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Matching demand with supply at low cost in 139 countries among 20 world regions with 100% intermittent wind, water, and sunlight (WWS) for all purposes

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ABSTRACT

Matching electricity, heat, and cold demand with supply at low cost is the greatest concern facing countries seeking to provide their all-purpose energy with 100% clean, renewable wind, water, and sunlight (WWS). Implementing WWS worldwide could eliminate 4–7 million annual air pollution deaths, first slow then reverse global warming, and provide energy sustainably. This study derives zero-load-loss technical solutions to matching demand with 100% WWS supply; heat, cold, and electricity storage; hydrogen production; assumed all-distance transmission; and demand response for 20 world regions encompassing 139 countries after they electrify or provide direct heat for all energy in 2050. Multiple solutions are found, including those with batteries and heat pumps but zero added hydropower turbines and zero thermal energy storage. Whereas WWS and Business-As-Usual (BAU) energy costs per unit energy are similar, WWS requires ~42.5% less energy in a base case and ~57.9% less in a heat-pump case so may reduce capital and consumer costs significantly. Further, WWS social (energy + health + climate) costs per unit energy are one-fourth BAU's. By reducing water vapor, the wind turbines proposed may rapidly offset ~3% global warming while also displacing fossil-fuel emissions. Thus, with careful planning, the world's energy challenges may be solvable with a practical technique.

1. Introduction

Globally averaged temperatures in 2016 were over 1 °C higher than at the end of the 19th century [1]. To avoid 1.5 °C warming and eliminate the 4–7 million worldwide premature air pollution deaths occurring annually, the world must rapidly replace fossil fuels with zero-emissions energy sources. To help accomplish this goal, 139 individual country roadmaps were recently developed to transition all energy sectors (electricity, transportation, heating/cooling, industry, and agriculture/forestry/fishing) to use electricity and direct heat powered by 100% wind, water, and sunlight (WWS) by 2050, with 80% conversion by 2030 [2]. Only WWS technologies were used in that study, as they provide greater air pollution health and climate benefits than do bioenergy or fossil fuels with carbon capture and sequestration (CCS) [3]; use less land than crop-based bioenergy [3]; and result in less catastrophic risk, weapons proliferation risk, waste, and delays than nuclear power [3,4].

Whereas, the 139-country roadmaps estimate the numbers of WWS generators needed for each country to match annually-averaged electricity, heat, and cold power demand with WWS supply, they do not provide a detailed analysis of matching supply with demand over shorter time scales (e.g., minutes, hours, months, or seasons). Such an analysis is necessary, as the concern for load loss (supply shortfall) due to the variability of WWS resources and associated costs of mitigating such uncertainty is the greatest barrier facing the large-scale, worldwide adoption of WWS power [5].

Previous advanced studies have examined matching time-dependent demand with supply for up to 100% renewable energy by replacing conventional generators with WWS, or WWS plus bioenergy in either the electric power sector alone, or in the electric sector plus one or two other sectors after they have been electrified

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[6–30]. One particular set of studies examined grid stability with WWS and biofuels in Denmark and Europe for the combined electricity, heating, and transportation sectors while treating storage, district heating and cooling, energy efficiency, energy savings, and hydrogen for electricity [20,24]. All the above studies have uniformly found that time-dependent supply can match demand at high penetrations of renewable energy without nuclear power, natural gas, or fossil fuels with carbon capture.

Here, we match 2050 power demand with 100% WWS supply, storage, and transmission for 20 world regions encompassing the 139 countries for which 2050 roadmaps were previously developed [2]. WWS generators here supply electricity and direct heat for all energy sectors (electricity, transportation, heating/cooling, industry, agriculture/forestry/fishing) after transportation and high-temperature industrial heat are electrified. Some of the electricity in the transportation sector is used to produce, compress, and store hydrogen for fuel cells. Hydrogen is not used in any other sector. Low-temperature heat is electrified with heat pumps in one scenario, but is otherwise supplied from solar and geothermal heat, electric resistance heating, and heat storage, which itself come from either WWS direct heat or electricity. Cooling is obtained from electricity or cold storage generated from electricity. The 2050 electric plus heat loads for this study were determined by electrifying 2050 Business-As-Usual (BAU) loads in each sector in each country [2] then converting low-temperature electrical loads for heat back to heat itself. The 2050 BAU loads were projected from contemporary load data in each country after accounting for changes in population, economic output, and energy intensity [2].

Some important characteristics of this study are the following. First, total 2050 end-use WWS load in each country is derived from 2050 end-use BAU load accounting for reduced BAU load upon converting to WWS due to (a) the efficiency of electricity over combustion, (b), eliminating energy from mining, transporting, and refining fossil fuels, and (c) end-use energy efficiency improvements and reduced energy use beyond BAU. Second, 100% of all end-use energy, rather than 100% of just electricity (which is ~20% of total end use energy), is decarbonized. Third, grid solutions are found by considering many storage options, namely heat storage in rocks and water; cold storage in water and ice; electricity storage in CSP-storage, pumped hydropower, existing hydropower reservoirs, and batteries; and hydrogen storage; and by considering demand response and, in one scenario, heat pumps. Fourth, the wind and solar time series here are derived consistently in time for each country with GATOR-GCMOM, which treats kinetic energy extraction, thus wind speed reduction, by wind turbines. Fifth, GATOR-GCMOM accounts for the feedback of wind and solar energy extraction and electricity use to temperatures.

The main purpose of this study is to explore whether low-cost mixes using 100% WWS can match energy demand with intermittent supply, not to prescribe the *only* possible future energy mix in each region. Indeed, many different future scenarios can be constructed depending on the objective. The objective here is to determine whether a 100% WWS system, which we believe maximizes air quality and climate change benefits while minimizing catastrophic risk relative to systems using other technologies, can deliver energy reliably at a reasonable business cost worldwide.

2. Methods

The two primary tools used for this study are a global weather-climate-air-pollution Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model, GATOR-GCMOM [31–33] and the LOADMATCH grid integration model [34].

GATOR-GCMOM is used to provide a five-year, country-by-country time series of wind (onshore, offshore) and solar [photovoltaics (PV), CSP, thermal] resources, with output every 30 s, for use in LOADMATCH. It also calculates the impacts of such resource extraction on short-term climate, accounting for extreme weather events, competition among wind turbines for kinetic energy, and the feedback of extracted solar radiation to roof and surface temperatures. Inputs into GATOR-GCMOM include the numbers of wind and solar generators in each country, determined from Ref. [2].

LOADMATCH combines the wind and solar resource time series from GATOR-GCMOM with estimated time series for other WWS generators (geothermal, hydro, wave, and tidal electricity and geothermal heat); hourly load data for each country in each region; capacities for low-cost heat storage (in underground rocks and water), cold storage (in ice and water), electricity storage (in CSP storage, pumped hydropower, batteries, and hydropower reservoirs), and hydrogen storage; specifications of heat pumps and demand response; and costs of the above and of hydrogen electrolysis and compression and estimated short- and long-distance transmission and distribution to obtain low-cost, zero-load-loss grid solutions for each of 20 world grid regions considered. Table 1 summarizes the countries within each region.

The 20 grid regions were constituted based primarily on geographic proximity and some geo-political considerations. In practice, political opposition within the proposed regions is likely to result in some different groupings. However, because low-cost grid solutions under multiple WWS configurations are found here for all 20 regions spanning a wide range of geographic areas, resource availabilities, and demand conditions, increasing the number of regions or trading countries between regions should not inhibit the ability to obtain low-cost, stable solutions in other grid regions.

Previously, LOADMATCH was coupled with GATOR-GCMOM and used to study matching power demand with intermittent supply among the 48 contiguous U.S. states [34]. The numbers of wind and solar generators by state input into GATOR-GCMOM in that study were obtained from roadmaps for each of the 50 U S. states [35]. Multiple low-cost solutions were obtained by prioritizing storage of excess heat in rocks and water; storage of electricity in phase-change materials, pumped hydro, increased peak hydropower turbine output (with no increase in annual hydropower energy output), and hydrogen; and by using demand response. Transmission was assumed to be perfect, but losses through lines and costs of additional transmission lines needed were estimated.

This study expands on [34] by providing three scenarios, rather than one, where power demand matches supply, and by considering 20 world regions rather than one. The first scenario (Case A) uses batteries, substantial concentrated solar power (CSP) with storage where applicable, and hot and cold thermal energy storage, but zero added hydropower turbines in comparison with today, and no heat pumps. The second (Case B), which is similar to that used in Ref. [34], assumes zero battery storage, zero heat pumps, CSP-storage, hot and cold thermal energy storage, an increase in the hydropower maximum discharge rate in 12 regions and none in the other 8 (Table S1) but without changing the annually averaged hydropower energy output in any region. The third scenario (Case C) is the same as Case A (thus with batteries and additional CSP but no added hydropower turbines), except we eliminate all cold and hot thermal energy storage (including all underground thermal energy storage, hot and cold centralized water tanks, and ice storage), and replace it with a mix of air-source and ground-source electric heat pumps running on WWS electricity. Whereas, Cases A and B are applied to all 20 world regions, Case C is applied to 14 of the 20 regions representing 89.7% of the 139-country energy use, as a proof of concept demonstration. By obtaining solutions for three extreme cases (A-C), we postulate that multiple intermediate

Table 1
The 20 world regions and 139 countries within them treated here.

Region	Country(ies) Within Each Region
Africa	Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the Congo, Ivory Coast, Egypt Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, Tanzania, Togo, Tunisia, Zambia, Zimbabwe
Australia	Australia
Central America	Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua, Panama
Central Asia	Kazakhstan, Kyrgyz Republic, Pakistan, Tajikistan, Turkmenistan, Uzbekistan
China	China, Hong Kong, Democratic Republic of Korea, Mongolia
Cuba	Cuba
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
Haiti	Haiti, Dominican Republic
Iceland	Iceland
India	India, Nepal, Sri Lanka
Jamaica	Jamaica
Japan	Japan, South Korea
Mideast	Armenia, Azerbaijan, Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, Turkey, United Arab Emirates, Yemen
New Zealand	New Zealand
North America	Canada, United States of America
Philippines	Philippines
Russia	Georgia, Russia
South America	Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Dutch Antilles, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela
Southeast Asia	Bangladesh, Brunei Darussalam, Cambodia, Indonesia, Malaysia, Myanmar, Singapore, Thailand, Vietnam
Taiwan	Taiwan

solutions exist (e.g., a mixture of heat pumps, thermal energy storage, batteries, and/or added hydropower turbines).

Case B here is similar to the single case assumed in Ref. [34]. In that study, it was not made clear in the text but was evident from Fig. 2b, S4b, and S5b that the maximum possible hydropower discharge rate in the continental U.S. was increased by a factor of ~15 relative to the near-present-day maximum discharge rate by adding turbines without a corresponding change in annually averaged hydropower energy output. Here, for North America in Case B, the maximum discharge rate is allowed to increase up to only 2 times the near-present-day value. In Cases A and C, here, zero increases in hydropower turbines are allowed for any region (Table S1). Ref. [34] further neglected the cost of the additional hydropower turbines, which were subsequently calculated as ~3% of total energy costs. Here, for Case B, for North America, they are ~0.32% of the total energy cost due to the lesser increase in the hydropower maximum discharge rate (Table S9).

Next, the LOADMATCH and GATOR-GCMOM models are summarized. Section S1 describes them in more detail.

2.1. LOADMATCH

The grid integration model used is LOADMATCH [34]. The model requires the following inputs: (1) time-dependent, intermittent electric power produced from onshore and offshore wind, rooftop PV, utility PV, and CSP; and solar-thermal heat as modeled by GATOR-GCMOM; (2) time-dependent electricity from wave power obtained roughly by scaling the annual wave power from Ref. [2] by time-dependent GATOR-GCMOM offshore wind power; (3) baseload geothermal electricity, geothermal heat, and tidal electricity with annual production given in Ref. [2]; (4) time-dependent hydropower used for both baseload and load balancing as needed, but constrained by its near-current annual energy output and a maximum discharge rate; (5) specifications of Hot-Water and Chilled-Water Sensible-Heat Thermal Energy Storage (HW-STES and CW-STES), underground thermal energy storage (UTES), and ice storage (ICE); (6) specifications of electricity storage in (a) pumped hydropower storage (PHS), (b) phase-change materials coupled with concentrated solar power plants (CSP-PCM), and (c) batteries; (7) specifications of hydrogen electrolysis, compression, and storage; (8) specifications of electric heat pumps for air and water heating and cooling; (9) specifications of a demand response system; and (10) time-dependent load by region, determined from individual country data.

LOADMATCH also requires generator capital costs, operation and maintenance (O&M) costs; decommissioning costs; short- and long-distance transmission, distribution, and maintenance energy losses; and estimated lifetimes (Table S2). It further requires heat, cold, electricity, and hydrogen storage costs and efficiencies (losses during charging and discharging) as well as hydrogen electrolysis and compression costs and efficiencies (Table S3); maximum energy storage capacities and maximum charge/discharge rates (Table S4); discount rates, and short- and long-distance transmission and distribution costs (Table S9).

LOADMATCH runs quickly (e.g., ~2.6 min for a 5-year, 5.3 million time-step, simulation on a single Nehalem 5580 3.2 GHz processor) because it is a trial-and-error model with no knowledge of the load or generation data ahead of time, rather than an optimization model. Its main constraint is that it cannot permit load loss at any time, thus it is designed to exceed the utility-industry standard of a loss of load expectation (LOLE) of 1 day (24 h) in 10 years, minimizing risk to grid operators.

If load loss occurs because demand during any time step cannot be supplied, the simulation fails and parameters in Table S1 are repeatedly adjusted until a solution is obtained with zero load loss for all time steps of a simulation. The model determines the system cost, including estimated costs of transmission, distribution, and storage expansion once a zero-load-loss solution is obtained.

Here, zero-load-loss solutions for all 20 regions of the world are obtained within 0–10 simulations (thus in less than 1 h of computer time). Additional iterations are performed to find lower cost solutions. Table S1 shows the adjustment factors that generated the final results reported here for Cases A, B, and C. Table 2 summaries the final nameplate capacities of each generator for each grid region corresponding to the final low-cost, zero-load-loss solutions for Cases A, B, and C.

Whereas converting LOADMATCH from a trial-and-error model to a least-cost or least-carbon optimization model is possible, the

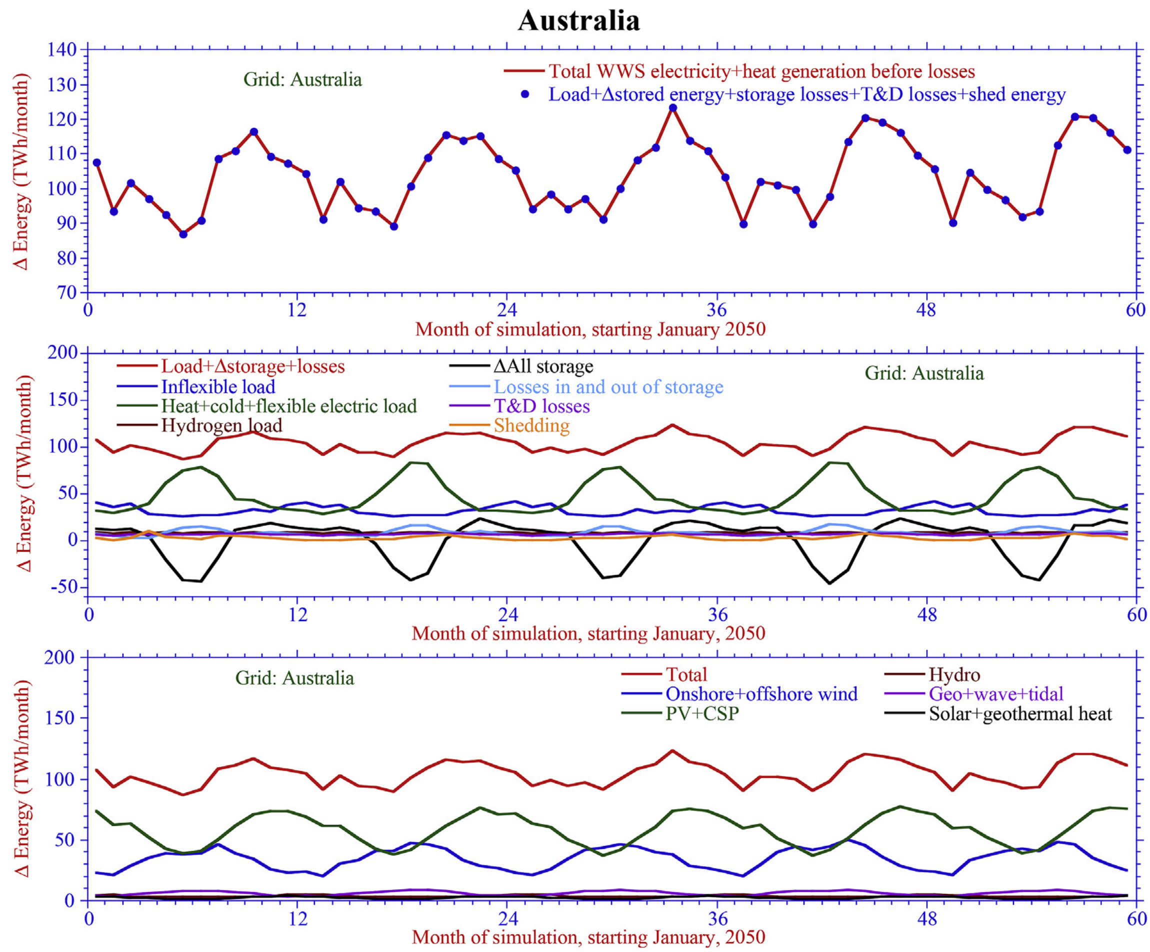

Fig. 1. Five-year (60-month) time-series comparison for Australia for Case A (no increase in hydropower peak discharge rate) of modeled (a) monthly-averaged total WWS power generation versus the sum of load plus losses plus changes in storage plus shedding, (b) breakdown of load plus losses plus changes in storage plus shedding into individual components, and (c) breakdown of WWS power generation by generation technology. Fig. S3 shows the same plots for all 20 world regions.

conversion would greatly limit the exploration of possible solution subspaces, and thus diminish the scope of this study. A nonlinear optimization model would require up to 4–5 orders of magnitude more computer time for a single simulation, thus greatly limit the number of simulations that can be run feasibly. Moreover, such an optimization is not guaranteed to produce a globally optimal solution over the many variables and millions of time steps used here, but rather only a locally optimal one. Thus LOADMATCH does not aim to find the *lowest*-cost stable solution to a grid problem, but rather to find multiple low-cost stable solutions.

LOADMATCH assumes a short- and long-distance transmission and distribution (T&D) system that carries power from distributed and centralized WWS generators to storage and load centers assuming perfect transmission. Costs of and power losses during T&D are accounted for, but power flows through individual transmission lines or substations are not currently modeled. As such, LOADMATCH is a grid integration model rather than a power flow model. A grid integration model, as defined here, attempts to match time-dependent power demand with supply, storage, and losses assuming either perfect transmission or simplistic transmission. A power flow model also attempts to match the same, but explicitly treats the flow of electricity through individual lines of an interconnected grid.

Some grid integration models account for single transmission lines between regions, but they are not power flow models and do not represent the detailed current or future grid accurately or simulate the time resolution treated here. It is not clear whether including more representation of transmission here would improve the accuracy of the transmission and distribution costs and losses until a much more detailed and time-resolved transmission system can be represented in reasonable computer time.

For this study, country-specific time-dependent loads for 2050–2054, needed as input into LOADMATCH, are derived as follows. First, 2050 annual country-specific end-use loads by consumption sector (residential, commercial, transportation, industrial, and agriculture/forestry/fishing) (Table S5) are taken from Ref. [2]. That study projects 2012 end-use BAU loads to 2050 from each sector in each of the 139 countries for which data are available from IEA [36], then electrifies the 2050 loads by sector after accounting for modest end-use energy efficiency improvements beyond BAU, with the assumption that some electricity goes to hydrogen production for fuel cells in transportation. Portions of the electricity are also intended for low-temperature heat, high-temperature heat, and cold.

Annual 2050 electric loads in each sector from Ref. [2] are then separated here into (1) electric plus heat loads needed for low-temperature heat, (2) electric loads needed for cooling and refrigeration, (3) electric loads needed to produce, compress, and store hydrogen for transportation, (4) electric loads subject to demand response, and (5) inflexible electric loads. Section S1.A.ii describes how these loads are calculated. Table 3 provides the resulting distribution of these loads by world region.

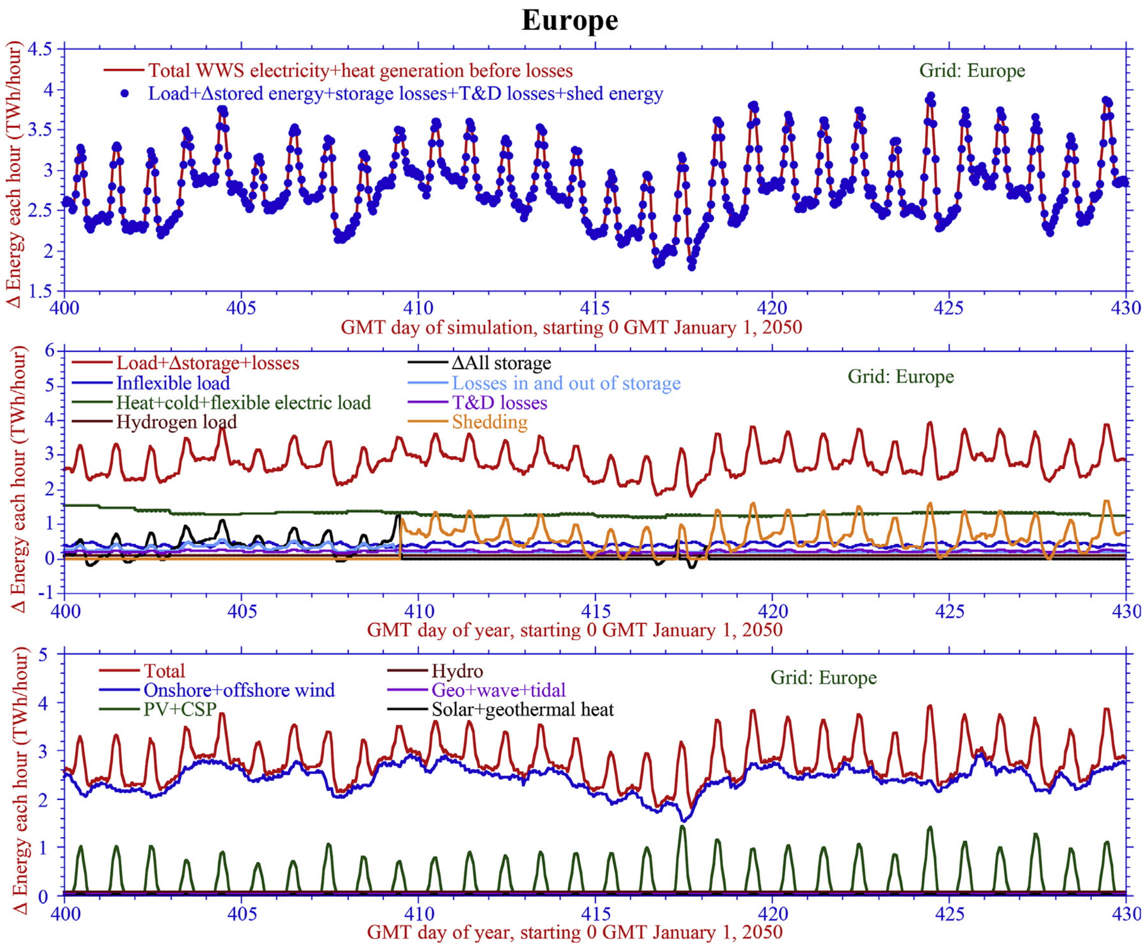

Fig. 2. Same as Fig. 1, but with hourly results for a 30-day period during the 5-year Case A simulation for Europe. Fig. S4 shows the same plots for all 20 world regions.

Major loads subject to demand response are transportation and high-temperature industrial processes. Of the total transportation electric load among 139 countries, 41.4% is assumed flexible for charging vehicles any time ahead of use, another 43.6% is assumed flexible for producing hydrogen for fuel cell vehicles any time ahead of use, and the rest (15%) is assumed to be inflexible for charging electric vehicles immediately before use. It is assumed that utility operators can incentivize when individuals or companies charge vehicles by, for example, offering different electrical rates for different times of day, as currently done many places worldwide.

Other flexible loads include 70% of high temperature industrial-process loads; 15% of energy for non-heating, non-cooling, non-transportation loads in each sector; and 75% of loads in the "other" sector (Table 3, footnote). It is assumed that utilities can offer industry different electrical rates at different times of day to incentivize shifting electric power consumption for high-temperature processes to non-peak times of day or night and to incentivize efficiency measures. The U.S. National Research Council [37] confirms this potential by stating (P.251), "*The ability of industry to cut peak electric loads is a motivator for utilities to incentivize demand response (shifting loads to off-peak periods) in industry … In combination with peak-load pricing for electricity, energy efficiency and demand response can be a lucrative enterprise for industrial customers.*" Although the benefits of demand response can significantly outweigh its costs [38], we conservatively assume equal financial benefits and costs.

If heat, cold, or hydrogen storage empties before those respective loads are satisfied, the remaining unsatisfied load becomes either inflexible or flexible electric load. We conservatively assume that 85% of such heat and cold loads and 100% of electricity loads for hydrogen become inflexible. The rest become flexible. Hourly inflexible load profiles for each grid region are described next.

Annual average 2050 inflexible loads for each of the 20 grid regions (Table 3) are converted to hourly 2050 inflexible loads for each region as follows. First, 2010–2014 hourly load data for 33 European countries are obtained from Ref. [39], and hourly load data estimated for 2030 for another 97 countries, either individually or grouped with other countries, are obtained from Refs. [40,41]. Fig. S1a shows hourly load data for several of the individual countries for 10-day periods in each of four seasons.

Second, in each grid region that has countries with hourly load data, an hourly load profile for the region for 2010–2014 or 2030 is estimated first by summing the hourly load profiles of the constituent countries for which data are available. The summed profiles are then multiplied by the 2050 annually averaged inflexible load among all countries in the region (Table 3) to the annually averaged load summed over only the countries that have data available. This gives the final hourly inflexible load profile for the region in 2050.

This method is used for grid regions comprising at least some countries with hourly load data. For 14 out of the 20 grid regions, hourly load data are available for all of the countries in the region. For two regions (South America and China) some countries (Dutch Antilles, Trinidad and Tobago, and Uruguay for the South America region and Hong Kong for the China region) are missing hourly load data. For those two grid regions, the method described above is still

Table 2
2050 total (new plus existing) nameplate capacity (GW) of WWS generators by world region, for Cases A, B, and C. Also provided are 139-country totals for 2050 and 2015, the nameplate capacity (MW) per device, and, for Cases A and B, the 139-country total number of devices needed. For all generators, the nameplate capacity also equals the maximum possible instantaneous discharge rate.

Region	Onshore wind	Offshore wind	Resi-dential roof-top PV	Comm/govt rooftop PV	Utility PV	CSP with storage	Geothermal-electricity	Hydropower	Wave	Tidal	Solar thermal	Geothermal heat
Case A (No increase in hydropower peak discharge rate)												
Africa	746.8	49.8	701.7	652.7	580.7	264.9	3.61	25.5	33.1	1.90	715.3	0.14
Australia	76.2	40.3	77.1	65.0	106.0	47.7	0.4	8.05	22.1	0.5	29.1	0.016
Central America	163.8	93.9	187.0	202.9	44.7	68.1	10.7	18.0	16.8	0.38	15.1	0.16
Central Asia	268.1	23.6	221.9	148.7	227.7	94.8	0	19.5	1.79	0.021	104.3	0.004
China	4687	610.6	1215	845.1	4204.3	753.9	1.86	301.3	8.71	3.02	916.6	17.9
Cuba	6.56	2.96	5.03	9.66	1.39	2.50	0	0.064	1.32	0.047	3.11	0
Europe	2602	665.3	544.0	455.3	2060	63.38	3.16	160.2	37.7	15.0	153.4	22.3
Haiti	2.89	1.44	6.73	7.32	8.08	2.75	0.68	0.604	0	0.052	3.44	0
Iceland	1.09	0.28	0	0	0	0	0.89	1.99	0.335	0.057	0	2.04
India	1383	39.9	892.8	540.2	668.8	231.1	0.28	49.1	5.67	0.72	180.3	0.99
Jamaica	0.476	0.767	1.85	1.99	1.90	0.450	0	0.023	0	0.02	0.997	0
Japan	35.3	183.9	89.8	59.0	3091.9	45.6	1.46	24.0	14.2	3.2	276.6	3.02
Mideast	610.5	134.0	504.1	433.7	1064.3	281.4	0.87	42.7	4.14	0.292	351.8	3.25
New Zealand	14.7	4.70	7.61	6.18	3.77	4.98	2.0	5.25	2.45	0.2	4.22	0.49
North America	1909	688.4	451.5	449.0	2092	447.7	11.5	158.3	71.1	2.35	236.8	18.9
Philippines	25.8	16.5	12.7	23.8	40.4	19.7	5.73	3.55	1.95	0.5	17.4	0.003
Russia	538.4	533.4	77.2	100.7	171.9	17.6	0.5	52.0	4.92	0.36	18.9	0.382
South America	635.4	260.5	407.2	417.4	163.1	295.9	5.35	151.5	36.8	1.22	168.8	0.585
Southeast Asia	129.9	638.9	339.2	329.4	1743	215.7	13.8	34.1	42.9	0.785	30.2	0.162
Taiwan	7.47	61.0	52.6	25.1	247.4	0	33.6	2.08	1.05	0.027	14.05	0.0001
Total 2050	**13,844**	**4050**	**5795**	**4773**	**16,521**	**2858**	**96.4**	**1058**	**307**	**30.7**	**3240**	**70.3**
Total 2015	**420.24**	**12.11**	**70.33**	**87.75**	**67.33**	**4.94**	**12.59**	**1058**	**0**	**0.547**	**0**	**70.3**
Device MW	**5**	**5**	**0.005**	**0.1**	**50**	**100**	**100**	**1300**	**0.75**	**1**	**50**	**50**
Device number	2,768,877	810,029	1.16 bil	47,731,500	330,427	28,582	964	814	409,380	30,651	64,808	1407
Case B (Increase in hydropower peak discharge rate in some regions)												
Region	Onshore wind	Offshore wind	Resi-dential roof-top PV	Comm/govt rooftop PV	Utility PV	CSP with storage	Geothermal-electricity	Hydropower	Wave	Tidal	Solar thermal	Geothermal heat
Africa	746.8	49.8	701.7	652.7	580.7	264.9	3.6	25.5	33.1	1.9	715.3	0.14
Australia	91.5	45.1	77.7	65.0	116.6	43.0	0.4	24.2	16.1	0.5	29.1	0.02
Central America	196.6	69.3	197.3	214.2	57.1	68.1	10.7	18.0	16.8	0.4	60.5	0.16
Central Asia	265.9	23.6	221.9	148.7	227.7	101.1	0.0	136.8	1.8	0.0	115.8	0.00
China	3716.7	1099.2	1700.9	1183.1	5465.6	980.1	1.9	301.3	8.7	3.0	0.0	17.90
Cuba	6.9	1.9	5.0	9.7	1.9	3.2	0.0	0.32	1.3	0.0	0.0	0.00
Europe	1734.8	628.4	679.9	569.1	3000.9	202.8	3.0	640.8	37.7	15.0	0.0	22.30
Haiti	2.9	1.4	6.7	7.3	8.1	2.8	0.7	0.60	0.0	0.1	3.4	0.00
Iceland	1.1	0.3	0.0	0.0	0.0	0.0	0.9	1.99	0.32	0.1	0.0	2.04
India	1198.4	39.9	892.8	540.2	812.2	312.0	0.3	98.2	5.7	0.7	72.1	0.99
Jamaica	0.476	0.767	1.850	1.990	1.900	0.450	0.0	0.023	0.0	0.020	0.997	0.00
Japan	64.2	252.9	87.2	57.3	4637.8	82.1	1.5	144.1	14.2	3.2	0.0	3.02
Mideast	712.2	93.8	315.0	271.1	1490.0	281.4	0.9	42.7	4.1	0.3	0.0	3.25
New Zealand	11.2	4.7	8.3	6.7	5.2	3.3	2.0	15.8	2.5	0.2	3.3	0.49
North America	1967.8	611.9	812.6	808.2	1270.0	380.5	11.5	316.7	71.1	2.4	99.4	18.90
Philippines	31.5	14.8	12.7	23.8	50.0	12.6	5.7	14.2	2.0	0.5	17.4	0.00
Russia	636.3	342.9	69.4	90.6	270.2	28.6	0.5	156.0	4.9	0.4	0.0	0.38
South America	826.0	208.4	407.2	417.4	212.0	189.4	5.4	303.0	36.8	1.2	166.7	0.59
Southeast Asia	382.0	830.5	339.2	329.4	2033.4	269.6	13.8	34.1	42.9	0.8	120.7	0.16
Taiwan	12.7	54.9	51.6	24.6	363.8	0.0	33.6	14.6	1.1	0.03	0.0	0.00
Total 2050	12,606	4374	6589	5421	20,605	3225	96.3	2289	301.1	30.6	1405	70.3
Total 2015	**420.24**	**12.11**	**70.33**	**87.75**	**67.33**	**4.94**	**12.59**	**1058**	**0**	**0.547**	**0**	**70.3**
Device MW	**5**	**5**	**0.005**	**0.1**	**50**	**100**	**100**	**1300**	**0.75**	**1**	**50**	**50**
Device number	2,521,174	874,874	1.32 bil	54,211,012	412,101	32,259	963	1761	401,524	30,599	28,095	1407
Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)												
Africa	678.9	33.2	350.9	326.3	580.7	176.6	3.61	25.5	33.1	1.90	0	0.14
Australia	76.2	37.9	69.1	57.8	106.0	33.4	0.40	8.05	22.1	0.50	0	0.016

(*continued on next page*)

Table 2 (*continued*)

Region	Onshore wind	Offshore wind	Resi-dential roof-top PV	Comm/govt rooftop PV	Utility PV	CSP with storage	Geothermal-electricity	Hydropower	Wave	Tidal	Solar thermal	Geothermal heat
Central America	229.4	21.3	187.0	202.9	42.8	42.5	10.7	18.0	16.8	0.38	0	0.16
Central Asia	265.9	18.9	95.1	63.7	207.0	88.4	0	19.5	1.79	0.02	0	0.003
China	4749	488.5	729.0	507.1	4204	603.1	1.86	301.3	8.71	3.02	0	17.9
Europe	1518	443.5	238.0	199.2	2141	63.4	3.16	160.2	37.7	15.0	0	22.3
Iceland	1.09	0.14	0	0	0	0	0.89	1.99	0.33	0.06	0	2.04
India	1844	31.9	744.0	450.2	668.8	254.2	0.28	49.1	5.67	0.72	0	0.99
Mideast	559.6	107.2	504.1	433.7	1064	439.7	0.87	42.7	4.14	0.292	0	3.25
New Zealand	8.62	3.36	8.30	6.74	3.77	4.98	2.00	5.25	2.45	0.20	0	0.49
North America	1158	611.9	451.5	449.0	1089	447.7	11.5	158.3	71.1	2.35	0	18.9
Philippines	12.59	13.17	12.7	23.8	23.1	11.8	5.73	3.55	1.95	0.5	0	0.003
Russia	538.4	228.6	77.2	100.7	171.9	15.4	0.50	52.0	4.92	0.36	0	0.38
South America	635.4	260.5	407.2	417.4	163.1	118.4	5.35	151.5	36.8	1.22	0	0.58

2050 nameplate capacities for individual countries are from Ref. [2] but summed among all countries in each grid region given in Table 1 and multiplied, for each applicable technology, by the final adjustment factor provided in Table S1. 2015 nameplate capacities for the sum of all countries are from Ref. [2]. Device MW = the nameplate capacity of one device in megawatts. Device number is the number of all devices in 2050 among 139 countries of the given nameplate capacity per device. In the case of hydropower in Case B (*), the device number increases between 2015 and 2050 because the device size is held constant. However, the number of reservoirs remains constant because it is assumed that turbines are added to existing reservoirs (increasing the device number) to increase the peak discharge rate of hydropower without increasing the annual average energy output or water flow rate of hydropower and without increasing reservoirs size. In Cases A and C, no increase in device number, total nameplate capacity, or number of turbines is assumed for hydropower.

applied but implicitly assumes that the hourly load profile for the countries without raw hourly load data is the same as the average hourly load profile among all other countries in the region.

For the remaining four grid regions, raw load data are not available. For these regions, we develop 2050 hourly inflexible load profiles with the exact same methodology as above, but using the 2030 hourly load profile of a single nearby country as the profile to scale to 2050 by. In the case of the grid regions of Cuba, Haiti-Dominican-Republic, and Jamaica, we use Mexico, which covers the same latitude range as those countries, as the profile to scale. For the Taiwan grid region, we use the profile of China to scale.

Fig. S1b shows the resulting hourly inflexible load profiles for all 20 regions treated here for both Cases A and B (which use the same inflexible load profiles as each other), for 10-day periods in each of four seasons in 2054.

For Case C, the inflexible load is modified by powering all heating and cooling with electric heat pumps with a 2050 coefficient of performance of 4, then distributing the annual additional electrical load daily with heating- and cooling-degree day data and adding this to inflexible load (see Section S1.A.ii for details).

Storage is divided into storage for low-temperature heat loads [Hot-Water Sensible-Heat Thermal Energy Storage (HW-STES) and underground thermal energy storage (UTES) in rocks], cold loads [Chilled-Water STES (CW-STES) and ice (ICE)], hydrogen, and electricity [phase-change materials coupled with concentrated solar power plants (CSP-PCM), pumped hydropower storage (PHS), and batteries. Hydropower (with reservoirs) is treated as an electricity source on demand with constraints discussed shortly. These storage media are described in detail in Section S1.A.iii. For Case C, no cold or low-temperature heat storage is used since all hot and cold loads are satisfied with electric heat pumps or existing geothermal heat.

Section S1.A.iv describes the order of operation of electricity, heat, cold, and hydrogen loads and storage as well as demand response.

2.2. GATOR-GCMOM

The LOADMATCH model requires inputs of intermittent wind and solar resources. These are determined from GATOR-GCMOM [31–33], which simulates weather, climate, and air pollution. Specifically, it treats feedbacks among meteorology, radiation, gases, aerosol particles, clouds, oceans, sea ice, snow, soil, and vegetation. Of relevance to the present study, GATOR-GCMOM predicts spatially varying time series power output from onshore and offshore wind turbines, rooftop and utility scale PV systems, CSP systems, and solar thermal heat systems. It accounts for competition among wind turbines for available kinetic energy, the temperature-dependence of PV output, the reduction in solar radiation to rooftops and the ground due to its extraction by PV and CSP, the impacts of these solar radiation changes on building and air temperatures, changes in temperature due to electricity use, and the impacts of time-dependent gas, aerosol, and cloud concentrations on solar and wind fields.

GATOR-GCMOM, developed starting in 1990, has been compared with wind, solar, and other meteorological and air quality data at high and low resolution in 18 peer-reviewed studies, including [31,32], and has taken part in 11 multi-model intercomparisons.

For the applications here, the model horizontal resolution was 4^{o}x5^{o}. While a higher horizontal resolution is desirable, the coarser resolution allows longer simulations and the treatment of more processes and feedbacks, including the feedback of wind turbines to kinetic energy [33] and the impacts of aerosol pollution particles on wind speeds, clouds, and precipitation [31,32]. Further, calculations of solar radiation, wind power, and temperatures account for subgrid scale cloudiness and subgrid variations in soil properties and moisture. Finally, our purpose is to generate statistically reasonable variation in wind speed over time, aggregated over each of the 20 regions, not to predict the exact wind speed in space and time. As shown in Ref. [42], varying horizontal resolution of a climate model does not have significant impact on the statistical accuracy of predicted winds regionally or seasonally.

Vertically, the model included 68 sigma-pressure-coordinate layers from the ground to 0.219 hPa ($\approx$60 km), with 15 layers in the bottom 1 km and 500-m vertical resolution from 1 to 21 km. Section S1·B describes the model, including wind and solar energy extraction, in detail.

Table 3
Annual average all-sector inflexible and flexible loads (GW) for 2050 by world region used in this study for Cases A, B, and C. "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 subject to demand response (DR)", and "load for H_2" production, compression, and storage (accounting for leaks as well). 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.

Cases A and B							
Region	Total load (GW)	Inflexible load (GW)	Flexible load (GW)	Cold load subject to storage (GW)	Low-temperature heat load subject to storage (GW)	Load subject to DR	Load for H_2 (GW)
Africa	759.5	172.5	587.0	46.1	326.8	154.1	60.0
Australia	118.9	36.73	82.2	10.3	25.1	36.0	10.8
Central America	199.1	59.28	139.8	10.8	45.0	59.4	24.6
Central Asia	262.0	67.82	194.2	14.8	99.4	69.8	10.1
China	3349	1044.1	2305	127.1	828.2	1225	124.7
Cuba	7.75	2.511	5.24	0.585	1.75	2.67	0.229
Europe	1420	355.2	1065	79.2	566.4	317.2	101.9
Haiti	8.35	1.726	6.63	0.594	3.50	1.31	1.22
Iceland	3.36	1.313	2.05	0.037	0.970	0.926	0.112
India	1022	284.77	737.2	51.9	306.6	306.9	71.8
Jamaica	1.97	0.539	1.427	0.133	0.431	0.531	0.332
Japan	444.8	125.99	318.8	44.4	135.6	111.4	27.4
Mideast	820.9	237.33	583.6	56.1	180.0	276.8	70.7
New Zealand	17.6	6.471	11.1	0.340	4.08	4.89	1.79
North America	1532	427.3	1104	99.8	425.0	436.3	143.3
Philippines	39.6	8.587	30.96	2.48	14.2	8.88	5.35
Russia	476.9	119.83	357.1	14.1	180.8	144.7	17.6
South America	598.4	185.11	413.3	36.9	104.1	212.5	59.9
Southeast Asia	658.2	168.41	489.8	38.2	187.0	177.4	87.2
Taiwan	99.8	29.81	70.0	6.22	19.5	35.5	8.69
Total	**11,840**	**3335**	**8504**	**640**	**3454**	**3582**	**828**
Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)							
Africa	465.1	251.0	214.1	0	0	154.1	60.00
Australia	90.99	44.18	46.81	0	0	35.97	10.84
Central America	155.0	71.02	83.98	0	0	59.43	24.55
Central Asia	171.8	91.85	80.00	0	0	69.85	10.15
China	2595	1245.	1350	0	0	1225.	124.7
Europe	910.1	491.1	419.0	0	0	317.2	101.9
Iceland	2.564	1.525	1.038	0	0	0.926	0.112
India	739.0	360.3	378.7	0	0	306.9	71.80
Mideast	634.5	287.0	347.5	0	0	276.8	70.72
New Zealand	14.07	7.392	6.679	0	0	4.886	1.793
North America	1117	537.8	579.6	0	0	436.3	143.3
Philippines	26.34	12.11	14.24	0	0	8.882	5.355
Russia	323.1	160.9	162.2	0	0	144.7	17.58
South America	487.1	214.8	272.4	0	0	212.5	59.87

For Cases A and B, cold and low-temperature heat loads subject to storage are obtained by multiplying the sector load for each region from Table S5 by the fractional load that is for cooling and heating, respectively, from Table S7, and by the fractions of cooling and heating loads (0.95) that are subject to storage, and summing the result over all sectors. For Case C, cold and low-temperature heat loads are zero because all such cooling and heating are provided by heat pumps with a coefficient of performance of 4, which reduce overall energy demand but increase the inflexible electricity load. In Cases A and B, 5% of the cooling and heating loads are not subject to storage, and these small loads are assumed satisfied with electric resistance heating, with a coefficient of performance of 1. In all cases, loads subject to demand response are assumed to be 15% of all non-air-and-water-heating and non-air-cooling-and-refrigeration loads in the residential, commercial, and agriculture/forestry/fishing sectors, 41.4% of the transportation load (to be used for battery charging ahead of use), 70% of high-temperature industrial load, and 75% of "other" sector load. In addition, 43.6% of the transportation electric load is used to produce, compress, and store H_2 ahead of its use. Annual-average H_2 loads are taken for each country directly from Ref. [2].

3. Wind and solar time series and impacts of wind turbines on climate

To provide an initial wind and solar power time series for LOADMATCH, a baseline GATOR-GCMOM simulation was run for five years (2050–2054) with 30 s dynamical time steps, using the original 100% WWS nameplate capacities from Ref. [2] placed within each of the 139 countries considered as described in Sections S1·B.v and S1 B.vi. This baseline simulation accounted for the reduction in the wind's kinetic energy and speed due to wind turbines and the subsequent conversion of electricity to heat (Section S1·B.v). The resulting GATOR-GCMOM estimates of energy generation from onshore and offshore wind, rooftop PV, utility PV, CSP, and solar thermal power were written to an output file every 30 s for five years for each generator in each country. Output for each generator was then summed every 30 s among the countries within each of the 20 world regions (Table 1). These summed regional results served as inputs into LOADMATCH.

To quantify the impacts of wind turbines on wind speeds, kinetic energies, and global temperatures, GATOR-GCMOM was then run a second time under the same conditions as the baseline simulation, except this time assuming wind turbines produced electric power based on modeled winds but did not perturb wind speed or kinetic energy.

The difference between the baseline simulation and the second simulation indicated that, with nameplate capacities from Ref. [2], wind turbine extraction of kinetic energy reduced globally averaged 100-m wind speeds by ~0.3% (Fig. S2b) and aggregate wind power output by ~6.7% (0.38 TW) (Fig. S2f) compared with no extraction of kinetic energy by turbines. However, wind-speed reduction by turbines reduced net evaporation of soil, lake, and ocean water, reducing water vapor (Fig. S2g), a greenhouse gas,

hence reducing global near-surface temperature by ~0.03 K (Fig. S2h), or ~3% of net global warming to date. The reasons for this result are explained in detail in Section S1.E.

4. Grid integration results

LOADMATCH was then run for each of the 20 world regions for 5.26 million 30-s time steps from 2050 to 2054. The wind and solar electricity-generation time series for each country from the baseline GATOR-GCMOM simulation (Section 3), summed among all countries in each world region, was used as input into LOADMATCH. LOADMATCH also used other WWS electricity generation and storage and time-dependent load data as input (Section 2). Three scenarios (Cases A, B, and C, described previously) were simulated. For each scenario, the initial inputs were adjusted (Table S1) with each run until a zero load-loss solution was found among all time steps, typically within 10 runs (Section 2). LOADMATCH was then run another 4–6 times to find lower-cost solutions. Thus multiple zero-load lost solutions were obtained for each region examined in Cases A, B, and C, but only the lowest-cost solution is presented here for each case and region. More simulations could lower costs even further, so the results here are not necessarily lowest-cost solutions.

Supply matched total load (end-use load plus changes in storage plus losses plus shedding) every 30 s for five years in all 20 regions encompassing the 139 countries for each Cases A and B and for the 14 regions examined in Case C (Figs. 1–2, S3–S6; Table S10). Tables 4 and S9 provide the resulting costs of all WWS energy (all electricity plus heat across all energy sectors) and costs per unit energy of the portion of WWS electricity replacing current BAU-sector electricity in each region for each case.

The WWS cost per unit energy in each case includes the costs of new electricity and heat generation, short-distance transmission, long-distance transmission, distribution, heat storage, cold storage, electricity storage, hydrogen production/compression/storage, and additional hydropower turbines (in Case B) (Table S9). Because WWS generators, storage, and transmission result in zero pollution emission during their lifetimes, and the production and decommissioning of WWS devices is also free of energy-related emissions in a 100% WWS world, WWS energy costs are assumed to be the same as WWS social costs (energy + health + climate costs) in 2050.

The 2050–2054 all-energy 100% WWS social cost per unit energy, when weighted by generation among all 20 regions was 10.6 (8.01–14.3) ¢/kWh-all-energy (USD 2013) in Case A and 10.7 (8.1–14.5) ¢/kWh-all-energy in Case B (Table 4). However, the individual regional averages (e.g., Case A) ranged from 5.1 ¢/kWh-all-energy (Iceland) to 13.7 ¢/kWh-all-energy (Southeast Asia). The similar costs in Cases A and B reflect the fact that Case A had higher battery and CSP costs, whereas Case B had higher hydropower turbine and solar thermal costs (Table S9). Over all grid regions, the additional hydropower turbines cost ~0.28% of total system cost in Case B (Table S9). Although batteries are currently a relatively expensive form of storage, they can be charged and discharged at will, whereas hydropower can only be discharged at will since it is charged naturally. Thus, more excess electricity was stored as electricity in Case A, whereas in Case B, more electricity was converted to and stored as heat. Because the excess stored electricity in Case A could be used either for electricity or direct heat, less production of heat from solar thermal was needed in Case A, saving some costs there.

The North America cost per unit energy in Case C was 10.6 (8.29–13.8) ¢/kWh-all-energy, which was extremely close to the costs in Case A, 10.5 (8.10–13.9) ¢/kWh-all-energy and in Case B, 10.1 (7.79–13.4) ¢/kWh-all-energy. The cost per unit energy for the other regions examined in Case C were similarly close to those in Cases A and B (Tables 4 and S9). Although the costs per unit energy are similar, the overall capital cost to consumers (cost per unit energy multiplied by energy consumed) is much less in Case C than in Case A or B because Case C requires much less energy and fewer energy generators than Case A or B due to the use of electric heat pumps in Case C for building heat and cold. Heat pumps reduced total thermal energy load by 75% (with a coefficient of performance of 4, assumed here), The reduction in thermal load translated to large reductions in total load in each country. For example, Africa, China, Europe, North America, and Russia needed 38.8%, 22.5%, 35.9%, 27.1%, and 32.2% less energy, respectively, in Case C than in Case A or B (Table 3). The 14-region-load reduction due to the use of heat pumps was 27.2% and the capital cost reduction was 26.4% (Table 3). Not only did the use of heat pumps reduce costs to consumers, but it also avoided the need for thermal energy storage entirely in the regions tested. An additional simulation for North America with 50% of cold and low-temperature heat energy provided by heat pumps and the rest by thermal energy storage resulted in almost the same cost per unit energy as in Cases A and C.

The all-energy costs discussed above are not directly comparable with future BAU electricity costs, which do not integrate transportation, heating/cooling, industry, or agriculture/forestry/fishing energy costs. Subtracting the costs of hydrogen used in transportation, transmission of electricity producing hydrogen, and HW-STES and UTES used for heating, gives a rough mean WWS social cost (which equals the business cost) of 9.74 (7.88–12.4) ¢/kWh-electricity among the 20 regions encompassing 139 countries in Case A and 9.93 (8.03–12.6) ¢/kWh in Case B (Table 4) for electricity replacing the current retail electricity sector.

This compares with a 139-country-average BAU (mainly fossil-fuel) direct (business) electricity cost of ~9.8 ¢/kWh-electricity and social cost of 38.3 (20.9–81.7) ¢/kWh-electricity, the latter of which equals the direct electricity cost plus an air pollution cost of ~12.7 (2.3–38) ¢/kWh [2] and a climate cost of ~15.8 (8.9–34) ¢/kWh [2]. The discount rates used for both the BAU and the WWS cases were the same, and were those for a social cost analysis of an intergenerational project (Table S9, footnote).

Thus, whereas the globally-averaged 2050 business costs per unit energy of BAU electricity and WWS electricity replacing BAU electricity are similar, the overall social cost per unit energy of WWS electricity in all cases is a quarter that of BAU. In addition, the actual price paid for BAU electricity on islands, such as in the Caribbean, is currently a mean of ~33 ¢/kWh [43], much higher than the estimated WWS costs found here (in Case A) of replacing BAU electricity in Haiti-Dominican Republic (9.25 ¢/kWh), Cuba (~10.8 ¢/kWh), or Jamaica (9.76 ¢/kWh) (Table 4). The BAU price in this case reflects, among other factors, the cost of transporting fuels to the islands and price hikes due to frequent supply shortages. Such costs do not arise with WWS electricity, which is produced locally, combined with storage.

In addition, as shown in Ref. [2], a WWS system requires ~42.5% less energy than the equivalent BAU system in the 139-country average before heat pumps are even accounted for because of the higher work:energy ratio of electricity over combustion (~23%); eliminating mining, transporting, and refining of fossil fuels and uranium (~12.6%); and end-use energy efficiency improvements and reduced energy use beyond BAU (~6.9%). As such, even if the business cost per unit energy is similar in the WWS and BAU cases, the annual absolute energy costs to all consumers in a region should be significantly less in the WWS case when considering the fact that much less energy is consumed in the WWS case.

The use of heat pumps (Case C) reduces all-sector energy consumption an additional 27.2% averaged among the Case C regions compared with Cases A and B (Table 4) and 57.9% compared with

Table 4
Summary of levelized costs of all energy (¢/kWh-all-energy-sectors, USD 2013) and of electricity only (¢/kWh-electricity-sector) in each region for Cases A, B, and C. Table S9 contains details of the cost breakdown in each region.

Region	End-use load (GW)	Total capital cost ($tril 2013)	Low (¢/kWh-all energy)	Mean (¢/kWh-all energy)	High (¢/kWh-all energy)	Low (¢/kWh-electric sector)	Mean (¢/kWh-electric sector)	High (¢/kWh-electric sector)
Case A (No increase in hydropower peak discharge rate)								
Africa	759.5	9.05	8.63	10.9	14.2	8.55	10.4	13.0
Australia	118.9	1.45	8.73	11.9	16.4	8.20	10.3	13.3
Central America	199.1	2.40	8.57	11.1	14.6	8.43	10.6	13.7
Central Asia	262.0	3.02	7.96	10.7	14.7	7.88	9.65	12.1
China	3349	29.5	7.36	9.42	12.4	7.31	8.90	11.2
Cuba	7.75	0.107	8.72	12.0	16.8	8.64	10.8	13.8
Europe	1420	13.2	7.96	10.0	13.0	7.89	9.78	12.5
Haiti	8.35	0.107	7.82	11.3	16.4	7.62	9.25	11.4
Iceland	3.36	0.0055	4.50	5.14	6.03	4.37	4.90	5.65
India	1022	12.5	7.68	11.5	17.4	7.46	9.09	11.4
Jamaica	1.97	0.028	8.31	12.3	18.1	8.03	9.76	12.0
Japan	444.8	7.42	10.1	13.5	18.4	9.98	12.6	16.1
Mideast	820.9	8.97	7.82	10.5	14.3	7.67	9.38	11.8
New Zealand	17.6	0.152	7.27	9.24	12.0	7.16	8.83	11.1
North America	1532	15.3	8.10	10.5	13.9	7.82	9.72	12.4
Philippines	39.6	0.47	8.48	11.1	14.7	8.37	10.6	13.7
Russia	476.9	4.05	7.54	9.79	13.1	7.51	9.55	12.6
South America	598.4	6.96	8.42	10.9	14.4	8.33	10.4	13.3
Southeast Asia	658.2	10.6	9.50	13.7	19.9	9.25	11.9	15.6
Taiwan	99.8	1.27	8.14	11.3	15.8	7.96	10.1	13.0
Total/average	**11,840**	**126.6**	**8.01**	**10.57**	**14.29**	**7.88**	**9.74**	**12.38**
Case B (Increase in hydropower peak discharge rate in some regions)								
Africa	759.5	9.05	8.55	10.9	14.2	8.55	10.4	13.0
Australia	118.9	1.37	8.62	11.4	15.4	8.14	10.1	12.9
Central America	199.1	2.40	8.77	11.1	14.4	8.56	10.7	13.6
Central Asia	262.0	3.08	8.07	10.8	14.8	8.00	9.82	12.4
China	3349	34.1	7.71	9.96	13.2	7.65	9.44	12.0
Cuba	7.75	0.099	8.10	11.1	15.6	8.02	9.88	12.4
Europe	1420	14.7	8.02	10.2	13.3	7.94	9.84	12.5
Haiti	8.35	0.107	7.82	11.3	16.4	7.62	9.25	11.4
Iceland	3.36	0.0055	4.50	5.14	6.03	4.37	4.90	5.65
India	1022	13.2	7.65	11.7	18.1	7.40	9.01	11.3
Jamaica	1.97	0.028	8.31	12.3	18.1	8.04	9.76	12.0
Japan	444.8	9.07	11.9	15.4	20.1	11.6	14.6	18.6
Mideast	820.9	7.99	7.25	9.65	13.2	7.14	8.69	10.9
New Zealand	17.6	0.134	6.86	8.56	10.9	6.75	8.19	10.2
North America	1532	15.2	7.79	10.1	13.4	7.70	9.54	12.1
Philippines	39.6	0.423	8.13	10.5	13.7	8.02	9.97	12.7
Russia	476.9	3.55	7.05	9.02	12.0	7.02	8.72	11.3
South America	598.4	6.54	8.27	10.7	14.1	8.18	10.2	12.9
Southeast Asia	658.2	11.9	10.7	14.9	21.1	10.4	13.4	17.5
Taiwan	99.8	1.27	8.17	10.9	14.7	8.07	10.0	12.6
Total/average	**11,840**	**134.2**	**8.14**	**10.74**	**14.51**	**8.03**	**9.93**	**12.62**
Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)								
Africa	465.1	5.11	8.31	10.4	13.2	8.21	10.1	12.7
Australia	90.99	1.09	8.71	11.1	14.5	8.55	10.8	13.9
Central America	155.0	2.02	9.09	11.6	15.1	8.91	11.2	14.3
Central Asia	171.8	1.80	8.10	10.1	12.9	8.06	9.97	12.6
China	2595	22.2	7.56	9.31	11.8	7.52	9.20	11.6
Europe	910.1	8.57	8.01	10.0	12.8	7.91	9.76	12.4
Iceland	2.564	0.0049	4.67	5.37	6.32	4.50	5.08	5.90
India	739.0	9.78	9.48	12.1	15.8	9.33	11.8	15.2
Mideast	634.5	8.52	9.02	11.5	14.9	8.88	11.2	14.3
New Zealand	14.07	0.121	7.19	8.95	11.3	7.07	8.65	10.8
North America	1117	11.3	8.29	10.6	13.8	7.88	9.86	12.7
Philippines	26.34	0.305	8.31	10.7	14.1	8.15	10.3	13.3
Russia	323.1	2.58	7.48	9.38	12.1	7.44	9.26	11.9
South America	487.1	5.37	8.41	10.7	13.8	8.32	10.4	13.3
Total/average	**7732**	**78.8**	**8.17**	**10.27**	**13.19**	**8.04**	**9.98**	**12.70**
#Case A	10.619	107.0	7.82	10.24	13.75	7.71	9.48	12.02
% Difference	−27.2	−26.4	4.45	**0.31**	−4.05	4.33	5.24	5.64

The term "electricity sector" in "$/kWh-electricity-sector" is end-use "retail" electricity in the BAU scenario. #Case A are values from Case A for the same countries in Case C. "% Difference" is the percent difference between Case C and Case A for the Case C countries. For comparison, the 2050 BAU load for all Case A countries is 20.604 TW and for all Case C countries is 18.344 TW. As such, the load in Case C for Case C countries is 57.9% lower than BAU, with 15.7% points due to the use of heat pumps and 42.2% points due to the higher work:energy ratio of electricity over combustio; eliminating energy in mining, transporting, and refining fossil fuels; and end-use energy efficiency improvements beyond BAU.

BAU for the same regions, suggesting a potentially much lower cost to consumers of WWS with heat pumps relative to BAU. Capital costs for Case C regions were 26.4% lower than for the same regions in Case A (Table 4). As such, although the business costs per unit energy of WWS versus BAU are similar, consumers may pay up to ~58% less in absolute dollars for WWS energy. In the island countries, they may pay as little as ~1/7th the BAU cost for WWS energy.

On the other hand, the analysis above does not include the cost of fossil fuel versus electric appliances, vehicles, or machines. While such costs in 2050 are highly uncertain, many such technologies are similar in cost today between WWS and BAU, and the rest are assumed to be similar by 2050. Yet, even if the business costs of WWS appliances, vehicles, and machines are higher than those of BAU in 2050, overall business costs of a transition should still be lower than or similar to BAU levels with WWS because of the 42.5% lower energy use in the WWS system without heat pumps and the 57.9% lower energy use in the WWS system with heat pumps.

