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# The cost of grid stability with 100 % clean, renewable energy for all purposes when countries are isolated versus interconnected

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ABSTRACT

This study examines the impacts on energy costs and requirements of interconnecting versus isolating the electric grids of countries in Western Europe when each country's all-purpose energy is provided by 100 % wind, water, and sunlight (WWS). A weather model is used to predict wind and solar fields and building heat and cold loads. A grid model is used to match electricity, heat, cold, and hydrogen demand with WWS supply; electricity, heat, cold, and hydrogen storage; and demand response. Stable solutions are found for all countries, including the smallest (Luxembourg and Gibraltar) and largest (France, Germany, Spain, Italy, and the United Kingdom), and for all combinations of countries. Results indicate that interconnecting countries reduces aggregate annual energy costs, overbuilding of generators and storage, energy shedding, and land/water area requirements in most, but not all, situations. Interconnecting Western Europe may decrease aggregate annual energy costs ~13 % relative to isolating each country. The best reductions are found by interconnecting hydropower-rich Norway with Denmark (20.6 %) and Northwestern Europe (13.7 %). Interconnecting the smallest countries, Luxembourg and Gibraltar, with larger countries benefits all countries. Whether isolated or interconnected, all countries examined, including France and Germany, can maintain a stable grid at low cost with 100 % WWS.


**Broader context**

With the increasing penetration of renewables in many countries, energy planners would like to ensure that electric power grids remains stable. Even when dominated by fossil fuels, an isolated grid may fail during an extreme weather event. Such an outage could happen in any isolated grid. This paper explores grid stability in the presence of 100 % clean, renewable energy for all purposes when individual countries are isolated versus interconnected on the grid. Fourteen countries in Western Europe are examined in a case study. Stable solutions are found for all individual countries in isolation and all combinations of countries under all weather conditions. Results indicate that interconnecting the whole of Western Europe may decrease aggregate annual energy costs by ~13% relative to isolating each country's grid. The best benefits are found by interconnecting hydropower-rich Norway with Denmark and with all of Northwestern Europe. Interconnecting the smallest countries, Luxembourg and Gibraltar, with larger countries benefits both the small and large countries but the smaller countries the most. Overall, interconnecting geographically diverse resources across country boundaries reduces aggregate annual energy costs, overbuilding of generators and storage, energy shedding, and land/water area requirements in most, but not all, situations. It also hedges against a sudden loss of renewable supply in one region but not others during an extreme weather event.

**Introduction**

With the increasing penetration of clean, renewable energy in many countries, an important issue is how to keep the grid stable continuously. One potential method is to interconnect geographically-dispersed renewable energy resources across country boundaries. This study examines whether such interconnections are, indeed, helpful for maintaining grid stability at low cost.

At least 61 countries worldwide have committed to providing 100 % of their electricity from renewable sources [1]. Commitments by cities, states, and businesses to provide 100 % of their electricity or all energy from renewables number in the hundreds [2]. To ensure that 100 % renewable energy policies will allow the

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electricity grid to remain stable, many studies have examined the feasibility of matching electricity and/or heat demand with supply, storage, and/or demand response upon transitioning one or more energy sectors to 100 % renewables [3–26].

However, less work has been done on the benefits of interconnecting versus isolating the electric power grids among multiple countries upon a transition to 100 % renewable electricity. Some studies on the subject are as follows. Archer and Jacobson [27] concluded from wind data alone, "When multiple wind sites are considered, the number of days with no wind power and the standard deviation of the wind speed, integrated across all sites, are substantially reduced in comparison with when one wind site is considered. Therefore a network of wind farms in locations with high annual mean wind speeds may provide a reliable and abundant source of electric power." That study thus suggested that interconnecting a geographically dispersed 100 % intermittent electricity system would reduce intermittency among all interconnected generators. Archer and Jacobson [28] subsequently found that interconnecting geographically-dispersed wind farms not only smoothened out power supply among all farms but also reduced transmission requirements. Czisch [3] simulated the benefits of interconnecting the wind and solar resources of Europe with those of western Eurasia, the Middle East, and North Africa through high-voltage direct-current (HVDC) transmission lines. Blakers et al. [29] explored the benefits of transmitting Australia's solar energy to Southeast Asia through HVDC lines. Grossman et al. [30] simulated the benefit of interconnecting solar production across multiple time zones to reduce solar output variability aggregated among all time zones. Bogdanov and Breyer [16] found that interconnecting 13 regions in Northeast Asia resulted in lower energy costs than an isolated system. Aghahosseini et al. [24] found that interconnecting North and South America reduced overall system energy costs slightly relative to if each continent were isolated from the other. Martin et al. [31] used an optimization model to conclude that by trading electricity and sharing emission targets, U.S. states can reduce both electricity costs and carbon emissions.

The present study builds upon these previous ones to examine the benefits of interconnecting versus isolating individual countries in western Europe that have vastly different renewable energy resources from each other. This study uses a unique combination of tools (spreadsheet model, weather prediction model, and grid integration model) not used in previously analyses to quantify the benefits of interconnecting. This study differs from our own previous grid integration studies [14,22,25] in that it compares the cost and other parameters of keeping the grid stable when countries are completely isolated versus fully interconnected with each other. This was not done in our previous studies. This study is also unique compared with previous studies that have examined interconnection versus isolation as it uses consistent future fields of wind and solar generation and building heat and cold loads every 30 s for a year. It also uses a trial-and-error grid simulation model rather than an optimization model (the Methods section discusses the differences), it examines unique combinations of countries, and it examines several parameters not considered in previous studies.

Interconnecting grids across multiple countries or states may be important from a grid security point of view, as seen by the inability of the Texas grid to import electricity during a February 14–18, 2021, severe storm and ensuing blackout. The Texas grid failed largely because low temperatures caused natural gas, coal, nuclear, and wind electricity generators to fail, with natural gas being the largest source of failure. A portion of frozen wind turbines were shut because none had de-icing equipment. The present study does not examine a case of widespread equipment failure, only the impact of intermittency, including during extreme weather events, on grid failure.

This study also examines whether it is possible to supply all energy needs for all purposes continuously to even small countries, such as Luxembourg and Gibraltar, with internally-produced 100 % clean, renewable energy and how interconnecting those countries with their neighbors may reduce energy costs. The study further examines how France, which provides 70 % of its electricity from nuclear, might power not only its electricity sector, but all energy sectors, with 100 % internally-produced wind, water, and solar (WWS) and how the resulting cost of energy changes upon interconnecting France with its neighbors. The study additionally examines how countries with substantial hydropower resources, such as Norway and Switzerland, improve the ability of their neighbors, through grid interconnection, to balance renewable supply with demand, storage, and demand response.

In reality, all countries in Europe are interconnected to some degree with each other, so the two extreme cases examined here, zero interconnection and perfect interconnection do not represent the reality of the current interconnection situation in Europe. However, they do bound the current situation, so a showing that grids can stay stable at low cost with 100 % WWS and storage in both the isolated and fully-interconnected cases suggests they can stay stable at low cost in cases in-between.

## Methods

The strategy behind this study is to simulate matching time-dependent 2050 demand with time-dependent WWS electricity and heat supply; electrolytic hydrogen production; electricity, heat, cold, and hydrogen storage; and demand response for individual countries and for combinations of countries in Western Europe (Table 1). This is done through the use of three tools: a spreadsheet model, a weather prediction model, and a grid integration model. The use of each tool is discussed, in turn.

The first tool used is a spreadsheet model. In this model, annual average (but not continuous) 2050 WWS electricity and heat loads for each individual country considered are derived, as in Jacobson et al. [25]. Such projections start with IEA [32] 2016 business-as-usual (BAU) end-use energy consumption data for all energy sectors (residential, commercial, transport, industrial, agriculture/forestry/fishing, and military), and for each energy type (oil, natural gas, coal, electricity, waste heat, solar and geothermal heat, and biofuels and waste) within each sector. Country data are summed here by region to provide the results in Table S1, which gives 2016 BAU loads by sector for each region and individual country considered here.

2016 BAU data are then projected for each country, sector, and fuel type to 2040 using "BAU reference scenario" projections for the same sectors and fuel types for one of 16 world regions from EIA [33]. The reference scenario is one of moderate economic growth and accounts for policies in different countries, population growth, economic and energy growth, some renewable energy growth, modest energy efficiency measures, and reduced energy use. Consumption of each fuel type in each sector in each country is then extrapolated from 2040 to 2050 using a 10-year moving linear extrapolation. Results are then summed here over all countries in each region. Table S1 and Table 2 give the resulting 2050 annual average BAU loads for each country and region.

The 2050 BAU energy for each fuel type in each sector and country is then transitioned to 2050 WWS electricity and heat in the same way as in Ref. 25. WWS electricity generators include onshore and offshore wind turbines, rooftop and utility-scale solar photovoltaics (PV), concentrated solar power (CSP) plants, tidal and wave devices, geothermal electric power plants, and existing hydroelectric power plants (no new reservoirs are assumed). WWS heat generators include solar and geothermal heat.

**Table 1**
The regions and country(ies) within each region simulated.

| Country or region | Name(s) of country(ies) within country or region |
|---|---|
| Belgium | Belgium |
| Denmark | Denmark |
| France | France |
| Germany | Germany |
| Gibraltar | Gibraltar |
| Italy | Italy |
| Luxembourg | Luxembourg |
| Netherlands | Netherlands |
| Norway | Norway |
| Portugal | Portugal |
| Spain | Spain |
| Sweden | Sweden |
| Switzerland | Switzerland |
| United Kingdom | United Kingdom |
| Nor-Den | Denmark, Norway |
| Nor-Den-Swe-Ger | Denmark, Germany, Norway, Sweden |
| Northern Europe | Belgium, Denmark, Germany, Luxembourg, Netherlands, Norway, Sweden |
| Swi-Fra | France, Switzerland |
| Swi-Ger | Germany, Switzerland |
| Northwest Europe | Belgium, Denmark, France, Germany, Luxembourg, Netherlands, Norway, Sweden, Switzerland |
| Swi-Ita | Italy, Switzerland |
| Spa-Por-Gib | Gibraltar, Portugal, Spain |
| Western Europe | Belgium, Denmark, France, Germany, Gibraltar, Italy, Luxembourg, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland |
| All Europe | Albania, Austria, Belarus, Belgium, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Gibraltar, Greece, Hungary, Ireland, Italy, Kosovo, Latvia, Lithuania, Luxembourg, Macedonia, Malta, Moldova Republic, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom |

Thus, for example, the source of building heat is moved from fossil fuels or bioenergy to air- and ground-source heat pumps running on WWS electricity and direct solar thermal or geothermal heat. Building cooling is provided by electric heat pumps.

Fossil fuel and biofuel vehicles are transitioned primarily to battery electric (BE) vehicles and some hydrogen fuel cell (HFC) vehicles, where the hydrogen in that case is produced using WWS electricity (i.e., green hydrogen). BE vehicles are assumed to dominate short- and long-distance light-duty ground transportation, construction machines, agricultural equipment, short- and moderate-distance trains (except where powered by electric rails or overhead wires), ferries, speedboats, short-distance ships, and short-haul aircraft traveling under 1500 km. HFC vehicles are assumed to make up all long-distance, heavy payload transport by road, rail, water, and air.

High-temperature industrial processes are electrified with electric arc furnaces, induction furnaces, resistance furnaces, dielectric heaters, and electron beam heaters.

Table S1 and Table 2 summarize the resulting 2050 WWS loads in each country and region examined here. As a result of electrification of all energy sectors, all-purpose end-use power demand decreases in each country or region by between 47.9 % and 75.8 % (Table S1). The world average (among 143 countries) reduction is 57.1 %, of which 38.3% points are due to the efficiency of using WWS electricity over combustion; 12.1% points are due to eliminating energy in the mining, transporting, and refining of fossil fuels; and 6.6% points are due to end-use energy efficiency improvements and reduced energy use beyond those in the BAU case [25]. Of the 38.3 % reduction due to the efficiency advantage of WWS electricity, 21.7% points are due to the efficiency advantage of WWS transportation, 3.4% points are due to the efficiency advantage of WWS electricity for industrial heat, and 13.2% points are due to the efficiency advantage of electric heat pumps.

Whereas, electrification of all energy sectors reduces overall energy needs substantially, it increases electricity requirements. For example, electricity provides ~21.5 % of all 2050 BAU end-use energy among all 143 countries in Ref. 25. Following almost-complete electrification of non-electricity sectors and providing all electricity with WWS in 2050, electricity and some direct heat provide 100 % of all end-use energy, but only 86 % more electricity than in the BAU case. As calculated here, in Europe, a mean of 51 % more electricity is required with WWS than with BAU (Table S3), but even with this increase, total end-use energy is still 59 % lower with WWS than with BAU (Table S1). In sum, overall energy requirements decrease but electricity requirements increase with WWS.

Next, a mix of WWS resources is estimated for each country to meet its all-sector annual-average end-use energy demand, as in Ref. 25. The mix is determined after a WWS resource analysis is performed for each country. Air pollution and climate damage in 2050 are estimated for each country, and the social cost benefits of reducing such damage with WWS are then calculated.

Here, we start with the annual-average 2050 WWS electricity and heat loads for each country of interest and the estimated number of WWS generators needed to meet such loads in the annual average, from Ref. 25. We then separate the total electricity and heat loads into flexible and inflexible loads, in the same manner as in Ref. 34, but for the countries and regions considered here. Flexible loads are loads subject to heat or cold storage (district heat storage or building water tank storage) and loads subject to demand response. Loads subject to demand response can be shifted forward in time a maximum of 8 h. Loads subject to heat/cold storage can be met with such storage or current or stored electricity. Inflexible loads much be met immediately with either current or stored electricity.

Next we run new one-year global simulations with the GATOR-GCMOM (Gas, Aerosol, Transport, Radiation, General Circulation,

**Table 2**
Key results from this study.

| Country or region | [a] Annual average BAU end-use load (GW) | [b] Annual average WWS end-use load (GW) | [c] Mean WWS Total capital cost ($tril 2013) | [d] Mean BAU (¢/kWh-all energy) | [e] Mean WWS (¢/kWh-all energy) | [f] Mean annual WWS all-energy private and social cost ($bil/yr) | [g] Mean annual BAU all-energy private cost ($bil/yr) | [h] Mean annual BAU health cost ($bil/yr) | [i] Mean annual BAU climate cost ($bil/yr) | [j] = g + h + i Mean annual BAU total social cost ($bil/yr) |
|---|---|---|---|---|---|---|---|---|---|---|
| Belgium | 69.7 | 29.2 | 0.302 | 11.12 | 10.5 | 26.9 | 67.9 | 23.4 | 68.9 | 160 |
| Denmark | 25.9 | 9.6 | 0.106 | 12.61 | 13.0 | 11.0 | 28.6 | 10.5 | 22.2 | 61.2 |
| France | 251.6 | 112.4 | 0.979 | 9.39 | 9.26 | 91.1 | 206.9 | 102.9 | 223.7 | 533.6 |
| Germany | 366.4 | 155.2 | 1.785 | 10.85 | 11.3 | 154.1 | 348.3 | 199.7 | 526.8 | 1075 |
| Gibraltar | 5.4 | 1.3 | 0.017 | 10.84 | 14.8 | 1.7 | 5.16 | 0.22 | 0.41 | 5.79 |
| Italy | 217.4 | 83.2 | 0.570 | 11.06 | 8.42 | 61.4 | 210.6 | 168.9 | 238.8 | 618.2 |
| Luxembourg | 6.0 | 2.3 | 0.039 | 11.96 | 15.9 | 3.2 | 6.33 | 1.42 | 6.31 | 14.06 |
| Netherlands | 105.7 | 40.1 | 0.422 | 11.15 | 11.2 | 39.2 | 103.2 | 35.8 | 115.6 | 254.6 |
| Norway | 47.0 | 20.2 | 0.033 | 6.61 | 6.10 | 10.8 | 27.2 | 6.9 | 31.0 | 65.1 |
| Portugal | 30.3 | 13.1 | 0.102 | 10.89 | 9.54 | 10.9 | 28.9 | 14.0 | 37.6 | 80.4 |
| Spain | 165.3 | 65.7 | 0.412 | 10.84 | 8.21 | 47.2 | 157.0 | 79.5 | 186.3 | 422.8 |
| Sweden | 58.5 | 30.5 | 0.163 | 8.70 | 8.33 | 22.2 | 44.6 | 10.4 | 33.7 | 88.6 |
| Switzerland | 33.6 | 16.0 | 0.040 | 7.79 | 6.15 | 8.6 | 22.9 | 12.4 | 26.3 | 61.6 |
| United Kingdom | 233.7 | 88.8 | 0.880 | 11.16 | 10.3 | 80.1 | 228 | 137 | 251 | 616 |
| Nor-Den | 72.8 | 29.8 | 0.084 | 8.74 | 6.63 | 17.3 | 55.8 | 17.3 | 53.2 | 126.3 |
| Nor-Den-Swe-Ger | 497.8 | 215.5 | 1.890 | 10.29 | 9.77 | 184.4 | 449 | 227 | 614 | 1290 |
| Northern Europe | 679.2 | 287.1 | 2.509 | 10.52 | 9.70 | 243.9 | 626 | 288 | 804 | 1718 |
| Swi-Fra | 285.2 | 128.4 | 0.981 | 9.20 | 8.66 | 97.4 | 230 | 115 | 250 | 595 |
| Swi-Ger | 400.1 | 171.2 | 1.797 | 10.59 | 10.6 | 159.6 | 371 | 212 | 553 | 1136 |
| Northwest Europe | 964.4 | 415.5 | 3.036 | 10.13 | 8.71 | 316.9 | 856 | 403 | 1054 | 2314 |
| Swi-Ita | 251.0 | 99.2 | 0.655 | 10.62 | 8.23 | 71.5 | 234 | 181 | 265 | 680 |
| Spa-Por-Gib | 201.0 | 80.1 | 0.508 | 10.85 | 8.17 | 57.3 | 191 | 94 | 224 | 509 |
| Western Europe | 1383 | 578.7 | 4.043 | 10.38 | 8.39 | 425.6 | 1257 | 666 | 1517 | 3441 |
| All Europe | 2293 | 939.7 | 6.407 | 10.34 | 8.30 | 683.7 | 2076 | 1589 | 2723 | 6388 |

Aggregate private energy cost (Columns f or g) equals annual average end use load (Column b or a) multiplied by the mean cost per unit energy (Column e or d, respectively) and by 8760 h per year. Tables S10–S13 give parameters for determining the costs of storage, energy generation, health damage, and climate damage, respectively. Table S10 gives the lifecycle costs and efficiencies of storage for each storage type. The discount rate used for generation, storage, transmission/distribution, and social costs is a social discount rate of 2 (1–3)% [25].

[a] 2050 annual-average end-use BAU load.
[b] 2050 annual-average end-use WWS load.
[c] Present value of the mean total capital cost for new WWS electricity, heat, cold, and hydrogen generation and storage and long-distance transmission.
[d] Mean levelized private costs of all BAU energy (¢/kWh-all-energy-sectors, averaged between today and 2050, in USD 2013). 0.83 Euro = 1 USD on May 13, 2021.
[e] Same as (d), but for WWS energy.
[f] WWS private (equals social) energy cost (2013 USD $billion/yr).
[g] BAU private energy cost (2013 USD $billion/yr).
[h] BAU health cost (2013 USD $billion/yr).
[i] BAU climate cost (2013 USD $billion/yr).
[j] BAU total social cost (2013 USD $billion/yr).

Mesoscale, and Ocean Model) [35–38] weather-climate-air-pollution model. This is the second tool used. The model predicts time-dependent (every 30 s) building heating and cooling loads (which were not previously calculated in Ref. 25), onshore and offshore wind electricity; rooftop and utility PV electricity; CSP electricity; and solar thermal heat supply for each country assuming the baseline number of generators estimated to meet annual average loads. From the offshore wind estimates, time-dependent wave power estimates are also derived [25].

GATOR-GCMOM accounts for the reduction in the wind's kinetic energy and speed due to the competition among wind turbines for limited available kinetic energy [37], the temperature-dependence of PV output [38], and the reduction in sunlight to building and the ground due to the conversion of radiation to electricity by solar devices [22,25]. It also accounts for (1) changes in air and ground temperature due to power extraction by solar and wind devices and subsequent electricity use [22,25]; (2) impacts of time-dependent gas, aerosol, and cloud concentrations on solar radiation and wind fields [36]; (3) solar radiation to rooftop PV panels at a fixed optimal tilt [38]; and (4) solar radiation to utility PV panels, half of which are at an optimal tilt and the other half of which track the sun with single-axis horizontal tracking [38].

Thermal loads in GATOR-GCMOM are calculated as follows [34]. The model predicts the ambient air temperature in each surface grid cell in each country and compares it with an ideal building interior temperature, 294.261 K (70 °F). It then calculates how much heating or cooling energy is needed every 30 s to maintain the interior temperature among all buildings in the grid cell (assuming an average *U*-value and surface area for buildings and a given number of buildings in each grid cell). The time series among all grid cells in a country are summed. The time-dependent result is then scaled by the ratio of the annual average 2050 heating or cooling demands required in a 100 % WWS world from Ref. 25 to the annual average heating or cooling load from the time series to obtain time-dependent heating and cooling loads that, when averaged, exactly equal the annual average load.

Time-dependent 2050 inflexible loads for each country are obtained by scaling hourly 2016 electricity loads for all but one European country from ENTSO-E [39] by the ratio of the annual average 2050 WWS inflexible load to the annual average load from the data profile. For Gibraltar, 2030 hourly load data from Neocarbon Energy [40] are used.

The third tool used here is the grid integration model, LOADMATCH [14,22,25]. This model simulates matching the time-dependent electricity and heat loads and losses with supply, storage, and demand response. Time-dependent (30-s resolution) 2050 WWS supplies and thermal loads from GATOR-GCMOM are inputs into LOADMATCH.

LOADMATCH is a trial-and-error grid simulation model. It works by running multiple simulations, one at a time. Each simulation marches forward one or more years, one timestep at a time, just as the real world does. The main constraint during a simulation is that the summed electricity, heat, cold, and hydrogen load, adjusted by demand response, must match energy supply and storage every timestep for an entire simulation period. If load is not met during any 30-s timestep, the simulation stops. Inputs (either the nameplate capacity of one or more generators; the peak charge rate, peak discharge rate, or peak capacity of storage; or characteristics of demand response) are then adjusted one at a time based on an examination of what caused the load mismatch (hence the description "trial-and-error" model). For example, if hydrogen or underground thermal energy storage is full when a mismatch occurs, a solution is to increase slightly the storage capacity of the one that is full. In cases where the cause is uncertain, generator nameplate capacities and storage peak discharge rates are increased one generator and one storage device at a time. Each update, another simulation is run from the beginning. New simulations are run until load is met every time step of the simulation period. After load is met once, additional simulations are performed with further-adjusted inputs to generate a set of lower-cost solutions that match load every timestep. The lowest cost solution among all successful simulations is then selected. The ratio of the final to initial nameplate capacity for each generator is the capacity adjustment factor (Table S5).

Unlike with an optimization model, which solves among all timesteps simultaneously, a trial-and-error model does not know the weather during the next timestep. Because a trial-and-error model is non-iterative, it requires less than a minute for a 3-year simulation with a 30-s timestep [25]. This is 1/500th to 1/100,000$^{th}$ the computer time of an optimization model for the same number of timesteps. The disadvantage of a trial-and-error model compared with an optimization model is that the former does not determine the least cost solution out of all possible solutions. Instead, it produces a set of viable solutions, from which the lowest-cost solution is selected.

Table S4 summarizes many of the processes treated in LOADMATCH. Model inputs are as follows: (1) time-dependent electricity produced from onshore and offshore wind turbines, wave devices, tidal turbines, rooftop PV panels, utility PV plants, CSP plants, and geothermal plants; (2) a hydropower plant peak discharge rate (nameplate capacity), which is set to the present-day nameplate capacity for this study, a hydropower plant mean recharge rate (from rainfall), and a hydropower plant annual average electricity output; (3) time-dependent geothermal heat and solar-thermal heat generation rates; (4) specifications of hot-water and chilled-water sensible-heat thermal energy storage (HW-STES and CW-STES) (peak charge rate, peak discharge rate, peak storage capacity, losses into storage, and losses out of storage); (5) specifications of underground thermal energy storage (UTES), including borehole, water pit, and aquifer storage; (6) specifications of ice storage (ICE); (7) specifications of electricity storage in pumped hydropower storage (PHS), phase-change materials coupled with CSP (CSP-PCM), and batteries; (8) specifications of hydrogen (for use in transportation) electrolysis, compression, and storage equipment; (9) specifications of electric heat pumps for air and water heating and cooling; (10) specifications of a demand response system; (11) specifications of losses along short- and long-distance transmission and distribution lines; (12) time-dependent electricity, heat, cold, and hydrogen loads, (13) scheduled and unscheduled maintenance downtimes for generators, storage, and transmission, and (14) costs of generation, storage, transmission and distribution, health damage, and climate damage.

Table S11 provides cost parameters of energy-generating technologies, short- and long-distance transmission, and distribution as well as lifetimes of energy-generating technologies. Table S10 provides cost parameters and lifetimes of storage technologies. Table S12 provides parameters for determining health costs. Table S13 provides social cost of carbon estimates.

One assumption here is that transmission is perfectly interconnected within each country and among all combinations of countries. This is because the countries considered here are small enough that they already have or could have well-interconnected transmission and distribution systems. Simulations of two or more interconnected countries are performed by aggregating their loads as if they were one country, so it is not possible to determine what the precise transfers of load are between countries. However, the study does estimate transmission and distribution (T&D) costs and T&D energy losses (Table S11 and Table S14) resulting from all transfers of electricity. Short-distance transmission costs, long-distance high-voltage direct current (HVDC) transmission costs, and distribution costs are tracked using a cost per kWh of electricity transmitted. HVDC capital costs are also tracked (Table S14). All electricity consumed is assumed to incur a short-distance transmission and distribution costs. When individual countries are considered, only 15 % of all electricity consumed is assumed to be subject to HVDC transmission cost in Germany, the United Kingdom, France, Norway, Sweden, Spain, Portugal, and Italy; 10 % is subject to HVDC cost in Denmark, the Netherlands, Belgium, and Switzerland; and 0 % is subject to HVDC cost in Luxembourg and Gibraltar (see Table S11, footnotes). When any two or more countries is interconnected, 30 % of all electricity consumed is subject to HVDC cost.

While the paper sacrifices spatial resolution needed to treat transmission explicitly, it treats time resolution (30 s) two orders of magnitude higher than in other studies (3600 s). This study also accounts for the spatial variation of wind and solar resources and thermal loads within countries, since all such calculations are performed with the global, 3-D gridded GATOR-GCMOM model.

Next, the order of operations in LOADMATCH, including how the model treats excess generation over demand and excess demand over generation, is summarized [25]. The first situation discussed is one in which the current (instantaneous) supply of WWS electricity or heat exceeds the current electricity or heat demand (load). The total load, whether for electricity or heat, consists of flexible and inflexible loads. Whereas flexible loads may be shifted forward in time with demand response, inflexible loads must be met immediately. If WWS instantaneous electricity or heat supply exceeds the instantaneous inflexible electricity or heat load, then the supply is used to satisfy that load. The excess WWS is then used to satisfy as much current flexible electric or heat load as possible. If any excess electricity exists after inflexible and current flexible loads are met, the excess electricity is sent to fill electricity, heat, cold, or hydrogen storage.

