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HYDROGEN INFRASTRUCTURE DEVELOPMENT

Realize energy, environmental benefits with circular H_2

H_2 value chain analysis comparing different transport vectors

HYDROGEN STORAGE

Long-duration H_2 storage in solution-mined salt caverns

SAFETY AND SUSTAINABILITY

Key safety considerations for the rolloutof H_2 infrastructure

Gulf Energy

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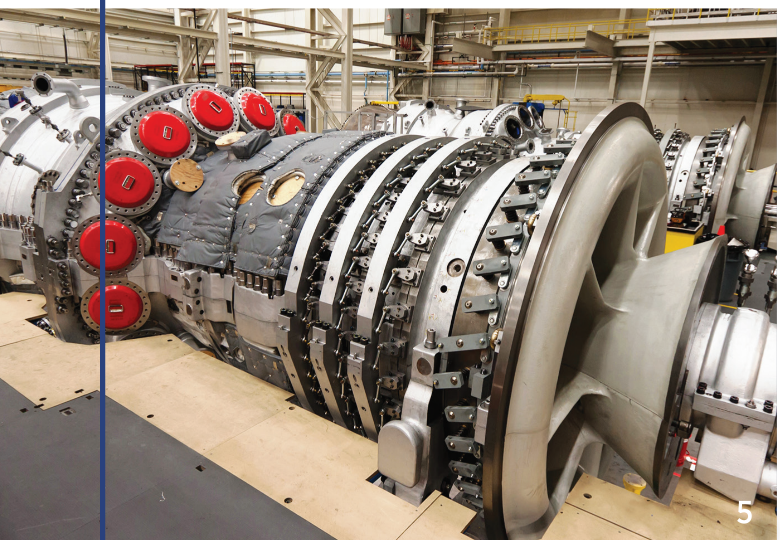

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Cover Image: Siemens has developed what is currently the world's largest PEM (proton exchange membrane) electrolyzer module for the research facility in Linz. With a capacity of 6 megawatts, the plant will be able to produce 1,200 cubic meters of "green" hydrogen an hour. Photo courtesy of Siemens AG.

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EDITORIAL COMMENT

U.S. eyes infrastructure buildout, price reductions for H_2

A. BLUME,
Editor-in-Chief

The industry report, "Roadmap to a U.S. hydrogen economy," released in October 2020, details how the U.S. can expand its global energy leadership by scaling up activity in the rapidly evolving H_2 economy. The U.S. already produces approximately 11.4 metric MMtpy of H_2—mostly in Texas, California and Louisiana—with an estimated value of about $17.6 B.

The vast majority of the U.S.' existing production is "gray" H_2 associated with CO_2 emissions. However, with a combination of CCS projects to make gray H_2 installations produce low-emissions "blue" H_2, and a growing number of green H_2 production projects powered by renewable energy, the Roadmap anticipates that H_2 from low-carbon sources could supply roughly 14% of the country's energy needs by 2050.

Green H_2 projects will get off the ground more quickly, and at larger scale, as the cost of such projects decreases. One of the goals of the current U.S. administration is to reduce the cost of low-carbon H_2 production, delivery and dispensing to $2/kg by 2025 and to $1/kg by 2030 (**FIG. 1**). At present, green H_2 in the U.S. has a price point of around $5/kg, while blue H_2 costs less than $2/kg, making blue H_2 projects more economical.

Infrastructure buildout is also needed to expand the use of low-carbon H_2. The transportation sector will benefit from H_2 infusion for long-haul trucks that require fast refueling, while the materials-handling sector is seeing growth in H_2 fueling for FCEVs.

Reaching the Roadmap's targets could drive around $140 B/yr in revenue by 2030, and approximately $750 B/yr in revenue by 2050. With sufficient near-term investment, the U.S. market for H_2 across all segments could total 12 metric MMt at the end of 2022, 13 metric MMt at the end of 2025 and 17 metric MMt at the end of 2030, compared to around 11 metric MMtpy in late 2020 (**TABLE 1**).