Table S9 provides a breakdown of the 2050 WWS overall levelized cost of energy by region in Cases A, B, and C. Aside from electricity generation, the largest components of cost are, respectively, distribution; short plus long-distance transmission; UTES storage; solar thermal collectors; CSP and stationary battery storage (in Case A); hydrogen production; hot and cold water and ice storage; and additional hydropower turbines (in Case B). In Case C, the costs of all thermal energy storage and solar thermal collectors are eliminated, but the electricity cost increases.

The region with the lowest overall energy cost is Iceland, because of the steady, low-cost onshore wind resources, the high geothermal resource, and the availability of significant hydropower backup to minimize other storage requirements.

The regions with the highest cost are Southeast Asia and Japan. Both require either significant battery storage (Case A) or significant oversizing of wind and solar installations (Case B) to provide sufficient electricity when wind and solar resources are low. If politically feasible, another option may be to connect the Japanese or Southeast Asian grids to the China grid.

The largest regions considered in terms of load were China, North America, and Europe. The mean costs of all energy in those regions in Case A ranged from 9.42 to 10.5 ¢/kWh-all-energy in 2013 USD (Table 4). The large geographical areas of these regions allowed for the time-series of aggregate wind and solar power supply to be less intermittent than if the supply area were small, consistent with data [44]. These regions also have a good balance of solar and wind, which are complementary in nature seasonally (e.g., Fig. S3, particularly for North America and Europe). For the China region, both solar and wind have less seasonal variation than in North America or Europe (Fig. S3). For China and North America, winds tended to peak at night, complementing the daytime solar peak (Fig. S4). In Europe, wind power dominated day and night (Fig. S4). These large regions also all have substantial existing hydropower resources that can provide peaking power.

The smallest regions considered in terms of load were Jamaica, Iceland, Cuba, and Haiti. Except for Iceland, which has unusually large WWS resources, these island regions had a higher energy cost (11.3–12.3 ¢/kWh-all-energy, Table 4) than the largest regions. All three of the non-Iceland small island regions are in geographic proximity to each other and are subject to similar meteorology. All three also have low hydropower resources for backup, and thus require other forms of storage. These countries generally have a higher fraction of energy coming from more expensive rooftop solar and a higher ratio of more expensive offshore to onshore wind due to land constraints.

Although the variability in solar and wind resources decreases when integrated over larger geographic areas, it is not possible to provide a general rule about the "optimal" size of a grid-integration region. The optimum is determined by the tradeoff between the benefit of reducing temporal variability and the cost of expanding the grid. These benefits and costs vary dramatically with particular conditions in different countries. For example, although Iceland is a very small region and in principle would benefit from being connected to the European mainland, the cost of such a connection would be very high and would provide little benefit because Iceland itself has abundant, low-cost, relatively stable WWS resources. As such, Iceland benefits more from being its own grid region than it does being integrated into a larger region.

Table S10 summarizes the load and supply makeup, losses, and changes in storage for each of the 20 regions. On average among the 20 regions in Case A (B), 76.4% (74.1%) of all energy produced or supplied from storage was used for end-use load; 6.6% (6.6%) was lost during short and long-distance transmission, distribution, and downtime; 7.9% (7.8%) was lost during transfer in and out of storage; and 9.1% (11.5%) was shed. Most storage losses occurred with UTES storage. Thus, Case A, which had more oversizing of generation, resulted in more shedding than did Case B.

Of all end-use load among the 20 regions in both Cases A and B, 29.2% was used for heating (either direct heat, heat from electricity, or stored heat produced directly or from electricity), 5.41% was used for cooling (either cold from electricity or stored cold produced from electricity), 7.0% was used for hydrogen produced from electricity and either stored or used immediately, and the rest was electricity for load or storage.

Of all energy generated (for end-use load + losses + shedding + changes in storage), among the 20 regions in Case A (B), 49.0% (43.6%) was generated by onshore plus offshore wind, 44.1% (50.6%) was generated by utility plus rooftop PV plus CSP, 3.4% (3.5%) was generated by hydropower, 0.55% (0.54%) was generated by geothermal electricity, 0.48% (0.47%) was generated by wave electricity, 0.05% (0.05%) was generated by tidal electricity, 2.0% (0.89%) was generated by solar heat, and 0.44% (0.43%) was generated by geothermal heat. Thus, Case A had a higher ratio of wind to solar output than did Case B because of the oversizing of onshore wind in Case A.

5. Conclusions

Grid integration studies for 100% all-sector wind, water, and solar scenarios were performed in parallel with global weather forecast modeling of intermittent wind and solar resources for 20 world regions encompassing 139 countries. Low-cost, zero-load-loss solutions were obtained for every 30-s model time step over the five-year period 2050–2054 for two different storage scenarios (Cases A and B) in all 20 regions and a third scenario (Case C) in 14 regions tested. In Case A, CSP-storage, batteries, and thermal energy storage dominated storage, and no hydropower turbines beyond current capacity or heat pumps were added. In Case B, thermal energy storage and CSP-with-storage dominated storage, and hydropower turbines were added without increasing the annual-average hydropower output. No batteries or heat pumps were assumed. In Case C, CSP and batteries dominated storage, and heat pumps with no storage replaced all cold and low-temperature heat thermal energy storage. No hydropower turbines were added.

The generation-weighted mean 2050–2054 world electricity-sector WWS social cost per unit energy among all regions in both Case A was 9.74 (7.88–12.4) ¢/kWh-electricity and in Case B was 9.93 (8.03–12.6) ¢/kWh (USD 2013), which compares with the fossil-fuel social cost of 38.3 (20.9–81.7) ¢/kWh-electricity and fossil-fuel business cost of ~9.8 ¢/kWh-electricity. Thus, the 100% WWS social cost per unit energy is around one-fourth that of the fossil fuel system, and the WWS business cost per unit energy is

about the same. The electricity-sector WWS social cost per unit energy in Case C was similar to in Cases A and B.

The all-sector WWS mean social cost per unit energy was 10.6 (8.0–14.3) ¢/kWh-all-energy (USD 2013) in Case A and 10.7 (8.14–14.5) ¢/kWh-all-energy in Case B. The all-sector WWS mean social cost in Case C was similar to in Cases A and B.

Those costs are costs per unit energy. However, a 100% WWS system without heat pumps requires ~42.5% less energy than does the BAU system in 2050 and a 100% WWS system with heat pumps and no thermal energy storage requires 57.9% less energy than does the BAU system, thus the absolute energy and capital costs to all consumers in a region may be much less with the WWS system. However, these energy costs do not account for cost differences between fossil fuel and electric appliances, vehicles, or machines. While such cost differences in 2050 are highly uncertain, many such technologies are similar in cost today between WWS and BAU, and the rest are assumed here to be similar by 2050. Even if the business costs of WWS appliances, vehicles, and machines are higher than those of BAU in 2050, overall business costs of a transition are expected to be lower than or similar to the BAU level with WWS because of the much lower energy use in the WWS system.

The results of this study suggest that low-cost solutions can be obtained with either (a) CSP with storage, batteries, and thermal energy storage; (b) CSP with storage, additional hydropower turbines, and no batteries or heat pumps; (c) CSP with storage, batteries, and heat pumps but no thermal energy storage or additional hydropower turbines; or (d) combinations of the above. As such solutions are not limited to one 100% WWS pathway. Instead, multiple 100% WWS pathways with different mixes of generation, storage, and transmission, and demand response, are possible.

Key elements of the solution applicable to different cases are to (1) produce heat directly from solar and geothermal heat resources and from electricity; (2) store electricity as heat after current electricity demand is satisfied and electricity storage is full; (3) if thermal energy storage is used, store excess heat in water and underground rocks when current heat demand is satisfied; (4) if thermal energy storage is used, produce cold directly from electricity and store excess cold in water and ice; (5) produce hydrogen from excess electricity after all electricity and heat storage are full, and store excess hydrogen; (6) store excess CSP electricity in a phase-change material and remaining excess electricity either in pumped-hydro storage, as heat in underground rocks, or as hydrogen; (7) increase the maximum discharge rates of CSP, the number of batteries, or the maximum discharge rate of hydropower (while keeping its annual energy production constant) to help meet peaks in demand; (8) use heat pumps for cold and low-temperature heat loads wherever possible; and (9) use demand response for some loads to reduce peaks in load.

The study also concludes that the large number of wind turbines proposed here might, in addition to avoiding fossil fuel emissions, avoid another 3% global warming by reducing water vapor. Although 3% is not large, it occurs much more rapidly than does the temperature reduction due to eliminating fossil fuel emissions.

Results from this study can inform planners and policy makers in 139 countries within 20 world regions about the main ingredients of a fully integrated all-sector 100% clean, renewable, efficient, and reliable energy infrastructure by 2050, if not sooner. As such, the results can guide practical implementation of solutions, including real investment and infrastructure upgrades worldwide.

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Appendix A. Supplementary data

Supplementary data related to this article can be found at https://doi.org/10.1016/j.renene.2018.02.009.

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Supporting Information

Matching Demand With Supply at Low Cost in 139 Countries Among 20 World Regions With 100% Intermittent Wind, Water, and Sunlight (WWS) for all Purposes

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This supporting information file contains additional descriptions of the simulations and data (Section S1); additional tables (Section S2); and additional figures (Section S3) to explain more fully the methods and results of this study.

S1. Supporting Materials and Methods

The two primary tools used for this study are a grid integration model (LOADMATCH) and a global weather-climate-air-pollution model (GATOR-GCMOM). These tools are described briefly in the main text (Methods Section) and in more detail next. Section S1.C discusses some uncertainties in this study.

S1.A. LOADMATCH

S1.A.i. Model Description

LOADMATCH [1] requires the following inputs: (1) time-dependent intermittent electric power produced from onshore and offshore wind, rooftop PV, utility PV, and CSP; and heat from solar thermal from GATOR-GCMOM; (2) time-dependent electricity from wave power obtained by scaling the annual wave power from [2] by time-dependent GATOR-GCMOM offshore wind power; (3) baseload geothermal electricity, geothermal heat, and tidal electricity with annual productions from [2]; (4) time-dependent hydropower used for baseload power and load balancing as needed but constrained by its near-current annual energy output from [2] and a maximum discharge rate; (5) specifications of Hot-Water and Chilled-Water Sensible-Heat Thermal Energy Storage (HW-STES and CW-STES), underground thermal energy storage (UTES), and ice (ICE) storage; (6) specifications of electricity storage in (a) pumped hydropower storage (PHS), (b) phase-change materials coupled with concentrated solar power plants (CSP-PCM), and (c) batteries; (7) specifications of hydrogen electrolysis, compression, and storage; (8) specifications of electric heat pumps for air and water heating and cooling; (9) specifications of a demand response system, and (10) time-dependent load by region, determined from individual country data.

LOADMATCH also requires generator capital costs, operation and maintenance (O&M) costs; decommissioning costs; short- and long-distance transmission, distribution, and

maintenance energy losses; and lifetime estimates (Table S2). It further requires heat, cold, electricity, and hydrogen storage costs and efficiencies (losses during charging and discharging) as well as hydrogen electrolysis and compression costs and efficiencies (Table S3); maximum energy storage capacities and maximum charge/discharge rates (Table S4); and discount rates and short- and long-distance transmission and distribution costs (Table S9).

In comparison with the previous 48-state grid integration study [1], this study considers 20 world regions representing a broader variety of geographical land areas and resource constraints. This study also treats existing geothermal heat, which was not treated in [1]. It further considers hydrogen for some transportation only, whereas [1] considered hydrogen for both transportation and industry. In addition, the present study examines the impacts of wind turbine energy extraction on global temperatures, which was not examined in [1].

LOADMATCH runs quickly (e.g., ~2.6 minutes for a 5-year (5.3 million time-step) simulation on a single Nehalem 5580 3.2 GHz processor) because it is a trial and error model rather than an optimization model. Its main constraint is that it cannot permit load loss at any time, thus it is designed to exceed the utility-industry standard of load loss once every 10 years. The focus on reliability reflects the fact that actual grid systems are based on reliability metrics, such as loss of load expectation (LOLE) and loss of load probability (LOLP). Other aspects of planning and operating the grid, such as control details regarding frequency regulation and transient stability, are not treated here because the model is not simulating individual buses.

If load loss occurs, then the model stops and is rerun with new parameter values. However, zero-load-loss solutions for all world regions considered here were obtained within 0-10 simulations (thus in less than two hours). The model determines the system cost once a zero-load-loss solution is obtained. Additional simulations are usually run to find even lower cost solutions.

LOADMATCH assumes a short- and long-distance transmission (T&D) system that carries power from distributed and centralized WWS generators to storage and load centers. Costs of and power losses during T&D are accounted for (Tables S2 and S9), but power flows through individual lines or substations are not modeled. The model also accounts for storage costs and power losses during charging/discharging.

S1.A.ii. Producing Time-Dependent Loads From Annual Loads

Table S5 provides the 2050 annual electric plus heat load by world region and sector within each region used here, obtained from [2]. The sectors include residential, commercial, industrial, transport, and agriculture/forestry/fishing.

Residential and commercial loads include all electric and heat loads consumed in residential and commercial buildings, respectively, aside from any duplicated in the other sectors.

Transport loads include energy consumed during any type of transport by road, rail, domestic and international aviation and navigation, or by pipeline, and by agricultural and

industrial use of highways. For pipelines, the energy required is for the support and operation of the pipelines.

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

Agriculture and forestry loads include energy consumed for agriculture, hunting, forestry; domestic power and heating for those activities; and traction (aside from agricultural highway use, which is counted in the transport sector). Fishing loads include fuel for inland, coastal, and deep-sea fishing; fuel delivered to international ships that have re-fueled in the country; and energy use in the fishing industry.

These loads are separated here into (1) electric and heat loads needed for low-temperature heating, (2) electric loads needed for cooling and refrigeration, (3) electric loads needed to produce, compress, and store hydrogen for fuel cells used in transportation only, (4) electric loads subject to demand response, and (5) inflexible electric loads.

Electricity and heat needed for building air and water heat are collectively referred to here as "low-temperature heat load" or just "heat load." A country's total load is heat load plus electricity load not used for low-temperature heat. Table S6 gives the percent of residential plus commercial total load that is low-temperature heat load for several countries and world regions from [3]. Worldwide, over 78% of all energy consumed in residential and commercial buildings is used for heating.

The percentages in Table S6 are multiplied by the total 2050 WWS loads in the residential and commercial sectors of all 139 countries here to estimate low-temperature heat loads in those sectors. The percent of total load that is low-temperature heat loads is estimated for the industrial sector as in [1]. Each country's low-temperature heat load by sector is summed over all sectors to give the country's total annually averaged heat load. The annual heat load is then multiplied by the fraction of the annual heat load that occurs on each day of the year, as estimated from the ratio of the number of heating degree days per day for 2013 and 2014 in the country [5] to the yearly average number of heating degree days per day, to give the daily heat load.

All electricity required for air conditioning and refrigeration in buildings is referred to here as "cold" load. Air conditioning load is estimated as $L_t * F_{ac}$ where L_t is the total load in the sector and

$$F_{ac} = \min(F_{ah}*C/H, F_e*F_{max})$$

is the fraction of total sector load that is for air conditioning. In this equation, F_{ah} is the fraction of total sector load that is air heating load, C and H are the average number of cooling and heating degree days in a year, respectively, F_e=1-F_h is the fraction of total load

that is electric (where F_h is the fraction of total load that is low-temperature heat load from Table S6), and F_{max} is the maximum allowable fraction of electric load that is for air conditioning (set to 0.4). In the residential sector, $F_{ah} = 0.701*F_h$, derived from $F_h=F_{ah}+F_{wh}$, where F_{wh} is the fraction of total load that is for water heating and $F_{wh}=0.4265*F_{ah}$ from U.S. data [1].

In the commercial sector, $F_{ah}=0.8252*F_h$, $F_{wh}=0.2118*F_{ah}$, and $F_{rf}=0.7383*F_{ac}$, where F_{rf} is the fraction of total load that is for refrigeration [1].

For the industrial sector, Table S6 gives the fraction of total load that is for high-temperature heating (F_{ht}) by country. The fraction of industrial load that is for air heating and cooling is estimated as $F_{hvac}=0.0624$, from U.S. data [1]. This is partitioned between air conditioning and low-temperature air heating, respectively, with

$$F_{ac} = \min(F_{hvac}*C/(H+C), F_e*F_{max})$$

$$F_{ah}=F_{hvac}-F_{ac}$$

Table S7 quantifies the resulting relevant fractions for the residential, commercial, and industrial sectors as well as the total number of heating and cooling degree days for each of the 20 world regions considered here.

The fractions in Table S7 are multiplied by the end-use annual average load in each sector in each region in Table S5 to give the total low-temperature air-heating load, water-heating load, air-conditioning load, refrigeration load, and high-temperature industrial heat load in each sector. For Case C, the fractions in Table S7 are multiplied by the loads in Table S5 applicable to Cases A and B, which are initial loads for Cases A, B, and C. The loads shown for Case C in Table S5 are final loads after all heating and cooling energy has been converted to heat pump electricity requirements.

The air and water heating loads are summed across all energy sectors to give the total low-temperature heat load for air plus water heating in each region. The air conditioning and refrigeration loads are similarly summed. For Cases A and B, the cold and low-temperature heat loads in each region are then multiplied by the fractions in the footnote to Table 3 to give the cold and low-temperature heat loads subject to storage in each grid region. The result is shown in Table 3. The remainders (5%) of the cold and low-temperature heat loads in Cases A and B are added to inflexible loads and are assumed satisfied with electric resistance heating or air conditioning, assuming conservatively a coefficient of performance of 1.

In Case C, the entire cold and low-temperature heat load in each region is assumed inflexible electric load powered with heat pumps. Thus, we use zero UTES, HW-STES, CW-STES, or ICE storage in this case. In general, air source heat pumps are used mostly in mild climates, whereas ground-source heat pumps are used more in very cold or very hot climates. The advantage of an air-source heat pump is that it doesn't require ground excavation. However, ground-source heat pump systems are now available at low cost due

to drilling small-diameter holes deep vertically (e.g., down to 150 m) rather than digging large horizontal swaths of backyard land [6]. Heat pumps can be ducted or ductless, in the latter case minimizing heat loss.

In this study, we account for the electricity required to run the heat pumps but not the cost of the heat pump itself or associated ducts (if any) or wires, to be consistent with the fact that we don't account for the cost of gas or oil air or water heaters or their required ducts and pipelines or hookup fees in the BAU case. In particular, for example, the utility hookup fee alone for gas to a residence can range from $2,000 to $10,000 beyond a similar cost for an electrical hookup fee. By avoiding the gas hookup, a consumer saves this amount in addition to avoiding the cost of gas pipes. Thus, even if heat pump equipment (or excavation in the case of ground source heat pumps) is more expensive, the additional cost may be more than offset by reduced costs of hookup and pipes.

Typical air source heat pumps have a coefficient of performance (CP) of 3.2-4.5, whereas ground source heat pumps have a CP of 4.2-5.2 [7]. We assume CP=4, which represents a combination of air source and ground source heat pumps. Thus, we assume 1 J of electricity is needed to move 4 J of hot or cold air with a heat pump. As a result, for every 4 J of heat load needed, we require a 1 J increase in electric power demand but a net 3 J decrease in total demand.

The additional electric power load due to heat pumps is added to inflexible electric load in the model. Table 3 shows the resulting increase in inflexible annually averaged load but decrease in total load in Case C relative to Cases A and B for 14 world regions. The additional inflexible electric load due to heating by heat pumps is distributed daily using the ratio of the number of heating degree days per day to the yearly average number of heating degree days per day in 2013 and 2014 [5] in each region. The regional values are determined by weighting country specific values by fractional total load in each country. The additional inflexible electric load due to cooling is distributed in the same way, but using cooling degree-day data by country for 2013 and 2014 [5].

The high-temperature industrial heat load is obtained by multiplying F_{ht} from Table S7 by the initial industrial load in Table S5 (which is the load shown for Cases A and B, even for Case C). The result is multiplied by the fraction given in the footnote to Table 3 to give the high-temperature heat load that is subject to demand response in Table 3. The portions of transportation and other loads in Table 3 subject to demand response are calculated as described in the footnote to Table 3.

Table 3 gives, in part, the annual average all-sector cold load (air conditioning plus large-scale refrigeration) subject to storage by region in Cases A and B. Daily cold loads subject to storage are then calculated from this value multiplied by the fraction of the annual cold load that occurs on each day of the year in the region. This latter parameter is estimated as the ratio of the number of cooling degree days per day to the yearly average number of cooling degree days per day in 2013 and 2014 [5] in each country of the region, weighted by the fractional load among all countries of the region. For this calculation, a minimum

number of cooling degree days per day (0.01) is used to ensure some energy is used for refrigeration when the number of cooling degree days is otherwise zero.

Similarly, regional low-temperature air plus water heat loads subject to storage by day are estimated as follows. Daily low-temperature annually-averaged heat loads subject to storage by region from Table 3 are multiplied by the ratio of the number of heating degree days per day to the yearly average number of heating degree days per day in 2013 and 2014 [5] in each region. This parameter is determined by weighting each country specific ratio of the same parameter by its fractional load in the region then summing over all countries in the region. Again, a minimum number of heating degree days per day (0.01) is used to ensure at least some energy is used for water heating and showers each day even when the number of heating degree days is otherwise zero.

Table 3 also provides the annually averaged load needed by region to produce, compress, and store hydrogen, which accounts for energy needed to produce leaked hydrogen as well. Annual electric loads needed by each country for hydrogen in fuel cells for long-distance trucks, trains, ships, and aircraft are from [2]. In this study, no hydrogen is used for any sector aside from transportation. The hydrogen load is spread evenly during the year, but hydrogen is produced by excess WWS any time prior to the time it is needed.

All remaining loads are electrical and are separated into inflexible loads that must be satisfied immediately and loads that are subject to demand response thus are “flexible.” The flexible loads must be satisfied within a certain number of hours (a maximum of 8 here). All flexible loads not met after the demand response time limit are converted to inflexible loads that must be met immediately with current or stored electricity.

Table 3 provides the resulting distribution of inflexible and flexible loads by world region and how they were calculated. A major flexible load is transportation. Transportation energy use is assumed spread evenly during the year, but because batteries must be charged ahead of time and hydrogen must be produced from electricity ahead of use, the times these electricity loads are required are flexible. Of the total transportation electric load among 139 countries, 41.4% is assumed to be flexible for charging vehicles any time ahead of use, another 43.6% is assumed to be flexible for producing hydrogen for fuel cell vehicles any time ahead of use, and the rest (15%) is assumed to be inflexible for charging vehicles immediately before use.

It is assumed here that utility operators can incentivize when individuals or companies charge vehicles. Because batteries are charged hours to days ahead of their use, a good opportunity exists for an incentive structure to combine vehicle charging with grid load management[8,9]. Hydrogen is produced ahead of time from excess electricity from WWS electric power generators.

Other flexible loads in Table 3 include 70% of high temperature industrial-process loads; 15% of energy for non-heating, non-cooling, non-transportation, non-industrial loads in each sector; and 75% of loads in the “other” sector (Table 3, footnote). It is assumed that utilities can give industry incentives to consume power for many of their high-temperature

processes at non-peak times of day or night. For example, the U.S. National Research Council[10] states (P.251), "*The ability of industry to cut peak electric loads is a motivator for utilities to incentivize demand response (shifting loads to off-peak periods) in industry…In combination with peak-load pricing for electricity, energy efficiency and demand response can be a lucrative enterprise for industrial customers.*"

If heat, cold, or hydrogen storage empties before their associated loads are satisfied, the remaining unsatisfied loads become either inflexible or flexible electric loads. It is conservatively assumed here that 85% of unsatisfied heat and cold load subject to storage (in Cases A and B only, since Case C has no heat or cold load subject to storage) and 100% of unsatisfied electricity loads for hydrogen become inflexible. The rest become flexible.

Annual average 2050 inflexible loads for each grid region (Table 3) are converted to hourly inflexible loads using 2010-2014 or 2030 hourly load data for 130 out of the 139 countries considered here from [11, 12, 13], as described in the main text. Figure S1a shows the contemporary hourly load profiles for several countries for 10-day periods in each of four seasons. Figure S1b shows the resulting hourly inflexible load profiles for all 20 regions treated here, for 10-day periods in each of four seasons in 2054, for both Cases A and B. Daily inflexible cold and low-temperature heat loads in Case C are distributed daily as described earlier in this section.

S1.A.iii. Storage

Storage is divided into storage for cold loads, heat loads, hydrogen, and electricity.

Storage for cold loads includes Chilled-Water STES (CW-STES) and ice (ICE). These thermal energy storage media effectively store electricity. When excess WWS electricity is available, it can be used to cool or freeze water. Water and ice store cold until air conditioning or refrigeration is needed, usually during afternoon peak times of electric demand. At that time, water is sent through coils in the chilled water or ice, and the cold water is then sent directly to buildings, cooling the buildings, avoiding the need for peak electricity. Cold storage is assumed here in Cases A and B but not in Case C.

Storage for heat loads includes Hot-Water Sensible-Heat Thermal Energy Storage (HW-STES) and Underground Thermal Energy Storage (UTES) in rocks. HW-STES is heated (charged) by either direct solar or geothermal heat or excess electricity when too much WWS electricity is produced. UTES is heated by either excess WWS electricity that first heats water or by solar-heated glycol solution that transfers its heat to water. In both cases, the water runs through pipes underground, where it transfers its heat to rocks, such as done in the UTES system at the Drake Landing Community, Canada [14]. A related technique is seasonal heat storage in large water basins [15].

UTES is a form of district space and water heating, which is widespread, including 60% of Denmark. In that case, heat is stored in large boilers and distributed by pipes to homes for air and water heating. A key difference is that with UTES, heat can be stored for either days or months, whereas with water tanks, heat is generally stored for only a few days although

there is no reason it can't be stored for either days or months given sufficient storage size. Hot storage is assumed here in Cases A and B but not in Case C.

An alternative to using cold storage and heat storage with or without district heating is to use electric ground- or air-source heat pumps in buildings. This alternative is assumed in Case C here. While heat pumps require electricity on demand, the electric power requirements of using heat pumps to move heat are much less than the energy in the heat itself, depending on the coefficient of performance. Further, the electricity for heat pumps can come from batteries, rooftop solar, or a 100% WWS grid. In the case of water heating, the hot water can be produced days to hours ahead of the hot water use. Heat pumps can also use electricity at non-peak times of day to produce heat or cold that is stored for later use. However, for Case C here, it is assume that all cold air, refrigeration, hot air, and hot water loads are inflexible thus must be satisfied immediately by current or stored electricity.

Hydrogen is stored as a compressed gas to power on-board fuel cells for long-distance road, rail, and water transportation, and as a liquid for fuel cells to power jet turbines for long-distance flights. Hydrogen is not used as part of this study for fuel cells to produce grid electricity due to the inefficiency of this process. Unlike in our previous study [1], hydrogen is also not used here for any industrial combustion process because electrical arc furnaces, dielectric heaters, and induction furnaces are available for this task. When too much WWS electricity is available, some is used to produce hydrogen by electrolysis and to compress and store the hydrogen. Hydrogen is then either stored or used immediately for transportation.

Table S9 summarizes the costs of hydrogen electrolysis (including water cost), compression, and storage in each grid region. These costs are derived as follows. First, Table 2 provides the energy per year required for hydrogen production from electrolysis and hydrogen compression in each region. This energy per year is converted into hydrogen produced per year assuming 53.37 kWh/kg-H_2 for electrolysis and 5.639 kWh/kg-H_2 for compression [16]. Whereas, these are older estimates for conversion efficiency, we maintain them to ensure we do not overestimate hydrogen production due to other uncertainties in the analysis. Next, we size storage tanks equal to the resulting kg-H_2/year produced in each region multiplied by the ratio of the maximum number of days of hydrogen storage (Table S1) to the average number of days per year of simulation.

Electrolyzer costs are then calculated assuming a \$300-\$450/kW capital cost [17], a 10-15 year lifetime, a 50%-95% use factor, an annual operation and maintenance cost of 1.5% of capital cost [16], and an installation factor multiplied by capital cost of 1.2-1.3 [18]. The discount rate is given in the footnote to Table 9. The resulting electrolyzer cost is \$0.557 (0.195-0.918)/kg-H_2. Water costs for electrolysis are another \$0.00472-0.00944)/kg-H_2 [16].

Compressor costs are calculated assuming a capital cost of \$400,000-\$515,000 for a compression rate of 33 kg-H_2/hour from 20 to 350 bars followed by dry running piston compressing up to 950 bars [18], compressor lifetime of 10-15 years, a use factor of 50%-95%, annual operation and maintenance cost of 1.5% of capital cost, and an installation

factor multiplied by capital cost of 1.2-1.3 [18]. The resulting compressor cost is \$0.372 (0.148-0.596)/kg-H_2.

Storage costs are calculated assuming a capital cost of \$450-550/kg-H_2 [19], storage tank lifetimes of 30-50 years, annual operation and maintenance cost of 1.5% of capital cost, and an installation factor multiplied by capital cost of 1.2-1.3 [18]. The resulting overall hydrogen storage cost varies by region, depending on the maximum storage required. For example, for North America for Case A, it was \$2.06 (1.29-2.82)/kg-H_2-used (rather than stored), whereas for Africa, it was \$0.643 (0.056-1.23)/kg-H_2.

Table S9 gives the overall cost of hydrogen in ¢/all-kWh-delivered electricity used for all processes. The overall cost of H_2 in ¢/all-kWh-delivered is equal to the cost in ¢/kWh-to-H_2 multiplied by the fraction of delivered power used for hydrogen, derived from Table 3. The ¢/kWh-to-H_2 equals the \$/kg-H_2 divided by 59.009 kWh/ kg-H_2. These costs exclude electricity costs, which are included elsewhere in Table S9.

Storage media for electricity include phase-change materials coupled with concentrated solar power plants (CSP-PCM), pumped hydropower storage (PHS), and batteries. Hydropower (with reservoirs) is treated as an electricity source on demand. Lithium-ion batteries are used to power battery-electric vehicles but for simplicity, battery-electric vehicles are assumed not to feed power back to the grid. However, new stationary batteries are used for grid electricity in Cases A and C here. Note that our assumed use (and corresponding cost analysis) of *new* batteries may overstate our cost of battery storage, because it is likely that repurposing of *used* electric-vehicle batteries will be even more cost-effective for load balancing, since lithium batteries have substantial life after they are no longer desirable for transportation.

In all Cases A, B, and C, hydropower annual energy output is limited to near its 2015 values in each region. Because hydropower's greatest value is providing peaking power when other power is not available, we allow the option, for several regions in Case B only, to increase the maximum discharge rate of hydropower without changing reservoir size or annual energy output by increasing turbine nameplate capacity, as was done previously [1]. This can be accomplished by modifying the powerhouse to increase either the number or sizes of turbines and the flow rate of water to them by either adding pipes around or above dams or widening penstocks through dams. The cost of electrical equipment (turbines, generators, and transformers) in a hydropower plant ranges from ~\$560/kW for 500 MW plants to ~\$200-\$300/kW for 1000 MW plants (Figs. 4.5 and 4.7 of [20]). We assume large 1000-MW plants but also assume costs for additional pipes or widening penstocks and for equipment housing and assume costs could increase due to supply shortages in some countries, thus we assume the additional cost per MW of hydropower turbines is roughly \$385 (325-450) / kW, or ~14% of the total hydropower capital cost.

CSP is coupled with a PCM rather than molten salt because of the greater efficiency and lower cost of PCM [21]. However, if PCM does not live up to its potential, molten salt can continue to be used at only slightly higher cost. The maximum charge rate of CSP storage (and thus mirror collector size) can be up to a factor of 5 times the maximum discharge rate

of CSP steam turbines in order to increase CSP's capacity factor [22]. In [2] and here, the maximum CSP charge rate are ~2.61 times the maximum discharge rate (see footnote to Table S2), but more CSP plants were built than needed for annual average power in order to increase the discharge rate of stored CSP power during times of peak demand.

In LOADMATCH, when CSP collects more heat than can be used to power all the plant's steam turbines, the excess heat is stored in the PCM. If the charge rate of storage plus the discharge rate of the electric generators is exceeded, the excess CSP heat is shed.

The PHS charge and discharge rate (Table S4) are equal to each other and limited in each country to the present-day discharge rate plus a fraction of the present penetration, determined as the ratio of preliminary plus pending permits to existing PHS in the U.S., plus a minimum value for countries with no PHS currently installed.

S1.A.iv. Order of Operation

In LOADMATCH, heat load each time step is satisfied first with currently available solar and geothermal heat supplies. The solar supply is determined continuously from GATOR-GCMOM, which uses the number of solar collectors determined from [2] as input. The geothermal heat supply is assumed constant all year and determined from country output as estimated in [2]. If heat load exceeds supply in a time step, the load is satisfied next with HW-STES storage and then UTES storage. Any remaining heat load after that is partitioned 85% to inflexible electric load that must be satisfied immediately (within the same time step) by generated or stored electricity powering heat pump air or water heaters and 15% to flexible electric load that must be satisfied within the next 8 hours. If, during the 8 hours after the load should been met initially, the load is still not met, the flexible load is converted to an inflexible load. If an inflexible load is not satisfied immediately, the program stops, key input parameters (Table S1) are changed, and the program is re-run.

If solar plus geothermal heat supply exceeds heat load in a time step, the excess goes into HW-STES storage then UTES storage. If heat storage is full, the rest of the excess heat supply is shed.

Cold loads are satisfied first by a combination of 40% CW-STES storage and 60% ICE storage. Ice storage is favored because it takes up much less space. Remaining cold load is partitioned 85% to inflexible loads that must be satisfied immediately by electricity and 15% to flexible loads that must be satisfied by electricity within 8 hours.

Hydrogen for use in transportation is first obtained from storage, which is filled by hydrogen production from excess WWS electricity. If hydrogen storage is depleted, hydrogen is produced immediately from electricity. Hydrogen is not subject to demand response in the model.

If current electricity supply is not sufficient to satisfy an inflexible electric load during a time step, electricity is drawn from storage in the following order: CSP-PCM, PHS, stationary batteries (which are not required in the simulations here), and hydropower.

If current WWS supply generates more electricity than needed to satisfy current load, the excess is placed in storage in the following order: CSP-PCM for excess CSP heat, PHS, stationary batteries (if they exist), CW-STES, ICE, HW-STES, UTES, and hydrogen. Any remaining WWS electricity after that is shed. Although UTES is not an efficient way to store excess electricity, it is more efficient than is shedding excess electricity.

S1.B. GATOR-GCMOM

LOADMATCH requires input of intermittent wind and solar power generation. These are determined from the global weather-climate-air-pollution model GATOR-GCMOM (Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model) [23-28]. This model predicts output of time- and space-dependent electricity from onshore and offshore wind, rooftop and utility scale PV, and CSP; and solar-thermal heat production.

It accounts for competition among wind turbines for available kinetic energy, the temperature-dependence of PV output, the reduction in sunlight to building and ground due to extraction of radiation by solar devices, changes in air and ground temperature due to power extraction and electricity use by PV, and the impacts of time-dependent gas, aerosol, and cloud concentrations on solar radiation fields.

In general, the model simulates feedbacks among meteorology, solar and thermal-infrared radiation, gases, aerosol particles, cloud particles, oceans, sea ice, snow, soil, and vegetation. GATOR-GCMOM model predictions of wind and solar resources have been compared with data in multiple studies [e.g., 24, 25, 26, 28]. Below, the model is briefly described.

S1.B.i. Meteorological, Transport, and Surface Processes

The momentum, thermodynamic energy, and continuity equations are solved for the atmosphere with a potential-enstrophy, vorticity, energy, and mass-conserving scheme [29]. Winds and turbulence predicted by the model drive the horizontal and vertical transport of gases and size- and composition-resolved aerosol particles with a monotonic advection scheme [30]. Subgrid turbulent kinetic energy is calculated from [31] as a function of instantaneous modeled wind shear and buoyancy due to background processes and the extraction of energy by wind turbines themselves. The model treats 17 subgrid surface classes, including several types of soil classes plus water, ice, road and rooftop classes, in each surface grid cell. It treats energy and vapor exchange between the atmosphere and each subgrid surface class in each cell. Subgrid, subsurface temperatures and moisture are tracked perpetually and independently throughout each simulation. Each subgrid soil class is divided into vegetated and bare soil. Snow can accumulate on soil and vegetation. Oceans are represented in 3-D for some calculations and 2-D for others. A 2-D time-dependent mixed-layer ocean dynamics model driven by surface wind stress is used to solve for mixed-layer ocean velocities, mixed-layer heights, and horizontal energy transport in each grid cell [32]. The scheme conserves potential enstrophy, vorticity, energy, and mass and predicted gyres and major currents. Energy diffusion to the deep ocean is treated in 3-D. Air-ocean exchange, vertical diffusion through the ocean, and 3-D ocean equilibrium chemistry and pH are solved among the Na-Cl-Mg-Ca-K-H-O-Li-Sr-C-S-N-Br-F-B-Si-P system. Sea ice in

the model forms, evolves, and flows horizontally on subgrid water surfaces, and snow can accumulate on sea ice.

S1.B.ii. Gas and Aerosol Processes

Gas processes include emissions, photochemistry, gas-to-particle conversion, gas-to-cloud conversion, gas-cloud exchange, gas-precipitation exchange, gas-ocean exchange, advection, convection, molecular diffusion, turbulent diffusion, and dry deposition. SMVGEAR II solves gas photochemistry for tropospheric and stratospheric kinetic reactions, particle surface reactions, and photolysis reactions. Aerosol processes include anthropogenic and natural emissions, binary and ternary homogeneous nucleation, condensation, dissolution, internal-particle chemical equilibrium, aerosol-aerosol coagulation, aerosol activation of clouds, aerosol-hydrometeor coagulation, sedimentation, dry deposition, and transport [25]. Chemical equilibrium calculations include the determination of the solid/liquid/ion composition, pH, and liquid water content of aerosols as a function of size. The model treats any number of discrete aerosol size distributions, each with any number of discrete size bins and chemicals per size bin. Particle number and chemical mole concentrations are tracked in each grid cell. The components within each size bin of each aerosol size distribution are internally mixed in the bin but externally mixed from other bins and other size distributions.

S1.B.iii. Cloud and Aerosol-Cloud Processes

Cloud thermodynamics is parameterized to treat multiple subgrid cumulus clouds in each column based on an Arakawa-Schubert treatment. Aerosol particles of all composition and size and all gases are convected vertically within each subgrid cloud. Aerosol-cloud interactions and cloud and precipitation microphysics are time-dependent, explicit, and size- and composition-resolved. The model simulates the size- and composition-resolved microphysical evolution of clouds and precipitation from aerosol particles, the first and second aerosol indirect effects, the semi-direct effect, and cloud absorption effects I and II (which are the heating of a cloud due to solar absorption by absorbing inclusions in cloud drops and by swollen absorbing aerosol particles interstitially between cloud drops, respectively) [25].

S1.B.iv. Radiative Processes

For radiative calculations, each model column is divided into clear- and cloudy-sky columns, and separate calculations are performed for each. Radiative transfer is solved simultaneously through multiple layers of air and one snow, sea ice, or ocean water layer at the bottom to calculate, rather than prescribe, spectral albedos over these surfaces. The radiative code solves for atmospheric heating rates and actinic fluxes over each of 694 wavelengths/probability intervals in the ultraviolet, visible, solar-infrared, and thermal-infrared spectra, accounting for gas and size- and composition-dependent aerosol and cloud optical properties [25].

Aerosol and cloud optical properties are calculated by integrating spectral optical properties over each size bin of each aerosol and hydrometeor particle size distribution. Aerosol spectral optical of a given size are determined by assuming that black carbon, if present, is a core surrounded by a mixed shell and that the aerosol liquid water content is a function of

the ambient relative humidity and aerosol composition. Cloud spectral optical properties of a given size are determined accounting for scattering by aerosol particles between cloud particles, where aerosol particle liquid water content determined at the relative humidity of the cloud. Cloud drop, ice crystal, and graupel optical properties are determined accounting for the time-dependent evolution of black carbon, brown carbon, and soil dust inclusions within the drops, crystals, and graupel. Ice crystal and graupel optical properties also account for the nonsphericity of these particles [25].

The radiative transfer calculation also accounts for building and vegetation shading, angle of the sun, Earth-sun distance changes over time, and Earth-space refraction.

S1.B.v. Treatment of Wind Turbine Energy Extraction

For this study, 1.67 million 5-MW onshore and 938,000 5-MW offshore wind turbines with hub heights of 100 m above ground level were placed in GATOR-GCMOM among 139 countries based on the estimated number of turbines per country from [2]. The turbines were placed in farms distributed relatively evenly throughout each country, which would likely underestimate actual wind power because some many areas of countries have low wind potential. Each farm consisted of tens to hundreds of turbines. Because of the proximity of wind turbines to each other within a farm, it is necessary to account for the competitive extraction of the wind's kinetic energy by all turbines. Failing to account for such interaction results in an overestimate of available wind power.

The numerical treatment of energy extraction by each wind turbine is described in [27, 28]. Due to the coarse horizontal resolution used for the present simulations (4^ox5^o globally), wind turbines were not resolved in the horizontal; however, because of the fine vertical resolution used, they were resolved in the vertical, with five layers per turbine. All turbines extract the precise amount of energy from the wind as their power curve dictates.

Each turbine is characterized by its rated power, rotor diameter (D), hub height above the surface (100 m here), and horizontal spacing area (m^2) $A_{turb}=xDyD$, where x and y are constants that provide distances perpendicular to and parallel to, respectively, the prevailing wind direction (set to x=4, y=11). Each wind turbine intersects several model vertical layers. Kinetic energy is extracted from each model layer that intersects the turbine rotor each time step. The reduction in the wind's kinetic energy reduces wind speed in each turbine's wake, creating shear that converts more kinetic energy into turbulent kinetic energy (TKE) that is modeled with the level 2.5 TKE closure of Mellor and Yamada [31]. The kinetic energy extracted by turbines is used for electric power. To conserve energy in the model, the electric power is dissipated to heat as is kinetic energy lost to frictional dissipation of the winds at the ground. The heat produced creates buoyancy, giving rise to potential energy. Gradients in potential energy then regenerate some kinetic energy. Thus, the model conserves energy.

S1.B.vi. Treatment of Solar Energy Extraction by PV Panels and CSP Power Plants

GATOR-GCMOM also treats extraction of energy from residential rooftop photovoltaic (PV) systems, commercial/government rooftop PV systems, utility-scale PV systems, concentrated solar power (CSP) systems, and solar thermal systems. The numbers of each of

these devices in each country are obtained from [2]. GATOR-GCMOM distributes utility-scale PV and CSP plants in low latitude regions in each country and rooftop PV and solar thermal throughout each country proportional to population.

GATOR-GCMOM predicts time-dependent direct and diffuse solar radiation as a function of wavelength, accounting for time-dependent predicted gas, aerosol particle, and cloud concentrations and optical properties in the atmosphere (Section S1.B.iv). The radiative transfer calculation also accounts for surface albedo (and predicts albedo over water, snow, and ice surfaces), building and vegetation shading, angle of the sun, Earth-sun distance, Earth-space refraction, and solar intensity versus wavelength. As such, the model predicts the variable nature of solar radiation fields.

Solar PV and CSP in the model extract power, reducing solar radiation to the surface, thereby reducing panel, rooftop, and ground temperature. PV output in the model is a function of temperature, so extraction of solar radiation by the panels themselves, which affects surface temperature, also affects panel performance. The model also treats the dissipation of electrical energy to heat, so whereas panels reduce local temperatures by extracting sunlight, this energy is returned as heat upon electricity use.

Finally, since GATOR-GCMOM simulated meteorology from 2050-2054, time-dependent wind and solar fields account for higher greenhouse gas levels and a different climate than exist today. However, emission levels for the 139 countries are much lower than today due to the fact that a 100% WWS system will replace most current emissions by 2050.

S1.C. Accounting for Uncertainties in Assumptions

One uncertainty, applicable to any grid integration model investigating the future, arises due to the inconsistency between load and resource data sets. The wind and solar data are derived from GATOR-GCMOM for the years 2050-2054, but the load data are based on 2010-2014 or 2030 data extrapolated to 2050-2054. Because both load and WWS supply data are country-specific, they are roughly consistent with each other on both diurnal and seasonal scales. For example, high heat loads occur during winter due to low temperatures. The climate model also predicts low temperatures during winter, and the resulting winds and solar fields are consistent with the low temperatures and other meteorological conditions causing them. Thus, the same physical processes affecting wind and solar fields in the climate model affect loads on seasonal and diurnal scales.

Another uncertainty arises due to whether LOADMATCH captures potential losses of load due to scheduled or unscheduled maintenance of energy generators, random variation in load or WWS resources, or transmission congestion.

LOADMATCH treats these losses as follows. First, losses of energy due to down time from scheduled and unscheduled maintenance are estimated together with transmission and distribution losses. However, assuming that energy loss from a single down wind turbine equals the loss of energy available to consumers overestimates energy loss to consumers. The reason is that, when a single wind turbine is down, all the other turbines in a wind farm receive and extract more kinetic energy because of lesser competition among turbines for

the limited kinetic energy available, so the aggregate power loss among all turbines is slightly less than the power lost to the down turbine. The impact of this is that our assumption that energy loss to consumers is proportional to down time of wind turbines is conservative in that it slightly overestimates energy loss to consumers.

Uncertainties in load and WWS resources are accounted for to some extent in the variable nature of the load data and modeled wind and solar resources over the multiple years examined. Since LOADMATCH has no knowledge of the load or generation data even one time step ahead of time, its requirement to meet load 100% of the time, thus its exceedance of the electric utility industry standard of a LOLE of 1 day in 10 years, indicates the risk to grid operators of the supply not matching demand with the simulated system in place may be relatively minor.

Although the impact of transmission congestion on reliability is not modeled explicitly, sensitivity tests were run in [1] to check the impact on cost of different fractions of wind and solar power produced subject to long-distance transmission. The result was that, if congestion is an issue at the baseline level of long-distance transmission, increasing the transmission capacity will relieve congestion with only a modest increase in cost.

S1.D. Effect of Wind Turbines on Wind Speed and Kinetic Energy

Two global simulations with GATOR-GCMOM were run for 5 years (2050-2054), as described in the main text. The baseline simulation accounted for the reduction in the wind's kinetic energy and speed due to the conversion of kinetic energy to electrical energy by wind turbines, and the conversion of electrical energy to heat. The other simulation assumed wind turbines did not perturb wind speed or kinetic energy; instead, they extracted kinetic energy without removing it from the wind. The difference between the two simulations provides the impact of wind turbines on wind speed, kinetic energy, and global temperature.

Figures S2a and S2b respectively show the baseline modeled 100-m wind speed and the difference in wind speed due to accounting for energy extraction by the number of wind turbines given in Table 2. Wind speed loss at 100 m, averaged worldwide, was only ~0.3% (Figure S2b). Figures S2c and S2d compare modeled with Quikscat [33] near-surface wind speed data. The model generally matched the observed wind patterns and magnitudes. Figures S2e shows wind power extracted when turbines from the 139 countries extract kinetic energy from the wind, thereby reducing wind speed. Figure S2f shows the difference in wind power extracted when turbine extraction of kinetic energy reduced wind speed minus when it did not. This is the loss in wind power extracted due to accounting for competition among wind turbines for available kinetic energy. The power extracted among all onshore plus offshore turbines, while accounting for competition but before transmission, distribution, and maintenance (TDM) losses, was ~5.30 TW (Figure S2e). The onshore plus offshore nameplate capacity of wind in the simulation among the 139 countries was 13.02 TW, directly from the country roadmaps [2] giving a wind capacity factor before TDM losses of ~40.7% versus ~43.6% when competition was ignored. Thus, competition among turbines reduced aggregate power output by ~0.38 TW (Figure S2f), or ~6.7%. This result reaffirms the need to account for wind turbine extraction of kinetic energy when this many turbines is deployed worldwide, but it also reaffirms the fact that powering even ~37% of

the world's end use power with wind has little impact on the mean global wind speed. Local wind speed impacts are larger.

S1.E. Effect of Wind Turbines on Water Vapor and Global Temperature

Figures S2g and S2h indicate that energy extraction by wind turbines reduced column water vapor and global near-surface temperature, respectively. The reasons are as follows. Whereas, wind turbines reduce wind speeds thus surface evaporation downwind of each wind farm, thereby warming the surface there (since evaporation is a cooling process), they reduce atmospheric water vapor thus condensation, thereby cooling the larger-scale air (since condensation is a heating process) [27]. These two factors essentially cancel each other. However, water vapor is a greenhouse gas, and the net reduction in atmospheric water vapor due to wind turbines results in a net average global surface cooling. Some previous studies [e.g., 34] have found that wind farms may warm surface temperatures in the vicinity of the wind farm, consistent with the explanation above. However, such studies do not account for large-scale impacts, particularly of reduced water vapor, so don't provide the overall impacts of wind farms on global temperature as calculated here.

Figure S2g shows a net column water vapor reduction of ~1.1% during the simulation period due to turbines and Figure S2h shows the net global cooling of ~0.03 K due to turbines. This represents ~3% of net global warming to date of ~1 K. In sum, not only do wind turbines replace polluting fossil fuel plants, but they also reduce water vapor, reducing global warming further.

Although the global cooling due to wind turbines is modest compared with the cooling due to eliminating fossil fuel emissions, the cooling due to adding wind turbines begin to occur immediately after the turbines start operating, whereas the cooling due to reducing CO_2 emissions are realized primarily years to centuries after the emissions are reduced. Thus, adding turbines should stall the rise in global temperatures in the short term more significantly than their long-term benefit suggests, avoiding greater damage to human and animal health, biodiversity, agriculture, infrastructure, and coastlines than would otherwise occur in the short term.

S1.F. Energy Extraction by and Capacity Factors of PV and CSP Systems

Figure S2i shows that rooftop plus utility PV panels placed in GATOR-GCMOM (with a total nameplate capacity of 29.5 TW from [2]) extracted ~5.63 TW in the annual average, giving a mean annual capacity factor for 139-country solar PV predicted by the model as 19.1%. Figure S2j shows that CSP plants (with a generator total nameplate capacity of 3.45 TW from [2, Table 2] extracted ~1.90 TW, giving a mean annual capacity factor for CSP of 55.1%.

S2. Supporting Tables

Table S1. LOADMATCH capacity adjustment factors (CAFs), turbine scaling factors, and storage times by region for Cases A, B, and C.

Case A (No increase in hydropower peak discharge rate)

Region	(a) Onshore wind CAF	(b) Off-shore wind CAF	(c) Rooftop PV CAF	(d) Utility PV CAF	(e) Solar Thermal CAF	(f) CSP turbine factor	(g) Hydro turbine factor	(h) Storage HW-STES (hours)	(i) Storage UTES (days)	(j) Storage H_2 (days)
Africa	1.1	0.6	0.8	1	2	1.5	1	10	22	1
Australia	1	0.85	0.9	1	0.7	2	1	8	45	50
Central America	1	0.88	0.9	0.94	0.2	1.6	1	6	8	5
Central Asia	1.21	1	0.7	1.1	0.9	1.5	1	10	50	1
China	2.27	0.5	0.5	1	0.7	1	1	7	35	2
Cuba	1.8	0.95	0.8	1.01	1	1.6	1	8	11	1
Europe	2.4	0.9	0.8	1.03	0.3	0.5	1	6	4	2
Haiti	1	0.5	0.8	1.2	0.9	1.6	1	10	6	2
Iceland	0.6	0.2	0	0	0	0	1	8	0	33
India	1.5	0.5	0.6	1.4	0.4	1	1	6	52	9
Jamaica	1	0.7	0.8	1.01	0.95	0.95	1	6	4.6	5
Japan	1	1.6	0.7	2	1	1	1	8	50	1
Mideast	1.2	1	0.8	1	1	1.6	1	8	55	6
New Zealand	1.7	0.7	0.55	0.8	0.9	1.5	1	14	15	4
North America	1.65	0.9	0.5	1.73	0.5	2	1	14	19	23
Philippines	2.05	1	0.4	2.1	1	2.5	1	8	38	1
Russia	1.1	1.4	0.5	0.7	0.2	0.8	1	10	7	1
South America	1	1	0.7	1	0.8	2.5	1	14	20	1
Southeast Asia	0.5	1	0.5	3	0.1	1.6	1	9	29	7
Taiwan	1	1	1	1.7	0.4	0	1	14	24	10

Case B (Increase in hydropower peak discharge rate in some regions)

Region	(a) Onshore wind CAF	(b) Off-shore wind CAF	(c) Rooftop PV CAF	(d) Utility PV CAF	(e) Solar Thermal CAF	(f) CSP turbine factor	(g) Hydro turbine factor	(h) Storage HW-STES (hours)	(i) Storage UTES (days)	(j) Storage H_2 (days)
Africa	1.1	0.6	0.8	1	2	1.5	1	10	22	1
Australia	1.2	0.95	0.9	1.1	0.7	1.8	3	8	30	45
Central America	1.2	0.65	0.95	1.2	0.8	1.6	1	6	3	10
Central Asia	1.2	1	0.7	1.1	1	1.6	7	8	48	1
China	1.8	0.9	0.7	1.3	0	1.3	1	7	35	1
Cuba	1.9	0.6	0.8	1.4	0	2.05	5	8	12	1
Europe	1.6	0.85	1	1.5	0	1.6	4	8	11	2
Haiti	1	0.5	0.8	1.2	0.9	1.6	1	10	6	2
Iceland	0.6	0.2	0	0	0	0	1	8	0	33
India	1.3	0.5	0.6	1.7	0.16	1.35	2	6	60	9
Jamaica	1	0.7	0.8	1.01	0.95	0.95	1	6	4.6	5
Japan	2.0	2.2	0.68	3	0	1.8	6	8	15	45
Mideast	1.4	0.7	0.5	1.4	0	1.6	1	8	52	1
New Zealand	1.3	0.7	0.6	1.1	0.7	1	3	14	10	4
North America	1.7	0.8	0.9	1.05	0.21	1.7	2	14	25	1

Philippines	2.5	0.9	0.4	2.6	1	1.6	4	8	37	1
Russia	1.3	0.9	0.45	1.1	0	1.3	3	10	10	1
South America	1.3	0.8	0.7	1.3	0.79	1.6	2	14	20	1
Southeast Asia	1.47	1.3	0.5	3.5	0.4	2	1	9	23	7
Taiwan	1.7	0.9	0.98	2.5	0	0	10	14	18	1

Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)

Region	(a) Onshore wind CAF	(b) Off-shore wind CAF	(c) Rooftop PV CAF	(d) Utility PV CAF	(e) Solar Thermal CAF	(f) CSP turbine factor	(g) Hydro turbine factor	(h) Storage HW-STES (hours)	(i) Storage UTES (days)	(j) Storage H_2 (days)
Africa	1.0	0.4	0.4	1.0	0	1.0	1	0	0	1
Australia	1.0	0.8	0.8	1.0	0	1.4	1	0	0	7
Central America	1.4	0.2	0.9	0.9	0	1.0	1	0	0	5
Central Asia	1.2	0.8	0.3	1.0	0	1.4	1	0	0	1
China	2.3	0.4	0.3	1.0	0	0.8	1	0	0	2
Europe	1.4	0.6	0.35	1.07	0	0.5	1	0	0	2
Iceland	0.6	0.1	0	0	0	0	1	0	0	33
India	2.0	0.4	0.5	1.4	0	1.1	1	0	0	9
Mideast	1.1	0.8	0.8	1.0	0	2.5	1	0	0	6
New Zealand	1.0	0.5	0.6	0.8	0	1.5	1	0	0	4
North America	1.0	0.8	0.5	0.9	0	2.0	1	0	0	26
Philippines	1.0	0.8	0.4	1.2	0	1.5	1	0	0	1
Russia	1.1	0.6	0.5	0.7	0	0.7	1	0	0	1
South America	1.0	1.0	0.7	1.0	0	1.0	1	0	0	1

Columns (a)-(e) are LOADMATCH capacity adjustment factors (CAFs) that show the ratio of the final nameplate capacity used for this study, after running LOADMATCH, to the pre-LOADMATCH nameplate capacity estimated from [2]. Thus, a CAF less than 1.0 means that the LOADMATCH-stabilized grid requires less capacity than initially assumed in [2]. Column (f) is the ratio of CSP turbine nameplate capacity (CSP storage discharge rate) needed to keep the grid stable relative to the CSP turbine nameplate capacity needed for annual average power in each region, as determined from [2]. Jacobson et al. [2] estimated this factor as 1.6 for determining CSP nameplate capacities, so a number less than 1.6 here indicates fewer CSP turbines are needed here than estimated in [2] to keep the grid stable. Table 2 provides the final CSP nameplate capacity, accounting for this factor. Column (g) gives the ratio of the number of hydropower turbines needed, after running LOADMATCH, to 2015 hydropower nameplate capacity, assuming no change in the annually averaged energy output or storage capacity of the reservoir. A value of 1 indicates no change in the nameplate turbine capacity (maximum discharge rate) relative to 2015. In Case B, no changes occur in eight regions. Tables 2 and S4 show the hydropower maximum discharge rate, accounting for this factor. Columns (h), (i), and (j) respectively provide the number of hours of HW-STES storage and the number of days of UTES-storage, at the maximum discharge rate provided in Table S4 and the maximum number of days of hydrogen storage at the annual average hydrogen load for producing and compressing hydrogen given in Table 3. The number of hours of storage of PHS and CW-STES at their maximum discharge rates is 14 h; for batteries, 1.94 h (Table S4, footnote). The number of hours of CSP-PCM storage at its maximum discharge rate is 22.6 h (Table S4, footnote).

Table S2. Parameters for determining costs of energy.

	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	1.51 (1.27-1.74)	37 (35-40)	1.25 (1.2-1.3)	30 (25-35)	7.5 (5-10)
Offshore wind	3.92 (2.82-5.03)	80 (60-100)	2 (2-2)	30 (25-35)	7.5 (5-10)
Residential PV	3.18 (2.88-3.48)	27.5 (25-30)	0.75 (0.5-1)	44 (41-47)	1.5 (1-2)
Commercial/government PV	2.34 (2.16-2.51)	16.5 (13-20)	0.75 (0.5-1)	46 (43-49)	1.5 (1-2)
Utility-scale PV	1.47 (1.35-1.58)	19.5 (16.5-22.5)	0.75 (0.5-1)	48.5 (45-52)	7.5 (5-10)
CSP no storage	3.76 (3.35-4.16)	45 (36-54)	1.25 (1-1.5)	45 (40-50)	7.5 (5-10)
CSP with storage*	6.24 (5.61-6.86)	50 (40-60)	1.25 (1-1.5)	45 (40-50)	7.5 (5-10)
Geothermal for electricity	4.37 (2.53-6.21)	45 (36-54)	2.5 (2-3)	45 (40-50)	7.5 (5-10)
Hydropower	2.92 (2.42-3.43)	15.5 (15-16)	2.5 (2-3)	85 (70-100)	7.5 (5-10)
Wave	4.33 (2.96-5.70)	175 (100-250)	2 (2-2)	45 (40-50)	7.5 (5-10)
Tidal	3.85 (3.06-4.63)	125 (50-200)	2.5 (2-3)	45 (40-50)	7.5 (5-10)
Solar thermal for heat	1.35 (1.28-1.43)	50 (40-60)	1.25 (1-1.5)	35 (30-40)	3 (2-4)
Geothermal for heat	4.37 (2.53-6.21)	45 (36-54)	2 (1-3)	45 (40-50)	7.5 (5-10)

All data are from [2]. Costs are per MW of nameplate capacity. O&M=Operation and maintenance. TDM = transmission/distribution/maintenance. The cost of geothermal for heat is assumed to be the same as that for electricity. TDM losses are a percent (from Table S2) of all energy produced by the generator and are an average over short and long-distance (high-voltage direct current) lines. The cost of solar thermal collectors is from [1].