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

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

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

The second situation discussed is one in which current load exceeds WWS electricity or heat supply. When current inflexible plus flexible electricity load exceeds the current WWS electricity supply from the grid, the first step is to use electricity storage (CSP, pumped hydro, hydropower, and battery storage, in that order) to fill in the gap in supply. Sensitivity tests found that the order of charging and discharging electricity storage made little difference in the results. Also a question arises as to whether these options can be used to store electricity seasonally, such as for up to six months? Hydropower reservoirs can be used strategically for long term electricity storage. Although the storage time of batteries is only 1.94 h (Table S8), batteries can be concatenated together in series to provide multi-day or multi-week storage, but at the peak discharge rate of one battery. Alternatively, they can be used all at once in parallel to provide storage for 1.94 h but at the peak discharge rate of the sum of all batteries. As such, batteries, like hydropower, are versatile for providing long-term or short-term storage. However, batteries are currently somewhat expensive. Because of the availability of both hydropower and batteries, stable solutions are found here for all countries and regions without other seasonal electricity storage.

Electricity from storage is used to supply inflexible load first, followed by flexible load. If electricity storage becomes depleted and flexible load persists, demand response is used to shift the flexible load to a future hour.

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

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

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

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

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

## Results and discussion

GATOR-GCMOM was run on the global scale for one year (2050) at $1.5^\circ \times 1.5^\circ$ horizontal resolution. The model produced electricity from onshore and offshore wind turbines, rooftop and utility PV, and CSP; heat from solar thermal collectors; building air heating loads; and building air cooling loads every 30 s for each country in Table 1. Those results, along with the demand profiles previously described, were fed into LOADMATCH, which was run for each individual country and group of countries – 24 simulations total (Table 1) for a year.

LOADMATCH was run for each country and region with initial generator nameplate capacities and storage characteristics by country, from Ref. 25, that were estimated to meet annual average WWS loads. For each region, values were summed over all countries in the region. If the first simulation for a country or region did not result in a stable solution, inputs were adjusted each subsequent simulation until a zero-load-loss solution was found among all 30-s timesteps during 2050. Success typically occurred within 10 simulation attempts. After one successful simulation, the model was run for another 4 to 20 simulations, with further adjustments, to find additional lower-cost solutions. Thus, multiple zero-load loss solutions were obtained for each country and region, but only the lowest-cost solution is presented here. Table 3 provides the final generator nameplate capacities, whereas Table S5 provides capacity adjustment factors, which are the ratios of the final to first-guess generator nameplate capacities. Table S6 provides the final simulation-averaged capacity factors in each country or region. Table S7 provides the final storage peak charge rates, discharge rates, and capacities (assuming the maximum storage times at peak discharge given in Table S8).

Figure S1 shows the full 2050 time series of WWS power generation versus load plus losses plus changes in storage plus shedding for most countries and regions. Supply matched total load (end-use load plus changes in storage plus losses plus shedding) every 30 s for the year in all 24 countries and groups of countries. Table S9 confirms exact energy conservation numerically. It provides a detailed budget of energy demand, supply, losses, and changes in storage for each country and region. For example, it shows that, for “All Europe,” demand plus losses equals 10,216 TWh during the simulation, and this exactly equals supply plus changes of storage. Of that total, 8220.824 TWh is given in Table S9 as the end-use demand. Dividing that by 8747.4875 h of simulation gives 0.940 TW of annual-average end-use WWS load, which is the total shown in Table 2 for “All Europe.”

Tables 2, S14, and S15 summarize the resulting energy private and social costs and the sources of cost data (in the footnotes) for each of the 24 sets of simulations. Energy social costs are energy private costs plus health and climate costs due to energy. The WWS private cost includes the costs of new electricity and heat generation, short-distance transmission, long-distance transmission, distribution, heat storage, cold storage, electricity storage, and hydrogen production/compression/storage. WWS energy private costs (costs of energy alone) are assumed to equal WWS energy social costs, since in 2050, WWS generators, storage, and transmission will result in zero pollutant emissions while in use. Also, their manufacture and decommissioning will be free of energy-related emissions. The health and climate costs of zero emissions are zero.

Table S15 indicates that, for each of the 14 individual countries, WWS reduced annual aggregate private costs ($R_{APC}$) by 49 %–71 % and social costs ($R_{ASC}$) by 71 %–90 %. Thus, even without interconnecting countries, transitioning individual Western European countries reduces costs substantially relative to BAU. This result applies not only to the smallest countries, Gibraltar and

**Table 3**
Final (from LOADMATCH) 2050 total (existing plus new) nameplate capacity (GW) of WWS generators by region obtained here needed to match power demand with supply and storage continuously over time.

| Country or region | On-shore wind | Off-shore wind | Resi-dential roof PV | Comm/govt roof PV | Utility PV | CSP with stor-age | Geo elec-tricity | Hydro | Wave | Tidal | Solar ther-mal heat | Geo heat | % of 2050 in 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Belgium | 11.9 | 28.2 | 2.14 | 2.3 | 138.1 | 0 | 0 | 0.1 | 0 | 0.003 | 0.33 | 0.21 | 4.3 |
| Denmark | 27.3 | 11.7 | 3.07 | 2.0 | 9.6 | 0 | 0 | 0.009 | 0.8 | 0.073 | 0.89 | 0.35 | 14.4 |
| France | 162.5 | 33.6 | 72.7 | 86.9 | 171.2 | 0 | 0.04 | 18.5 | 4.1 | 1 | 1.63 | 2.35 | 8.6 |
| Germany | 238.5 | 94.7 | 73.6 | 275.4 | 344.8 | 0 | 0.03 | 4.5 | 1.1 | 0.035 | 14.0 | 2.85 | 12.1 |
| Gibraltar | 0.0 | 6.2 | 0.005 | 0 | 0 | 0 | 0 | 0 | 0 | 0.001 | 0 | 0 | 0.0 |
| Italy | 100 | 33.2 | 42.9 | 36.5 | 67.5 | 10.9 | 1.00 | 14.3 | 2.3 | 0.075 | 3.24 | 1.01 | 15.9 |
| Luxembourg | 2.0 | 0 | 0.31 | 0.4 | 11.4 | 0 | 0 | 0.034 | 0 | 0 | 0.03 | 0.00 | 2.4 |
| Netherlands | 21.1 | 60.9 | 3.07 | 5.1 | 145.9 | 0 | 0 | 0.037 | 0 | 0.012 | 0.61 | 0.79 | 4.3 |
| Norway | 5.7 | 2.1 | 3.08 | 0.7 | 3.3 | 0 | 0 | 30.4 | 0.2 | 0.350 | 0 | 1.30 | 70.8 |
| Portugal | 16.6 | 2.4 | 4.25 | 10.3 | 6.8 | 1.1 | 0.10 | 4.7 | 0.5 | 0.500 | 0.68 | 0.04 | 24.1 |
| Spain | 93.7 | 15.6 | 29.7 | 36.4 | 33.5 | 5.9 | 0.05 | 17.0 | 2.2 | 1.000 | 2.84 | 0.06 | 21.2 |
| Sweden | 32.8 | 12.5 | 6.31 | 3.7 | 29.0 | 0 | 0 | 16.4 | 0 | 0.100 | 0.34 | 5.60 | 28.2 |
| Switzerland | 6.5 | 0.0 | 2.96 | 6.3 | 6.7 | 0 | 0 | 13.9 | 0 | 0 | 1.15 | 1.73 | 48.7 |
| United Kingdom | 71.0 | 85.5 | 23.0 | 22.6 | 300.9 | 0 | 0 | 1.9 | 3.0 | 11.40 | 0.46 | 0.28 | 7.2 |
| Nor-Den | 18.0 | 7.8 | 6.01 | 2.4 | 11.2 | 0 | 0 | 30.5 | 1.0 | 0.423 | 0.89 | 1.65 | 52.0 |
| Nor-Den-Swe-Ger | 272.8 | 115.1 | 91.5 | 281.4 | 264.1 | 0 | 0.03 | 51.3 | 2.1 | 0.558 | 15.3 | 10.1 | 18.0 |
| Northern Europe | 340.2 | 182.7 | 99.2 | 292.3 | 478.5 | 0 | 0.03 | 51.5 | 2.1 | 0.573 | 16.2 | 11.1 | 14.7 |
| Swi-Fra | 206.6 | 35.4 | 78.6 | 99.4 | 82.1 | 4.5 | 0.04 | 32.4 | 4.1 | 1 | 2.78 | 4.08 | 12.1 |
| Swi-Ger | 258.1 | 75.7 | 79.5 | 302.6 | 278.7 | 0 | 0.03 | 18.3 | 1.1 | 0.035 | 15.2 | 4.58 | 14.1 |
| Northwest Europe | 462.7 | 225.2 | 177.8 | 207.7 | 631.5 | 4.5 | 0.07 | 83.9 | 6.2 | 1.573 | 19.0 | 15.2 | 15.4 |
| Swi-Ita | 114.3 | 33.2 | 47.7 | 46.6 | 83.6 | 7.8 | 1.00 | 28.2 | 2.3 | 0.075 | 4.38 | 2.75 | 18.5 |
| Spa-Por-Gib | 109.8 | 23.4 | 34.0 | 46.7 | 38.6 | 6.9 | 0.15 | 21.7 | 2.6 | 1.5 | 3.52 | 0.10 | 21.4 |
| Western Europe | 690.7 | 250.1 | 273.9 | 311.7 | 725.3 | 19.2 | 1.22 | 119.9 | 11.2 | 3.1 | 25.8 | 16.3 | 16.1 |
| All Europe | 1231 | 394.5 | 317.3 | 506.6 | 1106 | 21.1 | 3.17 | 167.4 | 15.5 | 15.0 | 36.7 | 22.3 | 12.4 |

The nameplate capacity equals the maximum possible instantaneous discharge rate. The last column is the percent of the total nameplate capacity needed in 2050 (the sum of all other columns in the table) that was already installed with WWS by the end of 2018.

Luxembourg, but also to France, Germany, Italy, Spain, and the UK, for example.

Fig. 1 compares the aggregate annual WWS cost when each of nine regions is interconnected versus when each country within each region provides 100 % of its own WWS energy in isolation from the other countries in the region. Let's start with Denmark and Norway. The costs per unit energy for 100 % WWS in Denmark and Norway, when each grid is isolated from each other, are 13.0 and 6.1 ¢/kWh-all-energy (USD 2013), respectively (Table 1). The corresponding mean annual aggregate cost of energy (cost per unit


**Fig. 1.** 2050 annual private cost of WWS energy (USD 2013) for groups of countries in Table 1 found here when the countries are interconnected among themselves versus isolated and the resulting totals added. Values are from Table 1.

energy multiplied by energy consumed per year) in each case is $11.0 and $10.8 billion/yr, respectively (Table 1). The cost per unit energy to keep the grid stable in Norway is low due to the substantial built-in hydropower storage already available. In fact, In 2018, Norway already has 71 % of the WWS nameplate capacity it needs to supply 100 % WWS across all energy sectors in 2050 (Table 3). Denmark, on the other hand, has relatively little hydro (and only 14.4 % of its needed nameplate capacity already installed in 2018), so Denmark needs to spend on additional storage and on additional electricity generation beyond that needed for annual average power. As a result of the overbuilding, 29.4 % of all Denmark's energy is shed during the simulation in which its grid is isolated, whereas only 2.4 % of Norway's is shed (Table S9).

When the two countries are interconnected, Norwegian hydro is able to fill in the gaps in Denmark's WWS supply, reducing the need to overbuild generation or storage, thereby reducing shedding and annual aggregate costs substantially. For example, interconnecting Norway and Denmark eliminates the need for 200 GW of batteries in Denmark (Table S7) and reduces the overall nameplate capacity of generators summed between the two countries by 22.6 % (Fig. 2, Table 3). Shedding decreases 96 % relative to not interconnecting the countries (Fig. 3, Table S9). Aggregate annual WWS energy costs decline by 20.6 % (Fig. 1, Table 2).

Interconnecting Norway with other countries in addition to Denmark similarly reduces costs. Fig. 1 shows that combining Norway, Denmark, Sweden, and Germany reduces aggregate annual cost by ~7 % relative to isolating all those countries. Adding in the Netherlands, Belgium, and Luxembourg to that mix (Northern Europe), reduces overall energy cost by ~8.8 % relative to isolating the countries. Adding France and Switzerland to that group (Northwest Europe) reduces overall costs by ~13.7 %. Adding Italy, Spain, Portugal, and Gibraltar to that group (Western Europe) reduces overall costs by ~12.9 %. Lesser overall cost benefits are found by combining Switzerland with either Germany, France, or Italy. Part of the reason is that Switzerland has less than half the installed hydropower as Norway. Another reason is that WWS costs per unit energy in Germany, France, and Italy, when isolated, are all lower than in Denmark.

The most expensive countries per unit energy, when providing 100 % of their own WWS energy, are Luxembourg (15.9 ¢/kWh) and Gibraltar (14.8 ¢/kWh) (Table 2). When Luxembourg is interconnected with the seven countries of Northern Europe (Table 1), the average cost of WWS energy across all countries (including Luxembourg) is only 9.7 ¢/kWh (Table 2). In addition, the aggregate annual cost among all seven countries declines by 8.8 % (Fig. 1) and shedding declines by 29.7 % (Fig. 3). Similarly, when Gibraltar is interconnected with Spain and Portugal, the average cost of WWS energy across the three countries is 8.17 ¢/kWh, which is lower than that of either Spain, Portugal, or Gibraltar individually (Table 2). Finally, the aggregate annual cost among the three countries declines 4.3 % (Fig. 1) and shedding declines 8.6 % (Fig. 3) compared with when the countries are isolated. Thus, interconnecting benefits the smallest countries in a region the most but also usually benefits large countries.

When countries are interconnected, the country in the region that requires the most capital investment when it is isolated (Table S14) is likely to be the same country that must make the most investment when the countries are linked. For example, in the Norway-Denmark-Sweden-Germany region, Germany needs to make the most investment.

Table 2 indicates that the cost per unit energy in France, Spain, and Italy are all already relatively low (9.26, 8.21, and 8.42 ¢/kWh, respectively) when each countries provides 100 % of its own energy from WWS in isolation. This bodes well for France, for example, which then does not need to rely on nuclear power for electricity in the future. Because the WWS cost per unit energy is already low in France, Spain, and Italy, interconnecting these countries doesn't change costs substantially. For example, connecting Switzerland with Italy increases annual aggregate costs by ~2.1 % (Fig. 1) and connecting Switzerland with France decreases annual aggregate costs by only ~2.4 % (Fig. 1).

Footprint is the physical land, water surface, or sea floor surface area removed by an energy technology from use for any other purpose. Spacing is the area between some technologies, such as wind turbines, wave devices, and tidal turbines, needed to minimize interference of the wake of one turbine with downwind

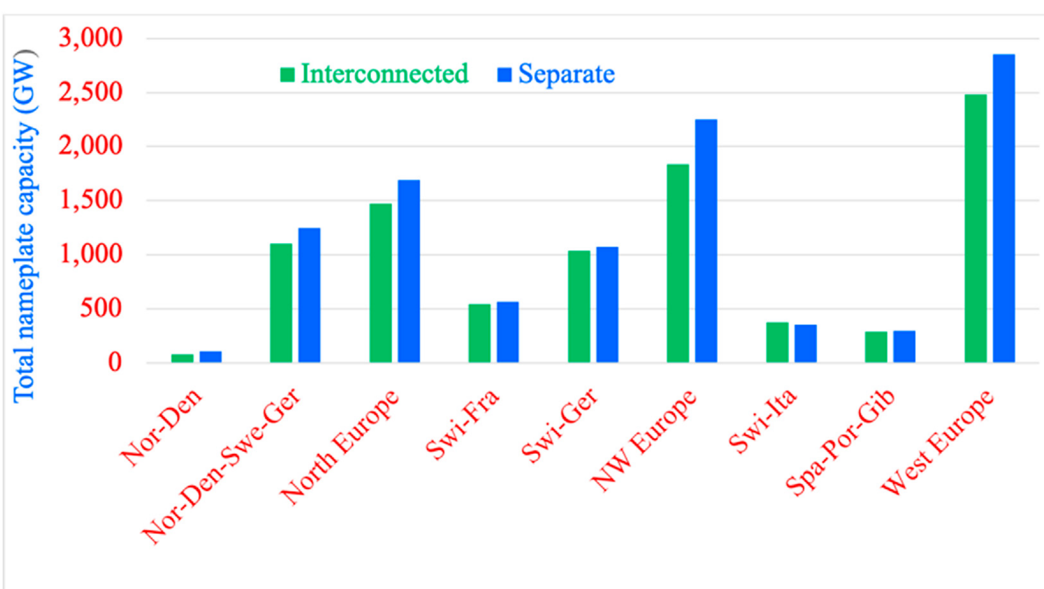


**Fig. 2.** New plus existing final nameplate capacity, summed over all WWS electricity generators, when countries in a given region are interconnected versus isolated. Values are from Table 3.

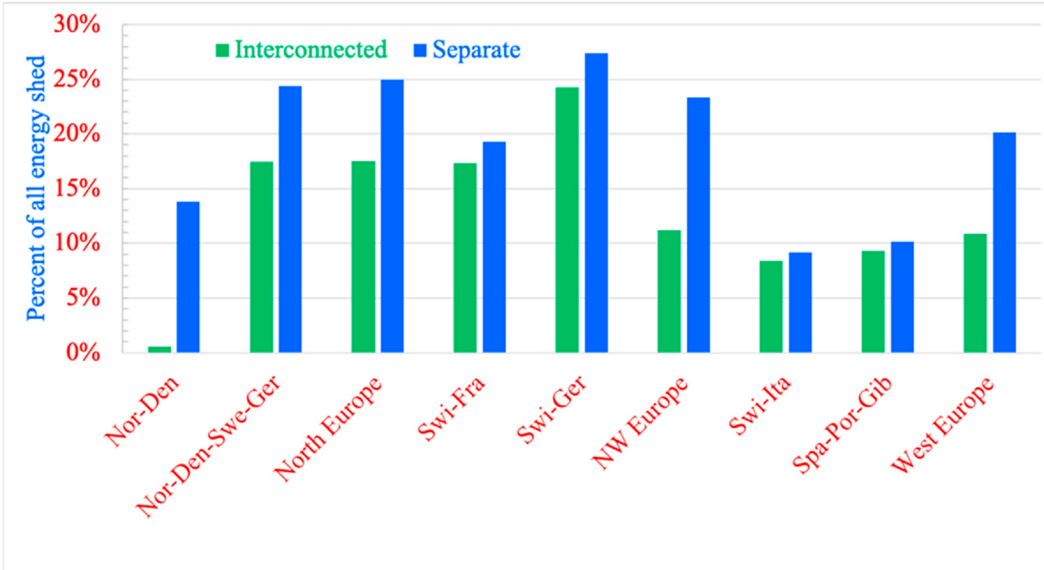


**Fig. 3.** Percent of all energy produced that is shed when countries in a region are interconnected versus isolated, as found in this study. Values are from Table S9.

turbines. Fig. 4 shows that interconnecting countries slightly reduces the footprint plus spacing land area required in most all cases. The reductions are due to the corresponding reductions in generator nameplate capacity needed (Fig. 2).

The reduction in nameplate capacity and either land or water area needed due to interconnecting countries can be critical to a transition to WWS in some countries. For example, Germany has economic rights to ~56,400 $km^2$ of offshore water area (10,900 $km^2$ and 12,500 $km^2$ within 12 nautical miles of its coasts in the Baltic Sea and North Sea, respectively, and 4500 $km^2$ and 28,500 $km^2$ in its Exclusive Economic Zones in the Baltic Sea and North Sea, respectively). With an isolated grid, Germany needs ~94.7 GW of offshore wind to maintain a stable grid with 100 % WWS in 2050 (Table 3). However, connecting Germany just to Switzerland reduces the offshore wind needs by 20 %, to 75.7 GW (Table 3). With an average European offshore wind installed power density of 7.2 MW/$km^2$ [41], this translates to a difference between 13,152 $km^2$ (23.3 %) and 10,513 $km^2$ (18.6 %) of Germany's available offshore water area for wind turbine spacing. Given that the closer wind farms are packed to each other, the lower their capacity factors [37], the additional 2600 $km^2$ of open ocean due to interconnecting not only leaves more ocean available for non-energy uses, improves views from the coast, and reduces public objection to offshore wind, but it also increases offshore wind capacity factors.

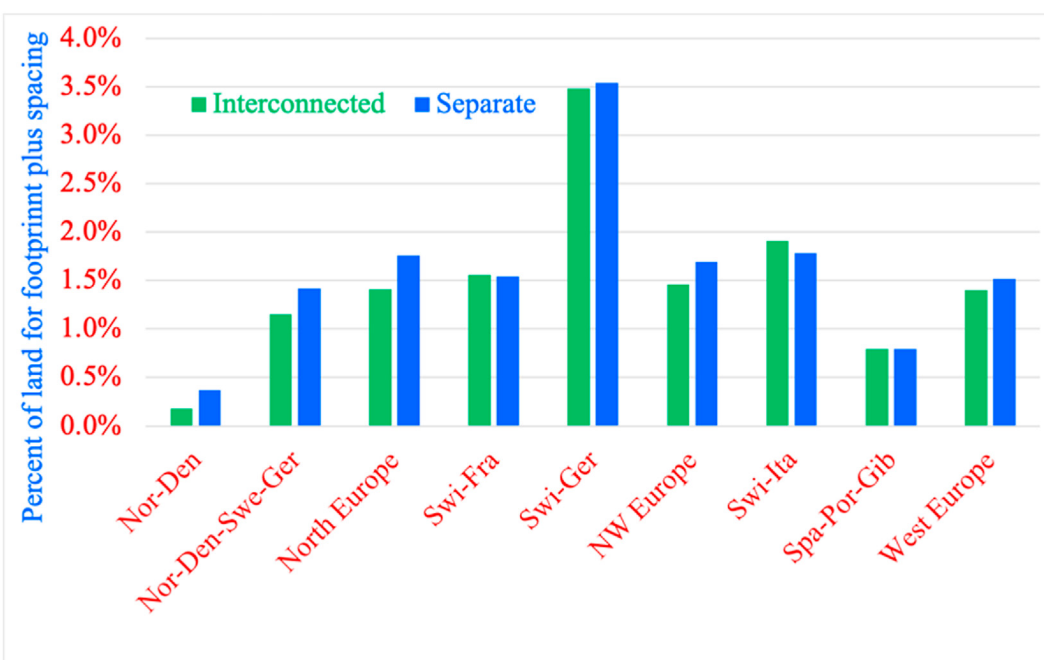


**Fig. 4.** Footprint plus spacing land areas needed for new WWS electricity generators when countries in a region are interconnected versus isolated. Values are from Table S16.

A final issue worthy of discussion is whether hydrogen should be used in sectors other than transportation. In previous work [42], we included some hydrogen combustion for high-temperature industrial processes. However, many electric machines that produce high temperatures (arc furnaces, induction furnaces, resistance furnaces, etc.) exist, so it is not clear hydrogen combustion is needed for high temperatures in industry. Further, using electricity to produce hydrogen by electrolysis and more electricity to compress and store and/or transport hydrogen is less efficient than using electricity directly to produce high temperatures. For those reasons, this study assumes the use of electricity instead of electrolytic hydrogen for high temperature processes. On the other hand, hydrogen will be useful for producing steel to almost eliminate process (non-energy) $CO_2$ emissions from steel production [43]. This process is not treated here.

Another potential use of hydrogen not treated here is for grid electricity. Using electrolytic hydrogen to produce grid electricity is less efficient than using and storing electricity in batteries due to the energy loss involved in producing, compressing, storing, and transporting hydrogen and using hydrogen in a fuel cell. However, a more useful application of stored hydrogen may be for combined electricity and heat production in a fuel cell in remote microgrids [44], but that process was also not treated.

In sum, although we did not treat hydrogen to obtain high temperatures for industry or to produce electric power, such uses of hydrogen are feasible with 100 % WWS, but possibly at a higher cost than using electricity directly.

## Conclusions and implications

In this study, grid stability in the presence of 100 % clean, renewable energy for all purposes was examined in Western European countries when the countries were isolated from each other versus interconnected in various combinations. The study found that all individual countries in Western Europe can provide 100 % of their all-purpose energy from clean, renewable WWS sources within the country. These include the smallest countries, Luxembourg and Gibraltar, as well as large ones. What's more, the annual private cost of WWS energy in all individual countries is 49 %–71 % lower than BAU energy in those countries. The annual social cost of 100 % WWS in those isolated countries is 71 %–90 % lower than in the BAU case in each country. Thus, France, for example, which currently provides 70 % of its electricity from nuclear power, can instead provide 100 % of its all-sector energy from clean, renewable electricity and heat at very low cost. Germany, too, has potential to provide 100 % of its all-purpose energy at low cost from internally-produced WWS.

Interconnecting countries reduces annual costs further by reducing storage requirements and excess generation nameplate capacity. The reductions in both also reduce shedding and land requirements in most cases. Interconnecting Norway, a country with substantial hydropower resources, with other countries, contributes greatly to cost reductions in the other countries. On the other hand, interconnecting small countries, such as Luxembourg and Gibraltar, with larger countries reduces the cost per unit energy and overall energy costs the most in the small countries but also benefits the larger countries. Results here are largely consistent with those from previous studies [3,16,24,27–31] that found smoother, more reliable renewable energy output and lower costs upon interconnecting geographically-dispersed renewables. This study, however, uses a different set of tools (spreadsheet model, weather prediction model, and grid integration model). It also quantifies benefits of such a transition for several combinations of countries in Western Europe not previously examined.

The main implication of this work is that interconnecting countries can usually serve as an additional benefit to grid stability and cost reduction in a 100 % clean, renewable energy world. Interconnecting two or more isolated grids also hedges against a sudden loss of renewable supply in one isolated grid but not others during an extreme weather event. This benefit is relevant because, even when dominated by fossil fuels, an isolated grid that has no outside electricity support may fail during an extreme weather event, as it did during the February 14–18, 2021 Texas storm. Such an outage could happen in any isolated grid.

Interconnecting countries has political limits. Limits arise if the public doesn't accept too many additional transmission lines. On the other hand, adding transmission may avoid the need to build new WWS generation in a country, reducing objection. Limits can also arise if one country doesn't want to cede too much reliance of its energy security on the goodwill of its neighbors, fearing that a neighbor may shut off the electricity supply during a conflict. This risk must be balanced by the lower cost and increased efficiency of a well-interconnected system.

This study finds that countries can be powered with either locally-produced or geographically-distributed 100 % clean, renewable energy sources. Interconnecting geographically diverse resources across country boundaries reduces aggregate annual energy costs in most, but not all, cases.

## CRediT authorship contribution statement

**Mark Z. Jacobson:** Conceptualization, Methodology, Investigation, Software, Writing – original draft, Writing – review & editing, Visualization.

## Declaration of competing interest

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

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## Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2021.07.115.