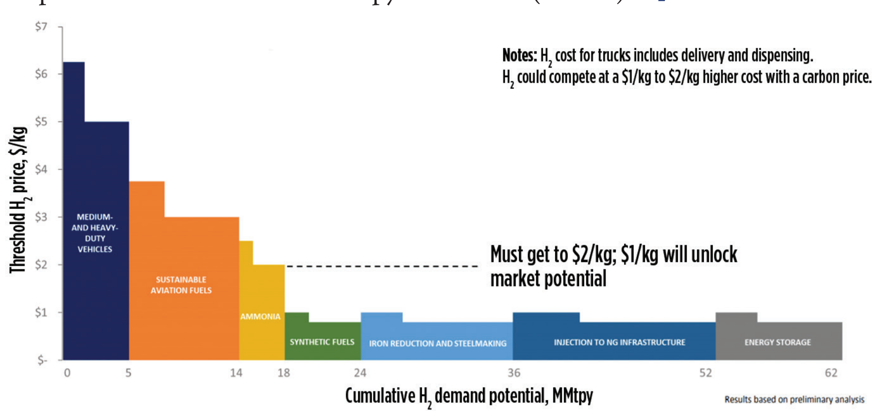

FIG. 1. Market potential for H_2 use in U.S. based on cost. Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Hydrogen and Fuel Cell Technologies Office.

TABLE 1. Targeted milestones for H_2 scale-up in the U.S.

Milestone	2021	2022	2025	2030
H_2 demand, metric MMt	11	12	13	17
FCEV sales	2,500	30,000	150,000	1,200,000
Material-handling FCEVs	25,000	50,000	125,000	300,000
H_2 fueling stations	63	165	1,000	4,300
Material-handling fueling stations	120	300	600	1,500
Yearly investment	TBD	$1 B	$2 B	$8 B

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GREEN H_2

Raven SR to build first waste-to-H_2 plant

Raven SR Inc., a renewable fuels company, has selected POWER Engineers Inc. and Stellar J Corp. to complete the final design, engineering and fabrication of the company's first commercial renewable fuels production facilities, to be located in the San Francisco Bay area. The facilities will convert a blend of green waste and food waste into green H_2 for the commercial transportation market.

Raven SR's first commercial systems will produce up to 10,000 kg/d of renewable H_2 from a blend of green waste and food waste that is being diverted from landfilling. Raven SR's patented steam/CO_2 reformation process makes it one of the only non-combustion waste-to-H_2 processes in the world. Raven SR's first commercial systems can reduce landfill waste by up to 200 tpd, converting it to nearly 10 tpd of renewable H_2, which is enough to power around 200 heavy-duty trucks per day.

The Bay Area sites will also serve as the first two H_2 hubs in a partnership between Raven SR and Hyzon Motors Inc. to fuel regional Hyzon fleets, and to supply H_2 for commercial fuel stations in the region. Hyzon and Raven SR have announced the co-development of 100 H_2 hubs in the U.S. and internationally.

LIQUEFACTION

Joule Processing commercializes ultra-efficient H_2 liquefaction

Joule Processing has signed an exclusive partnership agreement with JTurbo Engineering and Technology to provide its twin-expander refrigeration technology for H_2 liquefaction. Joule will utilize the technology to bring an ultra-energy-efficient H_2 liquefaction plant to market.

The plant is the newest addition to Joule's suite of modular process systems. The plants are capable of liquifying H_2 for transportation at near-atmospheric pressure and temperatures below –400°F, with a minimum specific energy consumption.

Joule's H_2 liquefaction plant is designed specifically for the new H_2 economy, featuring a compact, simple design. The technology liquefies H_2 with very low energy consumption, utilizing JTurbo's patent-pending twin-expander processes for both precooling and liquefaction and subcooling refrigeration cycles. At present, Joule is offering standardized H_2 liquefaction plants at capacities of 10 metric tpd, 15 metric tpd and 30 metric tpd of liquid H_2.

TRANSPORTATION/ MOBILITY

Novel path toward zero-emissions shipping

Hydrogenious LOHC Technologies GmbH and Johannes Østensjø Dy AS recently founded the JV company Hydrogenious LOHC Maritime AS. The aim is to develop and market emissions-free liquid organic H_2 carrier (LOHC)-based applications for shipping and to have a commercial product ready for operation from 2025.