*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 S3. The cost of CSP with storage depends on the ratio of the CSP storage maximum charge rate plus direct electricity use rate (which equals the maximum discharge rate) to the CSP maximum discharge rate. For this table, for the purpose of benchmarking the "CSP with storage" cost, we use a ratio of 3.2:1. (In other words, if 3.2 units of sunlight come in, a maximum of 2.2 units can go to storage and a maximum of 1 unit can be discharged directly as electricity at the same time.) The ratio for "CSP no storage" is 1:1. In our actual simulations and cost calculations we assume a ratio of 2.61:1 for CSP with storage (Table S4), 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 S3. Lifecycle costs of new storage capacity and round-trip efficiencies of the storage technology assumed in this study.

Storage technology	Capital cost of storage beyond power generation ($/maximum-deliverable-kWh)			Round-trip charge/store/ discharge efficiency (%)
	Middle	Low	High	
Electricity				
PHS	[1]14	12	16	[7]80
CSP-PCM	[2]20	15	23	[8]99
LI Batteries	[3]160	120	200	[9]85
Cold				
CW-STES	[4]6.5	0.13	12.9	[10]84.7
ICE	[5]36.7	12.9	64.5	[4]82.5
Heat				
HW-STES	[4]6.5	0.13	12.9	[10]83
UTES	[6]0.90	0.071	1.71	[11]56

[1]Poonpun and Jewell [35].
[2]Nithyanandam and Pitchumani [21] provide the cost of the phase-change material and storage tanks. The cost of CSP mirrors and other components needed to heat the phase-change material that is put in storage is accounted for in the capital cost of CSP (Table S2).
[3]Shahan [36].
[4]IRENA [37].
[5]Habeebullah [38]; IRENA [37].
[6]Gaine and Duffy [39]; Rehau [40].
[7]Wikipedia [41]. PHS efficiency is the ratio of electricity delivered to the sum of electricity delivered and electricity used to pump the water.
[8]Wikipedia [42]. The CSP-PCM efficiency is the ratio of the heat available for the steam turbine after storage to the heat from the solar collector that goes into storage. The energy losses due to reflection and absorption by the CSP mirrors (45% of incident solar energy) and due to converting CSP heat to electricity (71.3%) are accounted for in the CSP efficiency without storage.
[9] Battery efficiency is the ratio of electricity delivered to electricity put into the battery.
[10]Stagner [43]. CW-STES and HW-STES efficiencies are the ratio of the energy returned as cooling and heating, respectively, after storage to the energy in the electricity input into storage.
[11]Sibbitt et al. [14]. The UTES efficiency is the fraction of heated fluid entering underground storage that is ultimately returned during the year (either short or long term) as air or water heat for a building.

Table S4. Maximum instantaneous charge rates, maximum instantaneous discharge rates, and maximum energy storage capacities of the different types of electricity storage (PHS, CSP-PCM, batteries, hydropower), cold storage (CW-STES, ICE), and heat storage (HW-STES, UTES) technologies treated here, by region, for Cases A, B, and C.

Case A (No increase in hydropower peak discharge rate)

	Africa			**Australia**			**Central America**			**Central Asia**		
Storage technology	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh
PHS	23.2	23.2	0.325	8.59	8.59	0.12	6.0	6.0	0.084	12.0	12.0	0.168
CSP-elec.	264.9	264.9	--	47.7	47.7	--	68.1	68.1	--	94.8	94.8	--
CSP-PCM	427.2	--	5.98	77.0	--	1.08	109.8	--	1.54	152.8	--	2.14
Batteries	0	0	0	260	260	0.504	250	250	0.485	100	100	0.194
Hydropower	11.05	25.5	96.79	3.73	8.05	32.6	7.58	18.0	66.4	8.24	19.5	72.2
CW-STES	18.4	18.4	0.258	4.13	4.13	0.058	4.34	4.34	0.061	5.92	5.92	0.083
ICE	27.7	27.7	0.387	6.19	6.19	0.087	6.50	6.50	0.091	8.88	8.88	0.124
HW-STES	701.8	701.8	7.02	125.7	125.7	1.005	156.3	156.3	0.938	329.2	329.2	3.29
UTES-heat	715.3	701.8	370.6	29.1	125.7	135.7	15.1	156.3	30.02	104.3	329.2	395.1
UTES-elec.	2106	--	--	377.0	--	--	469.0	--	--	658.4	--	--
	China			**Cuba**			**Europe**			**Haiti**		
PHS	96.6	96.6	1.35	3.0	3.0	0.042	198.9	198.9	2.78	2.0	2.0	0.028
CSP-elec.	753.9	753.9	--	2.50	2.50	--	63.4	63.4	--	2.75	2.75	--
CSP-PCM	1216	--	17.0	4.03	--	0.056	102.2	--	1.43	4.43	--	0.062
Batteries	500	500	0.97	20	20	0.039	1000	1000	1.94	0	0	0
Hydropower	137.9	301.3	1208	0.028	0.064	0.245	72.4	160.2	634.2	0.269	0.604	2.35
CW-STES	50.8	50.8	0.712	0.234	0.234	0.0033	31.7	31.7	0.44	0.238	0.238	0.0033
ICE	76.2	76.2	1.07	0.351	0.351	0.005	47.5	47.5	0.66	0.357	0.357	0.005
HW-STES	2818	2818	19.7	45.4	45.4	0.364	1586	1586	9.52	111.9	111.9	1.12
UTES-heat	916.6	2818	2367	3.11	45.4	12.0	153.4	1586	152.3	3.44	111.9	16.1
UTES-elec.	5635	--	--	45.4	--	--	2380	--	--	111.9	--	--
	Iceland			**India**			**Jamaica**			**Japan**		
PHS	0	0	0	28.8	28.8	0.403	3.0	3.0	0.042	190.6	190.6	2.67
CSP-elec.	0	0	--	231.1	231.1	--	0.450	0.450	--	45.6	45.6	--
CSP-PCM	0	--	0	372.6	--	5.22	0.726	--	0.010	73.6	--	1.03
Batteries	0	0	0	500	500	0.970	0	0	0	1500	1500	2.91
Hydropower	0.944	1.986	8.27	21.8	49.1	190.8	0.009	0.023	0.081	11.2	24.0	98.3
CW-STES	0.015	0.015	.0002	20.8	20.8	0.291	0.053	0.053	.0007	17.8	17.8	0.249
ICE	.0224	.0224	.0003	31.2	31.2	0.436	0.080	0.080	.0011	26.6	26.6	0.373
HW-STES	2.08	2.08	.0167	2925	2925	17.6	46.2	46.2	0.277	482.9	482.9	3.86
UTES-heat	0	0	0	180.3	2925	3651	1.00	46.2	5.10	276.6	482.9	579.5
UTES-elec.	0	--	--	2925	--	--	13.9	--	--	1449	--	--
	Mideast			**New Zealand**			**North America**			**Philippines**		
PHS	14.5	14.5	0.203	6.0	6.0	0.084	125.4	125.4	1.76	22.4	22.4	0.314
CSP-elec.	281.4	281.4	--	4.98	4.98	--	447.7	447.7	--	19.7	19.7	--
CSP-PCM	453.7	--	6.35	8.03	--	0.112	721.9	--	10.1	31.7	--	0.444
Batteries	300	300	0.582	35	35	0.068	880	880	1.71	80	80	0.155
Hydropower	17.8	42.7	155.9	2.38	5.25	20.8	71.0	158.3	622.3	1.53	3.55	13.4
CW-STES	22.4	22.4	0.314	0.136	0.136	0.002	39.9	39.9	0.559	0.992	0.992	0.014
ICE	33.7	33.7	0.47	0.204	0.204	0.003	59.9	59.9	0.839	1.49	1.49	0.021
HW-STES	844.0	844.0	6.75	11.2	11.2	0.156	1309	1309	18.3	14.2	14.2	0.114
UTES-heat	351.8	844.0	1114	4.22	11.2	4.023	236.8	1309	597.1	17.4	14.2	13.0
UTES-elec.	2532	--	--	22.4	--	--	2619	--	--	42.7	--	--

	Russia			South America			Southeast Asia			Taiwan		
PHS	20.3	20.3	0.284	19.4	19.4	0.272	53.6	53.6	0.751	49.1	49.1	0.687
CSP-elec.	17.6	17.6	--	295.9	295.9	--	215.7	215.7	--	0	0	--
CSP-PCM	28.4	--	0.398	477.2	--	6.68	347.8	--	4.87	0	--	0
Batteries	400	400	0.776	0	0	0	1500	1500	2.91	350	350	0.679
Hydropower	23.1	52.0	202.1	67.2	151.5	588.5	15.0	34.1	131.5	0.982	2.08	8.60
CW-STES	5.64	5.64	0.079	14.7	14.7	0.206	15.3	15.3	0.214	2.49	2.49	0.035
ICE	8.46	8.46	0.118	22.1	22.1	0.309	22.9	22.9	0.321	3.73	3.73	0.052
HW-STES	572.0	572	5.72	529.5	529.5	7.41	2049	2049	18.4	227.3	227.3	3.18
UTES-heat	18.9	572	96.1	168.8	529.5	254.1	30.2	2049	1426	14.0	227.3	130.3
UTES-elec.	572	--	--	1059	--	--	4099	--	--	454	--	--

Case B (Increase in hydropower peak discharge rate in some regions)

	Africa			Australia			Central America			Central Asia		
Storage technology	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh
PHS	23.2	23.2	0.325	8.59	8.59	0.12	6.0	6.0	0.084	12.0	12.0	0.168
CSP-elec.	264.9	264.9	--	43.0	43.0	--	68.1	68.1	--	101.1	101.1	--
CSP-PCM	427.2	--	5.98	69.3	--	0.97	109.8	--	1.54	163.0	--	2.28
Batteries	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower	11.05	25.5	96.79	3.73	24.2	32.6	7.58	18.0	66.4	8.24	136.8	72.2
CW-STES	18.4	18.4	0.258	4.13	4.13	0.058	4.34	4.34	0.061	5.92	5.92	0.083
ICE	27.7	27.7	0.387	6.19	6.19	0.087	6.50	6.50	0.091	8.88	8.88	0.124
HW-STES	701.8	701.8	7.02	125.7	125.7	1.005	156.3	156.3	0.938	329.2	329.2	3.29
UTES-heat	715.3	701.8	370.6	29.1	125.7	90.5	60.5	156.3	11.3	115.8	329.2	379.3
UTES-elec.	2106	--	--	377.0	--	--	469.0	--	--	658	--	--
	China			**Cuba**			**Europe**			**Haiti**		
PHS	96.6	96.6	1.35	3.0	3.0	0.042	198.9	198.9	2.78	2.0	2.0	0.028
CSP-elec.	980.1	980.1	--	3.20	3.20	--	202.8	202.8	--	2.75	2.75	--
CSP-PCM	1580	--	22.1	5.16	--	0.072	327.0	--	4.58	4.43	--	0.062
Batteries	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower	137.9	301.3	1208	0.028	0.320	0.245	72.4	640.8	634.2	0.269	0.604	2.35
CW-STES	50.8	50.8	0.712	0.234	0.234	0.0033	31.7	31.7	0.44	0.238	0.238	0.0033
ICE	76.2	76.2	1.07	0.351	0.351	0.005	47.5	47.5	0.66	0.357	0.357	0.005
HW-STES	2818	2818	19.7	45.4	45.4	0.364	1586	1586	9.52	111.9	111.9	1.12
UTES-heat	0	2818	2367	0	45.4	13.1	0	1586	418.8	3.44	111.9	16.1
UTES-elec.	5635	--	--	45.4	--	--	2380	--	--	111.9	--	--
	Iceland			**India**			**Jamaica**			**Japan**		
PHS	0	0	0	28.8	28.8	0.403	3.0	3.0	0.042	190.6	190.6	2.67
CSP-elec.	0	0	--	312.0	312.0	--	0.450	0.450	--	82.1	82.1	--
CSP-PCM	0	--	0	503.1	--	7.04	0.726	--	0.010	132.4	--	1.85
Batteries	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower	0.944	1.986	8.27	21.8	98.2	190.8	0.009	0.023	0.081	11.2	144.1	98.3
CW-STES	0.015	0.015	.0002	20.8	20.8	0.291	0.053	0.053	.0007	17.8	17.8	0.249
ICE	.0224	.0224	.0003	31.2	31.2	0.436	0.080	0.080	.0011	26.6	26.6	0.373
HW-STES	2.08	2.08	.0167	2925	2925	17.6	46.2	46.2	0.277	482.9	482.9	3.86
UTES-heat	0	0	0	72.1	2925	4213	1.00	46.2	5.10	0	482.9	173.8
UTES-elec.	0	--	--	2925	--	--	13.9	--	--	1449	--	--
	Mideast			**New Zealand**			**North America**			**Philippines**		
PHS	14.5	14.5	0.203	6.0	6.0	0.084	125.4	125.4	1.76	22.4	22.4	0.314
CSP-elec.	281.4	281.4	--	3.32	3.32	--	380.5	380.5	--	12.6	12.6	--

CSP-PCM	453.7	--	6.35	5.35	--	0.075	613.6	--	8.59	20.3	--	0.284
Batteries	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower	17.8	42.7	155.9	2.38	15.8	20.8	71.0	316.7	622.3	1.53	14.2	13.4
CW-STES	22.4	22.4	0.314	0.136	0.136	0.002	39.9	39.9	0.559	0.992	0.992	0.014
ICE	33.7	33.7	0.47	0.204	0.204	0.003	59.9	59.9	0.839	1.49	1.49	0.021
HW-STES	844.0	844.0	6.75	11.2	11.2	0.156	1309	1309	18.3	14.2	14.2	0.114
UTES-heat	0	844.0	1054	3.28	11.2	2.68	99.4	1309	786	17.4	14.2	12.7
UTES-elec.	2532	--	--	22.4	--	--	2619	--	--	42.7	--	--
	Russia			**South America**			**Southeast Asia**			**Taiwan**		
PHS	20.3	20.3	0.284	19.4	19.4	0.272	53.6	53.6	0.751	49.1	49.1	0.687
CSP-elec.	28.6	28.6	--	189.4	189.4	--	269.6	269.6	--	0	0	--
CSP-PCM	46.2	--	0.647	305.4	--	4.28	434.8	--	6.09	0	--	0
Batteries	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower	23.1	156.0	202.1	67.2	303	588.5	15.0	34.1	131.5	0.982	14.6	8.60
CW-STES	5.64	5.64	0.079	14.7	14.7	0.206	15.3	15.3	0.214	2.49	2.49	0.035
ICE	8.46	8.46	0.118	22.1	22.1	0.309	22.9	22.9	0.321	3.73	3.73	0.052
HW-STES	572.0	572	5.72	529.5	529.5	7.41	2049	2049	18.4	227.3	227.3	3.18
UTES-heat	0	572	137.3	166.7	529.5	254.1	120.7	2049	1131	0	227.3	98.2
UTES-elec.	572	--	--	1059	--	--	4099	--	--	454	--	--

Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)

	Africa			**Australia**			**Central America**			**Central Asia**		
Storage technology	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh	Max charge rate GW	Max dis-charge rate GW	Max capac-ity TWh
PHS	23.2	23.2	0.325	8.59	8.59	0.12	6.0	6.0	0.084	12.0	12.0	0.168
CSP-elec.	176.6	176.6	--	33.4	33.4	--	42.5	42.5	--	88.4	88.4	--
CSP-PCM	384.8	--	3.99	53.9	--	0.75	68.6	--	0.96	142.6	--	2.00
Batteries	0	0	0	100.	100.	0.194	310	310	0.601	100	100	0.194
Hydropower	11.05	25.5	96.79	3.73	8.05	32.6	7.58	18.0	66.4	8.24	19.5	72.2
CW-STES	0	0	0	0	0	0	0	0	0	0	0	0
ICE	0	0	0	0	0	0	0	0	0	0	0	0
HW-STES	0	0	0	0	0	0	0	0	0	0	0	0
UTES-heat	0	0	0	0	0	0	0	0	0	0	0	0
UTES-elec.	0	--	--	0	--	--	0	--	--	0	--	--
	China			**Europe**			**Iceland**			**India**		
PHS	96.6	96.6	1.35	198.9	198.9	2.78	0	0	0	28.8	28.8	0.403
CSP-elec.	603.1	603.1	--	63.4	63.4	--	0	0	--	254.2	254.2	--
CSP-PCM	972.5	--	13.6	102.2	--	1.43	0	--	0	409.9	--	5.74
Batteries	300	300	0.582	100	100	0.194	0	0	0	3100	3100	6.01
Hydropower	137.9	301.3	1208	72.4	160.2	634.2	0.944	1.986	8.27	21.8	49.1	190.8
CW-STES	0	0	0	0	0	0	0	0	0	0	0	0
ICE	0	0	0	0	0	0	0	0	0	0	0	0
HW-STES	0	0	0	0	0	0	0	0	0	0	0	0
UTES-heat	0	0	0	0	0	0	0	0	0	0	0	0
UTES-elec.	0	--	--	0	--	--	0	--	--	0	--	--
	Mideast			**New Zealand**			**North America**			**Philippines**		
PHS	14.5	14.5	0.203	6.0	6.0	0.084	125.4	125.4	1.76	22.4	22.4	0.314
CSP-elec.	439.7	439.7	--	4.98	4.98	--	447.7	447.7	--	11.8	11.8	--
CSP-PCM	709.0	--	9.93	8.03	--	0.112	721.9	--	10.1	19.0	--	0.266
Batteries	1,320	1,320	2.56	5	5	0.010	500	500	0.97	10	10	0.019
Hydropower	17.8	42.7	155.9	2.38	5.25	20.8	71.0	158.3	622.3	1.53	3.55	13.4

CW-STES	0	0	0	0	0	0	0	0	0	0	0	0
ICE	0	0	0	0	0	0	0	0	0	0	0	0
HW-STES	0	0	0	0	0	0	0	0	0	0	0	0
UTES-heat	0	0	0	0	0	0	0	0	0	0	0	0
UTES-elec.	0	--	--	0	--	--	0	--	--	0	--	--
	Russia			**South America**								
PHS	20.3	20.3	0.284	19.4	19.4	0.272						
CSP-elec.	15.4	15.4	--	118.4	118.4	--						
CSP-PCM	24.9	--	0.348	190.9	--	2.67						
Batteries	50	50	0.097	0	0	0						
Hydropower	23.1	52.0	202.1	67.2	151.5	588.5						
CW-STES	0	0	0	0	0	0						
ICE	0	0	0	0	0	0						
HW-STES	0	0	0	0	0	0						
UTES-heat	0	0	0	0	0	0						
UTES-elec.	0	--	--	0	--	--						

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. The storage time (hours) equals the maximum capacity divided by the maximum discharge rate. Storage times by region for all devices are given in Table S1 and its footnote.

The PHS charge/discharge rate is calculated as described in the text. The battery charge/discharge rate in Case B is zero for all regions, but specified in Case A. In both cases, the energy storage capacity equals the maximum discharge rate multiplied by the maximum number of hours of storage at full discharge, set to 14 hours for PHS and 1.94 hours for batteries (patterned after the Tesla Powerwall 1 -- 3.3 kW maximum charge/discharge rate and 6.4 kWh maximum storage).

Heat captured by CSP solar collectors can either be used immediately to produce electricity, put in storage, or both. The maximum direct CSP electricity production rate (CSP-elec) equals the maximum electricity discharge rate. 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. Thus, the maximum overall simultaneous direct electricity plus storage CSP production rate is 2.612 multiplied by the discharge rate[1] (see also the footnote to Table S2). The maximum discharge rate is also the nameplate capacity of the steam turbines, given in Table 2. The maximum energy storage capacity equals the maximum electricity discharge rate multiplied 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 can be charged only naturally, 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 here that hydro is recharged at that rate, where its annual energy output for 2050 is estimated from [2], close to its current value. Hydropower' maximum discharge rate is calculated as its 2015 nameplate capacity from [2] multiplied by the hydro turbine factor from Table S1, which is unity for Case A but varies from 1 to 10 by region for Case B. Resulting peak discharge rates are provided in Tables 2 and S4. The purpose of the turbine factor in Case B is to increase the maximum possible discharge rate of hydropower when needed without increasing reservoir size. The cost of additional turbines in that case is accounted for and provided in Table S10. The maximum storage capacity is set equal to the 2050 annual energy output of hydro, as determined in [2].

The CW-STES charge/discharge rate is set equal to 40% of the annually averaged cold load given in Table 3. The ICE storage charge/discharge rate is set to 60% of the same annually averaged cold load. The storage capacity equals the discharge rate multiplied by the maximum number of hours of storage at full discharge, set to 14 hours.

The HW-STES charge and discharge rates are set equal to the maximum daily heat load during a year, calculated as the maximum among all days, of the product of the annual average heat load from Table 3 and the ratio of the heating degree days per day each day to the annual average number of heating degree days per day. The storage capacity equals the discharge rate multiplied the maximum number of hours of storage at full discharge, given in Table S1.

UTES heat stored in underground rocks can be charged by either solar or geothermal heat or excess electricity. The maximum charge rate of heat to UTES storage (UTES-heat) is set to the nameplate capacity of the solar thermal collectors (Table 2). The maximum charge rate of excess electricity converted to heat stored in UTES (UTES-elec.) is set to 0.3-3 times the maximum discharge rate of heat from UTES (UTES-heat), set by trial and error for each country. The maximum UTES heat discharge rate is set to that of HW-STES storage. The UTES-heat storage capacity equals the UTES maximum discharge rate multiplied the maximum number of days of storage at full discharge, given in Table S1.

Table S5. 2050 annual average end-use electric plus heat load by sector and region after energy in all sectors has been converted to WWS. Regional sums are obtained by summing country data from [2] in each region. Instantaneous loads can be higher or lower than annual average loads. For Cases A and B, the loads are both initial and final loads. For Case C, the loads are final loads after converting heating and cooling to heat pumps with a coefficient of performance of 4. The initial loads for Case C are the same as for Cases A and B.

Cases A and B Initial and Final Annual Average Loads

Region	End-use load (GW)	Residential load (GW)	Commercial load (GW)	Industrial load (GW)	Transport load (GW)	Ag/Forestry/Fishing load (GW)	Other load (GW)
Africa	759.5	360.8	61.4	166.8	121.8	24.2	24.6
Australia	118.9	18.0	20.4	55.5	21.6	3.18	0.238
Central America	199.1	42.6	16.4	83.6	45.9	7.71	2.89
Central Asia	262.0	92.6	31.3	95.4	24.6	5.94	12.2
China	3,349.1	751.9	162.4	1,885.5	372.4	64.6	112.4
Cuba	7.75	1.89	0.545	4.03	0.536	0.203	0.544
Europe	1,419.8	460.4	280.6	384.2	252.1	35.0	7.56
Haiti	8.35	4.10	0.775	1.09	2.21	0.180	0.0
Iceland	3.36	0.687	0.543	1.62	0.218	0.278	0.011
India	1,022.0	315.7	56.8	400.8	147.3	65.6	35.8
Jamaica	1.97	0.292	0.308	0.685	0.596	0.082	0.003
Japan	444.8	78.2	124.9	171.3	60.5	7.66	2.19
Mideast	820.9	174.3	72.4	397.5	134.3	24.7	17.7
New Zealand	17.6	2.71	3.27	6.95	3.25	1.30	0.088
North America	1,531.7	289.7	313.8	552.4	310.2	36.2	29.3
Philippines	39.6	10.8	7.56	9.82	10.6	0.751	0
Russia	476.9	149.1	52.6	212.9	51.4	10.9	0.059
South America	598.4	96.8	48.4	273.0	151.3	27.0	1.77
Southeast Asia	658.2	179.9	61.2	223.0	171.5	20.3	2.33
Taiwan	99.8	13.6	11.1	52.2	16.9	1.37	4.58
Total/average	**11,839.5**	**3,044**	**1,326.7**	**4,978.0**	**1,899.3**	**337.3**	**254.3**

Case C Final Loads (Supply 100% of cold and low-temperature heat with heat pumps with no storage)

Region	End-use load (GW)	Residential load (GW)	Commercial load (GW)	Industrial load (GW)	Transport load (GW)	Ag/Forestry/Fishing load (GW)	Other load (GW)
Africa	465.1	120.1	18.5	156.0	121.8	24.2	24.6
Australia	90.99	7.34	6.74	51.9	21.6	3.18	0.24
Central America	155.0	15.3	5.02	78.2	45.9	7.71	2.89
Central Asia	171.8	30.8	9.15	89.2	24.6	5.94	12.2
China	2,595	236.3	45.9	1,763	372.4	64.6	112.4
Europe	910.1	168.9	87.4	359.3	252.1	35.0	7.56
Iceland	2.56	0.30	0.24	1.52	0.22	0.28	0.011
India	739.0	99.4	16.1	374.8	147.3	65.6	35.8
Mideast	634.5	63.7	22.4	371.7	134.3	24.7	17.7
New Zealand	14.07	1.35	1.59	6.50	3.25	1.30	0.088
North America	1,117	118.8	106.1	516.6	310.2	36.2	29.3
Philippines	26.34	3.60	2.21	9.18	10.6	0.75	0
Russia	323.1	46.7	15.0	199.1	51.4	10.9	0.059
South America	487.1	36.4	15.3	255.3	151.3	27.0	1.77

Table S6. Percent of 2010 residential plus commercial total annual average heat load that is low-temperature heat load (the rest is for electricity) and percent of industrial total annual average load that is high-temperature heat load by country or region in 2010. Derived from data in De Stercke [3]

Country or region	Low-temperature heat load as a % of electricity plus heat load, in the residential and commercial sectors	High-temperature heat load as a % of electricity plus high-temperature heat load in the industrial sector
Asia other	81.6	64.3
Australia	64.9	62.3
Brazil	66.0	65.8
Canada	72.3	64.0
China	85.7	63.7
Russia	88.1	72.1
France	75.7	57.8
Germany	80.4	58.8
India	85.6	70.5
Italy	81.6	58.1
Japan	66.5	59.4
LAM other	75.6	62.3
MEA other	74.3	70.9
Nigeria	96.3	83.6
OECD other	74.8	59.0
Poland	86.5	66.6
RE other	81.1	63.4
South Africa	74.6	50.3
United Kingdom	80.5	58.8
United States	68.9	64.3
World average	78.7	64.7

Asia other = Asia other than China and India; LAM other = Latin America other than Brazil; MEA other = Middle East and Africa other than South Africa and Nigeria; OECD other = countries in the Organization for Economic Cooperation and Development other than Australia, France, Germany, Japan, Italy, United Kingdom, United States; RE other = reforming economies in Eastern Europe and the former Soviet Union other than Poland and Russia.

Table S7. Cooling degree days (CDD), heating degree days (HDD), and fractions of total residential, commercial, and industrial annual average loads required for air heating (F_{ah}), water heating (F_{wh}), air cooling (F_{ac}), refrigeration (F_{rf}), and high-temperature industrial processes (F_{ht}). The text describes parameter derivations.

			Residential			Commercial				Industrial			
Region	**CDD**	**HDD**	F_{ah}	F_{wh}	F_{ac}	F_{ah}	F_{wh}	F_{ac}	F_{rf}	F_{ht}	F_{ah}	F_{ac}	F_{rf}
Africa	3348	811	0.572	0.244	0.074	0.639	0.135	0.090	0.067	0.635	0.012	0.050	0.024
Australia	1523	1086	0.455	0.194	0.140	0.536	0.113	0.140	0.104	0.623	0.026	0.036	0.024
Central America	1298	1446	0.530	0.226	0.098	0.624	0.132	0.098	0.072	0.623	0.033	0.030	0.024
Central Asia	3176	4505	0.572	0.244	0.074	0.673	0.143	0.074	0.054	0.643	0.037	0.026	0.024
China	1756	5282	0.601	0.256	0.057	0.707	0.150	0.057	0.042	0.637	0.047	0.016	0.024
Cuba	4057	150	0.530	0.226	0.098	0.624	0.132	0.098	0.072	0.623	0.002	0.060	0.024
Europe	663	5223	0.544	0.232	0.069	0.641	0.136	0.081	0.060	0.592	0.055	0.007	0.024
Haiti	5015	4.8	0.530	0.226	0.098	0.624	0.132	0.098	0.072	0.623	0.0001	0.062	0.024
Iceland	3.7	8447	0.524	0.224	0.0002	0.617	0.131	0.0003	.0002	0.590	0.062	0	0.024
India	5151	927	0.600	0.256	0.058	0.706	0.150	0.058	0.043	0.705	0.0095	0.053	0.024
Jamaica	6486	14.0	0.53	0.226	0.0976	0.624	0.132	0.0976	0.072	0.623	0.0001	0.0623	0.024
Japan	1596	4038	0.466	0.199	0.134	0.549	0.116	0.134	0.099	0.594	0.045	0.018	0.024
Mideast	4601	1516	0.521	0.222	0.103	0.613	0.130	0.103	0.076	0.709	0.016	0.047	0.024
New Zealand	121	2974	0.455	0.194	0.019	0.536	0.113	0.022	0.016	0.623	0.060	0.002	0.024
North America	1066	5592	0.486	0.207	0.093	0.572	0.121	0.109	0.081	0.642	0.052	0.010	0.024
Philippines	6471	3.65	0.572	0.244	0.074	0.673	0.143	0.074	0.054	0.643	0	0.062	0.024
Russia	471	8292	0.618	0.263	0.035	0.727	0.154	0.041	0.031	0.721	0.059	0.003	0.024
South America	2231	1042	0.505	0.215	0.112	0.587	0.124	0.115	0.085	0.643	0.020	0.043	0.024
Southeast Asia	6115	61	0.572	0.244	0.074	0.673	0.143	0.074	0.054	0.643	0.0006	0.062	0.024
Taiwan	3707	489	0.572	0.244	0.074	0.673	0.143	0.074	0.054	0.643	0.007	0.055	0.024

Table S8. Average 2050-2054 capacity factors (percent of nameplate capacity produced as electricity before transmission, distribution or maintenance losses) by region in this study for Cases A, B, and C.

Case A (No increase in hydropower peak discharge rate)

Region	Onshore wind	Off-shore wind	Rooftop PV	Utility PV	CSP with storage	Geo-thermal elec-tricity	Hydropower	Wave	Tidal	Solar thermal	Geo-thermal heat
Africa	36.2	42.4	20.2	19.6	57	78.9	44.7	25.5	22.5	10.1	97.4
Australia	37.2	46.1	19.7	21.6	60	90.1	57.7	33.7	24.6	10.1	97.4
Central America	29.1	35.4	22.4	22.2	61.2	83.2	54.4	12.7	23.0	11.2	97.3
Central Asia	53.7	50.0	17.4	19.6	53.4	0	43.9	12.2	21.6	8.7	96.6
China	46.7	40.3	18.9	20	53.7	89.3	48.8	13.8	23.5	9.4	97.3
Cuba	38.1	40.7	23.2	23.2	64	0	49.3	37.9	23.2	11.6	--
Europe	42.9	49.5	15.5	15.3	49.1	87.6	52.1	25.9	23.9	7.4	97.3
Haiti	36.8	47.6	23	23	63.5	88.1	45.7	--	21.6	11.6	--
Iceland	49.8	58.2	--	--	--	92.5	56.3	31.8	25.2	--	97.3
India	44.1	40.1	18.4	21.2	59.2	86.6	53.4	13.5	23.7	9.3	97.3
Jamaica	40.5	45.0	22.8	22.8	63	--	41.5	--	21.4	11.5	--
Japan	39.6	40.8	18.3	19.6	50.6	90.9	60.6	14.1	24.9	9.0	97.3
Mideast	47.6	46.2	20.9	22	60.9	79.3	54.1	12.1	23.1	10.7	97.3
New Zealand	56.9	60.5	16.8	17.9	48.7	88.2	47.0	35.7	24.1	8.3	97.3
North America	40.2	37.7	18.6	18	52.8	87.5	48.4	29.4	23.6	9.2	97.3
Philippines	31.0	34.7	21.9	21.9	61.1	83.7	44.3	13.0	22.9	11.1	98.3
Russia	47.2	57.4	13.8	15.5	42.1	86.3	45.9	25.6	23.6	6.8	97.3
South America	16.6	39.9	21.4	21.6	59	89.5	46.4	19.9	23.9	10.8	97.3
Southeast Asia	12.7	24.4	20.5	20	55	88.3	57.2	23.8	22.5	10.4	97.4
Taiwan	28.4	37.1	21.4	22	--	91.8	56.0	14.3	25.1	10.7	97.3
Average	**42.5**	**41.3**	**19.2**	**19.3**	**55.7**	**88.3**	**49.7**	**24.1**	**23.8**	**9.62**	**97.3**

Case B (Increase in hydropower peak discharge rate in some regions)

Region	Onshore wind	Off-shore wind	Rooftop PV	Utility PV	CSP with storage	Geo-thermal elec-tricity	Hydropower	Wave	Tidal	Solar thermal	Geo-thermal heat
Africa	36.2	42.4	20.2	19.6	57	78.9	44.7	25.5	22.5	10.1	97.4
Australia	37.2	46.1	19.7	21.6	60	90.1	6.6	33.7	24.6	10.1	97.4
Central America	29.1	35.4	22.4	22.2	61.2	83.2	50.7	12.7	23.0	11.2	97.3
Central Asia	53.7	50.0	17.4	19.6	53.4	0	0.9	12.2	21.6	8.7	96.6
China	46.7	40.3	18.9	19.8	53.7	89.3	48.6	13.8	23.5	--	97.3
Cuba	38.1	40.7	23.2	23.2	64.0	0	2.1	37.9	23.2	--	--
Europe	42.9	49.5	15.5	15.3	49.1	87.6	3.5	25.9	23.9	--	97.3
Haiti	36.8	47.6	23	23	63.5	88.1	45.7	--	21.6	11.6	--
Iceland	49.8	58.2	--	--	--	92.5	56.3	31.8	25.2	--	97.3
India	44.1	40.1	18.4	21.2	59.2	86.6	14.4	13.5	23.7	9.3	97.3
Jamaica	40.5	45.0	22.8	22.8	63	--	41.5	--	21.4	11.5	--
Japan	39.6	40.8	18.3	19.6	50.6	90.9	1.7	14.1	24.9	--	97.3
Mideast	47.6	46.2	20.9	22.0	60.9	79.3	54.1	12.1	23.1	--	97.3
New Zealand	56.9	60.5	16.8	17.9	48.7	88.2	6.5	35.7	24.1	8.3	97.3

North America	40.2	37.7	18.6	18.0	52.8	87.5	13.1	29.4	23.6	9.2	97.3
Philippines	31.0	34.7	21.9	21.9	61.1	83.7	3.2	13.0	22.9	11.1	98.3
Russia	47.2	57.4	13.8	15.5	42.1	86.3	5.8	25.6	23.6	--	97.3
South America	16.6	39.9	21.4	21.6	59.0	89.5	14.3	19.9	23.9	10.8	97.3
Southeast Asia	12.7	24.4	20.5	20.0	55.0	88.3	48.3	23.8	22.5	10.4	97.4
Taiwan	28.4	37.1	21.4	22.0	--	91.8	0.8	14.3	25.1	--	97.3
Average	**41.1**	**39.7**	**19.0**	**19.2**	**55.3**	**88.3**	**15.2**	**23.9**	**23.8**	**10.0**	**97.3**

Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)

Region	Onshore wind	Off-shore wind	Rooftop PV	Utility PV	CSP with storage	Geo-thermal elec-tricity	Hydropower	Wave	Tidal	Solar thermal	Geo-thermal heat
Africa	36.2	42.4	20.2	19.6	57	78.9	50.7	25.5	22.5	0	97.4
Australia	37.2	46.1	19.7	21.6	60	90.1	51.9	33.7	24.6	0	97.4
Central America	29.1	35.4	22.4	22.2	61.2	83.2	54.5	12.7	23	0	97.3
Central Asia	53.7	50	17.4	19.6	53.4	0	43.5	12.2	21.6	0	96.6
China	46.7	40.3	18.9	19.8	53.7	89.3	49.5	13.8	23.5	0	97.3
Europe	42.9	49.5	15.5	15.3	49.1	87.6	53.7	25.9	23.9	0	97.3
Iceland	49.8	58.2	--	--	--	92.5	61.6	31.8	25.2	0	97.3
India	44.1	40.1	18.4	21.2	59.2	86.6	46.9	13.5	23.7	0	97.3
Mideast	47.6	46.2	20.9	22.0	60.9	79.3	43.7	12.1	23.1	0	97.3
New Zealand	56.9	60.5	16.8	17.9	48.7	88.2	48.6	35.7	24.1	0	97.3
North America	40.2	37.7	18.6	18	52.8	87.5	48.0	29.4	23.6	0	97.3
Philippines	31	34.7	21.9	21.9	61.1	83.7	44.2	13	22.9	0	98.3
Russia	47.2	57.4	13.8	15.4	42.1	86.3	49.5	25.6	23.6	0	97.3
South America	16.6	39.9	21.4	21.6	59	89.5	53.6	19.9	23.9	0	97.3

Capacity factors account for array losses (extraction of kinetic energy by turbines) in the case of wind turbines. In all cases, they are before transmission, distribution, and maintenance losses, which are given in Table S2. The average is weighted by nameplate capacity (Table 2). "–" indicates no installation of the technology. All solar panels are non-tracking, fixed tilt.

Table S9. Summary of 2050 mean capital costs of new electricity plus heat generators and storage ($ trillion in 2013 USD) and mean levelized costs of energy (LCOE) (¢/kWh-all-energy or ¢/kWh-electricity-replacing-BAU-electricity) averaged over the 5-year simulation for each world region in Cases A, B, and C.

Case A (No increase in hydropower peak discharge rate)

	Africa	Australia	Central America	Central Asia	China	Cuba	Europe
Capital cost new generators only ($tril)	7.56	1.18	2.24	2.42	25.4	0.082	12.4
Cap cost new generators + storage ($tril)	9.05	1.46	2.4	3.02	29.5	0.107	13.2
Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Long-distance transmission	0.33	0.35	0.36	0.35	0.35	0.17	0.35
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Electricity generators	5.28	5.43	6.15	4.96	4.43	5.83	5.43
Additional hydro turbines	0	0	0	0	0	0	0
Solar thermal collectors	1.02	0.265	0.082	0.431	0.296	0.434	0.117
CSP-PCM+PHS+battery storage	0.106	0.569	0.359	0.19	0.099	0.667	0.169
CW-STES+ICE storage	0.014	0.02	0.012	0.013	0.009	0.017	0.013
HW-STES storage	0.039	0.036	0.02	0.053	0.025	0.199	0.028
UTES storage	0.286	0.67	0.089	0.885	0.415	0.909	0.063
H_2 production/compression/storage	0.137	0.835	0.289	0.067	0.07	0.051	0.135
Electricity LCOE (¢/kWh-electricity)	**10.44**	**10.33**	**10.64**	**9.65**	**8.9**	**10.34**	**9.78**
Total LCOE (¢/kWh-all-energy)	**10.93**	**11.9**	**11.08**	**10.67**	**9.42**	**12**	**10.03**

	Haiti	Iceland	India	Jamaica	Japan	Mideast	New Zealand
Capital cost new generators only ($tril)	0.079	0.0054	8.59	0.02	5.97	7.2	0.127
Cap cost new generators + storage ($tril)	0.107	0.0055	12.5	0.028	7.42	8.97	0.152
Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Long-distance transmission	0.17	0.10	0.35	0.057	0.35	0.35	0.17
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Electricity generators	4.8	1.08	4.67	5.16	7.05	4.69	4.16
Additional hydro turbines	0	0	0	0	0	0	0
Solar thermal collectors	0.446	0	0.191	0.549	0.673	0.464	0.26
CSP-PCM+PHS+battery storage	0.127	0	0.169	0.263	0.759	0.177	0.531
CW-STES+ICE storage	0.016	0.003	0.011	0.015	0.022	0.015	0.0043
HW-STES storage	0.568	0.021	0.073	0.598	0.037	0.035	0.038
UTES storage	1.133	0	2.1	1.524	0.765	0.797	0.135
H_2 production/compression/storage	0.275	0.22	0.207	0.395	0.107	0.215	0.224
Electricity LCOE (¢/kWh-electricity)	**9.25**	**4.90**	**9.09**	**9.79**	**12.55**	**9.38**	**8.83**
Total LCOE (¢/kWh-all-energy)	**11.25**	**5.14**	**11.49**	**12.29**	**13.48**	**10.46**	**9.24**

	North America	Philip-pines	Russia	South America	Southeast Asia	Taiwan	Total/ Average
Capital cost new generators only ($tril)	13.8	0.394	3.76	6.31	8.55	0.989	**107**
Cap cost new generators + storage ($tril)	15.3	0.47	4.05	6.96	10.6	1.27	**127**
Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	**1.15**
Long-distance transmission	0.35	0.35	0.36	0.35	0.36	0.059	**0.35**
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	**2.57**
Electricity generators	5.29	5.46	5.24	5.9	7.24	5.39	**5.18**
Additional hydro turbines	0	0	0	0	0	0	**0.00**

Solar thermal collectors	0.167	0.475	0.043	0.305	0.05	0.152	**0.30**
CSP-PCM+PHS+battery storage	0.21	0.626	0.186	0.15	0.568	0.77	**0.21**
CW-STES+ICE storage	0.015	0.014	0.0067	0.014	0.013	0.014	**0.01**
HW-STES storage	0.051	0.012	0.051	0.053	0.119	0.135	**0.04**
UTES storage	0.229	0.193	0.118	0.249	1.27	0.77	**0.56**
H_2 production/compression/storage	0.474	0.235	0.064	0.174	0.35	0.27	**0.19**
Electricity LCOE (¢/kWh-electricity)	**9.72**	**10.59**	**9.55**	**10.4**	**11.9**	**10.11**	**9.74**
Total LCOE (¢/kWh-all-energy)	**10.51**	**11.08**	**9.79**	**10.91**	**13.69**	**11.29**	**10.56**

Case B (Increase in hydropower peak discharge rate in some regions)

	Africa	**Australia**	**Central America**	**Central Asia**	**China**	**Cuba**	**Europe**
Capital cost new generators only ($tril)	7.56	1.21	2.27	2.45	31.3	0.083	13.8
Cap cost new generators + storage ($tril)	8.99	1.37	2.4	3.08	34.1	0.099	14.7
Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Long-distance transmission	0.33	0.35	0.35	0.35	0.36	0.18	0.36
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Electricity generators	5.28	5.65	5.65	6.2	5.27	5.79	5.62
Additional hydro turbines	0	0.041		0	0	0.01	0.103
Solar thermal collectors	1.02	0.265	0.206	0.329	0	0	0
CSP-PCM+PHS+battery storage	0.106	0.115	0.061	0.105	0.089	0.171	0.055
CW-STES+ICE storage	0.014	0.02	0.012	0.012	0.0085	0.017	0.013
HW-STES storage	0.039	0.036	0.02	0.02	0.025	0.199	0.028
UTES storage	0.234	0.447	0.055	0.033	0.415	0.992	0.173
H_2 production/compression/storage	0.316	0.766	0.494	0.382	0.065	0.051	0.135
Electricity LCOE (¢/kWh-electricity)	**10.44**	**10.13**	**10.13**	**10.67**	**9.44**	**9.88**	**9.84**
Total LCOE (¢/kWh-all-energy)	**11.06**	**11.42**	**11.42**	**11.15**	**9.96**	**11.13**	**10.21**

	Haiti	**Iceland**	**India**	**Jamaica**	**Japan**	**Mideast**	**New Zealand**
Capital cost new generators only ($tril)	0.079	0.0054	8.98	0.02	8.74	6.84	0.118
Cap cost new generators + storage ($tril)	0.105	0.0055	13.2	0.028	9.07	7.99	0.134
Short-dist. transmiss. (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Long-distance transmission	0.17	0.1	0.36	0.057	0.36	0.36	0.17
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Electricity generators	4.8	1.08	4.77	5.16	10.315	4.52	3.83
Additional hydro turbines	0	0	0.015	0	0.082	0	0.183
Solar thermal collectors	0.446	0	0.076	0.549	0	0	0.202
CSP-PCM+PHS+battery storage	0.127	0	0.093	0.263	0.1	0.103	0.099
CW-STES+ICE storage	0.016	0.003	0.011	0.015	0.022	0.015	0.004
HW-STES storage	0.568	0.021	0.073	0.598	0.037	0.035	0.038
UTES storage	0.944	0	2.421	1.33	0.229	0.753	0.09
H_2 production/compression/storage	0.585	0.134	0.207	0.676	0.517	0.15	0.224
Electricity LCOE (¢/kWh-electricity)	**9.25**	**4.9**	**9.01**	**9.76**	**14.58**	**8.69**	**8.19**
Total LCOE (¢/kWh-all-energy)	**11.37**	**5.06**	**11.74**	**12.37**	**15.38**	**9.65**	**8.56**

	North America	**Philip-pines**	**Russia**	**South America**	**Southeast Asia**	**Taiwan**	**Total/ Average**
Capital cost new generators only ($tril)	14	0.372	3.32	5.87	10.4	1.14	**119**
Cap cost new generators + storage ($tril)	15.2	0.423	3.55	6.54	11.9	1.27	**134**

Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	**1.15**
Long-distance transmission	0.35	0.35	0.36	0.35	0.36	0.06	**0.35**
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	**2.57**
Electricity generators	5.3	5.22	4.56	5.63	9.03	6.13	**5.64**
Additional hydro turbines	0.032	0.082	0.067	0.077	0	0.038	**0.03**
Solar thermal collectors	0.07	0.475	0	0.301	0.199	0	**0.12**
CSP-PCM+PHS+battery storage	0.081	0.164	0.023	0.097	0.131	0.06	**0.09**
CW-STES+ICE storage	0.015	0.014	0.007	0.014	0.013	0.014	**0.01**
HW-STES storage	0.051	0.012	0.051	0.053	0.119	0.135	**0.04**
UTES storage	0.301	0.188	0.169	0.249	1.01	0.578	**0.55**
H_2 production/compression/storage	0.163	0.235	0.064	0.173	0.351	0.151	**0.18**
Electricity LCOE (¢/kWh-electricity)	**9.54**	**9.97**	**8.72**	**10.15**	**13.4**	**10.01**	**9.95**
Total LCOE (¢/kWh-all-energy)	**10.09**	**10.46**	**9.02**	**10.66**	**14.92**	**10.88**	**10.74**

Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)

	Africa	**Australia**	**Central America**	**Central Asia**	**China**	**Europe**	**Iceland**
Capital cost new generators only ($tril)	5.02	1.04	1.9	1.73	21.9	8.48	0.0049
Cap cost new generators + storage ($tril)	5.11	1.09	2.02	1.8	22.2	8.57	0.0049
Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Long-distance transmission	0.36	0.36	0.36	0.36	0.36	0.35	0.11
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Electricity generators	5.95	6.39	6.68	5.63	5.04	5.66	1.258
Additional hydro turbines	0	0	0	0	0	0	0
Solar thermal collectors	0	0	0	0	0	0	0
CSP-PCM+PHS+battery storage	0.118	0.342	0.491	0.278	0.096	0.0634	0
CW-STES+ICE storage	0	0	0	0	0	0	0
HW-STES storage	0	0	0	0	0	0	0
UTES storage	0	0	0	0	0	0	0
H_2 production/compression/storage	0.224	0.315	0.371	0.103	0.091	0.211	0.288
Electricity LCOE (¢/kWh-electricity)	**10.1**	**10.76**	**11.19**	**9.97**	**9.2**	**9.76**	**5.08**
Total LCOE (¢/kWh-all-energy)	**10.37**	**11.12**	**11.62**	**10.09**	**9.31**	**10.01**	**5.37**

	India	**Mideast**	**New Zealand**	**North America**	**Philip-pines**	**Russia**	**South America**
Capital cost new generators only ($tril)	8.7	7.91	0.116	10.9	0.293	2.55	5.32
Cap cost new generators + storage ($tril)	9.78	8.52	0.121	11.3	0.305	2.58	5.37
Short-dist. transmission (¢/kWh-all-energy)	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Long-distance transmission	0.36	0.36	0.18	0.36	0.36	0.36	0.36
Distribution	2.57	2.57	2.57	2.57	2.57	2.57	2.57
Electricity generators	6.8	6.51	4.54	5.61	5.99	5.15	6.28
Additional hydro turbines	0	0	0	0	0	0	0
Solar thermal collectors	0	0	0	0	0	0	0
CSP-PCM+PHS+battery storage	0.955	0.628	0.231	0.219	0.314	0.053	0.076
CW-STES+ICE storage	0	0	0	0	0	0	0
HW-STES storage	0	0	0	0	0	0	0
UTES storage	0	0	0	0	0	0	0
H_2 production/compression/storage	0.287	0.278	0.279	0.709	0.353	0.095	0.213
Electricity LCOE (¢/kWh-electricity)	**11.8**	**11.18**	**8.65**	**9.86**	**10.31**	**9.26**	**10.4**
Total LCOE (¢/kWh-all-energy)	**12.12**	**11.5**	**8.95**	**10.62**	**10.74**	**9.38**	**10.65**

Capital costs for new generators are given in Table S2 and for storage are given in Table S3.

The LCOEs are derived from capital costs assuming a discount rate of 2.0 (1-3)% and lifetimes, annual O&M, and end-of-life decommissioning costs that vary by technology from Table S2, all divided by the total annualized end-use load met in Table 4.

The discount rate is a social discount rate for a social cost analysis of an intergenerational project [2]. The justification of this discount rate is discussed extensively in [2] and references therein. In particular Drupp et al. [44] surveyed 197 experts and find that 92% are comfortable with a social discount rate for intergenerational projects between 1% and 3%. The upper value of 3% is consistent with the values from OMB [45] and Moore et al. [46].

Since the total 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 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 the portion of long-distance transmission associated with H_2.

Long-distance transmission costs are 1.2 (0.3-3.2) ¢/kWh for 1200-2000 km lines [2]. We assume that 30% of all annually-averaged electric energy generated is subject to long-distance transmission lines in all regions except Cuba (15%), Haiti (15%), Iceland (15%), Jamaica (5%), New Zealand (15%), and Taiwan (5%), since these regions are all islands that are only 230-1600 km long.

Storage costs are the product of the storage capacity and the capital cost per unit of storage capacity of each storage technology (Table S3), annualized with the same discount rates and annual O&M percentages as for power generators, but with storage lifetimes of 32.5 (25-40) years and divided by the annual-average end-use load met in Table 4.

H_2 costs are derived in Section S1.A.iii. These costs exclude electricity costs, which are included elsewhere in the table.

Table S10. Summary of energy requirements met, losses, energy supplies, and changes in storage, during the 5-year (43,811.5 hour) simulations for each world region in Cases A, B, and C. All units are TWh over the 5-year simulation.

Case A (No increase in hydropower peak discharge rate)

	Africa	Australia	Central America	Central Asia	China
A1. Total end use demand	**33,274**	**5,210**	**8,721**	**11,475**	**146,708**
Electricity for electricity inflexible demand	8,538	1,905	2,838	3,286	49,511
Electricity for electricity, heat, cold storage + DR	22,107	2,830	4,807	7,744	91,734
Electricity for H_2 direct use + H_2 storage	2,629	475	1,076	445	5,462
A2. Total end use demand	**33,274**	**5,210**	**8,721**	**11,475**	**146,708**
Electricity for direct use, electricity storage, + H_2	18,090	4,008	6,561	6,847	109,312
Electricity + heat for heat storage	14,296	1,091	1,964	4,325	36,067
Electricity for cold storage	887	111	196	303	1,328
A3. Total end use demand	**33,274**	**5,210**	**8,721**	**11,475**	**146,708**
Electricity for direct use, electricity storage, DR	14,309	3,185	5,201	6,031	99,414
Electricity for H_2 direct use + H_2 storage	2,629	475	1,076	445	5,462
Electricity+heat for heat direct use + heat storage	14,316	1,098	1,970	4,351	36,263
Electricity for cold direct use + cold storage	2,021	452	475	648	5,568
B. Total losses	**7,440**	**1,052**	**1,892**	**3,190**	**42,458**
Transmission, distribution, downtime losses	2,178	387	565	907	12,973
Losses CSP storage	22.53	6.53	9.03	4.17	43.30
Losses PHS storage	0.93	9.90	7.82	1.71	37.73
Losses battery storage	0	6.28	9.68	0.19	6.16
Losses CW-STES + ICE storage	160.24	19.97	35.45	54.78	239.91
Losses HW-STES storage	1,730	119	321	520	4,782
Losses UTES storage	2,180	347	256	1,158	7,842
Losses from shedding	1,168	157	688	543	16,534
Net end-use demand plus losses (A1 + B)	***40,714***	***6,262***	***10,613***	***14,665***	***189,166***
C. Total WWS supply before T&D losses	**40,511**	**6,226**	**10,630**	**14,602**	**188,848**
Onshore + offshore wind electricity	12,763	2,055	3,549	6,818	106,558
Rooftop + utility PV+ CSP electricity	23,572	3,492	6,083	7,000	71,170
Hydropower electricity	498.97	203.50	430.03	375.38	6,446
Wave electricity	369.66	326.08	93.12	9.51	52.77
Geothermal electricity	124.75	15.79	389.72	0	72.73
Tidal electricity	18.69	5.39	3.84	0.19	31.05
Solar heat	3,157	128.23	74.37	399.39	3,754
Geothermal heat	5.85	0.69	7.01	0.15	762.61
D. Net taken from (+) or added to (-) storage	**203.67**	**35.91**	**-16.65**	**63.28**	**318.20**
CSP storage	0.344	0.221	-0.768	-0.535	-1.693
PHS storage	-0.032	0.045	-0.042	-0.042	-0.135
Battery storage	0	-0.126	-0.243	-0.049	-0.097
CW-STES+ICE storage	0.581	0.108	-0.076	-0.052	-0.178
HW-STES storage	6.317	-0.251	-0.255	2.469	17.743
UTES storage	195.16	24.20	-15.01	61.27	297.17
H_2 storage	1.30	11.71	-0.259	0.219	5.386
Energy supplied plus taken from storage (C+D)	***40,714***	***6,262***	***10,613***	***14,665***	***189,166***

	Cuba	Europe	Haiti	Iceland	India

A1. Total end use demand	**339.35**	**62,200**	**365.89**	**147.16**	**44,753**
Electricity for electricity inflexible demand	122.76	17,838	89.61	58.25	13,754
Electricity for electricity, heat, cold storage + DR	206.56	39,900	222.83	83.99	27,854
Electricity for H_2 direct use + H_2 storage	10.04	4,463	53.44	4.92	3,146
A2. Total end use demand	**339.35**	**62,200**	**365.89**	**147.16**	**44,753**
Electricity for direct use, electricity storage, + H_2	251.92	36,598	202.90	103.87	30,570
Electricity + heat for heat storage	76.78	24,714	153.41	42.50	13,408
Electricity for cold storage	10.65	888	9.58	0.79	774
A3. Total end use demand	**339.35**	**62,200**	**365.89**	**147.16**	**44,753**
Electricity for direct use, electricity storage, DR	226.90	29,457	132.99	98.10	25,922
Electricity for H_2 direct use + H_2 storage	10.04	4,463	53.44	4.92	3,146
Electricity+heat for heat direct use + heat storage	76.78	24,811	153.41	42.50	13,408
Electricity for cold direct use + cold storage	25.64	3,469	26.04	1.64	2,277
B. Total losses	**92.98**	**28,836**	**73.23**	**61.21**	**10,699**
Transmission, distribution, downtime losses	23.00	6,399	23.13	15.63	3,257
Losses CSP storage	0.35	3.36	0.47	0	22.25
Losses PHS storage	3.50	186.57	1.35	0	31.06
Losses battery storage	0.39	24.65	0	0	38.81
Losses CW-STES + ICE storage	1.92	160.39	1.73	0.14	139.85
Losses HW-STES storage	8.40	4,710	23.03	0.01	1,182
Losses UTES storage	26.02	319	16.52	0	4,976
Losses from shedding	29.40	17,033	7.00	45.43	1,051
Net end-use demand plus losses (A1 + B)	***432.3***	***91,036***	***439.1***	***208.4***	***55,452***
C. Total WWS supply before T&D losses	**435**	**91,053**	**432**	**208**	**53,118**
Onshore + offshore wind electricity	162	63,301	77	31	27,384
Rooftop + utility PV+ CSP electricity	233	21,944	299	0	23,760
Hydropower electricity	1.38	3,656	12.09	48.98	1,149
Wave electricity	21.91	427.38	0.00	4.67	33.55
Geothermal electricity	0	121.45	26.24	36.06	10.63
Tidal electricity	0.48	156.49	0.50	0.63	7.51
Solar heat	15.84	495.68	17.43	0	731.17
Geothermal heat	0.00	951.63	0.00	86.96	42.17
D. Net taken from (+) or added to (-) storage	**-3.12**	**-17.40**	**7.22**	**-0.02**	**2,334**
CSP storage	-0.014	-0.143	-0.005	0.000	0.444
PHS storage	-0.011	-0.278	-0.003	0.000	-0.040
Battery storage	-0.010	-0.194	0.000	0.000	-0.097
CW-STES+ICE storage	0.006	-0.111	0.007	0.0003	-0.073
HW-STES storage	-0.091	-0.952	-0.067	-0.008	15.796
UTES storage	-3.00	-15.23	7.23	0.00	2,304
H_2 storage	-0.001	-0.489	0.053	-0.009	13.958
Energy supplied plus taken from storage (C+D)	***432.3***	***91,036***	***439.1***	***208.4***	***55,452***

	Jamaica	Japan	Mideast	New Zealand	North America
A1. Total end use demand	**86.13**	**19,483**	**35,961**	**769**	**67,101**
Electricity for electricity inflexible demand	27.62	6,898	11,866	296	21,556
Electricity for electricity, heat, cold storage + DR	43.98	11,385	20,997	394	39,266
Electricity for H_2 direct use + H_2 storage	14.53	1,200	3,099	79	6,280
A2. Total end use demand	**86.13**	**19,483**	**35,961**	**769**	**67,101**
Electricity for direct use, electricity storage, + H_2	66.14	13,223	27,349	591	47,450

Electricity + heat for heat storage	18.88	5,926	7,880	175	18,500
Electricity for cold storage	1.11	334	732	3	1,152
A3. Total end use demand	**86.13**	**19,483**	**35,961**	**769**	**67,101**
Electricity for direct use, electricity storage, DR	46.90	10,401	22,524	497	37,832
Electricity for H_2 direct use + H_2 storage	14.53	1,200	3,099	79	6,280
Electricity+heat for heat direct use + heat storage	18.88	5,937	7,880	179	18,615
Electricity for cold direct use + cold storage	5.82	1,945	2,458	15	4,375
B. Total losses	**15.27**	**15,323**	**8,582**	**219**	**18,663**
Transmission, distribution, downtime losses	4.89	2,485	2,758	67	5,943
Losses CSP storage	0.10	8.13	47.34	0.13	26.14
Losses PHS storage	3.33	620.72	26.53	0.28	62.13
Losses battery storage	0.00	114.31	56.27	0.03	7.29
Losses CW-STES + ICE storage	0.20	60.35	132.19	0.60	208.12
Losses HW-STES storage	1.86	505	664	26	2,989
Losses UTES storage	4.20	2,242	3,065	14	1,907
Losses from shedding	0.69	9,288	1,832	111	7,521
Net end-use demand plus losses (A1 + B)	***101.4***	***34,806***	***44,543***	***988***	***85,765***
C. Total WWS supply before T&D losses	**99**	**34,739**	**44,619**	**990**	**85,691**
Onshore + offshore wind electricity	24	3,898	15,452	490	45,020
Rooftop + utility PV+ CSP electricity	70	28,798	26,318	237	34,174
Hydropower electricity	0.42	637.90	1,011	108.20	3,357
Wave electricity	0.00	88.09	22.00	38.38	915.39
Geothermal electricity	0.00	58.12	30.21	77.25	441.78
Tidal electricity	0.19	34.96	2.96	2.11	24.29
Solar heat	5.03	1,095.34	1,644	15.29	953.15
Geothermal heat	0.00	128.82	138.55	20.78	804.92
D. Net taken from (+) or added to (-) storage	**2.53**	**66.56**	**-76.01**	**-1.13**	**73.96**
CSP storage	0.007	0.771	0.747	-0.028	-2.527
PHS storage	-0.004	1.982	-0.101	-0.021	-0.439
Battery storage	0.000	0.568	-0.291	-0.017	-0.427
CW-STES+ICE storage	0.002	-0.154	-0.305	0.001	-0.349
HW-STES storage	0.229	2.897	3.376	-0.039	13.749
UTES storage	2.26	59.90	-88.61	-1.01	-7.26
H_2 storage	0.036	0.591	9.166	-0.017	71.212
Energy supplied plus taken from storage (C+D)	***101.4***	***34,806***	***44,543***	***988***	***85,765***

