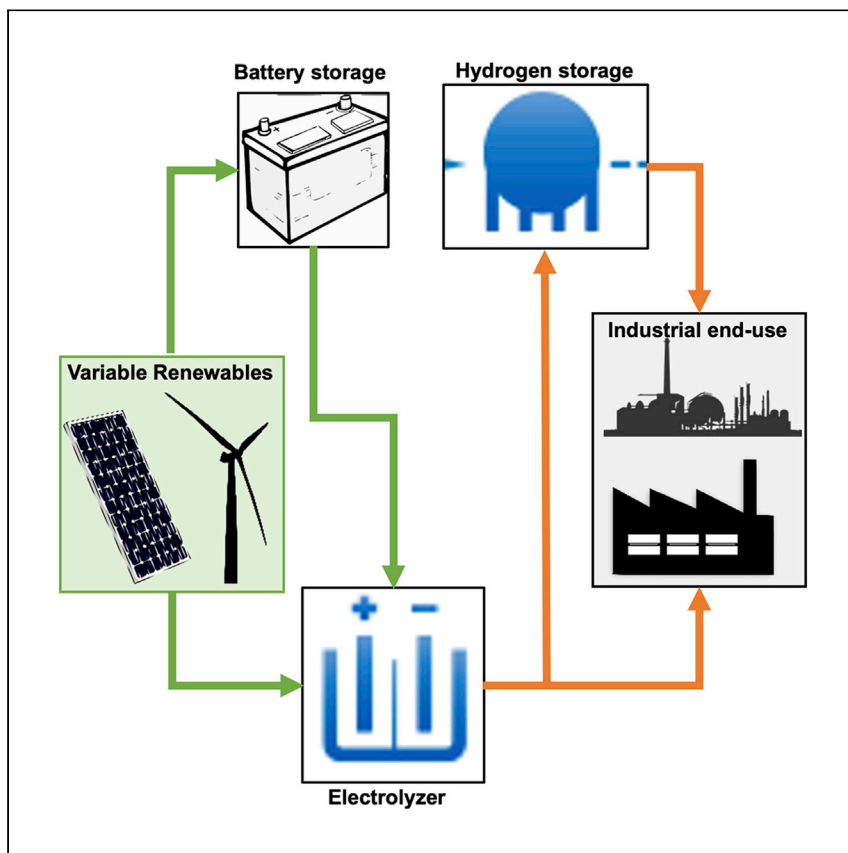


Article

Can Industrial-Scale Solar Hydrogen Supplied from Commodity Technologies Be Cost Competitive by 2030?



Identifying cost-effective, low-carbon H₂ production could accelerate the energy transition through decarbonization of end-use applications where direct electricity use remains challenged. Mallapragada et al. investigate the techno-economic outlook of industrial-scale H₂ supply produced from integrating commercially available PV, electrolyzer, and storage technologies across the continental United States.

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HIGHLIGHTS

Assesses cost of continuous H₂ supply via PV-electrolysis coupled with energy storage

Modeling least-cost design and operations shows value of oversizing PV capacity

Assesses cost of H₂ across continental United States for a range of component cost projections

Identifies combination of component costs and locations with levelized costs of \$2.5/kg or less

Article

Can Industrial-Scale Solar Hydrogen Supplied from Commodity Technologies Be Cost Competitive by 2030?

Dharik Sanchan Mallapragada,^{1,5,*} Emre Gençer,¹ Patrick Insinger,¹ David William Keith,^{2,3} and Francis Martin O'Sullivan^{1,4}

SUMMARY

Expanding decarbonization efforts beyond the power sector are contingent on cost-effective production of energy carriers, like H₂, with near-zero life-cycle carbon emissions. Here, we assess the levelized cost of continuous H₂ supply (95% availability) at industrial-scale quantities (~100 tonnes/day) in 2030 from integrating commodity technologies for solar photovoltaics, electrolysis, and energy storage. Our approach relies on modeling the least-cost plant design and operation that optimize component sizes while adhering to hourly solar availability, production requirements, and component inter-temporal operating constraints. We apply the model to study H₂ production costs spanning the continental United States and, through extensive sensitivity analysis, explore system configurations that can achieve \$2.5/kg levelized costs or less for a range of plausible 2030 technology projections at high-irradiance locations. Notably, we identify potential sites and system configurations where PV-electrolytic H₂ could substitute natural gas-derived H₂ at avoided CO₂ costs (≤\$120/ton), similar to the cost of deploying carbon capture and sequestration.

INTRODUCTION

Can solar-powered electrolytic hydrogen (H₂) supply industrial-scale quantities at sufficiently low cost by 2030 to allow large-scale, low-carbon production of energy-intensive products such as ammonia, carbon-neutral hydrocarbons, chemicals, or steel? This question is relevant for broader decarbonization efforts and in particular for industrial sectors, where progress regarding emissions reduction has been relatively modest (CO₂ emissions from the United States industrial sector decreased by 9% from 2008–2018 versus 26% for the power sector¹), and direct use of low-carbon electricity may be difficult.^{2–5} Although low-carbon H₂ production has historically attracted interest for decarbonizing transportation,⁶ it might be more important in displacing fossil fuel use in industrial processes or as an intermediate in producing energy carriers such as ammonia or hydrocarbons. This observation is supported by recently announced pilot projects for use of electrolytic H₂ in steel production and petroleum refining.⁷ Such large-scale demands for low-carbon H₂ will only be relevant under policies that drive rapid decarbonization with stringent carbon emission constraints. Assuming such policies, we examine the cost effectiveness of solar-powered electrolysis for industrial-scale (~100 tonnes/day) H₂ supply with high (95%) annual availability and its competitiveness with natural gas (NG) with carbon capture and sequestration (CCS).

Compared with distributed end uses, centralized end uses may provide a more appealing near-term opportunity for deploying emerging H₂ production routes,

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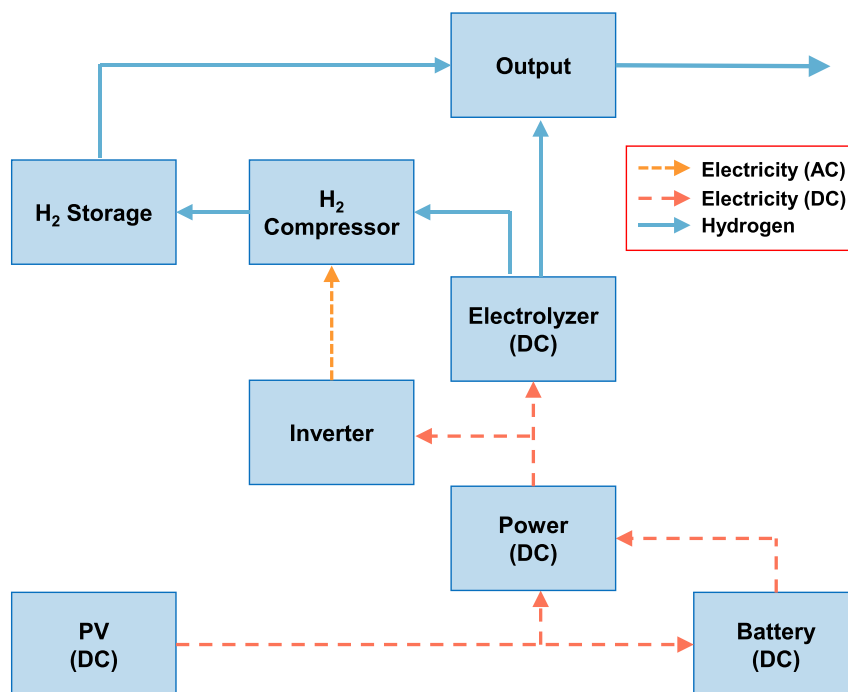


Figure 1. Schematic of the Integrated PV-Electrolysis-Storage Process for Continuous H₂ Production

Dotted lines indicate electricity flows, and solid lines indicate H₂ flows. AC, alternating current; DC, direct current.

like electrolysis, for a few reasons. First, existing H₂ demand is centralized, originating from petroleum refineries and chemical production facilities, whose typical H₂ consumption is supported by one or more production facilities producing H₂ on the order of 100 tons per day.⁶ Second, centralized energy uses can potentially be served with on-site H₂ production that avoids the need for significant additional infrastructure for H₂ transport.⁶ Third, targeting centralized end uses provides an opportunity to rapidly scale up commercially available but nascent technologies, like polymer electrolyte (PEM) electrolyzers, and, in the process, lower costs that could make them cost-effective for serving distributed end uses of H₂, like residential heating or transportation, in the future. Fourth, compared with direct electrification of distributed energy demands, like transportation, there is limited potential for direct electrification of many industrial operations, especially those relying on high-temperature heat inputs or direct use of fossil fuels as a feedstock (e.g., steel and ammonia), which makes H₂ use for these applications more appealing.

