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

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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.

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.

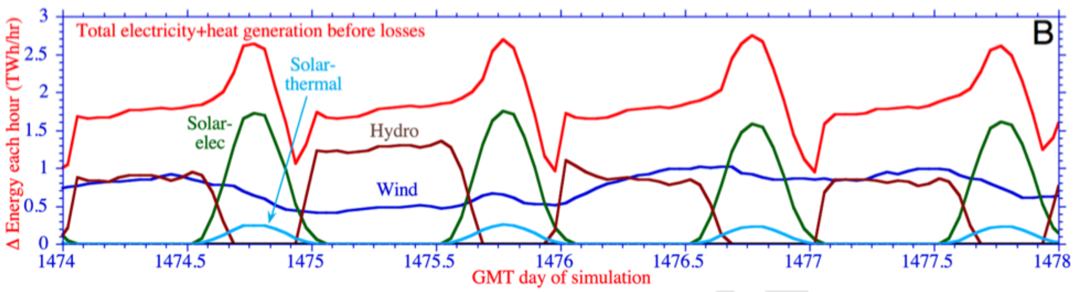

Fig. S1. Panel B of Figure 4 of ref. [11]

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

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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].

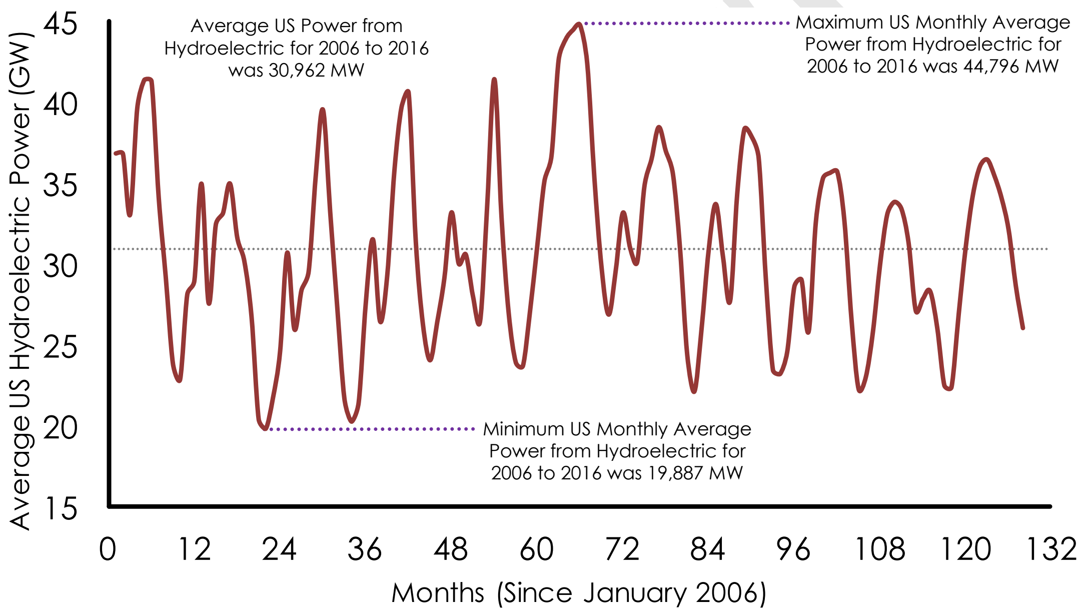

Fig. S2. The average power output from all the U.S. hydroelectric plants for 2006 through August 2016. The annual cycle from hydrology can be seen throughout the plot. The last five years are water constrained and the power output suffers as a result. The peak average monthly power is 44,796 MW for Spring 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 / $\mathrm{kWh_{th}}$, (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 / $\mathrm{kWh_{th}}$. 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).