	Philip-pines	**Russia**	**South America**	**Southeast Asia**	**Taiwan**
A1. Total end use demand	**1,733**	**20,893**	**26,217**	**28,822**	**4,370**
Electricity for electricity inflexible demand	470	5,731	9,154	8,365	1,481
Electricity for electricity, heat, cold storage + DR	1,028	14,392	14,440	16,636	2,508
Electricity for H_2 direct use + H_2 storage	235	770	2,623	3,820	381
A2. Total end use demand	**1,733**	**20,893**	**26,217**	**28,822**	**4,370**
Electricity for direct use, electricity storage, + H_2	1,111	12,924	21,271	20,131	3,448
Electricity + heat for heat storage	566	7,824	4,393	8,179	852
Electricity for cold storage	56	145	553	512	69
A3. Total end use demand	**1,733**	**20,893**	**26,217**	**28,822**	**4,370**
Electricity for direct use, electricity storage, DR	765	11,588	17,420	15,149	2,862
Electricity for H_2 direct use + H_2 storage	235	770	2,623	3,820	381
Electricity+heat for heat direct use + heat storage	624	7,918	4,562	8,179	854

Electricity for cold direct use + cold storage	109	618	1,611	1,673	273
B. Total losses	**519**	**7,373**	**4,384**	**7,533**	**1,318**
Transmission, distribution, downtime losses	144	2,055	1,789	2,334	379
Losses CSP storage	1.76	0.03	44.50	41.67	0.00
Losses PHS storage	4.06	0.43	5.23	143.91	115.69
Losses battery storage	0.05	0.15	0.00	180.55	11.69
Losses CW-STES + ICE storage	10.09	26.21	99.87	92.41	12.51
Losses HW-STES storage	51	1,485	549	684	98
Losses UTES storage	181	405	754	3,577	272
Losses from shedding	127	3,401	1,143	480	430
Net end-use demand plus losses (A1 + B)	***2,251***	***28,267***	***30,601***	***36,355***	***5,688***
C. Total WWS supply before T&D losses	**2,244**	**28,293**	**30,508**	**35,996**	**5,674**
Onshore + offshore wind electricity	600	24,530	9,161	7,554	1,086
Rooftop + utility PV+ CSP electricity	1,264	2,567	16,903	26,456	3,111
Hydropower electricity	68.92	1,045	3,077	853.57	51.03
Wave electricity	11.13	55.16	320.77	446.70	6.58
Geothermal electricity	210.17	18.91	209.83	535.19	1,353.18
Tidal electricity	5.02	3.72	12.72	7.74	0.29
Solar heat	84.22	56.69	798.31	136.86	65.64
Geothermal heat	0.14	16.27	24.93	6.91	0.00
D. Net taken from (+) or added to (-) storage	**7.76**	**-25.91**	**93.08**	**358.72**	**14.59**
CSP storage	0.028	-0.099	-0.163	1.431	0.000
PHS storage	-0.031	-0.071	-0.027	0.040	0.319
Battery storage	-0.016	-0.194	0.000	-0.728	-0.170
CW-STES+ICE storage	0.031	-0.049	0.464	0.401	-0.014
HW-STES storage	0.103	-1.430	-0.673	13.834	2.386
UTES storage	7.53	-24.02	92.19	330.56	10.19
H_2 storage	0.116	-0.042	1.293	13.183	1.878
Energy supplied plus taken from storage (C+D)	***2,251***	***28,267***	***30,601***	***36,355***	***5,688***

Case B (Increase in hydropower peak discharge rate in some regions)

	Africa	**Australia**	**Central America**	**Central Asia**	**China**
A1. Total end use demand	**33,274**	**5,210**	**8,721**	**11,475**	**146,708**
Electricity for electricity inflexible demand	8,538	1,885	2,824	3,320	49,564
Electricity for electricity, heat, cold storage + DR	22,107	2,850	4,822	7,711	91,682
Electricity for H_2 direct use + H_2 storage	2,629	475	1,076	445	5,462
A2. Total end use demand	**33,274**	**5,210**	**8,721**	**11,475**	**146,708**
Electricity for direct use, electricity storage, + H_2	18,090	3,985	6,543	6,886	109,374
Electricity + heat for heat storage	14,296	1,092	1,960	4,286	36,131
Electricity for cold storage	887	133	218	304	1,203
A3. Total end use demand	**33,274**	**5,210**	**8,721**	**11,475**	**146,708**
Electricity for direct use, electricity storage, DR	14,309	3,185	5,201	6,031	99,414
Electricity for H_2 direct use + H_2 storage	2,629	475	1,076	445	5,462
Electricity+heat for heat direct use + heat storage	14,316	1,098	1,970	4,351	36,263
Electricity for cold direct use + cold storage	2,021	452	475	648	5,568
B. Total losses	**7,440**	**1,320**	**2,464**	**3,338**	**50,543**
Transmission, distribution, downtime losses	2,178	412	584	917	13,338
Losses CSP storage	22.53	4.61	7.91	4.33	69.75

Losses PHS storage	0.93	8.16	6.48	1.38	33.26
Losses battery storage	0.00	0.00	0.00	0.00	0.00
Losses CW-STES + ICE storage	160.24	24.00	39.42	54.86	217.32
Losses HW-STES storage	1,730	141	306	513	4,795
Losses UTES storage	2,180	278	145	1,136	9,458
Losses from shedding	1,168	453	1,375	712	22,631
Net end-use load plus losses (A1 + B)	***40,714***	***6,530***	***11,186***	***14,814***	***197,250***
C. Total WWS supply before T&D losses	**40,511**	**6,551**	**11,193**	**14,752**	**196,902**
Onshore + offshore wind electricity	12,763	2,399	3,586	6,765	95,343
Rooftop + utility PV+ CSP electricity	23,572	3,467	6,416	7,148	94,224
Hydropower electricity	498.97	209.79	400.33	385.30	6,415
Wave electricity	369.66	326.08	93.12	9.51	52.77
Geothermal electricity	124.75	15.79	389.72	0.00	72.73
Tidal electricity	18.69	5.39	3.84	0.19	31.05
Solar heat	3,157	128.23	297.47	443.77	0
Geothermal heat	5.85	0.69	7.01	0.15	762.61
D. Net taken from (+) or added to (-) storage	**203.67**	**-21.76**	**-7.43**	**61.31**	**348.71**
CSP storage	0.344	0.145	-0.768	-0.570	-1.254
PHS storage	-0.032	-0.009	-0.042	-0.042	-0.135
Battery storage	0	0	0	0	0
CW-STES+ICE storage	0.581	0.108	-0.076	-0.052	-0.178
HW-STES storage	6.317	-0.251	-0.363	2.469	17.744
UTES storage	195.16	-22.62	-5.63	59.28	329.84
H_2 storage	1.296	0.872	-0.555	0.219	2.693
Energy supplied plus taken from storage (C+D)	***40,714***	***6,530***	***11,186***	***14,814***	***197,250***

	Cuba	Europe	Haiti	Iceland	India
A1. Total end use demand	**339.35**	**62,200**	**365.89**	**147.16**	**44,753**
Electricity for electricity inflexible demand	122.54	19,827	89.61	58.25	13,799
Electricity for electricity, heat, cold storage + DR	206.77	37,910	222.83	83.99	27,808
Electricity for H_2 direct use + H_2 storage	10.04	4,463	53.44	4.92	3,146
A2. Total end use demand	**339.35**	**62,200**	**365.89**	**147.16**	**44,753**
Electricity for direct use, electricity storage, + H_2	251.67	38,938	202.90	103.87	30,624
Electricity + heat for heat storage	76.78	22,360	153.41	42.50	13,403
Electricity for cold storage	10.90	902	9.58	0.79	726
A3. Total end use demand	**339.35**	**62,200**	**365.89**	**147.16**	**44,753**
Electricity for direct use, electricity storage, DR	226.90	29,457	132.99	98.10	25,922
Electricity for H_2 direct use + H_2 storage	10.04	4,463	53.44	4.92	3,146
Electricity+heat for heat direct use + heat storage	76.78	24,811	153.41	42.50	13,408
Electricity for cold direct use + cold storage	25.64	3,469	26.04	1.64	2,277
B. Total losses	**89.60**	**22,663**	**73.23**	**61.21**	**10,862**
Transmission, distribution, downtime losses	23.41	5,848	23.13	15.63	3,241
Losses CSP storage	0.44	13.40	0.47	0.00	35.17
Losses PHS storage	2.65	203.35	1.35	0.00	29.60
Losses battery storage	0.00	0.00	0.00	0.00	0.00
Losses CW-STES + ICE storage	1.97	162.88	1.73	0.14	131.12
Losses HW-STES storage	8.85	3,975	23.03	0.01	1,135
Losses UTES storage	27.22	1,600	16.52	0.00	5,054
Losses from shedding	25.05	10,861	7.00	45.43	1,236
Net end-use demand plus losses (A1 + B)	***428.9***	***84,863***	***439.1***	***208.4***	***55,615***

C. Total WWS supply before T&D losses	**431**	**84,774**	**432**	**208**	**52,638**
Onshore + offshore wind electricity	149	46,205	77	31	23,826
Rooftop + utility PV+ CSP electricity	259	32,930	299	0	27,188
Hydropower electricity	1.45	3,982	12.09	48.98	1,237
Wave electricity	21.91	427.38	0.00	4.67	33.55
Geothermal electricity	0.00	121.45	26.24	36.06	10.63
Tidal electricity	0.48	156.49	0.50	0.63	7.51
Solar heat	0	0	17.43	0	292.47
Geothermal heat	0.00	951.63	0.00	86.96	42.17
D. Net taken from (+) or added to (-) storage	**-2.55**	**88.86**	**7.22**	**-0.02**	**2,977.63**
CSP storage	-0.018	-0.458	-0.005	0	0.763
PHS storage	-0.011	-0.278	-0.003	0	-0.040
Battery storage	0	0	0	0	0
CW-STES+ICE storage	0.006	-0.111	0.007	0.0003	-0.073
HW-STES storage	-0.091	8.480	-0.067	-0.008	15.797
UTES storage	-2.44	76.82	7.23	0	2,947.23
H_2 storage	0.005	4.400	0.053	-0.009	13.958
Energy supplied plus taken from storage (C+D)	***428.9***	***84,863***	***439.1***	***208.4***	***55,615***

	Jamaica	Japan	Mideast	New Zealand	North America
A1. Total end use demand	**86.13**	**19,483**	**35,961**	**769**	**67,101**
Electricity for electricity inflexible demand	27.62	6,842	11,831	352	21,561
Electricity for electricity, heat, cold storage + DR	43.98	11,441	21,032	339	39,260
Electricity for H_2 direct use + H_2 storage	14.53	1,200	3,099	79	6,280
A2. Total end use demand	**86.13**	**19,483**	**35,961**	**769**	**67,101**
Electricity for direct use, electricity storage, + H_2	66.14	13,157	27,308	657	47,456
Electricity + heat for heat storage	18.88	5,927	7,874	110	18,525
Electricity for cold storage	1.11	399	779	3	1,120
A3. Total end use demand	**86.13**	**19,483**	**35,961**	**769**	**67,101**
Electricity for direct use, electricity storage, DR	46.90	10,401	22,524	497	37,832
Electricity for H_2 direct use + H_2 storage	14.53	1,200	3,099	79	6,280
Electricity+heat for heat direct use + heat storage	18.88	5,937	7,880	179	18,615
Electricity for cold direct use + cold storage	5.82	1,945	2,458	15	4,375
B. Total losses	**15.27**	**29,980**	**9,141**	**142**	**16,019**
Transmission, distribution, downtime losses	4.89	3,639	3,066	61	5,415
Losses CSP storage	0.10	13.21	43.90	0.20	26.72
Losses PHS storage	3.33	352.43	25.36	1.95	93.87
Losses battery storage	0.00	0.00	0.00	0.00	0.00
Losses CW-STES + ICE storage	0.20	72.13	140.74	0.52	202.39
Losses HW-STES storage	1.86	696	801	14	2,951
Losses UTES storage	4.20	1,917	3,059	10	2,351
Losses from shedding	0.69	23,290	2,005	54	4,979
Net end-use demand plus losses (A1 + B)	***101.4***	***49,462***	***45,102***	***911***	***83,121***
C. Total WWS supply before T&D losses	**99**	**49,446**	**45,166**	**912**	**83,023**
Onshore + offshore wind electricity	24	5,631	16,763	404	44,776
Rooftop + utility PV+ CSP electricity	70	42,871	27,198	222	32,029
Hydropower electricity	0.42	634.04	1,011	134.91	3,630
Wave electricity	0.00	88.09	22.00	38.38	915.39

Geothermal electricity	0.00	58.12	30.21	77.25	441.78
Tidal electricity	0.19	34.96	2.96	2.11	24.29
Solar heat	5.03	0	0	11.89	400.32
Geothermal heat	0.00	128.82	138.55	20.78	804.92
D. Net taken from (+) or added to (-) storage	**2.53**	**16.24**	**-63.67**	**-0.77**	**97.74**
CSP storage	0.007	1.386	-1.463	-0.019	-2.148
PHS storage	-0.004	0.741	-0.101	-0.021	-0.439
Battery storage	0	0	0	0	0
CW-STES+ICE storage	0.002	-0.155	-0.308	0.001	-0.349
HW-STES storage	0.229	2.896	3.376	-0.039	13.749
UTES storage	2.26	2.26	-66.70	-0.67	83.83
H_2 storage	0.036	9.104	1.528	-0.017	3.096
Energy supplied plus taken from storage (C+D)	***101.4***	***49,462***	***45,102***	***911***	***83,121***

	Philip-pines	**Russia**	**South America**	**Southeast Asia**	**Taiwan**
A1. Total end use demand	**1,733**	**20,893**	**26,217**	**28,822**	**4,370**
Electricity for electricity inflexible demand	494	6,576	9,377	8,155	1,469
Electricity for electricity, heat, cold storage + DR	1,004	13,547	14,217	16,847	2,520
Electricity for H_2 direct use + H_2 storage	235	770	2,623	3,820	381
A2. Total end use demand	**1,733**	**20,893**	**26,217**	**28,822**	**4,370**
Electricity for direct use, electricity storage, + H_2	1,138	13,919	21,534	19,883	3,434
Electricity + heat for heat storage	539	6,842	4,170	8,179	854
Electricity for cold storage	56	133	514	760	82
A3. Total end use demand	**1,733**	**20,893**	**26,217**	**28,822**	**4,370**
Electricity for direct use, electricity storage, DR	765	11,588	17,420	15,149	2,862
Electricity for H_2 direct use + H_2 storage	235	770	2,623	3,820	381
Electricity+heat for heat direct use + heat storage	624	7,918	4,562	8,179	854
Electricity for cold direct use + cold storage	109	618	1,611	1,673	273
B. Total losses	**483**	**5,465**	**3,313**	**14,928**	**2,323**
Transmission, distribution, downtime losses	141	1,920	1,707	2,883	458
Losses CSP storage	1.41	0.40	38.11	33.09	0.00
Losses PHS storage	14.68	4.23	48.21	30.47	116.19
Losses battery storage	0.00	0.00	0.00	0.00	0.00
Losses CW-STES + ICE storage	10.05	24.00	92.77	137.18	14.73
Losses HW-STES storage	52	1,259	516	848	119
Losses UTES storage	159	540	697	2,873	209
Losses from shedding	105	1,717	215	8,123	1,406
Net end-use demand plus losses (A1 + B)	***2,216***	***26,358***	***29,530***	***43,750***	***6,693***
C. Total WWS supply before T&D losses	**2,210**	**26,376**	**29,403**	**43,566**	**6,680**
Onshore + offshore wind electricity	652	21,764	9,634	11,001	1,052
Rooftop + utility PV+ CSP electricity	1,167	3,327	14,615	30,299	4,217
Hydropower electricity	80.61	1,191	3,797	721.43	51.10
Wave electricity	11.13	55.16	320.77	446.70	6.58
Geothermal electricity	210.17	18.91	209.83	535.19	1,353.18
Tidal electricity	5.02	3.72	12.72	7.74	0.29
Solar heat	84.22	0	788.34	547.42	0
Geothermal heat	0.14	16.27	24.93	6.91	0
D. Net taken from (+) or added to (-) storage	**5.67**	**-17.66**	**127.88**	**183.55**	**13.16**

CSP storage	0.035	-0.162	1.568	-0.325	0.000
PHS storage	-0.031	-0.071	0.135	-0.188	0.284
Battery storage	0	0	0	0	0
CW-STES+ICE storage	0.031	-0.049	0.464	0.385	-0.014
HW-STES storage	0.102	-1.430	-0.664	13.833	2.386
UTES storage	5.41	-16.33	125.08	156.66	10.32
H_2 storage	0.116	0.380	1.293	13.183	0.188
Energy supplied plus taken from storage (C+D)	***2,216***	***26,358***	***29,530***	***43,750***	***6,693***

Case C (100% of cold and low-temperature heat from electric heat pumps; no thermal-energy storage)

	Africa	Aust-ralia	Central America	Central Asia	China
A1. Total end use demand	**20,377**	**3,987**	**6,791**	**7,528**	**113,682**
Electricity for electricity inflexible demand	10,997	1,936	3,112	4,024	54,546
Electricity for electricity, heat, cold storage + DR	6,751	1,576	2,604	3,060	53,673
Electricity for H_2 direct use + H_2 storage	2,629	475	1,076	445	5,462
A2. Total end use demand	**20,377**	**3,987**	**6,791**	**7,528**	**113,682**
Electricity for direct use, electricity storage, + H_2	20,377	3,987	6,791	7,528	113,682
Electricity + heat for heat storage	0	0	0	0	0
Electricity for cold storage	0	0	0	0	0
A3. Total end use demand	**20,377**	**3,987**	**6,791**	**7,528**	**113,682**
Electricity for direct use, electricity storage, DR	17,748	3,511	5,715	7,084	108,220
Electricity for H_2 direct use + H_2 storage	2,629	475	1,076	445	5,462
Electricity+heat for heat direct use + heat storage	0	0	0	0	0
Electricity for cold direct use + cold storage	0	0	0	0	0
B. Total losses	**7,470**	**1,530**	**2,770**	**4,574**	**60,258**
Transmission, distribution, downtime losses	1,729	348	488	835	12,433
Losses CSP storage	23.67	4.60	6.64	3.47	33.46
Losses PHS storage	21.81	8.42	13.39	0.84	42.62
Losses battery storage	0	1.05	29.07	0.08	6.58
Losses CW-STES + ICE storage	0	0	0	0	0
Losses HW-STES storage	0	0	0	0	0
Losses UTES storage	0	0	0	0	0
Losses from shedding	5,695	1,168	2,233	3,735	47,742
Net end-use demand plus losses (A1 + B)	***27,847***	***5,516***	***9,562***	***12,103***	***173,940***
C. Total WWS supply before T&D losses	**27,846**	**5,516**	**9,563**	**12,101**	**173,942**
Onshore + offshore wind electricity	11,379	2,007	3,259	6,662	105,669
Rooftop + utility PV+ CSP electricity	15,381	2,978	5,380	5,057	60,817
Hydropower electricity	566.61	183.12	430.55	372.53	6,536
Wave electricity	369.66	326.08	93.12	9.51	52.77
Geothermal electricity	124.75	15.79	389.72	0.00	72.73
Tidal electricity	18.69	5.39	3.84	0.19	31.05
Solar heat	0	0	0	0	0
Geothermal heat	5.85	0.69	7.01	0.15	762.61
D. Net taken from (+) or added to (-) storage	**1.20**	**-0.08**	**-1.11**	**1.54**	**-1.75**
CSP storage	0.801	0.110	-0.480	1.311	-0.962
PHS storage	0.057	-0.009	-0.042	0.055	-0.135
Battery storage	0	-0.049	-0.301	-0.049	-0.058
CW-STES+ICE storage	0	0	0	0	0
HW-STES storage	0	0	0	0	0

UTES storage	0	0	0	0	0
H_2 storage	0.338	-0.130	-0.292	0.219	-0.598
Energy supplied plus taken from storage (C+D)	***27,847***	***5,516***	***9,562***	***12,103***	***173,940***

	Europe	Iceland	India	Mideast	New Zealand
A1. Total end use demand	**39,873**	**112.31**	**32,369**	**27,799**	**616**
Electricity for electricity inflexible demand	21,515	66.81	15,777	12,574	324
Electricity for electricity, heat, cold storage + DR	13,896	40.58	13,446	12,126	214
Electricity for H_2 direct use + H_2 storage	4,463	4.92	3,146	3,099	79
A2. Total end use demand	**39,873**	**112.31**	**32,369**	**27,799**	**616**
Electricity for direct use, electricity storage, + H_2	39,873	112.31	32,369	27,799	616
Electricity + heat for heat storage	0	0	0	0	0
Electricity for cold storage	0	0	0	0	0
A3. Total end use demand	**39,873**	**112.31**	**32,369**	**27,799**	**616**
Electricity for direct use, electricity storage, DR	35,411	107.39	29,223	24,700	538
Electricity for H_2 direct use + H_2 storage	4,463	4.92	3,146	3,099	79
Electricity+heat for heat direct use + heat storage	0	0	0	0	0
Electricity for cold direct use + cold storage	0	0	0	0	0
B. Total losses	**22,333**	**97.17**	**27,304**	**17,613**	**184**
Transmission, distribution, downtime losses	4,487	15.71	3,898	2,891	53
Losses CSP storage	5.01	0	7.02	48.94	0.33
Losses PHS storage	256.28	0	5.30	1.32	0.66
Losses battery storage	5.08	0	8.46	10.80	0.02
Losses CW-STES + ICE storage	0	0	0	0	0
Losses HW-STES storage	0	0	0	0	0
Losses UTES storage	0	0	0	0	0
Losses from shedding	17,580	81.46	23,385	14,661	130
Net end-use demand plus losses (A1 + B)	***62,206***	***209.5***	***59,673***	***45,412***	***801***
C. Total WWS supply before T&D losses	**62,207**	**209**	**59,674**	**45,402**	**801**
Onshore + offshore wind electricity	38,127	27	36,139	13,849	304
Rooftop + utility PV+ CSP electricity	18,654	0	22,433	30,543	246
Hydropower electricity	3,769	53.63	1,009	817.16	111.88
Wave electricity	427.38	4.67	33.55	22.00	38.38
Geothermal electricity	121.45	36.06	10.63	30.21	77.25
Tidal electricity	156.49	0.63	7.51	2.96	2.11
Solar heat	0	0	0	0	0
Geothermal heat	951.63	86.96	42.17	138.55	20.78
D. Net taken from (+) or added to (-) storage	**-0.93**	**0.07**	**-1.38**	**9.39**	**-0.07**
CSP storage	-0.143	0.000	0.529	8.714	-0.028
PHS storage	-0.278	0.000	-0.040	-0.020	-0.021
Battery storage	-0.019	0.000	-0.601	-0.256	-0.002
CW-STES+ICE storage	0	0	0	0	0
HW-STES storage	0	0	0	0	0
UTES storage	0	0	0	0	0
H_2 storage	-0.489	0.069	-1.269	0.952	-0.017
Energy supplied plus taken from storage (C+D)	***62,206***	***209.5***	***59,673***	***45,412***	***801***

	North America	Philip-pines	Russia	South America

A1. Total end use demand	**48,952**	**1,154**	**14,155**	**21,343**
Electricity for electricity inflexible demand	23,558	530	7,047	9,410
Electricity for electricity, heat, cold storage + DR	19,113	389	6,338	9,310
Electricity for H_2 direct use + H_2 storage	6,280	235	770	2,623
A2. Total end use demand	**48,952**	**1,154**	**14,155**	**21,343**
Electricity for direct use, electricity storage, + H_2	48,952	1,154	14,155	21,343
Electricity + heat for heat storage	0	0	0	0
Electricity for cold storage	0	0	0	0
A3. Total end use demand	**48,952**	**1,154**	**14,155**	**21,343**
Electricity for direct use, electricity storage, DR	42,672	920	13,385	18,720
Electricity for H_2 direct use + H_2 storage	6,280	235	770	2,623
Electricity+heat for heat direct use + heat storage	0	0	0	0
Electricity for cold direct use + cold storage	0	0	0	0
B. Total losses	**13,328**	**399**	**6,463**	**4,259**
Transmission, distribution, downtime losses	4,230	96	1,482	1,457
Losses CSP storage	42.55	1.46	0.48	24.18
Losses PHS storage	64.17	1.63	9.44	60.20
Losses battery storage	4.45	0.0002	0.47	0
Losses CW-STES + ICE storage	0	0	0	0
Losses HW-STES storage	0	0	0	0
Losses UTES storage	0	0	0	0
Losses from shedding	8,987	300	4,971	2,718
Net end-use demand plus losses (A1 + B)	***62,280***	***1,553***	***20,617***	***25,602***
C. Total WWS supply before T&D losses	**62,287**	**1,553**	**20,618**	**25,601**
Onshore + offshore wind electricity	30,502	371	16,869	9,161
Rooftop + utility PV+ CSP electricity	26,273	887	2,526	12,317
Hydropower electricity	3,326	68.70	1,128	3,554
Wave electricity	915.39	11.13	55.16	320.77
Geothermal electricity	441.78	210.17	18.91	209.83
Tidal electricity	24.29	5.02	3.72	12.72
Solar heat	0	0	0	0
Geothermal heat	804.92	0.14	16.27	24.93
D. Net taken from (+) or added to (-) storage	**-7.27**	**0.09**	**-0.22**	**1.10**
CSP storage	-0.610	0.056	-0.087	0.955
PHS storage	-0.433	-0.031	-0.071	0.107
Battery storage	-0.243	-0.002	-0.024	0
CW-STES+ICE storage	0	0	0	0
HW-STES storage	0	0	0	0
UTES storage	0	0	0	0
H_2 storage	-5.988	0.065	-0.042	0.040
Energy supplied plus taken from storage (C+D)	***62,280***	***1,553***	***20,617***	***25,602***

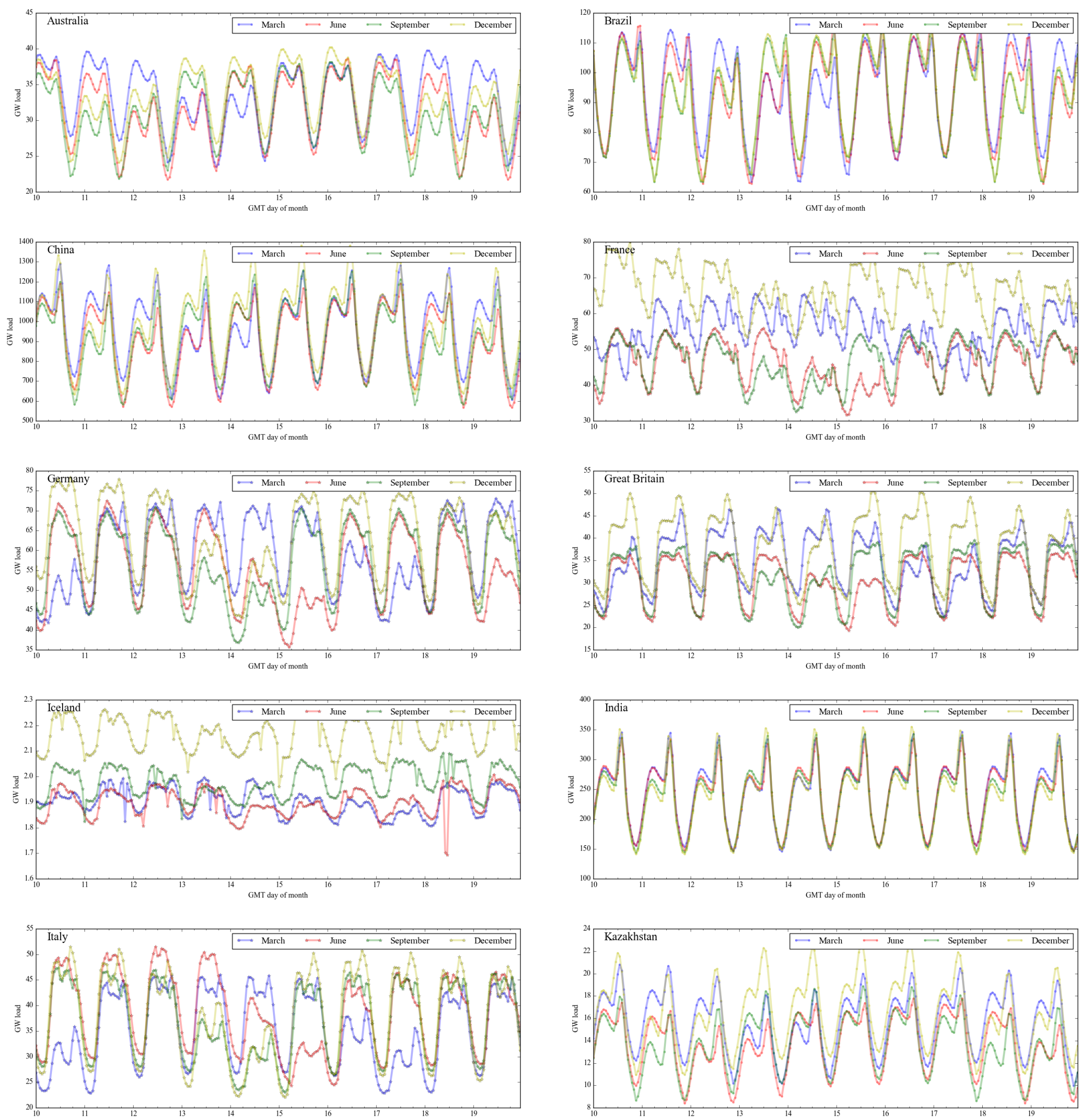
End-use demands in A1, A2, A3 should be identical. Transmission/distribution/maintenance losses are given in Table S2. Round-trip storage efficiencies are given in Table S3. Electricity generation that exceeds demand for electricity end use, cold storage capacity, heat storage capacity, and H_2 storage capacity, is shed. Onshore and offshore wind turbines in the climate model are assumed to be 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. Each rooftop and utility-scale solar PV panel in GATOR-GCMOM is assumed to be fixed tilt and to have a nameplate capacity of 390 W and a panel area of 1.629668 m^2 [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%. Capacity factors of all generators are given in Table S8. The efficiency of the solar thermal for heat hot fluid collection (energy in fluid divided by incident radiation) is 34%.

S3. Supporting Figures

Figure S1. (a) Hourly load profiles during 10-day periods in each of four seasons for several individual countries or groups of countries. Data for European countries are from ENTSO-E [11] and are shown for 2014. Data for all other countries are from NeoCarbon Energy [12] and Breyer et al. [13] and are for 2030. All days begin at 12 AM GMT. (b) Same as (a), except for all 20 world regions in 2054 after the country-specific data have been summed among all countries in the region then multiplied by the annual inflexible load of each region and divided by the annually-averaged sum load from the data to give hourly inflexible loads, as described in the text.

Figure S1a. Contemporary (2014 for Europe; 2030 elsewhere) all-electric load



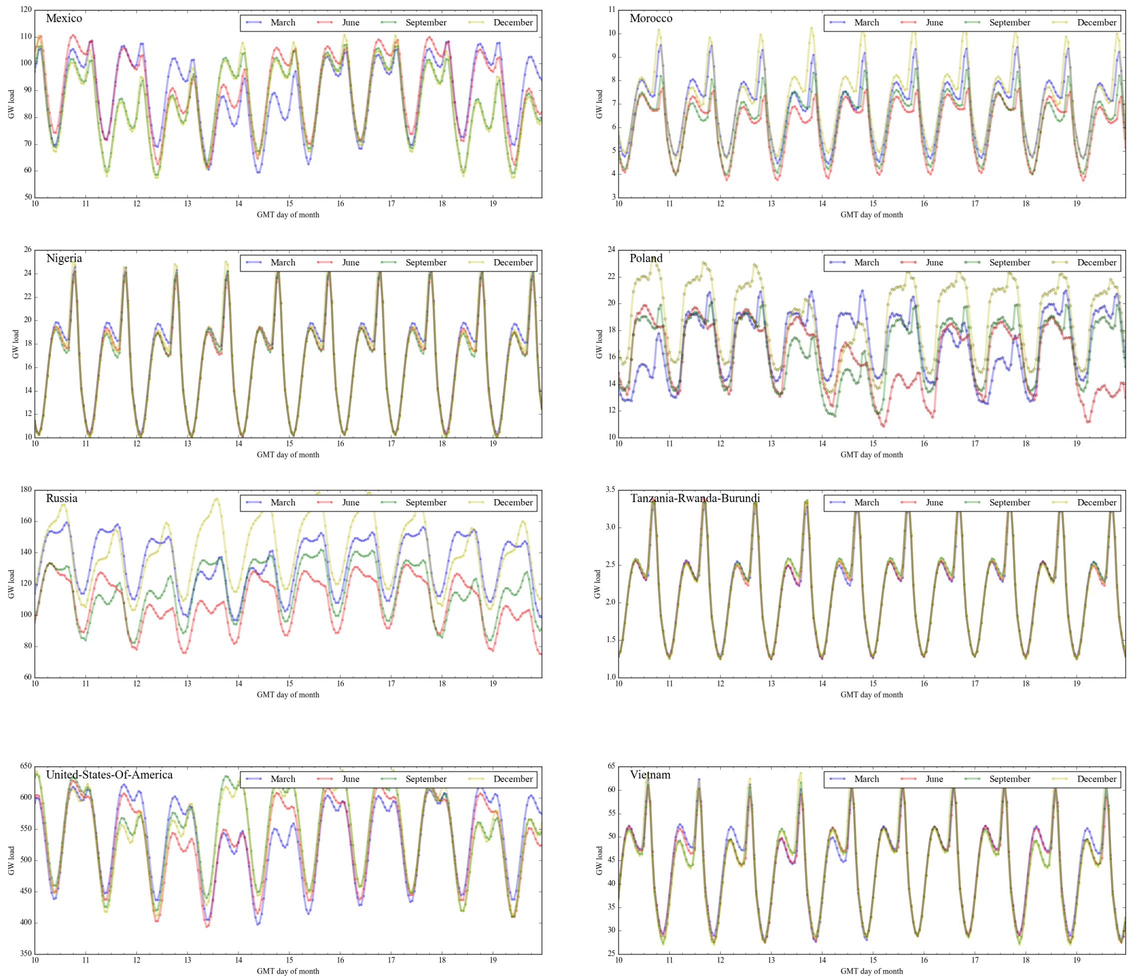
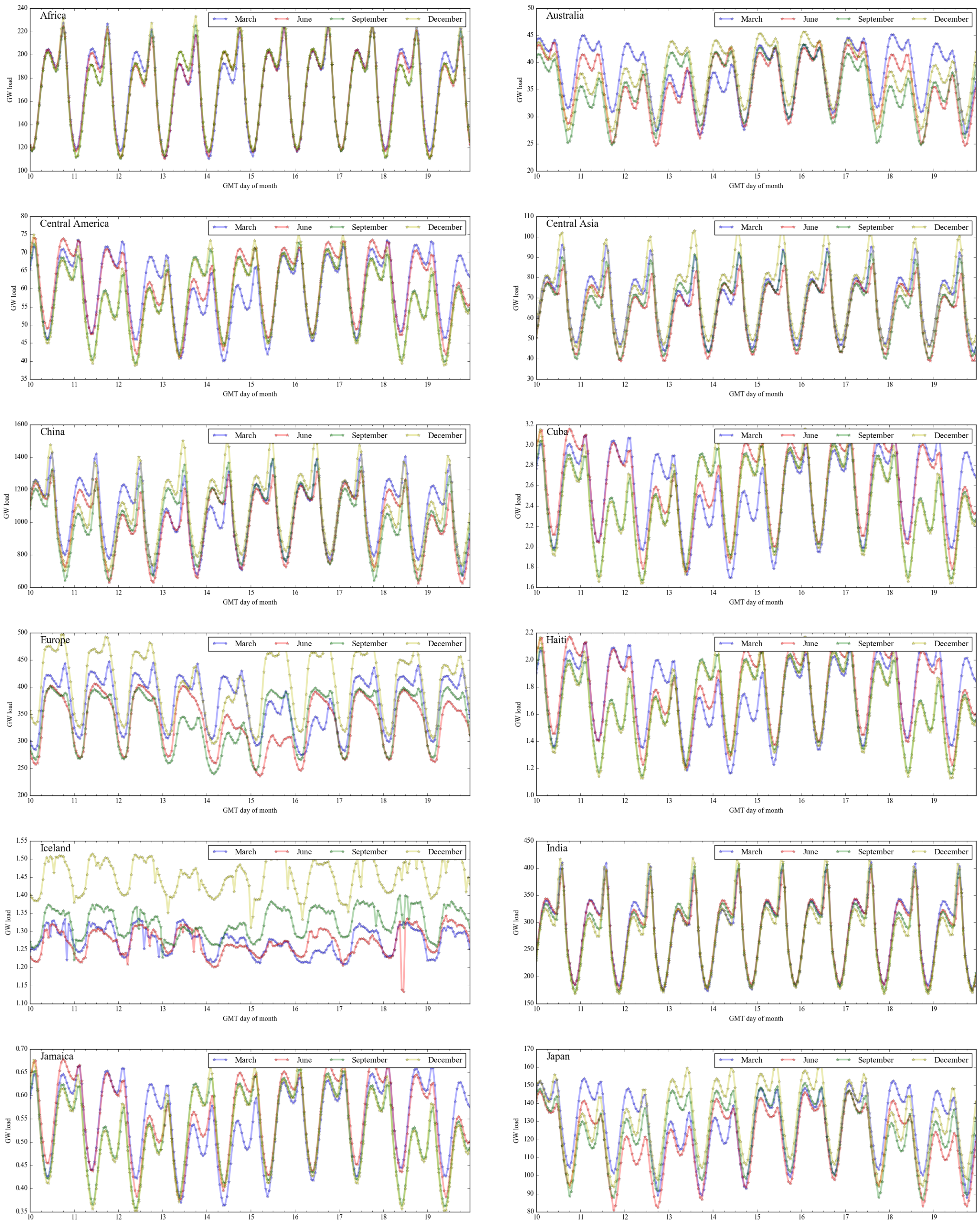

Mexico
Morocco
Nigeria
Poland
Russia
Tanzania-Rwanda-Burundi
United-States-Of-America
Vietnam
March
June
September
December
GW load
GMT day of month

Figure S1b. Hourly inflexible loads for 20 World Regions during 10-day periods in four seasons in 2054. The inflexible loads apply to both Cases A and B but not Case C.



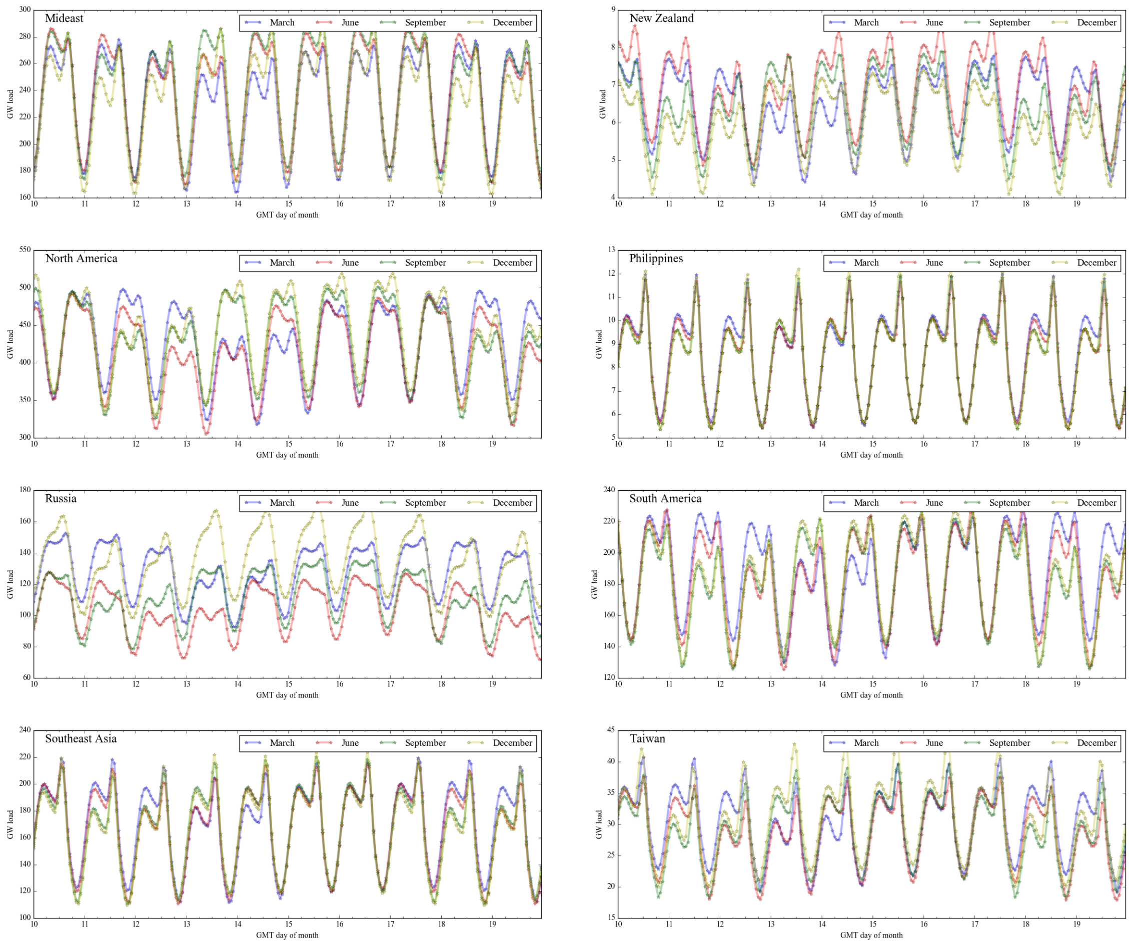
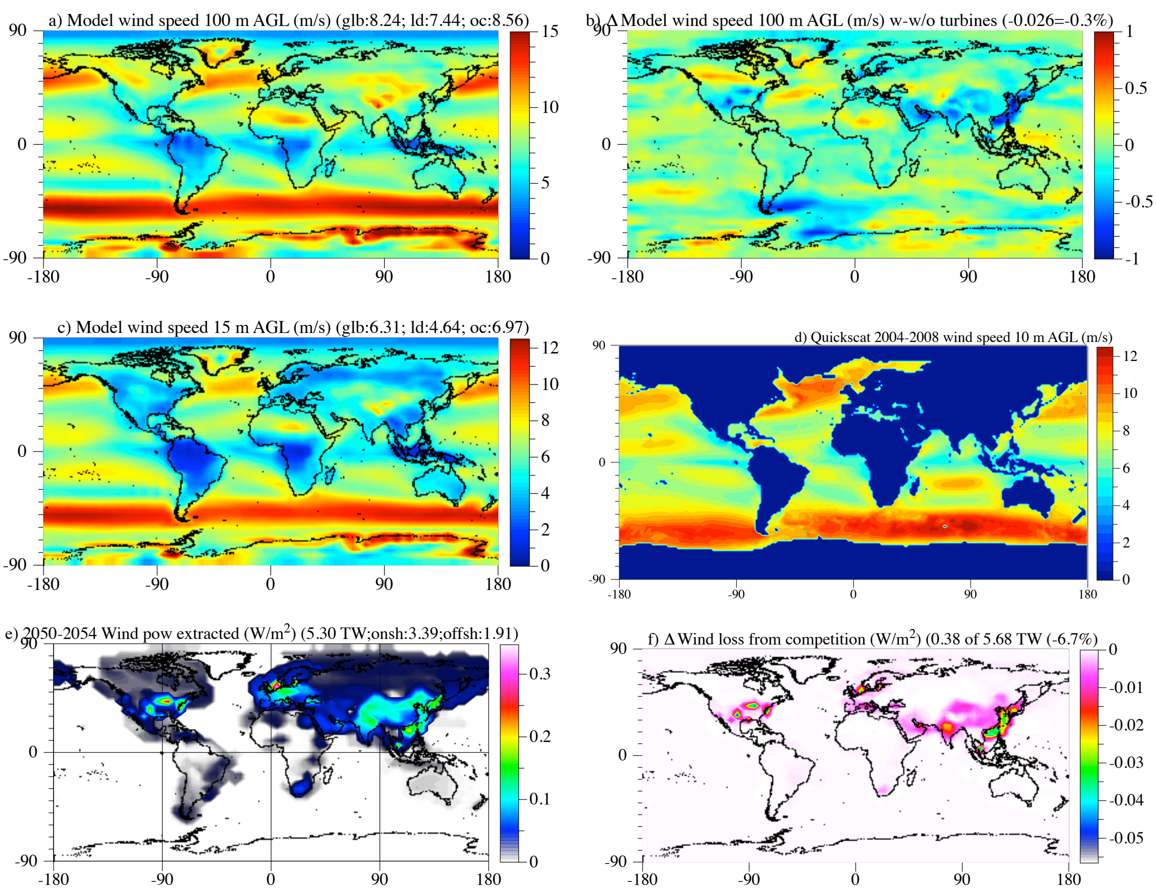

Mideast
New Zealand
North America
Philippines
Russia
South America
Southeast Asia
Taiwan
March
June
September
December
GW load
GMT day of month

Figure S2. (a) Baseline GATOR-GCMOM modeled (at $4^{o}x5^{o}$ horizontal resolution) 100-m above ground level (AGL) wind speeds, averaged over five years (2050-2054), when wind turbines do not extract kinetic energy from the wind. Onshore and offshore wind turbines are placed in each of 139 countries as specified in [2], with a combined nameplate capacity of 13.02 TW. (b) Difference in modeled 100-m wind speed 2050-2054 when wind turbines extract kinetic from the wind minus when they don't. The difference is the wind speed loss due to turbine energy extraction. (c) Modeled 15-m wind speeds averaged over 2050-2054. (d) Quikscat [33] satellite retrievals of wind speeds over the oceans at 10 m above sea level for comparison. (e) Wind power extracted when turbines extract kinetic energy from the wind, thereby reducing wind speed, but before transmission and distribution losses are accounted for. (f) Difference in wind power extracted when turbine extraction of kinetic energy reduces wind speed minus when it does not. This is the loss in wind power extracted due to accounting for competition among wind turbines for available kinetic energy. (g) Change in column water vapor due to wind turbines energy extraction and wind speed reduction. (h) Change in near-surface air temperature due to wind turbine energy extraction and wind speed reduction. (i) Solar PV power generated due to all PV (rooftop plus utility-scale), with a combined nameplate capacity of 29.5 TW [from 2], during the 5-year simulation with wind turbines extracting energy. (j) CSP power generated, with a total nameplate capacity of 3.45 TW [from 2], during the 5-year simulation with wind turbines extracting energy. PV and CSP devices are placed in each of 139 countries as specified in [2].



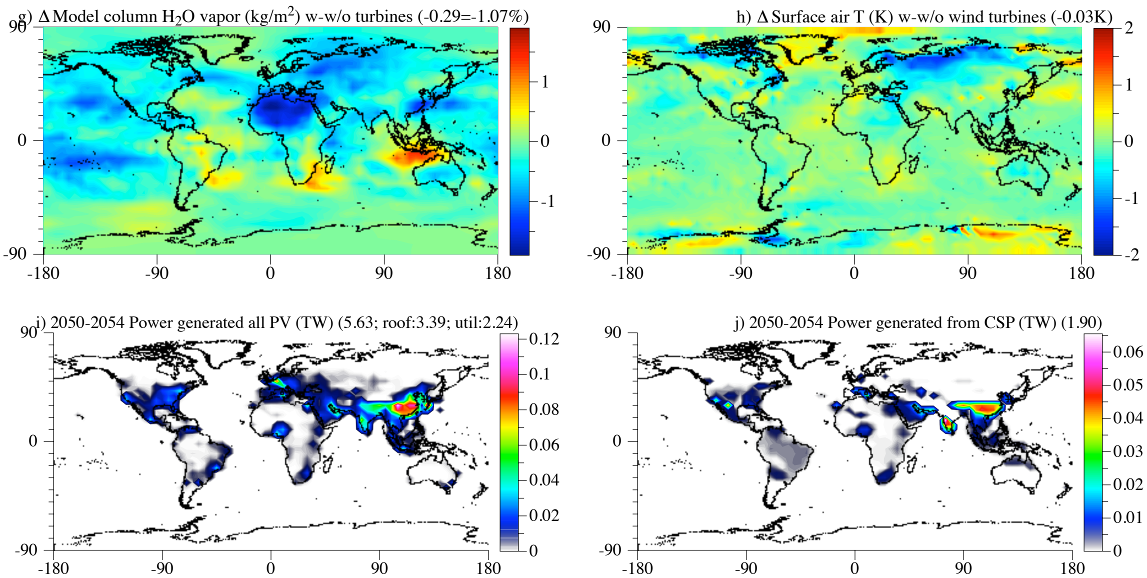
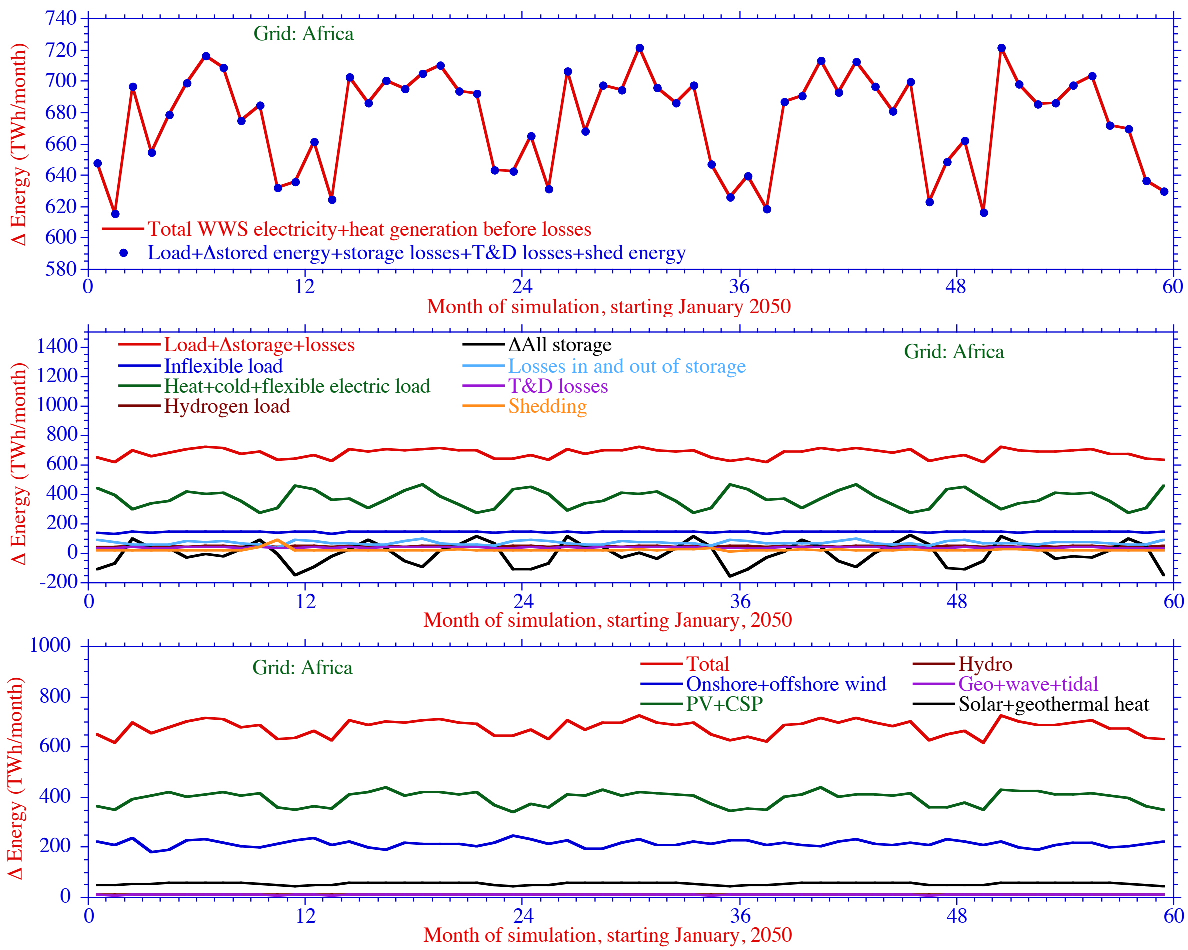
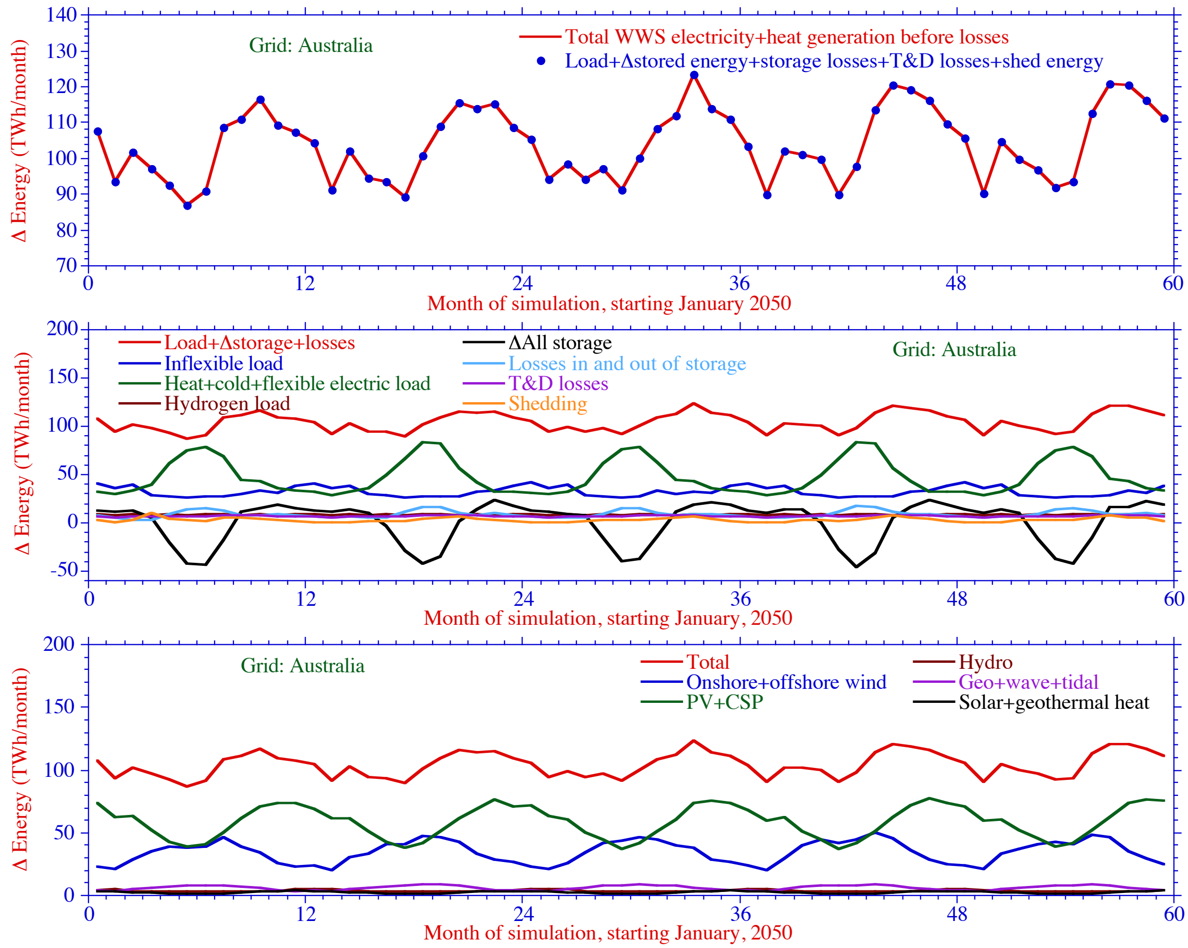

g) Δ Model column H2O vapor (kg/m2) w-w/o turbines (-0.29=-1.07%)
h) Δ Surface air T (K) w-w/o wind turbines (-0.03K)
i) 2050-2054 Power generated all PV (TW) (5.63; roof:3.39; util:2.24)
j) 2050-2054 Power generated from CSP (TW) (1.90)
90
0
-90
-180
-90
0
90
180
1
0
-1
2
1
0
-1
-2
0.12
0.1
0.08
0.06
0.04
0.02
0
0.06
0.05
0.04
0.03
0.02
0.01
0

Figure S3. Five-year (60-month) time-series comparison, for Case A (no increase in hydropower peak discharge rate) and for each of the 20 world regions examined, of modeled (a) monthly-averaged total WWS power generation with load plus losses plus changes in storage plus shedding, (b) breakdown of load plus losses plus changes in storage plus shedding into individual components, and (c) breakdown of WWS power generation by generation technology.