Here we focus on the techno-economic outlook in 2030 for round-the-clock electrolytic H₂ supply using dedicated solar photovoltaics (PV) installations and other commodity hardware (Figure 1)—battery energy storage, PEM electrolyzer systems, and gaseous H₂ energy storage—in pressure vessels or in geological formations, with the caveat that the latter may be geographically limited in its availability. We focus on 2030 for two reasons: industrial sector decarbonization will need to start by then to meet mid-century climate stabilization goals,⁸ and it is far enough away that significant cost declines in electrolysis can possibly be realized but close enough that forecasts are meaningful. The rapid ongoing development of large-scale electrolysis^{7,9–11} and the continued cost declines of utility-scale PV^{12,13} make it more likely that solar H₂ systems developed by combining commodity hardware will be cheaper

than advanced first-of-kind integrated H₂ production systems within this time frame.¹⁴ With respect to H₂ storage, currently available pressure vessel bulk H₂ storage is based on storing H₂ in pressurized tubes (~100 bar) that can be bundled together according to required storage volumes.^{15,16} Unlike NG, storage of H₂ in pressure vessels requires specialized construction materials that are resistant to H₂ embrittlement and fatigue.¹⁵ With growing interest in developing H₂ supply chains for refueling stations, pressure vessel bulk H₂ storage in pipe bundles is offered by several vendors (see Air Products and Chemicals Inc.¹⁶ as an example) for commercial deployment. In contrast, large-scale H₂ storage in geological formations is practiced at scale, with five currently operating facilities across the world that use salt caverns and other hard rock formations to store thousands of tonnes of H₂ at pressures of around 100–200 bar.^{17–19} Available literature regarding potential geological H₂ storage sites in the United States has focused on salt caverns, depleted oil and gas reservoirs, and aquifers distributed across the country, many of which are currently used for NG storage.²⁰

For convenience, we model a strictly isolated PV-H₂ system (Figure 1) that does not account for possible interactions with the grid to sell excess PV electricity or import electricity during times of low PV output. Of course, any real-world system may choose to be grid connected, but our analysis provides a limiting case. In a world with policy sufficiently strong to justify industrial-scale low-carbon H₂ production, it may be reasonable to assume relative oversupply of electricity from variable renewable energy (VRE) at certain times of the day and strong economic incentives for low-carbon dispatchable electricity sources.²¹ Policy supporting low-carbon fuel production would therefore also entail much larger growth of solar electricity generation, which is likely to intensify diurnal electricity price structures like the “Duck” curve currently observed in California,²² where prices are depressed during hours of peak PV output and increase sharply at sundown. In this context, standalone systems, like that shown in Figure 1, may be advantageous because they can potentially mitigate the facility’s exposure to intra-day and intra-year electricity price volatility. Additionally, the process shown in Figure 1 can also maximize the credits earned from low-carbon policies, such as the Low Carbon Fuel Standard (LCFS) in California, by relying exclusively on carbon-free electricity. The credit value for zero-carbon H₂ has been estimated at \$2/kg.²³ Finally, we analyze PV rather than wind-based H₂ production because the former resource is more widely available and has a nearly an order of magnitude higher areal density and lower land use impact compared with wind generation (28 MW/km^{2,24} versus 5 MW/km^{2,25}).

Although techno-economic analysis of electrolytic H₂ production has been studied extensively in the literature, few studies have accounted for the temporal variability in the attributes of electricity supply (availability, emission intensity, and costs) and its effect on system metrics like levelized costs and emission intensity.^{2,14,26–29} A key finding across these studies is that grid-based or grid-supported electrolytic H₂ production tends to be more cost effective than systems using VRE generation exclusively because they allow increased electrolyzer utilization and do not need additional investment in electricity generation equipment. For example, one study estimates the levelized cost for PV electricity-based electrolytic H₂ to be \$6.1/kg when supplemented by grid electricity (priced at \$0.07/kWh) and \$12.1/kg when electricity is sourced entirely from PV.¹⁴ However, electrolysis using on-site VRE generation and no storage versus using on-site VRE generation and grid-based electricity not only results in different H₂ production patterns over time but also potentially different greenhouse gas (GHG) emissions per kilogram of H₂ produced. Another study evaluated the cost of electrolytic H₂ across a variety of electricity

tariffs and with dynamic electrolyzer operation to be in the range of \$2.6–\$12.3/kg³⁰ but did not consider optimizing relative sizing of system components. Similarly, other studies that account for the effect of hourly operational variability on levelized costs of electrolytic H₂ did not optimize the relative sizing of system components (e.g., electrolyzer, PV, or wind capacity)^{31–33} or consider the effect of onsite H₂ storage (G. Saur, 2011, Fuel Cell and Hydrogen Energy, conference).³⁵ Other analyses have focused on potential interactions of electrolyzers with the electric grid by flexibly scheduling power consumption and provision of energy and ancillary services.^{29,36,37}

Our analysis of the cost-effectiveness of electrolytic H₂ production focuses on a facility (Figure 1), which relies exclusively on PV-sourced electricity to provide a continuous supply of H₂ for an industrial customer using on-site energy storage. A novel methodological contribution of this study involves the co-optimization of capacity of PV, electrolysis, energy storage, and other balance-of-plant components (e.g., inverter, H₂ compressor) to ensure continuous production while accounting for hourly variations in PV resource throughout the entire year and inter-temporal constraints governing equipment operation. This is accomplished by solving an integrated design and operations optimization model that models plant operations throughout the entire year at an hourly resolution (Experimental Procedures). Using this framework, we are also able to evaluate the trade-offs between energy storage as electricity or H₂ and the resulting effect on levelized cost under current and possible future technology cost and performance projections. Optimal sizing of system components is particularly important for VRE-dominant processes and systems where capital cost tends to dominate total costs.²⁹ For example, we find that the least-cost system design for the process shown in Figure 1 consistently sizes electrolyzer capacity smaller than the PV capacity across range of locations and cost scenarios. Additionally, we perform a spatial analysis of levelized H₂ production costs across the continental United States that, when considered with spatial distribution of existing H₂ demand, reveals regions with near-term deployment potential. For these candidate locations, we perform extensive sensitivity analysis to identify the impact of component cost and performance parameters and system factors, like plant annual availability, on achieving costs of \$2.5/kg or less. The threshold value of \$2.5/kg is near the higher end of the range of estimated levelized costs for H₂ production from NG with CCS (“blue H₂”), either via steam methane reforming (SMR) or autothermal reforming (ATR) approaches. There is a wide range of cost estimates for blue H₂ produced in central facilities in the literature, from \$1.2/kg to nearly \$3/kg, primarily because of varying assumptions about NG prices, cost of capital, and cost of CO₂ transportation and storage.^{6,38–42} Incidentally, another assessment of the long-term cost competitiveness of H₂ to serve various end-use sectors also highlights \$2.5/kg as a key cost benchmark.⁴² Finally, we compare our results against the costs of NG-based H₂ production and conclude by noting the main implications and areas of future work.

RESULTS

Design and Cost Outcomes for a Plausible 2030 Cost Scenario

Figure 2 highlights the cost-optimal system design trends to produce H₂ round-the-clock at 4.17 tonnes/h (or 100 tonnes/day) across nearly 1,500 locations in the United States for the 2030 cost scenario defined in Table 1. These results are based on modeling a full year of plant operations at an hourly resolution, with PV resource characterized using typical meteorological year (TMY) data (Experimental Procedures; Note S2). Here we define “round-the-clock” to correspond to an annual plant

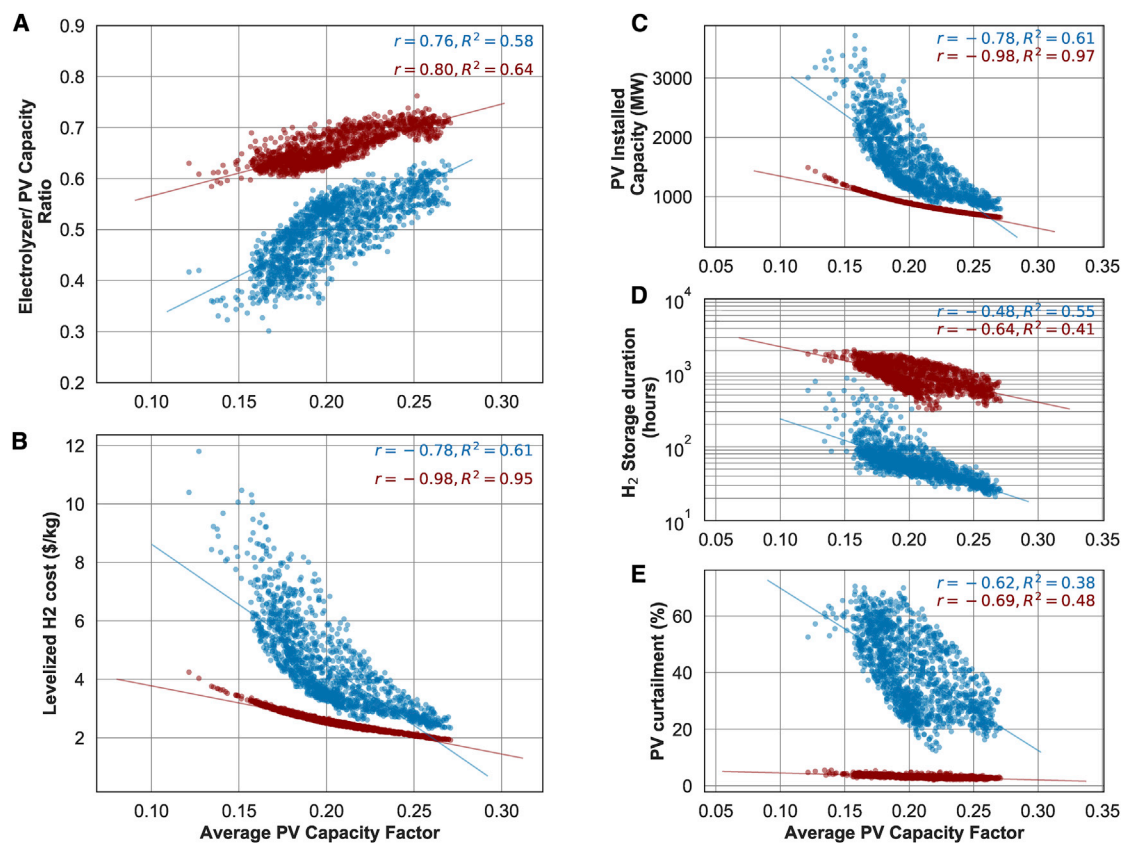


Figure 2. Least-Cost Design Trends for Continuous H₂ Supply from PV-Electrolysis + Storage across the Continental United States