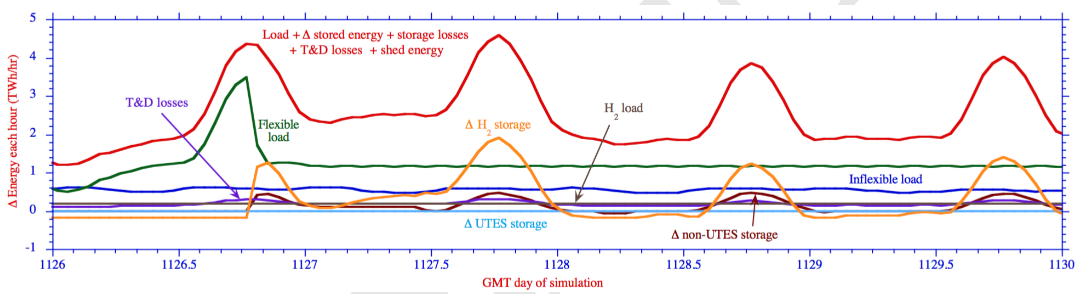

Fig. S3. Lowermost panel of Figure S6 of ref. [11]

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 $\sim$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

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

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).

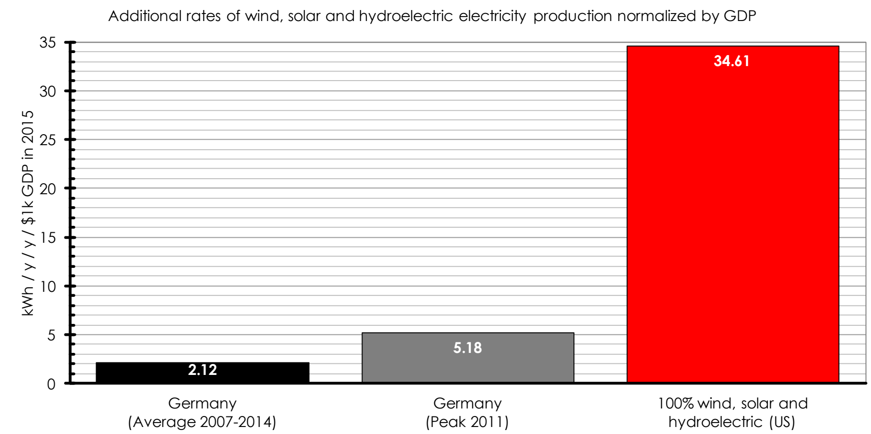

Fig. S4. GDP-normalized wind, solar and hydroelectric power addition rates of Germany (data from ref. [51]) and the rates implied for the 100% wind, solar and hydroelectric power system from ref. [11].

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).

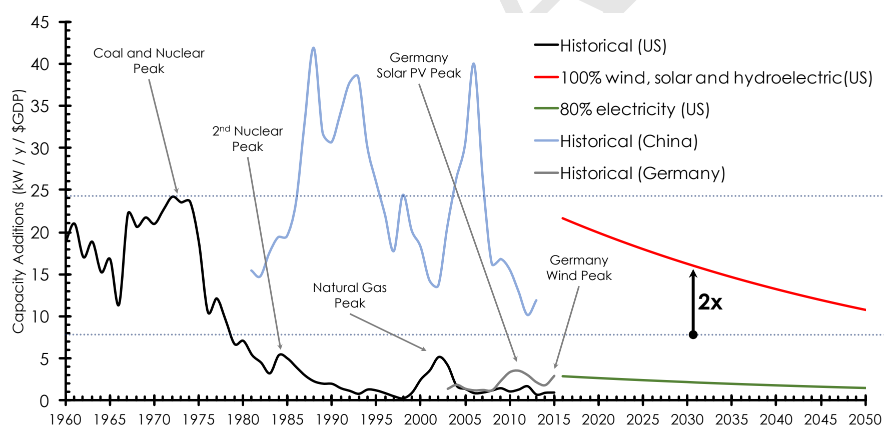

Fig. S5. Installed capacity per year per $ GDP. Historical data for the United States, China and Germany are shown along with the estimates for the 100% wind, solar and hydroelectric power system proposal [11] and the 80% carbon-free electricity system shown in ref. [1]. The 100% wind, solar and hydroelectric 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.

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 $\sim$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 ∼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.

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