Africa

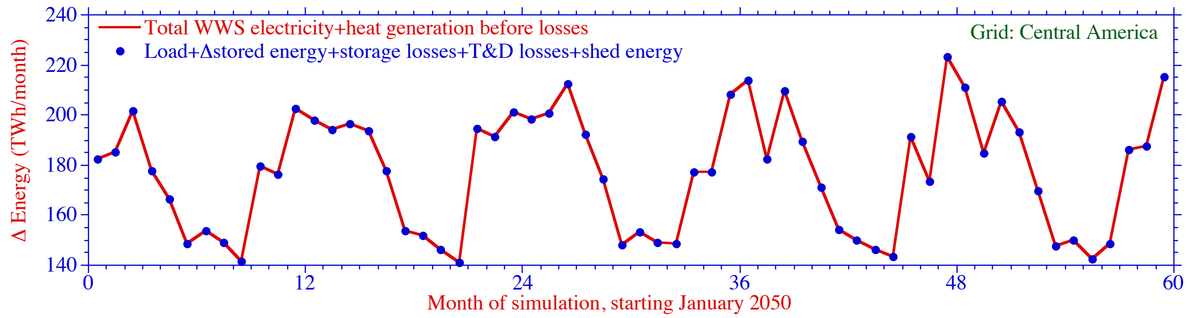


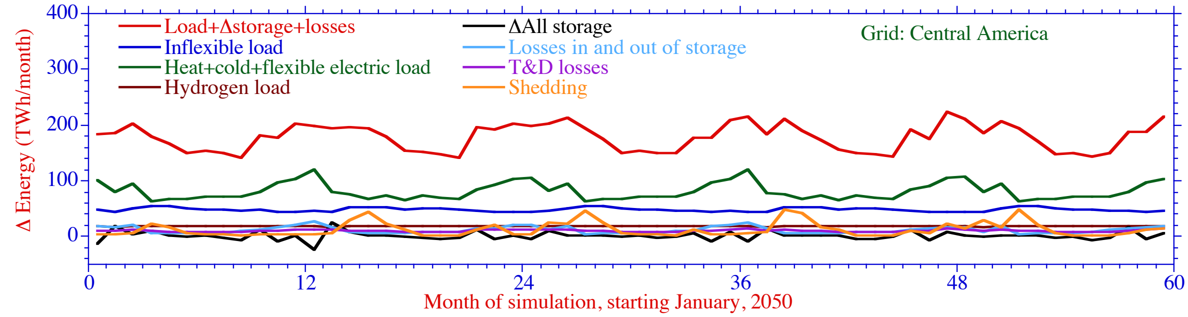
Australia

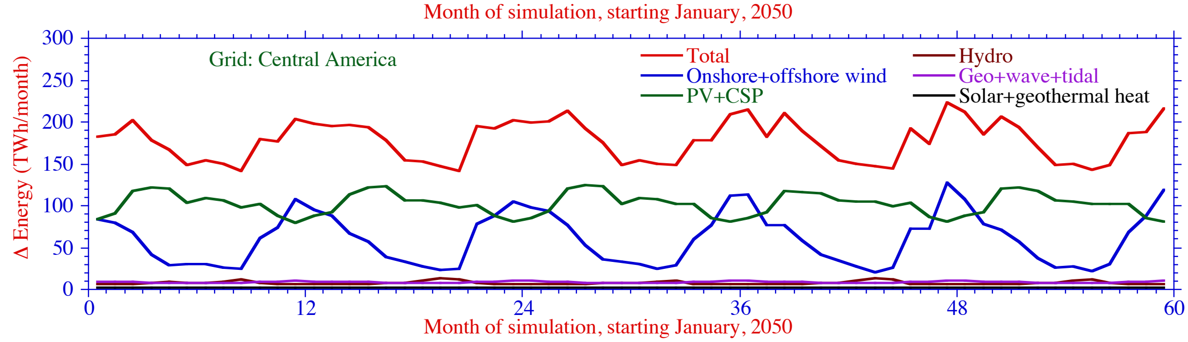


Grid: Australia
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Australia
Δ Energy (TWh/month)
Month of simulation, starting January, 2050
Grid: Australia
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

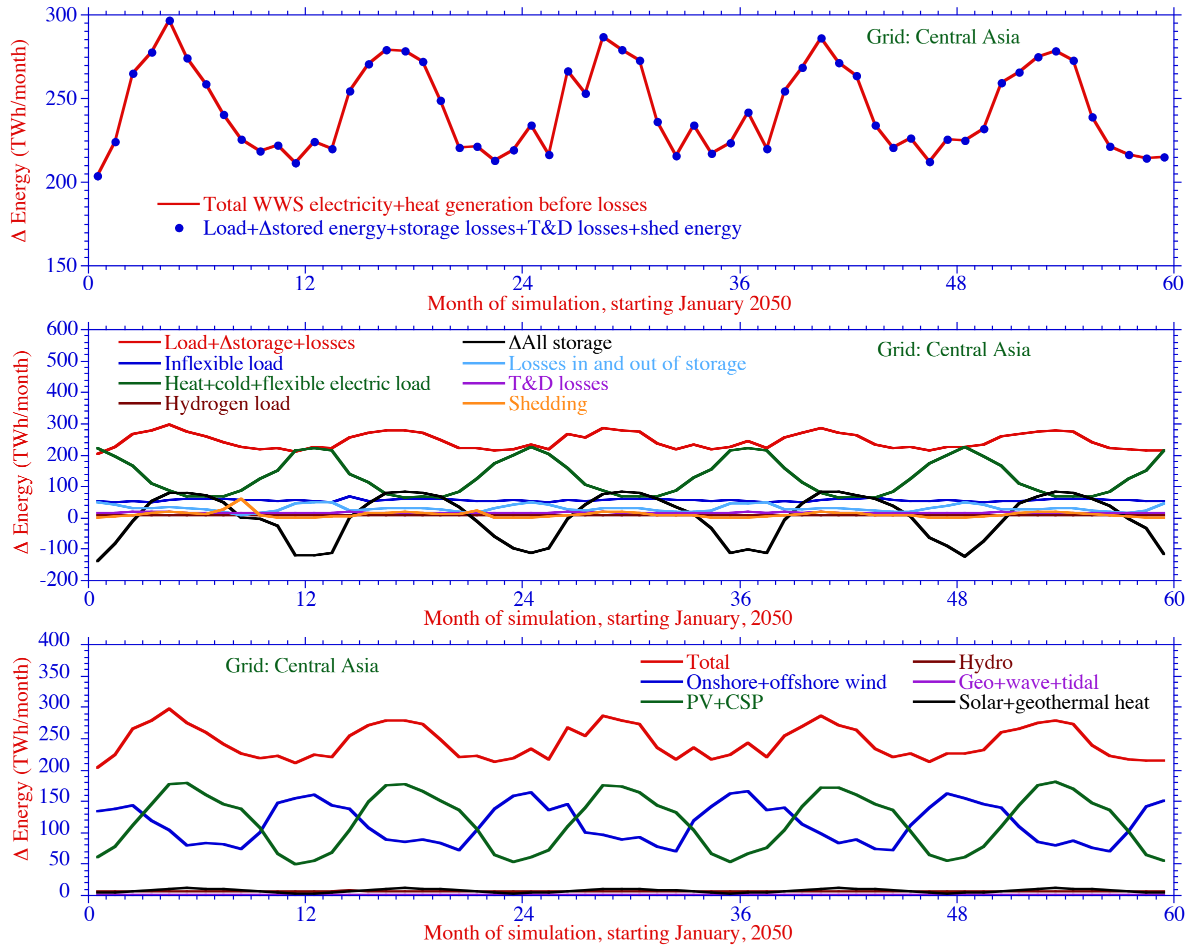
Central America



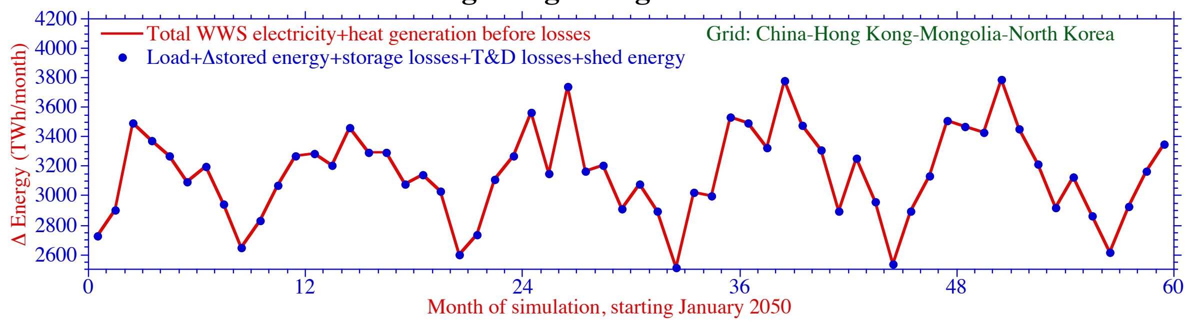


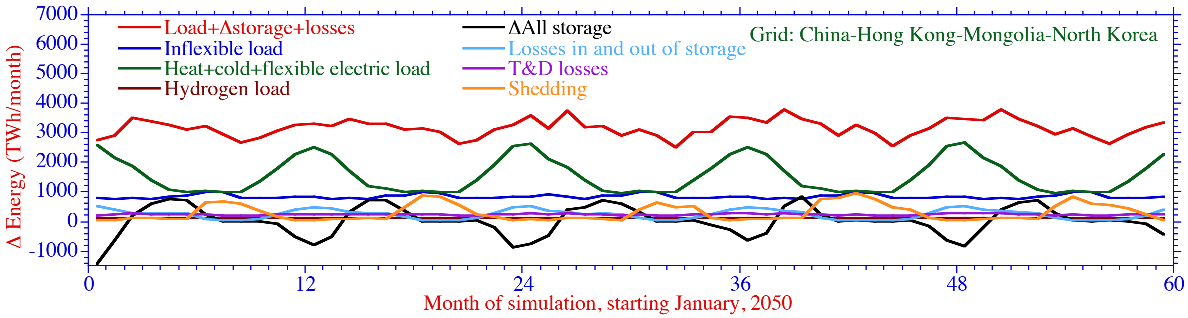


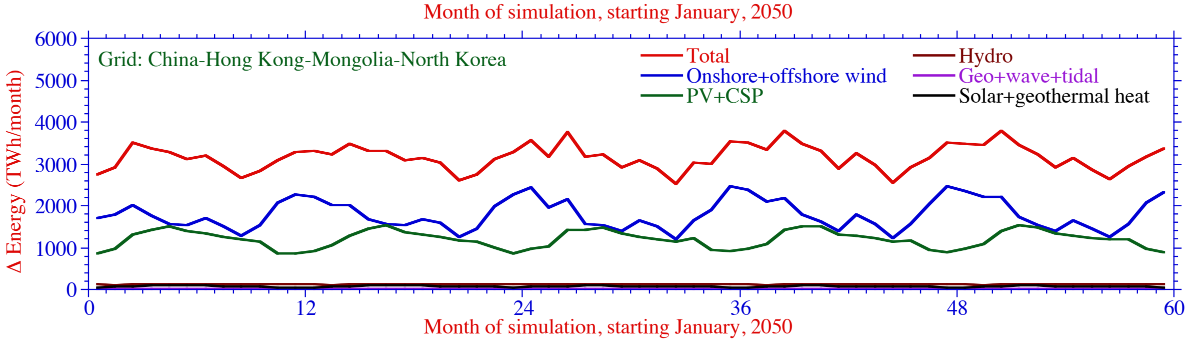
Central Asia



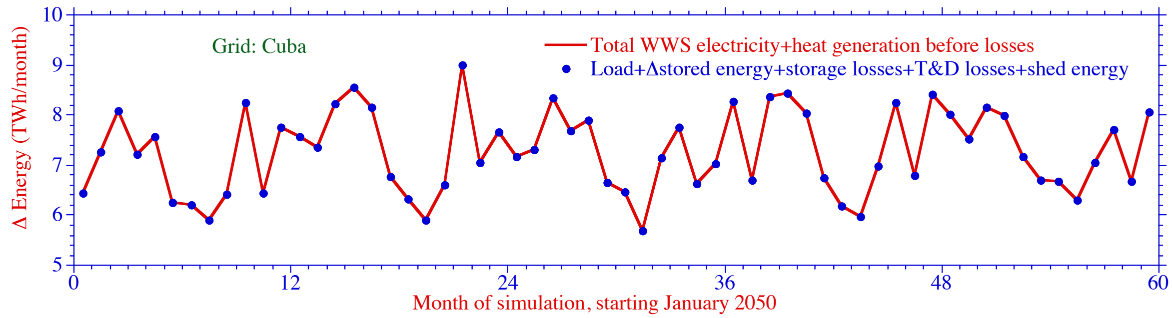
China-Hong Kong-Mongolia-North Korea

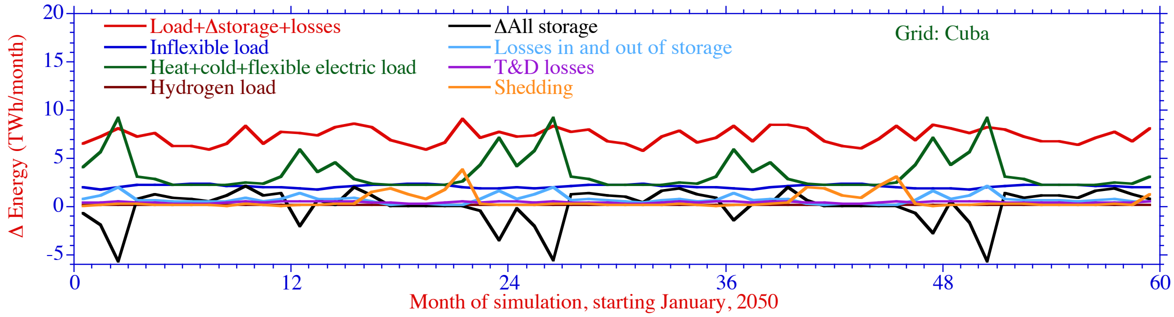


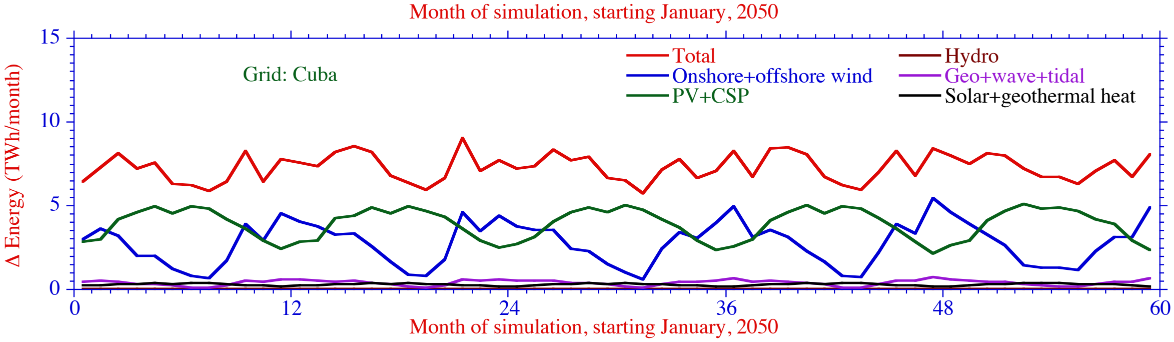




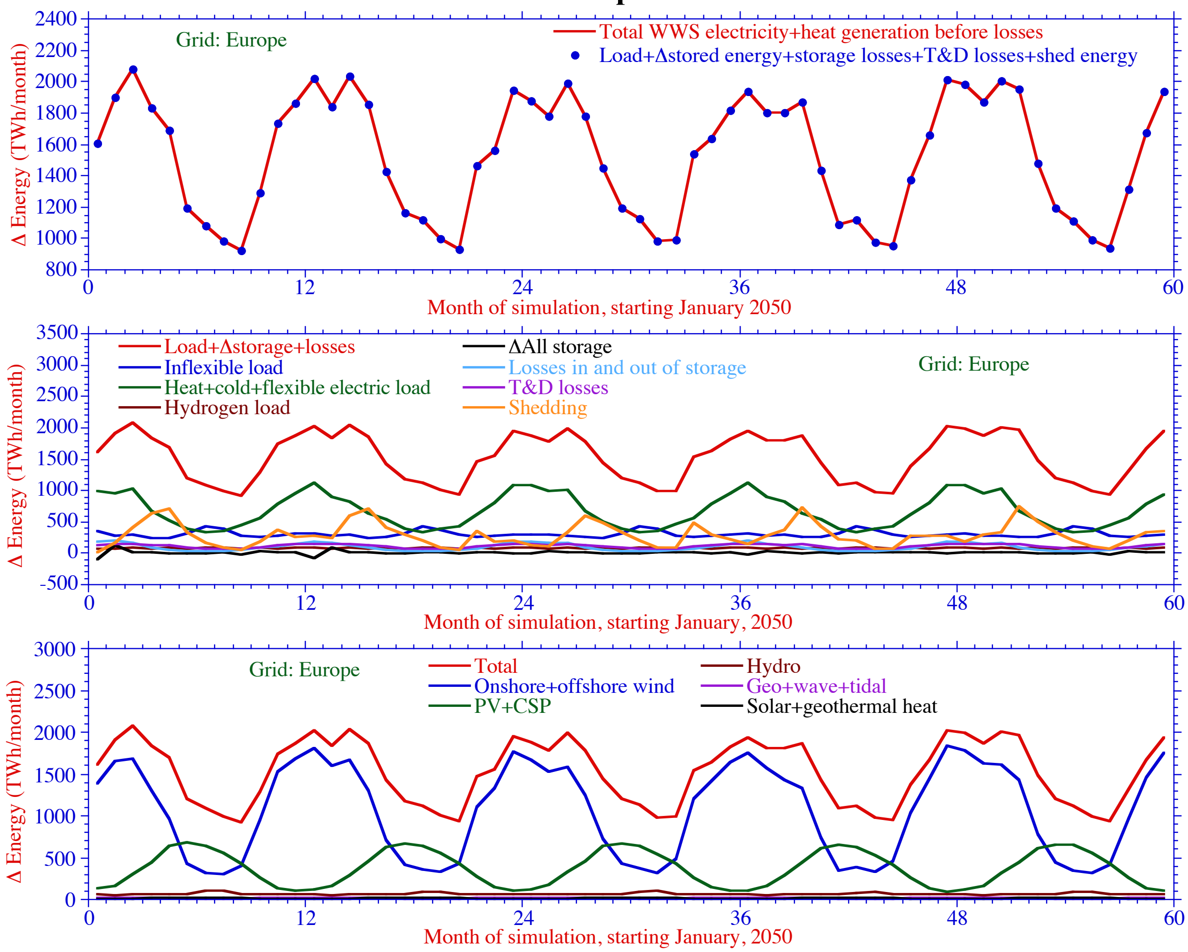
Cuba


Grid: Cuba
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050

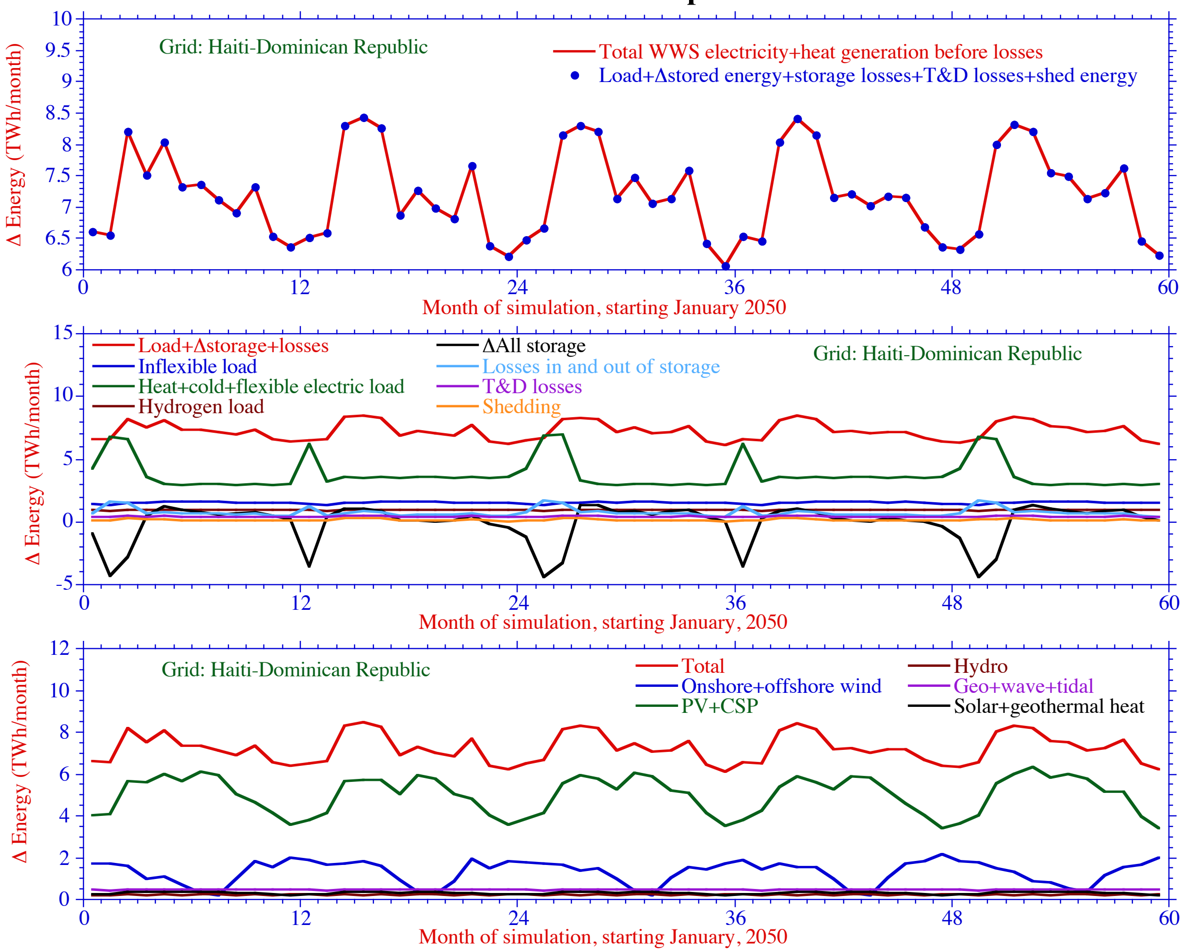

Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Cuba
Δ Energy (TWh/month)
Month of simulation, starting January, 2050


Grid: Cuba
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

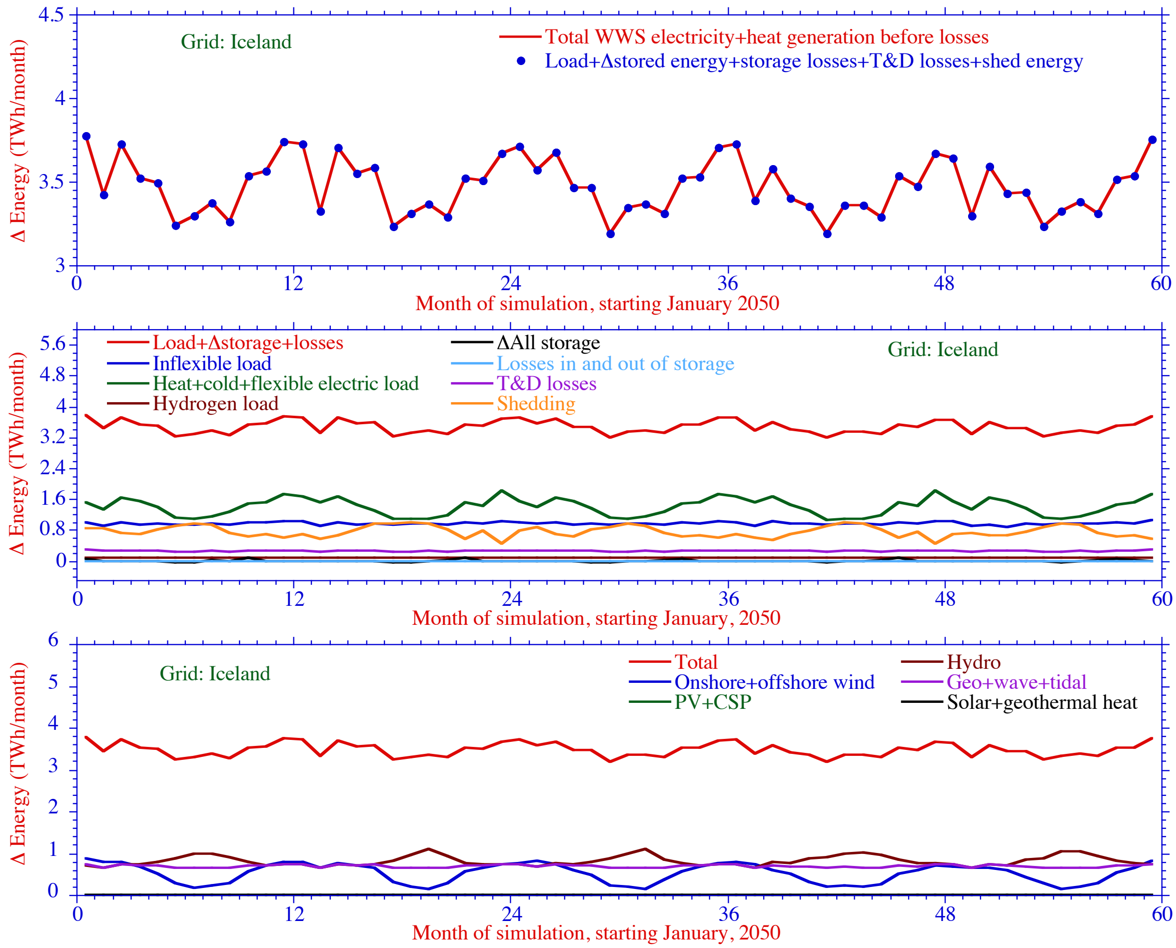
Europe


Grid: Europe
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Month of simulation, starting January, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat

Haiti-Dominican Republic

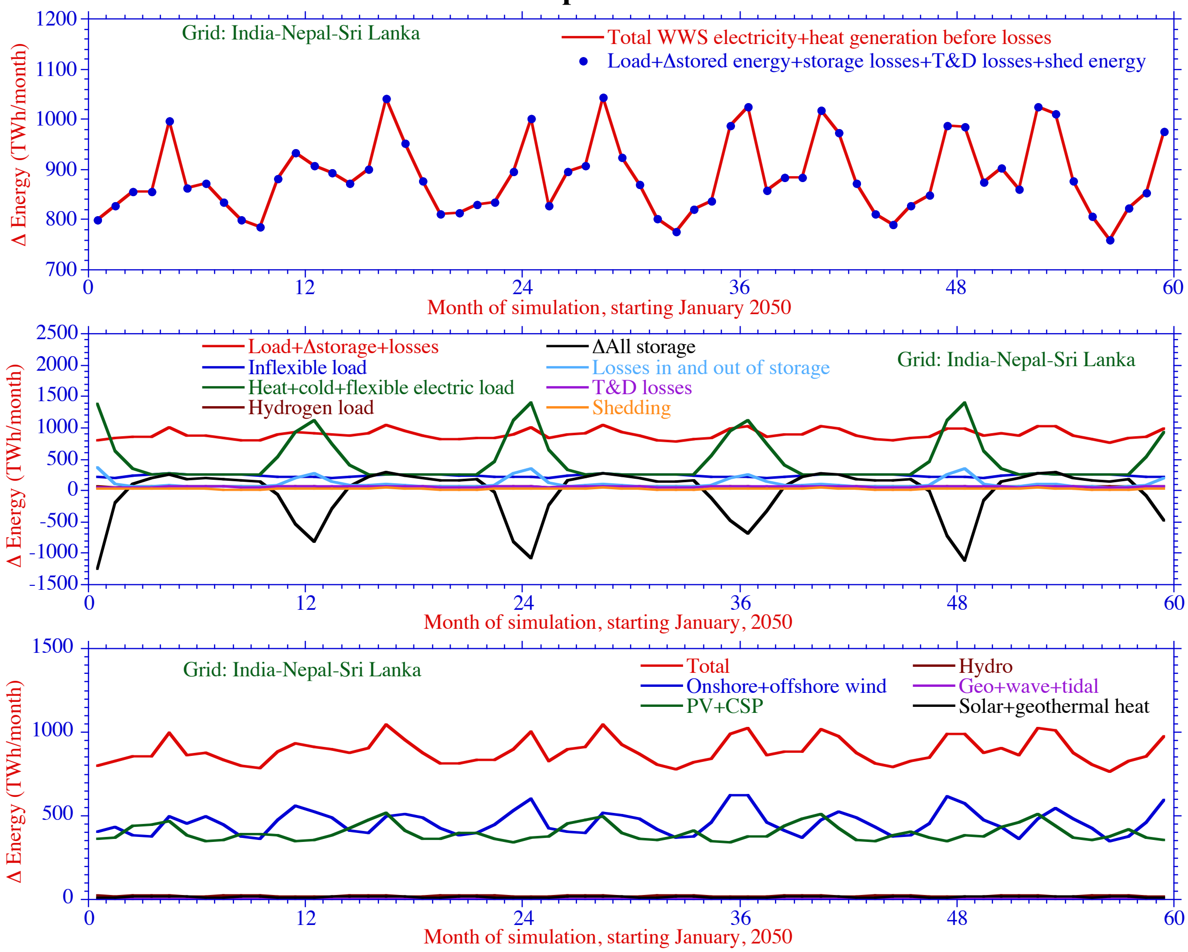


Iceland

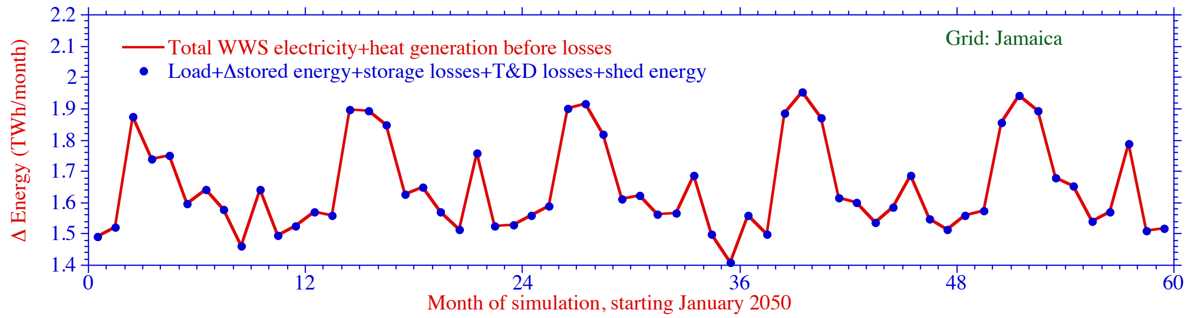


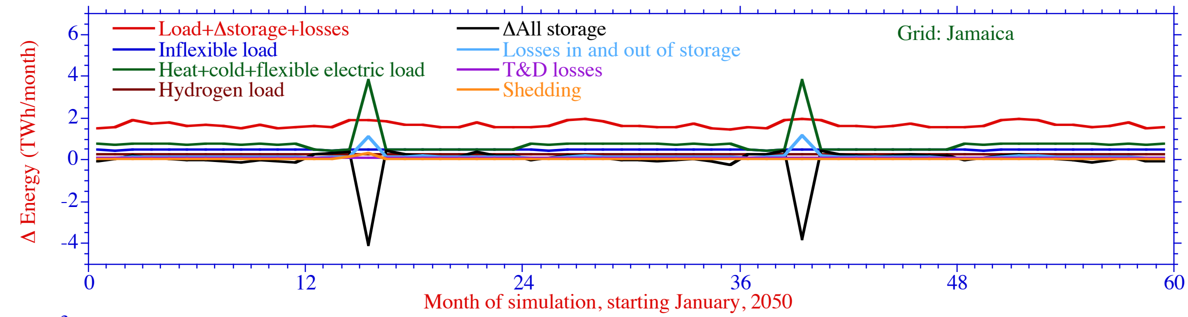
Grid: Iceland
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Iceland
Δ Energy (TWh/month)
Month of simulation, starting January, 2050
Grid: Iceland
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

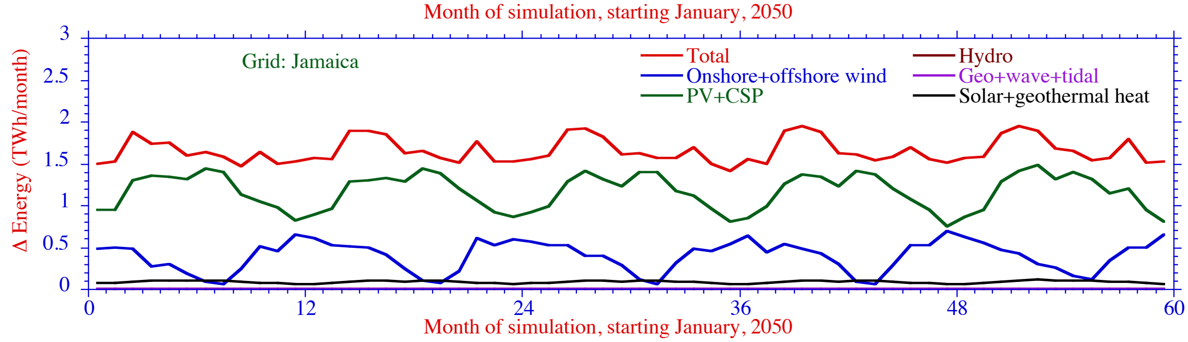
India-Nepal-Sri Lanka



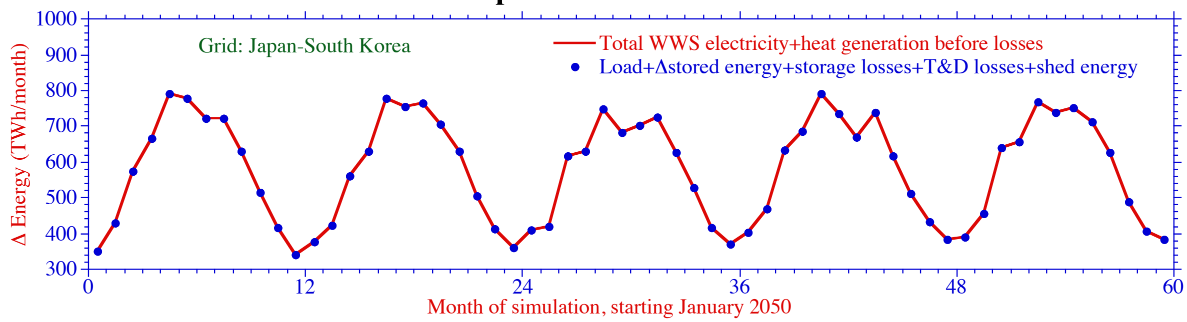
Jamaica

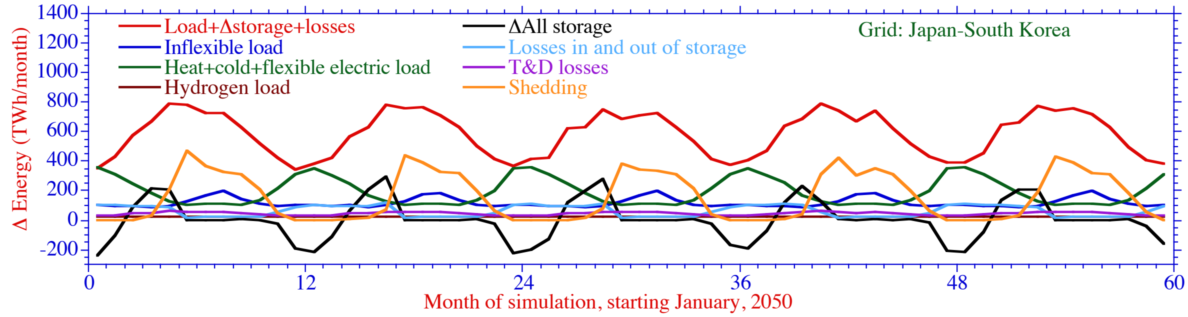

Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Jamaica
Δ Energy (TWh/month)
Month of simulation, starting January 2050

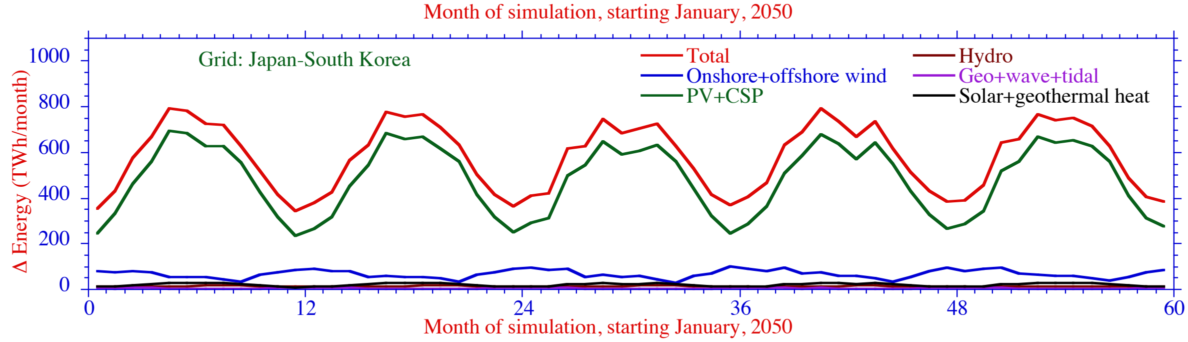

Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Jamaica
Δ Energy (TWh/month)
Month of simulation, starting January, 2050


Grid: Jamaica
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

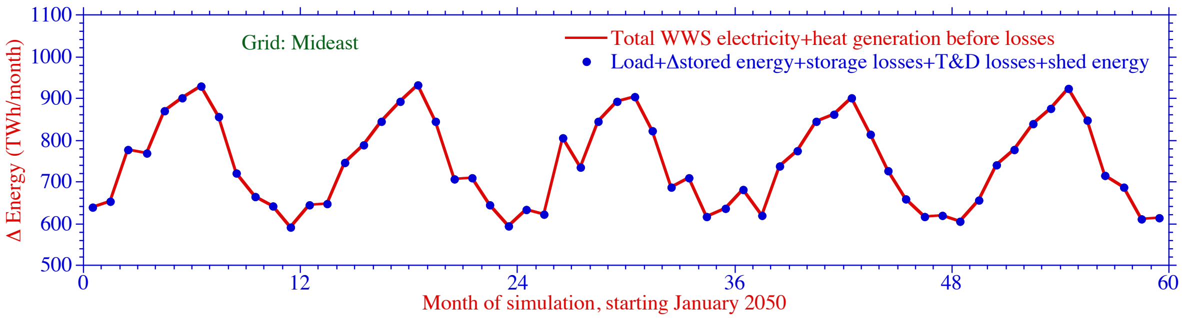
Japan-South Korea

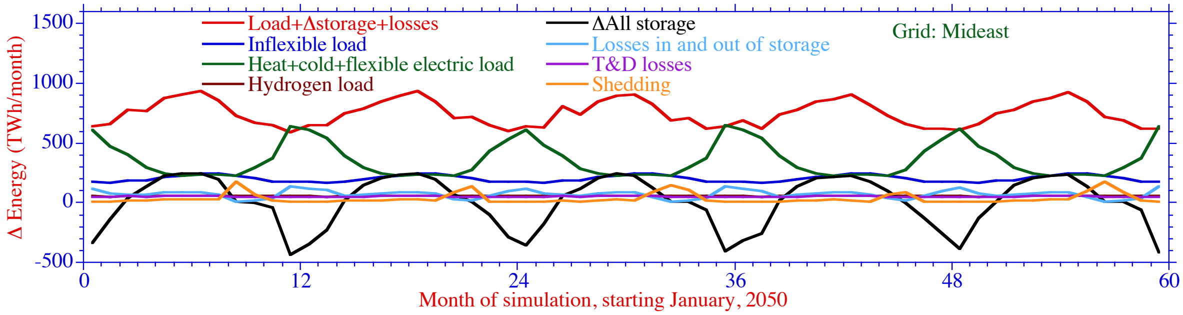


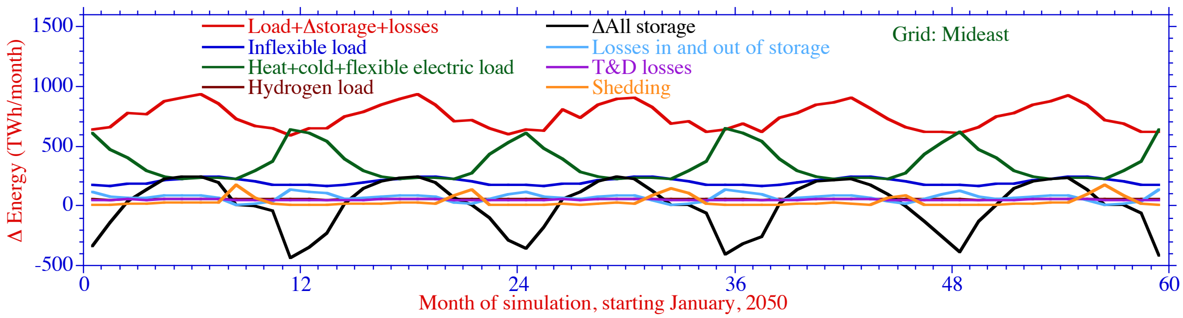




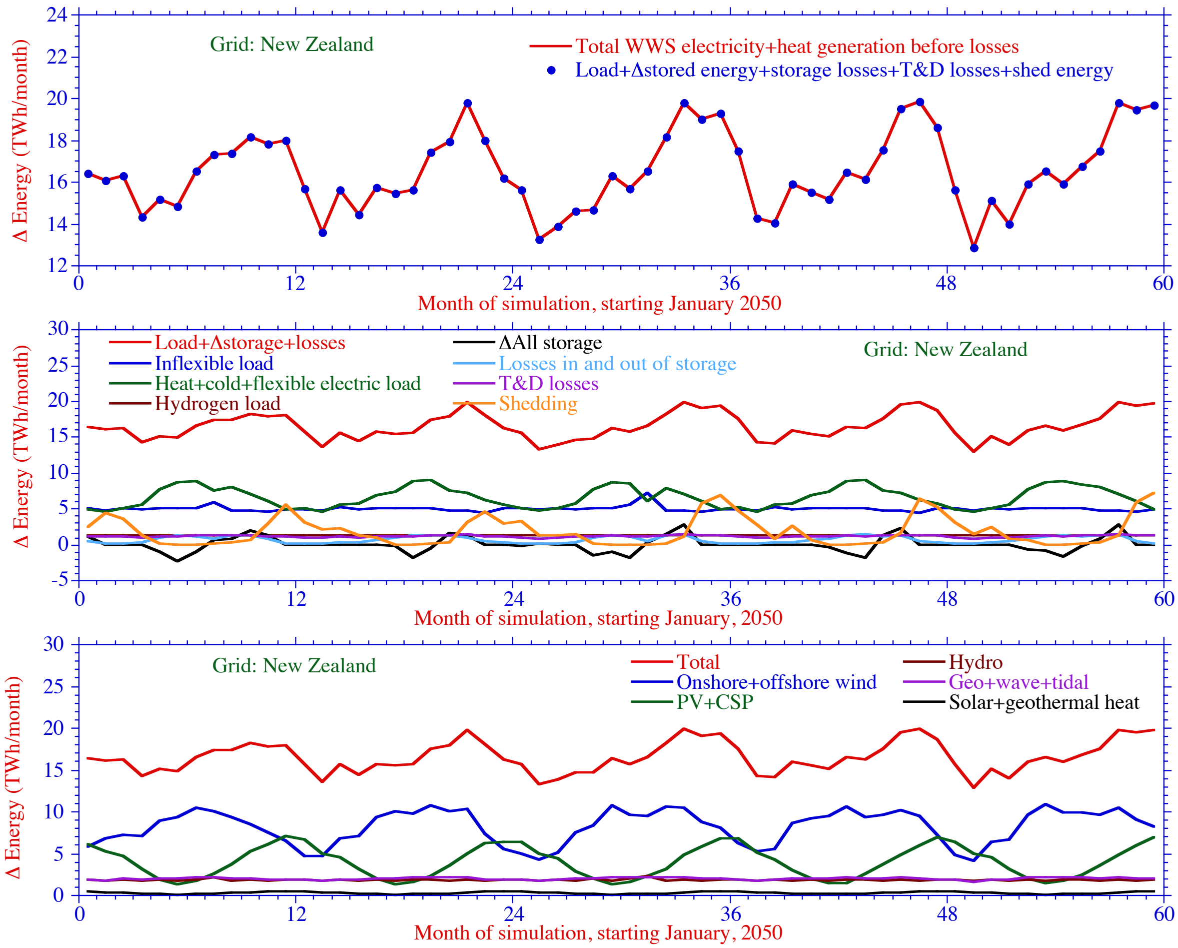
Mideast


Grid: Mideast
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050


Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Mideast
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

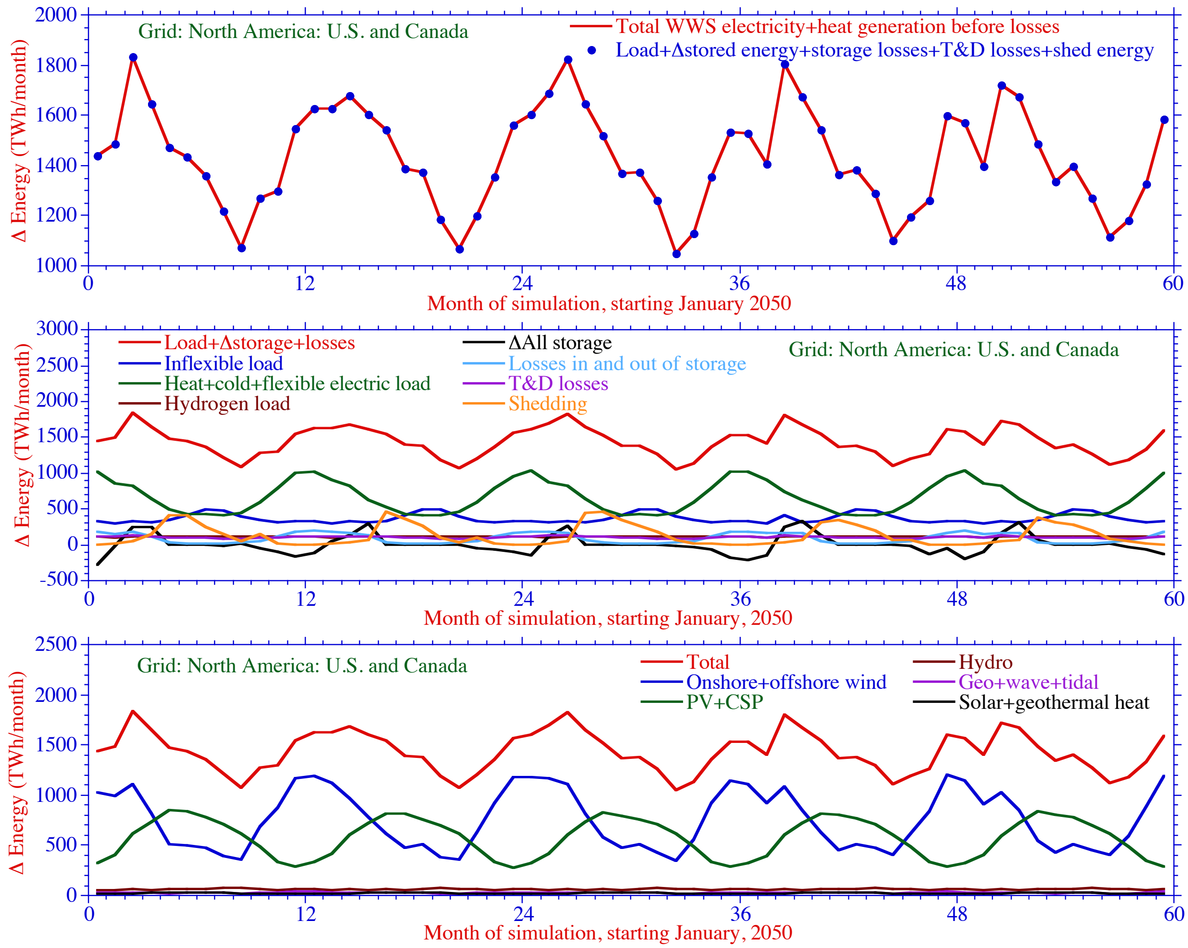

Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Mideast
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

New Zealand

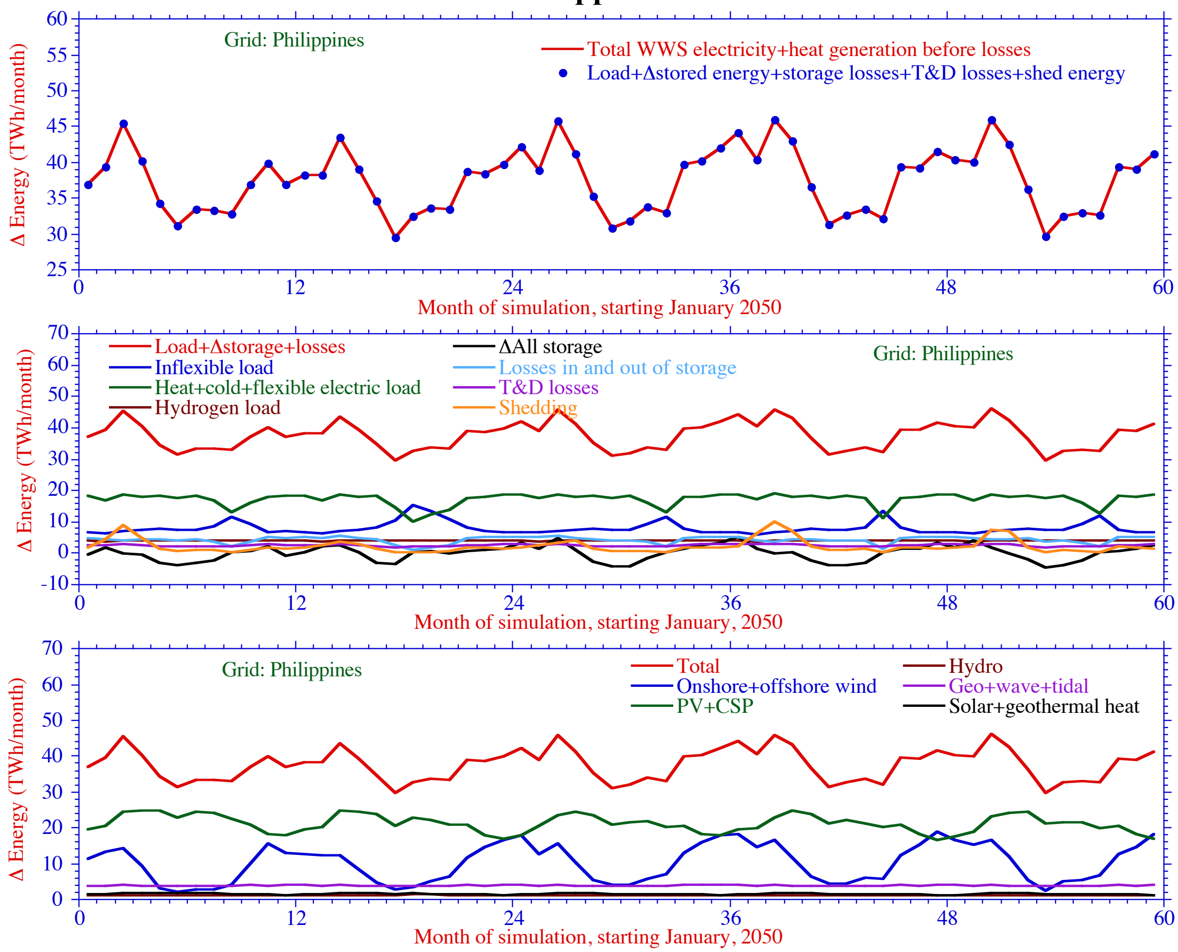


Grid: New Zealand
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: New Zealand
Δ Energy (TWh/month)
Month of simulation, starting January, 2050
Grid: New Zealand
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