Results correspond to nameplate H₂ production capacity of 100 tonnes/day (4.17 tonnes/h, 10% hourly tolerance) and 95% annual availability for various locations in the United States under the 2030 cost scenario with pressure vessel (blue) and geological H₂ storage (red) defined in Tables 1 and S4. Each point represents the design outcome for a different location in the United States, and the line corresponds to the least-squares linear fit of the data.

(A) Ratio of installed electrolyzer capacity to PV capacity.

(B) Levelized H₂ production cost (\$/kg).

(C) PV installed capacity (megawatts).

(D) H₂ storage duration (h).

(E) PV curtailment as a percentage of available generation.

r , correlation coefficient; R^2 , coefficient of determination of the linear fit shown for each figure. PV availability was characterized using TMY insolation data from the National Solar Radiation Database.⁵⁷ Duration of H₂ storage was calculated by dividing the capacity of installed H₂ storage (in tonnes) with the design flow rate (4.17 tonnes/h).

availability of 95% (defined in Table 1) while allowing hourly H₂ supply rates to vary within 10%. The 2030 cost scenario was developed based on component cost projections in the literature and includes (1) PV capital cost of \$500/kW (based on direct current [DC] capacity), which is plausible according to available projections;^{12,43,44} (2) a 62% decline in capital costs for electrolyzer systems from their current levels of \$800/kW (for multi-MW-scale systems^{10,11,45}), which is the lower end of projections available in the literature^{10,11,46,47} (see Note S2 for further details); (3) an increase in electrolyzer efficiency from current estimates of 58% to 70% on a lower heating value (LHV) basis³⁷; (4) a 33% reduction in capital cost of pressure vessel H₂ storage compared with current (2020) cost estimates.⁴⁸ (the 2030 capital cost estimate is based on adjusting costs for pipe storage of NG [maximum pressure of 100 bar]¹⁵ to account for the different volumetric energy density of H₂ and NG); and (5) a lower range of capital costs reported for geological H₂ storage that is consistent with the large storage volumes being considered here^{17–19} (see Table S5 for a brief

Table 1. Key Technology Performance and Cost Assumptions for 2020 and 2030 Scenarios and Sources

Parameters	2020	2030	References/Explanation
Capital Costs			
PV (\$/kW DC)	850	500	single-axis tracking system with 0° tilt from horizontal; 2020 costs based on lower range of values noted in 2018 in the United States (see Figure 8 of Bolinger et al. ⁵⁹); 2030 estimate based on projections by Bloomberg New Energy Finance, ¹² National Renewable Energy Laboratory ⁴³ , and Mallapragada et al. ⁴⁴
Electrolyzer, PEM (\$/kW)	800	300	2020 costs based on cost estimates reported from multiple sources ^{9–11,45,46} and Figure 4 in Fuel Cells and Hydrogen Joint Undertaking ⁴⁷ ; 2030 costs based on lower end of projections for PEM systems ^{10,11,46,47}
Pressure vessel H ₂ storage (\$/kg)	516	345	pressurized pipes (100 bar); 2020 costs ⁴⁸ ; 2030 costs based on NG storage while accounting for H ₂ volumetric energy density ¹⁵
Geological H ₂ storage (\$/kg)	33	3	salt cavern (100 bar); 2020 costs from Ahluwalia et al. ⁴⁸ ; 2030 costs based on lower range of reported costs ^{19,60} , consistent with large-scale storage volumes (see Table S5)
Compressor (\$/kW)	1200	1200	Parks et al. ⁶¹
Battery storage power (\$/kW)	589	477	Low-end costs estimates for 2020 and 2030 ¹³
Battery storage energy (\$/kWh)	206	77	Low-end costs estimates for 2020 and 2030 ¹³
FOM Costs (% of Capex)			
PV	1%	1%	National Renewable Energy Laboratory ⁴³
Electrolyzer	7%	5%	includes annualized stack replacement cost; 2020 values from Eichman et al. ³⁷ ; 2030 values based on International Renewable Energy Agency ²⁸
H ₂ storage	1%	1%	Penev and Hunter ⁶²
Compressor	4%	4%	Penev and Hunter ⁶²
Operational Parameters			
Flow rate, minimum hourly utilization factor	4.17 tonnes/h, 90%		assumption
Annual plant availability	95%		Percentage of hours when facility is supplying H ₂ ; similar to NG-based H ₂ production facility
Electrolyzer efficiency, LHV (%)	58%	70%	2020 value based on International Energy Agency ⁶ ; future values based on Table 2 in Eichman et al. ³⁷ and range of values cited in Table 3 of International Energy Agency ⁶
Battery storage round-trip efficiency (%)	92%		assumption
H ₂ compression electricity input (kWh/kg)	1.0		energy input for 30 to 100 bar compression ¹⁵

Remaining input parameters and their justification are provided in Table S4. Electrolyzer FOM costs reflect the estimated annualized cost of stack replacements based on a current cell stack life time of 5 years^{6,47} and a project lifetime of 20 years (Note S2). DC, direct current; LHV, lower heating value. All dollar values are 2016 United States dollars unless noted otherwise.

literature summary of bulk H₂ storage capital costs). Although the sensitivity of system outcomes to alternative future component cost and performance assumptions are explored in more detail in the next section, here we present the major system design trends and favorable locations for initial deployment of PV-electrolytic H₂ based on the 2030 cost scenario described above and in Table 1.

Across locations and the two types of H₂ storage, the electrolyzer size is estimated to be less than the PV capacity because peak PV availability, such as with capacity factors greater than 90%, occurs for only less than 100 h of the year across locations (Figure S2). This finding, also observed in the case of the 2020 cost scenario (Figure S1), is in contrast to prior techno-economic assessments of electrolytic H₂ production,^{6,14,27,28} which universally assume electrolyzer capacity to be equal to PV capacity irrespective of location or production requirements and, consequently, overlook the cost savings resulting from oversizing PV arrays. Smaller electrolyzer capacity relative to PV array leads to unutilized PV generation at hours of peak output (Figure 2E), but part of the “lost” H₂ production during the peak hours can be offset by increasing electrolyzer utilization during the “shoulder” hours; i.e., hours on either side of the hours with PV peak output. The cost

savings from oversizing the PV array relative to the electrolyzer is reinforced by the finding that the size of the electrolyzer relative to the PV array is positively correlated with the average PV capacity factor, as shown in Figure 2A. Regions with a higher PV capacity factor, synonymous with lower PV installed capacity (Figure 2C) and a greater number of hours of peak PV availability in a day, rely predominantly on these hours to produce the majority of daily H₂ requirements because the ability to produce H₂ during the shoulder hours is limited by PV power output (Figure S3). The opposite is true in the case of regions with a low PV capacity factor that are synonymous with larger installed PV capacity and, consequently, more PV generation during shoulder hours.

The cost of H₂ storage also affects electrolyzer sizing, with higher relative electrolyzer capacity (58%–76% of PV capacity) in the case of inexpensive geological H₂ storage compared with pressure vessel H₂ storage (30%–63% of PV capacity). The availability of low-cost H₂ storage (i.e., geological) makes it cost effective to use more of the PV electricity supply whenever it is available and store the produced H₂ for providing supply at other times. Consequently, system design with geological H₂ storage leads to larger relative electrolyzer size (Figure 2A), lower PV installed capacity (Figure 2C), greater H₂ storage capacity (Figure 2D), and lower PV curtailment (Figure 2E) compared with design outcomes with more expensive pressure vessel H₂ storage. PV curtailment predominantly occurs in the summer season (Figure 3), whereas plant operation in the winter nearly utilizes all available PV generation and even includes scheduled production downtimes, as illustrated in Figure 3, to minimize H₂ storage requirements and costs.

Despite the prevalence of PV curtailment (Figure 2E), battery storage is not chosen as part of the system design across any of the locations for the 2030 cost scenario (Figure S4). Even though battery storage will improve electrolyzer utilization beyond what is possible with PV alone (~30%; Figure S12), it is orders of magnitude more expensive (on a per-kilogram H₂ stored basis) than the estimated cost of pressure vessel H₂ storage for the 2030 scenario. For example, a battery storage capital cost of \$350/kWh is approximately equal to \$11665/kg of H₂ stored, not accounting for losses in storage and H₂ production. This makes it less valuable to deploy battery storage even when it can time-shift some or all of the curtailed PV generation and improve electrolyzer utilization. A small amount of battery storage is deployed in the most expensive H₂ storage scenario evaluated here, corresponding to the 2020 costs with pressure vessel H₂ storage (Figure S4).

