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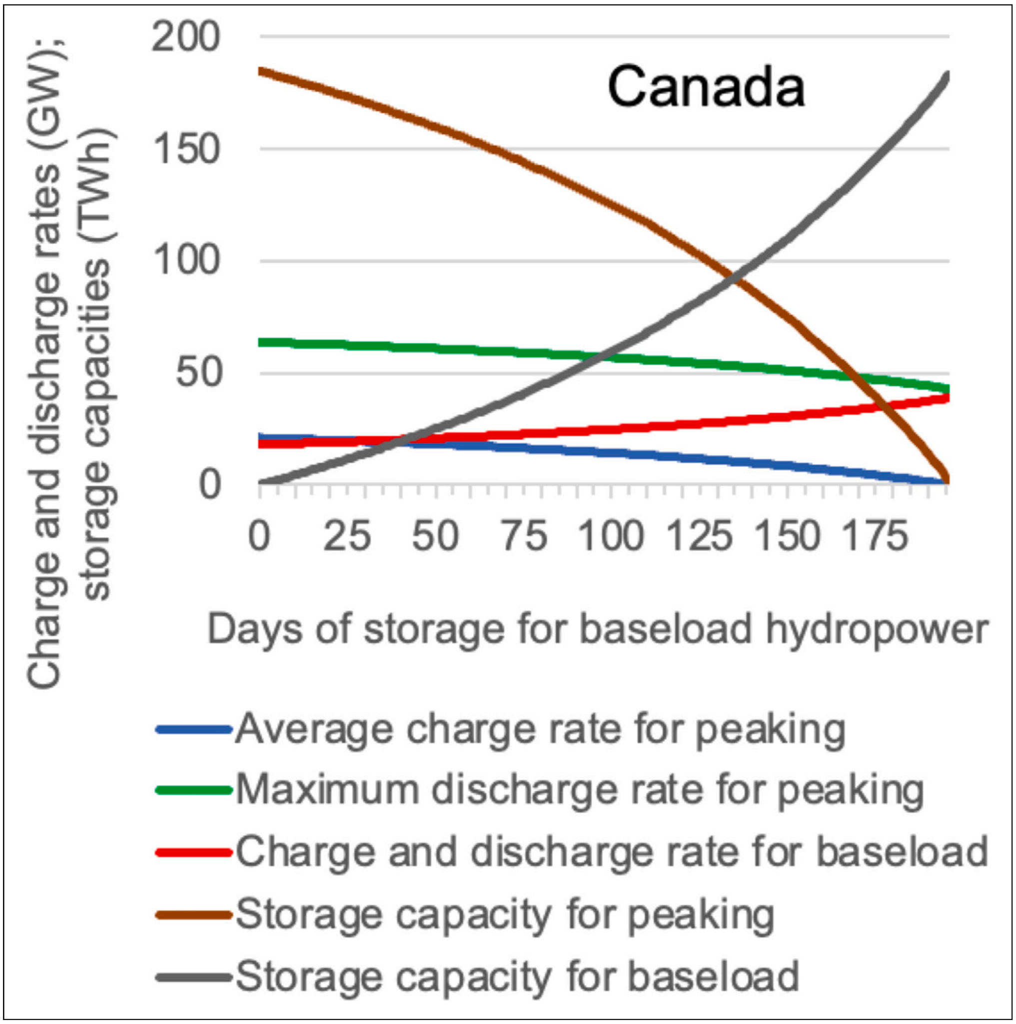

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Highlights

World grid is stability tested with hydropower (CH), batteries (BS), and hydrogen (GHS)

Lowest cost is with CH, CH + BS, or CH + BS + GHS but never CH + GHS or GHS alone

Combining (versus isolating) grid and non-grid hydrogen infrastructure reduces cost

A new method is developed to model hydropower for both peaking and baseload power

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Batteries or hydrogen or both for grid electricity storage upon full electrification of 145 countries with wind-water-solar?

Mark Z. Jacobson[1,2,*]

SUMMARY

Grids require electricity storage. Two emerging storage technologies are battery storage (BS) and green hydrogen storage (GHS) (hydrogen produced and compressed with clean-renewable electricity, stored, then returned to electricity with a fuel cell). An important question is whether GHS alone decreases system cost versus BS alone or BS + GHS. Here, energy costs are modeled in 145 countries grouped into 24 regions. Existing conventional hydropower (CH) storage is used along with new BS and/or GHS. A method is developed to treat CH for both baseload and peaking power. In four regions, only CH is needed. In five, CH + BS is the lowest cost. Otherwise, CH + BS + GHS is the lowest cost. CH + GHS is never the lowest cost. A metric helps estimate whether combining GHS with BS reduces cost. In most regions, merging (versus separating) grid and non-grid hydrogen infrastructure reduces cost. In sum, worldwide grid stability may be possible with CH + BS or CH + BS + GHS. Results are subject to uncertainties.

INTRODUCTION

The world is undergoing an energy revolution: a rapid transition from combustion fuels powering electricity, heat, and mechanical processes to clean, renewable energy sources providing electricity and heat for the same processes. Given that humanity depends on such a transition to address air pollution, global warming, and energy security, it is important to ensure that the new energy system is reliable and inexpensive. One concern with such a system, though, is the uncontrollable variability of wind and solar electricity generation, which gives rise to the need for backup to fill in gaps between supply and demand (load) on the electricity grid.[1]

Historically, most gaps have been filled with conventional hydropower (CH), pumped hydropower storage (PHS), and natural gas. However, a future clean, renewable grid will eliminate natural gas use. And, although PHS sites abound,[2] growth rates of PHS and CH will be limited by zoning impediments in some locations and resource limits in others. It has been hypothesized, therefore, that battery storage (BS) and green hydrogen storage (GHS) (hydrogen produced from clean, renewable electricity, then compressed, stored, and returned to electricity with a fuel cell) may be needed substantially in a future clean, renewable grid.[3–9] Other types of electricity storage, such as concentrated solar power (CSP) with storage, flywheels, compressed air storage, and gravitation storage with solid masses exist but have not taken root to the extent that batteries have to date and GHS is anticipated to in the future. Given the potential large-scale use of BS and GHS in future energy systems, an important question is whether GHS, which has a lower round-trip efficiency, higher cost of discharging electricity, but lower storage capacity cost than BS, results in a lower or higher overall system cost than does BS alone or BS + GHS.