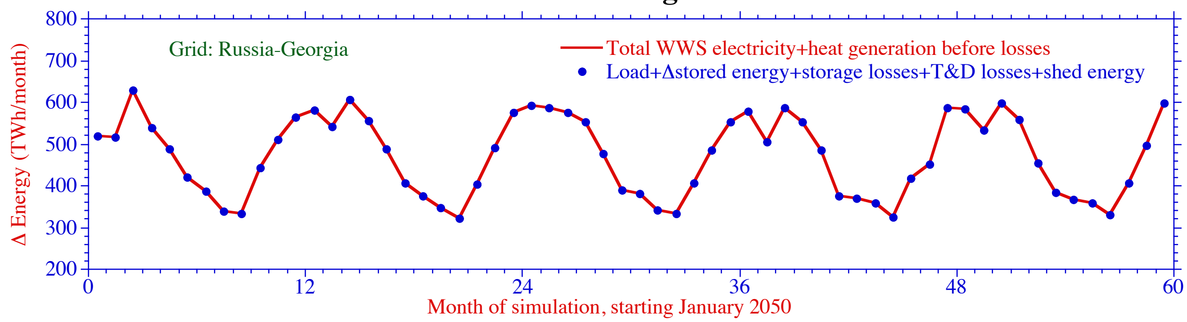
North America

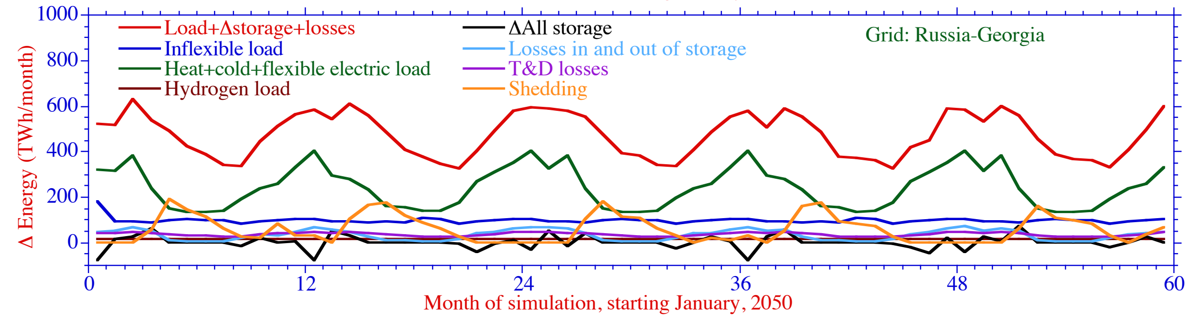


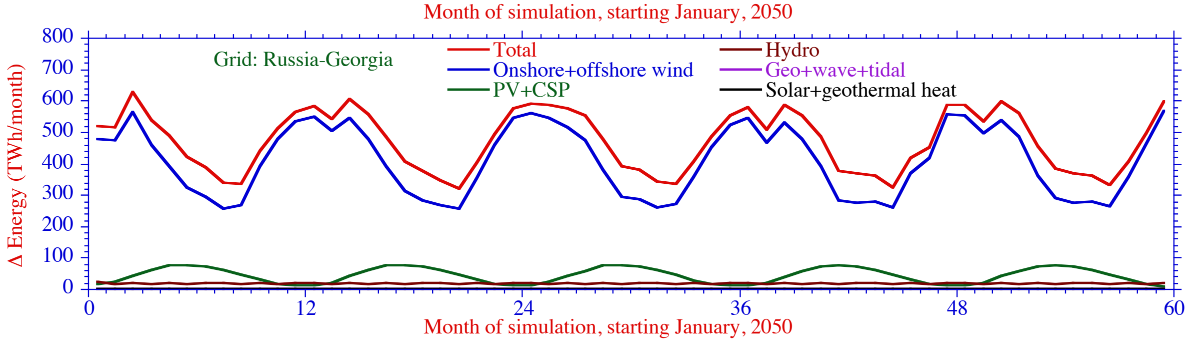
Philippines



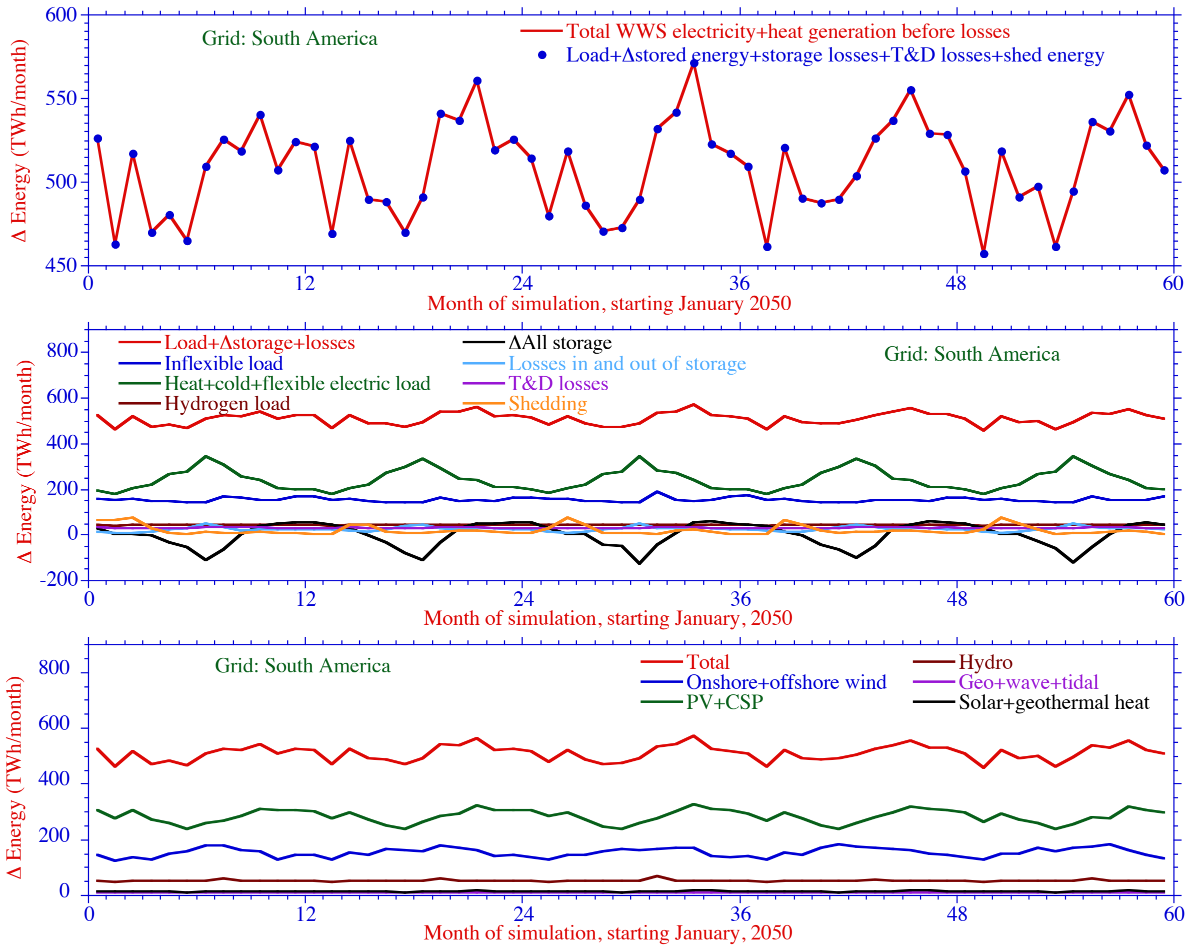
Russia-Georgia



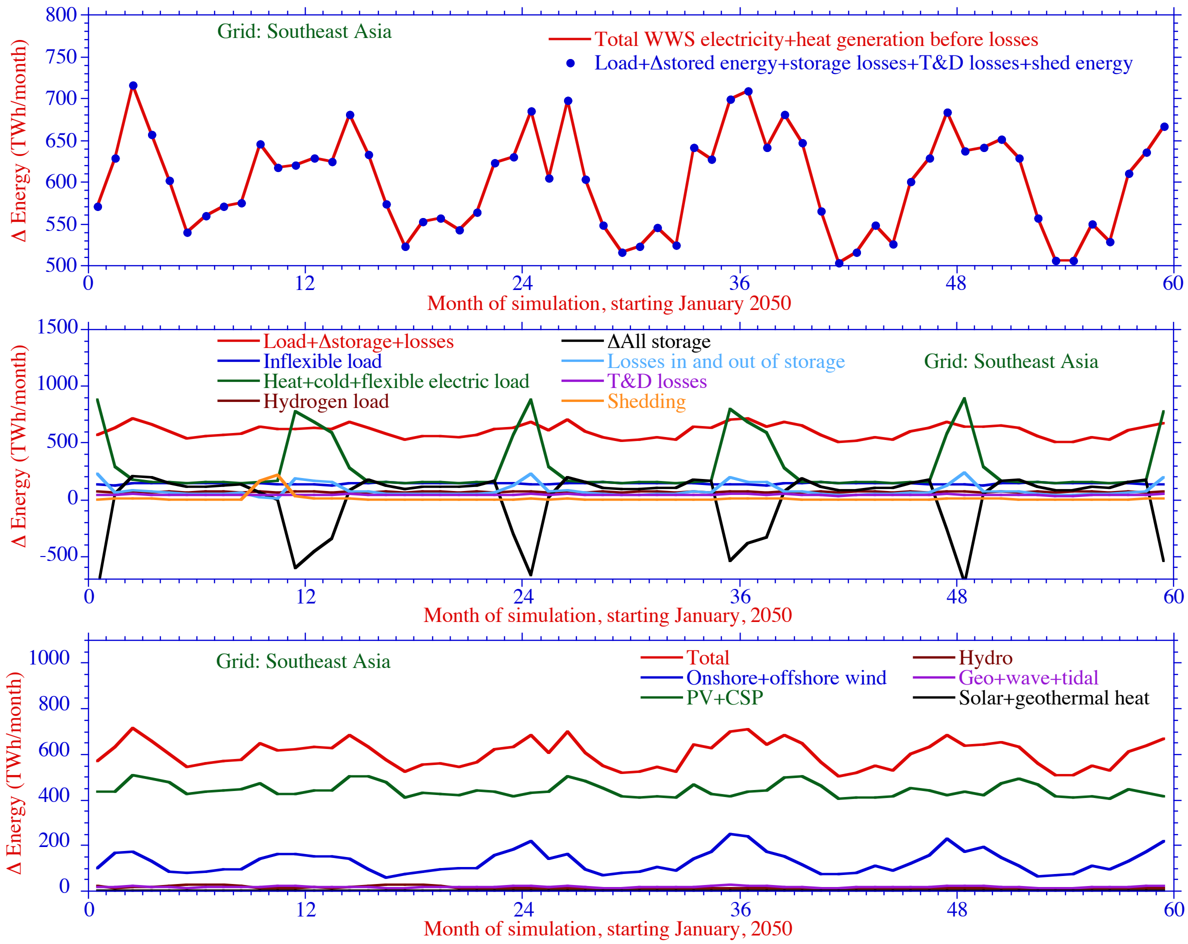




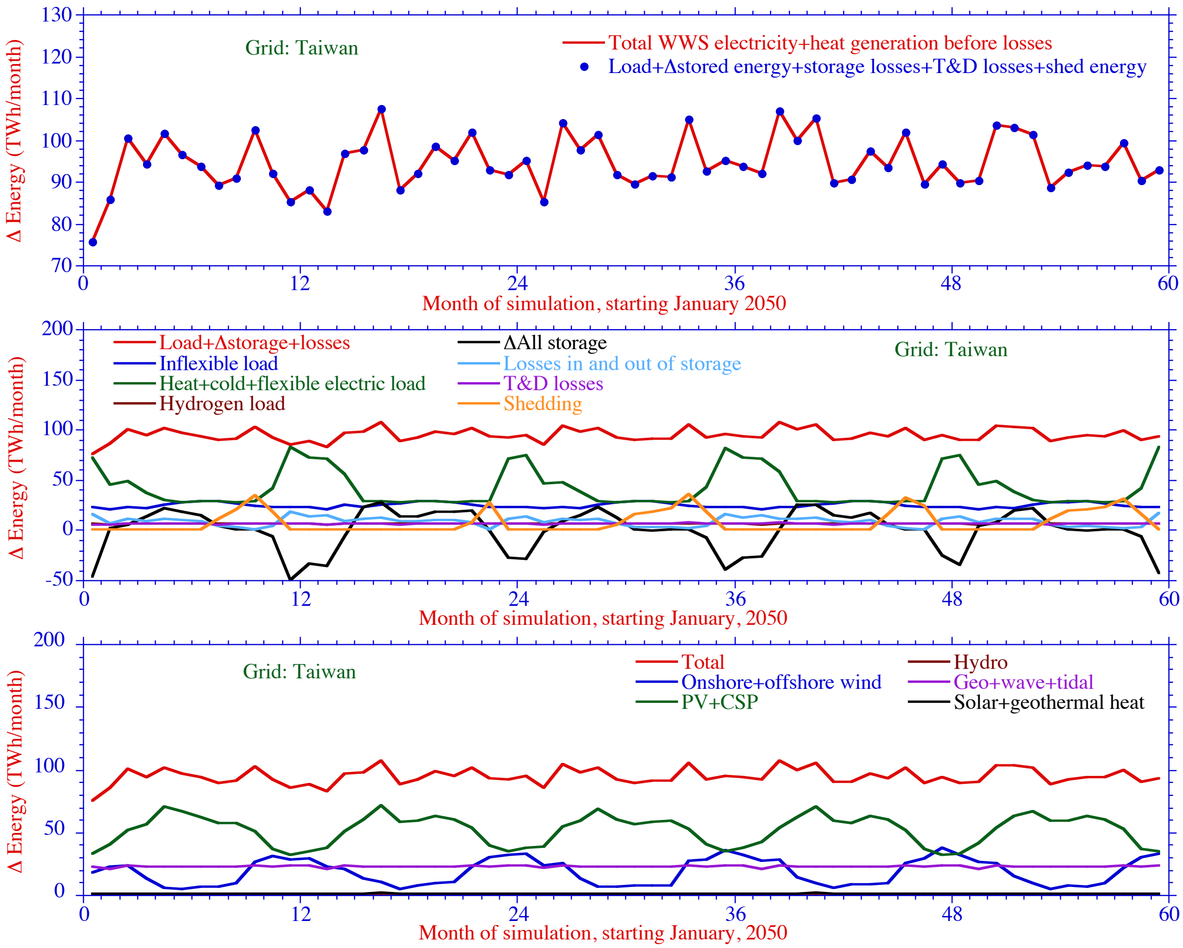
South America



Southeast Asia



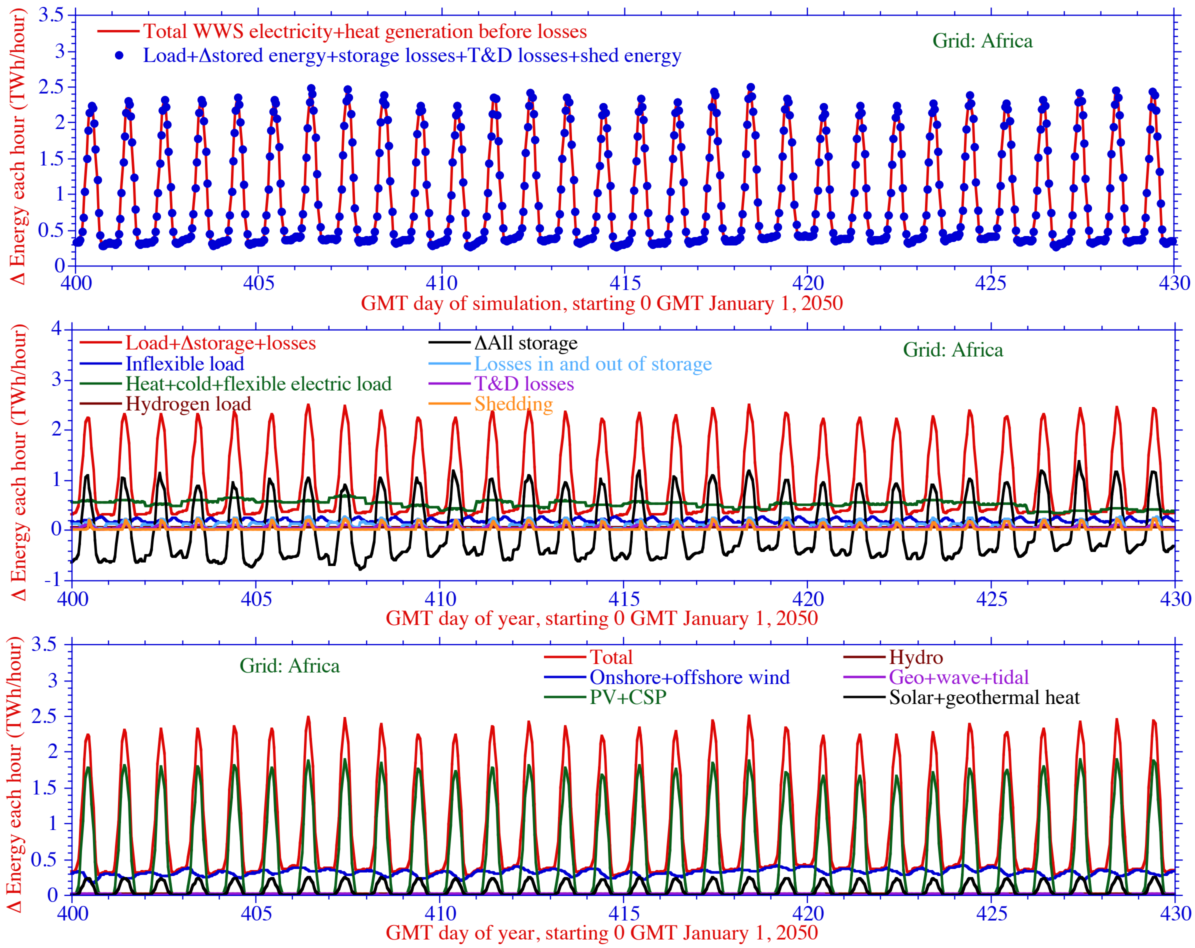
Taiwan



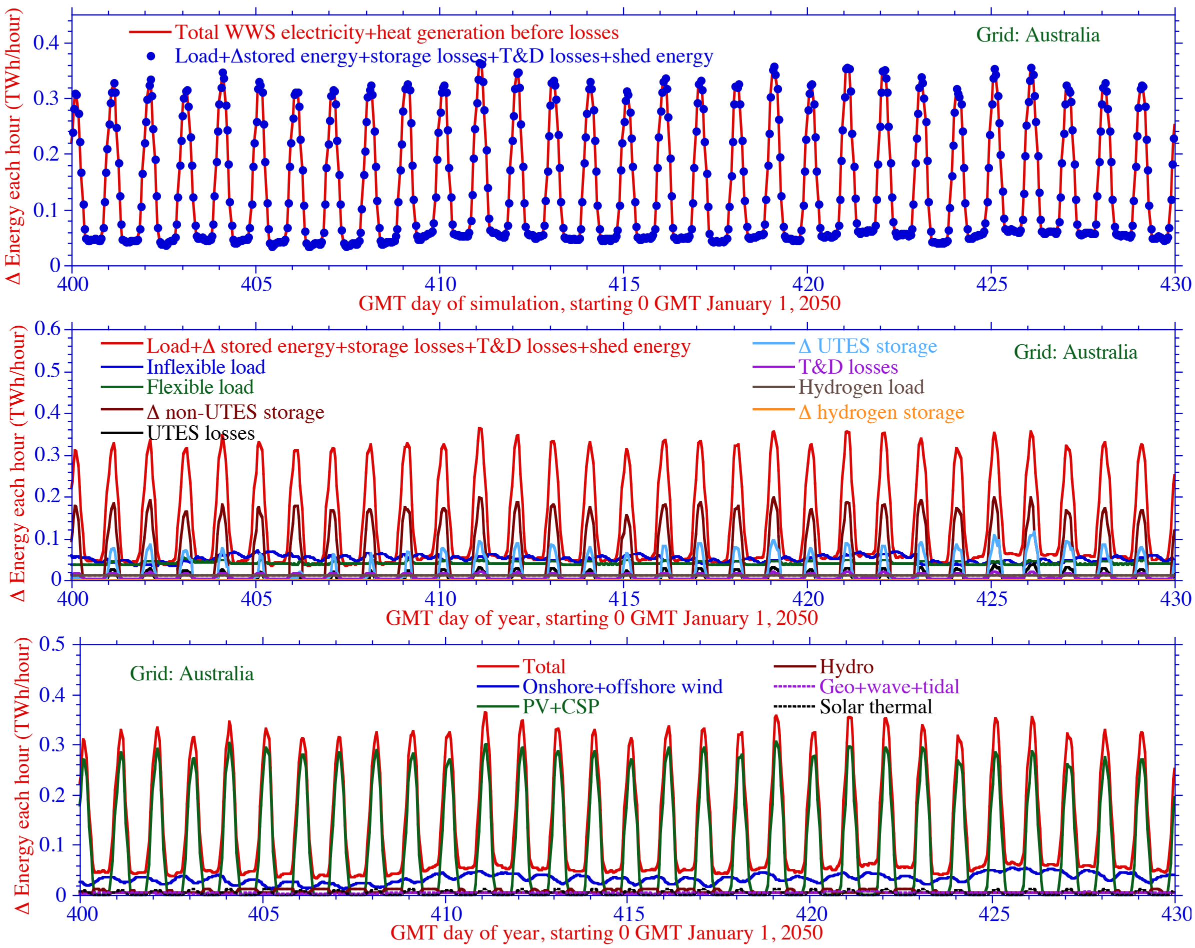
Grid: Taiwan
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Taiwan
Month of simulation, starting January, 2050
Grid: Taiwan
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Month of simulation, starting January, 2050

Figure S4. Same as Figure S3, which shows results for Case A, but with hourly results for a 30-day period during the 5-year simulation for each world region.

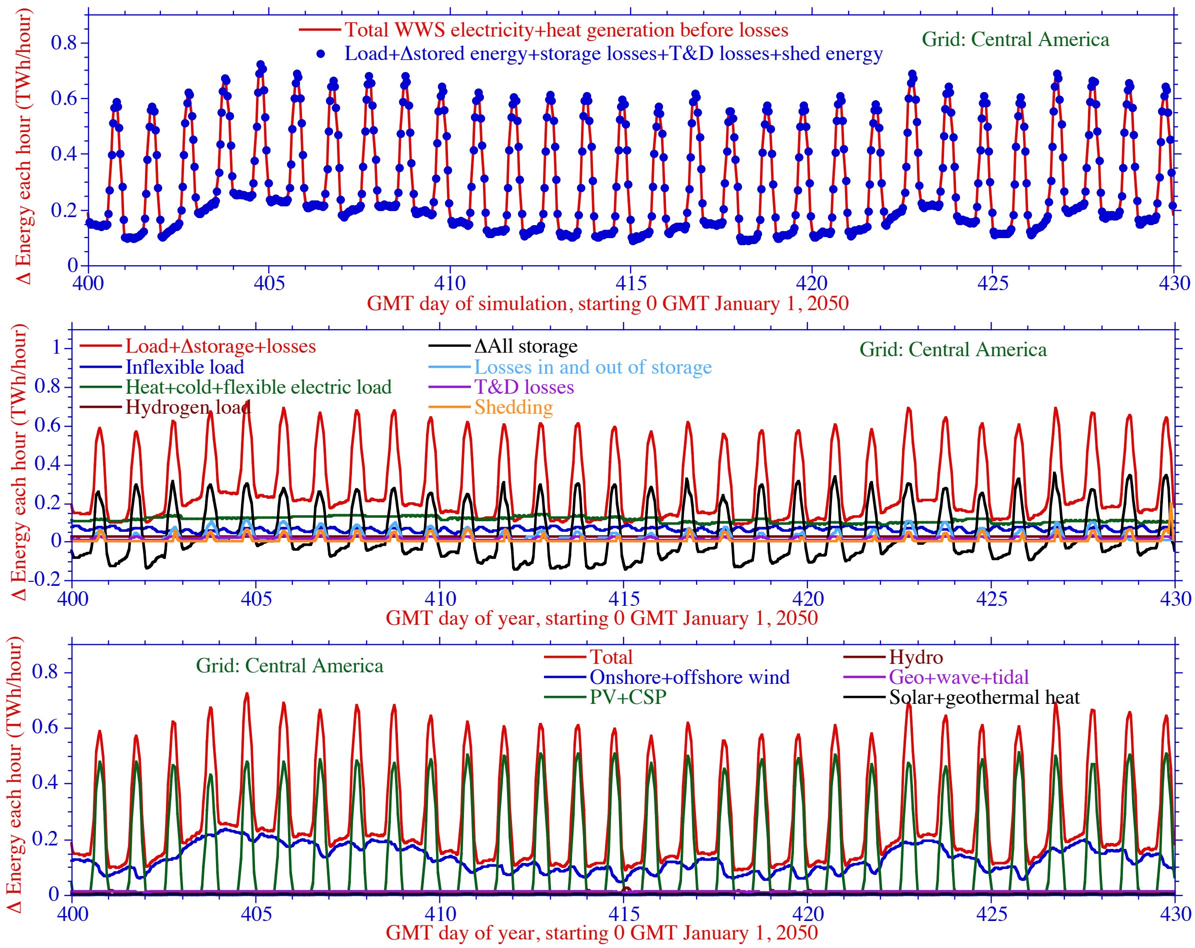
Africa



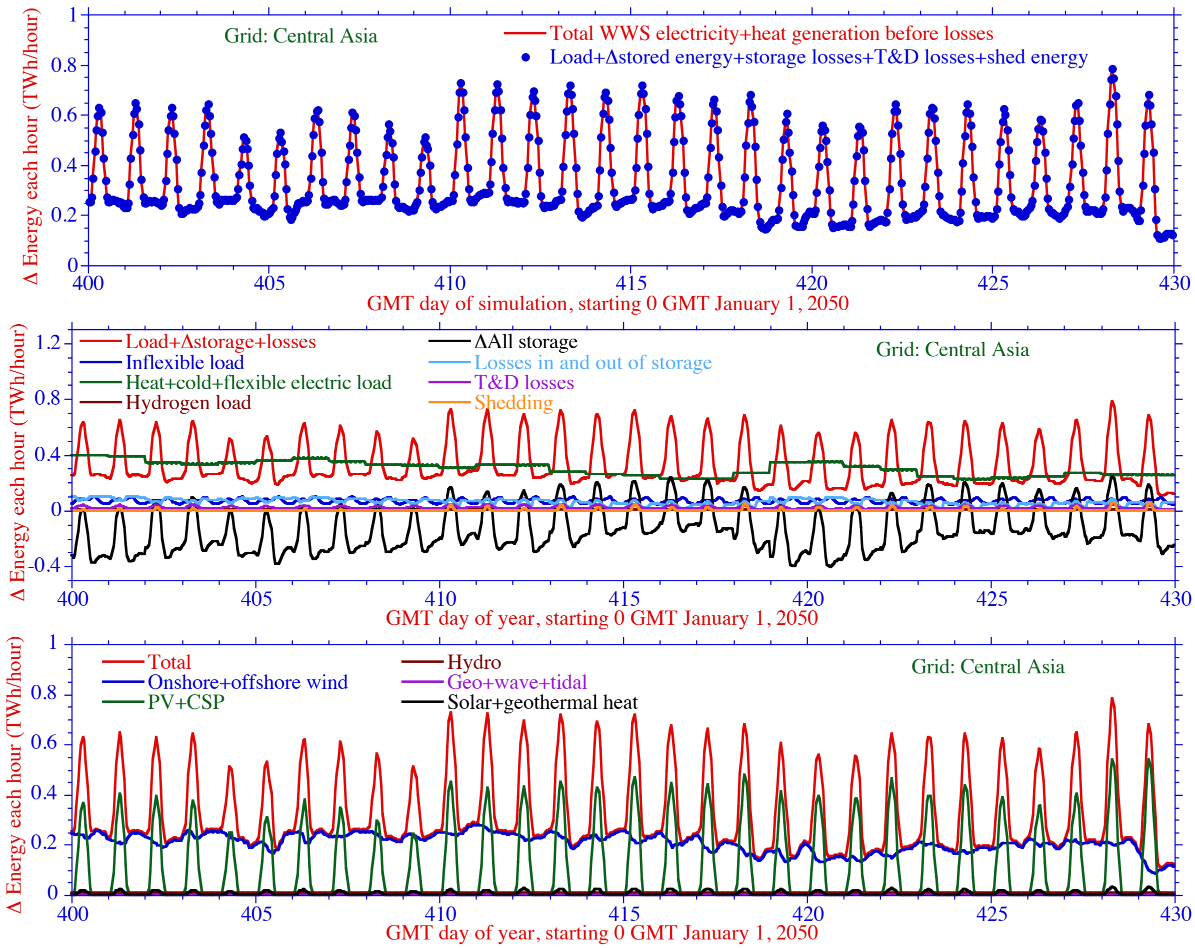
Australia


Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Australia
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δ stored energy+storage losses+T&D losses+shed energy
Inflexible load
Flexible load
Δ non-UTES storage
UTES losses
Δ UTES storage
T&D losses
Hydrogen load
Δ hydrogen storage
Grid: Australia
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050
Grid: Australia
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar thermal
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050

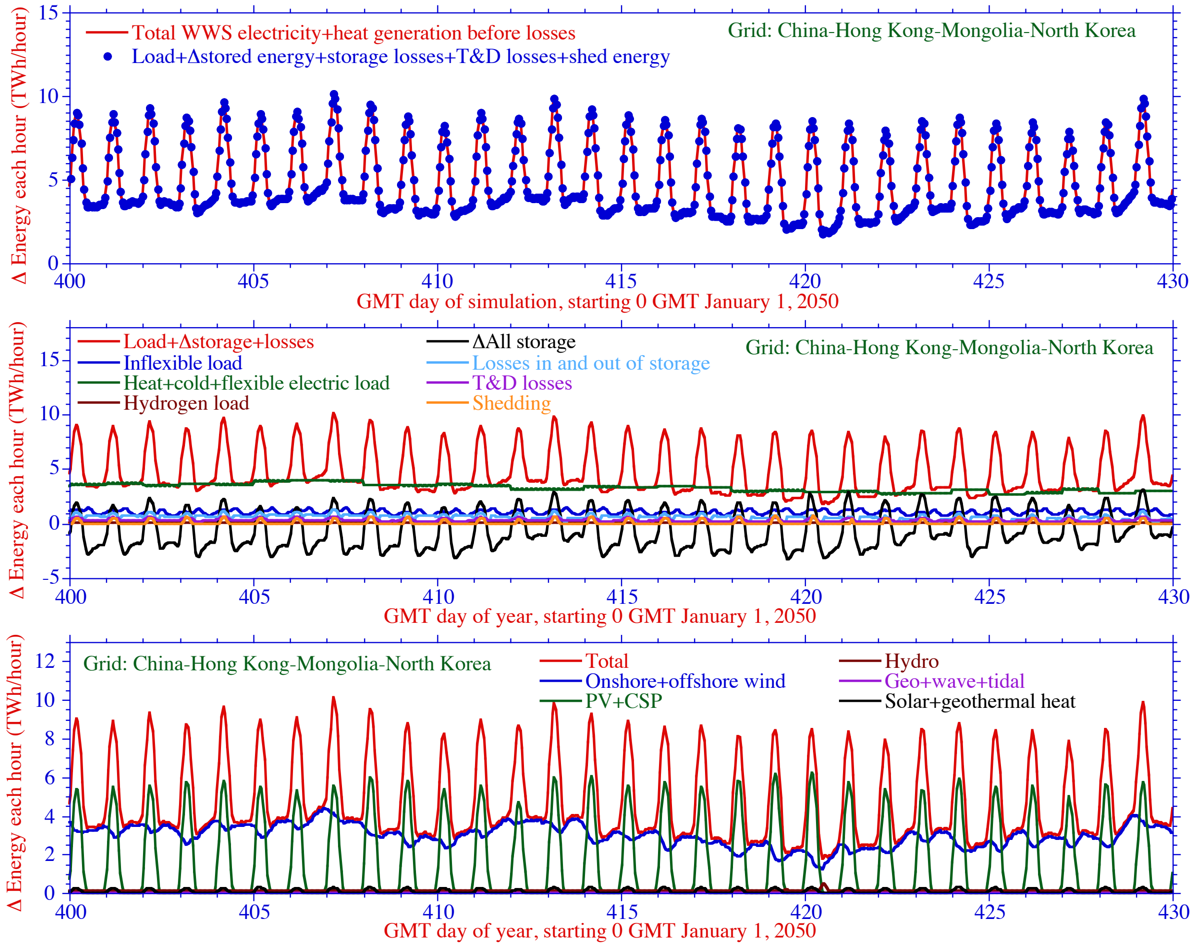
Central America



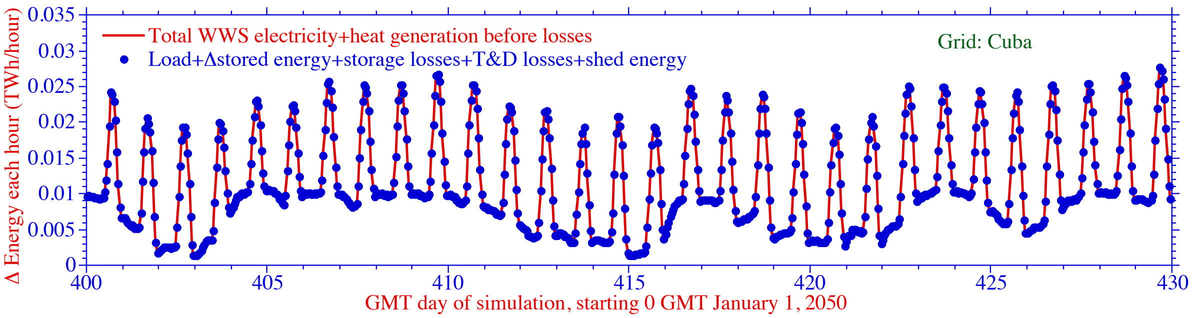
Central Asia



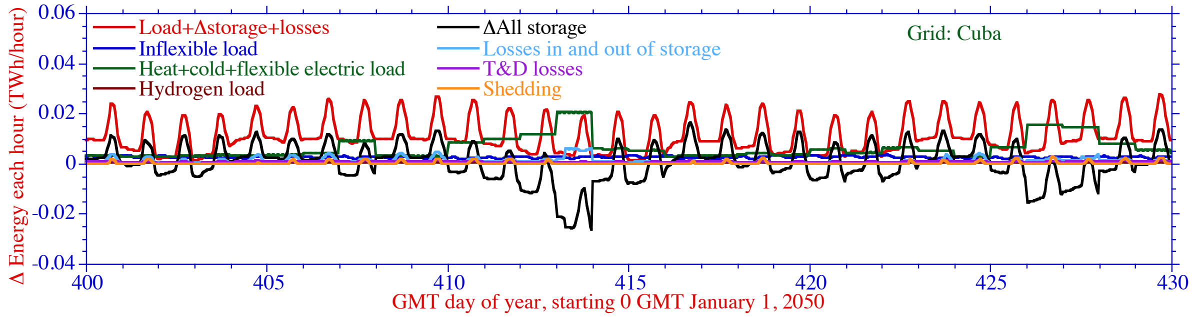
China-Hong Kong-Mongolia-North Korea



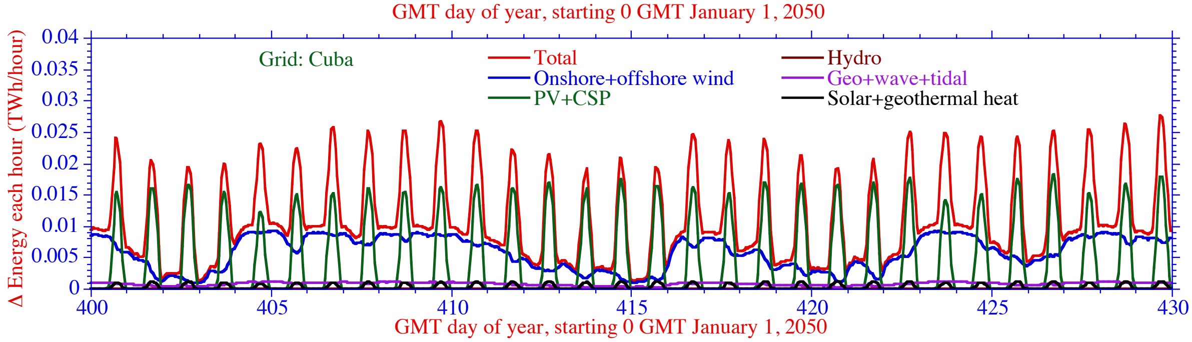
Cuba



Δ Energy each hour (TWh/hour)
0.035
0.03
0.025
0.02
0.015
0.01
0.005
0
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Cuba
400
405
410
415
420
425
430
GMT day of simulation, starting 0 GMT January 1, 2050

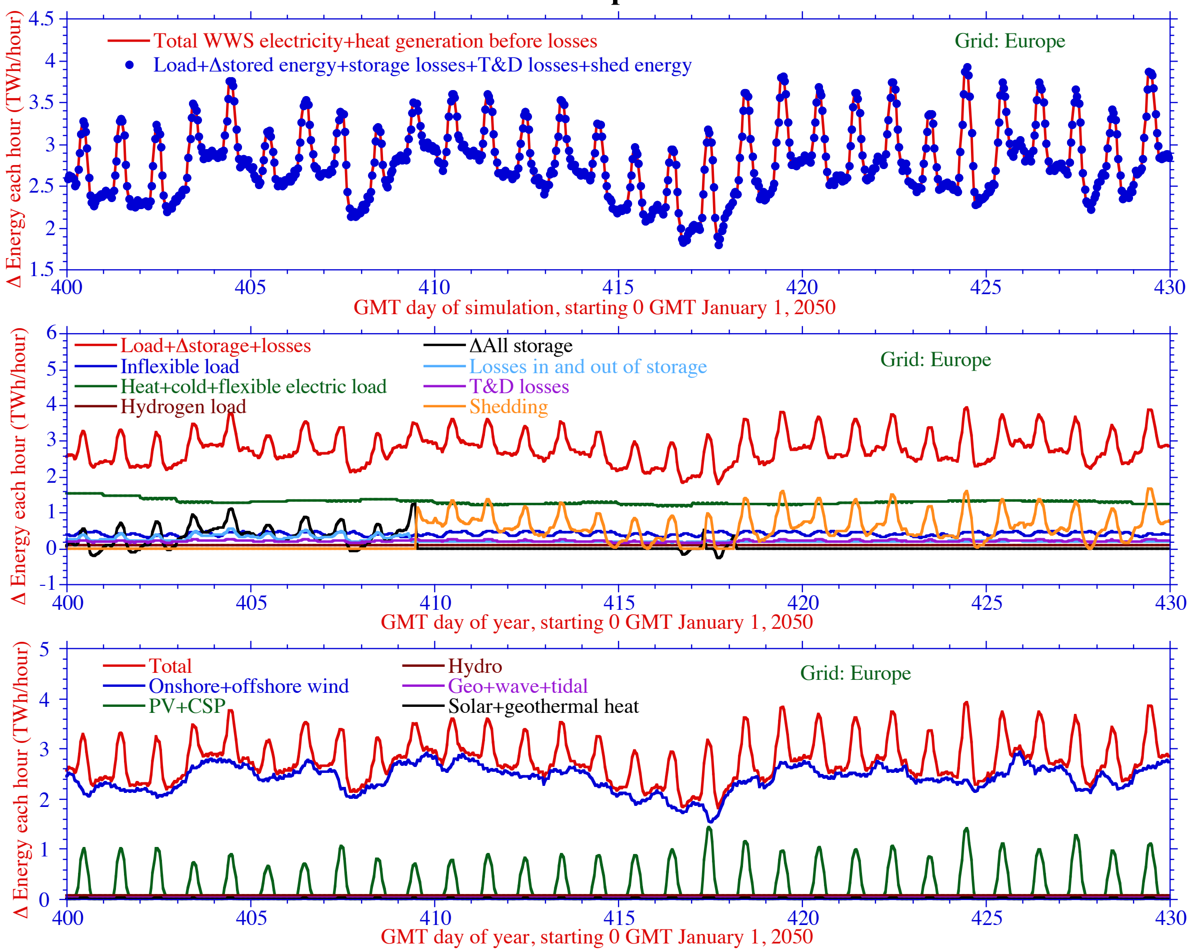


Δ Energy each hour (TWh/hour)
0.06
0.04
0.02
0
-0.02
-0.04
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Cuba
400
405
410
415
420
425
430
GMT day of year, starting 0 GMT January 1, 2050



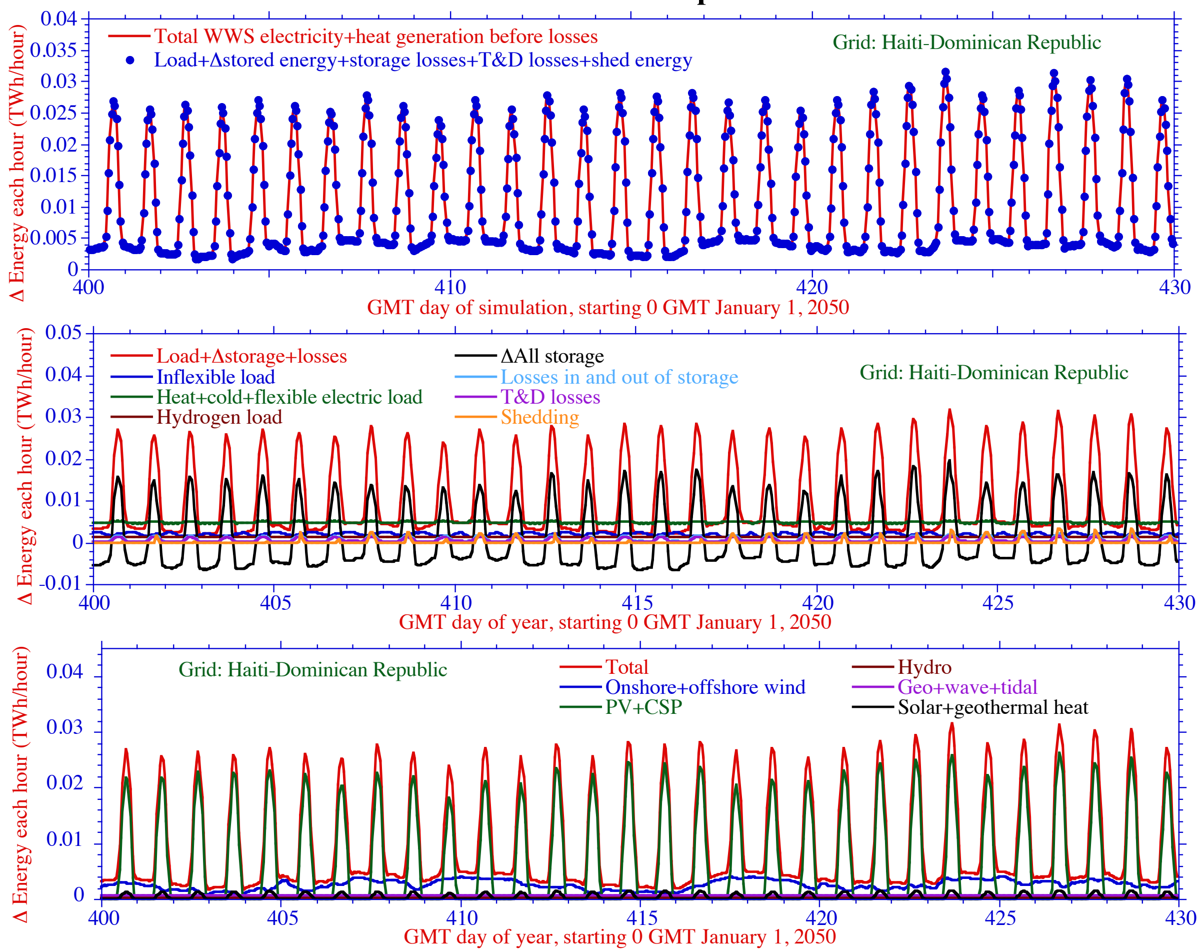
Δ Energy each hour (TWh/hour)
0.04
0.035
0.03
0.025
0.02
0.015
0.01
0.005
0
Grid: Cuba
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
400
405
410
415
420
425
430
GMT day of year, starting 0 GMT January 1, 2050

Europe

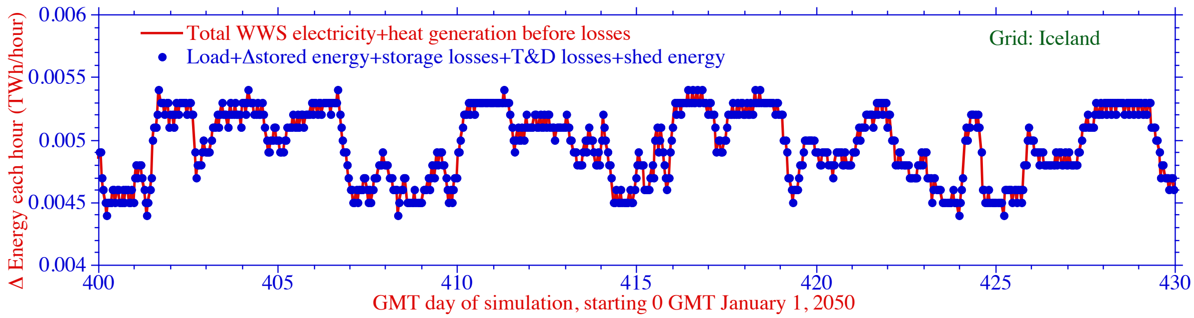


Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Europe
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Europe
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Grid: Europe
GMT day of year, starting 0 GMT January 1, 2050

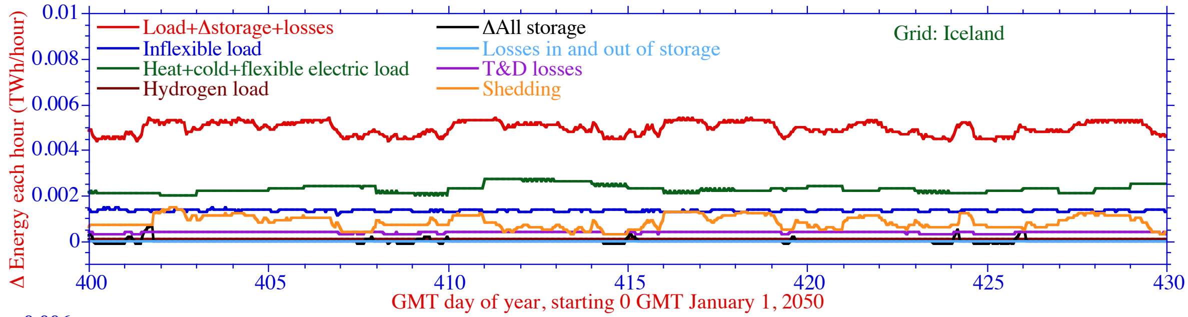
Haiti-Dominican Republic



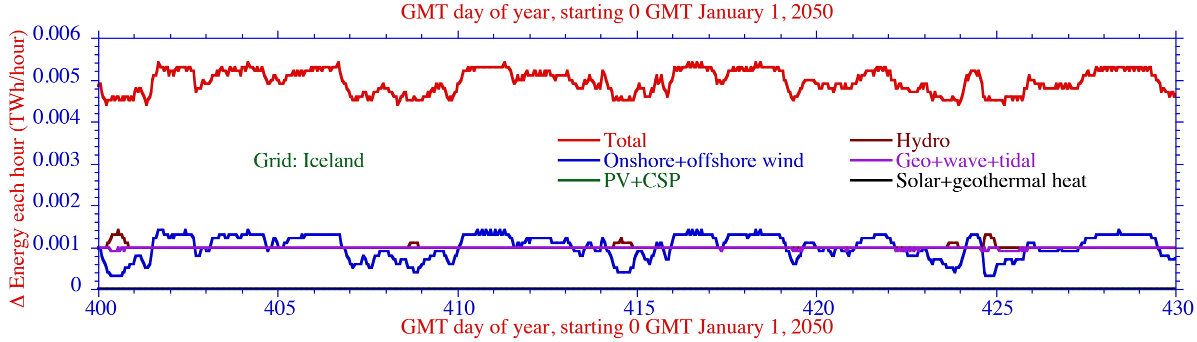
Iceland



Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Iceland
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050

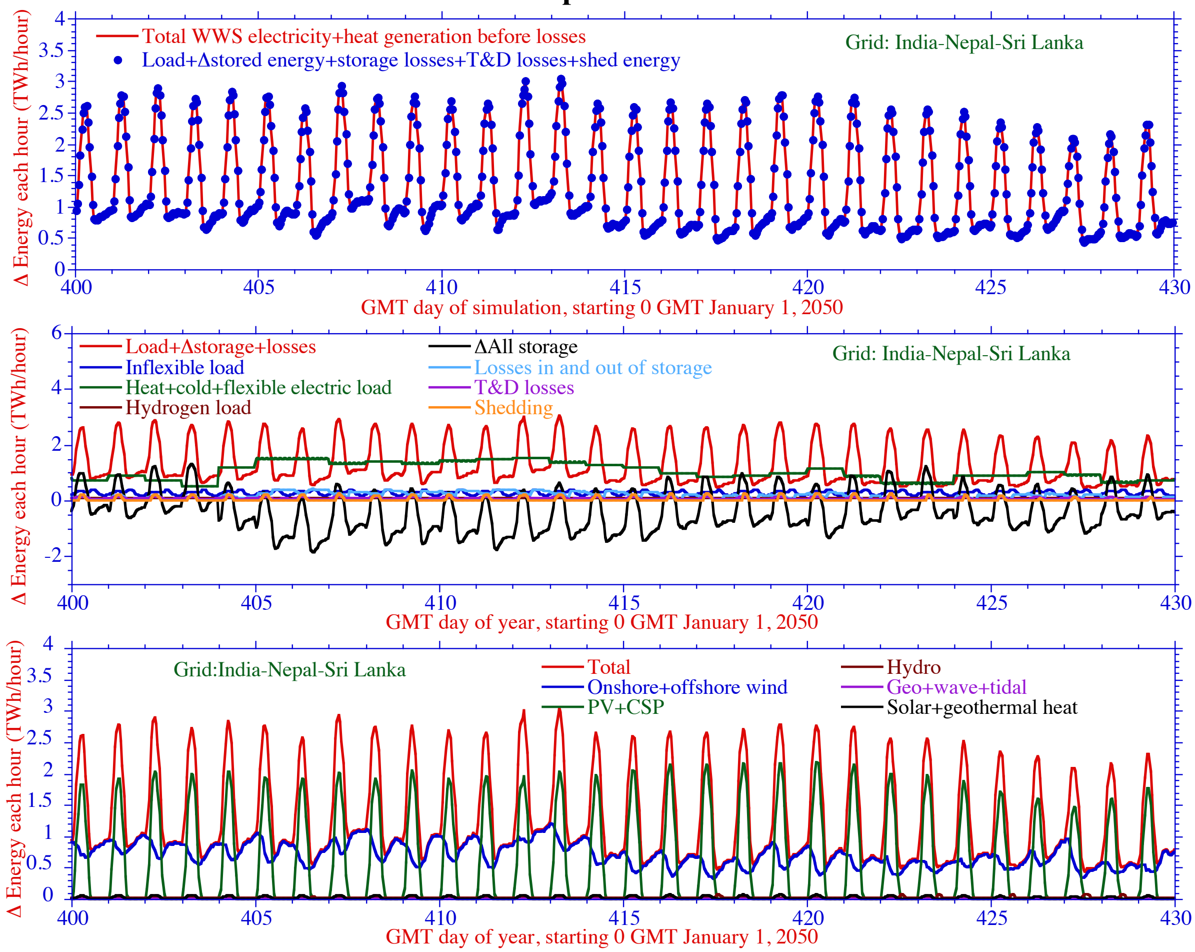


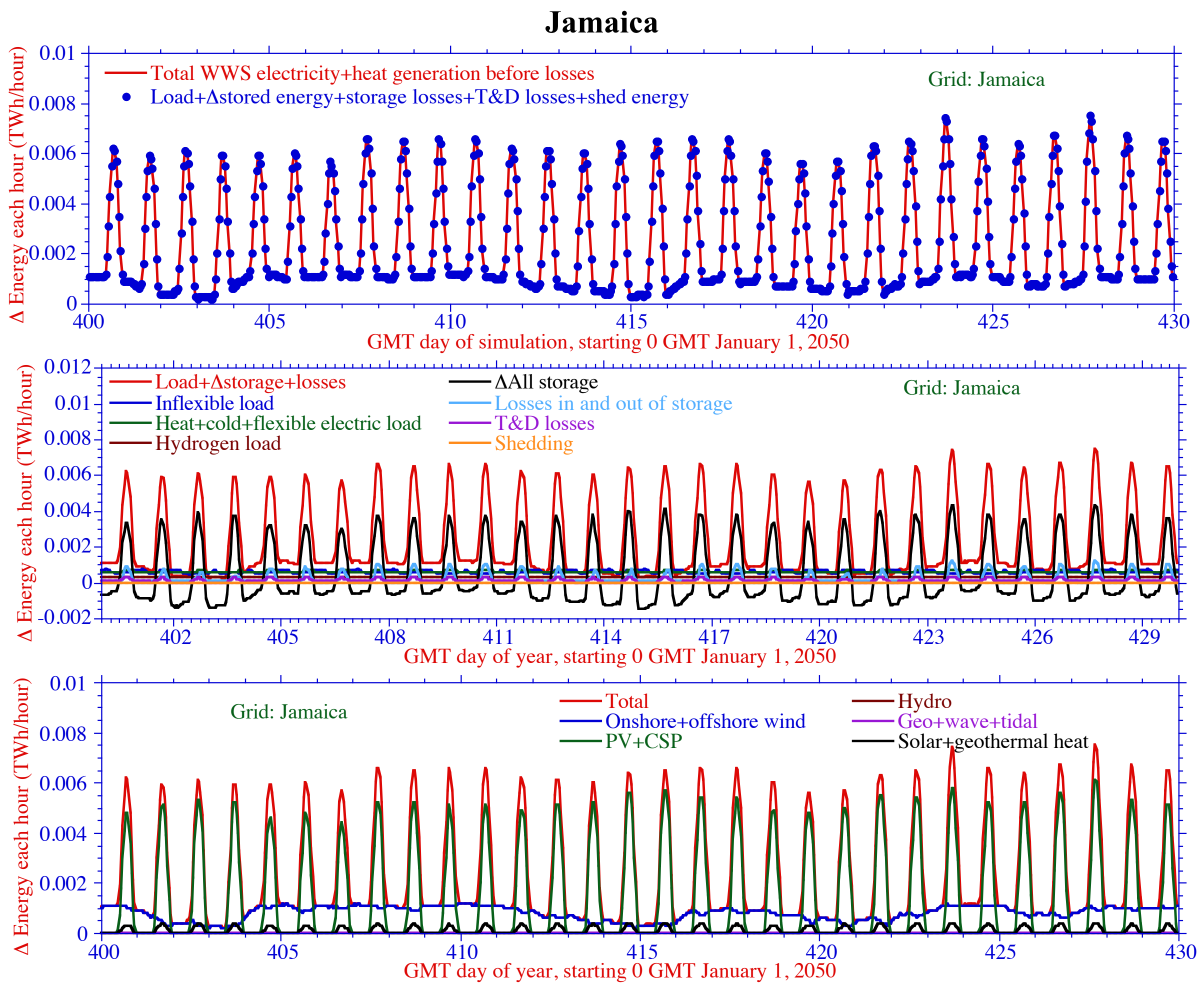
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Iceland
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050



Grid: Iceland
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050

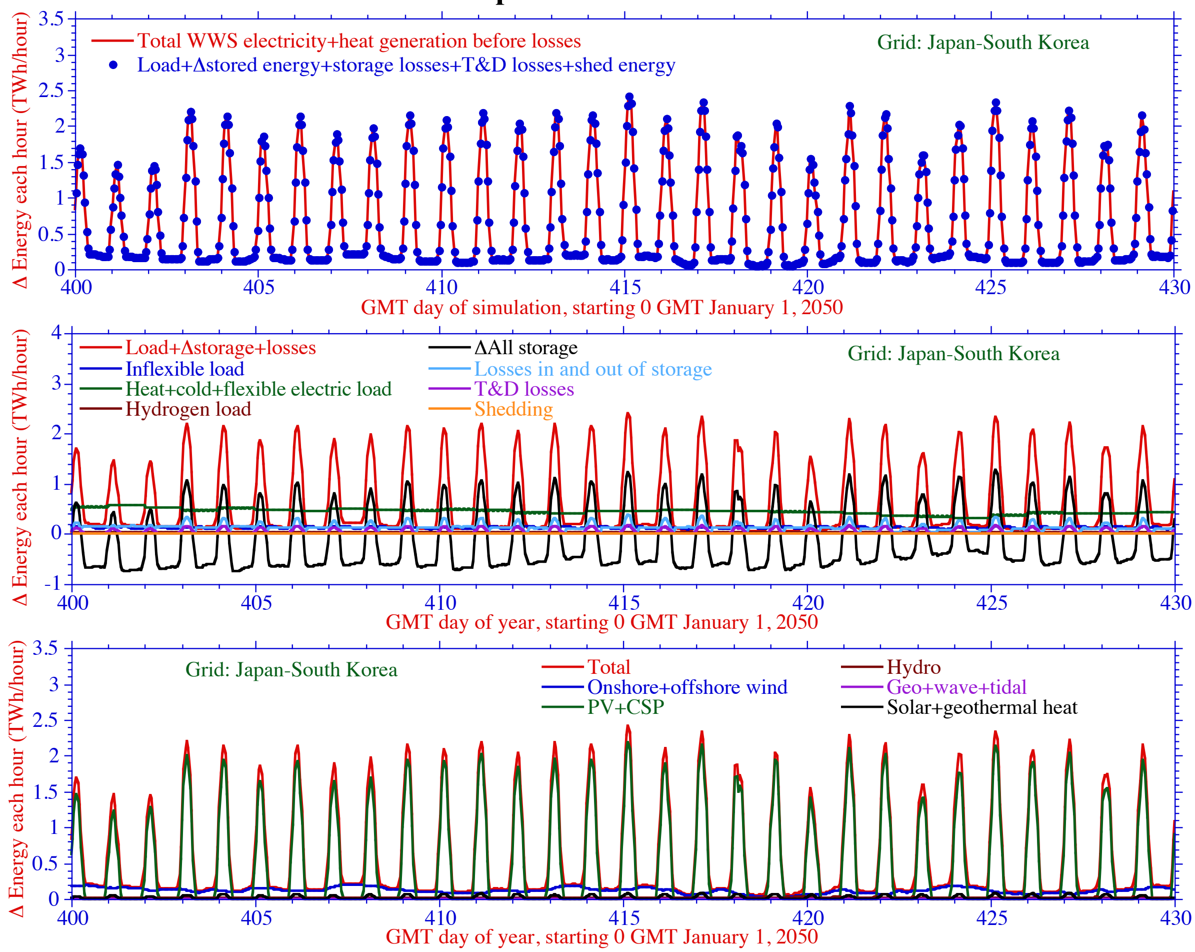
India-Nepal-Sri Lanka



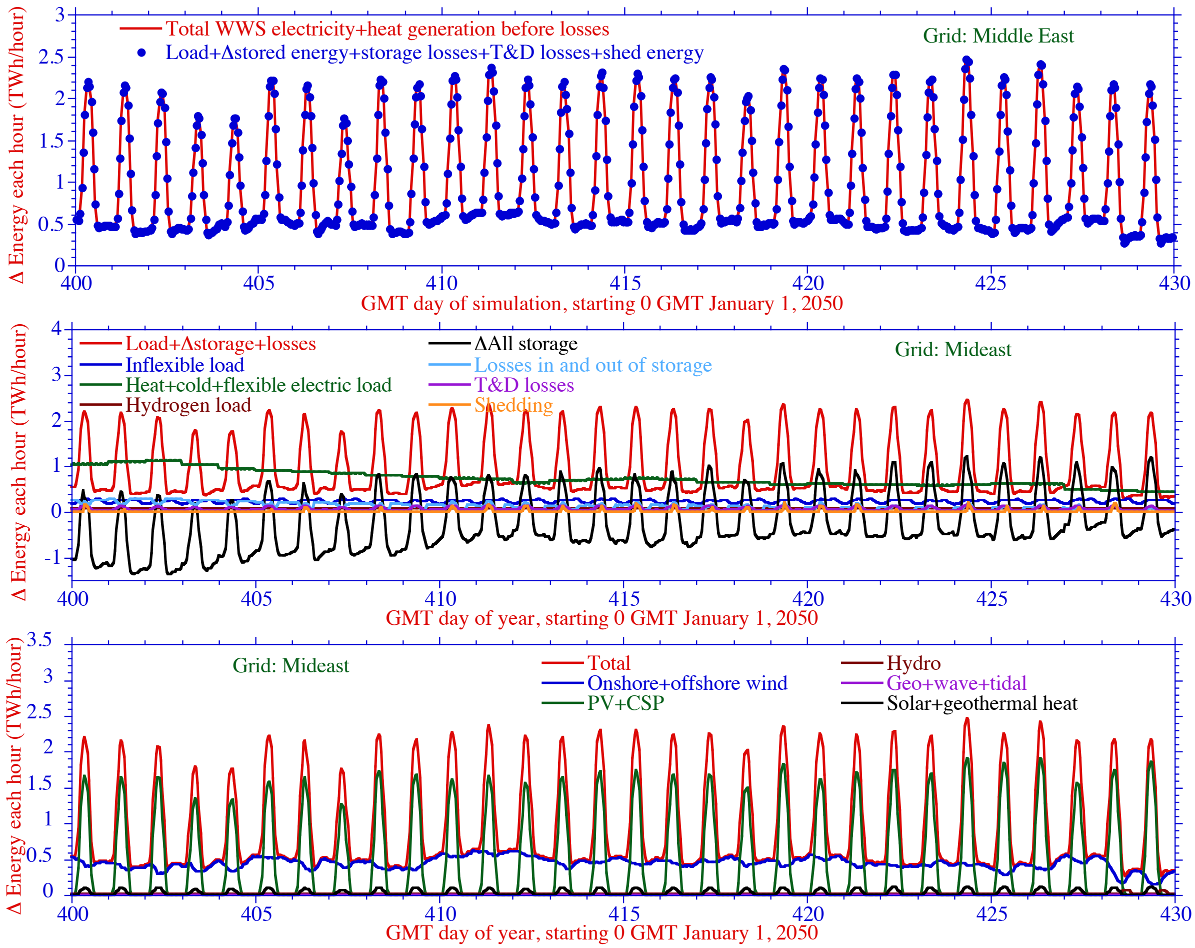


Jamaica
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Jamaica
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Jamaica
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050
Grid: Jamaica
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050

Japan-South Korea

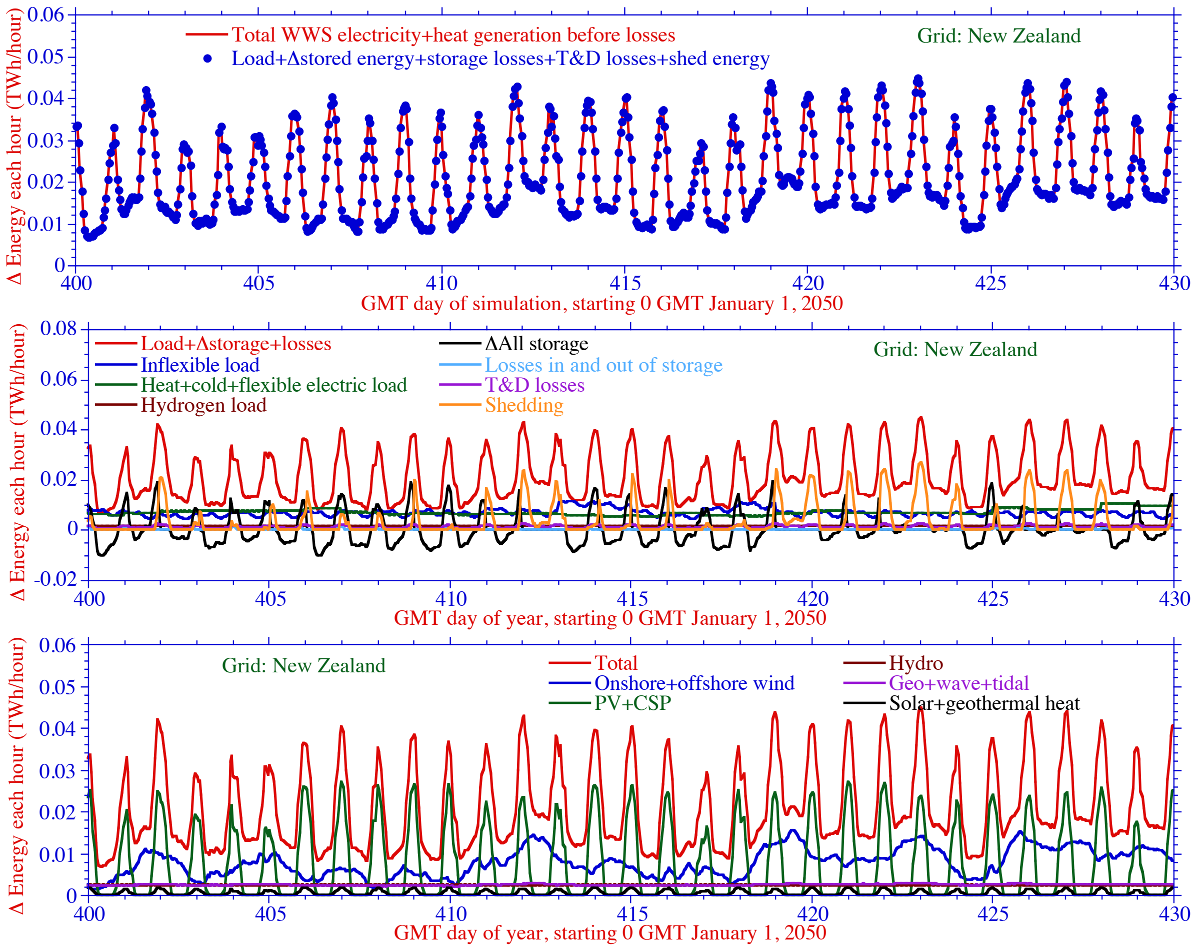


Mideast



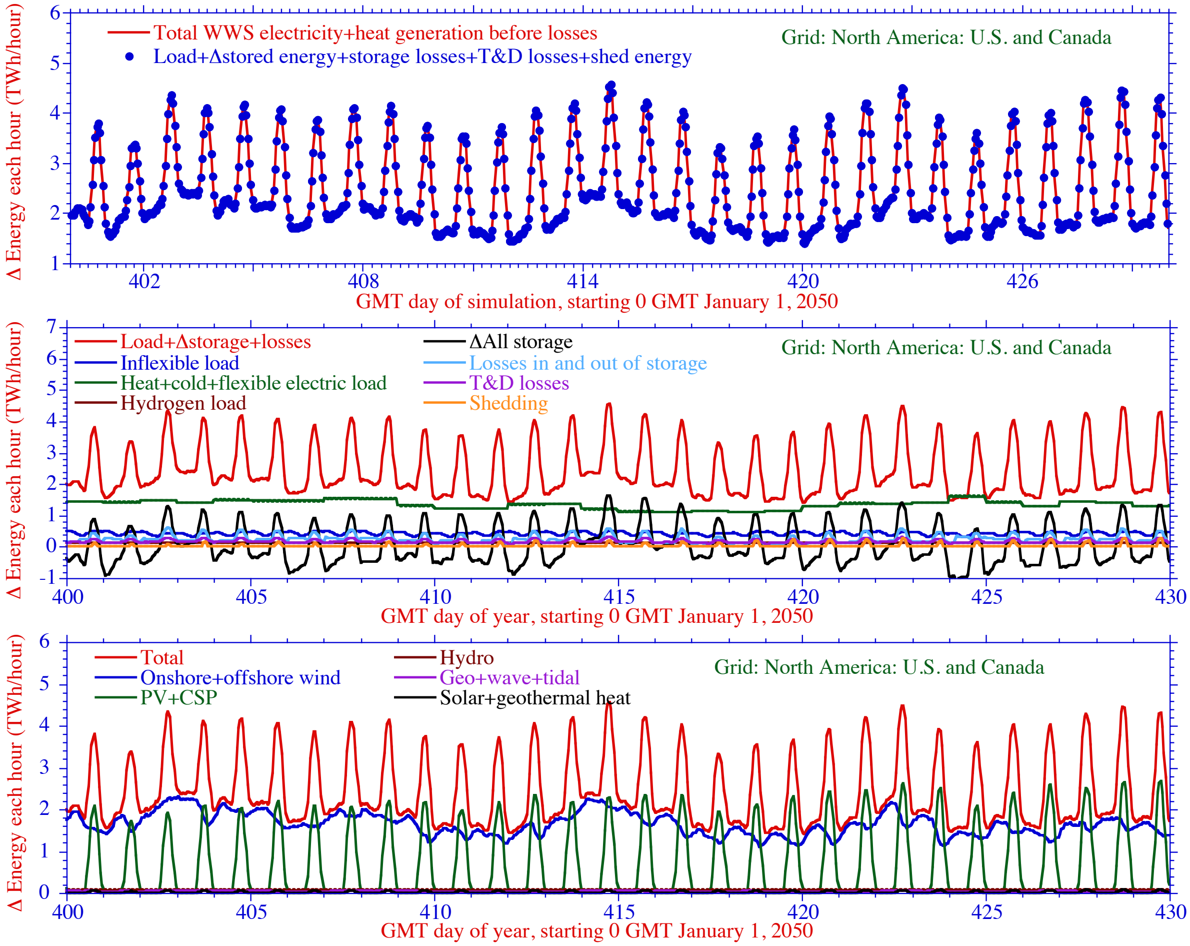
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Middle East
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Mideast
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat