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# Electronic Supplementary Information

## The Cost of Grid Stability With 100% Clean, Renewable Energy for all Purposes When Countries are Isolated Versus Interconnected

**Mark Z. Jacobson**

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

## Supporting Tables

**Table S1.** 1st row for each country or region: 2018 annually-averaged total end-use business-as-usual (BAU) load (GW) and percentage of the total load by sector. 2nd row: estimated 2050 annually-averaged total end-use load (GW) and percentage of the total load by sector if conventional fossil-fuel, nuclear, and biofuel use continues from today to 2050 under a BAU trajectory. 3rd row: estimated 2050 total end-use load (GW) and percent of total load by sector if 100% of BAU end-use all-purpose delivered load in 2050 is instead provided by WWS. The last column shows the percent reductions in total 2050 BAU load due to switching from BAU to WWS, including the effects of reduced energy use due to (a) the higher work to energy ratio of electricity over combustion, (b) eliminating energy use for the upstream mining, transporting, and/or refining of coal, oil, gas, biofuels, bioenergy, and uranium, and (c) policy-driven increases in end-use efficiency beyond those in the BAU case.

| Country or region | Scenario | 2050 Total end-use load (GW) | Resid-ential percent of total end-use load | Com-mercial per-cent of total end-use load | Indus-trial per-cent of total end-use load | Trans-port per-cent of total end-use load | Ag/For/Fish-ing per-cent of total end-use load | Mil-itary/other per-cent of total end-use load | (a) Percent change end-use load w/WWS due to higher work: energy ratio | (b) Percent change end-use load w/WWS due to eliminat-ing upstream | (c) Percent change end-use load w/WWS due to effic-iency beyond BAU | Overall percent change in end-use load with WWS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Belgium | BAU 2016 | 59.96 | 18.0 | 10.3 | 31.8 | 38.0 | 1.7 | 0.11 | | | | |
| | BAU 2050 | 69.7 | 18.1 | 11.5 | 32.4 | 36.3 | 1.6 | 0.1 | | | | |
| | WWS 2050 | 29.2 | 14.1 | 14.3 | 48 | 22.4 | 1.1 | 0.03 | -43.39 | -7.91 | -6.81 | -58.11 |
| Denmark | BAU 2016 | 21.5 | 27.5 | 12.1 | 20.0 | 35.7 | 4.6 | 0 | | | | |
| | BAU 2050 | 25.9 | 28.9 | 13.7 | 21.3 | 32 | 4.1 | 0 | | | | |
| | WWS 2050 | 9.6 | 26.9 | 20.5 | 26.8 | 22.3 | 3.5 | 0 | -47.76 | -8.44 | -6.64 | -62.84 |
| France | BAU 2016 | 204.6 | 25.9 | 15.1 | 22.6 | 33.2 | 2.9 | 0.41 | | | | |
| | BAU 2050 | 251.6 | 26.9 | 17.5 | 22.1 | 30.6 | 2.5 | 0.4 | | | | |
| | WWS 2050 | 112.4 | 25.3 | 23.3 | 29.7 | 19.8 | 1.7 | 0.2 | -40.57 | -5.86 | -8.92 | -55.34 |
| Germany | BAU 2016 | 303.8 | 24.5 | 14.8 | 30.8 | 29.8 | 0 | 0.05 | | | | |
| | BAU 2050 | 366.4 | 24.3 | 16 | 30.5 | 29.2 | 0 | 0.04 | | | | |
| | WWS 2050 | 155.2 | 19.2 | 19.2 | 43.2 | 18.4 | 0 | 0.02 | -41.69 | -8.39 | -7.56 | -57.64 |
| Gibraltar | BAU 2016 | 5.14 | 0 | 0.026 | 0.071 | 99.4 | 0 | 0.49 | | | | |
| | BAU 2050 | 5.43 | 0 | 0.044 | 0.076 | 99.4 | 0 | 0.52 | | | | |
| | WWS 2050 | 1.31 | 0 | 0.142 | 0.2 | 98 | 0 | 1.68 | -69.72 | -1.88 | -4.17 | -75.78 |
| Italy | BAU 2016 | 165.5 | 25.8 | 12.4 | 26.2 | 33.2 | 2.3 | 0.12 | | | | |
| | BAU 2050 | 217.4 | 24.4 | 13.2 | 24.3 | 36.1 | 1.9 | 0.1 | | | | |
| | WWS 2050 | 83.2 | 19.2 | 20.3 | 35.6 | 23.5 | 1.5 | 0 | -42.19 | -11.58 | -7.97 | -61.74 |
| Luxembourg | BAU 2016 | 5.43 | 12.2 | 10.3 | 17.7 | 59.4 | 0.49 | 0 | | | | |
| | BAU 2050 | 6.04 | 12.5 | 11.8 | 18.1 | 57.2 | 0.5 | 0 | | | | |
| | WWS 2050 | 2.3 | 9.7 | 15.9 | 36.5 | 37.6 | 0.2 | 0 | -52.72 | -2.65 | -6.61 | -61.98 |
| Netherlands | BAU 2016 | 89.0 | 14.7 | 10.1 | 29.9 | 39.5 | 5.8 | 0.04 | | | | |
| | BAU 2050 | 105.6 | 15.5 | 11.7 | 31.1 | 36.4 | 5.3 | 0.04 | | | | |
| | WWS 2050 | 40.1 | 12.8 | 17.1 | 41.3 | 24.4 | 4.4 | 0.02 | -45.37 | -10.08 | -6.6 | -62.04 |
| Norway | BAU 2016 | 33.0 | 17.2 | 11.6 | 47.7 | 21.9 | 1.4 | 0.28 | | | | |
| | BAU 2050 | 47 | 17.5 | 13.2 | 45.8 | 22.2 | 1.1 | 0.21 | | | | |
| | WWS 2050 | 20.2 | 27.2 | 21.6 | 38.6 | 11.3 | 1.3 | 0.1 | -24.03 | -25.15 | -7.78 | -56.96 |
| Portugal | BAU 2016 | 24.6 | 14.1 | 10.4 | 33.5 | 39.6 | 2.2 | 0.16 | | | | |
| | BAU 2050 | 30.3 | 15.2 | 13.6 | 33.7 | 35.5 | 1.9 | 0.13 | | | | |
| | WWS 2050 | 13.1 | 17.1 | 22.1 | 39.4 | 20 | 1.3 | 0.08 | -37.81 | -12.06 | -6.97 | -56.84 |
| Spain | BAU 2016 | 131.7 | 15.2 | 10.7 | 28.7 | 42.5 | 2.7 | 0.23 | | | | |
| | BAU 2050 | 165.3 | 15.6 | 12.4 | 29.4 | 40.1 | 2.3 | 0.2 | | | | |
| | WWS 2050 | 65.7 | 18.3 | 19.4 | 34.8 | 25.5 | 1.7 | 0.3 | -39.77 | -13.6 | -6.89 | -60.26 |
| Sweden | BAU 2016 | 47.6 | 20.8 | 12.0 | 35.6 | 30.6 | 0.95 | 0 | | | | |
| | BAU 2050 | 58.5 | 23.4 | 14.2 | 32.8 | 28.9 | 0.80 | 0 | | | | |
| | WWS 2050 | 30.5 | 24.1 | 16.9 | 42.3 | 16.1 | 0.6 | 0 | -34.02 | -6.45 | -7.43 | -47.9 |
| Switzerland | BAU 2016 | 27.7 | 27.5 | 16.3 | 19.3 | 35.5 | 0.53 | 0.91 | | | | |
| | BAU 2050 | 33.6 | 27.1 | 18 | 18 | 35.6 | 0.5 | 0.80 | | | | |
| | WWS 2050 | 16 | 25.4 | 20.8 | 27.4 | 25.5 | 0.6 | 0.3 | -40.56 | -3.25 | -8.6 | -52.41 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| United Kingdom | BAU 2016 | 193.9 | 26.0 | 11.3 | 23.8 | 37.4 | 0.79 | 0.75 | | | | |
| | BAU 2050 | 233.7 | 26.9 | 13 | 25.1 | 33.6 | 0.70 | 0.68 | | | | |
| | WWS 2050 | 88.8 | 24.6 | 19.6 | 31.7 | 23.1 | 0.73 | 0.32 | -44.32 | -9.46 | -8.22 | -62.0 |
| Nor-Den | BAU 2016 | 54.5 | 21.3 | 11.8 | 36.8 | 27.3 | 2.7 | 0.17 | | | | |
| | BAU 2050 | 72.9 | 21.6 | 13.4 | 37.1 | 25.7 | 2.2 | 0.13 | | | | |
| | WWS 2050 | 29.8 | 27.1 | 21.2 | 34.8 | 14.8 | 2.0 | 0.07 | -32.46 | -19.21 | -7.37 | -59.05 |
| Nor-Den-Swe-Ger | BAU 2016 | 405.9 | 23.6 | 14.1 | 32.2 | 29.6 | 0.47 | 0.06 | | | | |
| | BAU 2050 | 497.8 | 23.8 | 15.4 | 31.7 | 28.6 | 0.4 | 0.02 | | | | |
| | WWS 2050 | 215.5 | 21.0 | 19.2 | 41.9 | 17.6 | 0.4 | 0.01 | -39.44 | -9.75 | -7.52 | -56.70 |
| Northern Europe | BAU 2016 | 560.3 | 21.5 | 13.0 | 31.6 | 32.4 | 1.4 | 0.06 | | | | |
| | BAU 2050 | 679.1 | 21.8 | 14.4 | 31.6 | 30.9 | 1.3 | 0.02 | | | | |
| | WWS 2050 | 287.1 | 19.1 | 18.3 | 42.4 | 19.2 | 1.0 | 0.01 | -33.83 | -7.98 | -6.27 | -48.08 |
| Swi-Fra | BAU 2016 | 232.3 | 26.0 | 15.2 | 22.2 | 33.5 | 2.6 | 0.47 | | | | |
| | BAU 2050 | 285.2 | 26.9 | 17.6 | 21.6 | 31.2 | 2.3 | 0.45 | | | | |
| | WWS 2050 | 128.4 | 25.3 | 23.0 | 29.4 | 20.5 | 1.6 | 0.21 | -40.57 | -5.55 | -8.88 | -54.99 |
| Swi-Ger | BAU 2016 | 331.5 | 24.7 | 15.0 | 29.9 | 30.3 | 0.04 | 0.12 | | | | |
| | BAU 2050 | 400 | 24.5 | 16.2 | 29.5 | 29.7 | 0.0 | 0.07 | | | | |
| | WWS 2050 | 171.2 | 19.8 | 19.3 | 41.7 | 19.1 | 0.1 | 0.03 | -41.60 | -7.96 | -7.65 | -57.20 |
| Northwest Europe | BAU 2016 | 792.6 | 22.8 | 13.7 | 28.9 | 32.7 | 1.8 | 0.18 | | | | |
| | BAU 2050 | 964.3 | 23.3 | 15.3 | 28.6 | 31.0 | 1.6 | 0.15 | | | | |
| | WWS 2050 | 415.5 | 21.0 | 19.8 | 38.4 | 19.6 | 1.2 | 0.07 | -40.79 | -8.37 | -7.76 | -56.92 |
| Swi-Ita | BAU 2016 | 193.2 | 26.1 | 13.0 | 25.2 | 33.5 | 2.1 | 0.23 | | | | |
| | BAU 2050 | 251 | 24.8 | 13.8 | 23.5 | 36.0 | 1.7 | 0.19 | | | | |
| | WWS 2050 | 99.2 | 20.2 | 20.4 | 34.3 | 23.8 | 1.4 | 0.05 | -41.97 | -10.46 | -8.05 | -60.49 |
| Spa-Por-Gib | BAU 2016 | 161.4 | 14.5 | 10.3 | 28.6 | 43.9 | 2.5 | 0.23 | | | | |
| | BAU 2050 | 201 | 15.1 | 12.2 | 29.3 | 41.0 | 2.2 | 0.19 | | | | |
| | WWS 2050 | 80.1 | 17.8 | 19.5 | 35.0 | 25.8 | 1.6 | 0.29 | -40.28 | -13.05 | -6.83 | -60.16 |
| Western Europe | BAU 2016 | 1,120 | 22.1 | 13.0 | 28.4 | 34.4 | 2.0 | 0.18 | | | | |
| | BAU 2050 | 1,383 | 22.3 | 14.5 | 28.0 | 33.2 | 1.7 | 0.15 | | | | |
| | WWS 2050 | 578.8 | 20.3 | 19.8 | 37.5 | 21.0 | 1.3 | 0.09 | -40.94 | -9.55 | -7.66 | -58.15 |
| All Europe | BAU 2016 | 1,620 | 23.5 | 12.2 | 29.6 | 32.2 | 2.3 | 0.21 | | | | |
| | BAU 2050 | 2,293 | 24.4 | 13.6 | 28.4 | 31.5 | 1.9 | 0.20 | | | | |
| | WWS 2050 | 940 | 22.1 | 18.9 | 37.6 | 19.9 | 1.3 | 0.1 | -41.6 | -9.9 | -7.6 | -59.0 |

BAU 2016 values are from IEA (Ref. S2). 2050 BAU values for individual countries are extrapolated from 2016 values, as described in Ref. S1, then summed here for groups of countries. Briefly, EIA's International Energy Outlook (IEO) (Ref. S3) projects energy use by end-use sector, fuel, and 16 world regions out to 2040 in a reference (BAU) scenario that represents modest economic growth. This is extended to 2075 using a ten-year moving linear extrapolation. The EIA projections account for policies, population growth, economic and energy growth, some modest renewable energy additions, and modest energy efficiency measures and reduced energy use in each sector. EIA sectors and fuels are then mapped to IEA sectors and fuels, and each country's 2016 energy consumption by sector and fuel from Ref. 2 is scaled by the ratio of EIA's 2050/2016 energy consumption by sector and fuel for each region. The transportation load includes, among other loads, energy produced in each country for international transportation and shipping. 2050 WWS values are estimated from 2050 BAU values assuming electrification of end-uses and effects of additional energy-efficiency measures beyond those in the BAU case, as discussed in detail in Ref. S1.

**Table S2.** 2050 annual average end-use electric plus heat load (GW) by sector after energy in all sectors has been converted to WWS. Instantaneous loads can be higher or lower than annual average loads.

| Country or region | Total | Resi-dential | Com-mercial | Trans-port | Industrial | Agricul-ture/forest /fishing | Military/ other |
|---|---|---|---|---|---|---|---|
| Belgium | 29.2 | 4.11 | 4.19 | 6.53 | 14.03 | 0.33 | 0.01 |
| Denmark | 9.61 | 2.58 | 1.98 | 2.15 | 2.58 | 0.33 | 0 |
| France | 112.4 | 28.46 | 26.22 | 22.23 | 33.39 | 1.87 | 0.21 |
| Germany | 155.2 | 29.79 | 29.83 | 28.56 | 67.02 | 0 | 0.03 |
| Gibraltar | 1.32 | 0.00 | 0.00 | 1.29 | 0.00 | 0 | 0.02 |
| Italy | 83.2 | 15.94 | 16.86 | 19.51 | 29.60 | 1.23 | 0.04 |
| Luxembourg | 2.30 | 0.22 | 0.37 | 0.86 | 0.84 | 0.01 | 0 |
| Netherlands | 40.1 | 5.14 | 6.84 | 9.77 | 16.56 | 1.78 | 0.01 |
| Norway | 20.2 | 5.49 | 4.36 | 2.29 | 7.81 | 0.25 | 0.02 |
| Portugal | 13.1 | 2.24 | 2.89 | 2.62 | 5.15 | 0.17 | 0.01 |
| Spain | 65.7 | 12.02 | 12.73 | 16.75 | 22.85 | 1.15 | 0.20 |
| Sweden | 30.5 | 7.36 | 5.16 | 4.89 | 12.88 | 0.19 | 0 |
| Switzerland | 16.0 | 4.06 | 3.33 | 4.08 | 4.38 | 0.10 | 0.05 |
| United Kingdom | 88.8 | 21.81 | 17.42 | 20.50 | 28.15 | 0.65 | 0.29 |
| Nor-Den | 29.8 | 8.08 | 6.33 | 4.43 | 10.39 | 0.59 | 0.02 |
| Nor-Den-Swe-Ger | 215.5 | 45.22 | 41.33 | 37.88 | 90.29 | 0.77 | 0.05 |
| Northern Europe | 287.1 | 54.70 | 52.72 | 55.04 | 121.71 | 2.88 | 0.07 |
| Swi-Fra | 128.4 | 32.52 | 29.55 | 26.31 | 37.77 | 1.97 | 0.26 |
| Swi-Ger | 171.2 | 33.85 | 33.16 | 32.64 | 71.40 | 0.10 | 0.08 |
| Northwest Europe | 415.5 | 87.22 | 82.27 | 81.35 | 159.48 | 4.85 | 0.32 |
| Swi-Ita | 99.2 | 20.00 | 20.19 | 23.59 | 33.97 | 1.33 | 0.09 |
| Spa-Por-Gib | 80.1 | 14.26 | 15.62 | 20.66 | 28.00 | 1.31 | 0.23 |
| Western Europe | 578.7 | 117.4 | 114.7 | 121.5 | 217.1 | 7.39 | 0.59 |
| All Europe | 939.7 | 207.2 | 177.7 | 187.3 | 353.7 | 12.6 | 1.19 |

Total values are taken directly from Table S1 and sector values are obtained by multiplying the total by the WWS 2050 percentages in Table S1.

**Table S3.** Annual average WWS all-sector inflexible and flexible loads (GW) in 2050 by country or region. "Total load" is the sum of "inflexible load" and "flexible load." "Flexible load" is the sum of "cold load subject to storage," "low-temperature heat load subject to storage," "load for $H_2$" production, compression, and storage (accounting for leaks as well), and "all other loads subject to demand response (DR)." Annual average loads are distributed in time as described in the text. Thus, instantaneous loads, either flexible or inflexible, can be much higher or lower than annual average loads. Also shown is the annual hydrogen mass needed in each region, estimated as the load multiplied by 8,760 hr/yr and divided by 59.01 kWh/kg-$H_2$. The last column shows the ratio of WWS:BAU electricity, where WWS electricity is effectively all end-use 2050 WWS energy and BAU electricity is 2050 electricity in the BAU electricity sector.

| Country or region | Total end-use load (GW) | Inflexible load (GW) | Flexible load (GW) | Cold load subject to storage (GW) | Low-temperature heat load subject to storage (GW) | Load for $H_2$ (GW) | All other loads subject to DR (GW) | $H_2$ needed (Tg-$H_2$/yr) | WWS: BAU electricity load |
|---|---|---|---|---|---|---|---|---|---|
| Belgium | 29.2 | 12.9 | 16.3 | 0.3 | 3.0 | 2.41 | 10.7 | 0.36 | 1.99 |
| Denmark | 9.6 | 3.7 | 5.9 | 0.04 | 2.20 | 0.80 | 2.8 | 0.12 | 1.62 |
| France | 112.4 | 54.6 | 57.7 | 1.44 | 15.5 | 6.83 | 33.9 | 1.01 | 1.30 |
| Germany | 155.2 | 71.3 | 84.0 | 1.66 | 20.3 | 9.36 | 52.7 | 1.39 | 1.58 |
| Gibraltar | 1.3 | 0.2 | 1.1 | 0.00 | 0.00 | 0.56 | 0.6 | 0.08 | 41.8 |
| Italy | 83.2 | 39.5 | 43.7 | 0.99 | 8.30 | 5.62 | 28.8 | 0.83 | 1.51 |
| Luxembourg | 2.3 | 0.9 | 1.4 | 0.02 | 0.20 | 0.34 | 0.9 | 0.05 | 1.99 |
| Netherlands | 40.1 | 18.0 | 22.1 | 0.29 | 4.16 | 3.78 | 13.9 | 0.56 | 2.01 |
| Norway | 20.2 | 8.8 | 11.4 | 0.10 | 4.14 | 0.71 | 6.4 | 0.11 | 0.99 |
| Portugal | 13.1 | 6.4 | 6.7 | 0.10 | 1.30 | 1.02 | 4.2 | 0.15 | 1.52 |
| Spain | 65.7 | 30.3 | 35.4 | 1.12 | 6.25 | 5.87 | 22.1 | 0.87 | 1.48 |
| Sweden | 30.5 | 12.6 | 17.9 | 0.16 | 5.37 | 1.36 | 11.0 | 0.20 | 1.32 |
| Switzerland | 16.0 | 7.9 | 8.1 | 0.08 | 1.56 | 1.02 | 5.4 | 0.15 | 1.40 |
| United Kingdom | 88.8 | 40.3 | 48.5 | 0.43 | 13.0 | 7.73 | 27.3 | 1.15 | 1.53 |
| Nor-Den | 29.8 | 12.5 | 17.3 | 0.14 | 6.41 | 1.51 | 9.3 | 0.22 | 1.14 |
| Nor-Den-Swe-Ger | 215.5 | 96.6 | 118.9 | 2.04 | 31.7 | 12.2 | 72.9 | 1.82 | 1.46 |
| Northern Europe | 287.1 | 128.4 | 158.7 | 2.59 | 39.1 | 18.8 | 98.3 | 2.78 | 1.57 |
| Swi-Fra | 128.4 | 64.3 | 64.1 | 1.25 | 15.3 | 7.85 | 39.7 | 1.17 | 1.32 |
| Swi-Ger | 171.2 | 81.5 | 89.7 | 1.40 | 19.4 | 10.4 | 58.5 | 1.54 | 1.56 |
| Northwest Europe | 415.5 | 190.5 | 225.0 | 4.12 | 56.7 | 26.6 | 137.6 | 3.95 | 1.48 |
| Swi-Ita | 99.2 | 47.4 | 51.7 | 1.06 | 9.86 | 6.64 | 34.2 | 0.99 | 1.49 |
| Spa-Por-Gib | 80.1 | 36.9 | 43.1 | 1.23 | 7.54 | 7.45 | 26.9 | 1.11 | 1.51 |
| Western Europe | 578.7 | 260.9 | 317.8 | 7.73 | 78.2 | 39.7 | 192.2 | 5.89 | 1.49 |
| All Europe | 939.7 | 423.6 | 516.1 | 11.1 | 133.6 | 63.3 | 308.1 | 9.40 | 1.51 |

**Table S4.** Several of the processes treated in the LOADMATCH model.

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

**Table S5.** LOADMATCH-derived final capacity adjustment factors (CAFs), which are the ratios of the final nameplate capacity of several generators to meet load continuously, after running LOADMATCH, to the pre-LOADMATCH initial nameplate capacity estimated herein (e.g., Table 3 of Ref. S1) to meet load in the annual average. Thus, a CAF less than 1.0 means that the LOADMATCH-stabilized grid meeting hourly demand requires less than the nameplate capacity needed to meet annual average load (which is our initial, pre-LOADMATCH nameplate-capacity assumption). Column (f) is the ratio of CSP turbine nameplate capacity (CSP storage maximum discharge rate) needed to keep the grid stable here relative to the pre-LOADMATCH nameplate capacity estimate for annual average power plus for keeping the grid stable. The pre-LOADMATCH factor is 1.6 (thus an estimated 60% more CSP turbines were added to keep the grid stable). Thus, a number less than 1.6 here indicates fewer CSP turbines are needed compared with the pre-LOADMATCH estimate. Table 3 provides the final CSP nameplate capacity, accounting for this factor. All generators not on this list have a CAF = 1.

| Country or region | (a) Onshore wind CAF | (b) Off-shore wind CAF | (c) Res. Roof PV CAF | (d) Com./ Gov Roof PV CAF | (e) Utility PV CAF | (f) CSP turbine factor | (g) Solar Thermal CAF |
|---|---|---|---|---|---|---|---|
| Belgium | 2 | 1.8 | 0.7 | 0.7 | 1.3 | 0 | 0.019 |
| Denmark | 2.5 | 2.3 | 0.8 | 0.8 | 0.8 | 0 | 0.308 |
| France | 1.4 | 0.95 | 1 | 1 | 2.2 | 0 | 0.044 |
| Germany | 1.5 | 1.25 | 1 | 3 | 2 | 0 | 0.264 |
| Gibraltar | 0 | 0.9 | 0.8 | 0.8 | 0.1 | 0 | 0 |
| Italy | 1.1 | 1 | 0.8 | 0.8 | 1.2 | 1.4 | 0.132 |
| Luxembourg | 4.5 | 0 | 1.4 | 1.5 | 1 | 0 | 0.014 |
| Netherlands | 2 | 1.5 | 0.7 | 1.2 | 1.5 | 0 | 0.037 |
| Norway | 0.8 | 0.8 | 0.5 | 0.5 | 0.5 | 0 | 0 |
| Portugal | 1.35 | 0.8 | 0.8 | 0.8 | 1.1 | 1 | 0.177 |
| Spain | 1.3 | 0.8 | 0.8 | 0.8 | 0.8 | 1 | 0.145 |
| Sweden | 1 | 1 | 0.8 | 0.8 | 1 | 0 | 0.052 |
| Switzerland | 0.5 | 0 | 0.5 | 0.5 | 0.5 | 0 | 0.228 |
| United Kingdom | 1.5 | 1.2 | 0.8 | 0.8 | 1.8 | 0 | 0.013 |
| Nor-Den | 1 | 1 | 0.6 | 0.6 | 0.6 | 0 | 0.173 |
| Nor-Den-Swe-Ger | 1.3 | 1.2 | 1 | 2.8 | 1.2 | 0 | 0.236 |
| Northern Europe | 1.5 | 1.2 | 1 | 2.7 | 1.1 | 0 | 0.161 |
| Swi-Fra | 1.6 | 1 | 1 | 1 | 0.9 | 1 | 0.066 |
| Swi-Ger | 1.5 | 1 | 1 | 2.9 | 1.5 | 0 | 0.261 |
| Northwest Europe | 1.3 | 1.2 | 1 | 1 | 1.2 | 1 | 0.133 |
| Swi-Ita | 1.1 | 1 | 0.8 | 0.8 | 1.2 | 1 | 0.149 |
| Spa-Por-Gib | 1.3 | 0.8 | 0.8 | 0.8 | 0.8 | 1 | 0.15 |
| Western Europe | 1.3 | 1 | 1 | 1 | 1.15 | 1 | 0.135 |
| All Europe | 1.42 | 1 | 0.68 | 0.9 | 1 | 1 | 0.109 |

**Table S6.** Average 2050-2052 capacity factors (percent of nameplate capacity produced as electricity before transmission, distribution or maintenance losses) by country or region obtained in this study.

| Country or region | On-shore wind | Off-shore wind | Rooftop PV | Utility PV | CSP with storage | Geo-thermal elec-tricity | Hydropower | Wave | Tidal | Solar thermal | Geo-thermal heat |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Belgium | 0.40 | 0.45 | 0.18 | 0.19 | -- | -- | 0.77 | -- | 0.25 | 0.10 | 0.97 |
| Denmark | 0.33 | 0.39 | 0.18 | 0.20 | -- | -- | 0.61 | 0.14 | 0.24 | 0.10 | 0.97 |
| France | 0.41 | 0.51 | 0.19 | 0.21 | -- | 0.89 | 0.59 | 0.27 | 0.24 | 0.10 | 0.97 |
| Germany | 0.35 | 0.39 | 0.18 | 0.19 | -- | 0.91 | 0.75 | 0.14 | 0.25 | 0.10 | 0.97 |
| Gibraltar | 0.00 | 0.34 | 0.24 | 0.26 | -- | -- | -- | 0.14 | 0.29 | -- | -- |
| Italy | 0.38 | 0.49 | 0.21 | 0.24 | 0.80 | 0.88 | 0.56 | 0.14 | 0.24 | 0.12 | 0.97 |
| Luxembourg | 0.37 | -- | 0.18 | 0.19 | -- | -- | 0.49 | -- | -- | 0.10 | -- |
| Netherlands | 0.41 | 0.44 | 0.19 | 0.20 | -- | -- | 0.76 | -- | 0.25 | 0.10 | 0.97 |
| Norway | 0.36 | 0.39 | 0.18 | 0.19 | -- | -- | 0.59 | 0.27 | 0.24 | -- | 0.97 |
| Portugal | 0.35 | 0.46 | 0.21 | 0.25 | 0.84 | 0.85 | 0.48 | 0.26 | 0.23 | 0.12 | 0.97 |
| Spain | 0.37 | 0.56 | 0.22 | 0.26 | 0.87 | 0.85 | 0.49 | 0.29 | 0.23 | 0.12 | 0.97 |
| Sweden | 0.27 | 0.35 | 0.18 | 0.20 | -- | -- | 0.70 | -- | 0.25 | 0.10 | 0.97 |
| Switzerland | 0.38 | -- | 0.19 | 0.20 | -- | -- | 0.82 | -- | -- | 0.10 | 0.97 |
| United Kingdom | 0.41 | 0.48 | 0.18 | 0.19 | -- | -- | 0.66 | 0.31 | 0.24 | 0.10 | 0.97 |
| Nor-Den | 0.34 | 0.39 | 0.18 | 0.20 | -- | -- | 0.63 | 0.17 | 0.24 | 0.10 | 0.97 |
| Nor-Den-Swe-Ger | 0.34 | 0.38 | 0.18 | 0.19 | -- | 0.91 | 0.70 | 0.16 | 0.24 | 0.10 | 0.97 |
| Northern Europe | 0.34 | 0.40 | 0.18 | 0.19 | -- | 0.91 | 0.72 | 0.16 | 0.24 | 0.10 | 0.97 |
| Swi-Fra | 0.41 | 0.51 | 0.19 | 0.21 | 0.70 | 0.89 | 0.53 | 0.27 | 0.24 | 0.10 | 0.97 |
| Swi-Ger | 0.35 | 0.39 | 0.18 | 0.19 | -- | 0.91 | 0.73 | 0.14 | 0.25 | 0.10 | 0.97 |
| Northwest Europe | 0.37 | 0.42 | 0.19 | 0.20 | 0.70 | 0.90 | 0.68 | 0.23 | 0.24 | 0.10 | 0.97 |
| Swi-Ita | 0.38 | 0.49 | 0.21 | 0.23 | 0.80 | 0.88 | 0.53 | 0.14 | 0.24 | 0.11 | 0.97 |
| Spa-Por-Gib | 0.37 | 0.50 | 0.22 | 0.25 | 0.86 | 0.85 | 0.47 | 0.28 | 0.23 | 0.12 | 0.97 |
| Western Europe | 0.37 | 0.44 | 0.20 | 0.21 | 0.80 | 0.88 | 0.62 | 0.23 | 0.24 | 0.11 | 0.97 |
| All Europe | 0.36 | 0.45 | 0.20 | 0.21 | 0.80 | 0.86 | 0.61 | 0.24 | 0.24 | 0.11 | 0.97 |

Capacity factors of offshore and onshore wind turbines account for array losses (extraction of kinetic energy by turbines). In all cases, capacity factors are before transmission, distribution, and maintenance losses, which are given in Table S11. The average capacity factor across multiple countries is weighted by the final nameplate capacity (Table 3). The symbol "--" indicates no installation of the technology. Rooftop PV panels are fixed-tilt at the optimal tilt angle of the country they reside in; utility PV panels are half fixed optimal tilt and half single-axis horizontal tracking (Ref. S4).