Many studies to date have treated the matching of energy demand with 100% renewable supply and storage for both short and long periods.[8–15] Two studies found that adding turbines to existing CH dams without increasing annual CH electricity generation enables hydropower to be used for meeting short-term peaks in demand and long-term electricity storage needs in the United States and worldwide, respectively.[12,13] Several studies have also found that concatenating 2- or 4-h batteries for both short and long-duration electricity storage enables the matching of demand with supply, storage, and demand response on the grid for multiple years at low cost.[10,11,13,14] Some studies have assumed the use of heat stored seasonally underground and the use of excess renewable electricity to produce that heat.[10–14] Other studies have assumed the use of excess electricity to produce hydrogen for non-grid purposes.[10–17] One study examined the conditions under which GHS is useful in a district energy system.[4] Other studies have treated the use of GHS for grid or non-grid storage.[3–9] Some of these studies compared using BS alone versus BS + GHS in a 100% renewable system in a region, concluding that combining BS with GHS may reduce energy cost in the region.[8,9] A further study has analyzed the impact of electricity storage capacity cost, discharge efficiency, and other parameters on the cost of keeping the grid stable with long-duration storage technologies.[18] However, no study has compared the cost of matching supply with demand, storage, and demand response worldwide upon converting all energy sectors to 100% clean, renewable

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energy and using CH with BS and/or GHS as the main storage options. Also, no study has compared the overall energy cost of isolating versus merging hydrogen electrolyzers and storage for grid versus non-grid purposes.

Here, the cost of matching power demand with supply, storage, and demand response in 24 world regions encompassing 145 countries is examined with a time-dependent trial-and-error simulation model (Methods) run over three years. The predominant electricity storage technologies used are CH with BS and/or GHS. A method is developed to treat CH for both baseload and peaking power. Four cases are examined. In all cases, all energy sectors in each country are first electrified as much as possible and use direct heat for the rest of their energy. The electricity and heat are then provided with 100% wind-water-solar (WWS). Green hydrogen is also used in all four cases for three non-grid purposes: steel manufacturing, ammonia manufacturing, and long-distance transport. This study follows from two previous studies: one in which grid stability was analyzed in 145 countries when green hydrogen was used only for long-distance transport[11] and a second in which green hydrogen was used for long-distance transport and steel and ammonia manufacturing but not for grid electricity.[16]

Results here suggest that four regions need only CH. In the remaining 20 regions, CH + BS is least cost only where the ratio of the needed storage capacity to peak discharge rate is low. In all other regions, where the ratio is usually, but not always, high, CH + BS + GHS is least cost. CH + GHS alone is never least cost. Also, merging electrolyzer and storage equipment for grid and non-grid hydrogen generally reduces cost versus separating such equipment. Thus, using existing CH for baseload and peaking together, with either BS alone or with BS + GHS, can help power the world with 100% clean, renewable energy. This new information should help planners create a more efficient and cost-effective future energy system. Results are subject to uncertainties, including whether they may change when a simulation model (this study) versus an optimization model is used (see limitations of the study).

Simulations: Four cases compared

This work is carried out through computer modeling. Simulations are run with LOADMATCH[10–14,16] (Methods and Notes S3–S7), a model that matches time-dependent electricity, heat, cold, and hydrogen demand with supply, storage, and demand response. LOADMATCH is modified here to treat GHS as an additional grid electricity storage option beyond CH, PHS, CSP with storage, and BS, which are already treated (Table S2). The processes added for GHS are hydrogen production and compression with WWS grid electricity, hydrogen storage for grid electricity, and conversion of stored hydrogen back to grid electricity with fuel cells. The model also treats green hydrogen for steel and ammonia manufacturing and long-distance transport.[16] Table S7 summarizes the 2050 hydrogen budget needed by country for each of these non-grid uses. LOADMATCH is further modified here to treat CH for both baseload and peaking power. Previously, it was used only to provide peaking power. A set of six equations and six unknowns is solved (Equations S7–S12) to distribute CH parameters between peaking and baseload power while conserving several properties (Note S5).

BS and GHS each has advantages and disadvantages. The advantages of batteries for grid electricity storage are that they (1) emit no air pollutants when charging if the electricity charging them is from a clean, renewable source and no air pollution ever when discharging; (2) charge and discharge rapidly (100% discharge in 10–20 ms[7] versus 100% in 5 min for an open-cycle natural gas turbine[19] and 15 s for CH[20]); (3) provide, when concatenated together, substantial peaking power for a short period, or low power for days to weeks to months, or anything in between[10,11]; (4) do not take up much space or have the same zoning impediments as CH or PHS; and (5) can save grid operators substantial money compared with natural gas turbines due to providing frequency control ancillary service and contingency reserve service more effectively than can natural gas.[21] Disadvantages of BS are its (1) high capital cost per kWh of storage capacity, (2) degradation over time, and (3) requirement, in many cases, for metals that must be mined or obtained from recycling. However, battery cost has declined and battery degradation has decreased in the past decade. For example, at least one manufacturer warranties batteries now for 15,000 cycles or 15 years.[22] Finally, whereas lithium used in most batteries is mined, it is also recycled.[22,23]

Advantages of GHS are that (1) electrolyzers result in no air pollutants during hydrogen production if the electricity source is clean and renewable, and fuel cells produce only water vapor during electricity generation; (2) electrolyzers create hydrogen rapidly, and fuel cells produce electricity within seconds to a minute[7]; (3) GHS can provide peaking power for a short period, or low power for days to weeks to months, or anything in between[4]; (4) GHS requires only modest space and does not face the same zoning problems as CH or PHS; (5) GHS may save grid operators money like batteries do, and (6) GHS' costs per unit storage capacity are lower than those of batteries.

Disadvantages of GHS are as follows: (1) the round-trip efficiency of BS is 2.3–4 times that of GHS,[20] (2) the cost per kWh of discharging electricity from GHS is higher than that from BS; (3) hydrogen from GHS may leak, impacting the atmosphere; and (4) platinum, needed in electrolyzers and fuel cells, may be a limiting factor in GHS growth. The cost issues are evaluated here. With respect to leakage, gasoline vehicles already emit hydrogen. Even if all vehicles worldwide are transitioned to hydrogen fuel cell vehicles, the hydrogen leakage rate needs to exceed 3% for hydrogen emissions to exceed those of gasoline vehicles.[24] Instead, most vehicles will be replaced by battery electric ones, suggesting a large reduction in hydrogen emissions upon a world transition to clean, renewable energy. Also, hydrogen leak rates are expected to be less than 1%, as most hydrogen will be produced near where it is consumed (so few pipelines will be needed), hydrogen infrastructure will be new and designed to eliminate leaks, and hydrogen will not be mined like natural gas is, reducing a major source of leaks. With respect to platinum, it is also used in catalytic converters in gasoline vehicles. Because a transition will eliminate gasoline vehicles, platinum will no longer be needed for catalytic converters. Thus, platinum should not be a limiting factor in hydrogen use.

It is assumed here that hydrogen used for grid electricity will be stored as a compressed gas. More expensive and energy-intensive liquefied hydrogen storage is needed only when space is a constraint, such as when hydrogen is used in rockets or airplanes. Liquid hydrogen is also needed when hydrogen is transported by ship. However, this study assumes that electricity is transmitted and electrolytic hydrogen is produced and stored at steel and ammonia factories and long-distance transport hubs (e.g., airports, docks, train stations, major truck stops, and military bases), minimizing the need for hydrogen piping or shipping. As such, liquefied hydrogen is not treated here for GHS. Similarly, liquid organic hydrogen carriers,[25] which have been proposed to transport hydrogen by pipeline and ship and which require more chemicals and energy than does compressed hydrogen, are not treated here.