The focus is onboard LOHC/fuel cell propulsion systems on a MW scale. By binding the H_2 to the LOHC, it will be a particularly safe technology. Hydrogenious' LOHC applies to conventional bunkering facilities onboard, as well as in ports.

Funding agency Enova, owned by the Norwegian Ministry of Climate and Environment, will support the JV's initial project, HyNjord, with NOK 26 MM (€2.5 MM).

Hyzon, RenewH$_2$ collaborate on LH$_2$ production

Hyzon Motors Inc. has signed an MOU with RenewH$_2$ to collaborate on the supply and demand side of liquid H_2 production. Under the MOU, RenewH$_2$ plans to reform biogenic methane gas to generate H_2. The H_2 would then be liquefied and delivered to H_2 fueling stations, which are expected to be developed in collaboration with Hyzon. Through this collaboration, the stations can be located near Hyzon customers to help provide consistent demand for the fuel.

Both companies are interested in expanding liquid H_2 infrastructure due to its advantages over H_2 gas. Because of its power density, liquid H_2 is projected to provide a range approximately twice as far as 700-bar gaseous H_2. The range for liquid H_2 vehicles is expected to be up to 1,000 mi, based on Hyzon's recently announced agreement to develop ultra-heavy-duty liquid H_2-fueled trucks.

The greater range means fewer fueling stations, thereby reducing the need for liquid H_2 to be transported to many locations. In addition, the refueling infrastructure capital and operating costs are expected to be lower when compared to gaseous H_2, due to the elimination of the compression and refrigeration equipment.

RenewH$_2$ is expected to begin producing H_2 at its Wyoming facility in 2023, with ultimate capacity of 300 tpd using steam methane reformers. In addition to producing liquid H_2, RenewH$_2$ expects to store and deliver the fuel. Per the MOU, the fuel could be delivered by a fleet of Class-8 Hyzon trucks, owned and operated by RenewH$_2$.

Hyundai to develop H_2 fuel cell for mobile power

Hyundai Motor Co. signed an MOU with Hyundai Electric & Energy Systems Co. to develop an H_2 fuel cell package for mobile power generation. Under the MOU, the two parties will develop an H_2 fuel cell package dedicated for mobile power generators and alternative maritime power (AMP) supply solutions, based on Hyundai Motor's polymer electrolyte membrane fuel cell (PEMFC) system that is used in Hyundai Motor's fuel cell vehicles.

The new fuel cell-based package system is expected to be a game-changer in the mobile generator market, which is dominated by diesel generators. Environmentally friendly, distributed power solutions like the one planned can address carbon-neutral electric needs in a variety of industrial sectors such as port facilities, construction sites and industrial complexes.

Under the agreement, Hyundai Motor will supply PEMFC fuel cell systems and provide technical support, while Hyundai Electric will develop and commercialize a fuel cell-based power generation package, which includes mobile generators and AMP supply systems. Hyundai Electric will also explore a variety of business models for marketing the new package in South Korea and abroad.

Air Products, Cummins to accelerate development of H_2 trucks

Air Products and Cummins Inc. signed an MOU to accelerate the integration of H_2 fuel cell trucks in the Americas, Europe and Asia. Cummins will provide H_2 fuel cell electric powertrains integrated into selected OEM partners' heavy-duty trucks for Air Products, as Air Products begins the process of converting its global fleet of distribution vehicles to H_2 fuel cell vehicles.

Following a successful demonstration and pilot phase, Air Products plans to convert its global fleet of approximately 2,000 trucks to H_2 fuel cell zero-emissions vehicles. Cummins and Air Products expect the demonstration phase to begin in 2022. Additionally, Cummins and Air Products will work together to increase the accessibility of renewable H_2, including H_2 infrastructure opportunities that promote the adoption of H_2 for mobility.

STORAGE

Howden to provide storage for steel pilot

Howden will deliver an H_2 storage compression solution for HYBRIT, the world's first fossil-free steel plant, in Svartöberget, Sweden. A joint project between Sweden's SSAB, LKAB and Vattenfall, HYBRIT is the deployment of a pilot project for large-scale H_2 storage.

Howden will supply a high-pressure diaphragm compression package to integrate the storage cycle of the H_2 production. The H_2 compression includes installation and commissioning of a packaged, three-stage diaphragm compressor.