**Table S7.** Aggregate (among all storage devices in a country or region) maximum instantaneous charge rates, maximum instantaneous discharge rates, and maximum energy storage capacities of the different types of electricity storage (PHS, CSP-PCM, batteries, hydropower), cold storage (CW-STES, ICE), and heat storage (HW-STES, UTES) technologies treated here, by country or region. Table S8 gives the maximum number of hours of storage at the maximum discharge rate. The product of the maximum discharge rate and hours of storage gives the maximum energy storage capacity.

| | **Belgium** | | | **Denmark** | | | **France** | | | **Germany** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Storage technology | Max charge rate GW | Max dis-charge rate GW | Max stor-age capac-ity TWh | Max charge rate GW | Max dis-charge rate GW | Max stor-age capac-ity TWh | Max charge rate GW | Max dis-charge rate GW | Max stor-age capac-ity TWh | Max charge rate GW | Max dis-charge rate GW | Max stor-age capac-ity TWh |
| PHS | 6.585 | 6.585 | 0.092 | 2 | 2 | 0.028 | 26.45 | 26.45 | 0.37 | 25.82 | 25.82 | 0.36 |
| CSP-elec. | 0 | 0 | -- | 0 | 0 | -- | 0 | 0 | -- | 0 | 0 | -- |
| CSP-PCM | 0 | -- | 0 | 0 | -- | 0 | 0 | -- | 0 | 0 | -- | 0 |
| Batteries | 300 | 300 | 0.582 | 200 | 200 | 0.388 | 500 | 500 | 0.97 | 1300 | 1300 | 2.522 |
| Hydropower | 0.055 | 0.12 | 0.484 | 0.004 | 0.009 | 0.036 | 8.44 | 18.53 | 73.96 | 2.09 | 4.45 | 18.30 |
| CW-STES | 0.102 | 0.102 | .0014 | 0.017 | 0.017 | .0002 | 0.57 | 0.57 | 0.008 | 0.66 | 0.66 | 0.009 |
| ICE | 0.152 | 0.152 | .0021 | 0.026 | 0.026 | .0004 | 0.86 | 0.86 | 0.012 | 1.00 | 1.00 | 0.014 |
| HW-STES | 8.81 | 8.81 | 0.053 | 4.980 | 4.980 | 0.030 | 47.08 | 47.08 | 0.28 | 60.33 | 60.33 | 0.36 |
| UTES-heat | 0.334 | 8.81 | 3.17 | 0.894 | 4.980 | 1.793 | 1.63 | 47.08 | 5.65 | 14.04 | 60.33 | 14.48 |
| UTES-elec. | 13.22 | -- | -- | 7.470 | -- | -- | 70.62 | -- | -- | 90.49 | -- | -- |
| | **Gibraltar** | | | **Italy** | | | **Luxembourg** | | | **Netherlands** | | |
| PHS | 2 | 2 | 0.028 | 28.44 | 28.44 | 0.40 | 6.54 | 6.54 | 0.09 | 2 | 2 | 0.028 |
| CSP-elec. | 0 | 0 | -- | 10.92 | 10.92 | -- | 0 | 0 | -- | 0 | 0 | -- |
| CSP-PCM | 0 | -- | 0 | 17.60 | -- | 0.25 | 0 | -- | 0 | 0 | -- | 0 |
| Batteries | 20 | 20 | 0.039 | 200 | 200 | 0.388 | 120 | 120 | 0.233 | 550 | 550 | 1.067 |
| Hydropower | 0 | 0 | 0 | 6.48 | 14.33 | 56.74 | 0.016 | 0.034 | 0.136 | 0.017 | 0.037 | 0.151 |
| CW-STES | .0001 | .0001 | .000001 | 0.40 | 0.40 | 0.006 | 0.008 | 0.008 | .0001 | 0.116 | 0.116 | 0.002 |
| ICE | .0002 | .0002 | .000003 | 0.59 | 0.59 | 0.008 | 0.012 | 0.012 | .0002 | 0.174 | 0.174 | 0.002 |
| HW-STES | .0023 | .0023 | 000001 | 24.71 | 24.71 | 0.15 | 0.678 | 0.678 | 0.004 | 10.94 | 10.94 | 0.066 |
| UTES-heat | 0 | .0023 | .0008 | 3.24 | 24.71 | 8.90 | 0.027 | 0.678 | 0.813 | 0.608 | 10.94 | 1.313 |
| UTES-elec. | .0034 | -- | -- | 37.07 | -- | -- | 1.016 | -- | -- | 16.41 | -- | -- |
| | **Norway** | | | **Portugal** | | | **Spain** | | | **Sweden** | | |
| PHS | 6.87 | 6.87 | 0.096 | 11.15 | 11.15 | 0.156 | 13.7 | 13.7 | 0.19 | 2.35 | 2.35 | 0.033 |
| CSP-elec. | 0 | 0 | -- | 1.08 | 1.08 | -- | 5.86 | 5.86 | -- | 0 | 0 | -- |
| CSP-PCM | 0 | -- | 0 | 1.74 | -- | 0.024 | 9.44 | -- | 0.13 | 0 | -- | 0 |
| Batteries | 0 | 0 | 0 | 150 | 150 | 0.291 | 50 | 50 | 0.097 | 200 | 200 | 0.388 |
| Hydropower | 13.9 | 30.4 | 121.9 | 2.060 | 4.730 | 18.05 | 7.45 | 17.02 | 65.26 | 7.60 | 16.37 | 66.57 |
| CW-STES | 0.039 | 0.039 | 0.001 | 0.039 | 0.039 | 0.001 | 0.45 | 0.45 | 0.006 | 0.064 | 0.064 | .0009 |
| ICE | 0.058 | 0.058 | 0.001 | 0.058 | 0.058 | 0.001 | 0.67 | 0.67 | 0.009 | 0.096 | 0.096 | .0013 |
| HW-STES | 7.76 | 7.76 | 0.047 | 3.122 | 3.122 | 0.019 | 18.73 | 18.73 | 0.11 | 11.30 | 11.30 | 0.07 |
| UTES-heat | 0 | 7.76 | 0.186 | 0.677 | 3.122 | 2.623 | 2.84 | 18.73 | 6.74 | 0.34 | 11.30 | 10.85 |
| UTES-elec. | 11.6 | -- | -- | 4.683 | -- | -- | 28.10 | -- | -- | 16.95 | -- | -- |
| | **Switzerland** | | | **United Kingdom** | | | **Nor-Den** | | | **Nor-Den-Swe-Ger** | | |
| PHS | 12.7 | 12.7 | 0.178 | 11.6 | 11.6 | 0.16 | 6.87 | 6.87 | 0.096 | 31.0 | 31.0 | 0.435 |
| CSP-elec. | 0 | 0 | -- | 0 | 0 | -- | 0 | 0 | -- | 0 | 0 | -- |
| CSP-PCM | 0 | -- | 0 | 0 | -- | 0 | 0 | -- | 0 | 0 | -- | 0 |
| Batteries | 0 | 0 | 0 | 500 | 500 | 0.97 | 0 | 0 | 0 | 1000 | 1000 | 1.94 |
| Hydropower | 6.29 | 13.87 | 55.10 | 0.83 | 1.87 | 7.27 | 13.9 | 30.5 | 121.9 | 23.6 | 51.3 | 206.8 |
| CW-STES | 0.033 | 0.033 | .0005 | 0.17 | 0.17 | 0.002 | 0.057 | 0.057 | 0.001 | 0.81 | 0.81 | 0.011 |
| ICE | 0.049 | 0.049 | .0007 | 0.26 | 0.26 | 0.004 | 0.085 | 0.085 | 0.001 | 1.22 | 1.22 | 0.017 |
| HW-STES | 4.46 | 4.46 | 0.03 | 32.66 | 32.66 | 0.20 | 12.76 | 12.76 | 0.077 | 84.4 | 84.4 | 0.506 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| UTES-heat | 1.15 | 4.46 | 0.11 | 0.46 | 32.66 | 11.76 | 0.89 | 12.76 | 0.306 | 15.3 | 84.4 | 30.4 |
| UTES-elec. | 6.68 | -- | -- | 49.00 | -- | -- | 19.14 | -- | -- | 126.6 | -- | -- |
| | **Northern Europe** | | | **Swi-Fra** | | | **Swi-Ger** | | | **Northwest Europe** | | |
| PHS | 40.2 | 40.2 | 0.562 | 37.1 | 37.1 | 0.520 | 36.5 | 36.5 | 0.511 | 75.3 | 75.3 | 1.05 |
| CSP-elec. | 0 | 0 | -- | 4.51 | 4.51 | -- | 0 | 0 | -- | 4.51 | 4.51 | -- |
| CSP-PCM | 0 | -- | 0 | 7.27 | -- | 0.102 | 0 | -- | 0 | 7.27 | -- | 0.102 |
| Batteries | 1400 | 1400 | 2.716 | 150 | 150 | 0.291 | 1200 | 1200 | 2.328 | 800 | 800 | 1.552 |
| Hydropower | 23.7 | 51.5 | 207.6 | 14.7 | 32.4 | 129.1 | 8.38 | 18.32 | 73.4 | 38.4 | 83.9 | 336.6 |
| CW-STES | 1.04 | 1.04 | 0.015 | 0.499 | 0.499 | 0.007 | 0.56 | 0.56 | .0079 | 1.6 | 1.6 | 0.023 |
| ICE | 1.56 | 1.56 | 0.022 | 0.748 | 0.748 | 0.011 | 0.84 | 0.84 | 0.012 | 2.5 | 2.5 | 0.035 |
| HW-STES | 103.0 | 103.0 | 0.618 | 46.2 | 46.2 | 0.277 | 57.31 | 57.31 | 0.34 | 154.3 | 154.3 | 0.926 |
| UTES-heat | 16.2 | 103.0 | 37.08 | 2.8 | 46.2 | 5.54 | 15.18 | 57.31 | 13.8 | 19.0 | 154.3 | 55.5 |
| UTES-elec. | 154.5 | -- | -- | 69.2 | -- | -- | 85.96 | -- | -- | 231.5 | -- | -- |
| | **Swi-Ita** | | | **Spa-Por-Gib** | | | **Western Europe** | | | **All Europe** | | |
| PHS | 39.1 | 39.1 | 0.548 | 22.8 | 22.8 | 0.319 | 122.5 | 122.5 | 1.72 | 197 | 197 | 2.76 |
| CSP-elec. | 7.80 | 7.80 | -- | 6.94 | 6.94 | -- | 19.2 | 19.2 | -- | 21.1 | 21.1 | -- |
| CSP-PCM | 12.6 | -- | 0.176 | 11.2 | -- | 0.157 | 31.0 | -- | 0.434 | 34.0 | -- | 0.475 |
| Batteries | 50 | 50 | 0.097 | 0 | 0 | 0 | 0 | 0 | 0 | 1400 | 1400 | 2.716 |
| Hydropower | 12.8 | 28.2 | 112 | 9.51 | 21.75 | 83.3 | 54.4 | 120 | 477 | 75.8 | 167.4 | 664 |
| CW-STES | 0.42 | 0.42 | 0.006 | 0.49 | 0.49 | 0.007 | 3.09 | 3.09 | 0.043 | 4.44 | 4.44 | 0.062 |
| ICE | 0.63 | 0.63 | 0.009 | 0.74 | 0.74 | 0.010 | 4.64 | 4.64 | 0.065 | 6.66 | 6.66 | 0.093 |
| HW-STES | 28.4 | 28.4 | 0.17 | 21.0 | 21.0 | 0.13 | 212 | 212 | 1.27 | 337 | 337 | 2.02 |
| UTES-heat | 4.38 | 28.4 | 13.63 | 3.52 | 21.0 | 10.1 | 25.8 | 212 | 76.3 | 36.7 | 337 | 202 |
| UTES-elec. | 42.6 | -- | -- | 31.5 | -- | -- | 318 | -- | -- | 505 | -- | -- |

PHS = pumped hydropower storage; PCM = Phase-change materials; CSP=concentrated solar power; CW-STES = Chilled-water sensible heat thermal energy storage; HW-STES = Hot water sensible heat thermal energy storage; and UTES = Underground thermal energy storage (either boreholes, water pits, or aquifers). The peak energy storage capacity equals the maximum discharge rate multiplied by the maximum number of hours of storage at the maximum discharge rate. Table S8 gives maximum storage times at the maximum discharge rate.

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

Hydropower's maximum discharge rate in 2050 is its 2018 nameplate capacity. Hydropower can be charged only naturally by rainfall and runoff, but its annual-average charge rate must equal at least its annual energy output divided by the number of hours per year. It is assumed simplistically that hydro is recharged at that rate, and that its annual energy output (TWh/yr) in 2050 is close to its 2018 output. It is further assumed that the maximum hydropower energy storage capacity available in reservoirs equals hydro's annual energy output, and this energy is recharged each year by rainfall and runoff. Whereas the present table gives hydro's maximum storage capacity, its output from storage during a given time step is limited by the smallest among three factors: the current energy available in the reservoir, the peak hydro discharge rate multiplied by the time step, and the energy needed during the time step to keep the grid stable.

The CW-STES charge/discharge rate is set equal to 40% of the maximum daily averaged cold load subject to storage. The ICE storage charge/discharge rate is set to 60% of the same peak cold load subject to storage.

The HW-STES peak discharge rate is set equal to the maximum instantaneous heat load subject to storage during any 30-second period of the two-year simulation. The values have been converted to electricity assuming the heat needed for storage is produced by heat pumps (with a coefficient of performance of 4) running on electricity. Because peak discharge rates are based on maximum rather than the annual average loads, they are higher than the annual-average low-temperature heat loads subject to storage in Table S3. The peak charge rate is set equal to the peak discharge rate.

UTES heat stored in underground soil (borehole storage) or water (water pit or aquifer storage) can be charged with either solar or geothermal heat or excess electricity (assuming the electricity produces heat with an electric heat pump at a coefficient of performance of 4). The maximum charge rate of heat (converted to equivalent electricity) to UTES storage (UTES-heat) is set to the nameplate capacity of solar thermal collectors divided by the coefficient of performance of a heat pump=4). In several countries and regions, no solar thermal collectors are used. When no solar thermal collectors are used, the maximum charge rate for UTES-heat is zero, and UTES is charged only with excess grid electricity running heat pumps. The maximum charge rate of excess grid electricity converted to heat stored in UTES (UTES-elec.) is set by trial and error for each country or region. The maximum UTES heat discharge rate is set equal to the maximum instantaneous heat load subject to storage. The maximum charge rate, discharge rate, and capacity of UTES storage are all in units of equivalent electricity that would give heat at a coefficient of performance of 4.

**Table S8.** Maximum number of hours or days of storage at the maximum discharge rate of each storage type (given in Table S7 for each country or region). The maximum discharge rate multiplied by the number of hours of storage equals the maximum storage capacity in Table S7. For all regions, the maximum CSP storage time at the maximum discharge rate is 22.6 h; that for PHS storage is 14 h; that for HW-STES storage is 6 h; that for CW-STES storage is 6 h; that for ICE storage is 14 h; and that for battery storage is 1.94 h.

| Country or region | UTES (day) | $H_2$ (day) |
|---|---|---|
| Belgium | 15 | 15 |
| Denmark | 15 | 15 |
| France | 5 | 5 |
| Germany | 10 | 5 |
| Gibraltar | 15 | 15 |
| Italy | 15 | 15 |
| Luxembourg | 50 | 50 |
| Netherlands | 5 | 10 |
| Norway | 1 | 1 |
| Portugal | 35 | 35 |
| Spain | 15 | 25 |
| Sweden | 40 | 5 |
| Switzerland | 1 | 1 |
| United Kingdom | 15 | 15 |
| Nor-Den | 1 | 1 |
| Nor-Den-Swe-Ger | 15 | 20 |
| Northern Europe | 15 | 17 |
| Swi-Fra | 5 | 10 |
| Swi-Ger | 10 | 10 |
| Northwest Europe | 15 | 15 |
| Swi-Ita | 20 | 25 |
| Spa-Por-Gib | 20 | 20 |
| Western Europe | 15 | 15 |
| All Europe | 25 | 5 |

**Table S9.** Budgets of WWS end-use energy demand met, energy losses, energy supplies, and changes in storage, during the 1-year (8,747.4875 hour) simulations here for all 24 countries/regions. All units are TWh over the 1-year simulation. Divide TWh by the number of hours of simulation to obtain annual-average power values (TW). Table 1 identifies the countries within each region. Figure S1 shows the time series of matching demand with supply and changes in storage for each country or region.

| | Bel-gium | Den-mark | France | Ger-many | Gib-raltar |
|---|---|---|---|---|---|
| **A1. Total end use demand** | **255** | **84** | **983** | **1,358** | **12** |
| Electricity for electricity inflexible demand | 116 | 33 | 488 | 634 | 2 |
| Electricity for electricity, heat, cold storage + DR | 119 | 44 | 435 | 642 | 5 |
| Electricity for $H_2$ direct use + $H_2$ storage | 21 | 7 | 60 | 82 | 5 |
| **A2. Total end use demand** | **255** | **84** | **983** | **1,358** | **12** |
| Electricity for direct use, electricity storage, + $H_2$ | 231 | 65 | 846 | 1,178 | 11 |
| Low-T heat load met by heat storage | 24 | 19 | 135 | 178 | 0 |
| Cold load met by cold storage | 0.34 | 0.17 | 1.86 | 2.33 | 0.00 |
| **A3. Total end use demand** | **255** | **84** | **983** | **1,358** | **12** |
| Electricity for direct use, electricity storage, DR | 206 | 58 | 775 | 1,084 | 7 |
| Electricity for $H_2$ direct use + $H_2$ storage | 21 | 7 | 60 | 82 | 5 |
| Electricity + heat for heat subject to storage | 26 | 19 | 136 | 178 | 0 |
| Electricity for cold load subject to storage | 2.22 | 0.37 | 12.56 | 14.52 | 0.00 |
| | | | | | |
| **B. Total losses** | **141** | **60** | **446** | **876** | **7** |
| Transmission, distribution, downtime losses | 29 | 10 | 91 | 134 | 1 |
| Losses CSP storage | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Losses PHS storage | 3.8 | 0.5 | 10.8 | 12.8 | 0.2 |
| Losses battery storage | 4 | 0.5 | 1.65 | 17.7 | 0.0 |
| Losses CW-STES + ICE storage | 0 | 0.0 | 0.34 | 0.4 | 0.0 |
| Losses HW-STES storage | 3 | 2.8 | 22 | 26.4 | 0.0 |
| Losses UTES storage | 5 | 3.6 | 15 | 32.3 | 0.0 |
| Losses from shedding | 96 | 42 | 305 | 653 | 5 |
| **Net end-use demand plus losses (A1 + B)** | ***397*** | ***144*** | ***1,429*** | ***2,234*** | ***18*** |
| | | | | | |
| **C. Total WWS supply before T&D losses** | **393** | **145** | **1,427** | **2,236** | **18** |
| Onshore + offshore wind electricity | 152 | 117 | 731 | 1,053 | 18 |
| Rooftop + utility PV+ CSP electricity | 240 | 25 | 582 | 1,143 | 0 |
| Hydropower electricity | 1 | 0 | 96 | 29 | 0 |
| Wave electricity | 0 | 1 | 10 | 1 | 0 |
| Geothermal electricity | 0 | 0 | 0.271 | 0.255 | 0 |
| Tidal electricity | 0.008 | 0.155 | 2.121 | 0.077 | 0.003 |
| Solar heat | 0.074 | 0.196 | 0.373 | 3.107 | 0 |
| Geothermal heat | 0.439 | 0.751 | 4.994 | 6.061 | 0 |
| | | | | | |
| **D. Net taken from (+) or added to (-) storage** | **3.24** | **-0.253** | **2.319** | **-1.887** | **-0.015** |
| CSP storage | 0 | 0 | 0 | 0 | 0 |
| PHS storage | -0.009 | -0.003 | -0.037 | -0.036 | 0.002 |
| Battery storage | -0.058 | -0.039 | -0.097 | -0.252 | -0.004 |
| CW-STES+ICE storage | 0 | 0 | -0.002 | -0.002 | 0 |
| HW-STES storage | -0.005 | -0.003 | 0.117 | -0.036 | 0 |
| UTES storage | 2.643 | -0.179 | 2.109 | -1.448 | 0 |
| $H_2$ storage | 0.67 | -0.029 | 0.23 | -0.112 | -0.013 |
| **Energy supplied plus taken from storage (C+D)** | ***397*** | ***144*** | ***1,429*** | ***2,234*** | ***18*** |

| | Italy | Lux-embourg | Neth-erlands | Norway | Por-tugal |
|---|---|---|---|---|---|
| **A1. Total end use demand** | **728** | **20** | **351** | **177** | **114** |

| | | | | | |
|---|---|---|---|---|---|
| Electricity for electricity inflexible demand | 352 | 8 | 160 | 103 | 57 |
| Electricity for electricity, heat, cold storage + DR | 326 | 9 | 158 | 68 | 48 |
| Electricity for $H_2$ direct use + $H_2$ storage | 49 | 3 | 33 | 6 | 9 |
| **A2. Total end use demand** | **728** | **20** | **351** | **177** | **114** |
| Electricity for direct use, electricity storage, + $H_2$ | 654 | 18 | 314 | 170 | 104 |
| Low-T heat load met by heat storage | 73 | 2 | 36 | 7 | 11 |
| Cold load met by cold storage | 1.03 | 0.02 | 0.38 | 0.17 | 0.13 |
| **A3. Total end use demand** | **728** | **20** | **351** | **177** | **114** |
| Electricity for direct use, electricity storage, DR | 597 | 15 | 279 | 134 | 93 |
| Electricity for $H_2$ direct use + $H_2$ storage | 49 | 3 | 33 | 6 | 9 |
| Electricity + heat for heat subject to storage | 73 | 2 | 36 | 36 | 11 |
| Electricity for cold load subject to storage | 8.65 | 0.17 | 2.53 | 0.85 | 0.85 |
| **B. Total losses** | **194** | **8** | **228** | **20** | **22** |
| Transmission, distribution, downtime losses | 60 | 2 | 43 | 14 | 8 |
| Losses CSP storage | 0.26 | 0.00 | 0.00 | 0.00 | 0.03 |
| Losses PHS storage | 8.7 | 1.1 | 1.0 | 0.1 | 1.7 |
| Losses battery storage | 1 | 0.02 | 6 | 0.0 | 0.05 |
| Losses CW-STES + ICE storage | 0 | 0.00 | 0 | 0.0 | 0.02 |
| Losses HW-STES storage | 10 | 0.12 | 5 | 0.9 | 1.13 |
| Losses UTES storage | 15 | 0.71 | 6 | 0.2 | 3.03 |
| Losses from shedding | 98 | 4 | 167 | 4.7 | 7.2 |
| **Net end-use demand plus losses (A1 + B)** | ***921*** | ***28*** | ***579*** | ***197.1*** | ***135.8*** |
| **C. Total WWS supply before T&D losses** | **917** | **27** | **579** | **197** | **132** |
| Onshore + offshore wind electricity | 471 | 6 | 310 | 25 | 60 |
| Rooftop + utility PV+ CSP electricity | 362 | 20 | 267 | 11 | 50 |
| Hydropower electricity | 70 | 0 | 0 | 156 | 20 |
| Wave electricity | 3 | 0 | 0 | 1 | 1 |
| Geothermal electricity | 7.697 | 0 | 0 | 0 | 0.741 |
| Tidal electricity | 0.157 | 0 | 0.026 | 0.744 | 1.014 |
| Solar heat | 0.817 | 0.006 | 0.135 | 0 | 0.174 |
| Geothermal heat | 2.158 | 0 | 1.681 | 2.766 | 0.075 |
| **D. Net taken from (+) or added to (-) storage** | **4.574** | **1.276** | **-0.338** | **0.313** | **3.309** |
| CSP storage | 0.121 | 0 | 0 | 0 | 0.019 |
| PHS storage | 0.203 | 0.034 | -0.003 | 0.087 | 0.137 |
| Battery storage | -0.039 | 0.207 | -0.107 | 0 | 0.001 |
| CW-STES+ICE storage | -0.001 | 0 | 0 | 0.001 | 0.001 |
| HW-STES storage | 0.133 | 0.004 | -0.007 | 0.042 | 0.017 |
| UTES storage | 2.337 | 0.665 | -0.131 | 0.168 | 2.36 |
| $H_2$ storage | 1.82 | 0.365 | -0.091 | 0.015 | 0.773 |
| **Energy supplied plus taken from storage (C+D)** | ***921*** | ***28*** | ***579*** | ***197.1*** | ***135.8*** |