Four simulations are run with LOADMATCH for each of 24 world regions (Table S1). The regions include a mix of nine multi-country regions (Africa, Central America, Central Asia, China region, Europe, India region, the Middle East, South America, and Southeast Asia) and 15 individual countries or pairs of countries (Australia, Canada, Cuba, Haiti-Dominican Republic, Israel, Iceland, Jamaica, Japan, Mauritius, New Zealand, the Philippines, Russia-Georgia, South Korea, Taiwan, and the United States). The 145 countries in these regions emit over 99.7% of the world's fossil-fuel CO_2.

The first simulation (Case I) is a baseline simulation in which non-grid hydrogen is used for steel and ammonia manufacturing and long-distance transport, but GHS is not treated. Instead, grid electricity storage includes only CH, BS, PHS, and/or CSP, assuming the maximum charge rates, discharge rates, storage capacities, and storage times in Table S15. Many types of batteries exist that can be used for grid electricity storage. These types include lithium-ion, lithium-iron-phosphate (LFP), iron-air, basalt-stone, sodium-sulfur, aluminum-ion, salt-water, and vanadium flow batteries, among others. Here, we assume the use of 4-h batteries with the measured efficiency of a 2021 lithium-ion Tesla Powerpack and a projected 2035 cost per kWh of lithium-ion batteries given in Table S27. WWS supply profiles are described in Note S3, demand profiles are described in Note S6, and both are graphed for each region and for the same 3-year period as here in Figure S1 of Jacobson et al.[16]

Case II is the same as Case I, except that in Case II, GHS is treated along with all the electricity storage options treated in Case I. In Case II, the same rectifiers, electrolyzers, compressors, and storage tanks are used for non-grid hydrogen as for GHS, and fuel cells are added to reproduce grid electricity from the communally stored hydrogen. Sharing hydrogen production and storage for both grid and non-grid purposes is expected to reduce costs due to economies of scale, a hypothesis that is tested here. Case II also assumes that electrolytic hydrogen is produced and stored at steel and ammonia factories and long-distance transport hubs. Fuel cells are located at these hubs and can feed electricity back to the grid from them. Aside from the addition of GHS, the only other difference between Cases I and II is that GHS replaces some BS in Case II. The replacement is limited by the fact that no changes in the nameplate capacities of WWS electricity generators or of heat, cold, or other electricity storage are permitted in Case II versus Case I. Table S19 and Figures S2 and S3 provide the BS and GHS characteristics in Case II for each region.

Case III is the same as Case II, except in Case III, different rectifiers, electrolyzers, compressors, and storage tanks are used for non-grid versus grid hydrogen, and fuel cells re-produce grid electricity only from the hydrogen stored in the grid-hydrogen storage tanks. These storage tanks do not need to be located at steel or ammonia manufacturing facilities or at a transport hub. They can be placed in other locations. Table S20 provides the BS and GHS characteristics in Case III.

In Case IV, GHS replaces all BS. The only way stable solutions are found in this case (with zero batteries) is with higher nameplate capacities of GHS equipment and, in most cases, of WWS generators, than in Cases I–III, driving up cost. Table S11 provides the difference in nameplate capacities by region in Case IV versus Cases I–III. Table S21 provides the GHS system characteristics in Case IV.

RESULTS

LOADMATCH is run for three years (2050–2052) with a 30-s timestep for Cases I–IV in each of the 24 world regions encompassing 145 countries (Table S1). In four of the 24 regions (Canada, Iceland, Russia region, and South America), BS is not needed to keep the grid stable, so GHS is not needed either. In those regions, an abundance of WWS resources (CH used for storage and generation plus wind and/or solar) avoids the need for BS. Because no BS or GHS is needed, results are the same in all four cases in those four regions.

In five of the remaining 20 regions, CH + BS alone (Case I) results in the lowest annual private energy cost relative to CH + BS + GHS (Cases II and III) or CH + GHS alone (Case IV) (Table 1; Figure 2). This occurs despite the fact that including GHS in Cases II and III reduces the nameplate capacity of BS needed by about half, from 17.2 TW/68.9 TWh in Case I to 8.8 TW/35.3 TWh in Case II and to 8.2 TW/32.9 TWh in Case III (Figure 1; Tables S18–S21).

The annual private cost of energy in Case II (CH + BS + GHS, where non-grid and grid hydrogen production and storage are merged) is lower than in all other cases in 11 regions, lower than in Case I in 14 regions, and lower than in Case III in 12 regions (Table 1; Figure 2). However, averaged over all 24 regions, Case II has a 1% higher annual cost of energy than Case I, due largely to the 6.1% higher cost of energy in Case II in the China region. The greatest percent cost reduction in Case II versus Case I (11.5%) occurs in Israel (Table 1). From a technology point of view, the cost increase among all regions in Case II versus Case I is attributable to a 49% reduction in the battery peak discharge rate and storage capacity among all regions offset by the addition of 1.12 GW of fuel cells, a 107% increase in hydrogen storage tank size (5.59–11.5 Tg-H_2), and a slight (0.3%) increase in electrolyzer plus compressor nameplate capacity (7.05 TW–7.07 TW) (Tables S18–S21).

The annual private cost of energy in Case III (CH + BS + GHS, where non-grid and grid hydrogen production and storage are separated) is lower than in all other cases in four regions, lower than in Case I in 10 regions, and lower than in Case II in eight regions (Table 1; Figure 2). Among all regions, Case III increases the annual private energy cost relative to Case I by 0.25%, which is less than the increase in Case II relative to Case I (Table 1). This slight overall cost increase in Case III is attributable to a 52.3% reduction (in Case III relative to Case I) in the battery peak discharge rate (17.23–8.22 TW) and capacity (68.9–32.9 TWh), offset by 1.12 GW greater fuel cell capacity, a 71% larger hydrogen storage tank size (9.56 instead of 5.59 Tg-H_2), and a 16% larger electrolyzer plus compressor nameplate capacity (8.17 instead of 7.05 TW) (Tables S18–S21). In sum, isolating the sources and storage of grid and non-grid hydrogen (Case III) increases annual private energy cost in more locations than merging such sources and storage (Case II) but increases overall annual private energy cost less than does Case II (Table 1).

Table 1. 2050 (a) end-use demand, (b)-(e) mean capital cost of an all-sector transition to WWS in Cases I-IV, (f)-(i) mean levelized cost of all-sector energy (LCOE) in WWS Cases I-IV, (j)-(m) mean annual all-energy private cost in WWS Cases I-IV; (n) mean annual all-energy private cost in the BAU case; and (o) Rideal = the ideal ratio of a battery's maximum storage capacity (TWh) to its discharge rate (TW) (thus a battery's ideal number of hours of storage), obtained by taking the ratio of the actual battery storage capacity in Case I to the maximum discharge rate actually occurring during each simulation in that case. All costs are in 2020 USD. Costs in italics are the lowest cost among all cases in the region.