The facility consists of a 100-m^3 H_2 storage built in an enclosed rock cavern approximately 30 m below ground. This offers a cost-effective solution, with the necessary pressure required, to store large amounts of energy in the form of H_2.

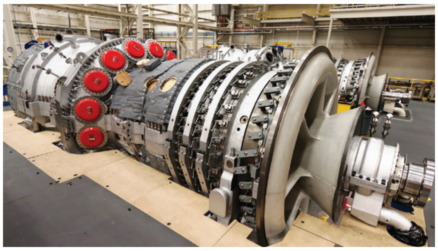
TURBOMACHINERY/ COMPRESSION

PPI compressors address key requirements for H_2 applications

Sundyne's PPI diaphragm compressors are being used for H_2 applications around the world. PPI compressors are ideal for H_2 applications for a number of reasons:

- High compression ratio: PPI diaphragm compressors are designed to meet the pressures required by mobility applications and industrial decarbonization projects.
- Product purity: PPI compressors feature triple diaphragm sets, which ensure that the process gas is isolated from the hydraulic oil. This provides absolute process purity for fuel cell applications.
- Reliability: Every process-contacting part in a PPI compressor is made from corrosion-resistant alloys, making them ideal for H_2 processing.
- Environmental safety: The static seals in PPI compressors ensure zero leakage of process gas to the atmosphere, and PPI's leak detection system immediately detects diaphragm or seal failure.
- Lower energy costs: PPI's rugged crank cases and drive trains are designed to deliver maximum compression at the lowest energy cost.
- Support for industry standards: All PPI compressors meet API 618 standards.
- Explosion-proof certification: PPI compressors are certified to meet the various standards for explosion-proof environments worldwide.
- Custom engineering: Sundyne collaborates with customers to manufacture customized PPI systems that are optimized for the gas pressure, molecular weight, heat, corrosion and velocity of each application. Sundyne utilizes the latest technology in solids modeling and FEA analysis to ensure that all working components are designed and tested to minimize wear, improve sealing and reduce corrosive and erosive effects.

Siemens Energy to provide H_2 turbines in Nebraska



Siemens Energy will provide two SGT6-5000F turbines to power Omaha Public Power District's (OPPD's) new Turtle Creek Station Peaking Plant in Papillion, Nebraska. The simple-cycle turbine facility will be used to modernize backup generation in OPPD's fleet, which means that the plant will run only as needed to provide a reliable source of electricity for the community.

The turbines offer the ability to run on up to 30% H_2 and biodiesel in support of future technology advancements. They also offer a fast start time and low emissions while helping rapidly stabilize transmissions systems to adjust for the variable output of solar generation.

Siemens Energy has set an ambitious target to have all its new gas turbines (including the SGT6-5000F) capable of burning 100% H_2 on or before the end of 2030.

PROJECTS UPDATE

A. BLUME, Editor-in-Chief

EUROPE

Shell starts up Europe's largest PEM electrolyzer

Europe's largest PEM H_2 electrolyzer commenced operations at Shell's Energy and Chemicals Park Rheinland in July, producing green H_2. Plans are underway to expand capacity of the electrolyzer from 10 MW to 100 MW at the Rheinland site, near Cologne. The Rheinland electrolyzer will use renewable electricity to produce up to 1,300 metric tpy of green H_2. The H_2 will initially be used to produce fuels with lower carbon intensity.

NextChem, Mytilineos study green H_2 plant in Italy

Maire Tecnimont subsidiary NextChem and Mytilineos plan to jointly develop engineering activities for the implementation of a green H_2 plant in Italy.

Under the agreement, Mytilineos will leverage NextChem's and Maire Tecnimont Group's engineering expertise in H_2 technologies to grow in the H_2 business. The project will convert renewable energy from one of Mytilineos' solar plants into green H_2.

Air Liquide to transform German H_2 network

Air Liquide is planning to build a green H_2 production plant in Oberhausen, Germany. With a total capacity to reach 30 MW, the first phase of the project is expected to be operational by early 2023 with 20 MW.