In general, differences in average PV capacity factor explain lesser of the spatial variability in H₂ storage requirements than the variability in installed PV capacity and relative electrolyzer size, as noted in the coefficient of determination (R²) values in Figure 2D. For example, even among the top PV resource sites (capacity factor ≥ 25%, 128 sites), the H₂ storage requirements differ by a factor of 2.5 for both storage types considered in Figure 2. Regions with a greater difference in PV availability between summer and winter months require increased H₂ storage capacity compared with regions with smaller seasonal variations in PV availability (Figure S5). Figure 3 illustrates the use of H₂ storage to manage diurnal and daily variations in PV availability and realize near-steady H₂ production flow (Figures 3C and 3D, product flow) for a hypothetical facility located in El Paso, TX.

Figure 4 shows the spatial distribution in levelized H₂ costs in the 2030 cost scenario with pressure vessel H₂ storage, with the highest costs (\$11.8/kg) and lowest costs (\$2.3/kg) observed in the United States northwest and southwest regions, respectively. Similar spatial trends are observed for the 2030 cost scenario with geological

El Paso, TX: 2030 Scenario with pressure vessel H₂ storage

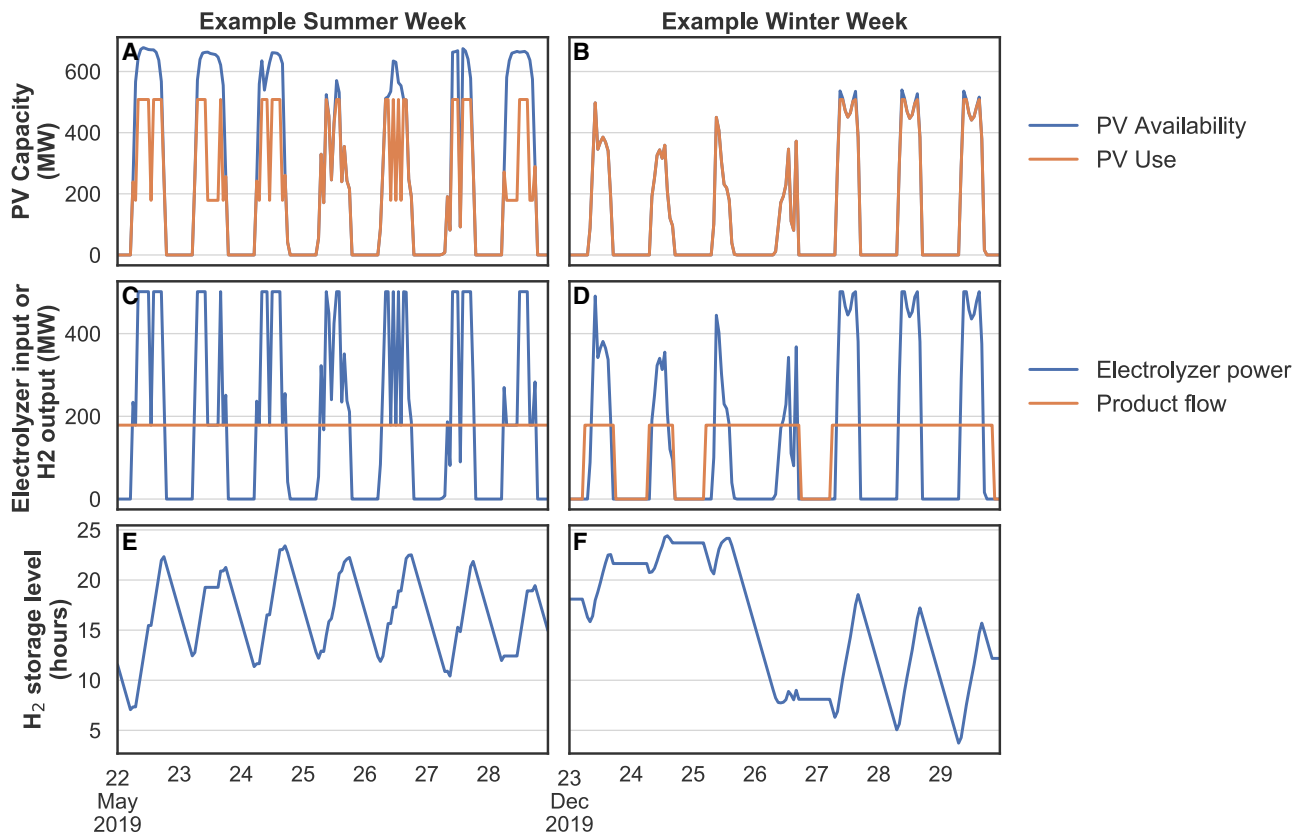


Figure 3. Illustration of Modeled Hourly Operations of a PV-Electrolysis H₂ Production Facility Located in El Paso, TX

(A–F) Average PV capacity factor = 25.9%. Operations are shown for a typical week in the summer (left) and winter (right). Shown are operational trends in PV (A and B), electrolyzer (C and D), and H₂ storage levels (E and F). The modeled facility is designed to produce 4.17 tonnes H₂/h (100 tons/day, with 10% hourly tolerance) and 95% annual plant availability. The time units used for displaying H₂ storage are estimated by dividing the hourly inventory of stored H₂ (in kilograms) with the nominal design flow rate of 4.17 tonnes H₂/h. The results shown correspond to the 2030 cost scenario with pressure vessel H₂ storage defined in Table 1.

H₂ storage, although the range of levelized costs is much smaller (\$1.9–\$4.2/kg) than the range of costs for the 2030 scenario with pressure vessel H₂ storage (Figure S6). Notably, the much lower cost of geological H₂ storage allows smoothening the temporal variations in PV availability at relatively low cost and leads to the average PV capacity factor being a strong indicator for levelized H₂ costs (R² value of 0.95 in Figure 2B). For the 2020 cost scenario, the spatial distribution in levelized H₂ costs is similar to the 2030 cost scenario, although the range of levelized costs is much higher (\$5.7–\$23.7/kg for pressure vessel H₂ storage [Figure S1] and \$5.1–\$11.4/kg and geological H₂ storage), indicating that the PV-electrolysis process shown in Figure 1 is currently not economically competitive with NG-based H₂ production routes.

Although the process shown in Figure 1 may not ever be an economically viable H₂ production pathway for low-quality PV resource regions like the United States northwest even in the 2030 cost scenario, there are 34 sites, mostly in the United States southwest and west Texas, with costs less than or equal to \$2.5/kg and 245 sites with costs less than \$3/kg while using pressure vessel H₂ storage. If geological H₂ storage is widely available, which we have not evaluated here, then many more

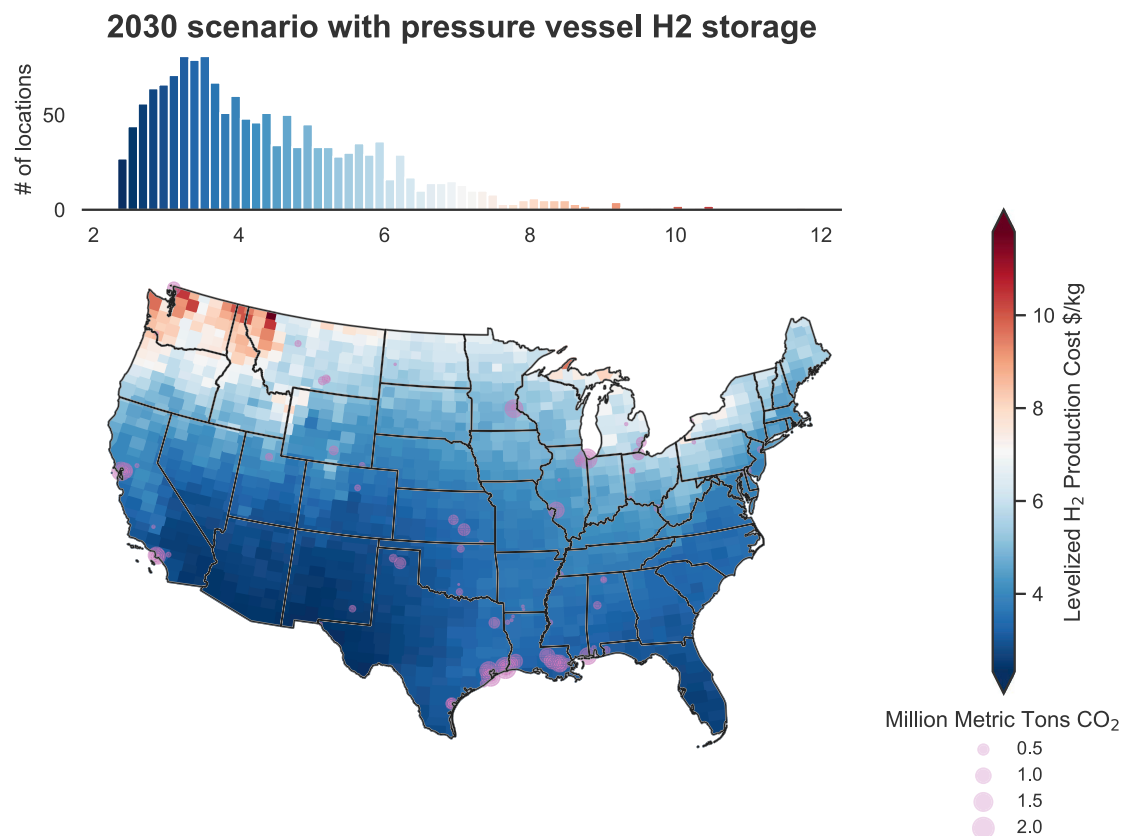


Figure 4. Costs of Continuous H₂ Supply via PV-Electrolysis + Pressure Vessel H₂ Storage for the 2030 Scenario in the Continental United States

