
30. Rehau (2015) Underground thermal energy storage (presentation).
31. Gaine K, Duffy A (2010) A life cycle cost analysis of large-scale thermal energy storage technologies for buildings using combined heat and power. *Conference Proceedings - Zero Emission Buildings*.
32. Sibbit B et al. (2012) The performance of a high solar fraction seasonal storage district heating system: Five years of operation.
33. IEA-ETSAP, IRENA (2013) Thermal energy storage: Technology brief e17.
34. Malana DJ, Dobson RT, Dinter F (2015) Solar Thermal Energy Storage in Power Generation Using Phase Change Material with Heat Pipes and Fins to Enhance Heat Transfer. *Energy Procedia* 69:925–936.
35. Levitan D (2014) Terrafore looks to cut molten salt energy storage costs in half. *IEEE Spectrum [Feb 27, 2014]*.
36. Deign J (2015) Research team in pcm storage breakthrough. *CSP Today [Jan 5, 2015]*.
37. Nithyanandam K, Pitchumani R (2014) Cost and performance analysis of concentrating solar power systems with integrated latent thermal energy storage. *Energy* 64:793–810.
38. US, DOE (2012) Sunshot vision study: February 2012.
39. Victor D (1990) Liquid hydrogen aircraft and the greenhouse effect. *International Journal of Hydrogen Energy* 15(5):357 – 367.
40. Laboratory SAINRE (2014) Techno-economic analysis of pem electrolysis for hydrogen production.
41. Jacobson MZ, Colella WG, Golden DM (2005) Cleaning the air and improving health with hydrogen fuel-cell vehicles. *Science* 308(5730):1901–1905.
42. Lew D (2013) Wind and solar curtailment. *in International Workshop on Large-Scale Integration of Wind Power Into Power Systems as Well as on Transmission Networks for Offshore Wind Power Plants, London, UK*.
43. US, EIA (2016) Electric power monthly with data for november 2015.
44. Clack CTM, Xie Y, MacDonald AE (2015) Linear programming techniques for developing an optimal electrical system including high-voltage direct-current transmission and storage. *International Journal of Electrical Power & Energy Systems*, vol. 68, pp. 103–114.
45. Mai T, Sandor D, Wiser R, Schneider T (2012) Renewable electricity futures study: Executive summary (national renewable energy laboratory).
46. European, Commission (2014) Impact assessment accompanying the communication from the european commission: A policy framework for climate and energy in the period from 2020 to 2030.
47. Mone C, Smith A, Maples B, Hand M (2015) 2013 cost of wind energy review (national renewable energy laboratory).
48. International, Renewable, Energy, Agency (2012) Renewable energy technologies cost analysis series: Wind power.
49. Oxera, Consulting, Ltd (2011) Discount rates for low-carbon and renewable generation technologies.
50. Iyer GC et al. (2015) Improved representation of investment decisions in assessments of CO2 mitigation. *Nature Climate Change* 5(5):436–440.
51. Bundesministerium für Wirtschaft und Energie B (2015) Zeitreihen zur entwicklung der erneuerbaren energien in deutschland.
52. Denholm P, Hand M, Jackson M, Ong S (2009) Land-use requirements of modern wind power plants in the United States (NREL).
53. Nickerson C, Ebel R, Borchers A, Carriazo F (2011) Major uses of land in the United States, 2007 (US department of agriculture, economic research service).
54. Ong S, Campbell C, Denholm P, Margolis R, Heath G (2013) Land-use requirements for solar power plants in the United States (NREL).
55. Miller NW, Shao M, Pajic S, D'Aquila RDD (2014) Western wind and solar integration study phase 3 frequency response and transient stability (national renewable energy laboratory subcontract report).
56. US, FERC (1995) Promoting wholesale competition through open access non-discriminatory transmission services by public utilities, docket rm95-8-000.
57. Chow CW et al. (2011) Intra-hour forecasting with a total sky imager at the {UC} san diego solar energy testbed. *Solar Energy* 85(11):2881 – 2893.
58. Mathiesen P, Kleissl J (2011) Evaluation of numerical weather prediction for intra-day solar forecasting in the continental United States. *Solar Energy* 85(5):967 – 977.
59. Marquez R, Coimbra CF (2011) Forecasting of global and direct solar irradiance using stochastic learning methods, ground experiments and the {NWS} database. *Solar Energy* 85(5):746 – 756.
60. Jacobson MZ (2001) GATOR-GCMM: 2. A study of daytime and nighttime ozone layers aloft, ozone in national parks, and weather during the SARMAP field campaign. *Journal of Geophysical Research* 106(D6):5403–5420.
61. Jacobson MZ, Archer CL (2012) Saturation wind power potential and its implications for wind energy. *Proceedings of the National Academy of Sciences of the United States of America* 109(39):15679–15684.
62. Jacobson MZ, Archer CL, Kempton W (2014) Taming hurricanes with arrays of offshore wind turbines. *Nature Climate Change* 4(3):195–200.
63. Taylor KE, Stouffer RJ, Meehl GA (2012) An overview of cmip5 and the experiment design. *Bulletin of the American Meteorological Society* 93(4):485–498.
64. Flato, G., J. Marotzke, B. Abiodun, P. Braconnot, S.C. Chou, W. Collins, P. Cox, F. Driouech, S. Emori, V. Eyring, C. Forest, P. Gleckler, E. Guilyardi, C. Jakob, V. Kattsov, C. Reason and M. Rummukainen, 2013: Evaluation of Climate Models. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
65. Martin CMS, Lundquist JK, Handschy MA (2015) Variability of interconnected wind plants: correlation length and its dependence on variability time scale. *Environmental Research Letters* 10(4):44004–44013.
66. Clack CTM et al. (2015) Demonstrating the effect of vertical and directional shear for resource mapping of wind power. *Wind Energy*, vol. 19, pp. 1687-1697.
67. Choukulkar A et al. (2015) A new formulation for rotor equivalent wind speed for wind resource assessment and wind power forecasting. *Wind Energy*, vol. 19, pp. 1439–1452.
68. Clack CTM (2016) Modeling Solar Irradiance and Solar PV Power Output to Create a Resource Assessment Using Linear Multiple Multivariate Regression. *Journal of Applied Meteorology and Climatology*, DOI:10.1175/JAMC-D-16-0175.1