New Zealand

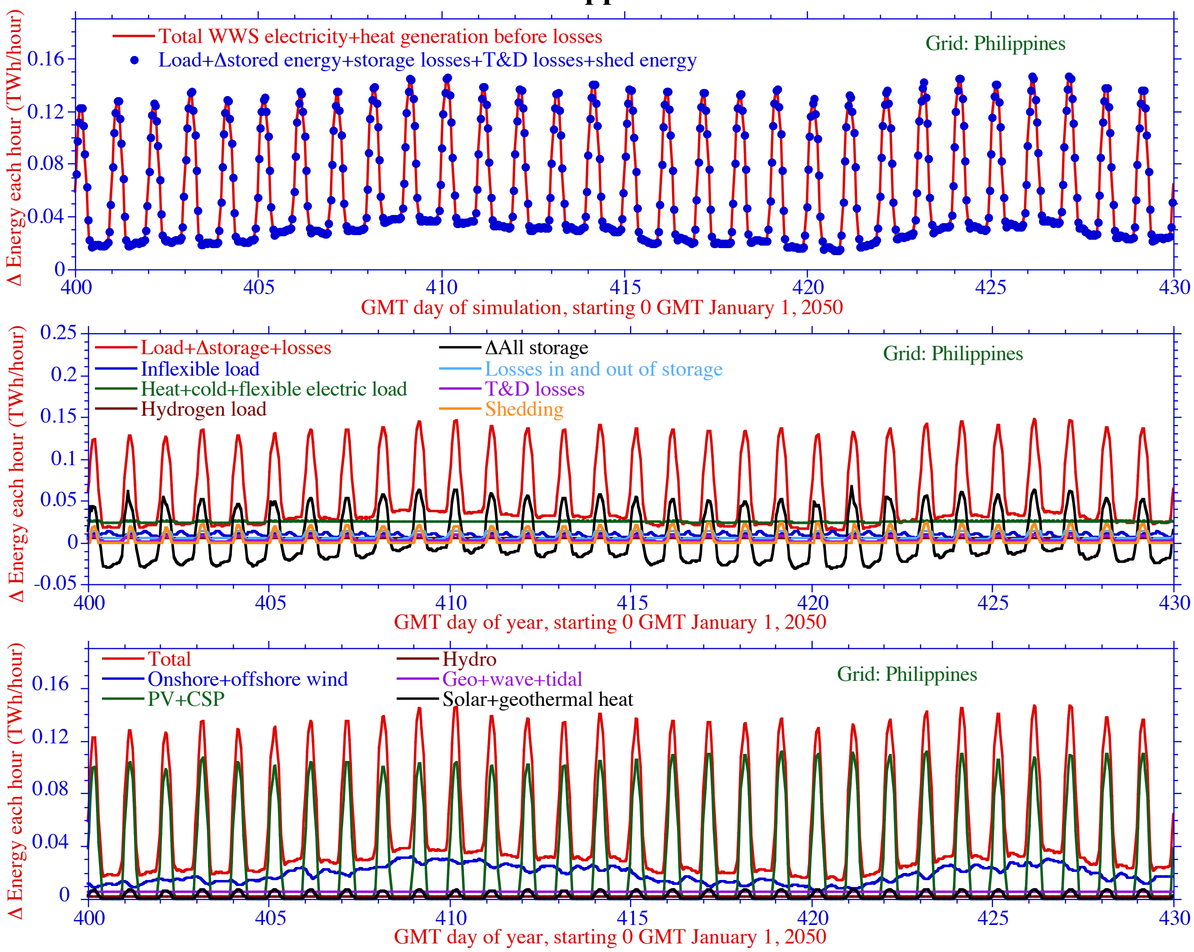


Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: New Zealand
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: New Zealand
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050
Grid: New Zealand
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050

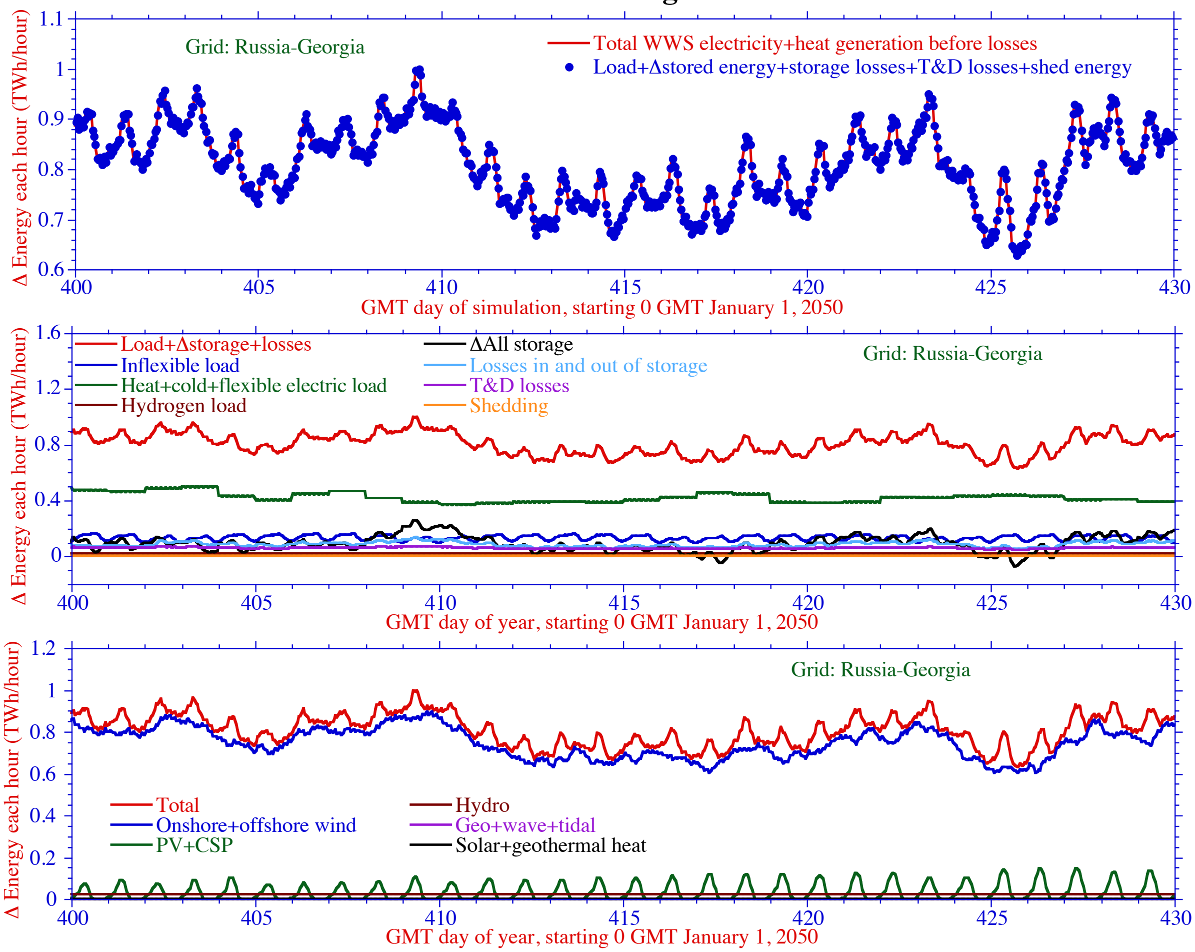
North America



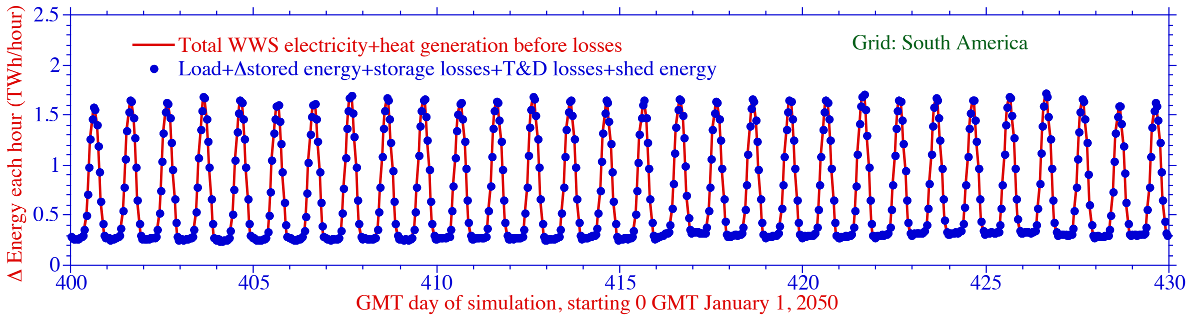
Philippines

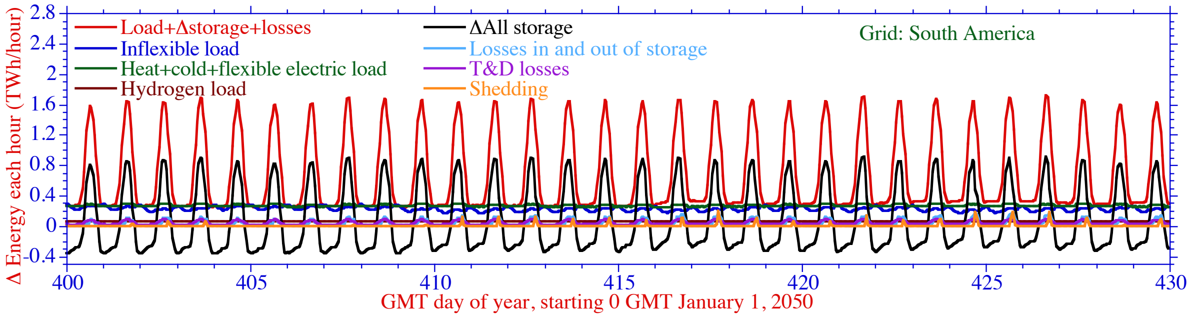


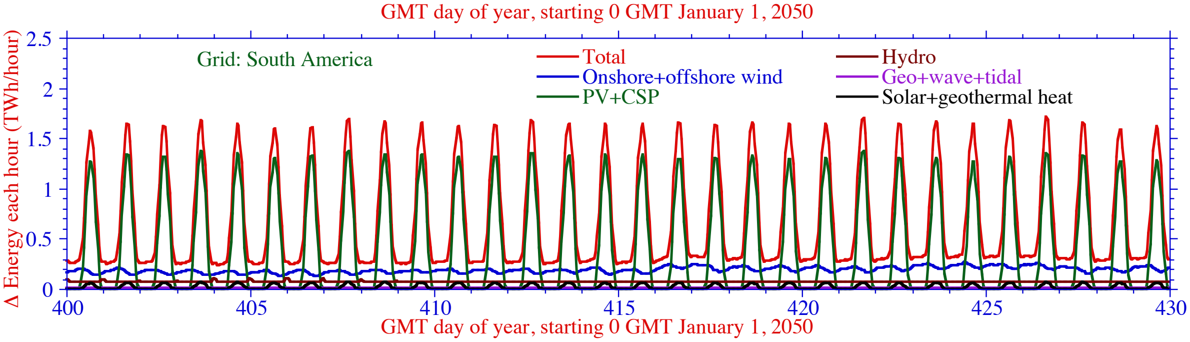
Russia-Georgia



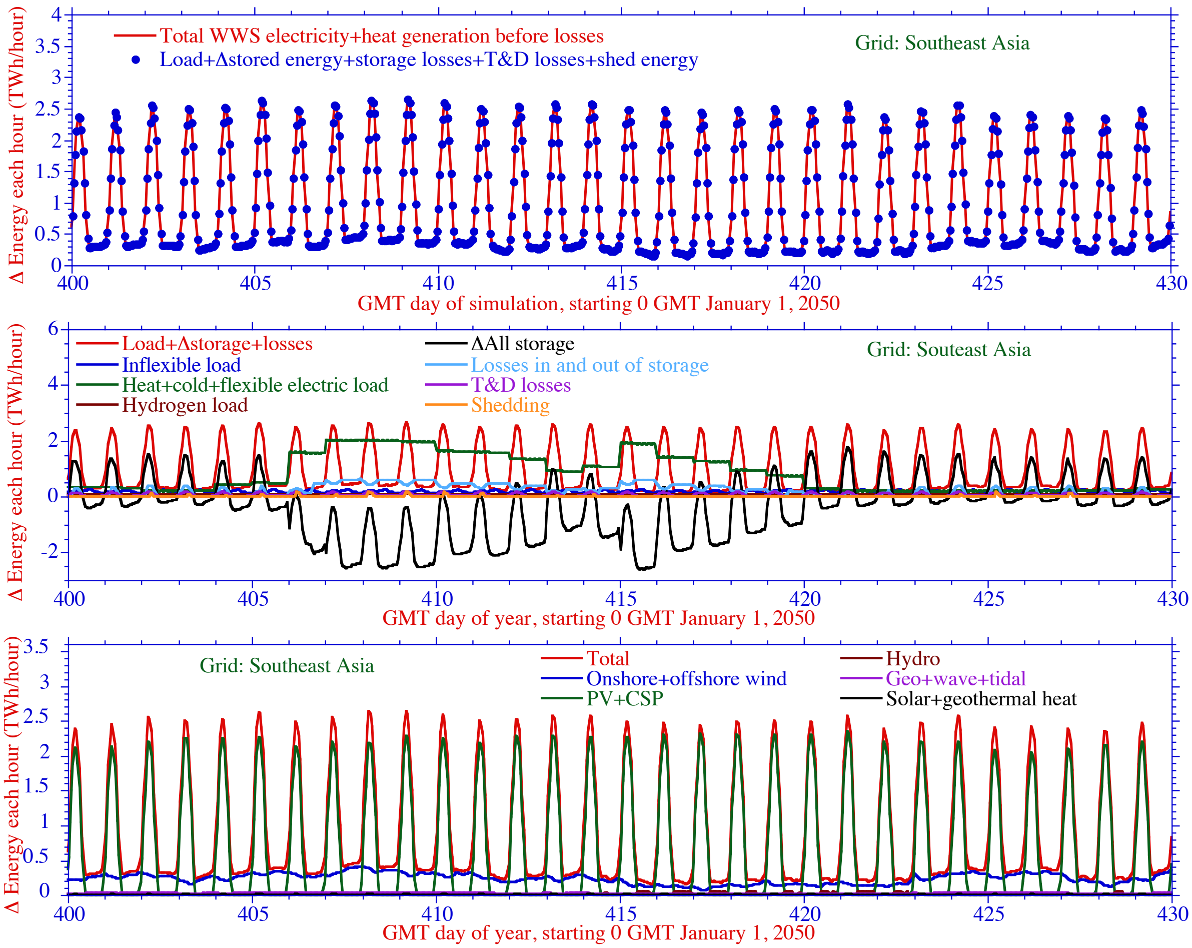
South America



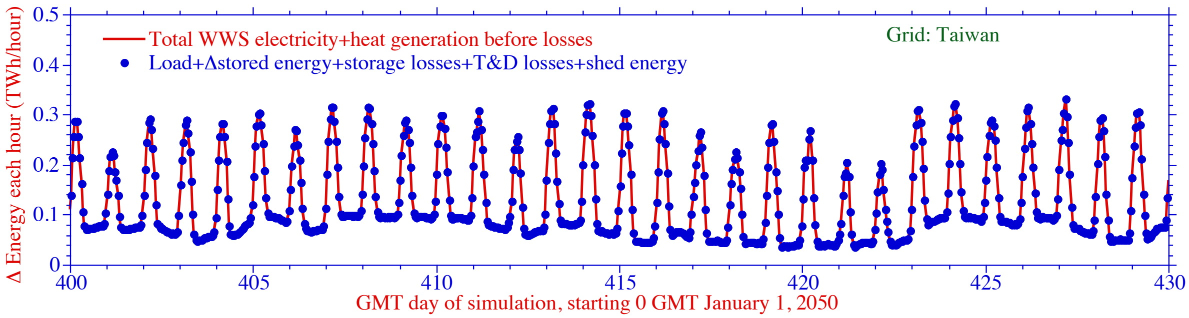




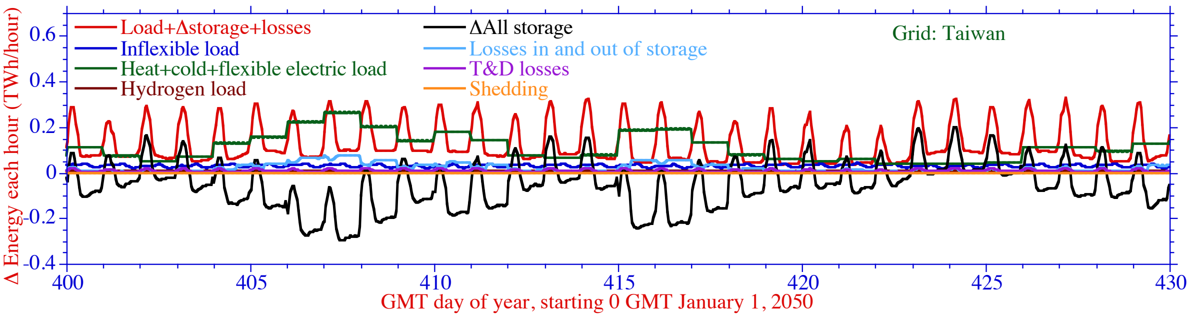
Southeast Asia



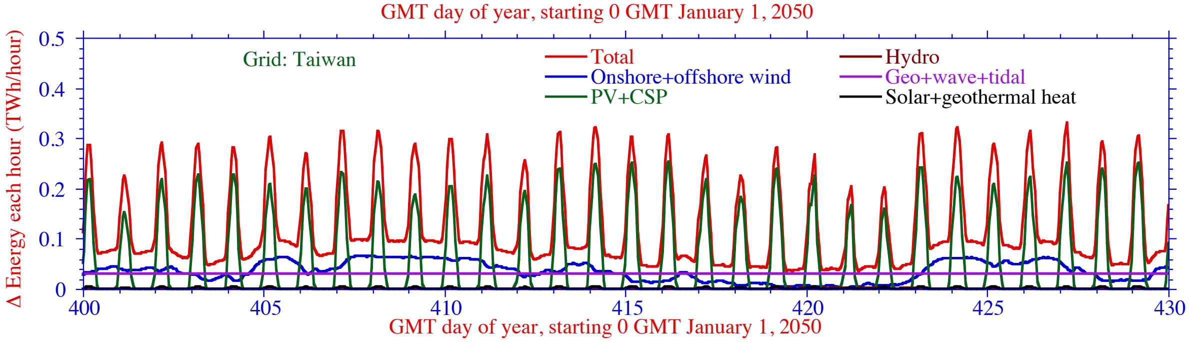
Taiwan



Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Taiwan
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050

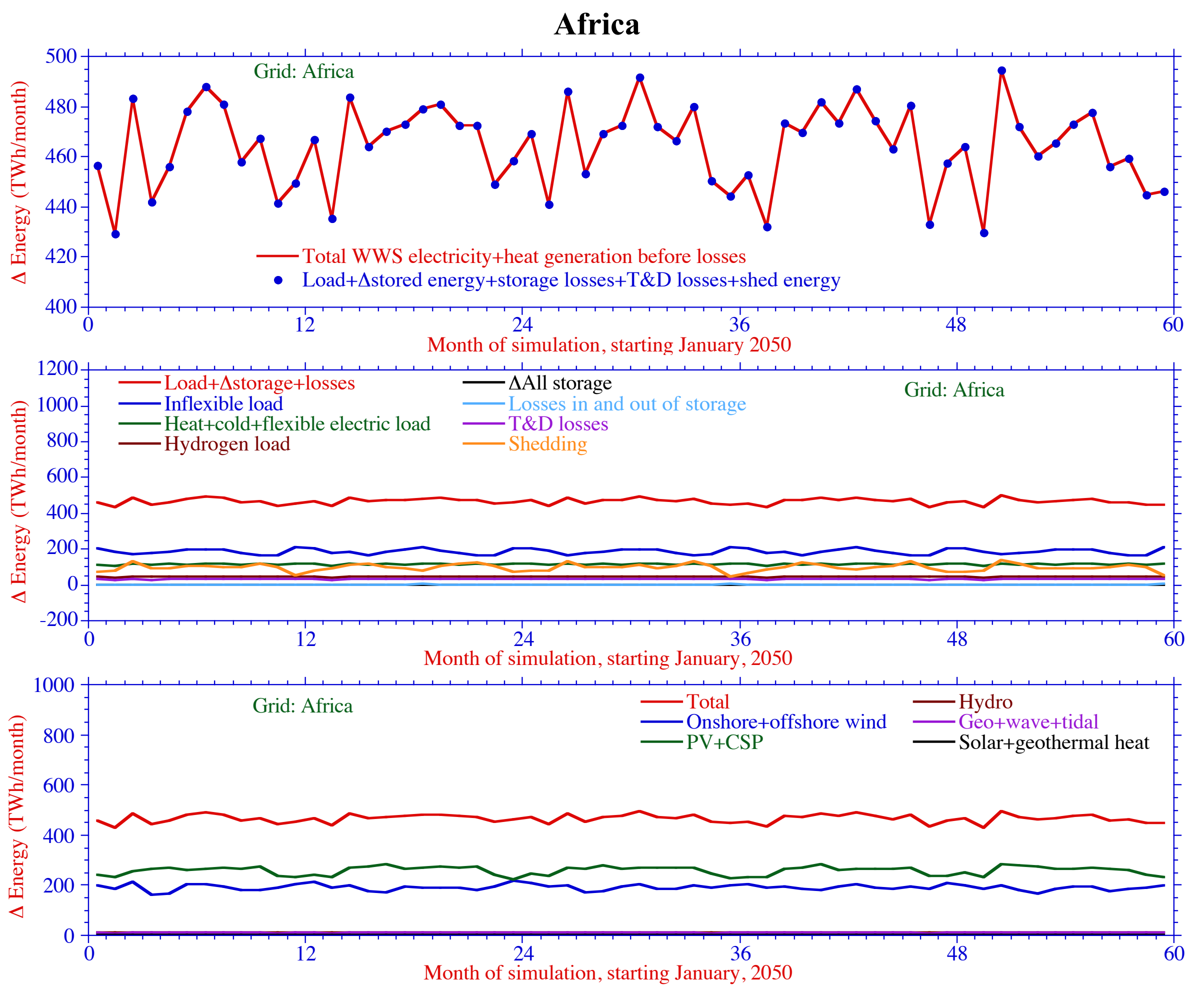


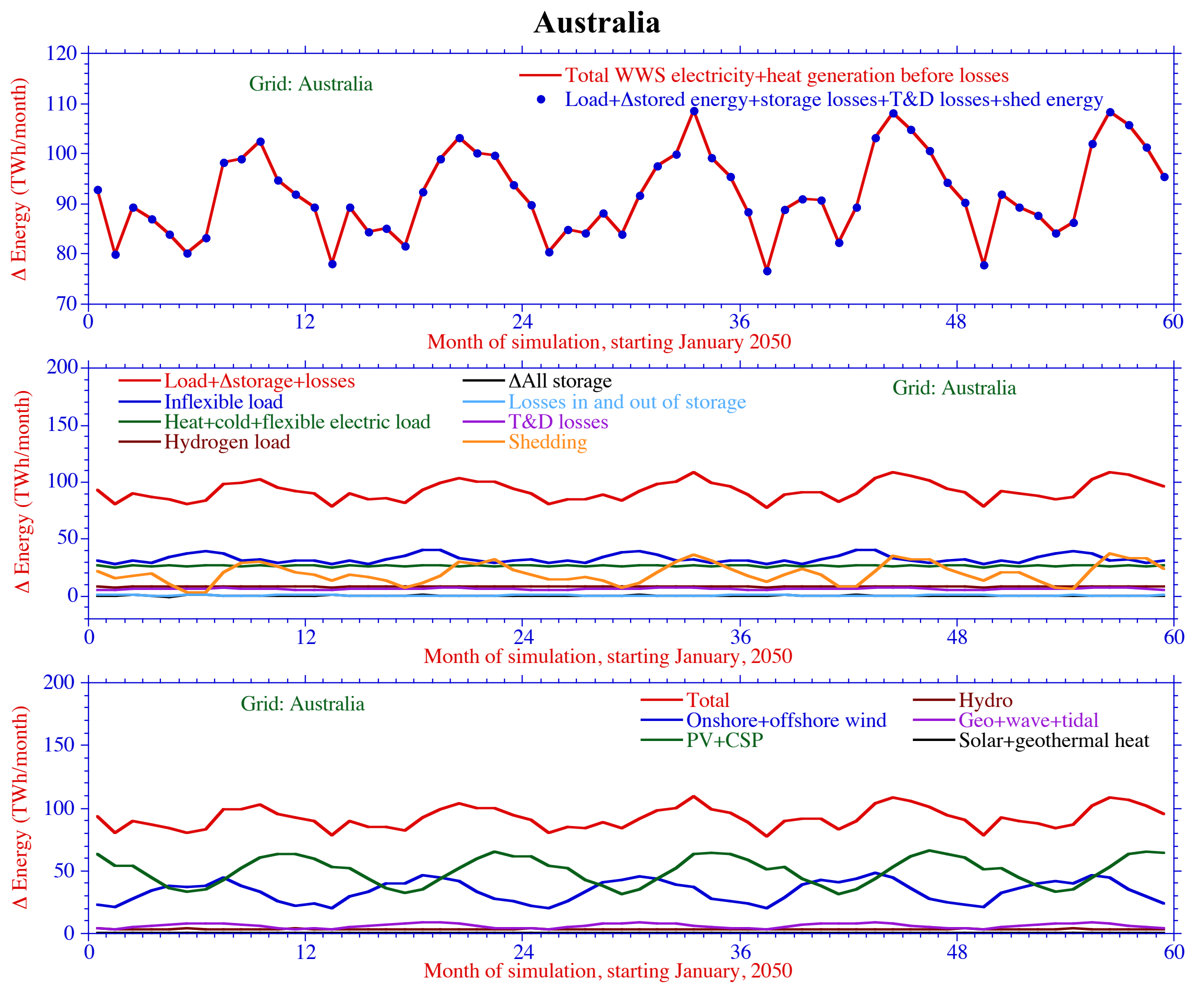
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Taiwan
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050



Grid: Taiwan
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050

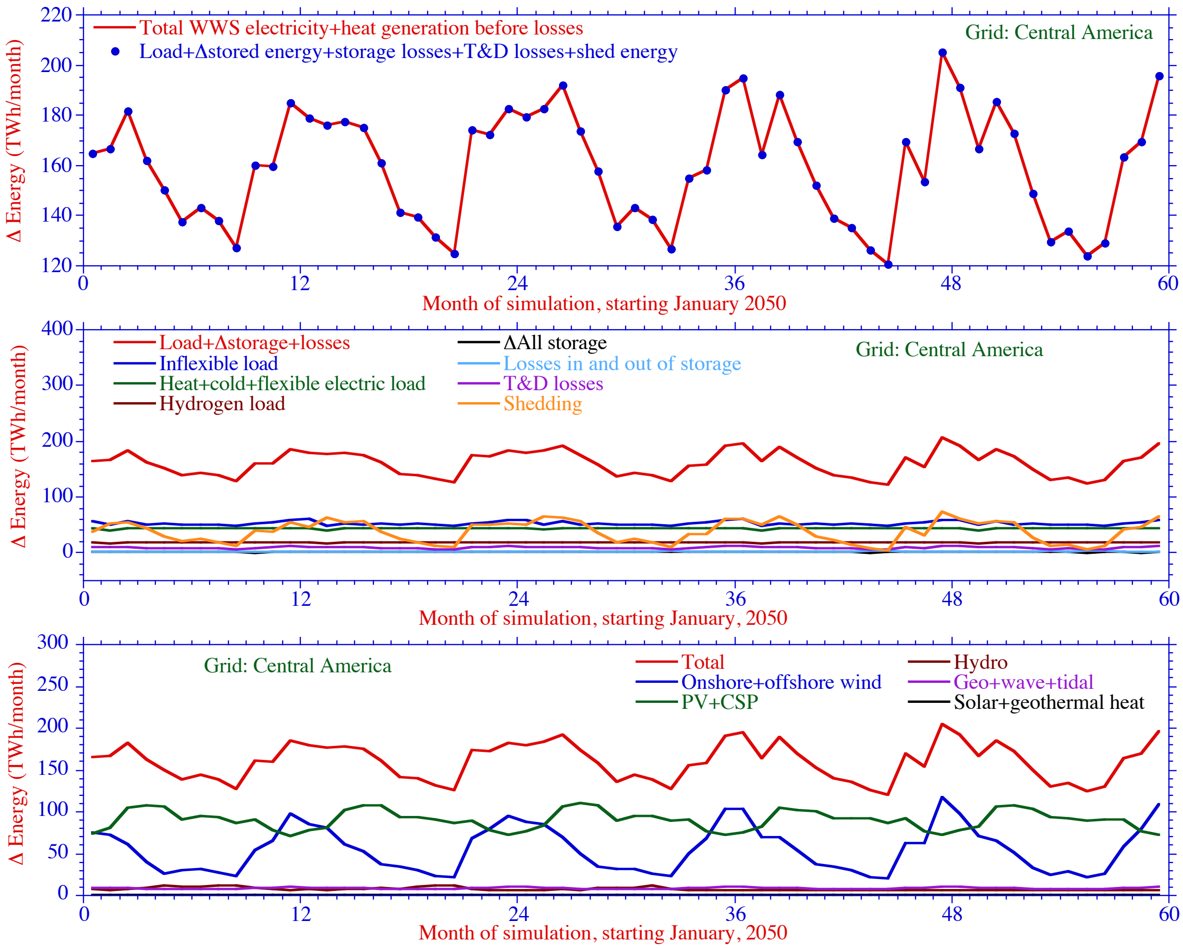
Figure S5. Five-year (60-month) time-series comparison, for Case C (no increase in hydropower peak discharge rate and with 100% electric heat pumps and 0% thermal energy storage for heating or cooling) for each of the 14 world regions examined in Case C, of modeled (a) monthly-averaged total WWS power generation with load plus losses plus changes in storage plus shedding, (b) breakdown of load plus losses plus changes in storage plus shedding into individual components, and (c) breakdown of WWS power generation by generation technology.



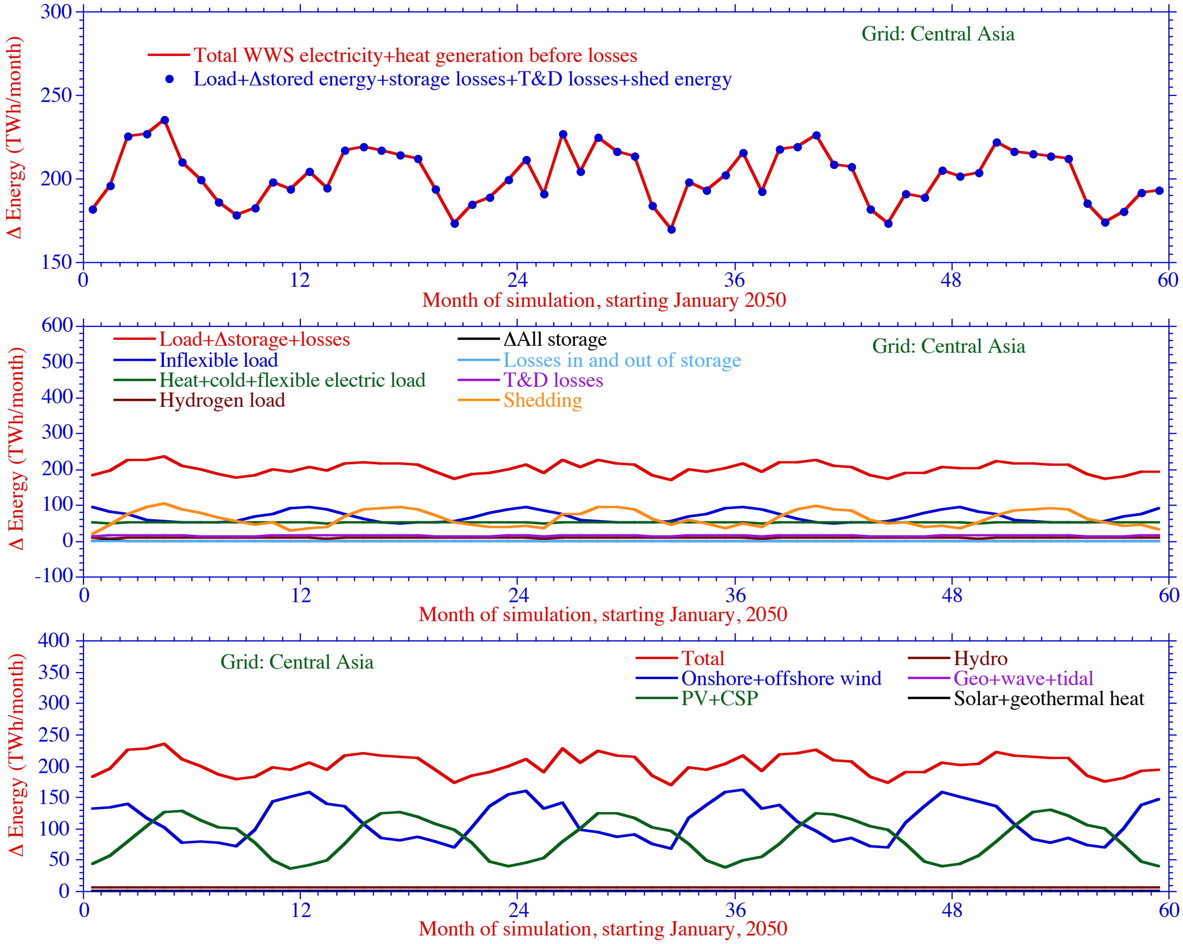


Australia
Grid: Australia
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Australia
Month of simulation, starting January, 2050
Grid: Australia
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Month of simulation, starting January, 2050

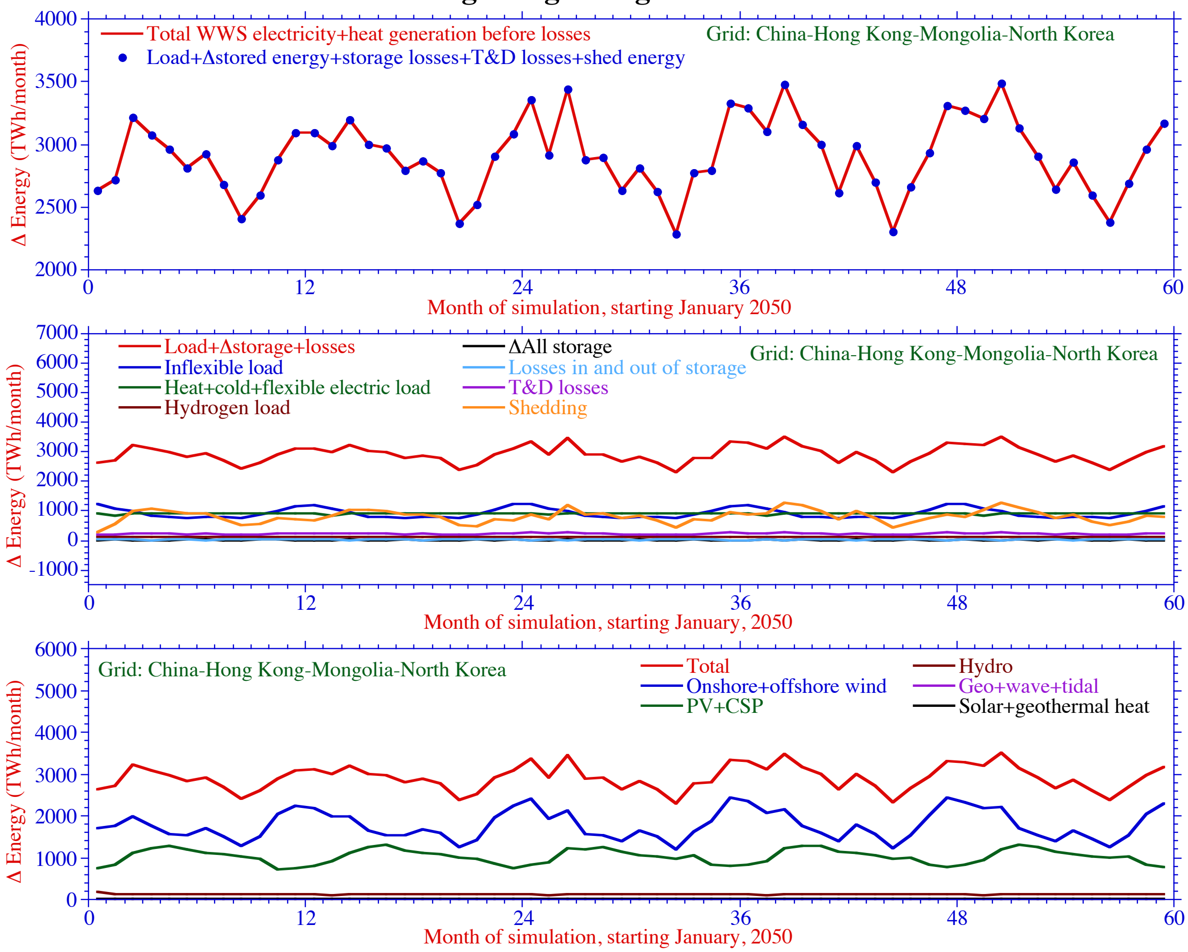
Central America



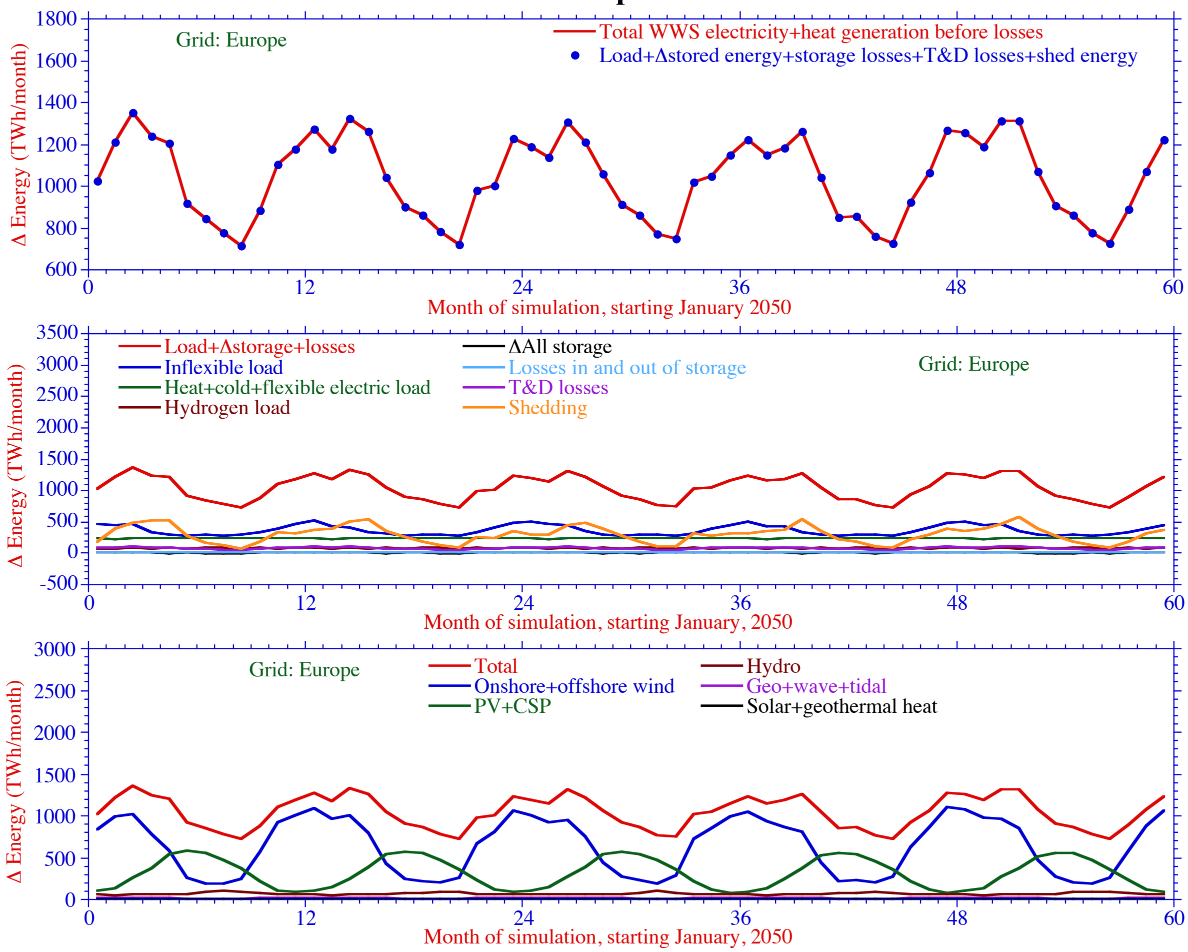
Central Asia



China-Hong Kong-Mongolia-North Korea

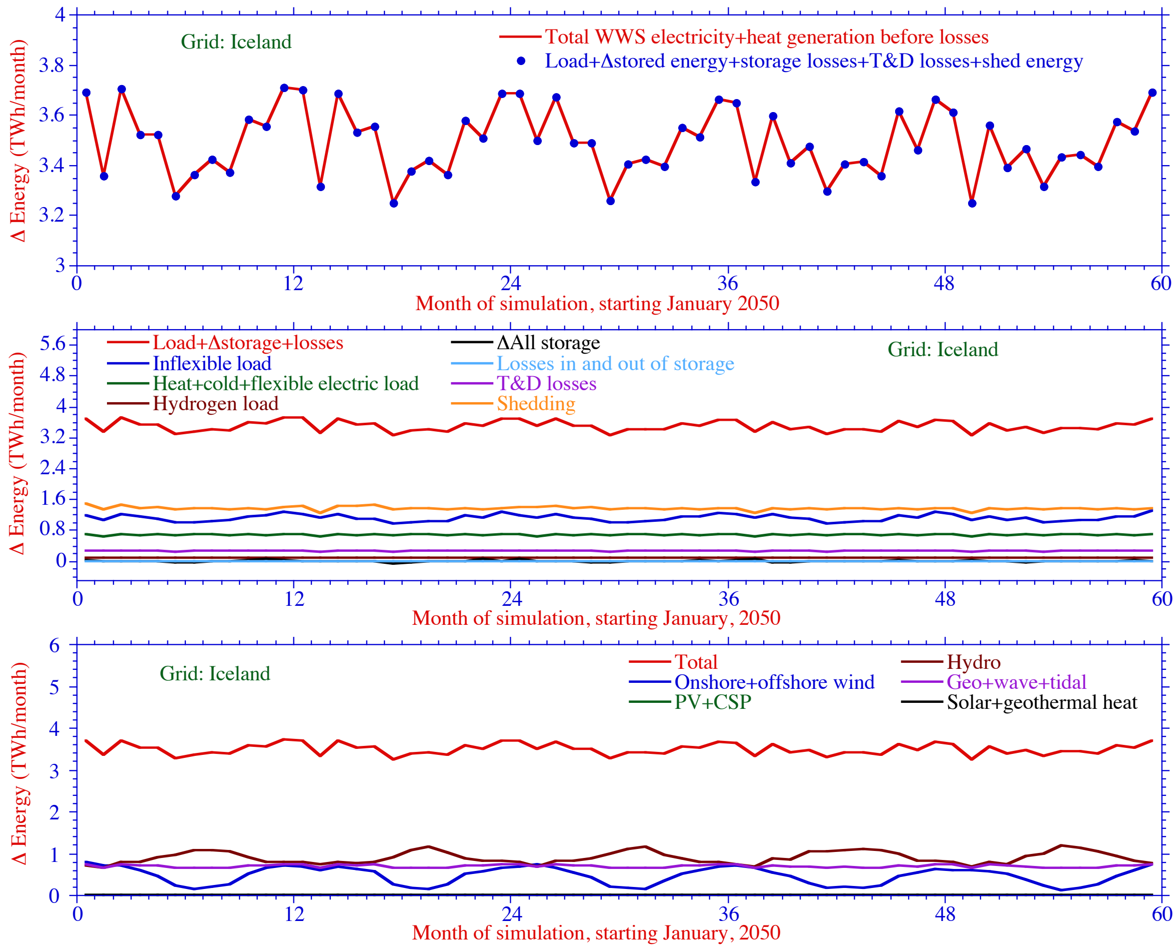


Europe

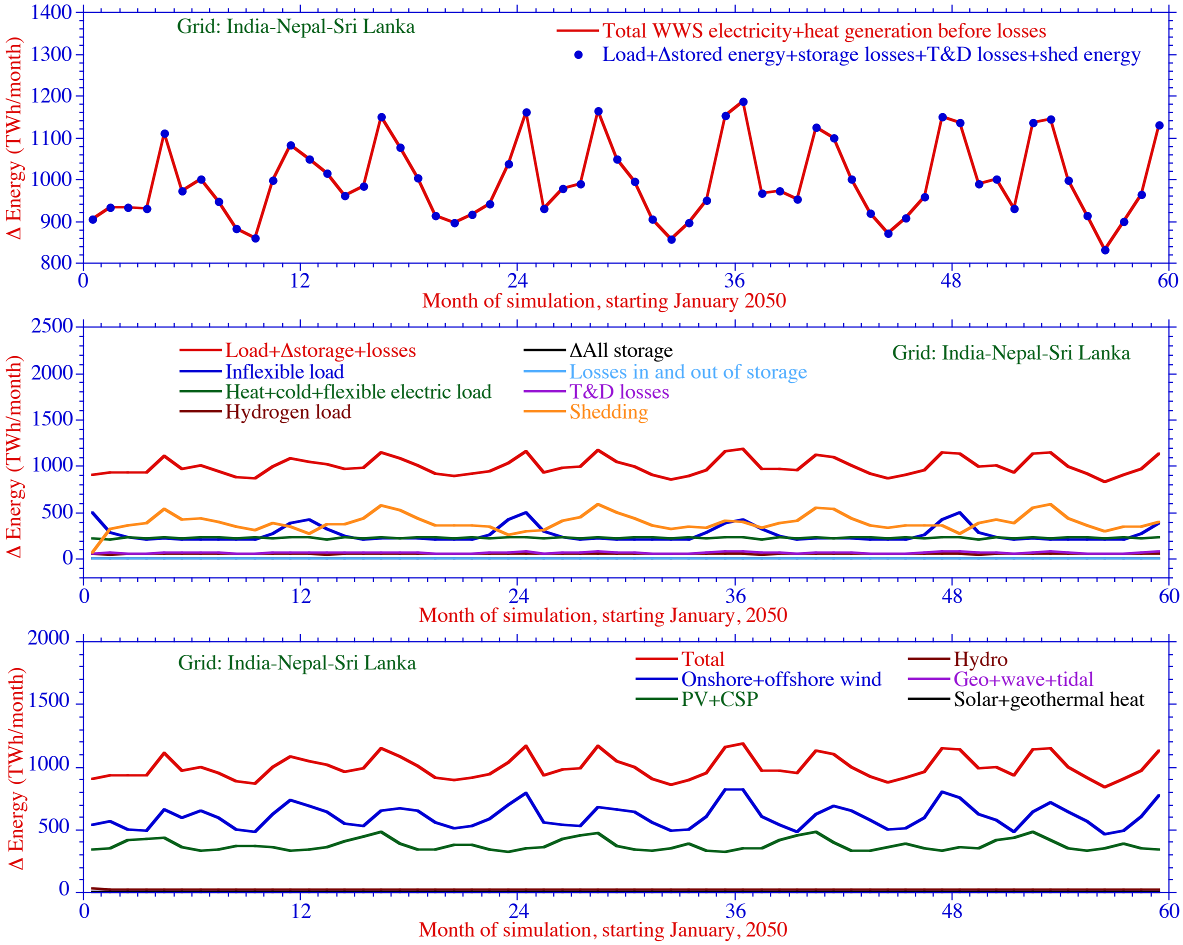


Grid: Europe
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Europe
Δ Energy (TWh/month)
Month of simulation, starting January, 2050
Grid: Europe
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

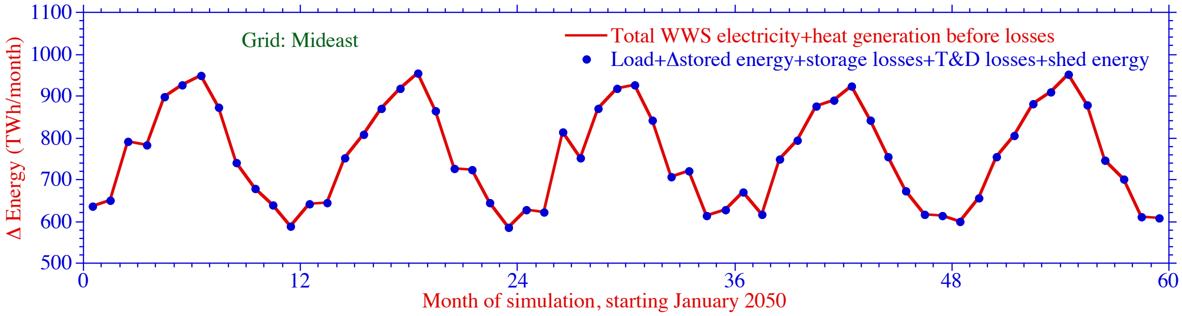
Iceland


Grid: Iceland
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Iceland
Δ Energy (TWh/month)
Month of simulation, starting January, 2050
Grid: Iceland
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

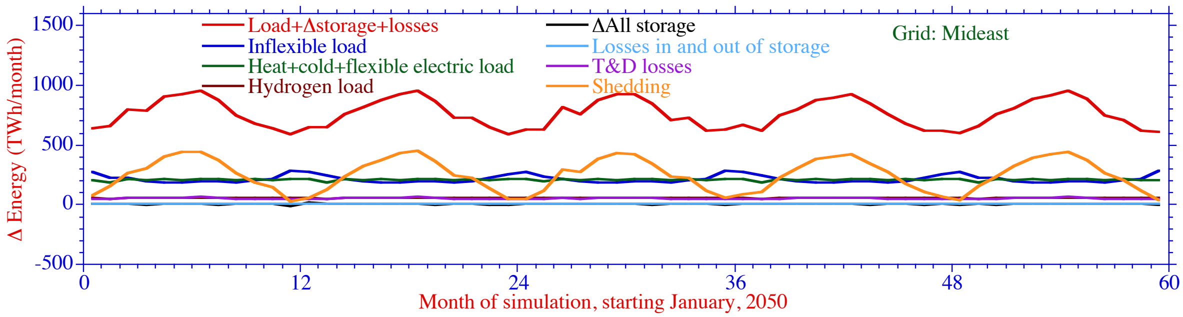
India-Nepal-Sri Lanka



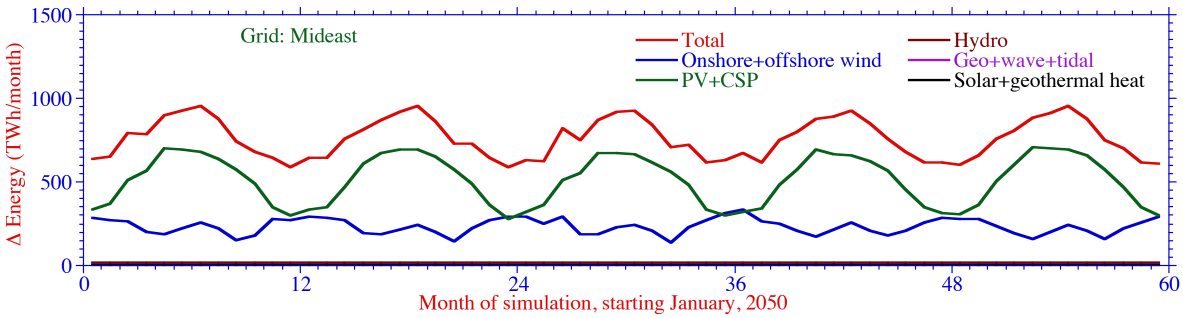
Mideast



Grid: Mideast
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050

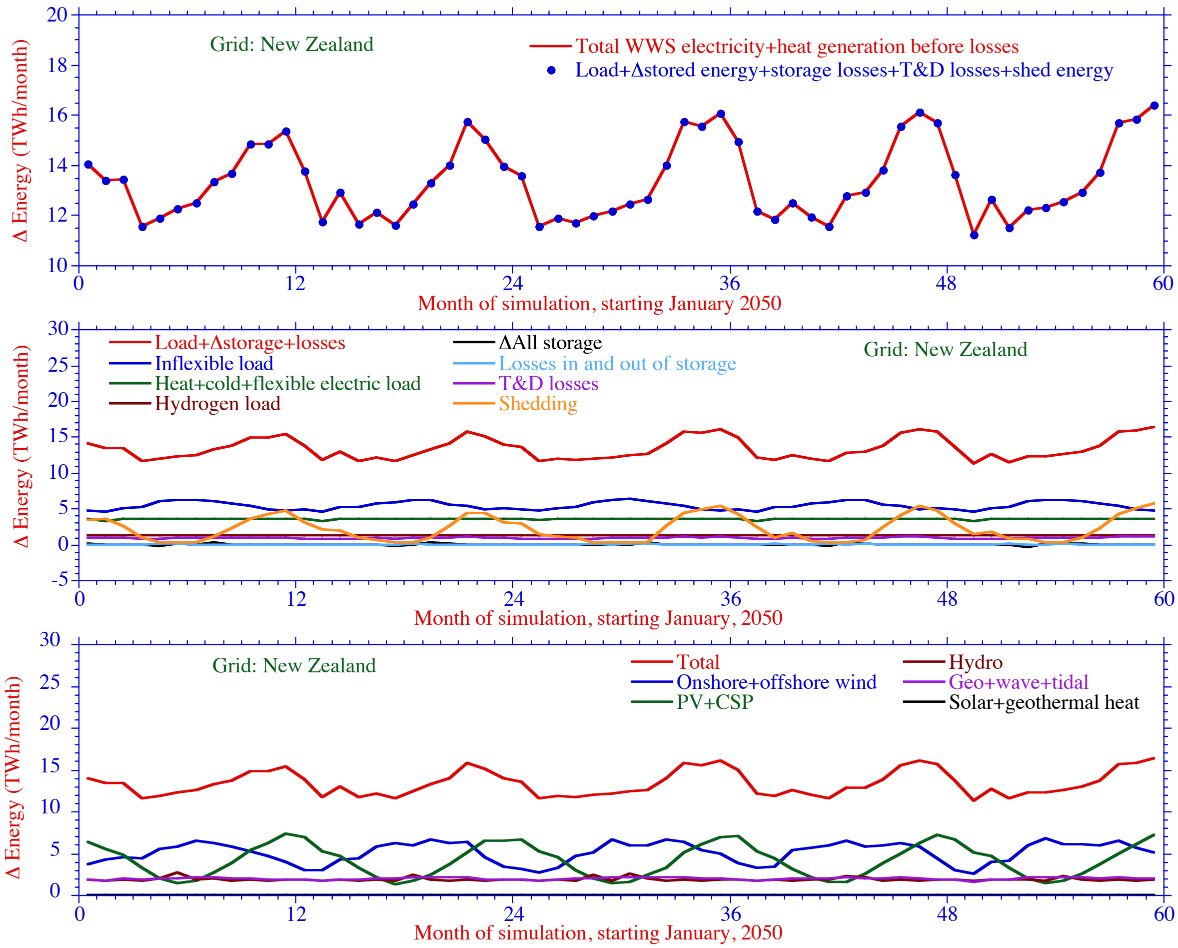


Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Mideast
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

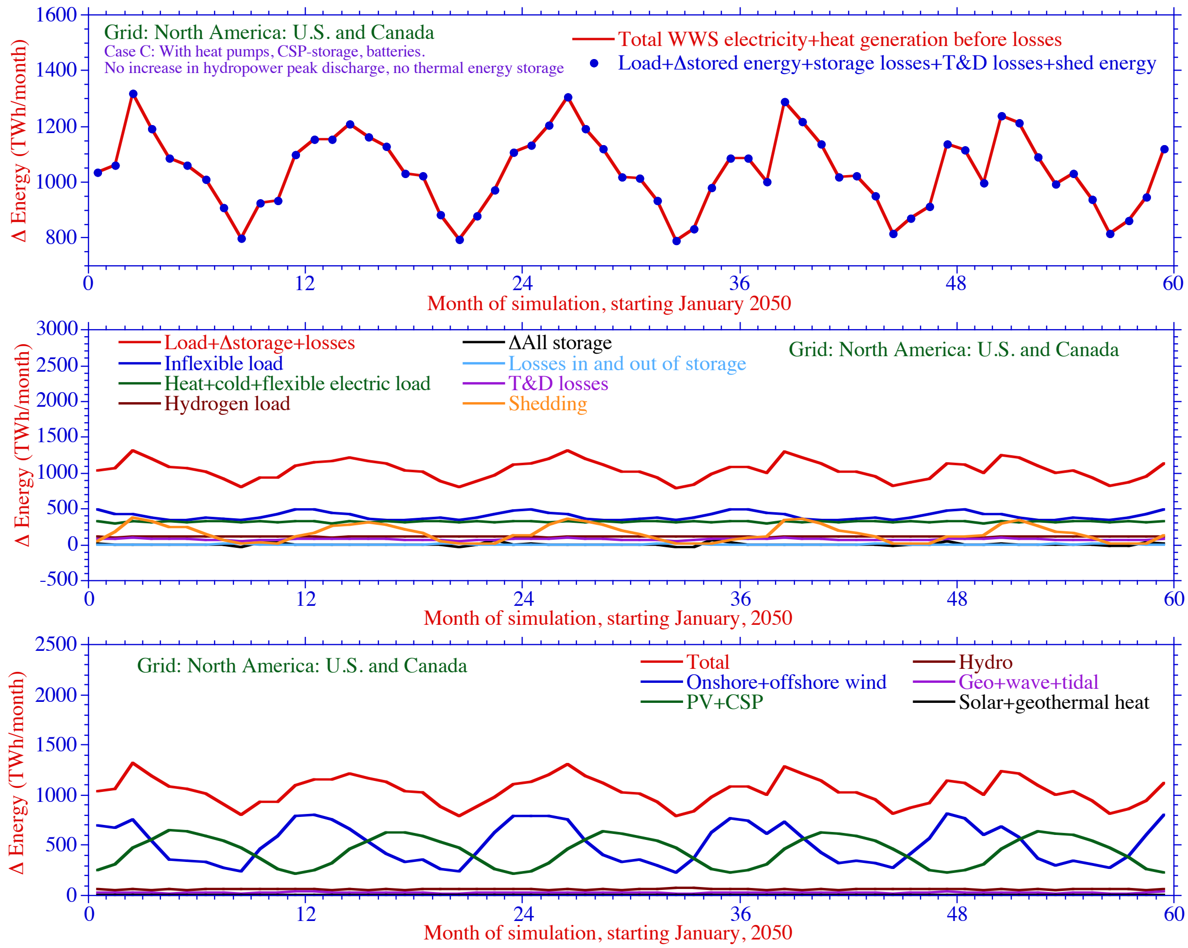


Grid: Mideast
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

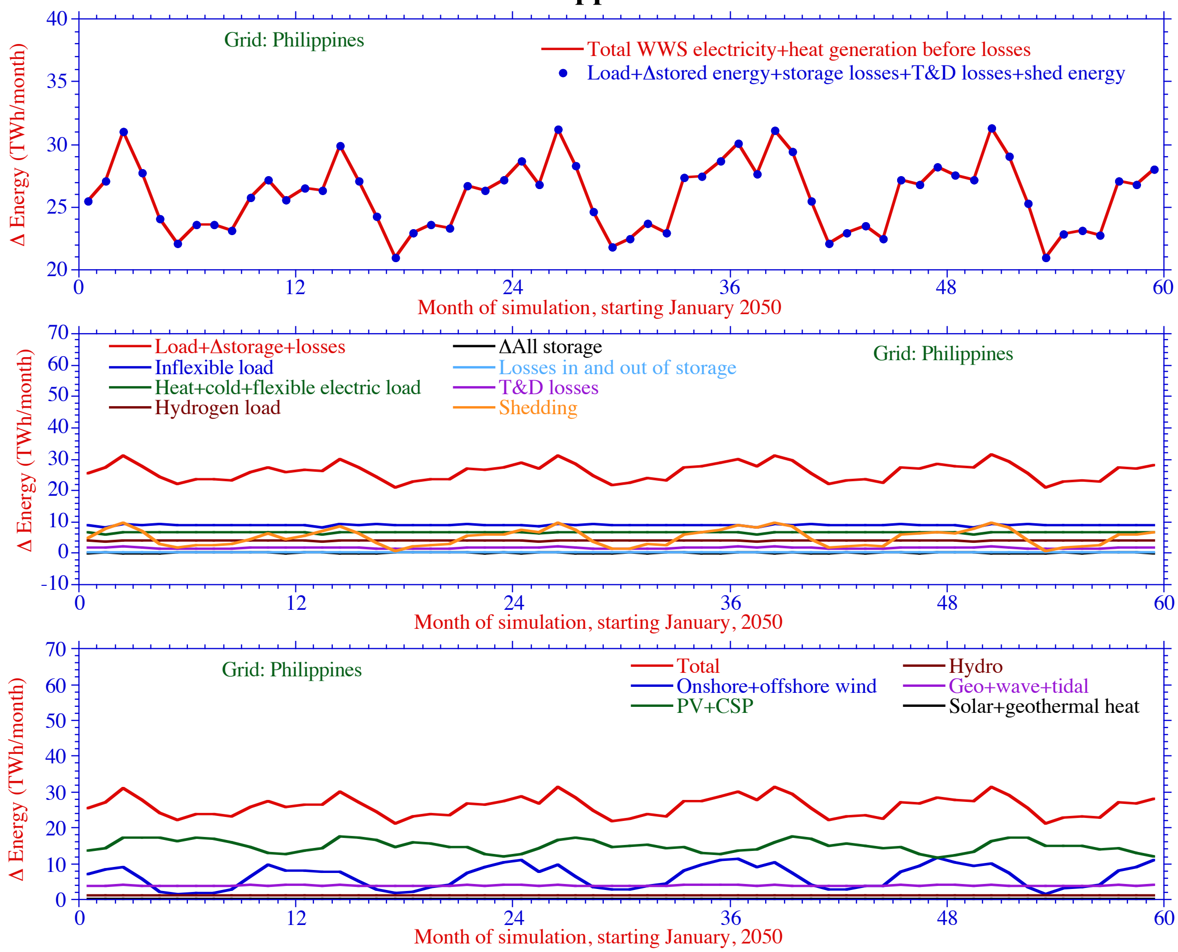
New Zealand


Grid: New Zealand
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Δ Energy (TWh/month)
Month of simulation, starting January 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: New Zealand
Δ Energy (TWh/month)
Month of simulation, starting January, 2050
Grid: New Zealand
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Δ Energy (TWh/month)
Month of simulation, starting January, 2050