	WWS annual-average end-use demand (GW)	WWS mean capital cost ($tril)				WWS mean LCOE (¢/kWh-all energy)				WWS mean annual all-energy private = social cost ($bil/y)				BAU mean annual all-energy private cost ($bil/y)	R_{ideal} (h)
Region	(a) All cases	(b) Case I	(c) Case II	(d) Case III	(e) Case IV	(f) Case I	(g) Case II	(h) Case III	(i) Case IV	(j) Case I	(k) Case II	(L) Case III	(m) Case IV	(n) BAU	(o) Case I
Africa	482.1	3.627	3.604	3.639	4.166	8.63	8.55	8.67	9.85	364.5	*361.2*	366.0	416.0	1,222	6.3
Australia	92.3	0.618	0.611	0.687	0.816	8.45	8.37	9.36	10.27	68.3	*67.7*	75.6	83.0	188.0	9.5
Canada	170.3	0.654	0.654	0.654	0.654	6.57	6.57	6.57	6.57	98.1	98.1	98.1	98.1	311.3	–
Central America	156.5	1.445	1.331	1.358	1.548	10.85	10.17	10.41	10.94	148.8	*139.5*	142.7	150.0	347.6	27.0
Central Asia	166.9	1.077	1.090	1.086	1.108	7.95	8.05	8.03	8.19	*116.3*	117.7	117.4	119.7	402.7	4.5
China region	2,424	14.44	15.45	14.64	15.72	8.16	8.66	8.26	8.82	*1,733*	1,838	1,754	1,873	4,248	5.1
Cuba	9.0	0.103	0.099	0.098	0.131	12.15	11.84	11.86	15.00	9.57	*9.32*	9.34	11.8	16.1	39.5
Europe	958.3	5.785	5.997	5.777	6.097	8.46	8.76	8.46	8.88	710.0	735.1	*709.9*	745.8	2,005	5.5
Haiti region	7.6	0.055	0.055	0.056	0.087	8.72	8.67	8.87	12.61	5.81	*5.78*	5.91	8.40	18.3	11.8
Iceland	3.2	0.003	0.003	0.003	0.003	7.07	7.07	7.07	7.07	1.96	1.96	1.96	1.96	3.7	–
India region	1,007	6.892	6.723	7.056	7.527	8.17	8.05	8.48	9.01	720.9	*710.2*	748.0	794.4	1,740	16.4
Israel	12.8	0.141	0.120	0.111	0.150	12.46	10.96	10.44	13.55	13.9	12.3	*11.7*	15.2	25.6	56.0
Jamaica	2.6	0.025	0.024	0.025	0.029	10.57	10.44	10.65	12.22	2.37	*2.34*	2.38	2.74	5.5	22.6
Japan	186.3	1.311	1.293	1.293	1.371	9.39	9.32	9.32	9.56	153.2	*152.08*	152.13	156.0	326.3	13.0
Mauritius	1.9	0.018	0.019	0.019	0.021	11.75	12.14	12.56	13.46	*1.95*	2.01	2.08	2.23	4.8	25.1
Middle East	706.5	4.523	4.502	4.479	4.545	8.05	8.03	8.03	8.19	498.3	497.3	*496.7*	507.0	1,517	12.2

(*Continued on next page*)

Table 1. ***Continued***

	WWS annual-average end-use demand (GW)	WWS mean capital cost ($tril)				WWS mean LCOE (¢/kWh-all energy)				WWS mean annual all-energy private = social cost ($bil/y)				BAU mean annual all-energy private cost ($bil/y)	R_{ideal} (h)
Region	(a) All cases	(b) Case I	(c) Case II	(d) Case III	(e) Case IV	(f) Case I	(g) Case II	(h) Case III	(i) Case IV	(j) Case I	(k) Case II	(L) Case III	(m) Case IV	(n) BAU	(o) Case I
New Zealand	16.7	0.098	0.096	0.096	0.096	8.47	8.37	8.38	8.39	12.39	*12.251*	12.254	12.27	23.0	4.1
Philippines	41.0	0.412	0.419	0.413	0.482	10.85	11.32	11.06	12.58	*39.0*	40.7	39.7	45.2	83.8	18.4
Russia region	268.3	1.317	1.317	1.317	1.317	7.40	7.40	7.40	7.40	174.0	174.0	174.0	174.0	702.4	–
South America	468.7	3.124	3.124	3.124	3.124	8.89	8.89	8.89	8.89	365.1	365.1	365.1	365.1	806.4	–
Southeast Asia	584.6	7.183	7.214	7.195	8.362	12.48	12.54	12.52	14.58	*639.3*	642.1	641.3	746.8	1,183	11.8
South Korea	154.4	1.830	1.734	1.746	2.003	12.85	12.32	12.46	13.75	173.8	*166.7*	168.5	185.9	281.2	30.1
Taiwan	89.9	0.983	0.802	0.839	0.970	12.07	10.17	10.64	11.81	95.0	*80.1*	83.8	93.0	153.5	58.1
United States	959.5	6.667	6.476	6.456	7.758	8.92	8.74	8.72	10.19	749.8	734.5	*733.3*	856.4	2,189	15.4
All regions	**8,970**	**62.33**	**62.75**	**62.17**	**68.08**	**8.78**	**8.87**	**8.80**	**9.50**	**6,895**	**6,966**	**6,912**	**7,464**	**17,805**	

All costs are in 2020 USD. Costs in italics are the lowest cost among all cases in the region.

The four cases are defined as follows: Case I (baseline): no hydrogen is used for grid electricity but hydrogen is used for non-grid purposes (steel and ammonia manufacturing and long-distance transport); Case II: hydrogen is used for both grid and non-grid purposes, but hydrogen rectifiers, electrolyzers, compressors, and storage tanks are shared for both purposes, and fuel cells are used to produce grid electricity when needed from the communal hydrogen storage; Case III: same as Case II, except that unique rectifiers, electrolyzers, compressors, and storage tanks are used for grid versus non-grid hydrogen, and fuel cells are used to produce grid electricity when needed from the grid hydrogen storage; and Case IV: same as Case II, except all batteries for grid electricity storage are replaced by GHS. The end-use demand is the same in all four cases.

The mean annual all-energy private costs in Cases I–IV used in column (n) are from Table S36. Battery storage capacity in Case I is from Table S18. The maximum discharge rate actually occurring during each simulation is from Table S17.