| | **Spain** | **Sweden** | **Switz-erland** | **United Kingdom** | **Nor-Den** |
|---|---|---|---|---|---|
| **A1. Total end use demand** | **575** | **267** | **140** | **777** | **261** |
| Electricity for electricity inflexible demand | 272 | 115 | 79 | 356 | 146 |
| Electricity for electricity, heat, cold storage + DR | 251 | 140 | 52 | 354 | 101 |
| Electricity for $H_2$ direct use + $H_2$ storage | 51 | 12 | 9 | 68 | 13 |
| **A2. Total end use demand** | **575** | **267** | **140** | **777** | **261** |
| Electricity for direct use, electricity storage, + $H_2$ | 518 | 224 | 137 | 663 | 247 |
| Low-T heat load met by heat storage | 55 | 43 | 3 | 114 | 14 |
| Cold load met by cold storage | 1.80 | 0.20 | 0.00 | 0.60 | 0.13 |
| **A3. Total end use demand** | **575** | **267** | **140** | **777** | **261** |

| | | | | | |
|---|---|---|---|---|---|
| Electricity for direct use, electricity storage, DR | 459 | 206 | 117 | 592 | 190 |
| Electricity for $H_2$ direct use + $H_2$ storage | 51 | 12 | 9 | 68 | 13 |
| Electricity + heat for heat subject to storage | 55 | 47 | 14 | 114 | 56 |
| Electricity for cold load subject to storage | 9.78 | 1.39 | 0.72 | 3.80 | 1.24 |
| **B. Total losses** | **143** | **38** | **12** | **467** | **26** |
| Transmission, distribution, downtime losses | 46 | 21 | 10 | 88 | 21 |
| Losses CSP storage | 0.13 | 0.00 | 0.00 | 0.00 | 0.00 |
| Losses PHS storage | 4.5 | 1.1 | 1.1 | 5.1 | 1.1 |
| Losses battery storage | 0 | 0 | 0.00 | 5.63 | 0.00 |
| Losses CW-STES + ICE storage | 0 | 0 | 0.00 | 0.11 | 0.02 |
| Losses HW-STES storage | 9 | 3 | 0.03 | 18.24 | 1.84 |
| Losses UTES storage | 7 | 11 | 0.09 | 17.46 | 0.80 |
| Losses from shedding | 76 | 2 | 0 | 332 | 2 |
| **Net end-use demand plus losses (A1 + B)** | ***717*** | ***305*** | ***152.0*** | ***1,244*** | ***286.9*** |
| **C. Total WWS supply before T&D losses** | **711** | **295** | **152** | **1,237** | **286** |
| Onshore + offshore wind electricity | 382 | 116 | 22 | 609 | 80 |
| Rooftop + utility PV+ CSP electricity | 247 | 67 | 27 | 585 | 33 |
| Hydropower electricity | 74 | 100 | 99 | 11 | 168 |
| Wave electricity | 5 | 0 | 0 | 8 | 1 |
| Geothermal electricity | 0.373 | 0 | 0 | 0 | 0 |
| Tidal electricity | 2.038 | 0.217 | 0 | 23.593 | 0.899 |
| Solar heat | 0.758 | 0.073 | 0.256 | 0.098 | 0.193 |
| Geothermal heat | 0.136 | 11.915 | 3.688 | 0.604 | 3.517 |
| **D. Net taken from (+) or added to (-) storage** | **5.988** | **10.053** | **0.303** | **6.939** | **0.466** |
| CSP storage | 0.04 | 0 | 0 | 0 | 0 |
| PHS storage | 0.053 | 0.03 | 0.16 | -0.016 | 0.087 |
| Battery storage | -0.01 | 0.049 | 0 | -0.097 | 0 |
| CW-STES+ICE storage | -0.001 | 0.002 | 0.001 | -0.001 | 0.002 |
| HW-STES storage | 0.101 | 0.061 | 0.024 | -0.02 | 0.069 |
| UTES storage | 2.637 | 9.764 | 0.096 | 4.612 | 0.276 |
| $H_2$ storage | 3.168 | 0.147 | 0.022 | 2.46 | 0.033 |
| **Energy supplied plus taken from storage (C+D)** | ***717*** | ***305*** | ***152.0*** | ***1,244*** | ***286.9*** |

| | **Nor-Den-Swe-Ger** | **Northern Europe** | **Swi-Fra** | **Swi-Ger** | **Northwest Europe** |
|---|---|---|---|---|---|
| **A1. Total end use demand** | **1,885** | **2,512** | **1,123** | **1,498** | **3,635** |
| Electricity for electricity inflexible demand | 861 | 1,139 | 570 | 722 | 1,700 |
| Electricity for electricity, heat, cold storage + DR | 918 | 1,208 | 484 | 685 | 1,702 |
| Electricity for $H_2$ direct use + $H_2$ storage | 107 | 164 | 69 | 91 | 233 |
| **A2. Total end use demand** | **1,885** | **2,512** | **1,123** | **1,498** | **3,635** |
| Electricity for direct use, electricity storage, + $H_2$ | 1,608 | 2,166 | 988 | 1,326 | 3,142 |
| Low-T heat load met by heat storage | 274 | 342 | 134 | 170 | 488 |
| Cold load met by cold storage | 3.16 | 3.98 | 1.58 | 1.46 | 5.02 |
| **A3. Total end use demand** | **1,885** | **2,512** | **1,123** | **1,498** | **3,635** |
| Electricity for direct use, electricity storage, DR | 1,483 | 1,984 | 909 | 1,225 | 2,870 |
| Electricity for $H_2$ direct use + $H_2$ storage | 107 | 164 | 69 | 91 | 233 |
| Electricity + heat for heat subject to storage | 277 | 342 | 134 | 170 | 496 |
| Electricity for cold load subject to storage | 17.81 | 22.68 | 10.91 | 12.27 | 36.02 |
| **B. Total losses** | **720** | **977** | **412** | **773** | **1,030** |

| | | | | | |
|---|---|---|---|---|---|
| Transmission, distribution, downtime losses | 158 | 222 | 97 | 133 | 308 |
| Losses CSP storage | 0.00 | 0.00 | 0.09 | 0.00 | 0.11 |
| Losses PHS storage | 15.7 | 20.1 | 11.5 | 18.2 | 35.1 |
| Losses battery storage | 5.29 | 12.16 | 0.26 | 12.71 | 8.70 |
| Losses CW-STES + ICE storage | 0.57 | 0.72 | 0.29 | 0.26 | 0.91 |
| Losses HW-STES storage | 36.89 | 46.78 | 22.08 | 24.10 | 66.86 |
| Losses UTES storage | 49.67 | 63.58 | 13.94 | 32.67 | 86.78 |
| Losses from shedding | 454 | 611 | 266 | 551 | 523 |
| **Net end-use demand plus losses (A1 + B)** | ***2,605*** | ***3,489*** | ***1,535*** | ***2,271*** | ***4,664*** |
| | | | | | |
| **C. Total WWS supply before T&D losses** | **2,582** | **3,466** | **1,535** | **2,272** | **4,615** |
| Onshore + offshore wind electricity | 1,191 | 1,666 | 891 | 1,054 | 2,316 |
| Rooftop + utility PV+ CSP electricity | 1,047 | 1,443 | 473 | 1,087 | 1,746 |
| Hydropower electricity | 315 | 325 | 149 | 117 | 501 |
| Wave electricity | 3 | 3 | 10 | 1 | 13 |
| Geothermal electricity | 0.255 | 0.255 | 0.271 | 0.255 | 0.527 |
| Tidal electricity | 1.192 | 1.226 | 2.121 | 0.077 | 3.347 |
| Solar heat | 3.367 | 3.586 | 0.632 | 3.364 | 4.237 |
| Geothermal heat | 21.494 | 23.613 | 8.681 | 9.749 | 32.295 |
| | | | | | |
| **D. Net taken from (+) or added to (-) storage** | **23.319** | **22.505** | **-0.042** | **-1.945** | **48.806** |
| CSP storage | 0 | 0 | -0.01 | 0 | -0.01 |
| PHS storage | -0.043 | -0.056 | -0.052 | -0.051 | -0.105 |
| Battery storage | -0.194 | -0.272 | -0.029 | -0.233 | -0.155 |
| CW-STES+ICE storage | -0.003 | -0.004 | -0.002 | -0.002 | -0.006 |
| HW-STES storage | -0.051 | -0.062 | 0.094 | -0.034 | -0.093 |
| UTES storage | 19.174 | 17.455 | -0.554 | -1.375 | 41.019 |
| $H_2$ storage | 4.436 | 5.444 | 0.511 | -0.249 | 8.156 |
| **Energy supplied plus taken from storage (C+D)** | ***2,605*** | ***3,489*** | ***1,535*** | ***2,271*** | ***4,664*** |

| | Swi-Ita | Spa-Por-Gib | West-ern Europe | All Europe |
|---|---|---|---|---|
| **A1. Total end use demand** | **868** | **700** | **5,063** | **8,221** |
| Electricity for electricity inflexible demand | 422 | 330 | 2,334 | 3,803 |
| Electricity for electricity, heat, cold storage + DR | 388 | 305 | 2,382 | 3,864 |
| Electricity for $H_2$ direct use + $H_2$ storage | 58 | 65 | 347 | 554 |
| **A2. Total end use demand** | **868** | **700** | **5,063** | **8,221** |
| Electricity for direct use, electricity storage, + $H_2$ | 780 | 632 | 4,371 | 7,069 |
| Low-T heat load met by heat storage | 86 | 66 | 680 | 1,136 |
| Cold load met by cold storage | 1.16 | 1.99 | 11.68 | 15.33 |
| **A3. Total end use demand** | **868** | **700** | **5,063** | **8,221** |
| Electricity for direct use, electricity storage, DR | 714 | 559 | 3,965 | 6,401 |
| Electricity for $H_2$ direct use + $H_2$ storage | 58 | 65 | 347 | 554 |
| Electricity + heat for heat subject to storage | 86 | 66 | 684 | 1,169 |
| Electricity for cold load subject to storage | 9.26 | 10.72 | 67.60 | 97.17 |
| | | | | |
| **B. Total losses** | **202** | **161** | **1,365** | **1,995** |
| Transmission, distribution, downtime losses | 69 | 55 | 416 | 668 |
| Losses CSP storage | 0.20 | 0.16 | 0.45 | 0.48 |
| Losses PHS storage | 12.2 | 6.0 | 49.8 | 79.4 |
| Losses battery storage | 0.40 | 0.00 | 0.00 | 8 |
| Losses CW-STES + ICE storage | 0.21 | 0.36 | 2.11 | 3 |
| Losses HW-STES storage | 11.40 | 10.17 | 101.84 | 160 |
| Losses UTES storage | 18.06 | 9.71 | 93.84 | 181 |

| | | | | |
|---|---|---|---|---|
| Losses from shedding | 90 | 80 | 700 | 896 |
| **Net end-use demand plus losses (A1 + B)** | ***1,069*** | ***861*** | ***6,427*** | ***10,216*** |
| | | | | |
| **C. Total WWS supply before T&D losses** | **1,061** | **851** | **6,355** | **10,040** |
| Onshore + offshore wind electricity | 519 | 456 | 3,190 | 5,457 |
| Rooftop + utility PV+ CSP electricity | 393 | 293 | 2,440 | 3,545 |
| Hydropower electricity | 132 | 90 | 646 | 895 |
| Wave electricity | 3 | 7 | 22 | 32 |
| Geothermal electricity | 7.697 | 1.114 | 9.338 | 23.859 |
| Tidal electricity | 0.157 | 3.055 | 6.558 | 30.991 |
| Solar heat | 1.085 | 0.933 | 5.973 | 8.505 |
| Geothermal heat | 5.845 | 0.211 | 34.663 | 47.501 |
| | | | | |
| **D. Net taken from (+) or added to (-) storage** | **8.186** | **10.007** | **72.856** | **175.868** |
| CSP storage | 0.086 | 0.045 | -0.043 | -0.048 |
| PHS storage | 0.223 | 0.024 | -0.172 | -0.276 |
| Battery storage | -0.01 | 0 | 0 | -0.272 |
| CW-STES+ICE storage | -0.001 | -0.001 | -0.011 | -0.016 |
| HW-STES storage | 0.153 | 0.114 | 0.509 | -0.202 |
| UTES storage | 4.15 | 6.609 | 59.72 | 169.845 |
| $H_2$ storage | 3.585 | 3.217 | 12.852 | 6.836 |
| **Energy supplied plus taken from storage (C+D)** | ***1,069*** | ***861*** | ***6,427*** | ***10,216*** |

End-use demands in A1, A2, A3 should be identical. Table S10 gives round-trip storage efficiencies. Table S11 gives transmission/distribution/maintenance losses as a percent of energy generated by a source. Generated electricity is shed when it exceeds the sum of electricity demand, cold storage capacity, heat storage capacity, and $H_2$ storage capacity. Onshore and offshore wind turbines in GATOR-GCMOM are assumed to be Senvion (formerly Repower) 5 MW turbines with 126-m diameter rotors, 100 m hub heights, a cut-in wind speed of 3.5 m/s, and a cut-out wind speed of 30 m/s. Rooftop PV panels in GATOR-GCMOM are modeled as fixed-tilt panels at the optimal tilt angle of the country they resided in; utility PV panels are modeled as half fixed optimal tilt and half single-axis horizontal tracking. All panels are assumed to have a nameplate capacity of 390 W and a panel area of 1.629668 $m^2$, which gives a 2050 panel efficiency (Watts of power output per Watt of solar radiation incident on the panel) of 23.9%, which is an increase from the 2015 value of 20.1%. Each CSP plant before storage is assumed to have the mirror and land characteristics of the Ivanpah solar plant, which has 646,457 $m^2$ of mirrors and 2.17 $km^2$ of land per 100 MW nameplate capacity and a CSP efficiency (fraction of incident solar radiation that is converted to electricity) of 15.796%, calculated as the product of the reflection efficiency of 55% and the steam plant efficiency of 28.72%. The efficiency of the solar thermal for heat hot fluid collection (energy in fluid divided by incident radiation) is assumed to be 34%.

**Table S10.** Present value of the mean 2019 to 2050 lifecycle costs of new storage capacity and round-trip efficiencies of the storage technologies treated here.

| Storage technology | Present-value of lifecycle cost of new storage ($/kWh-max energy storage capacity) | | | Round-trip charge/store/ discharge efficiency (percent) |
|---|---|---|---|---|
| | Middle | Low | High | |
| **Electricity** | | | | |
| PHS | 14 | 12 | 16 | 80 |
| CSP-PCM | 20 | 15 | 23 | 55, 28.72, 99 |
| LI Batteries | 60 | 30 | 90 | 85 |
| **Cold** | | | | |
| CW-STES | 6.5 | 0.13 | 12.9 | 84.7 |
| ICE | 36.7 | 12.9 | 64.5 | 82.5 |
| **Heat** | | | | |
| HW-STES | 6.5 | 0.13 | 12.9 | 83 |
| UTES | 0.90 | 0.071 | 1.71 | 56 |

From Ref. S1.

PHS = pumped hydropower storage; CSP-PCM = concentrated solar power with phase change material for storage; LI Batteries = lithium ion batteries; CW-STES = cold water sensible-heat thermal energy storage; ICE = ice storage; HW-STES = hot water sensible-heat thermal energy storage; UTES = underground thermal energy storage (modeled as borehole). PHS efficiency is the ratio of electricity delivered to the sum of electricity delivered and electricity used to pump the water.

Storage costs per unit energy generated in the overall system of each storage technology are calculated as the product of the maximum energy storage capacity (Table S7) and the lifecycle-averaged capital cost of storage per unit maximum energy storage capacity (this table), annualized with the same discount rate as for power generators (Table S11, footnote), but with 2050 storage lifetimes of 17 (12 to 22) years for batteries and 32.5 (25 to 40) years all other storage, all divided by the annual average end-use load met.

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

**Table S11.** Parameters for determining costs of energy from electricity and heat generators.

| | Capital cost new installations ($Million/MW) | O&M Cost ($/kW/yr) | Decom-missioning cost (% of capital cost) | Lifetime (years) | TDM losses (% of energy generated) |
|---|---|---|---|---|---|
| Onshore wind | 1.27 (1.07-1.47) | 37.5 (35-40) | 1.25 (1.2-1.3) | 30 (25-35) | 7.5 (5-10) |
| Offshore wind | 1.86 (1.49-2.24) | 80 (60-100) | 2 (2-2) | 30 (25-35) | 7.5 (5-10) |
| Residential PV | 2.97 (2.65-3.28) | 27.5 (25-30) | 0.75 (0.5-1) | 44 (41-47) | 1.5 (1-2) |
| Commercial/government PV | 2.06 (1.80-2.31) | 16.5 (13-20) | 0.75 (0.5-1) | 46 (43-49) | 1.5 (1-2) |
| Utility-scale PV | 1.32 (1.16-1.49) | 19.5 (16.5-22.5) | 0.75 (0.5-1) | 48.5 (45-52) | 7.5 (5-10) |
| CSP with storage[a] | 4.84 (4.42-5.26) | 50 (40-60) | 1.25 (1-1.5) | 45 (40-50) | 7.5 (5-10) |
| Geothermal for electricity | 3.83 (2.47-5.18) | 45 (36-54) | 2.5 (2-3) | 45 (40-50) | 7.5 (5-10) |
| Hydropower | 2.81 (2.38-3.25) | 15.5 (15-16) | 2.5 (2-3) | 85 (70-100) | 7.5 (5-10) |
| Wave | 4.01 (2.74-5.28) | 175 (100-250) | 2 (2-2) | 45 (40-50) | 7.5 (5-10) |
| Tidal | 3.57 (2.85-4.29) | 125 (50-200) | 2.5 (2-3) | 45 (40-50) | 7.5 (5-10) |
| Solar thermal for heat | 1.22 (1.12-1.33) | 50 (40-60) | 1.25 (1-1.5) | 35 (30-40) | 3 (2-4) |
| Geothermal for heat | 3.83 (2.47-5.18) | 45 (36-54) | 2 (1-3) | 45 (40-50) | 7.5 (5-10) |

From Ref. S1. 1 Euro = 1 USD on March 1, 2021.

Capital costs (per MW of nameplate capacity) are an average of 2019 and 2050. O&M=Operation and maintenance. TDM = transmission/distribution/maintenance. TDM losses are a percentage of all energy produced by the generator and are an average over short and long-distance (high-voltage direct current) lines.

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

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

Long-distance transmission costs are $0.00406 (0.00152-0.00903)/kWh (in USD 2013) (Ref. S1), which assumes 1,200 to 2,000 km lines. It is assumed that 30% of all annually-averaged electricity generated is subject to long-distance transmission in all multi-country regions; 15% of all electricity is subject to long-distance transmission in Germany, the UK, France, Norway, Sweden, Spain, Portugal, and Italy; 10% is subject to long-distance transmission in Denmark, the Netherlands, Belgium, and Switzerland; and 0% is subject to long-distance transmission in Luxembourg and Gibraltar.

The discount rate used for generation, storage, transmission/distribution, and social costs is a social discount rate of 2 (1-3)% (Ref. S1).

[a]The capital cost of CSP with storage includes the cost of extra mirrors and land but excludes costs of phase-change material and storage tanks, which are given in Table S10. The cost of CSP with storage depends on the ratio of the CSP storage maximum charge rate plus direct electricity use rate (which equals the maximum discharge rate) to the CSP maximum discharge rate. For the purpose of benchmarking the "CSP with storage" cost in this table, we use a ratio of 3.2:1. (In other words, if 3.2 units of sunlight come in, a maximum of 2.2 units can go to storage and a maximum of 1 unit can be discharged directly as electricity at the same time.) The ratio for "CSP no storage" is 1:1. In our actual simulations and cost calculations, we assume a ratio of 2.61:1 for CSP with storage[1] and find the cost for this assumed ratio by interpolating between the "CSP with storage" benchmark value and the "CSP no storage" value in this table.

**Table S12.** Parameters in the calculation of the value of statistical life over time and by country.

| Parameter | LCHB | Middle | HCLB |
|---|---|---|---|
| U.S. VOSL in base year 2006 ($VOSL_{US,BYV}$) ($mil/death USD 2006) | 9.00 | 7.00 | 5.00 |
| U.S. VOSL in target year 2050 ($VOSL_{US,Y}$) ($mil/death USD 2013) | 15.37 | 10.40 | 6.47 |
| 2006 global average VOSL ($mil/death USD 2006) | 4.00 | 3.48 | 3.43 |
| 2050 global average VOSL ($mil/death USD 2013) | 8.15 | 7.09 | 6.99 |
| U.S. GDP per capita in 2006 ($G_{US,BYV}$) (USD $/person 2006) | 52,275 | 52,275 | 52,275 |
| U.S. GDP per capita target year 2050 ($G_{US,Y}$) (USD $/person 2013) | 96,093 | 96,093 | 96,093 |
| Multiplier for morbidity impacts ($F_1$) | 1.25 | 1.15 | 1.05 |
| Multiplier for non-health impacts ($F_2$) | 1.10 | 1.10 | 1.05 |
| Fractional reduction in mortalities per year ($\Delta A_c$) | -0.014 | -0.015 | -0.016 |
| Exponent giving change in mortality with population change ($\kappa$) | 1.14 | 1.11 | 1.08 |
| Fraction of country's VOSL fixed at U.S. TY value ($T$) | 0.10 | 0.00 | 0.00 |
| GDP/capita elasticity ($\gamma_{GDP,US,BYV}$) of VOSL, U.S. base year 2006 | 0.75 | 0.50 | 0.25 |
| GDP/capita elasticity ($\gamma_{GDP}$) of VOSL, all years | -0.15 | -0.15 | -0.15 |

These parameters, from Ref. S1, are applied to the equations in Note S39 of Ref. S1. LCHB = low cost, high benefit. HCLB = high cost, low benefit. VOSL = value of statistical life. GDP = gross domestic product at purchasing power parity (PPP). Multiply LCHB VOSL by the high estimate of air pollution premature deaths to obtain the high estimate of air pollution cost in the BAU case (or greatest avoided air pollution benefit in the WWS case). 1 Euro = 1 USD on March 1, 2021.

**Table S13.** Low, mid, and high estimates of the social cost of carbon (SCC).

| Parameter | Low estimate | Mid estimate | High estimate |
|---|---|---|---|
| 2010 Global SCC (2007 USD) | 125 | 250 | 600 |
| Annual percentage increase in SCC | 1.8 | 1.5 | 1.2 |
| 2050 Global SCC (2013 USD) | 282 | 500 | 1,063 |

Units of the SCC are USD per metric tonne-$CO_2$e. These parameters are derived from the sources discussed in Note S40 of Ref. S1. 1 Euro = 1 USD on March 1, 2021.