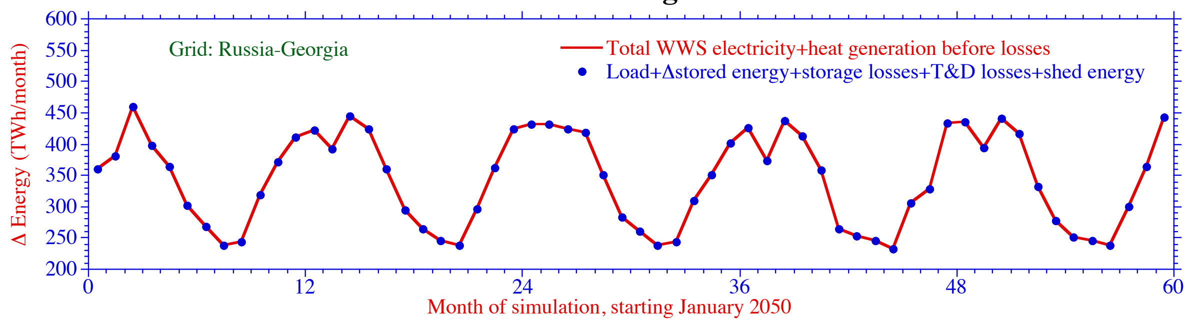
North America

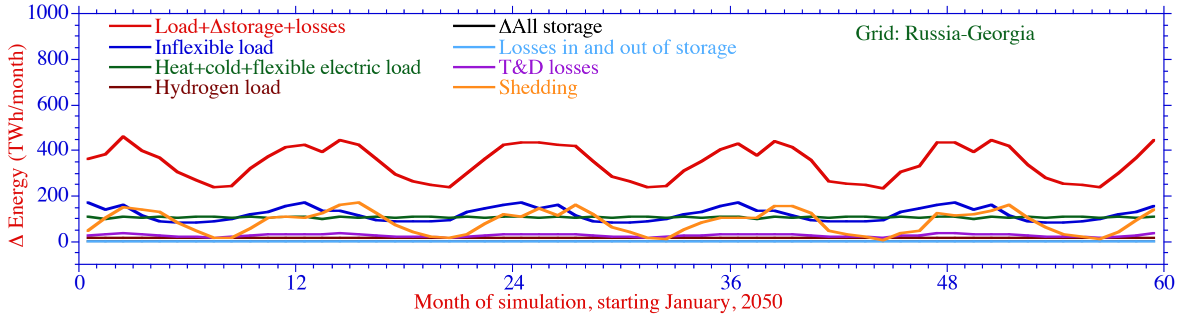


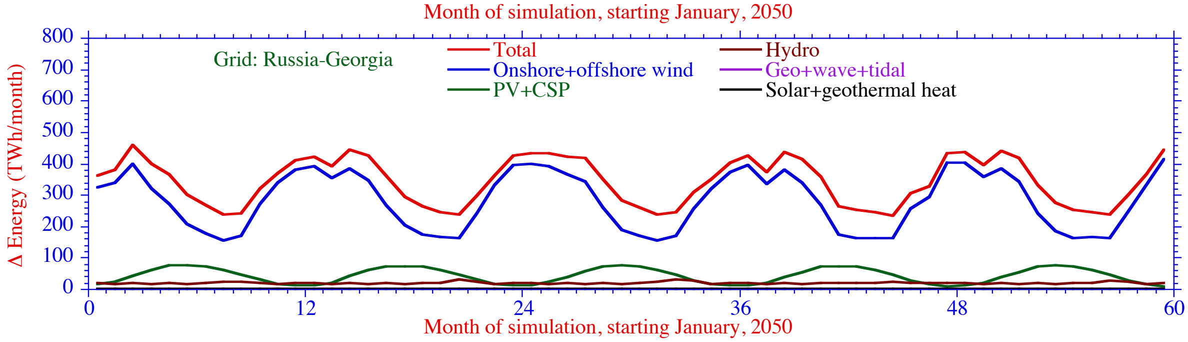
Philippines



Russia-Georgia







South America

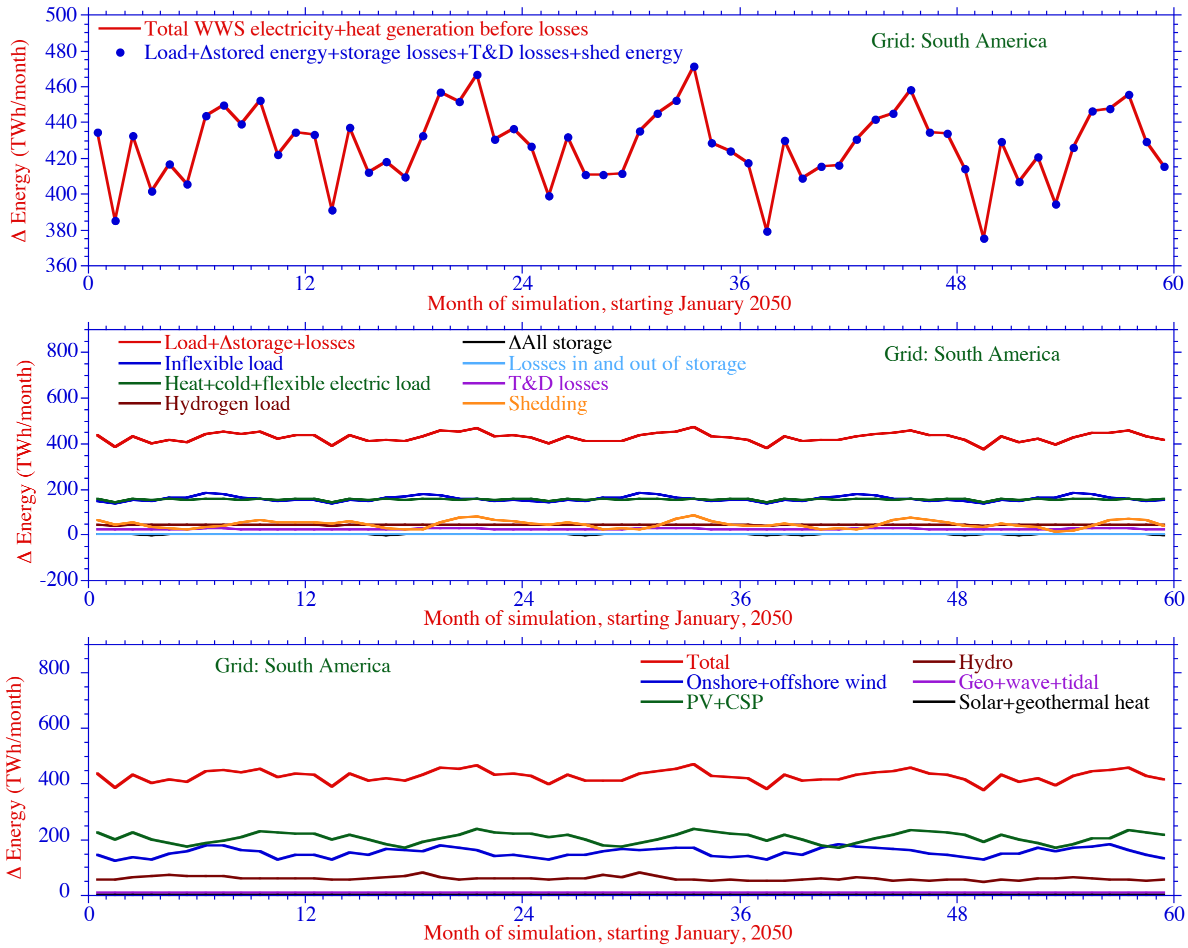
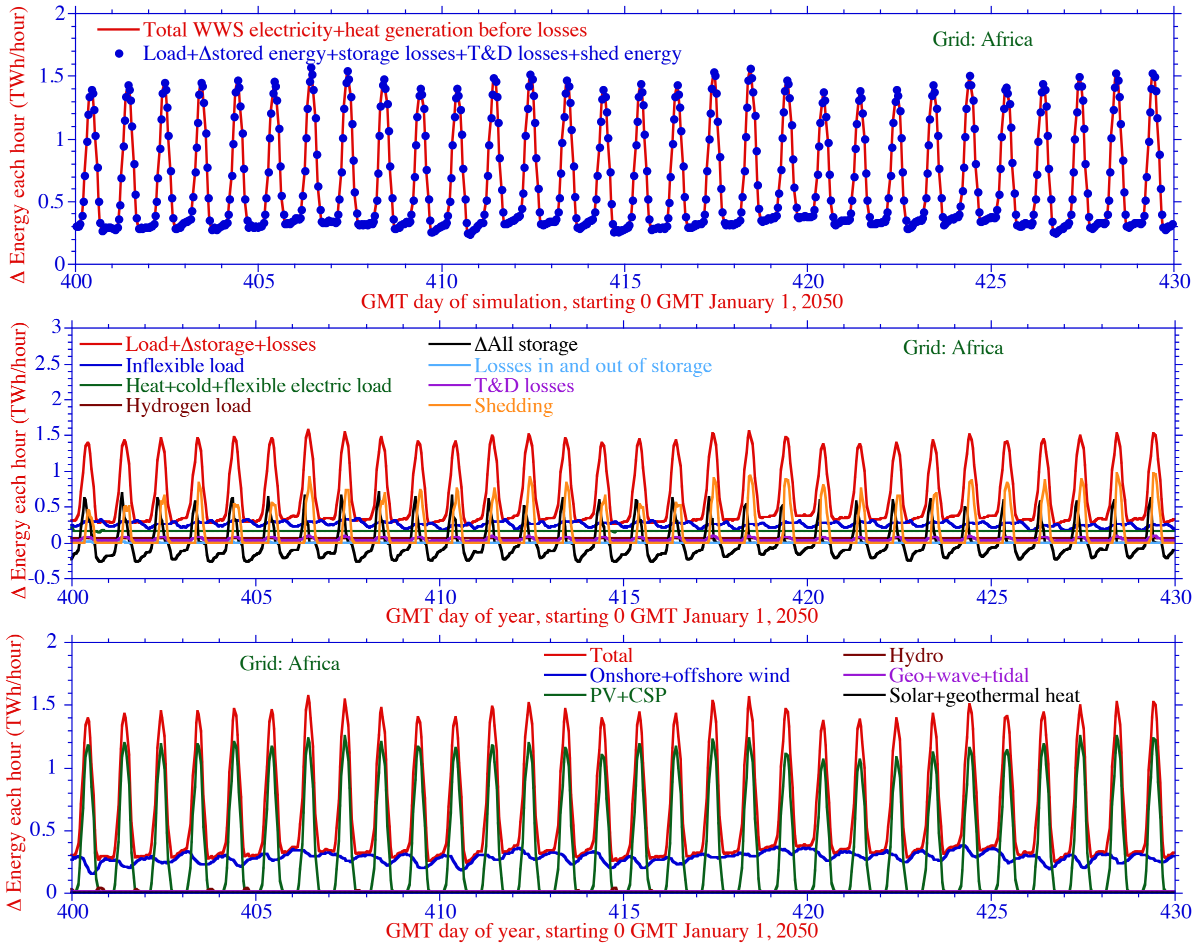
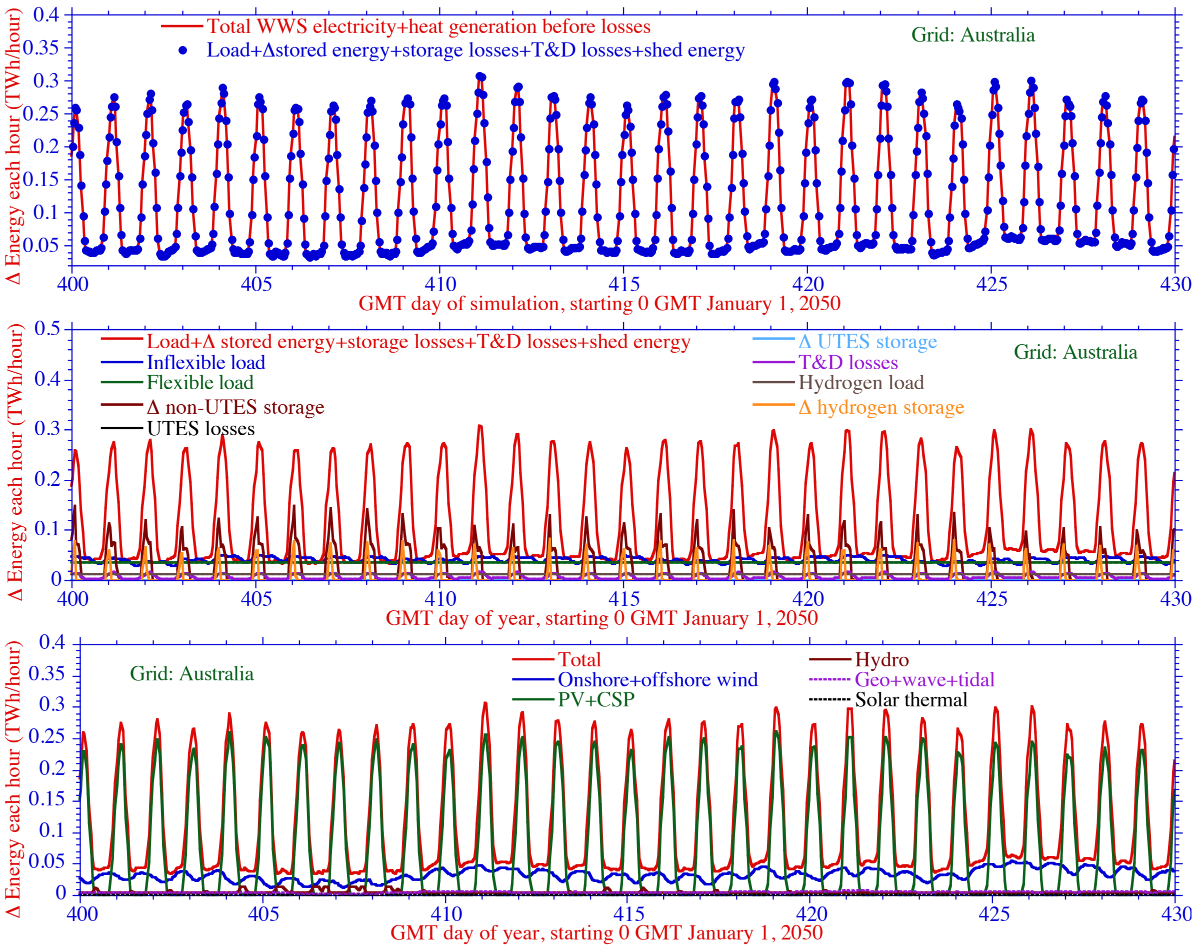


Figure S6. Same as Figure S5, which shows results for Case C, but with hourly results for a 30-day period during the 5-year simulation for each of the 14 world regions examined in Case C.

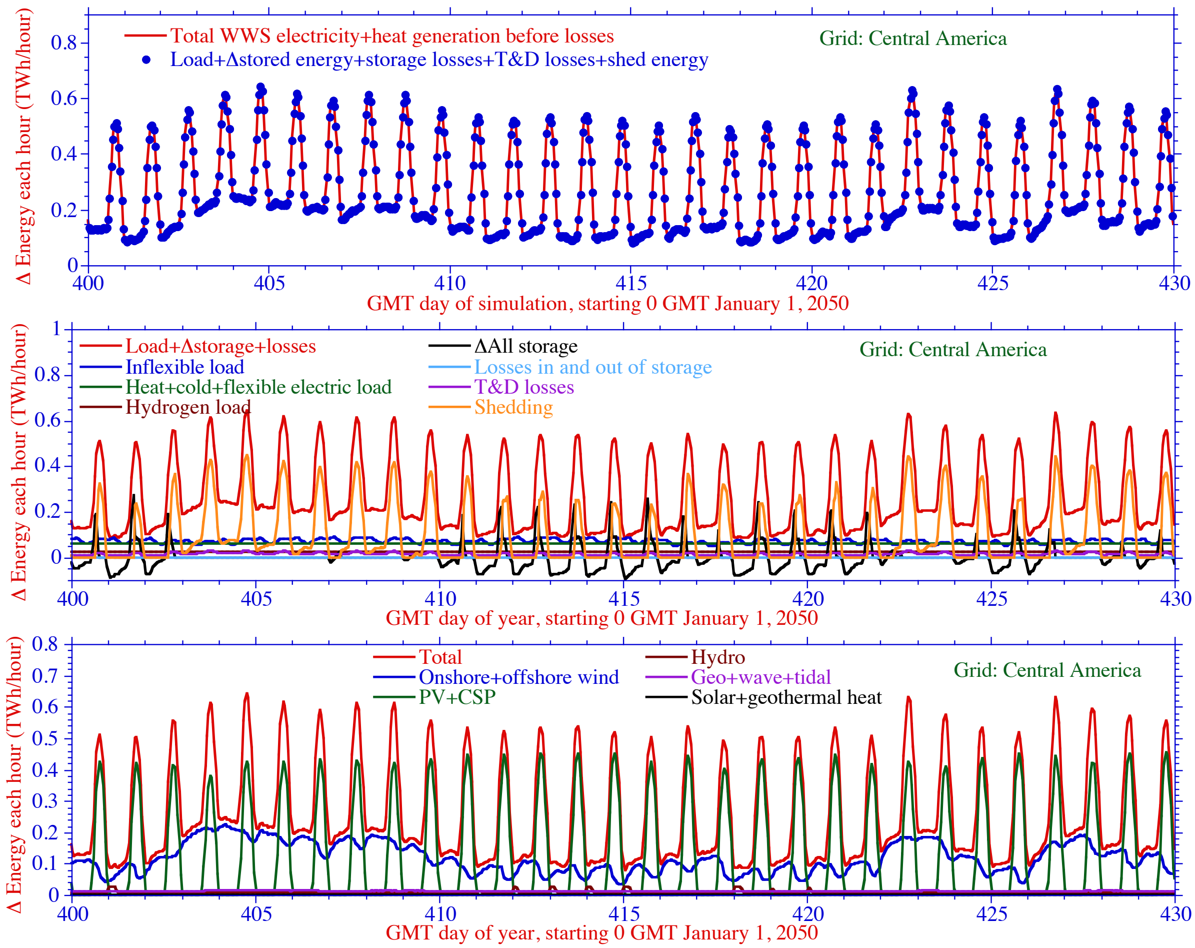
Africa



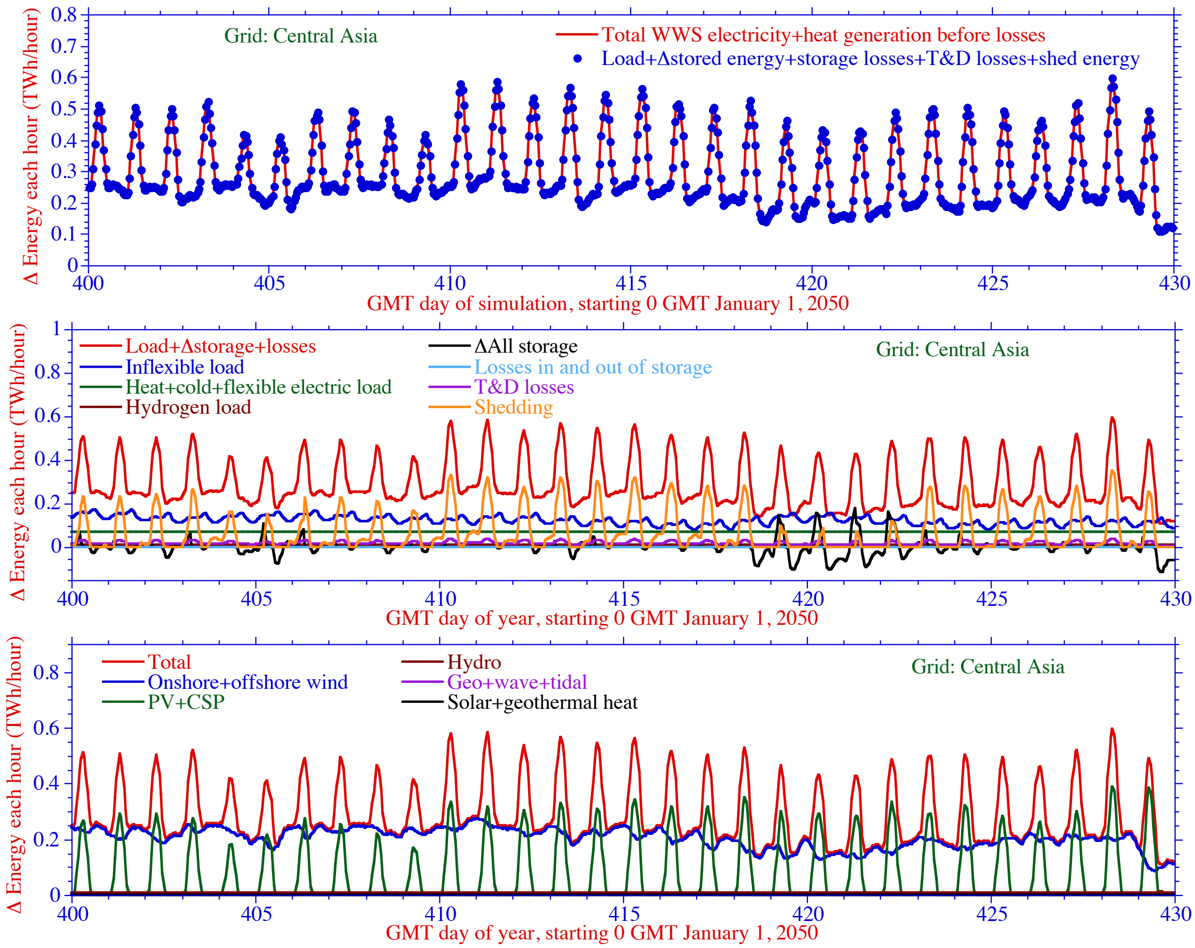
Australia


Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Australia
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δ stored energy+storage losses+T&D losses+shed energy
Inflexible load
Flexible load
Δ non-UTES storage
UTES losses
Δ UTES storage
T&D losses
Hydrogen load
Δ hydrogen storage
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar thermal

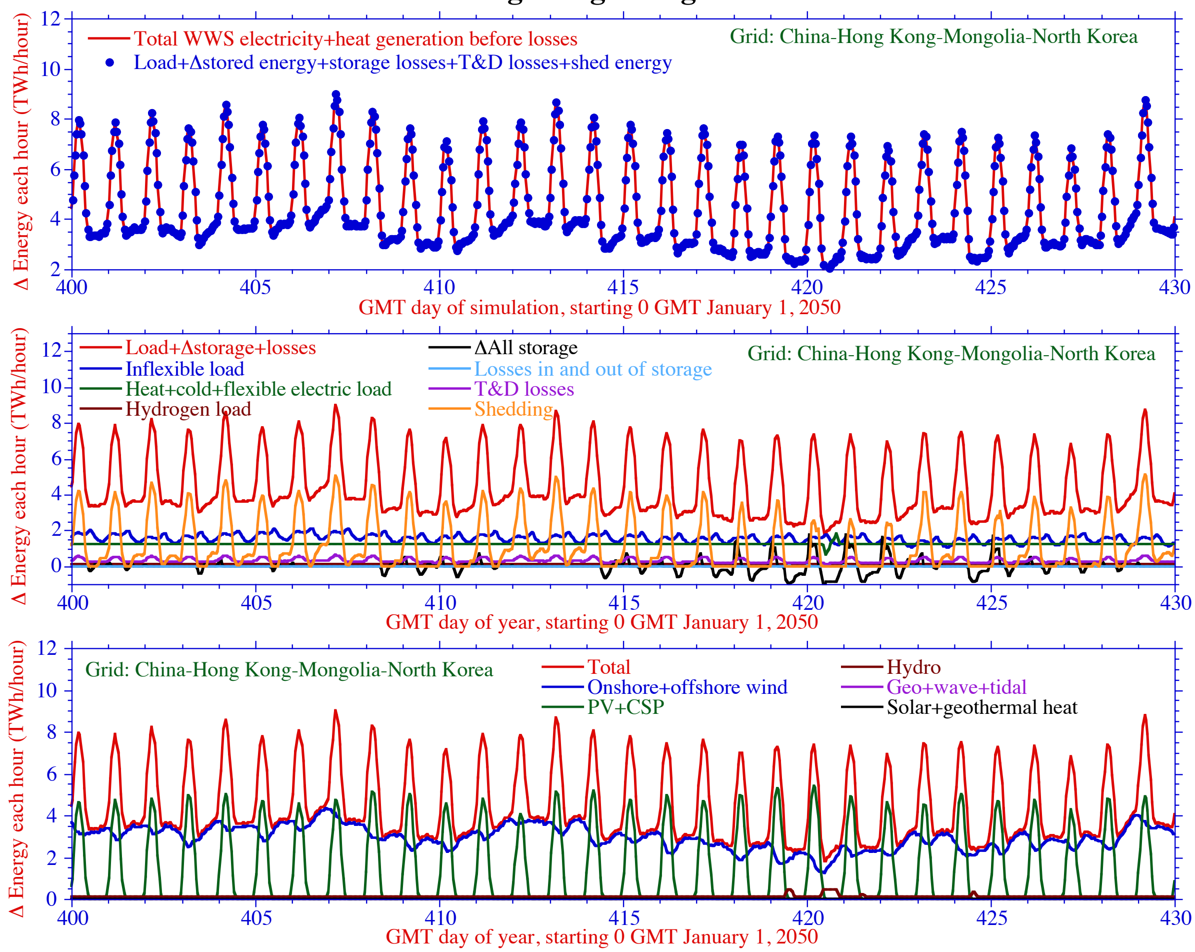
Central America



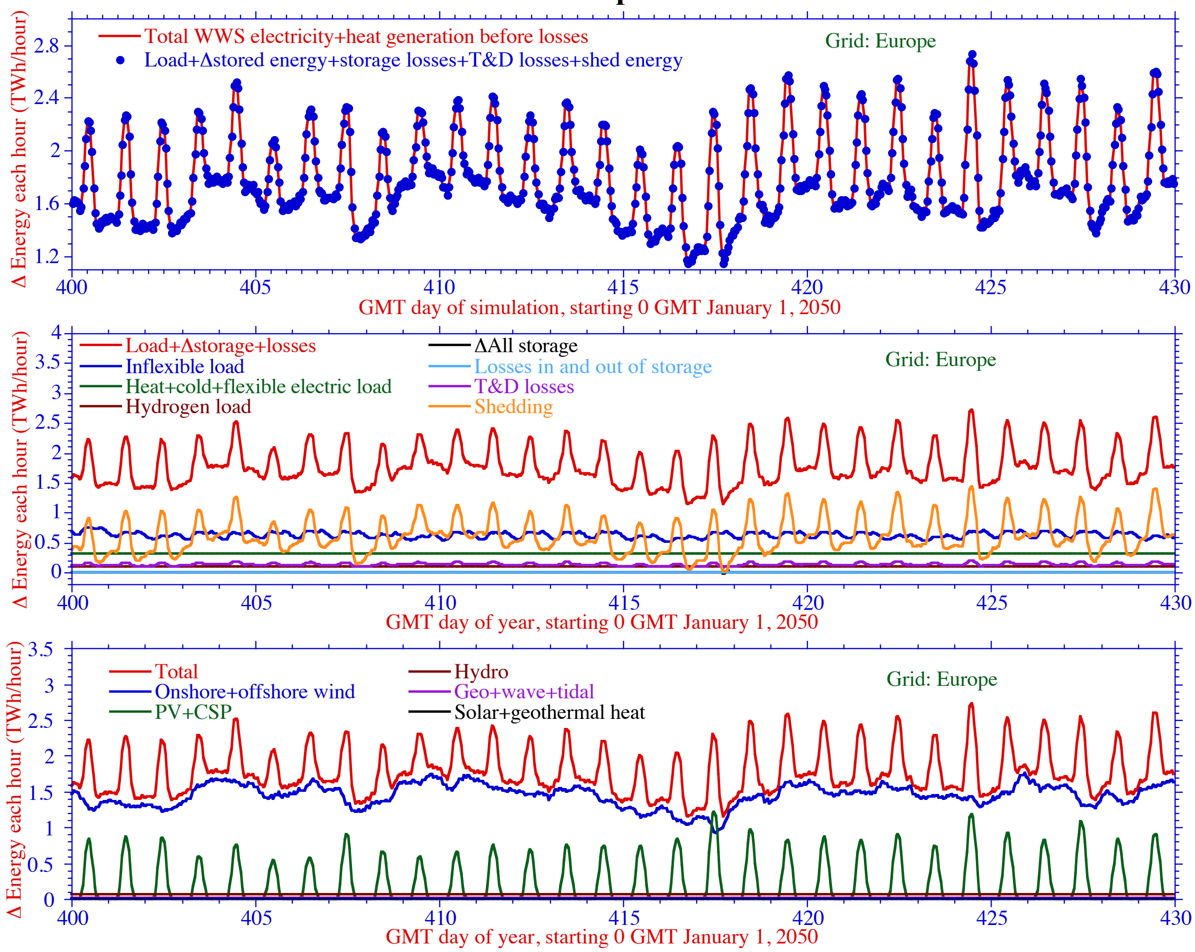
Central Asia



China China-Hong Kong-Mongolia-North Korea

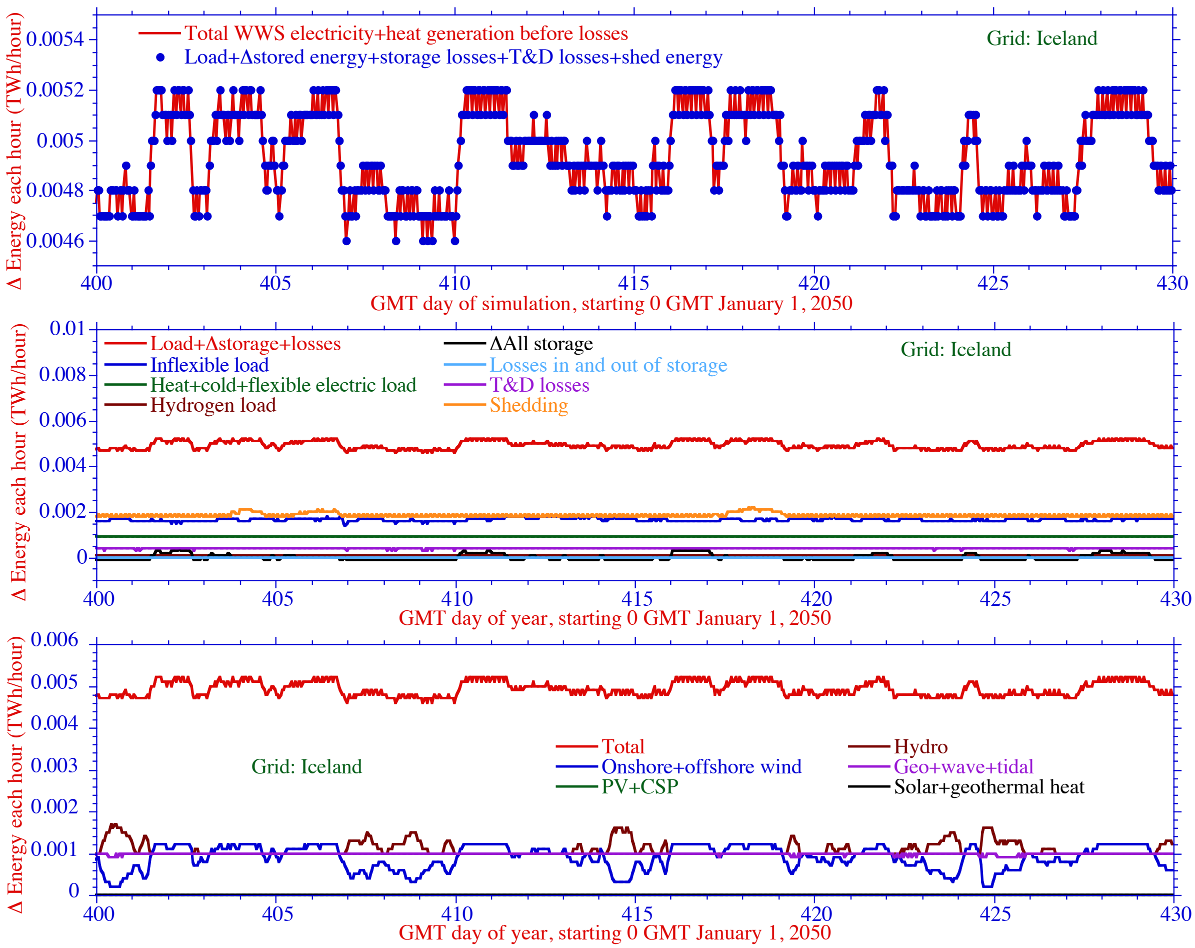


Europe

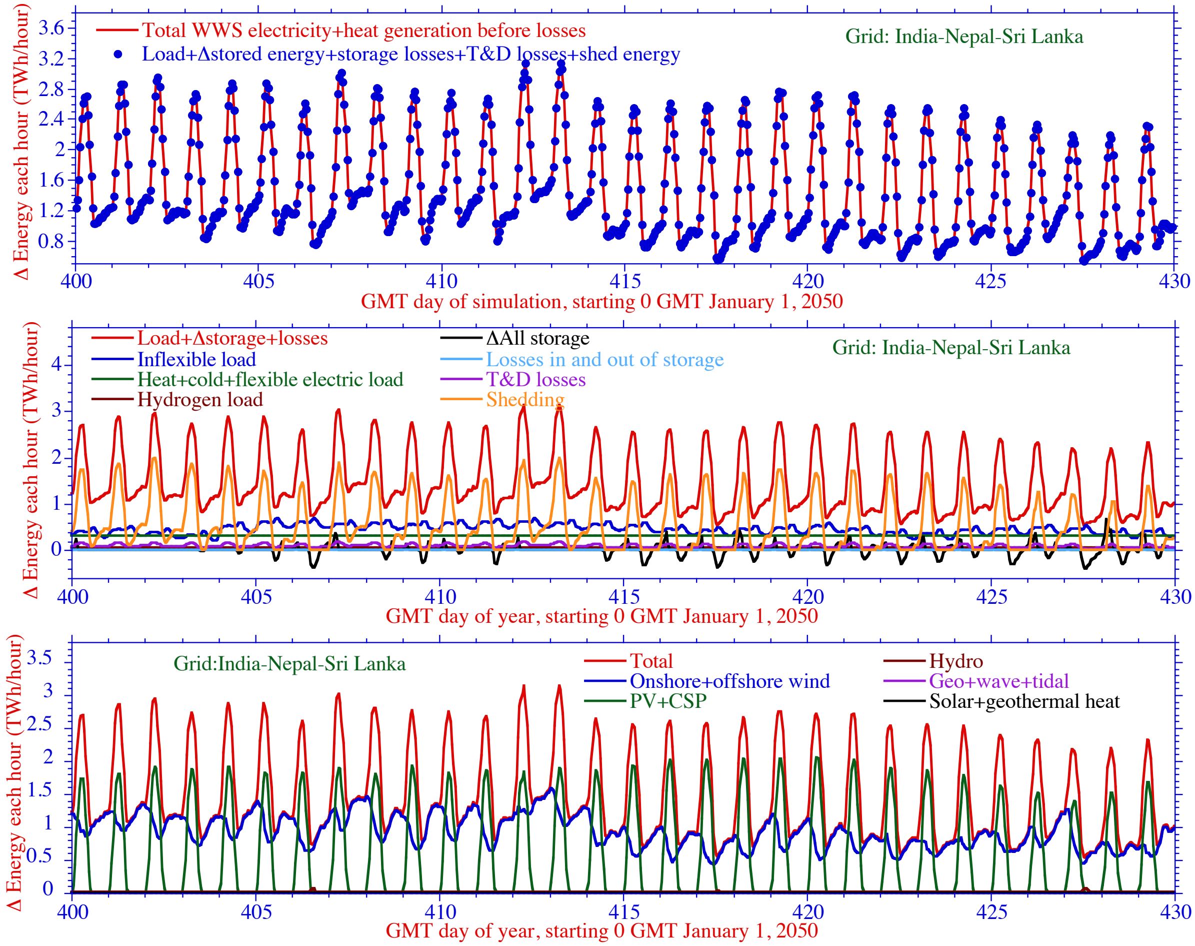


Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Europe
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat

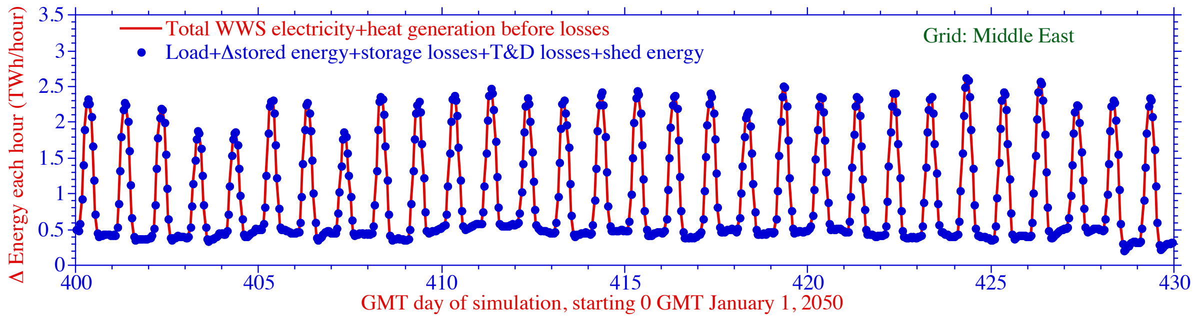
Iceland


Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Iceland
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat

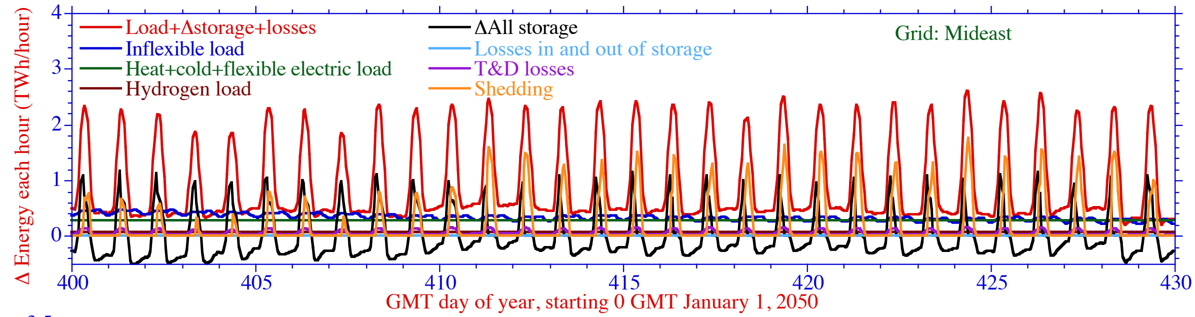
India-Nepal-Sri Lanka



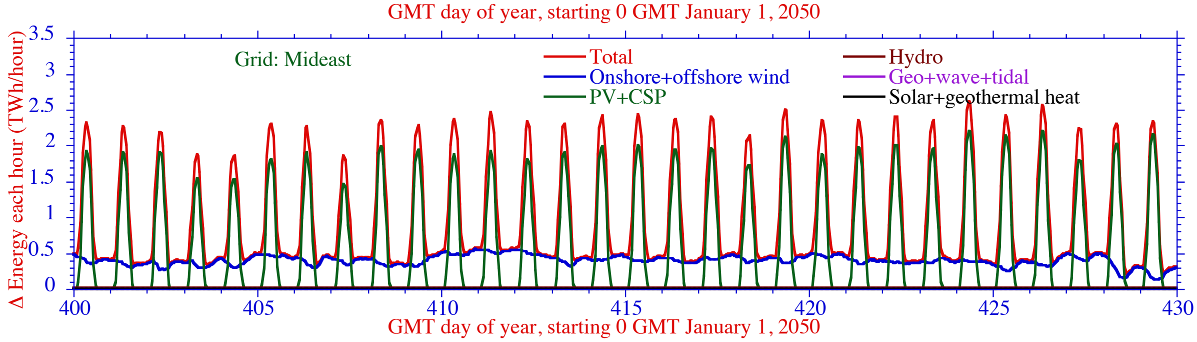
Mideast



Δ Energy each hour (TWh/hour)
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Middle East
GMT day of simulation, starting 0 GMT January 1, 2050

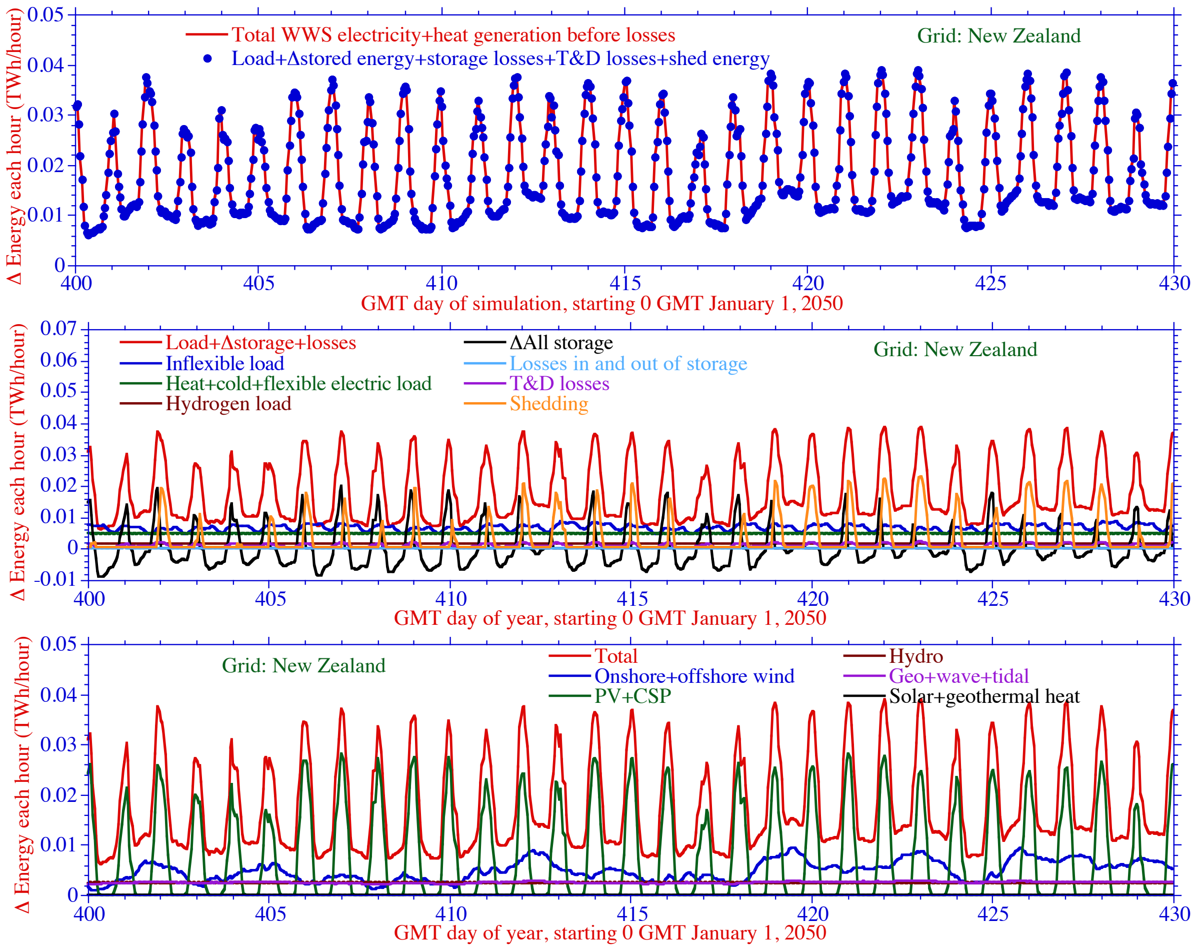


Δ Energy each hour (TWh/hour)
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Mideast
GMT day of year, starting 0 GMT January 1, 2050



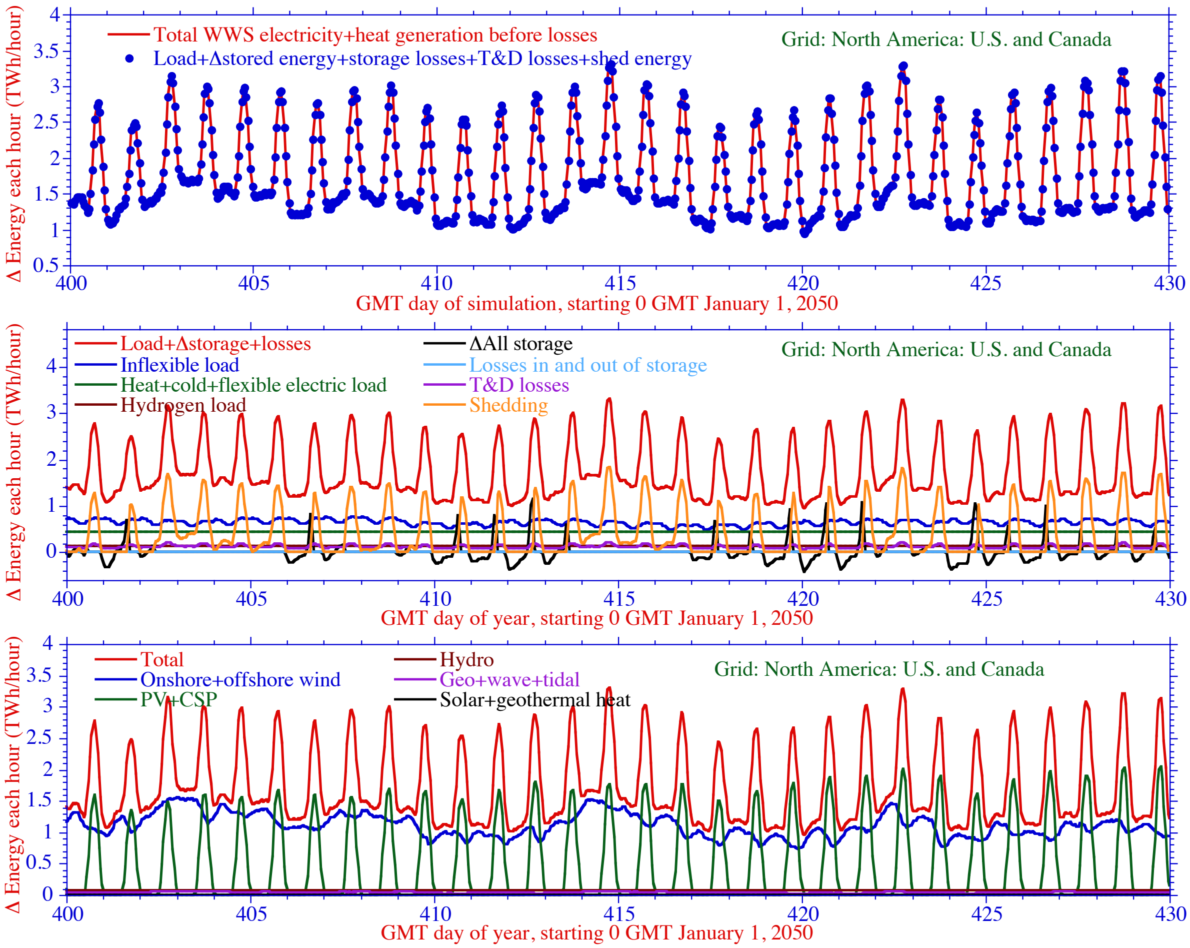
Δ Energy each hour (TWh/hour)
Grid: Mideast
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
GMT day of year, starting 0 GMT January 1, 2050

New Zealand

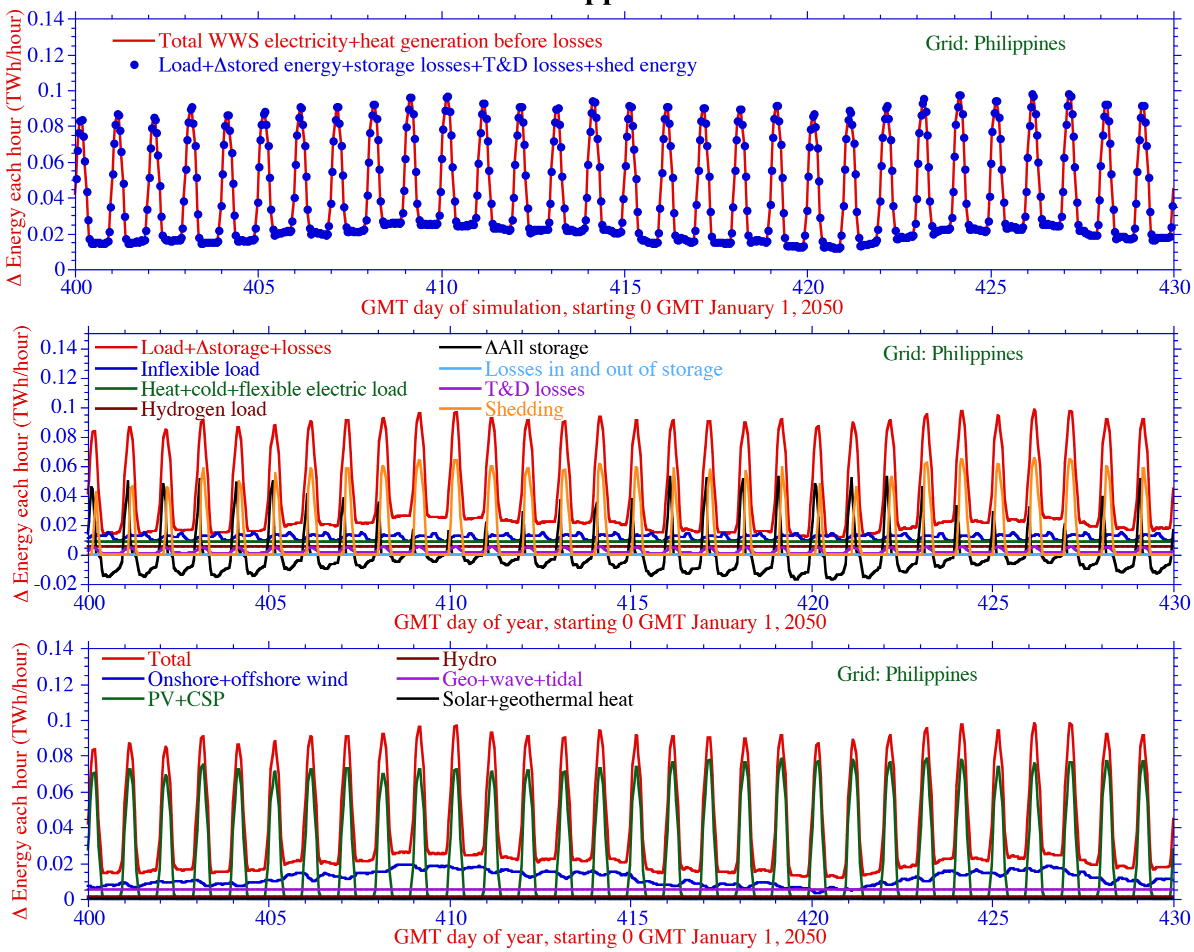


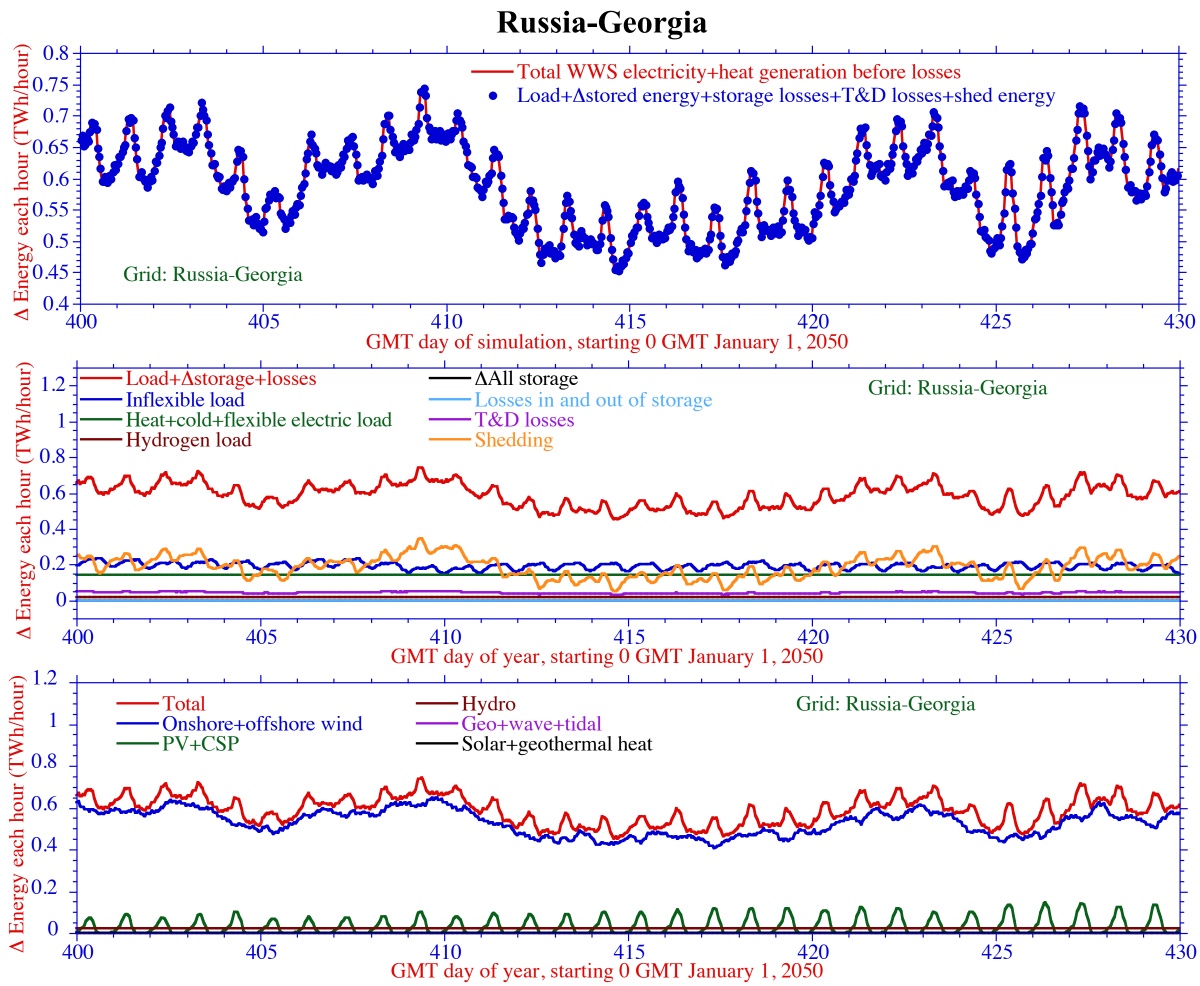
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: New Zealand
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat

North America

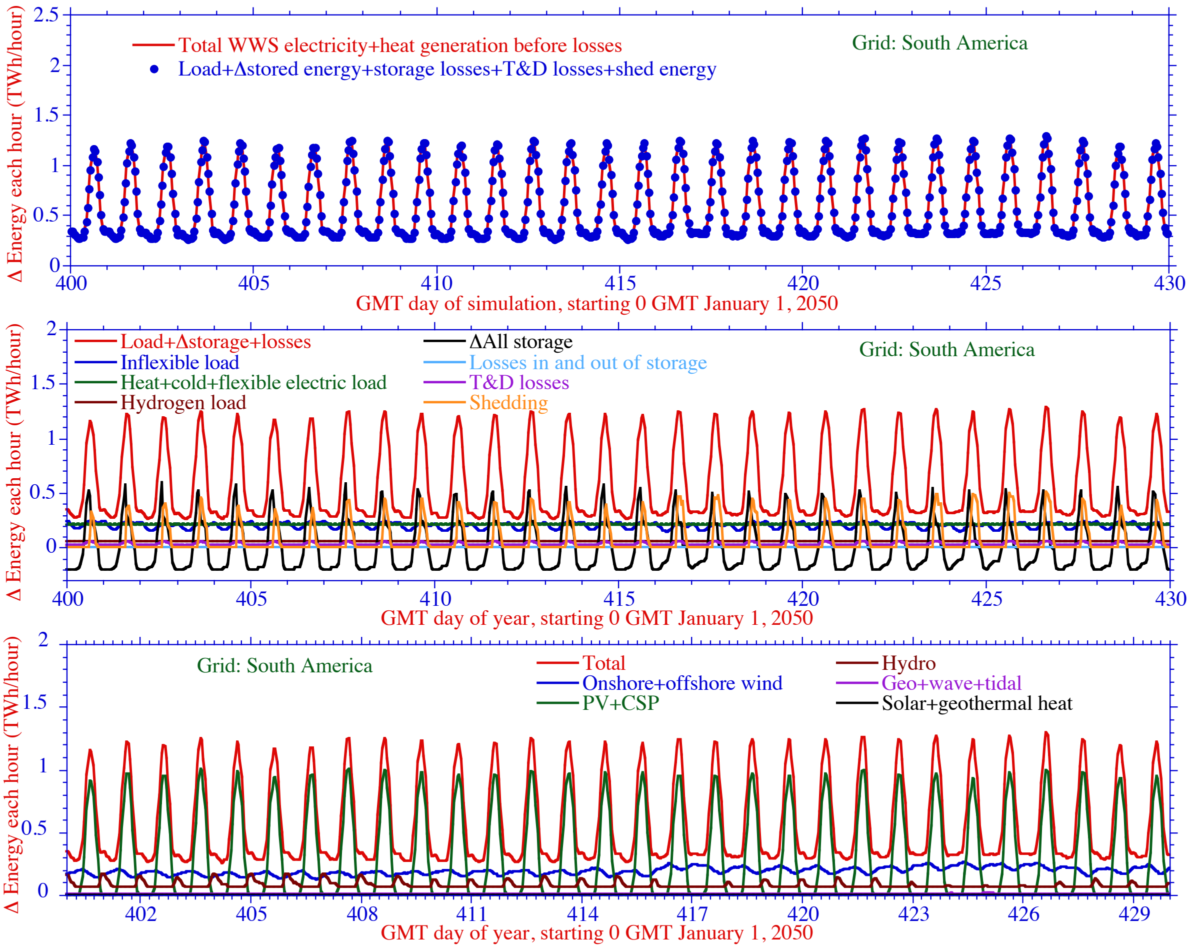


Philippines




Russia-Georgia
Total WWS electricity+heat generation before losses
Load+Δstored energy+storage losses+T&D losses+shed energy
Grid: Russia-Georgia
Δ Energy each hour (TWh/hour)
GMT day of simulation, starting 0 GMT January 1, 2050
Load+Δstorage+losses
Inflexible load
Heat+cold+flexible electric load
Hydrogen load
ΔAll storage
Losses in and out of storage
T&D losses
Shedding
Grid: Russia-Georgia
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050
Total
Onshore+offshore wind
PV+CSP
Hydro
Geo+wave+tidal
Solar+geothermal heat
Grid: Russia-Georgia
Δ Energy each hour (TWh/hour)
GMT day of year, starting 0 GMT January 1, 2050

South America



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