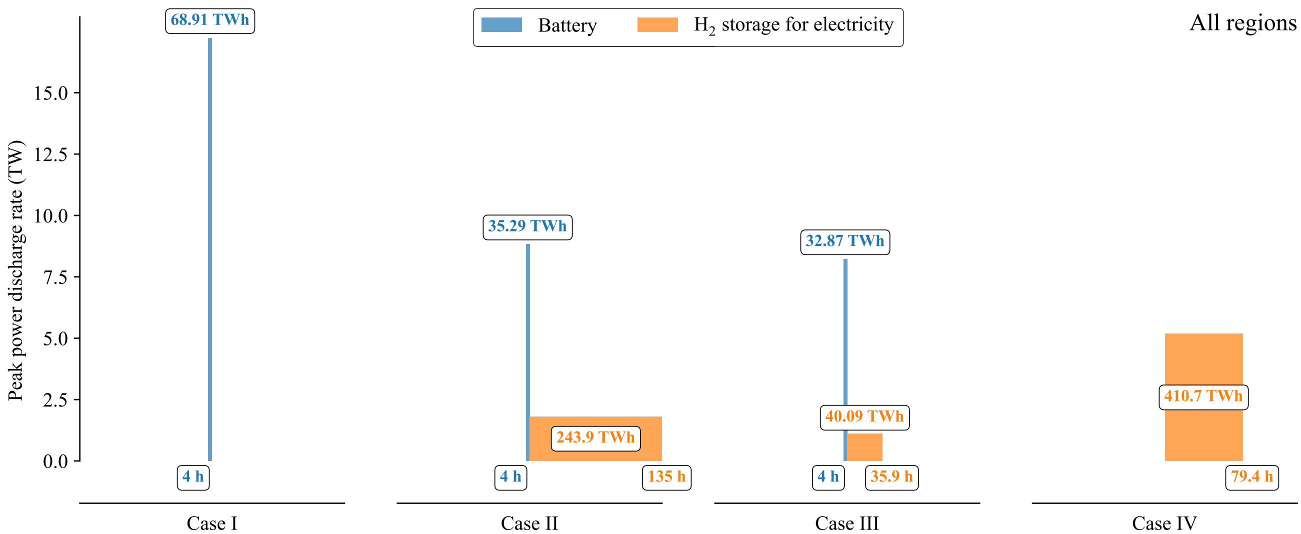

Figure 1. Peak power discharge rate, peak storage capacity, and hours of storage at the peak discharge rate for battery storage and green hydrogen storage in each Case I–IV, for the sum of 20 world regions in which battery storage for grid electricity is needed in this study

Figures S2 and S3 and Tables S18–S21 show results for each individual region. The number of hours of storage equals the storage capacity divided by the peak power discharge rate. In Case I, no GHS is used for grid electricity, and in Case IV, no BS is used. In Case II, the hydrogen storage is communal for grid and non-grid hydrogen. The storage capacity in that case is that of the communal storage, and the peak power discharge rate is the nameplate capacity of the fuel cell discharging for grid electricity. Thus, the number of hours of storage is the time it takes to fully discharge the communal storage at the peak discharge rate as if it is being discharged solely for grid electricity. In Case III, the hydrogen storage capacity is solely that of hydrogen for grid electricity, and the fuel cells used for grid electricity consume only that hydrogen. Case IV is the same as Case II, except with no batteries.

From Tables S18–S21, Case III requires greater electrolyzer and compressor nameplate capacities than does Case II. This is due to the need to produce hydrogen separately for non-grid versus grid storage in Case III. However, Case III requires lower hydrogen and battery storage capacities and battery peak discharge rates than does Case II. In Case II, the GHS peak discharge rate among all regions is 20.5% that of BS, but the GHS storage capacity for grid plus non-grid hydrogen is 6.9 times that of BS. In Case III, the GHS peak discharge rate is 13.6% that of BS, but the GHS storage capacity for only grid electricity storage is only 1.2 times that of BS (Figure 1; Table S19). Thus, in both Cases II and III, BS is used primarily for its peak discharging ability, whereas GHS is used primarily for its storage capacity.

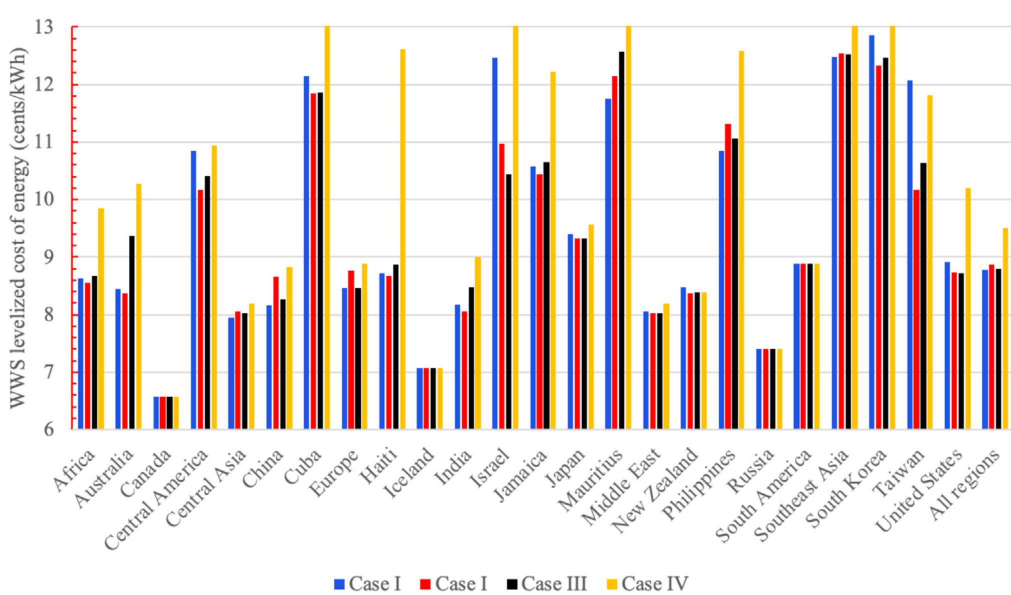

Figure 2. 2050 mean levelized cost of all WWS energy in Cases I–IV (2020 USD)

Table 1 contains the numerical data. Tables S33–S35 contain a breakdown of the levelized costs by component for each region and case.

Case IV (using CH with BS but without GHS) never results in the lowest annual energy cost (Table 1). This is because the cost of obtaining the peak discharge rates needed in each region is higher for GHS alone than for BS alone or BS + GHS. Also, in many regions, additional wind or solar electricity generators are needed to provide sufficient energy to power GHS due to the low round-trip efficiency of GHS compared with BS. Only in New Zealand and Taiwan is using CH + GHS (Case IV) less expensive than using CH + BS (Case I), but even in those regions, CH + GHS is more expensive than CH + BS + GHS (Cases II and III).

A result found here, that using CH + BS + GHS reduces the cost of a 100% renewable energy system versus CH + BS (in 15 of the 20 regions where BS is used), is supported by Auguadra et al.,[8] who found the same result for Spain with an optimization model. The result is also supported by Marocco et al.,[9] who found that using BS with GHS reduced system cost by ∼35% compared with BS alone for the Froan Islands, Norway. That study concluded that including GHS allows the battery and renewable generators not to be oversized due to the low cost of the long-term storage capability of GHS.