**Table S14.** Summary of 2050 WWS mean capital costs of new electricity plus heat generators and storage ($ trillion in 2013 USD) and mean levelized private costs of energy (LCOE) (USD ¢/kWh-all-energy or ¢/kWh-electricity-replacing-BAU-electricity) averaged over each simulation for each country or region (defined in Table 1). Also shown are the energy consumed per year in each case and the resulting aggregate annual energy cost to the country or region. 1 Euro = 1 USD on March 1, 2021.

| | Bel-gium | Denmark | France | Germany | Gibraltar | Italy | Lux-embourg |
|---|---|---|---|---|---|---|---|
| Capital cost new generators only ($trillion) | 0.25 | 0.076 | 0.87 | 1.56 | 0.012 | 0.49 | 0.019 |
| Cap cost generators-storage-$H_2$-HVDC ($trillion) | 0.30 | 0.11 | 0.98 | 1.78 | 0.017 | 0.57 | 0.039 |
| *Components of total LCOE (¢/kWh-all-energy)* | | | | | | | |
| Short-dist. transmission | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 |
| Long-distance transmission | 0.04 | 0.04 | 0.06 | 0.06 | 0.00 | 0.06 | 0.00 |
| Distribution | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 |
| Electricity generators | 5.43 | 6.59 | 5.01 | 6.55 | 7.81 | 4.20 | 4.70 |
| Additional hydro turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar thermal collectors | 0.03 | 0.17 | 0.06 | 0.13 | 0.00 | 0.06 | 0.01 |
| CSP-PCM+PHS+battery storage | 1.18 | 2.38 | 0.52 | 0.96 | 1.91 | 0.34 | 6.19 |
| CW-STES+ICE storage | 0.002 | 0.001 | 0.003 | 0.002 | 0.000 | 0.003 | 0.002 |
| HW-STES storage | 0.008 | 0.013 | 0.011 | 0.010 | 0.000 | 0.008 | 0.008 |
| UTES storage | 0.06 | 0.11 | 0.03 | 0.05 | 0.00 | 0.06 | 0.21 |
| $H_2$ production/compression/storage | 0.32 | 0.32 | 0.14 | 0.14 | 1.64 | 0.26 | 1.35 |
| **Total LCOE (¢/kWh-all-energy)** | **10.5** | **13.0** | **9.26** | **11.3** | **14.8** | **8.42** | **15.9** |
| LCOE (¢/kWh-replacing BAU electricity) | 10.1 | 12.6 | 9.07 | 11.1 | 13.1 | 8.09 | 14.3 |
| GW annual avg. end-use demand (Table S3) | 29.2 | 9.61 | 112 | 155 | 1.32 | 83.2 | 2.30 |
| TWh/y end-use demand (GW x 8,760 h/y) | 256 | 84 | 984 | 1,360 | 12 | 729 | 20 |
| **Annual energy cost ($billion/yr)** | **26.9** | **11.0** | **91.1** | **154** | **1.7** | **61.4** | **3.2** |
| | Neth-erlands | Norway | Portugal | Spain | Sweden | Switz-erland | United Kingdom |
| Capital cost new generators only ($trillion) | 0.34 | 0.026 | 0.069 | 0.35 | 0.12 | 0.035 | 0.76 |
| Cap cost generators-storage-$H_2$-HVDC ($trillion) | 0.42 | 0.03 | 0.10 | 0.41 | 0.16 | 0.040 | 0.88 |
| *Components of total LCOE (¢/kWh-all-energy)* | | | | | | | |
| Short-dist. transmission | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 |
| Long-distance transmission | 0.04 | 0.06 | 0.06 | 0.06 | 0.06 | 0.04 | 0.06 |
| Distribution | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 |
| Electricity generators | 5.78 | 2.38 | 3.92 | 3.99 | 3.41 | 2.20 | 5.72 |
| Additional hydro turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar thermal collectors | 0.05 | 0.12 | 0.06 | 0.05 | 0.36 | 0.28 | 0.01 |
| CSP-PCM+PHS+battery storage | 1.55 | 0.03 | 1.40 | 0.13 | 0.75 | 0.08 | 0.65 |
| CW-STES+ICE storage | 0.002 | 0.001 | 0.002 | 0.004 | 0.001 | 0.001 | 0.001 |
| HW-STES storage | 0.007 | 0.010 | 0.006 | 0.007 | 0.009 | 0.007 | 0.009 |
| UTES storage | 0.02 | 0.01 | 0.12 | 0.06 | 0.21 | 0.00 | 0.08 |
| $H_2$ production/compression/storage | 0.29 | 0.06 | 0.54 | 0.48 | 0.10 | 0.11 | 0.34 |
| **Total LCOE (¢/kWh-all-energy)** | **11.2** | **6.10** | **9.54** | **8.21** | **8.33** | **6.15** | **10.3** |
| LCOE (¢/kWh-replacing BAU electricity) | 10.9 | 6.03 | 8.87 | 7.66 | 8.01 | 6.02 | 9.87 |
| GW annual avg. end-use demand (Table S3) | 40.1 | 20.2 | 13.1 | 65.7 | 30.5 | 16.0 | 88.8 |
| TWh/y end-use demand (GW x 8,760 h/y) | 351 | 177 | 114 | 575 | 267 | 140 | 778 |
| Annual energy cost ($billion/yr) | **39.2** | **10.8** | **10.9** | **47.2** | **22.2** | **8.6** | **80.1** |
| | Nor-Den | Nor-Den-Swe-Ger | North-ern Europe | Swi-Fra | Swi-Ger | North-west Europe | Swi-Ita |
| Capital cost new generators only ($trillion) | 0.068 | 1.59 | 2.10 | 0.87 | 1.53 | 2.60 | 0.55 |
| Cap cost generators-storage-$H_2$-HVDC ($trillion) | 0.084 | 1.89 | 2.51 | 0.98 | 1.80 | 3.04 | 0.66 |
| *Components of total LCOE (¢/kWh-all-energy)* | | | | | | | |
| Short-dist. transmission (¢/kWh-all-energy) | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 |
| Long-distance transmission | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 |
| Distribution | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 | 2.38 |
| Electricity generators | 2.81 | 5.17 | 5.10 | 4.64 | 5.89 | 4.47 | 4.02 |
| Additional hydro turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar thermal collectors | 0.14 | 0.16 | 0.13 | 0.08 | 0.14 | 0.12 | 0.10 |
| CSP-PCM+PHS+battery storage | 0.02 | 0.54 | 0.56 | 0.17 | 0.81 | 0.24 | 0.12 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CW-STES+ICE storage | 0.001 | 0.002 | 0.002 | 0.002 | 0.002 | 0.002 | 0.002 |
| HW-STES storage | 0.011 | 0.010 | 0.009 | 0.009 | 0.009 | 0.010 | 0.007 |
| UTES storage | 0.01 | 0.08 | 0.08 | 0.03 | 0.05 | 0.08 | 0.08 |
| $H_2$ production/compression/storage | 0.09 | 0.26 | 0.27 | 0.19 | 0.19 | 0.25 | 0.36 |
| **Total LCOE (¢/kWh-all-energy)** | **6.63** | **9.77** | **9.70** | **8.66** | **10.6** | **8.71** | **8.23** |
| LCOE (¢/kWh-replacing BAU electricity) | 6.51 | 9.41 | 9.33 | 8.43 | 10.4 | 8.36 | 7.77 |
| GW annual avg. end-use demand (Table S3) | 29.8 | 215.5 | 287.1 | 128.4 | 171.2 | 415.5 | 99.2 |
| TWh/y end-use demand (GW x 8,760 h/y) | 261 | 1,888 | 2,515 | 1,124 | 1,500 | 3,640 | 869 |
| Annual energy cost ($billion/yr) | **17.3** | **184.4** | **243.9** | **97.4** | **159.6** | **316.9** | **71.5** |

| | Spa-Por-Gib | Western Europe | All Europe |
|---|---|---|---|
| Capital cost new generators only ($trillion) | 0.42 | 3.54 | 5.49 |
| Cap cost generators-storage-$H_2$-HVDC ($trillion) | 0.51 | 4.04 | 6.41 |
| *Components of total LCOE (¢/kWh-all-energy)* | | | |
| Short-dist. transmission (¢/kWh-all-energy) | 1.05 | 1.05 | 1.05 |
| Long-distance transmission | 0.12 | 0.12 | 0.12 |
| Distribution | 2.38 | 2.38 | 2.38 |
| Electricity generators | 4.01 | 4.37 | 4.18 |
| Additional hydro turbines | 0 | 0 | 0 |
| Solar thermal collectors | 0.05 | 0.10 | 0.09 |
| CSP-PCM+PHS+battery storage | 0.05 | 0.03 | 0.19 |
| CW-STES+ICE storage | 0.003 | 0.003 | 0.003 |
| HW-STES storage | 0.007 | 0.009 | 0.009 |
| UTES storage | 0.07 | 0.08 | 0.13 |
| $H_2$ production/compression/storage | 0.43 | 0.26 | 0.16 |
| **Total LCOE (¢/kWh-all-energy)** | **8.17** | **8.39** | **8.30** |
| LCOE (¢/kWh-replacing BAU electricity) | 7.65 | 8.04 | 8.00 |
| GW annual avg. end-use demand (Table S3) | 80.1 | 578.7 | 939.7 |
| TWh/y end-use demand (GW x 8,760 h/y) | 701 | 5,070 | 8,232 |
| Annual energy cost ($billion/yr) | **57.3** | **425.6** | **683.7** |

Capital costs per new nameplate capacity of generators are given in Table S11.

Capital costs per new storage capacity of storage devices are given in Table in Table S10.

$H_2$ costs are derived as in Note S38 and Note S43 of Ref. S1. These costs exclude electricity costs, which are included separately in the present table.

Short- and long-distance transmission costs and distribution costs per unit energy are given in Table S11 (footnotes).

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

The LCOEs of electricity generators are derived from assumed capital costs, annual O&M costs, lifetimes, and end-of-life decommissioning costs, that vary with technology, and a social discount rate, all given in Table S11, together with the total annualized end-use demand met, given in the present table. LCOEs of storage options

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

**Table S15.** Private and social costs for each country or region. This is the 2050 country- or regional average WWS versus BAU mean social cost per unit energy. Also shown is the WWS-to-BAU aggregate social cost ratio and the components of its derivation.

| | Belgium | Den-mark | France | Ger-many | Gib-raltar | Italy |
|---|---|---|---|---|---|---|
| a) BAU electricity private cost per unit energy (¢/kWh)[1] | 11.1 | 12.6 | 9.39 | 10.9 | 10.8 | 11.1 |
| b) BAU health cost per unit energy (¢/kWh) | 3.83 | 4.61 | 4.67 | 6.22 | 0.46 | 8.87 |
| c) BAU climate cost per unit energy (¢/kWh) | 11.3 | 9.80 | 10.2 | 16.4 | 0.9 | 12.5 |
| **d) BAU social cost per unit energy (¢/kWh) (a+b+c)** | **26.2** | **27.0** | **24.2** | **33.5** | **12.2** | **32.5** |
| **e) WWS private and social cost per unit energy (¢/kWh)[1]** | **10.5** | **13.0** | **9.26** | **11.3** | **14.8** | **8.42** |
| f) BAU end-use power demand (GW)[2] | 69.7 | 25.9 | 251.6 | 366.4 | 5.4 | 217.4 |
| g) WWS end-use power demand (GW)[2] | 29.2 | 9.6 | 112.4 | 155.2 | 1.3 | 83.2 |
| h) BAU aggregate annual energy private cost ($bil/yr) (af) | 67.9 | 28.6 | 207 | 348 | 5.2 | 211 |
| i) BAU health cost ($bil/yr) (bf) | 23.4 | 10.4 | 103 | 200 | 0.2 | 169 |
| j) BAU climate cost ($bil/yr) (cf) | 68.9 | 22.2 | 224 | 527 | 0.4 | 239 |
| **k) BAU social cost ($bil/yr) (df)** | **160** | **61.2** | **534** | **1,075** | **5.8** | **618** |
| **l) WWS private and social cost ($bil/yr) (eg)** | **26.8** | **11.0** | **91.1** | **154** | **1.7** | **61.4** |
| m) WWS-to-BAU energy private cost/kWh ratio ($R_{WWS:BAU-E}$) (e/a) | 0.94 | 1.03 | 0.99 | 1.04 | 1.36 | 0.76 |
| n) BAU-energy-private-to-social-cost/kWh ratio ($R_{BAU-S:E}$) (a/d) | 0.42 | 0.47 | 0.39 | 0.32 | 0.89 | 0.34 |
| o) WWS-kWh-used-to-BAU-kWh-used ratio ($R_{WWS:BAU-C}$) (g/f) | 0.42 | 0.37 | 0.45 | 0.42 | 0.24 | 0.38 |
| **WWS-to-BAU aggregate social cost ratio ($R_{ASC}$) (mno)** | **0.17** | **0.18** | **0.17** | **0.14** | **0.29** | **0.10** |
| **WWS-to-BAU aggregate private cost ratio ($R_{APC}$) (mo)** | **0.40** | **0.38** | **0.44** | **0.44** | **0.33** | **0.29** |
| **WWS-to-BAU social cost per unit energy ratio ($R_{SCE}$) (mn)** | **0.40** | **0.48** | **0.38** | **0.34** | **1.21** | **0.26** |

| | Luxem-bourg | Neth-erlands | Norway | Por-tugal | Spain | Sweden |
|---|---|---|---|---|---|---|
| a) BAU electricity private cost per unit energy (¢/kWh)[1] | 12.0 | 11.2 | 6.61 | 10.9 | 10.8 | 8.70 |
| b) BAU health cost per unit energy (¢/kWh) | 2.68 | 3.87 | 1.67 | 5.27 | 5.49 | 2.02 |
| c) BAU climate cost per unit energy (¢/kWh) | 11.9 | 12.5 | 7.5 | 14.2 | 12.9 | 6.6 |
| **d) BAU social cost per unit energy (¢/kWh) (a+b+c)** | **26.6** | **27.5** | **15.8** | **30.3** | **29.2** | **17.3** |
| **e) WWS private and social cost per unit energy (¢/kWh)[1]** | **15.9** | **11.2** | **6.10** | **9.54** | **8.21** | **8.33** |
| f) BAU end-use power demand (GW)[2] | 6.0 | 105.7 | 47.0 | 30.3 | 165.3 | 58.5 |
| g) WWS end-use power demand (GW)[2] | 2.3 | 40.1 | 20.2 | 13.1 | 65.7 | 30.5 |
| h) BAU aggregate annual energy private cost ($bil/yr) (af) | 6.3 | 103 | 27.2 | 28.9 | 157 | 44.6 |
| i) BAU health cost ($bil/yr) (bf) | 1.4 | 35.8 | 6.9 | 14.0 | 79 | 10.4 |
| j) BAU climate cost ($bil/yr) (cf) | 6.3 | 116 | 31.0 | 37.5 | 186 | 33.7 |
| **k) BAU social cost ($bil/yr) (df)** | **14.1** | **255** | **65.1** | **80.4** | **423** | **88.6** |
| **l) WWS private and social cost ($bil/yr) (eg)** | **3.2** | **39.2** | **10.8** | **10.9** | **47.2** | **22.2** |
| m) WWS-to-BAU energy private cost/kWh ratio ($R_{WWS:BAU-E}$) (e/a) | 1.33 | 1.00 | 0.92 | 0.88 | 0.76 | 0.96 |
| n) BAU-energy-private-to-social-cost/kWh ratio ($R_{BAU-S:E}$) (a/d) | 0.45 | 0.41 | 0.42 | 0.36 | 0.37 | 0.50 |
| o) WWS-kWh-used-to-BAU-kWh-used ratio ($R_{WWS:BAU-C}$) (g/f) | 0.38 | 0.38 | 0.43 | 0.43 | 0.40 | 0.52 |
| **WWS-to-BAU aggregate social cost ratio ($R_{ASC}$) (mno)** | **0.23** | **0.15** | **0.17** | **0.14** | **0.11** | **0.25** |
| **WWS-to-BAU aggregate private cost ratio ($R_{APC}$) (mo)** | **0.51** | **0.38** | **0.40** | **0.38** | **0.30** | **0.50** |
| **WWS-to-BAU social cost per unit energy ratio ($R_{SCE}$) (mn)** | **0.60** | **0.41** | **0.39** | **0.31** | **0.28** | **0.48** |

| | Switz-erland | United Kingdom | Nor-Den | Nor-Den-Swe-Ger | North-ern Europe | Swi-Fra |
|---|---|---|---|---|---|---|
| a) BAU electricity private cost per unit energy (¢/kWh)[1] | 7.79 | 11.2 | 8.74 | 10.3 | 10.5 | 9.20 |
| b) BAU health cost per unit energy (¢/kWh) | 4.22 | 6.7 | 2.71 | 5.21 | 4.84 | 4.62 |
| c) BAU climate cost per unit energy (¢/kWh) | 8.9 | 12.3 | 8.3 | 14.1 | 13.5 | 10.0 |
| **d) BAU social cost per unit energy (¢/kWh) (a+b+c)** | **20.9** | **30.1** | **19.8** | **29.6** | **28.9** | **23.8** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **e) WWS private and social cost per unit energy (¢/kWh)**[1] | **6.15** | **10.3** | **6.63** | **9.77** | **9.70** | **8.66** |
| f) BAU end-use power demand (GW)[2] | 33.6 | 233.7 | 72.8 | 497.8 | 679.2 | 285.2 |
| g) WWS end-use power demand (GW)[2] | 16.0 | 88.8 | 29.8 | 215.5 | 287.1 | 128.4 |
| h) BAU aggregate annual energy private cost ($bil/yr) (af) | 22.9 | 228 | 55.8 | 449 | 626 | 230 |
| i) BAU health cost ($bil/yr) (bf) | 12.4 | 137 | 17.3 | 227 | 288 | 115 |
| j) BAU climate cost ($bil/yr) (cf) | 26.3 | 251 | 53.2 | 614 | 805 | 250 |
| **k) BAU social cost ($bil/yr) (df)** | **61.6** | **616** | **126** | **1,290** | **1,719** | **595** |
| **l) WWS private and social cost ($bil/yr) (eg)** | **8.6** | **80.1** | **17.3** | **184** | **244** | **97** |
| m) WWS-to-BAU energy private cost/kWh ratio ($R_{WWS:BAU-E}$) (e/a) | 0.79 | 0.92 | 0.76 | 0.95 | 0.92 | 0.94 |
| n) BAU-energy-private-to-social-cost/kWh ratio ($R_{BAU-S:E}$) (a/d) | 0.37 | 0.37 | 0.44 | 0.35 | 0.36 | 0.39 |
| o) WWS-kWh-used-to-BAU-kWh-used ratio ($R_{WWS:BAU-C}$) (g/f) | 0.48 | 0.38 | 0.41 | 0.43 | 0.42 | 0.45 |
| **WWS-to-BAU aggregate social cost ratio ($R_{ASC}$) (mno)** | **0.14** | **0.13** | **0.14** | **0.14** | **0.14** | **0.16** |
| **WWS-to-BAU aggregate private cost ratio ($R_{APC}$) (mo)** | **0.38** | **0.35** | **0.31** | **0.41** | **0.39** | **0.42** |
| **WWS-to-BAU social cost per unit energy ratio ($R_{SCE}$) (mn)** | **0.29** | **0.34** | **0.33** | **0.33** | **0.34** | **0.36** |

| | Swi-Ger | North-west Europe | Swi-Ita | Spa-Por-Gib | Western Europe | All Europe |
|---|---|---|---|---|---|---|
| a) BAU electricity private cost per unit energy (¢/kWh)[1] | 10.6 | 10.1 | 10.6 | 10.8 | 10.4 | 10.3 |
| b) BAU health cost per unit energy (¢/kWh) | 6.05 | 4.77 | 8.25 | 5.32 | 5.50 | 7.91 |
| c) BAU climate cost per unit energy (¢/kWh) | 15.8 | 12.5 | 12.1 | 12.7 | 12.5 | 13.6 |
| **d) BAU social cost per unit energy (¢/kWh) (a+b+c)** | **32.4** | **27.4** | **30.9** | **28.9** | **28.4** | **31.8** |
| **e) WWS private and social cost per unit energy (¢/kWh)**[1] | **10.6** | **8.71** | **8.23** | **8.17** | **8.39** | **8.30** |
| f) BAU end-use power demand (GW)[2] | 400.1 | 964.4 | 251.0 | 201.0 | 1,383 | 2,293 |
| g) WWS end-use power demand (GW)[2] | 171.2 | 415.5 | 99.2 | 80.1 | 578.7 | 939.7 |
| h) BAU aggregate annual energy private cost ($bil/yr) (af) | 371 | 856 | 234 | 191 | 1,258 | 2,076 |
| i) BAU health cost ($bil/yr) (bf) | 212 | 403 | 181 | 94 | 666 | 1,588 |
| j) BAU climate cost ($bil/yr) (cf) | 553 | 1,054 | 265 | 224 | 1,518 | 2,723 |
| **k) BAU social cost ($bil/yr) (df)** | **1,136** | **2,314** | **680** | **509** | **3,441** | **6,387** |
| **l) WWS private and social cost ($bil/yr) (eg)** | **160** | **317** | **71** | **57** | **426** | **684** |
| m) WWS-to-BAU energy private cost/kWh ratio ($R_{WWS:BAU-E}$) (e/a) | 1.00 | 0.86 | 0.77 | 0.75 | 0.81 | 0.80 |
| n) BAU-energy-private-to-social-cost/kWh ratio ($R_{BAU-S:E}$) (a/d) | 0.33 | 0.37 | 0.34 | 0.38 | 0.37 | 0.33 |
| o) WWS-kWh-used-to-BAU-kWh-used ratio ($R_{WWS:BAU-C}$) (g/f) | 0.43 | 0.43 | 0.40 | 0.40 | 0.42 | 0.41 |
| **WWS-to-BAU aggregate social cost ratio ($R_{ASC}$) (mno)** | **0.14** | **0.14** | **0.11** | **0.11** | **0.12** | **0.11** |
| **WWS-to-BAU aggregate private cost ratio ($R_{APC}$) (mo)** | **0.43** | **0.37** | **0.31** | **0.30** | **0.34** | **0.33** |
| **WWS-to-BAU social cost per unit energy ratio ($R_{SCE}$) (mn)** | **0.33** | **0.32** | **0.27** | **0.28** | **0.30** | **0.26** |

[1]This is the BAU electricity-sector cost of energy per unit energy. It is assumed to equal the BAU all-energy cost of energy per unit energy. The WWS cost per unit energy is for all energy, which is almost all electricity (plus a small amount of direct heat).

[2]Multiply GW by 8,760 hr/yr to obtain GWh/yr.

**Table S16.** Footprint and spacing areas. Footprint areas are for new utility PV farms, CSP plants, solar thermal plants for heat, geothermal plants for electricity and heat, and hydropower plants. Spacing areas are for new onshore wind turbines. Solar PV footprint can reside within onshore wind spacing areas.

| Country or region | Region land area ($km^2$) | Footprint Area ($km^2$) | Spacing area ($km^2$) | Land footprint area as percentage of country/region land area (%) | Land spacing area as a percentage of country/region land area (%) |
|---|---|---|---|---|---|
| Belgium | 30,280 | 1,658 | 505 | 5.48 | 1.67 |
| Denmark | 42,430 | 111 | 1,168 | 0.26 | 2.75 |
| France | 547,561 | 2,022 | 7,508 | 0.37 | 1.37 |
| Germany | 348,540 | 3,876 | 9,462 | 1.11 | 2.71 |
| Gibraltar | 7 | 0.15 | 0 | 2.15 | 0.00 |
| Italy | 294,140 | 998 | 4,574 | 0.34 | 1.55 |
| Luxembourg | 2,590 | 138 | 95 | 5.34 | 3.68 |
| Netherlands | 33,720 | 1,752 | 896 | 5.20 | 2.66 |
| Norway | 365,268 | 40 | 204 | 0.01 | 0.06 |
| Portugal | 91,590 | 110 | 571 | 0.12 | 0.62 |
| Spain | 498,800 | 480 | 3,582 | 0.10 | 0.72 |
| Sweden | 407,340 | 351 | 1,306 | 0.09 | 0.32 |
| Switzerland | 39,516 | 66 | 328 | 0.17 | 0.83 |
| United Kingdom | 241,930 | 3,581 | 2,937 | 1.48 | 1.21 |
| Nor-Den | 407,698 | 130 | 608 | 0.03 | 0.15 |
| Nor-Den-Swe-Ger | 1,163,578 | 2,880 | 10,533 | 0.25 | 0.91 |
| Northern Europe | 1,230,168 | 5,438 | 13,681 | 0.44 | 1.11 |
| Swi-Fra | 587,077 | 1,050 | 9,750 | 0.18 | 1.66 |
| Swi-Ger | 388,056 | 3,053 | 10,454 | 0.79 | 2.69 |
| Northwest Europe | 1,817,245 | 7,354 | 19,142 | 0.40 | 1.05 |
| Swi-Ita | 333,656 | 1,087 | 5,300 | 0.33 | 1.59 |
| Spa-Por-Gib | 590,397 | 568 | 4,129 | 0.10 | 0.70 |
| Western Europe | 2,701,782 | 8,679 | 28,772 | 0.32 | 1.06 |
| All Europe | 5,671,860 | 13,207 | 54,362 | 0.23 | 0.96 |

Spacing areas are areas between wind turbines needed to avoid interference of the wake of one turbine with the next. Such spacing area can be used for multiple purposes, including farmland, rangeland, open space, or utility PV. Footprint areas are the physical land areas, water surface areas, or sea floor surface areas removed from use for any other purpose by an energy technology. Rooftop PV is not included in the footprint calculation because it does not take up new land. Conventional hydro new footprint is zero because no new dams are proposed as part of these roadmaps. Offshore wind, wave, and tidal are not included in the spacing area calculation because they don't take up new land. Table S25 of Ref. S1 gives the installed power densities assumed here as follows: Onshore wind: 19.8 MW/$km^2$ (land spacing)[S5]; offshore wind (ocean spacing): 7.2 MW/$km^2$ (ocean spacing)[S5]; utility PV (footprint): 81.8 MW/$km^2$; and CSP (footprint): 34.1 MW/$km^2$. The onshore and offshore wind installed power densities originate from Ref. S5. Areas are given both as an absolute area and as a percentage of the country or region land area, which excludes inland or coastal water bodies. For comparison, the total area and land area of Earth are 510.1 and 144.6 million $km^2$, respectively.

**Table S17. Changes in the Numbers of Long-Term, Full-Time Jobs**

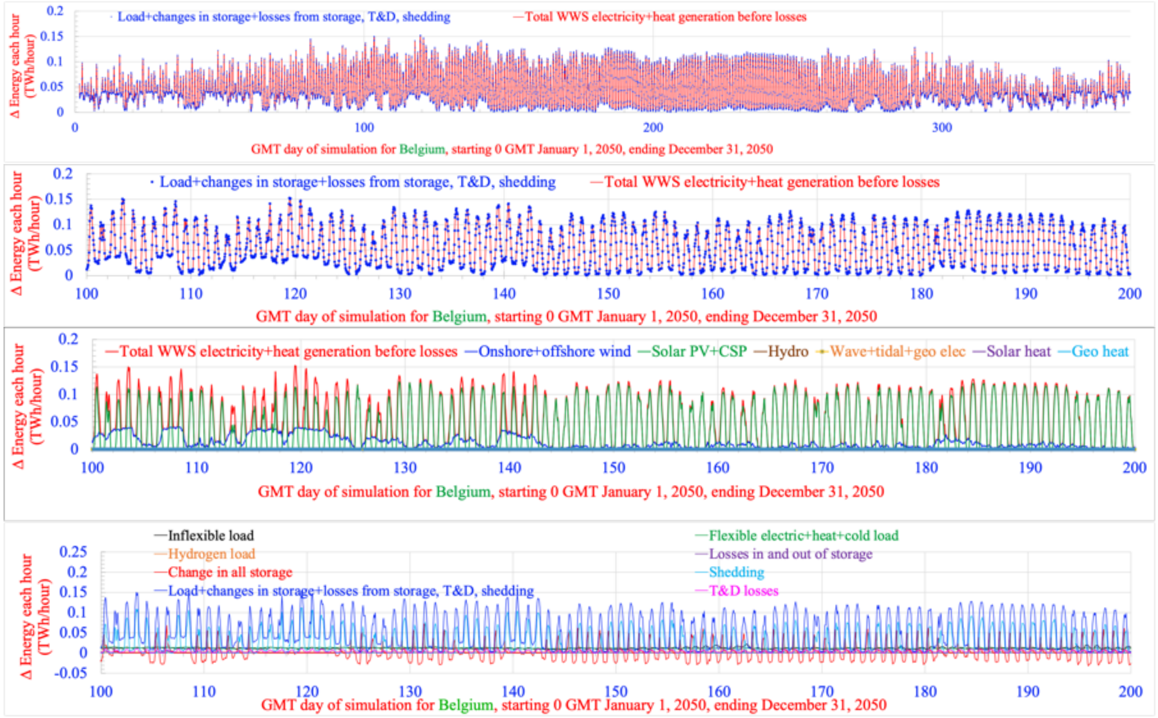
Estimated numbers of long-term, full-time jobs created and lost due to transitioning from BAU energy to WWS across all energy sectors. The job creation numbers account for new jobs in the electricity, heat, cold, and hydrogen generation, storage, and transmission (including HVDC transmission) industries.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

| Country or region | Construction jobs produced | Operation jobs produced | Total jobs produced | Jobs lost | Net change in jobs |
|---|---|---|---|---|---|
| Belgium | 132,726 | 207,167 | 339,893 | 49,524 | 290,369 |
| Denmark | 48,160 | 83,886 | 132,046 | 34,109 | 97,937 |
| France | 357,356 | 422,364 | 779,720 | 194,522 | 585,198 |
| Germany | 676,656 | 879,068 | 1,555,724 | 287,543 | 1,268,181 |
| Gibraltar | 7,707 | 5,645 | 13,353 | 3,089 | 10,264 |
| Italy | 219,065 | 238,394 | 457,460 | 151,359 | 306,101 |
| Luxembourg | 24,108 | 37,464 | 61,572 | 3,374 | 58,198 |
| Netherlands | 167,991 | 294,911 | 462,902 | 105,769 | 357,133 |
| Norway | 18,855 | 25,168 | 44,023 | 182,642 | -138,619 |
| Portugal | 49,338 | 65,039 | 114,377 | 32,381 | 81,996 |
| Spain | 141,639 | 157,701 | 299,340 | 119,419 | 179,921 |
| Sweden | 65,987 | 105,556 | 171,542 | 67,585 | 103,957 |
| Switzerland | 23,791 | 24,901 | 48,693 | 25,773 | 22,920 |
| United Kingdom | 309,306 | 485,881 | 795,186 | 231,372 | 563,814 |
| Nor-Den | 36,416 | 50,975 | 87,391 | 216,751 | -129,360 |
| Nor-Den-Swe-Ger | 682,560 | 817,565 | 1,500,125 | 571,879 | 928,246 |
| Northern Europe | 909,377 | 1,185,268 | 2,094,645 | 730,546 | 1,364,099 |
| Swi-Fra | 335,700 | 318,126 | 653,826 | 220,295 | 433,531 |
| Swi-Ger | 670,514 | 824,005 | 1,494,519 | 313,316 | 1,181,203 |
| Northwest Europe | 1,060,421 | 1,320,577 | 2,380,998 | 950,841 | 1,430,157 |
| Swi-Ita | 231,610 | 240,444 | 472,054 | 177,132 | 294,922 |
| Spa-Por-Gib | 174,570 | 185,191 | 359,761 | 154,889 | 204,872 |
| Western Europe | 1,359,513 | 1,552,650 | 2,912,163 | 1,257,089 | 1,655,074 |
| All Europe | 2,261,735 | 2,770,760 | 5,032,495 | 2,176,604 | 2,855,891 |