The world-scale PEM electrolyzer will be built by a partnership of Air Liquide and Siemens Energy. By 2023, the two partners will implement a 20-MW electrolyzer plant that will produce renewable H_2 and renewable O_2. In a second phase, Air Liquide has planned to increase the plant capacity to 30 MW.

ASIA-PACIFIC

FFI studies green H_2 in New Zealand, India

Fortescue Future Industries and the Murihiku Hapu people have entered into a collaboration agreement to study and potentially construct a large-scale green H_2 generation project in Southland, New Zealand. The project seeks to build a large-scale H_2 plant, with the goal of starting production in early 2025 and expanding in stages in the future.

FFI has also entered into a framework agreement with JSW Future Energy Ltd. to explore opportunities to develop green H_2 projects in India. Under the agreement, FFI and JSW Energy will study potential projects for the production of green H_2 for steelmaking, mobility, green ammonia and other industrial applications in India.

Study for H_2 supply chain in South Australia

ENEOS Corp. has signed an MOU with Neoen Australia to conduct a study on a collaboration for the construction of a CO_2-free H_2 supply chain between Japan and South Australia.

Neoen will study stable renewable energy supply and water electrolysis cells for H_2 production. ENEOS will be responsible for more efficient production of methylcyclohexane (MCH) and maritime transport of MCH as a form of H_2 storage and transport from Australia to Japan.

NORTH AMERICA

Entergy plans H_2/gas plant in Texas

Entergy Texas Inc. is seeking approval to construct the Orange County Advanced Power Station, a 1,215-MW, dual-fuel, combined-cycle power facility. The plant will be capable of powering more than 230,000 homes with a combination of natural gas and H_2.

In addition to meeting customer needs across Southeast Texas, the Orange County Advanced Power Station will be built with a focus on long-term sustainability in an economy where many stakeholders and customers are focused increasingly on decarbonization.

If the Public Utility Commission approves Entergy's application, construction will begin in 2Q 2023. Entergy Texas expects the plant to be in service by summer 2026.

CF Industries to build green ammonia plant in Louisiana

Thyssenkrupp has entered into an engineering and supply contract with CF Industries to deliver a green H_2 plant for the production of green ammonia at the Donaldsonville manufacturing complex in Louisiana. Under the contract, thyssenkrupp will engineer and deliver a 20-MW H_2 production unit based on its alkaline water electrolysis, as well as all necessary utilities.

The plant will utilize renewable energy from the grid to produce green H_2, which then will be converted to 20,000 tpy of green ammonia. Engineering and procurement activities have been initiated, and the start of production is scheduled for 2023.

MIDDLE EAST/AFRICA

HYPORT Duqm develops green ammonia in Oman

Oman's green H_2 project, HYPORT Duqm, has signed a cooperation agreement with Uniper. Under the cooperation, Uniper will be joining the project team to provide engineering services and negotiate an exclusive offtake agreement for green ammonia.

In the first phase, the HYPORT Duqm project will develop a 250-MW to 500-MW green H_2 facility in the Special Economic Zone at Duqm. The facility is planned to come into operation in 2026 and will respond to global demand for green H_2 and its derivatives. HYPORT Duqm Phase 1 will establish a complete power-to-product value chain at utility scale to produce competitive green H_2 and green ammonia.

SOUTH AMERICA

Howden provides H_2 compression for green methanol plant

Howden has been selected to deliver an H_2 compression solution to Johnson Matthey (JM) for the world's first methanol plant to harness energy from the wind, in Patagonia, Chile. The Haru Oni project will enable production of e-fuels to supply Europe and other regions.

The JM-designed unit will take atmospheric CO_2 as feedstock for the conversion to e-methanol. This CO_2 will be recovered by direct air capture and combined with green H_2 produced by PEM electrolysis. The new production unit will deliver around 900,000 l/yr of e-methanol as early as 2022, with future full-scale production units ready by 2026 delivering 550 MM l/yr of e-fuels.

REGIONAL REPORT: NORTH AMERICA

North America sees ripe opportunity for low-carbon H_2 production

A. BLUME, Editor-in-Chief

With its highly developed industrial infrastructure and growing renewable energy sector offering a wealth of opportunities to produce low-carbon H_2, North America is ripe to join the H_2 frenzy taking place in the Europe and Asia-Pacific regions. Green H_2 will find increasing applications in the North American market, particularly the U.S., as production costs decline in the coming years. In the near term, the region is well poised to take advantage of blue H_2 projects as a bridge to large-scale green H_2 production powered by renewable energy.