An important component of the overall energy cost is the cost of producing and storing hydrogen and fuel cells. Tables S28–S32 indicate that, averaged over all regions, the mean costs of hydrogen plus fuel cells are \$6.50/kg-H_2, \$7.27/kg-H_2, \$7.35/kg-H_2, and \$7.44/kg-H_2 for Cases I–IV, respectively. In Case III, where separate electrolyzers and storage are used for non-grid versus grid hydrogen, the mean cost of grid hydrogen alone is \$19.1/kg-H_2 whereas that for non-grid hydrogen is \$6.798/kg-H_2. Because 202 Tg-H_2/y is needed for non-grid hydrogen but only 9.66 Tg/y is needed for grid hydrogen, the overall cost of hydrogen in Case III is \$7.35/kg-H_2, which is higher than in Case II (\$7.27/kg-H2), where non-grid and grid hydrogen production and storage are merged. Electricity cost comprises the largest fraction of hydrogen cost in most cases, followed by electrolyzer cost, storage cost, fuel cell cost, dispensing and fueling cost (for transport), compressor cost, and water cost. Water cost per unit mass of hydrogen is assumed constant in all regions, but in reality, water availability and cost vary by region. On the other hand, electrolyzers may now use seawater to produce hydrogen,[26] expanding the ease of obtaining water for electrolytic hydrogen. Even when water is relatively expensive, though, its high cost has little impact on overall cost because water is only a small component of overall electrolytic hydrogen cost.

DISCUSSION

So, why is CH + BS alone the low-cost option in 5 of the 20 regions that need BS, whereas CH + BS + GHS is the low-cost option in the rest? One reason can be seen from BS versus GHS costs and efficiencies. A second reason can be seen from the ratio of the battery storage capacity to the actual peak discharge rate of batteries during Case I simulations (Table 1).

First, the round-trip efficiency of BS (∼90%, Table S27) is much higher than that of GHS (∼45%, Tables S26). In addition, the cost of discharging batteries (∼\$240/kW, Table S27) in 2035 is projected to be lower than that of discharging fuel cells (∼\$500/kW, Table S26). However, the storage capacity cost of batteries (∼\$60/kWh, Table S27) in 2035 is expected to exceed that of GHS (∼\$12/kWh, Table S26). Because all batteries in this study are concatenated 4-h batteries (individually supplying electricity for 4 h at their peak discharge rate), batteries will be used optimally in a region when the ratio of their summed capacity (TWh) to their summed-peak discharge rate actually occurring during a simulation (TW) is close to 4 h. This ratio is called R_{ideal}. It is the ideal ratio of a battery's capacity to peak discharge rate (the ideal number of hours of battery storage at the battery's actual, not nameplate, peak discharge rate). If R_{ideal} is much higher than 4 h (e.g., 60 h), then the concatenated batteries in the region are being used mostly for long-term storage and less for their peak power discharging ability. Batteries can be used for long-term storage because, when concatenated together, they can discharge at low power for a long period or at their summed nameplate capacity for 4 h, or anything in between.[10,11] Because BS is more expensive per kWh than is GHS, replacing some BS with GHS should lower total cost when R_{ideal} is high. On the other hand, when R_{ideal} is low (close to 4 h), BS is being used for both peaking and storage, so the addition of GHS usually drives cost up because of the low round-trip efficiency of GHS coupled with its high cost of discharging electricity. Thus, when R_{ideal} is low, significantly more peaking power is needed for short periods than when R_{ideal} is high.

Table 1 shows R_{ideal} values from Case I. In all 5 regions in which BS alone (Case I) results in lower private annual cost than do Cases II–IV, R_{ideal} < 25.1 h. In all 5 regions where R_{ideal} > 25.1 h, Cases II and III result in lower cost than Case I. In those regions, the lower cost of GHS capacity outweighs its lower efficiency and its higher cost of discharging electricity compared with BS. However, in 10 regions where R_{ideal} < 25.1 h, Case II and/or Case III also result in lower cost than Case I. Thus, whereas a high value of R_{ideal} (>25.1 h) appears to be a good indicator (100% accuracy in the five regions where that occurred) of when BS should be combined with GHS, a low value (<25.1 h) is less accurate, predicting BS alone is the best option only ∼33% of the time (in 5 out of the 15 regions).

In Cases II and III, the nameplate capacities of all generators and of storage aside from BS and GSH are the same as in Case I. The cost reduction due to replacing some BS with GHS without changing the nameplate capacity of anything else, when R_{ideal}>25.1, can be explained with results for an individual region, South Korea. In that region, R_{ideal}∼30.1 h, and a mixture of GHS and BS (Case III) costs less than BS alone (Case I) (Table 1). This occurs for the following reason: 1,060 GW/4.24 TWh of BS in Case I is replaced, in Case III, with 220 GW/0.88 TWh of BS, 80 GW of electrolyzers and compressors, and 80 GW/4.0 TWh of fuel cells/hydrogen storage (thus 50 h of hydrogen storage) (Tables S18–S21). Thus, the overall storage capacities are similar in both cases (4.24 TWh in Case I versus 4.88 TWh in Case III), but the peak discharge rate in Case III (300 GW) is less than one-third that in Case I (1,060 GW). Overall, fewer 4-h batteries combined with 50 h of hydrogen storage (Case III) costs less than more 4-h batteries with no GHS (Case I). The BS in Case III is still needed for most all of its peaking capacity and a quarter of its storage capacity. In Case III, GHS is not needed much for peaking, but it supplies the other three-quarters of the storage capacity at a lower cost than BS supplies its storage capacity.

CH + GHS (Case IV) is more expensive in all regions (Table 1) than is either CH + BS (Case I) (aside from in New Zealand) or CH + BS + GHS (Cases II and III) (all regions) because GHS alone is too inefficient and costly to supply the peak discharge that BS or a combination of BS + GHS can supply.

In sum, when the ratio (R_{ideal}) of the battery storage capacity to the actual peak discharge rate needed in a region is high, a combination of BS for most peak discharging and for some storage capacity and GHS for the remaining peak discharging and most storage capacity is beneficial. Otherwise, when R_{ideal} is low, then BS alone or BS + GHS is always the best option. GHS alone is never the best option. R_{ideal} tends to be high (longer-duration GHS storage is helpful) in regions with either low hydropower resources, weak wind or solar resources, or low peaks in demand. Table S17 shows that combining CH with GHS and BS (Cases II and III) reduces R_{ideal} compared with CH + BS alone (Case I). For example, for Taiwan, R_{ideal} decreases from 58.1 to 8.8 h by including GHS. Thus, using GHS together with BS reduces the need for batteries for storage while maintaining their need for peaking.

Finally, because existing CH + BS dominates energy storage in Case I and CH + BS + GHS dominates storage in Cases II and III, and all three cases result in lower-cost solutions relative to BAU than Case IV (CH + GHS), another major finding of this study is that the 145 countries examined may be powered at low cost primarily by existing CH + BS or CH + BS + GHS.