The visualization is based on defining Voronoi polygons (Note S3) from costs estimated at 1,487 grid points using the integrated design and optimization model. PV resources in each location were characterized by TMY insolation data from the NREL Solar Radiation Database.⁵⁷ Pink markers indicate the location of existing H₂ production facilities according to the 2017 edition of the EPA GHG reporting program,⁵² with the size of the marker proportional to annual GHG emissions attributed to H₂ production at the facility in 2017.

locations (621 of 1,487 locations) could meet the \$2.5/kg cost threshold (Figure S6). Moreover, Figure 4 suggests that few low-cost regions, such as the Texas Gulf Coast and southern California, are also places with existing H₂ demand, as inferred by the presence of fossil fuel H₂ production facilities, making them attractive locations for practical deployment.

Figure 5 shows the breakdown of levelized H₂ costs for the 2030 scenario for 10 sites that have the highest average PV capacity factor among locations with existing fossil fuel-based H₂ production. Collectively, these sites accounted for 11.2 million tonnes of CO₂ equivalents per year or 25% of the GHG emissions associated with H₂ production in 2017 (Table S6). Because H₂ production sites are typically located close to the point of industrial consumption, these sites are promising locations for initial deployment of the PV-electrolytic H₂ process being studied here. Unsurprisingly, PV and electrolysis capital and fixed operating and maintenance (FOM) costs dominate the levelized cost across all the 10 locations, with PV costs alone accounting for between 61%–62% of total costs. Electrolyzer capital costs represent a smaller share of total costs because of their lower capital costs on a dollar per kilowatt basis versus PV and the oversizing of PV capacity relative to the electrolyzer capacity. Electrolyzer FOM costs, which include the estimated cost of periodical stack replacement (Note S2) contribute 11% of total costs across the locations. Compared with electrolyzer and PV costs, the cost of H₂ storage is a

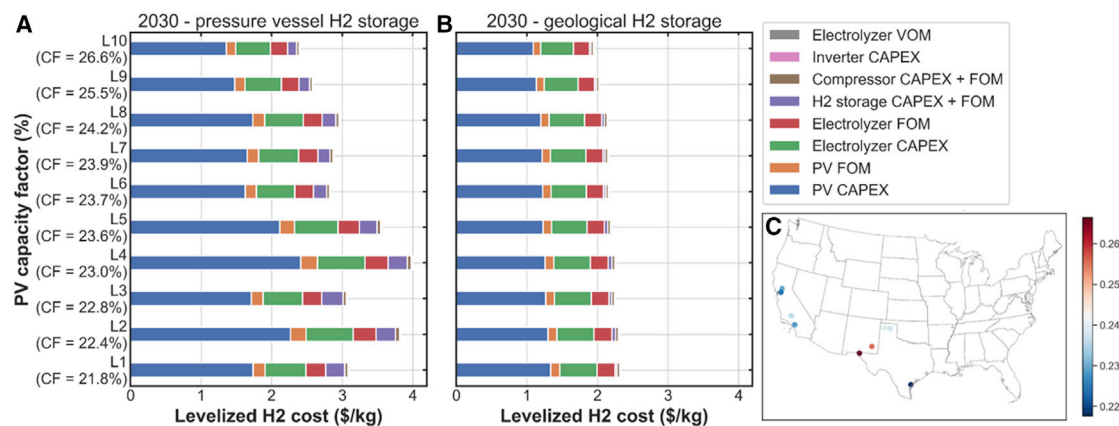


Figure 5. Levelized H₂ Cost Breakdown at 10 Favorable Sites for Near-Term Deployment for the 2030 Cost Scenario

(A and B) Breakdown of levelized H₂ costs for the 2030 scenario with pressure vessel H₂ storage (A) and geological H₂ storage (B), as defined in Table 1, at 10 potential sites that have the highest PV capacity factor among locations with existing fossil fuel-based H₂ production.

(C) Map of the locations, with color markers indicating differences in average PV capacity factor for the evaluated locations.

In (A) and (B), the costs of the inverter and electrolyzer are not visible because their contributions are relatively minor compared with the x axis scale. PV availability was characterized using TMY insolation data from the National Solar Radiation Database.³⁷ VOM, variable operating and maintenance; FOM, fixed operating and maintenance; capex, installed capital costs; CF, average PV capacity factor.

relatively minor share of total costs even when using the more expensive H₂ storage option of pressure vessels. The costs of the inverter, H₂ compression, and feed water costs (Figure 5, electrolyzer variable operating and maintenance [VOM]) contribute a relatively minor share of overall costs and are therefore not considered for further sensitivity analysis.

Effect of Inter-annual Variations in PV Resources

The estimated design trends and levelized costs discussed above are based on characterizing PV resources for each hour of the year using TMY insolation data, which are synthesized from multiple years of data and are commonly used to represent typical variability in PV resources in VRE-related design studies. Here we investigate the reliability of the resulting plant design to accommodate “atypical” variations in PV availability, such as inter-annual variability,⁴⁹ by simulating their operation over 20 years using historical PV resource data for 1998–2017. For this, we solved the design optimization model for each location and a specified cost scenario while fixing all sizing decisions to be equal to values identified from solving the model with TMY PV resource data. Figure 6 highlights the annual availability factor of TMY-based plant designs at 10 locations when simulated with PV resource data from historical weather years (1998–2017). Although inter-annual variations in PV availability result in less than a 95% annual availability factor for some years, the overall variation in annual availability is relatively narrow, with a lowest annual availability factor of 90%. Moreover, the number of hours of lost production (i.e., when plant output is below the design flow rate) is in the range of 5%–11% (Figure S7). Similar trends are observed in the case of a TMY-based plant design using geological H₂ storage (see Figure S8). These comparisons indicate that designs obtained using TMY data could yield a reasonably steady supply of H₂ even with inter-annual variations in PV availability and, thus, may be acceptable for a screening analysis to explore promising locations and general system design heuristics (e.g., an electrolyzer-to-PV ratio of less than 1). That said, use of multiple years of historical PV availability may be important for optimizing detailed plant design at a specific location.

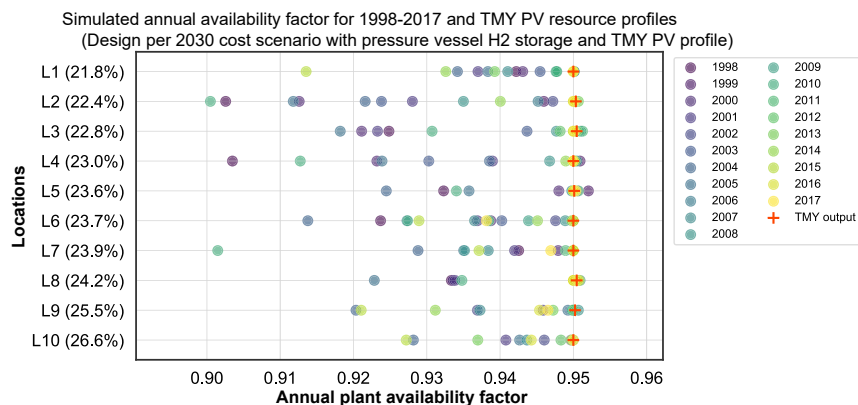


Figure 6. Effect of Inter-annual PV Variability on Annual Availability of H₂ Supply for TMY-Based Plant Designs

Shown is the annual plant availability factor for a H₂ production facility, sized using solar resource characterized via typical meteorological year (TMY) data, but simulated with historical PV resource availability profiles for 1998–2017 (colored circles). Plant availability factor is defined as the ratio of total annual H₂ production of the facility for each weather year (historical or TMY) relative to the design amount (after derating for maximum allowed variation in the hourly flow rate of 10%). Results are shown for 10 locations, identified in Figure 5, for the 2030 cost scenario with pressure vessel H₂ storage, as defined in Table 1.

Effect of Electrolyzer and H₂ Storage Cost and Performance

The results from the 2030 cost scenario analysis indicate a potential for numerous United States sites to produce H₂ via the process shown in Figure 1 at costs of \$2.5/kg or lower. However, there is considerable uncertainty regarding the cost and performance of individual components, particularly electrolysis and H₂ storage. Here we further explore the effect of component cost and performance as well as system design parameters on the cost competitiveness of electrolytic H₂ production at the 10 promising sites identified for initial deployment in Figure 5. The findings from sensitivity analyses at these 10 sites are meant to be illustrative of the possible outcomes at other similar resource quality locations in the United States, identified in the previous section. Given the relative immaturity of PEM electrolysis or H₂ storage compared with PV, we focus our analysis on the costs and performance of the former two technologies while keeping PV costs constant at the values assumed for 2030 (\$500/kW DC).