This is somewhat in contrast to Europe and Asia-Pacific, where significant climate-change concerns and carbon-reduction efforts have brought green H_2 into focus as an immediate and prioritized decarbonization solution. In North America, the market will largely determine how and where low-carbon H_2 reaches the U.S. energy system over the following decades.

High H_2 growth potential in U.S. In the U.S., H_2 has the potential to play a vital role in balancing the power grid. In combination with renewable energy generation, it can be used to supplement seasonal and large-scale energy storage requirements. H_2 can be blended with natural gas to power residential and commercial buildings, and it can help decarbonize the transportation and materials-handling industries with its use in FCEVs.

The report, "Roadmap to a U.S. hydrogen economy,"[1] developed by a coalition of major oil and gas, power, automotive, fuel cell and H_2 companies and released in October 2020, details how the U.S. can expand its global energy leadership by scaling up activity in the rapidly evolving H_2 economy. The Roadmap anticipates that H_2 from low-carbon sources could supply roughly 14% of the country's energy needs by 2050, including hard-to-electrify sectors that are dependent on natural gas, such as high-heat industrial processes and fertilizer manufacturing (FIG. 1).[1]

Furthermore, the Roadmap predicts that H_2 alone could reduce U.S. CO_2 levels by 16% and its NO_X levels by 36% by 2050. However, for these goals to be achieved, the U.S. must realize massive investment in its fledgling green H_2 industry in the near term. Greater federal investment is needed to build H_2 production and transport infrastructure, as is greater private-sector investment (see this issue's Editorial Comment for more information).

Also essential are new codes and standards to regulate the expanding H_2 supply chain, as well as further research into future large-scale H_2 production technologies, such as photoelectrochemical solar water splitting, thermochemical solar water splitting and microbial electrolysis of waste streams.

The U.S. is also studying the blending of up to 15% H_2 into the natural gas grid to reduce emissions, such as through the DOE's HyBlend project. Blends of up to 15% are feasible without significant changes to infrastructure. Blending 20% H_2 by 2050 would require approximately 900 TWh of electricity, enabling a doubling of existing renewable generation.

2030 H_2 price targets. In line with the need to fast-track research and investment, the U.S. DOE launched its Hydrogen Program Plan in November 2020 and its Hydrogen Energy Earthshot Initiative in June 2021. The Hydrogen Earthshot will help accelerate breakthroughs of more abundant, affordable and reliable clean energy solutions within the decade. Hydrogen Shot also seeks to reduce the cost of low-carbon H_2 production, delivery and dispensing by 80%, to \$1/kg by 2030, with an interim goal of reaching a price point of \$2/kg by 2025. At present, green H_2 in the U.S. costs around \$5/kg, while blue H_2 costs less than \$2/kg.

The Program Plan and Earthshot also outline a 2030 targeted price point of \$1/kg for H_2 for industrial and stationary power generation; \$9/kW for low-carbon H_2 storage; and a fuel cell system cost of \$900/kW for stationary, high-temperature installations with 40,000-hr durabil-

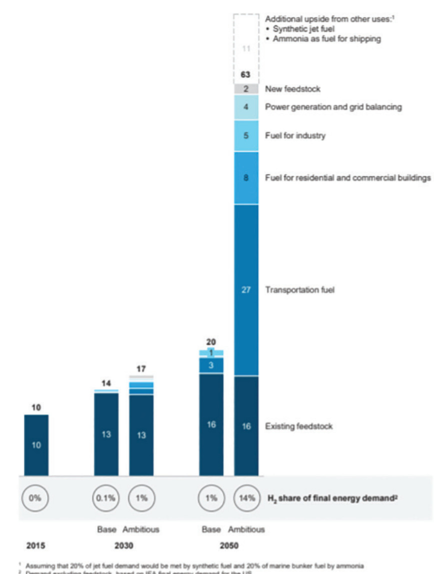


FIG. 1. U.S. low-carbon H_2 demand potential through 2050, metric MMtpy. Source: "Roadmap to a U.S. hydrogen economy," McKinsey & Co. and FCHEA.