Limitations of the study

The results here are subject to several uncertainties. First, because LOADMATCH is a trial-and-error simulation model (Methods) that finds low-cost solutions by repeating simulations under different conditions, rather than an optimization model that determines the least cost computationally, how do we know that the solutions here are truly low-cost solutions? In response, the issue examined here is not whether a solution with BS or GHS or both provides the lowest-overall system cost among all possible scenarios, it is whether a system designed around CH + BS alone (Case I) or CH + BS + GHS (Cases II–III) provides a lower cost solution than a system designed around CH + GHS (Case IV). With that in mind, the first question is whether a lower-cost solution can be obtained in Case I (CH + BS) versus Case IV (CH + GHS). The second question is whether CH + BS + GHS (Cases II–III) lowers the cost further relative to Cases I or IV. Case I is established by designing a system around BS. In Case IV, all BS is replaced by GHS. Thus, the system is designed around GHS rather than BS. The result is zero batteries but higher nameplate capacities of hydrogen equipment and, in most cases, WWS generators, than in Case I, driving up cost in all but two regions relative to Case I (Table 1). An optimization model would likely come to the same conclusion regarding Case IV, given that BS and GHS both perform the exact same function, but GHS needs more input energy due to its low round-trip efficiency.

Similarly, in Cases II and III, all generator nameplate capacities and other parameters aside from BS and GHS are the same as in Case I, and GHS replaces some BS. Thus, whether CH + BS + GHS (Cases II and III) can lower cost versus CH + BS (Case I) is just a question of the cost of each simulation in Cases II and III. An optimization would adjust multiple parameters simultaneously to provide the lowest-cost overall solution. However, an optimization cannot determine whether using CH+GHS+BS (Cases II and III) gives a lower cost than CH + BS (Case I) while holding all other parameters constant unless that constraint is included. If it is, then the result should be the same as in the present case. Indeed, other studies using optimization models under different circumstances than here have concluded the same as found here, that combining BS with GHS often reduces cost relative to BS alone.[8,9] In sum, it is not expected that using an optimization model will change the conclusions here, but future work will help to confirm this.

A second uncertainty is what the 2050 costs of BS and GHS will be compared with what was assumed in this study. In response, the conclusions here should continue to apply so long as the round-trip efficiency of BS exceeds that of GHS, the cost of discharging electricity from a battery continues to be lower than the cost of discharging from a fuel cell, and the cost per kWh of hydrogen storage continues to be less than that of battery storage.

To illustrate how changes in 2050 BS and GSH costs relative to what was assumed here could affect results, two sensitivity tests are run: one for the United States and the second for Southeast Asia. For the United States, the baseline annual private energy cost in Case II (CH + BS + GHS) is lower than in Case I (CH + BS), so CH + BS + GHS is less expensive than CH + BS alone. However, reducing the mean baseline battery cost from \$60/kWh (Table S27) to \$15/kWh causes the cost in Case I to fall below that in Case II, so CH + BS is now less expensive than CH + BS + GHS. For Southeast Asia, the baseline annual private energy cost in Case I is less than in Case II. Thus, CH + BS is less expensive than CH + BS + GHS. However, a decrease in the mean baseline hydrogen fuel cell cost from \$500/kW (Table S26) to \$200/kW decreases the annual energy cost in Case II relative to Case I, so CH + BS + GHS is now less expensive than CH + BS. Because both of these sensitivity test costs are conceivable, a big uncertainty in this study is the actual future cost of BS and GHS.

Finally, an important question is whether batteries with more than 4 h of storage at their peak discharge rate will affect the results found here. In response, longer-duration batteries can only increase the cost of scenarios that include BS unless the cost of longer-duration battery is much less per kWh than that of a 4-h battery. In other words, at the same cost per kWh, two 4-h batteries are always more useful and versatile than one 8-h battery. The reason is that, for example, two 10 kWh, 4-h batteries, when concatenated together, provide the exact same storage capacity as one 20 kWh, 8-h battery. However, the two 4-h batteries provide a peak discharge rate of 5 kW (=2 batteries x 10 kWh/4 h), whereas the 8-h battery provides a peak discharge rate of only 2.5 kW (=20 kWh/8 h). Thus, to obtain the same peaking power as the two 4-h batteries, two 8-h batteries are needed, doubling the cost of batteries. Thus, so long as two 4-h batteries cost the same per kWh as one 8-h battery, there is only a benefit (a higher peak discharge rate) and no disbenefit of using 4-h batteries.

STAR★METHODS

Detailed methods are provided in the online version of this paper and include the following:

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  - Data and code availability
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SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.isci.2024.108988.

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AUTHOR CONTRIBUTIONS

Conceptualization, methodology, investigation, software, writing, review, and editing, M.Z.J.

DECLARATION OF INTERESTS

The author declares no competing interests.

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STAR★METHODS

KEY RESOURCES TABLE

REAGENT or RESOURCE	SOURCE	IDENTIFIER
Software and algorithms		
Spreadsheet model for 145 countries	This paper	http://web.stanford.edu/group/efmh/jacobson/Articles/I/145-H2/145-H2-study.xlsx
Mathematical solution to solving a set of six equations and six unknowns to represent conventional hydropower	This paper	The solution is provided in the supplemental information file
Results among all regions examined	This paper	Output data for all regions examined are provided in the multiple tables and figures in the supplemental information file

RESOURCE AVAILABILITY

Lead contact

Further information and requests can be directed to the lead contact, Prof. Mark Z. Jacobson (jacobson@stanford.edu).

Materials availability

This study did not generate new physical materials.

Data and code availability

- The supplemental information contains most results. Additional results, including data going into all figures and tables, are available from the lead contact.
- The spreadsheet model used for this study is publicly available online.[27] The new mathematical solution here for peaking and baseload power from conventional hydropower is provided in this paper's supplemental information. This study did not develop the original GATOR-GCMOM or LOADMATCH codes.
- Any additional information needed to reanalyze the data reported in this study may be requested from the lead contact.

METHOD DETAILS

This paper uses the methodology from two previous studies,[11,16] but with the added treatments of GHS for backing up the electric grid and a new method of using CH for both baseload and peaking power. Three types of models are used: a spreadsheet model (Note S2), a 3-D global weather-climate-air pollution model (GATOR-GCMOM) (Note S3), and a grid model (LOADMATCH) (Notes S4–S7).

The spreadsheet model is used first to project 2018 business-*as*-usual (BAU) energy consumption in end-use sectors (also called total final consumption) from IEA,[28] to 2050 for each of seven fuel types (oil, natural gas, coal, electricity, heat for sale, solar and geothermal heat, and wood and waste heat) in each of six end-use energy sectors (residential, commercial, transportation, industrial, agriculture-forestry-fishing, and military-other), and for each of 145 countries (Note S2). The projections (Note S2) are by fuel type, energy sector, and region of the world. They assume moderate economic growth, policy changes by world region, population growth, energy growth, use of some renewable energy, and modest energy efficiency measures.