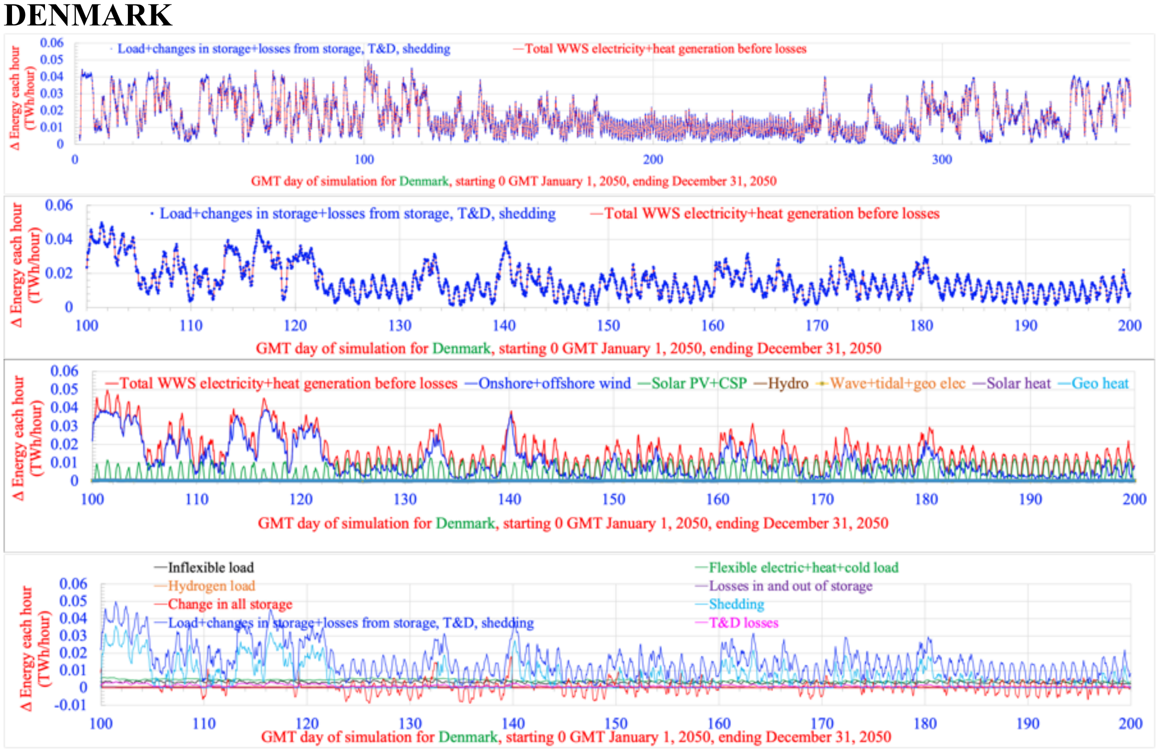
# Supporting Figures

**Figure S1.** 2050 time-series comparison for 21 of the 24 countries/regions defined in Table 1. First row: modeled time-dependent total WWS power generation versus load plus losses plus changes in storage plus shedding. Second row: same as first row, but for a window of 100 days during the year. Third row: a breakdown of WWS power generation by source during the window. Fourth row: a breakdown of inflexible load; flexible electric, heat, and cold load; flexible hydrogen load; losses in and out of storage; transmission and distribution losses; changes in storage; and shedding during the window. The model was run at 30-s resolution. Results are shown hourly. No load loss occurred during any 30-s interval.

## BELGIUM




## DENMARK



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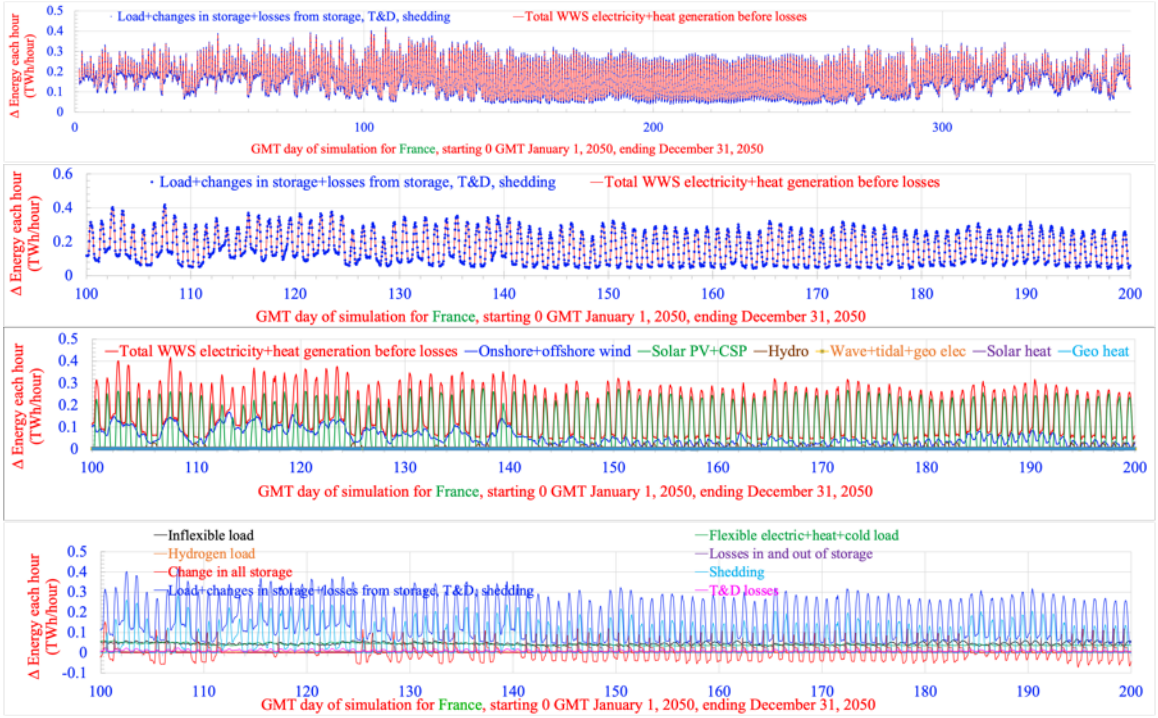
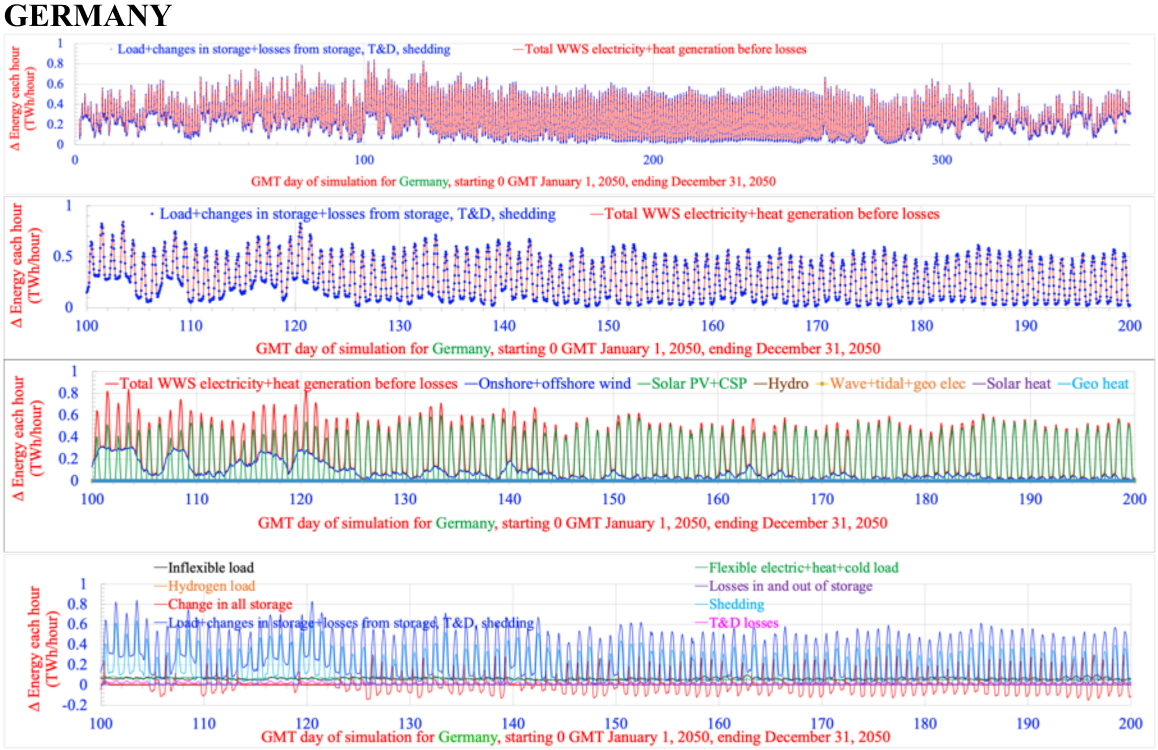
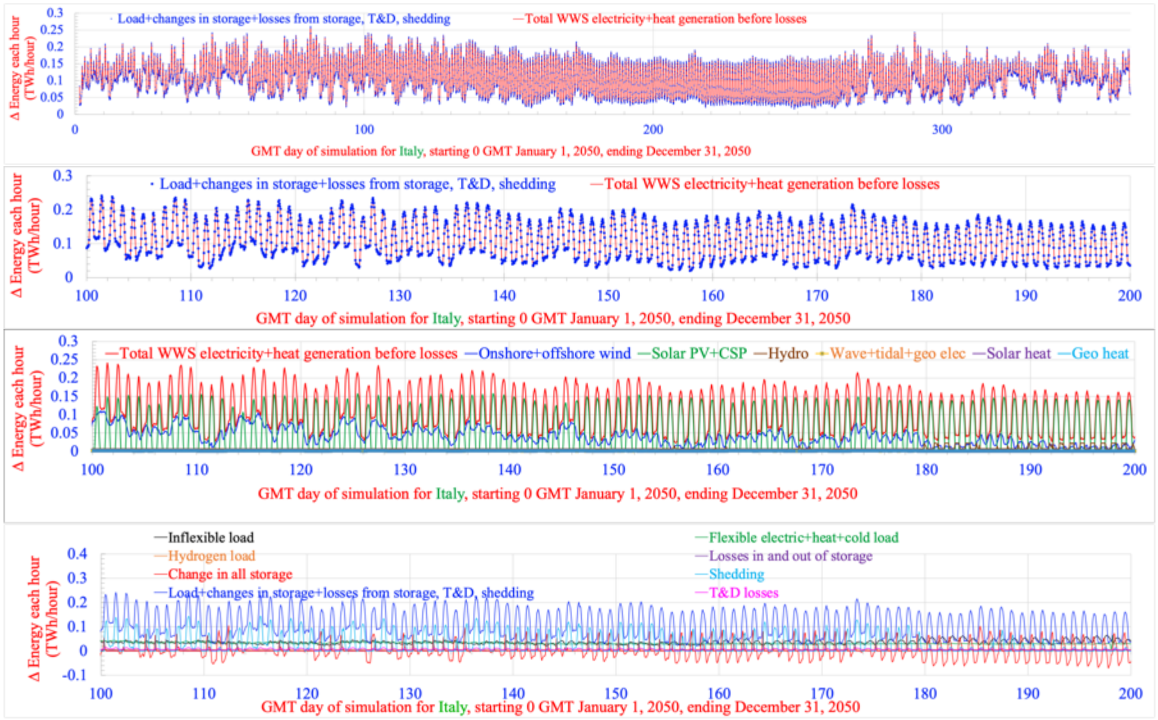


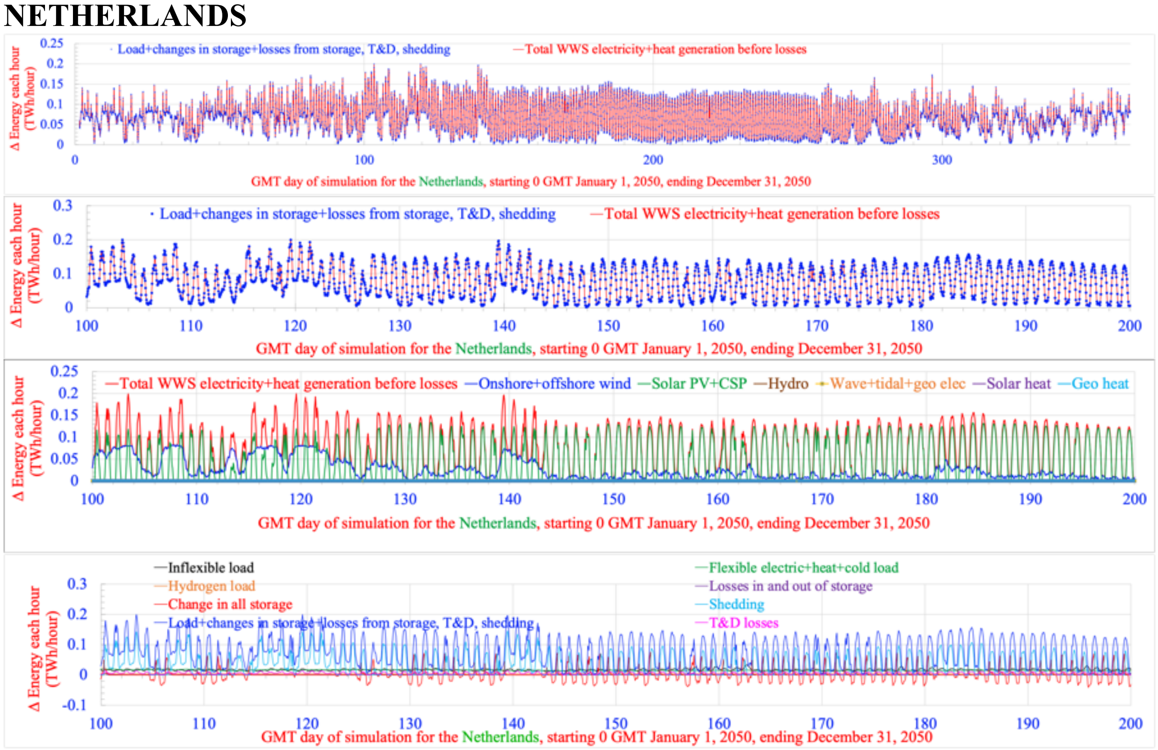

## GERMANY



## ITALY




## NETHERLANDS



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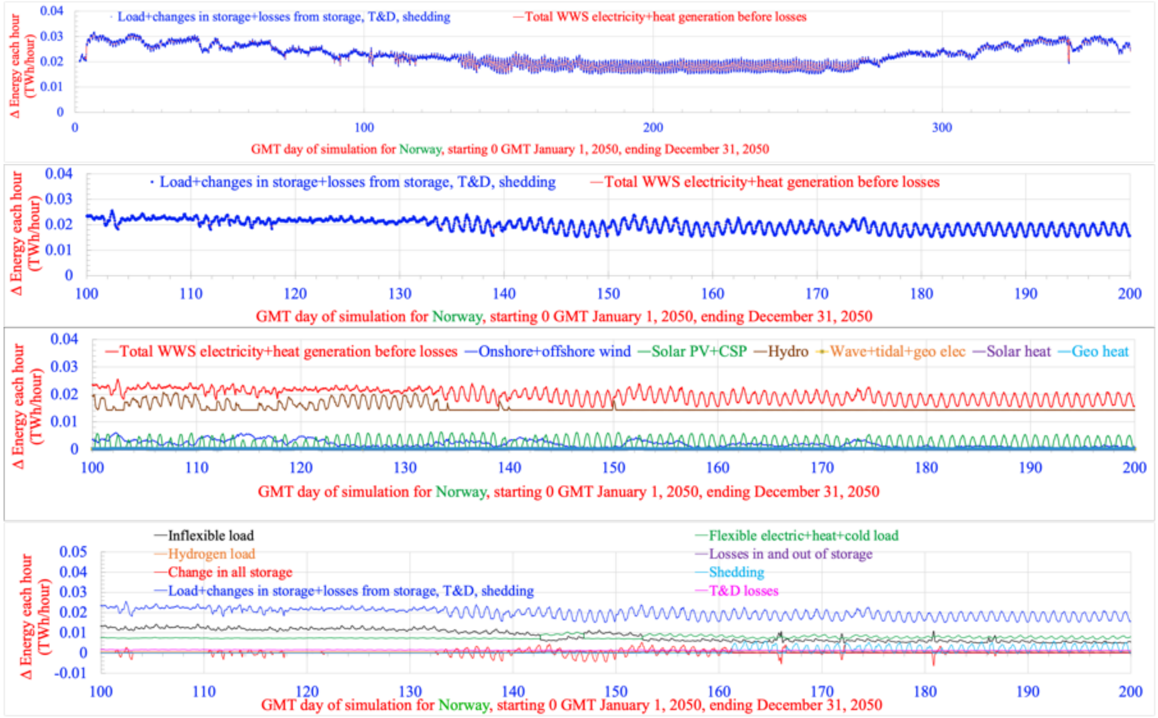


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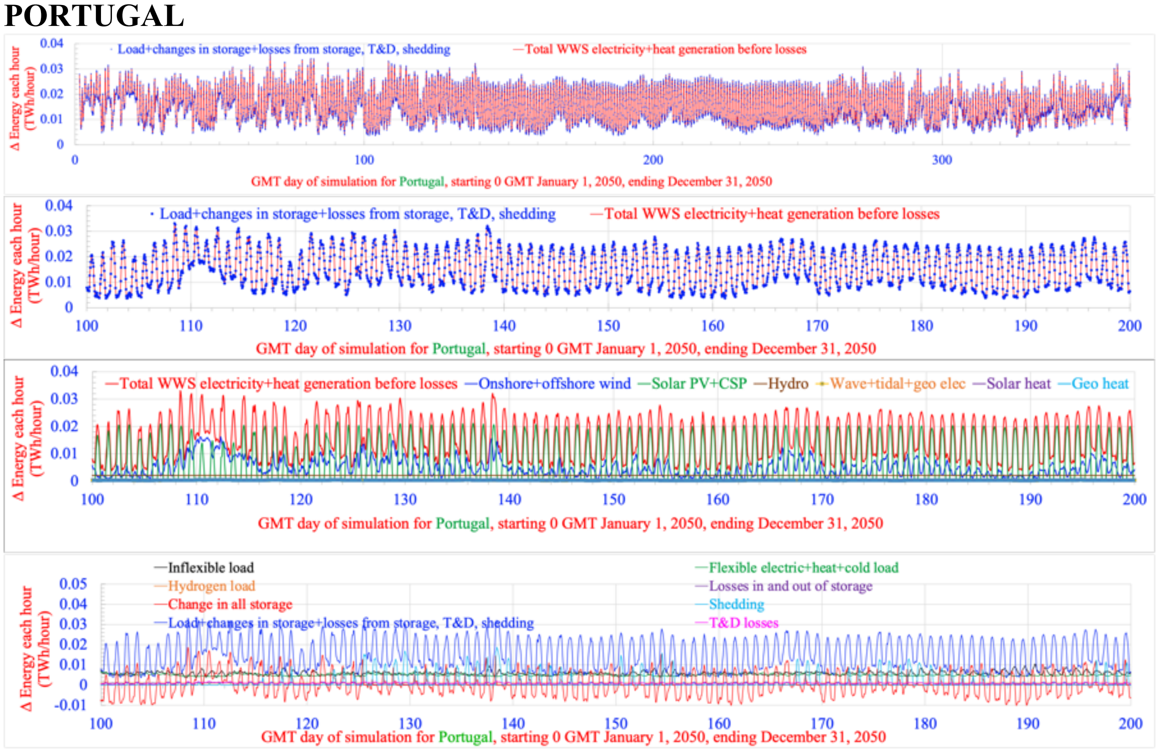
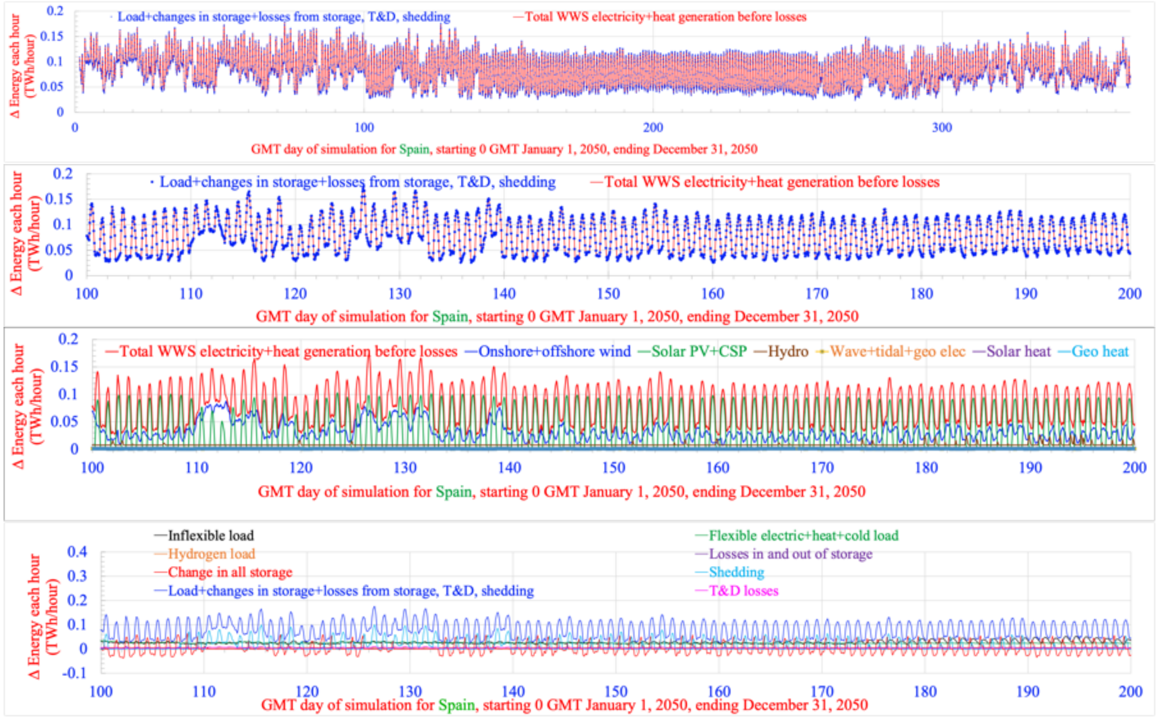
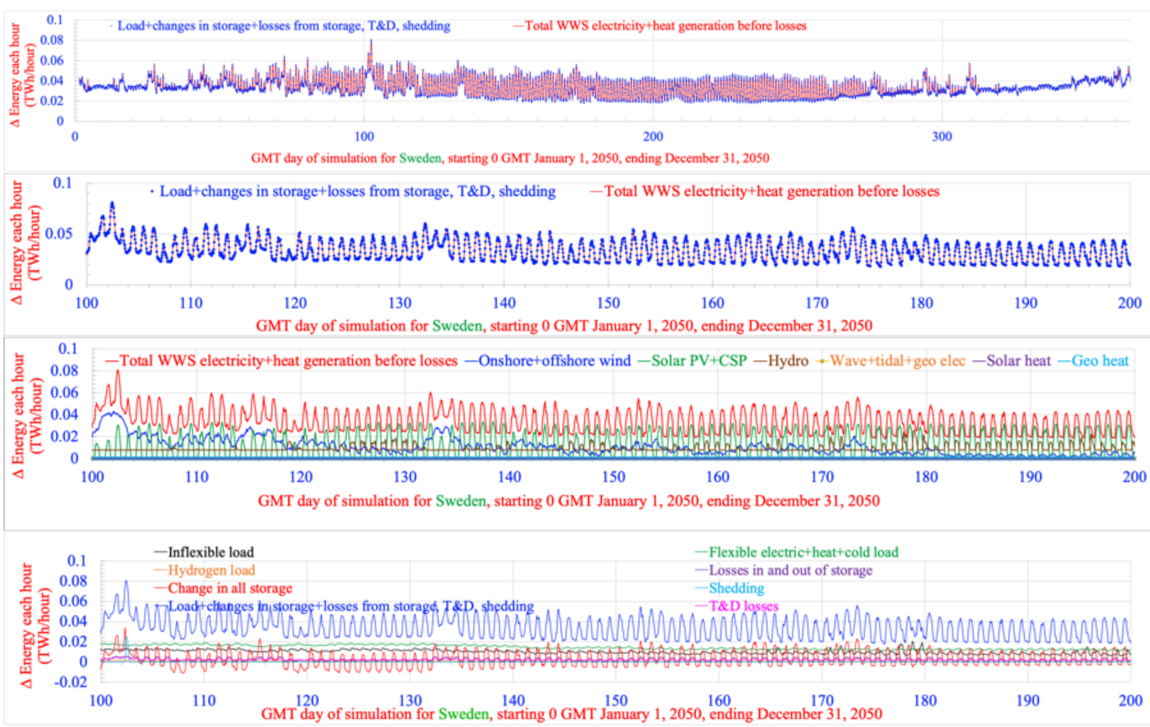