Figure 7 highlights the combination of electrolyzer capital costs, FOM costs, energy efficiency, and H₂ storage capital costs that lead to levelized costs of \$2.5/kg or lower while holding PV capital and FOM costs constant at \$500/kW DC and 1% of capital costs, respectively. The values for the remaining model input parameters used in Figure 7 correspond to the 2030 scenario defined in Table 1 and Table S4.

A central finding of Figure 7 is the effect of H₂ storage costs on the magnitude of electrolyzer capital cost reductions needed to achieve levelized H₂ costs of \$2.5/kg or less. This is indicated by the fewer number of green versus blue markers in each panel of Figure 7. The typical scale of geological H₂ storage, on the order of thousands of tonnes, overlaps with the storage capacity estimated for the process configurations highlighted in Figure 7. However, geological H₂ storage may be limited in its geographic availability, in which case further electrolyzer cost reductions are needed to offset the relatively high cost of pressure vessel H₂ storage. For instance, at the best PV resource location, L10, and an electrolyzer efficiency of 70%, Figure 7 highlights that achieving \$2.5/kg or lower levelized costs with

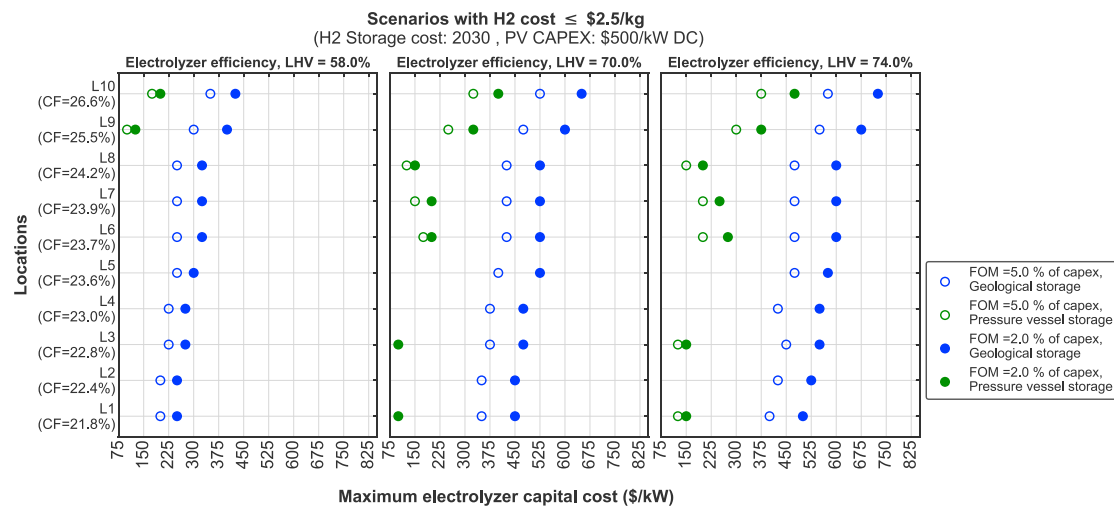


Figure 7. Combination of Locations, Electrolyzer Cost and Performance, and H₂ Storage Costs that Result in Levelized Costs ≤ \$2.5/kg

Parameters varied, including electrolyzer capital costs, FOM costs, energy efficiency (based on lower heating value [LHV]), and H₂ storage capital costs. The cost of geological and pressure vessel H₂ storage are equal to \$3/kg and \$345/kg, respectively, corresponding to the 2030 cost scenario. The costs of the remaining parameters are defined under the “2030” column in Tables 1 and S4. For each location, points are only marked for combinations of parameter values that result in costs of \$2.5/kg or lower. Filled and empty circles correspond to FOM costs equal to 2% and 5% of capital costs, respectively.

pressure vessel H₂ storage and geological H₂ storage requires electrolyzer capital cost reductions (compared with 2020 costs of \$800/kW) in the range of 50%–59% and 18%–34%, respectively. As a reference, electrolyzer capital costs are estimated to have declined by 3%–7% per year during 2003–2016.²⁹ Although a \$2.5/kg levelized cost threshold excludes the option of pressure vessel H₂ storage in 8 of the 10 sites in Figure 7 for the plausible 2030 scenario of electrolyzer cost and performance (capital cost of \$300/kW and 70% efficiency), a threshold cost of \$3/kg makes the system with pressure vessel H₂ storage feasible at 7 of 10 sites (Figure S9). Additionally, \$3/kg or lower levelized H₂ costs with pressure vessel H₂ storage appear to be feasible at multiple locations with 2030 electrolyzer cost and performance, even when the cost of pressure vessel storage remains the same as the 2020 estimates (Figure S10). Similarly, for geological H₂ storage, \$2.5/kg or lower levelized H₂ costs are achievable at 8 of the 10 sites with 2030 electrolyzer costs and performance and 2020 H₂ storage costs (Figure S11).

A comparison of the filled and unfilled markers of the same color in Figure 7 highlights the effect of decreasing electrolyzer FOM costs on levelized H₂ costs. As modeled here, FOM costs include the annualized cost of stack replacement, and this cost is expected to decrease as stack lifetimes increase.^{47,50} Figure 7 suggests that scenarios with high FOM costs (5% of installed capital costs [capex]) and geological storage (blue unfilled markers) lead to higher threshold values for electrolyzer capital costs (or lower levelized costs) compared with scenarios with low FOM costs (2% capex) and pressure vessel storage (green filled markers). This finding suggests that levelized costs are more sensitive to the type of H₂ storage compared with electrolyzer FOM costs.

The effect of increasing electrolyzer efficiency increases the number of combinations of electrolyzer costs, storage type, and locations that can achieve less than \$2.5/kg levelized H₂ costs (Figure 7, 24 markers in the left panel versus 32 markers in the center panel and 34 markers in the right panel). Based on the difference in maximum

electrolyzer capital cost across the panels in Figure 7, one can evaluate threshold cost increases associated with efficiency improvements that still result in levelized costs of \$2.5/kg or less. For example, with geological H₂ storage and FOM costs equal to 5% of capex, approaches that improve efficiency from 70% to 74% without increasing capital costs more than \$50–\$75/kW will be able to achieve levelized costs below \$2.5/kg at the 10 locations. Conversely, if electrolyzer efficiencies remain at their current levels of 58%, then electrolyzer capital costs will have to be in the range of \$200–\$350/kW to achieve levelized costs of \$2.5/kg or less at the 10 locations (Figure 7, left panel). Finally, this analysis assumes the electrolyzer energy efficiency to be independent of the device's power loading, whereas in practice, the system efficiency generally decreases with increasing loading levels because of resistive losses.^{28,36} For the process shown in Figure 1, however, the electrolyzer hourly loading is predominated by two states, at or near full operation or zero output (Figure S12). Consequently, the approximation of constant electrolyzer efficiency across loading levels has a relatively small effect on system design and cost outcomes (Figure S13).

Effect of System Factors

Although several studies of electrolytic H₂ production assume the annual plant availability to be the same as the PV capacity factor,^{14,28,29} our analysis defines it as an independent parameter. In general, increasing plant availability above the average PV capacity factor necessitates the need for additional energy storage and/or overbuilding PV capacity, both of which increase levelized costs. When H₂ storage is cheap, as in the case of geological H₂ storage, it is more cost-effective to increase H₂ storage capacity than overbuild PV capacity, whereas the opposite is true in case of higher H₂ storage costs corresponding to pressure vessel H₂ storage (Figures S14–S16). Figure 8 shows that plant availability requirements have a significant effect on levelized H₂ costs when considering more expensive pressure vessel H₂ storage. For instance, as plant availability is changed from 100% to 70%, the levelized costs for the highest PV capacity factor site, L10, decrease by nearly \$1/kg in the case of pressure vessel H₂ storage compared with less than \$0.2/kg in the case of underground H₂ storage. When contemplating H₂ infrastructure requirements to meet spatially distributed H₂ demand, the above finding suggests that it may be cost-effective to operate facilities with access to geological H₂ storage at or near 100% availability to compensate for the lower availability in H₂ supply from other facilities using pressure vessel H₂ storage (that may be located closer to demand).

Because the levelized cost is nearly entirely made up by capital costs, the assumed cost of capital is a key determinant of system costs. Figure S17 quantifies the sensitivity of the levelized costs to differing assumptions regarding the cost of capital, which is used to evaluate the fraction of total capital costs included in the annualized cost calculations (via the capital charge factor; Table S4). Across the locations and storage costs, changing cost of capital from the default value of 8.1% to 12% or 5% results in an increase or decrease in costs by roughly \$0.5–1/kg. The costs of H₂ at the highest PV resource sites show the smallest change with changing cost of capital because of the relatively small installed PV capacity, which dominates levelized costs (Figures 5A and 5B).