The spreadsheet model is then used to estimate the 2050 reduction in energy demand due to converting each fuel type in each end-use sector in each country to electricity, electrolytic hydrogen, or heat, and providing the electricity and heat with wind-water-solar (WWS) (Note S2). The reduction is calculated with the conversion factors by fuel type and sector given in Table S3. Such conversion factors assume the use of vehicles or equipment running primarily on electricity (Note S2). Overall, about 95% of the technologies needed for a transition are already commercial. Those not commercial include long-distance aircraft and ships, which can technically be powered by hydrogen fuel cells,[29] plus some industrial processes.

Third, the spreadsheet is used to estimate nameplate capacities of WWS electricity and heat generators that can meet the annual-average demand in each country (Note S2). Tables S4–S6 provide the 2018 demands from IEA,[28] 2050 BAU demands projected from 2018, and the estimated 2050 WWS demands converted from 2050 BAU demands, by energy sector and country. The WWS electricity-generating technologies treated include onshore and offshore wind turbines (Wind); tidal and wave devices, geothermal electric power plants, and hydroelectric power plants (Water); and rooftop/utility solar photovoltaics (PV) and CSP plants (Solar) (Table S2). WWS heat sources treated include solar thermal and geothermal heat generators. WWS electricity storage technologies include CH, PHS, CSP storage, BS, and GHS. WWS heat storage technologies include water tanks and underground storage in soil. WWS cold storage technologies include water tanks and ice. Hydrogen is also stored for non-grid purposes. WWS electricity is transported via alternating current (AC), high-voltage AC (HVAC), and/or high-voltage direct current (HVDC) transmission lines and AC distribution lines. Whereas transmission costs and losses are accounted for, this study assumes perfect transmission within each region simulated. Building heating and cooling can be either through units in each building or district heating/cooling. WWS machines and appliances include battery-electric vehicles, hydrogen fuel cell-electric vehicles for long-distance transport; electric heat pumps (for individual building air and water heating and air conditioning, clothes drying, district heating/cooling, and low-temperature industrial heating); induction cooktops; arc, induction, and resistance furnaces for medium- and high-temperature industrial heat; lawn mowers; and leaf blowers, for example (Table S2).

GATOR-GCMOM (Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model) is a global air pollution-weather-climate model (Note S3). It is used to predict, at 30-s resolution from 2050 to 2052, onshore and offshore wind electricity supply, rooftop solar PV electricity supply, utility solar PV electricity supply, CSP electricity supply, solar heat supply, building cooling demand, and building heating demand in each of 145 countries (Table S1). Time-dependent wave electricity supply is estimated proportionately to time-dependent offshore wind supply. To perform these calculations, GATOR-GCMOM uses 2050 nameplate capacities from the spreadsheet model for each energy generator in each country (Note S3). It calculates building cooling and heating demands by comparing modeled ambient air temperature each 30-s time step in each climate model near-surface grid cell within each country with an assumed comfort temperature for buildings while accounting for building characteristics[30] (Note S3). GATOR-GCMOM also accounts for competition among wind turbines for available kinetic energy and changes in air temperature due to wind turbines, PV panels, CSP plants, and solar heat devices. GATOR-GCMOM output is used as LOADMATCH input.

LOADMATCH (Notes S4–S7) simulates the matching of electricity, heat, cold, and hydrogen demand with supply and storage over time. LOADMATCH is a time-dependent trial-and-error simulation model. It works by running multiple simulations for each region, one at a time. Each simulation advances forward one timestep at a time, just as the real world does, for any number of years. The main constraints are that electricity, heat, cold, and hydrogen demands plus losses, adjusted by demand response, must each meet corresponding WWS supplies and storage every 30-s timestep of a simulation. The simulation stops if a demand is not met during a timestep. Inputs (either the nameplate capacity of one or more generators; the peak charge rate, peak discharge rate, or peak energy capacity of a storage device; or characteristics of demand response) are then adjusted one at a time after examining what caused the demand mismatch (hence the description "trial-and-error" model). Another simulation is then run from the beginning. New simulations (usually less than 10) are run until demand is met during each time step of the entire simulation. After demand is met once, another 4–20 simulations are generally performed with further-adjusted inputs based on user intuition and experience to generate a set of solutions that match demand during every timestep. From the set, the lowest-cost solution is then selected. Because LOADMATCH does not permit load loss at any time, it is designed to exceed the utility industry standard of load loss once every 10 years.

LOADMATCH is not an optimization model, so it does not find the lowest-cost solution. However, it produces a set of low-cost solutions from which the lowest cost can be determined. Its advantage over an optimization model is that it can treat many more processes while taking orders of magnitude less computer time. It is able to solve multi-year simulations with a 30-s time step in just minutes (Note S4).

Table S2 summarizes the processes in LOADMATCH. Note S4 describes many of the model's inputs. Note S5 describes the new treatment of hydropower in the model, including how hydropower's total nameplate capacity, energy storage capacity, and annual recharge are allocated between baseload and peaking power uses. The answer involves solving a set of six equations and six unknowns constrained by the fact that hydropower's total nameplate capacity, reservoir energy capacity, and recharge rate in each country are limited to ~2020 values, thus known. Hydropower's output and peaking use during a time step is also limited by the smallest among three factors: the actual energy currently available in storage for baseload or peaking use, the hydropower maximum discharge rate (nameplate capacity) for peaking or baseload use, multiplied by the time step, and (in the case of peaking) the energy needed during the time step to keep the grid stable. In addition, energy in the peaking and baseload portions of all reservoirs in a region cannot exceed the maximum storage capacity for peaking or baseload energy, respectively. Any excess is drained from the reservoir without producing power.

Table S15 provides the resulting maximum charge rates, discharge rates, and energy capacities for each baseload, peaking, and total hydropower for each region. Figure S1 shows how these variables vary as a function of baseload energy storage time. The total hydropower storage capacity in all hydropower reservoirs among the 145 countries examined is ~1,470 TWh, which is approximately the worldwide storage capacity estimated by IEA.[31] For comparison, the total battery storage capacity among all 145 countries in the base case (Case I) is 68.91 TWh (Table S15). Thus, the storage capacity of hydropower already existing in the world is 21.3 times the storage capacity of batteries needed for 100% WWS across all 145 countries in 2050. However, batteries in 2050 in Case I also require a peak discharge rate of 17.2 TW, which compares with 1.16 TW in 2020 and 2050 for CH. Thus, BS is used mostly for peaking, whereas CH is used mostly for energy storage in this study.

Note S6 discusses the treatments of time-dependent demand profiles, maximum storage sizes, and flexible and inflexible demand in LOADMATCH. Note S7 describes the model's order of operation, including how it treats excess generation over demand and excess demand over generation. Note S7 also provides details of how LOADMATCH treats demand response. Updates to LOADMATCH for this study are described in the section, "simulations: four cases compared." Once LOADMATCH simulations are complete, energy costs, health costs, climate costs, and employment numbers between WWS and BAU (Notes S8 and S10) and new land requirements of WWS generators (Note S9) are estimated.