## SPAIN




## SWEDEN



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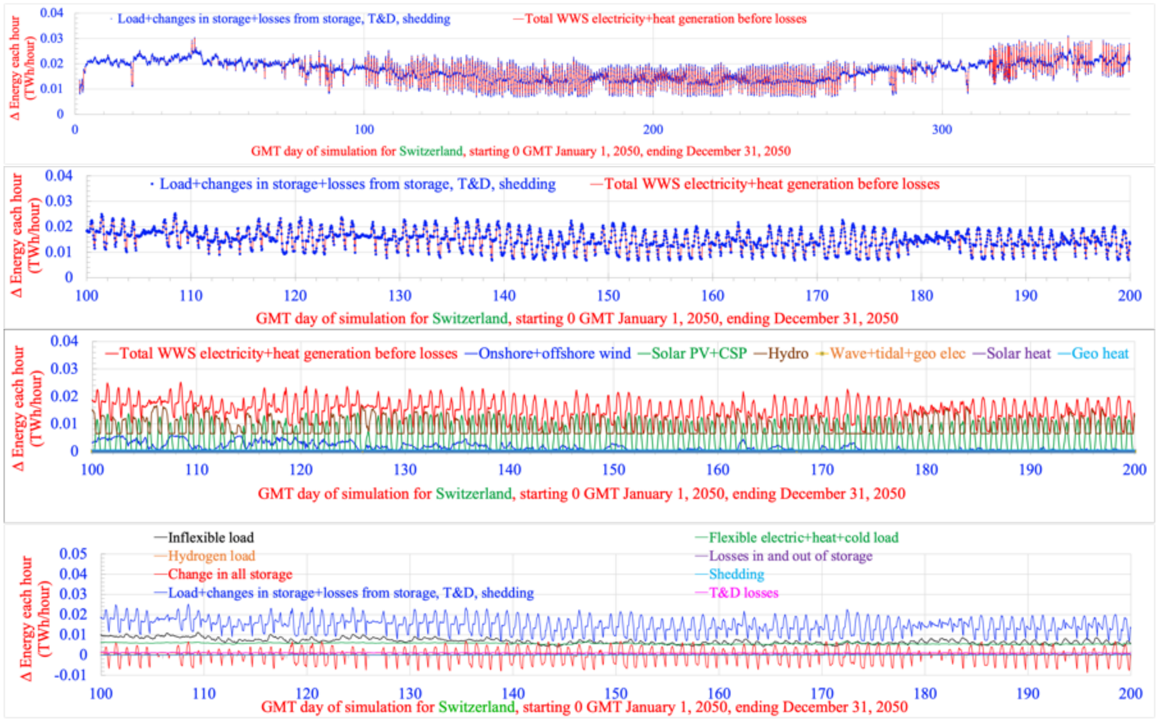
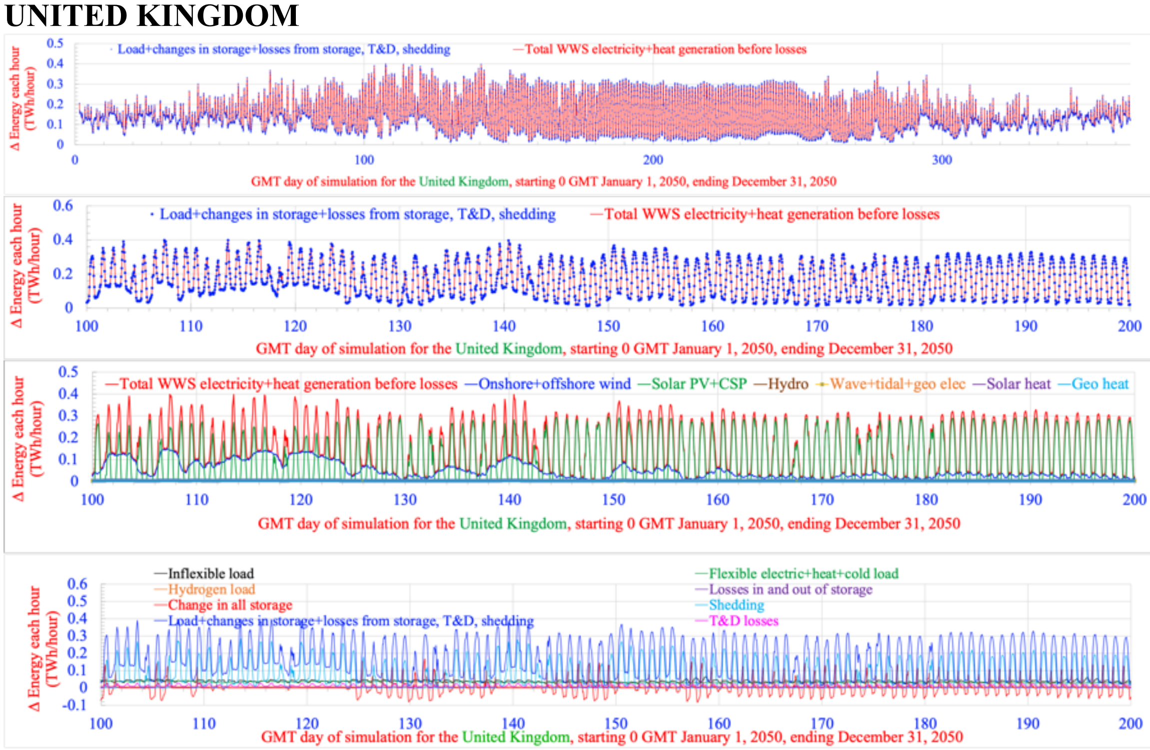
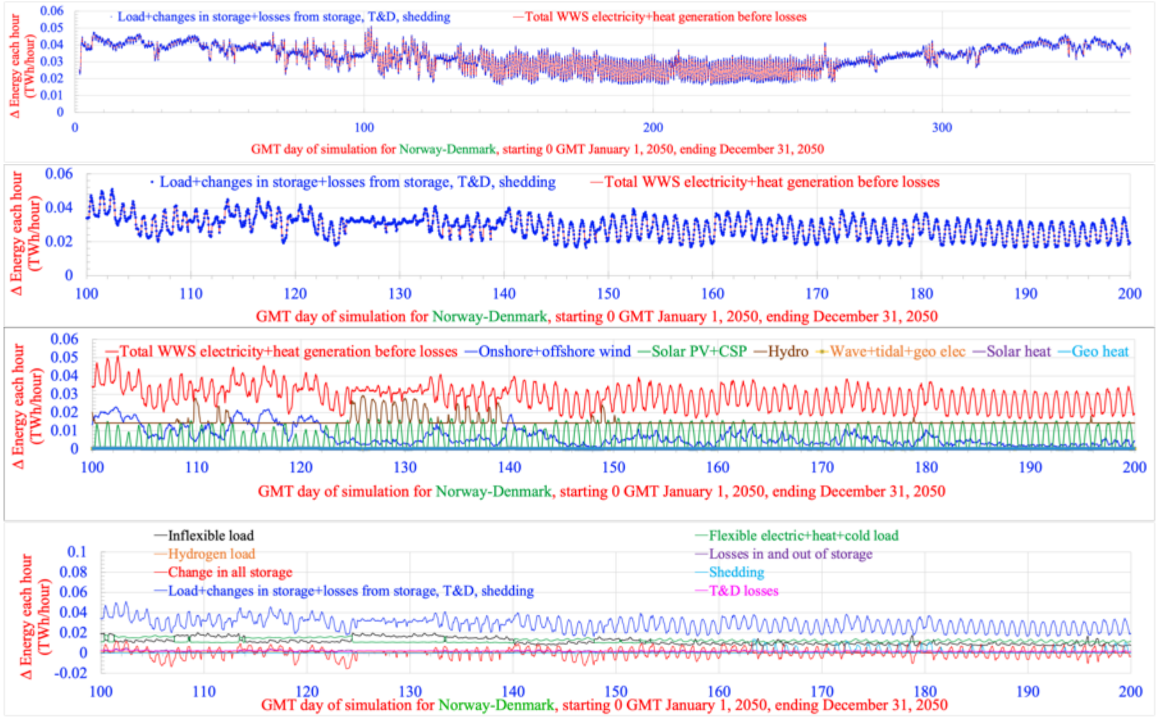


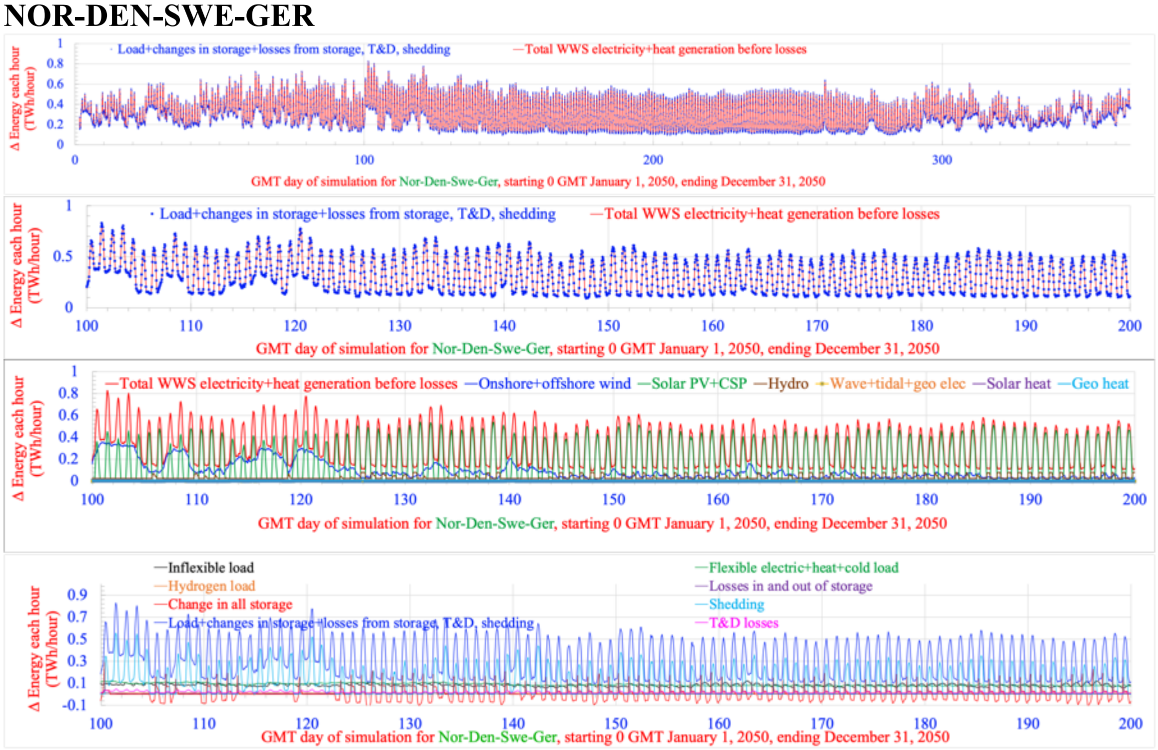

## UNITED KINGDOM



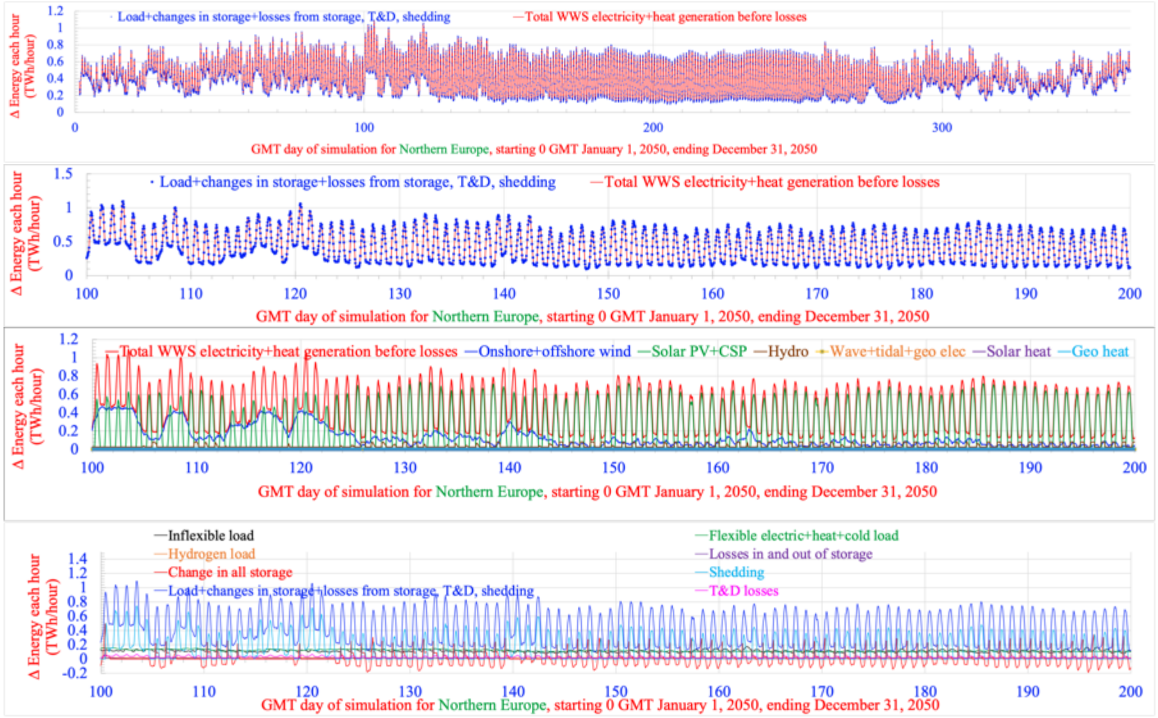
## NOR-DEN




## NOR-DEN-SWE-GER

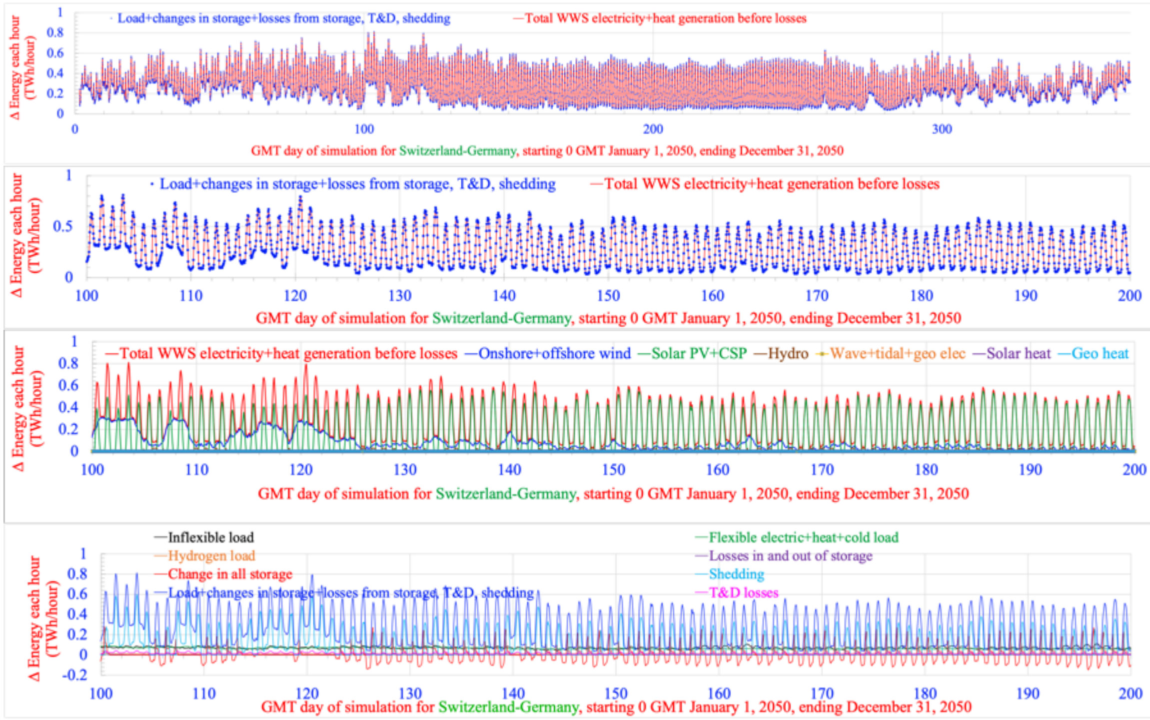


## NORTHERN EUROPE

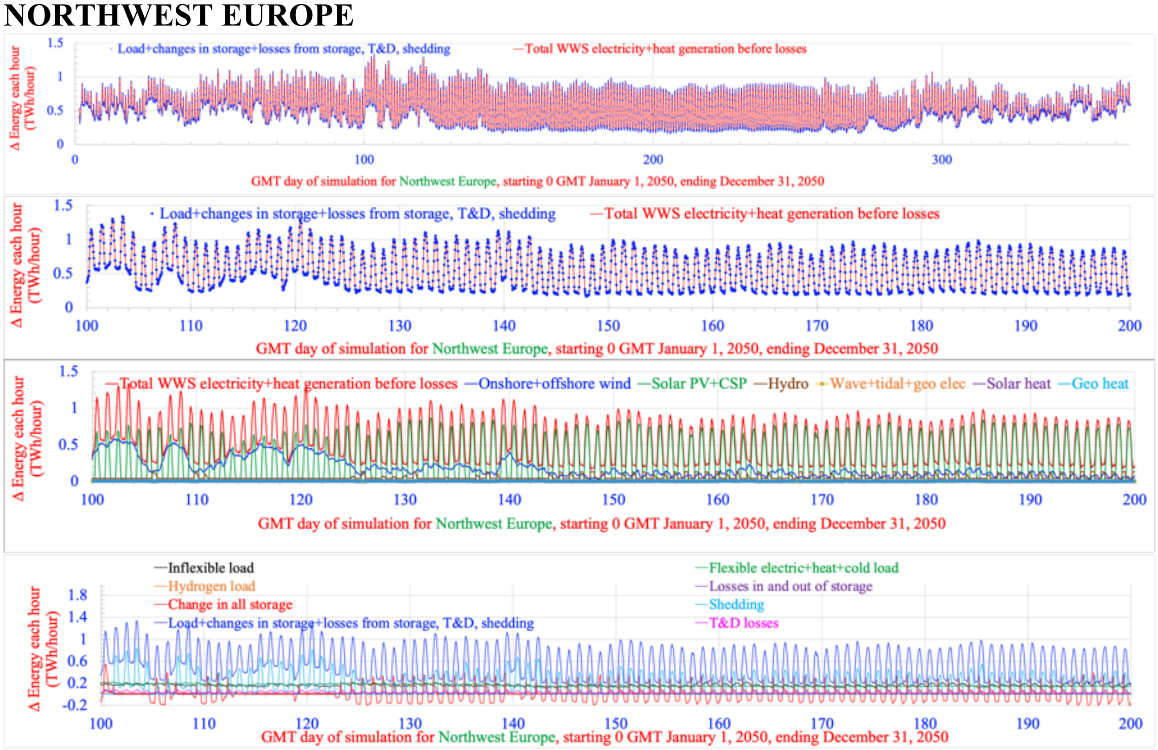



## SWI-FRA

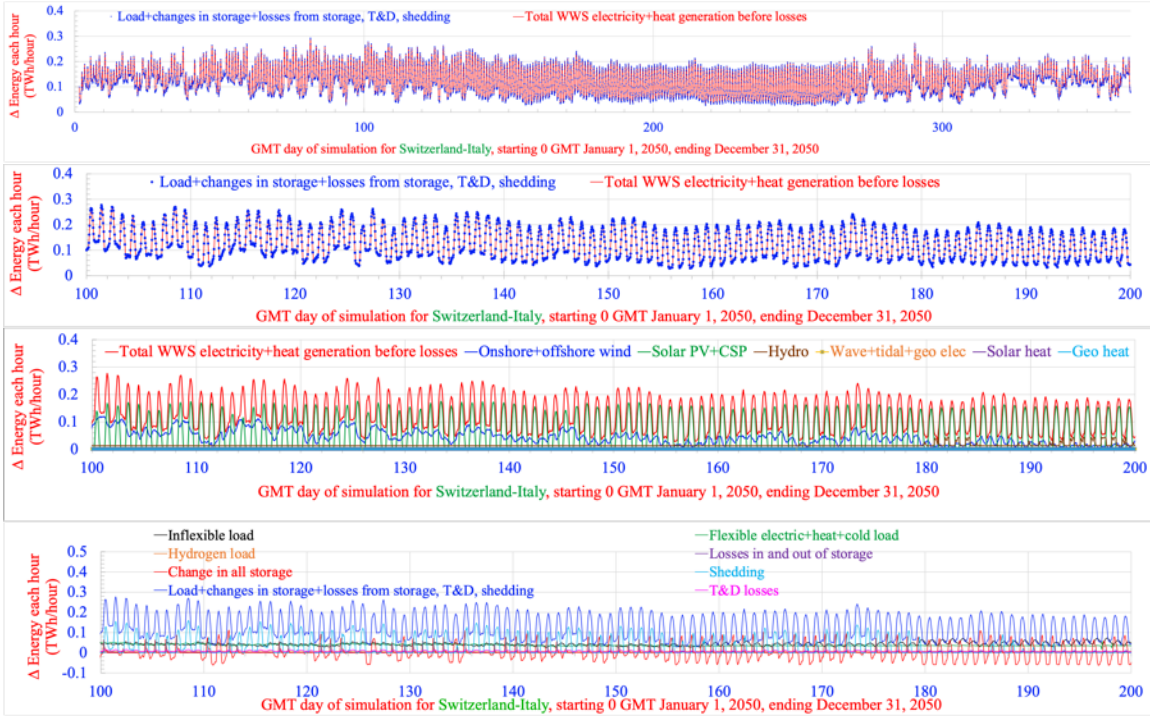
## SWI-GER




## NORTHWEST EUROPE



## SWI-ITA

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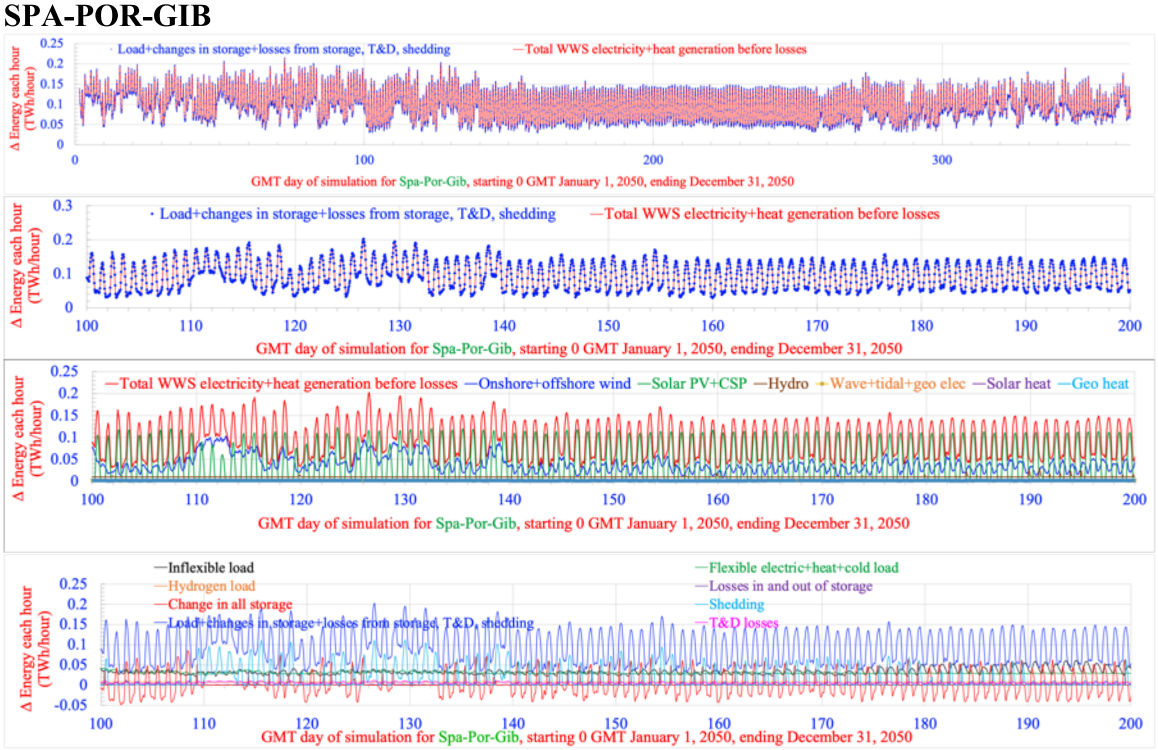
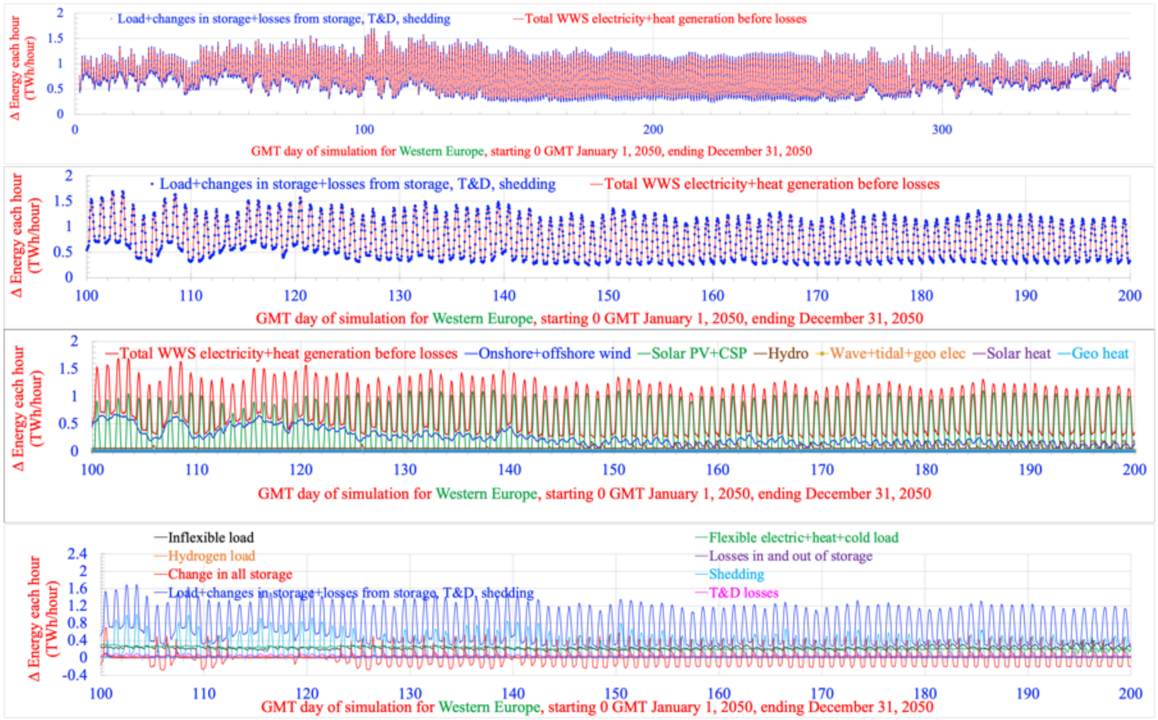


## WESTERN EUROPE



## Supporting References


S1. Jacobson, M.Z., Delucchi, M.A., Cameron, M.A., Coughlin, S.J., Hay, C., Manogaran, I.P., Shu, Y., and von Krauland, A.-K. (2019). Impacts of Green New Deal energy plans on grid stability, costs, jobs, health, and climate in 143 countries, One Earth*, 1*, 449-463.

S2. IEA (International Energy Agency). World Energy Statistics 2018. OECD Publishing, Paris.

S3. EIA (Energy Information Administration). U.S. International Energy Outlook 2016. DOE/EIA-0484. Available online: http://www.eia.gov/forecasts/ieo/pdf/0484(2016).pdf.

S4. Jacobson, M.Z., and Jadhav, V. (2018). World estimates of PV optimal tilt angles and ratios of sunlight incident upon tilted and tracked PV panels relative to horizontal panels. Solar Energy *169***,** 55-66.

S5. Enevoldsen, P., and M.Z. Jacobson (2021). Data investigation of installed and output power densities of onshore and offshore wind turbines worldwide, *Energy for Sustainable Development*, 60, 40-51.