Comparison with NG Pathways for the 2030 Scenario

Currently, NG SMR without CCS is the most economical pathway for H₂ production in the United States, with an estimated cost near \$1/kg of H₂ for centralized production (around 300 tonnes/day).^{26,39,40} Therefore, in the absence of any policy incentive (e.g., carbon price) for low-carbon H₂ production, there is no economic driver

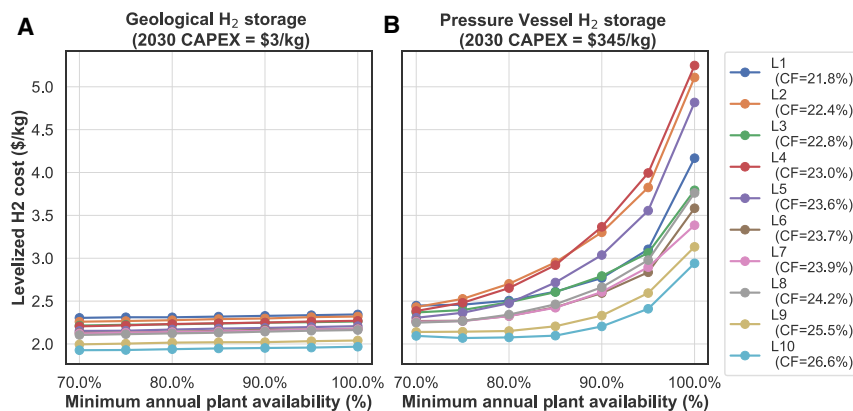


Figure 8. Effect of Annual Plant Availability Requirements on Levelized H₂ Costs

Shown is the sensitivity of levelized H₂ production costs to changes in minimum plant availability requirements for different H₂ storage capital costs and at various locations in the United States. Location labels, L1–L10, refer to the locations with the same name defined in Figure 5. Aside from storage capital costs, costs of other input parameters correspond to the 2030 scenario defined in Tables 1 and S4. Hourly H₂ production requirements held constant at 4.17 tonnes/h (with 10% hourly tolerance) across the differing plant availability requirement cases.

to deploy the PV-electrolysis process shown in Figure 1, even for the range of future technology costs and performance scenarios investigated above. The NG SMR process is associated with life cycle GHG emissions of 10–17 kg CO₂ equivalents/kg H₂,^{39,40} of which process GHG emissions account for approximately 9 kg CO₂/kg H₂,⁵¹ whereas the remaining emissions result from upstream activities (NG production, processing, and transmission). Figure 9 shows the estimated costs of avoiding process CO₂ emissions from NG SMR by substituting with H₂ produced from the process shown in Figure 1 for the 2030 scenario at the top 10 PV resource locations with existing NG-based H₂ production. These costs, referred as avoided CO₂ costs, are estimated as the ratio of the difference in levelized costs to the difference in CO₂ emission intensity between the two processes (Equation 1), where NG SMR is characterized with a cost of \$1.15/kg and 9.28 kg CO₂/kg H₂.²⁶

$$\text{Avoided CO}_2 \text{ cost} = \frac{\text{LevelizedCost}_{\text{PV-Electrolysis}} - \text{LevelizedCost}_{\text{NG-SMR}}}{\text{EmissionIntensity}_{\text{NG-SMR}} - \text{EmissionIntensity}_{\text{PV-Electrolysis}}} \quad (\text{Equation 1})$$

For 2030 electrolyzer cost and performance (defined in Table 1), the avoided CO₂ costs for 6 of the 10 sites (L3 and L6–L10) in Figure 7, which collectively accounted for 14.5% of H₂-related GHG emissions in 2017 (Table S6)⁵² is in the range of \$87–\$120/ton CO₂ with geological H₂ storage and \$135–\$207/ton CO₂ with pressure vessel H₂ storage. The range of avoided CO₂ costs for PV-electrolysis plus geological H₂ storage overlaps well with the range of avoided CO₂ costs (including cost of capture, transport, and storage) for NG-based H₂ with CCS based on SMR or ATR approaches (\$77–\$115 ton/CO₂).^{6,39,40} Despite the cost of CO₂ capture being slightly less for an ATR plant than an SMR plant, the choice of reforming technology has a relatively minor effect on the total avoided CO₂ costs for NG-based H₂ production^{6,40,42} and, consequently, on the comparison with PV-electrolytic H₂. The avoided CO₂ costs can be recovered in markets with incentives for fuel emission intensity reduction, such as the LCFS program in California, to achieve cost parity against more CO₂-emitting but cheaper cost pathways, like NG SMR without CCS. The average monthly price of emission credits generated via the LCFS program, which is capped at \$200/tonne CO₂, has ranged from \$122/tonne CO₂ to

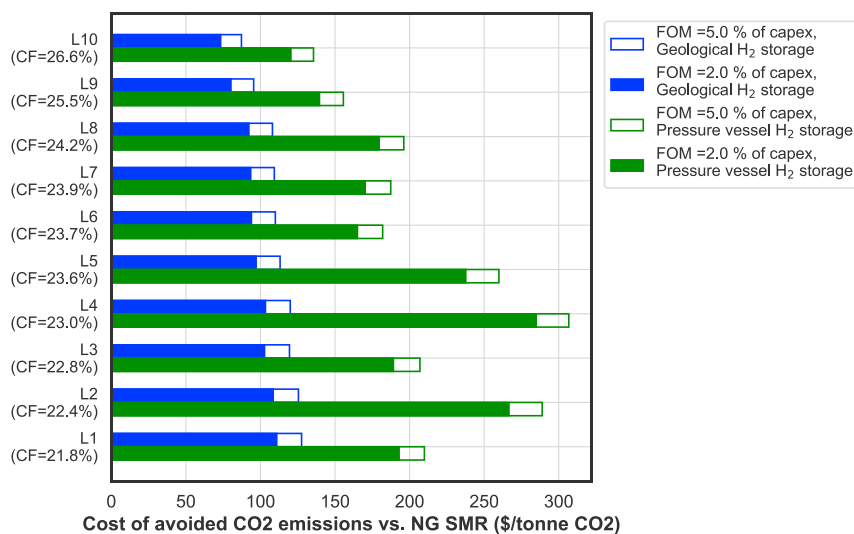


Figure 9. Avoided CO₂ Cost for H₂ Produced from PV-Electrolysis with Storage versus NG SMR

Shown are CO₂ avoided costs estimated based on the NG-SMR leveled cost of \$1.15/kg (2016 United States dollars)²⁷ and process emissions of 9.28 kg CO₂/kg H₂.⁴⁹ The results are based on the 2030 scenario defined in Tables 1 and S4. Capital cost of pressure vessel and geological H₂ storage correspond to \$345/kg and \$3/kg, respectively. Location labels, L1–L10, refer to the locations with the same name defined in Figure 5. Hourly H₂ production requirements held constant at 4.17 tonnes/h (with 10% tolerance) and 95% annual availability.

\$190/tonne CO₂ over the period of March 2018–February 2019.⁵³ This range overlaps with the range of avoided CO₂ costs estimated here.

The avoided CO₂ costs estimated here will likely be lower when calculated based on avoided life cycle GHG emissions instead of process GHG emissions because of higher upstream GHG emissions associated with NG-based H₂ compared with PV-electrolytic H₂.³⁹ For example, according to Parkinson et al.,³⁹ the central estimate for life cycle GHG emissions for H₂ produced from NG SMR and PV-electrolysis is 13.2 kg CO₂ equivalents/kg H₂ and 2.2 kg CO₂ equivalents/kg H₂, respectively. Using these life cycle GHG emissions rather than process-based GHG emissions in the avoided CO₂ cost calculations of Equation 1 lowers the avoided CO₂ cost for PV-electrolysis with either H₂ storage option for 6 of the 10 locations (L3 and L6–L10) by ~16% (\$74–\$100/tonne CO₂ for geological H₂ storage and \$114–\$174/tonne CO₂ for pressure vessel H₂ storage).

Although the design and cost outcomes presented here for PV-electrolysis correspond to a scale of 100 tons of H₂/day, many of the system components, with the exception of the H₂ compressor (which has a relatively small contribution to total costs; Figure 5), are modular in nature above a certain scale. This implies that the leveled costs are likely to be similar if the scale of production was changed, say, to serve distributed H₂ demand from a collection of H₂ fuel cell vehicle refueling stations (1–2 tonnes/day). For these end uses, PV-electrolysis coupled with pressure vessel H₂ storage could potentially be deployed closer to demand (i.e., refueling stations) to minimize H₂ transportation costs. Low-carbon H₂ supply with NG pathways at distributed scale has yet to be demonstrated, and centralized routes will be associated with additional delivery costs which, when completed via dedicated H₂ pipelines, are estimated to be around \$2/kg H₂.²⁷ Consequently, the delivered cost of H₂ from NG SMR coupled with pipeline transport for distributed end uses could be as

high as \$3/kg, not accounting for the cost of CCS. This implies that PV-electrolysis coupled with pressure vessel H₂ storage could potentially also be a cost-competitive supply option for distributed end uses at the highest PV resource locations if the 2030 cost scenario is realized.

DISCUSSION

Using plausible projections of 2030 costs and performance of commodity technologies for PV, electrolysis, and H₂ storage, we identify a set of sunny United States locations and plant configurations that could supply industrial-scale quantities of H₂ round-the-clock at costs at or below \$2.5/kg H₂.

The majority of the instances identified with a cost of \$2.5/kg or less are contingent on (1) a reduction in electrolyzer capital costs between 28% and 62% compared with current costs for multi-megawatt systems depending on the case; (2) ~20%–28% improvements in electrolyzer efficiency beyond current levels; (3) availability of geological H₂ storage, which not only enables low H₂ storage costs but could also provide sufficient storage capacity to support supply for industrial H₂ demand; and (4) PV capital costs of \$500/kW DC, which seems plausible given historical trends and available projections.^{12,43,44} Moreover, under these conditions, PV-electrolysis coupled with H₂ storage at select locations could displace NG-based H₂ supply with costs of avoiding process CO₂ emissions similar to costs estimated for deploying CCS at NG SMR facilities. These findings are made possible by the integrated design approach used in this study; notably, the costs would be considerably higher if one used the same technology cost and performance assumptions but did not optimize an individual component's size (e.g., electrolyzer to PV ratio < 1) at each location. Our approach not only quantifies the levelized cost effects associated with choices inherent in electrolyzer design, such as increasing efficiency versus decreasing capital costs, but also compares them with changes in costs and performance of other equipment; namely, the costs of PV and energy storage.

Estimates of future production costs are always uncertain. How might different assumptions change our conclusions? Factors that might lead to an under-estimate of costs include (1) a less than anticipated decline in the cost of individual technologies by 2030, notably electrolyzer and PV; (2) the potential cost savings from DC-DC integration of electrolyzer and PV systems being outweighed by the practicality and reduced performance of coupled operation; and (3) limitations regarding land availability and/or geological H₂ storage at the best sites, perhaps based on safety concerns about H₂ storage. Factors that might lead to an over-estimate of costs include our neglect of wind power and the benefits of the negative correlation between wind and solar availability in providing low-carbon power with higher availability than PV systems alone. The higher-capacity factor of wind as well as high resource availability in regions with low-quality solar resources (e.g., the United States Midwest) makes a compelling case for studying the economics of wind-based electrolytic H₂ production integrated with on-site storage. We neglected the benefits of grid integration, which could lower costs at the expense of increasing GHG emission intensity. Potential economic benefits of grid integration include providing ancillary services via electrolyzer operation, reducing the installed on-site capacity of renewable generation, electrolyzer and H₂ storage, as well as exporting any excess renewable electricity. The GHG emission effects of complete reliance on grid electricity for electrolysis, however, could be significant in the near term. For example, in California, renewables, including wind and solar, accounted for 29% of total generation in 2017,⁵⁴ leading to an average CO₂ emission intensity of electricity generation in

2017 of 212 kg CO₂/MWh.⁵⁵ This translates into CO₂ emissions of around 10 tonnes CO₂ per ton H₂ using a 70% electrolyzer efficiency, which is similar to the life cycle CO₂ emission intensity of H₂ produced from NG SMR. We neglected the use of curtailed PV electricity for consumption within the industrial plant that is also consuming the produced H₂. This approach could reduce electricity demand from the grid or onsite fossil-based generation, which reduces electricity supply costs for industrial application while also lowering plant direct and/or indirect CO₂ emissions. Finally, we only examined the United States, but the PV-electrolytic H₂ system may be even more cost effective in other regions with higher quality solar resources, such as Chile and India, regions with rapidly growing energy demands.

Our estimates of levelized H₂ cost and avoided CO₂ costs ignore the effect of existing policies supporting low-carbon H₂ or fuel production. As noted earlier, existing policies supporting renewable energy, like the LCFS and modified accelerated cost recovery system in the United States available for PV,⁵⁶ could further improve the cost effectiveness of dedicated PV-based electrolytic H₂. Such policies could also reduce the costs of competing H₂ supply technologies, such as NG SMR or ATR with CCS, so the effect on carbon-avoided costs is less clear.

Explicit treatment of the variability of PV output on timescales from hours to years is needed to understand the optimal system design and resulting H₂ production costs. In the analysis for the 2030 scenario with pressure vessel H₂ storage spanning nearly 1,500 locations, for example, the average PV capacity factor explains 61%, 61%, 58%, and 55% of the variation observed in, respectively, the H₂ production cost, installed PV capacity, relative electrolyzer size, and duration of installed H₂ storage capacity. Moreover, these values are based on characterizing annual PV resources at an hourly resolution using TMY data, but our simulations of plant availability using PV resource from individual years suggest that use of longer historical time series (or more judiciously selected annual time series) could be important to minimize costs in the practical design of high-availability, VRE-based H₂ production systems.

Future work could re-assess the promising sites identified for H₂ production in this study after factoring in the historical inter-annual variability in PV resources as well as the potential for geological H₂ storage sites and their various attributes (e.g., formation pressure, cushion gas requirements¹⁸). Further analysis is also needed to estimate the total potential supply of H₂ at each site that considers land availability constraints (e.g., excluding urban areas and preservation lands), manufacturing supply chain considerations, as well as the cost of importing H₂ from neighboring locations.

Previous attempts to expand the role of H₂ across the economy generally focused on transportation as the initial-use case. Instead, we argue for expanding use of H₂ in the industrial sector as a way to rapidly scale up electrolysis technologies and kickstart sectoral emission reduction efforts by 2030 to be consistent with mid-century deep decarbonization goals. Under a strong climate policy, our analysis suggests that electrolytic production of H₂ integrated with large solar PV arrays could, in areas of good solar resources, be cost competitive as an industrial feedstock by 2030.

EXPERIMENTAL PROCEDURES

Resource Availability

Lead Contact

Further information and requests for resources should be directed to the Lead Contact, Dharik Mallapragada (dharik@mit.edu).

Materials Availability

All of the data and methods used, including optimization models, are available from the Lead Contact upon reasonable request.

Data and Code Availability

The parameter inputs to characterize cost and performance technologies are documented in the study, with the exception of PV resource availability, which is drawn from a publicly available data source.⁵⁷ The scripts used to perform the modeling and a complete sample dataset are available at <https://www.dropbox.com/sh/ros1svybw09xhz/AADEajd-LPhYqRKeLOpDNYZAa?dl=0>.

Modeling Approach and Data Inputs

We use an integrated design and operations optimization model to evaluate the levelized cost of H₂ production across the continental United States. The model determines the cost-optimal size and hourly operation of all components throughout the year in the process shown in Figure 1 to meet the specified hourly H₂ production requirements while minimizing total annualized capital and operating costs. The model includes the following constraints associated with hourly plant operation: (1) inter-temporal constraints governing energy storage (H₂, battery) operation; (2) hourly limits on PV resource availability; (3) for each component, hourly power flows cannot exceed the installed power capacity; (4) throughput-based energy requirements for H₂ compression prior to storage; (5) minimum downtime requirements for the entire plant (12 h), and (6) annual plant availability requirements.

The model makes the following assumptions about individual component operation: (1) constant specific power consumption for the electrolyzer and compressor irrespective of loading; (2) fully flexible operation of the electrolyzer, compressor, H₂ storage, and battery energy storage, implying that each component can go from zero to the maximum power rating within an hour; (3) no minimum stable operating level for the electrolyzer; and (4) no minimum state of charge requirements for H₂ or battery storage. A complete mathematical description of the optimization model is available in Note S1. Unless stated otherwise, all results correspond to solutions where the optimization model was terminated with a 1% or lower optimality gap.

Annual hourly PV capacity factor data for the various United States locations evaluated was derived using TMY insolation data available from the National Solar Radiation Database (NSRDB)⁵⁷ in conjunction with the pvlib simulation toolbox.⁵⁸ The pvlib simulation toolbox⁵⁸ converts the insolation time series into a capacity factor time series (DC values) based on a pre-specified PV system configuration, which, in this analysis, is assumed to be a single-axis tracking system that is oriented horizontally. The cost and performance assumptions used to characterize operating and capital costs of various components across the 2020 and 2030 scenarios is summarized in Table 1 and Table S4.

The spatial distribution of levelized H₂ production costs shown in Figures 2 and 4 was developed based on evaluating the optimization model for 1,487 locations across the United States. These locations correspond to points on a grid developed from evenly spaced latitudes and longitudes spanning the continental United States land area. The levelized H₂ production costs estimated for the 1,487 locations were translated into a smooth color map for the continental United States using a Voronoi diagram (Note S3).

SUPPLEMENTAL INFORMATION

Supplemental Information can be found online at <https://doi.org/10.1016/j.xcrp.2020.100174>.

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AUTHOR CONTRIBUTIONS

Conceptualization, D.W.K., D.S.M., E.G., and F.M.O.; Methodology, D.S.M. and E.G.; Investigation, D.S.M., E.G., and P.I.; Writing—Original Draft, D.S.M.; Visualization, D.S.M. and P.I.; Project Administration and Funding Acquisition, D.W.K., D.S.M., and F.M.O.

DECLARATION OF INTERESTS

F.M.O. is Senior Vice President for Strategy at Orsted Onshore North America, a developer and owner of wind and solar projects in the United States. D.W.K. is a founder and board member of Carbon Engineering, a developer of direct air capture technologies that might be used to produce fuels using solar hydrogen as an input.

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