OPENING PHOTO: SoCalGas and SunLine Transit Agency's joint research project, H2 SilverSTARS, will produce green H_2 to fuel SunLine's fleet of 17 H_2 fuel cell electric buses. Photo: SoCalGas.

ity. Furthermore, the plans aim to bring down electrolyzer capital cost to \$250/kW–\$300/kW with 65% system efficiency and 80,000-hr durability (**FIG. 2**).[2]

Achieving these price targets will help meet the Biden–Harris Administration's goals of a 100% carbon-free electric sector by 2035 and net-zero carbon emissions by 2050.[2] The potential for U.S. H_2 exports is also being analyzed, with preliminary estimates of the cost of H_2 exports from the U.S. to Europe or Japan at \$5/kg–\$6/kg.

H_2 projects. As of June 2021, the U.S. has 182 MW of planned and installed PEM electrolyzer capacity (**FIG. 3**), according to the DOE. Regionally speaking, the U.S. has two potential H_2 hubs: the green-focused West Coast and the industrial-heavy Gulf Coast.

On the **West Coast,** California's low-carbon fuel standard is incentivizing research and development for H_2 technologies and renewable natural gas (RNG). The California Energy Commission and the California Resources Board have provided direct funding for the development of H_2 projects and technologies, putting California in the lead for U.S. H_2 development.

In recent and ongoing projects, SoCalGas' H2 Hydrogen Home is the first project in the U.S. to show how green H_2 can be used in pure form or as a blend to power homes. The project, which will be built in late 2021 in Downey, California, will encompass solar panels, a battery and an electrolyzer to convert solar energy into green H_2. In March 2021, SoCalGas became the largest gas utility in North America to commit to net-zero carbon emissions by 2045. A key component of this goal is to complete five H_2 pilot projects by 2025, including H2 Hydrogen Home.

The Los Angeles Department of Water and Power (LADWP) plans to convert its coal-fired Intermountain Power plant in Utah, which feeds the California market, to a mix of 30% electrolyzer-produced H_2 and 70% natural gas. The feedstock will rise to 100% H_2 over the coming decades. The 840-MW project will help the LADWP meet its 100% renewable energy targets. Also, San Diego Gas & Electric plans to bring two long-duration green H_2 storage projects online by 2022. In Nevada, industrial gases supplier Air Liquide is investing \$150 MM in a renewable liquid H_2 generation plant to produce 30 tpd of low-carbon H_2, or enough to supply 40,000 FCEVs, when it opens in 2022.

In California, the long-haul trucking sector is moving toward H_2, as the molecule offers a distinct cost advantage over diesel, even without the positive environmental impact. California has the largest total number of FCEVs in the U.S. and one of the largest networks of retail refueling stations in the world, and is expected to host 200 H_2 stations by 2025. Shell is building H_2 fueling stations in the Los Angeles area to serve the port's FCEV fueling needs. Also, SoCalGas and SunLine Transit Agency are testing two technologies that will produce H_2 from RNG at SunLine Transit Agency's H_2 fueling station in Thousand Palms, California. The research project, called H2 SilverSTARS, will produce green H_2 to fuel SunLine's fleet of 17 H_2 fuel cell electric buses (**OPENING PHOTO**).

On the **Gulf Coast,** the Houston, Texas area boasts almost 50 steam methane reformers (SMRs), as well as a 420-mi pipeline network to transport H_2. The geology of the Gulf Coast region is also favorable for constructing salt-dome caverns for H_2 storage. Houston can decarbonize its existing SMR-based infrastructure to create a significant H_2 market in the region over the next 2 yr–3 yr, according to think tank Center for Houston's Future. Texas is also home to a large portion of the U.S.' wind energy production and has significant solar power resources, making it favorable for the development of green H_2 production.

A number of utilities on the West and Gulf Coasts have made pledges to eliminate their carbon emissions by 2050, echoing the net-zero commitments by European and Asian governments and corporations. In line with its own pledge, Gulf Coast utility Entergy plans to build a 1,215-MW power plant near Bridge City,

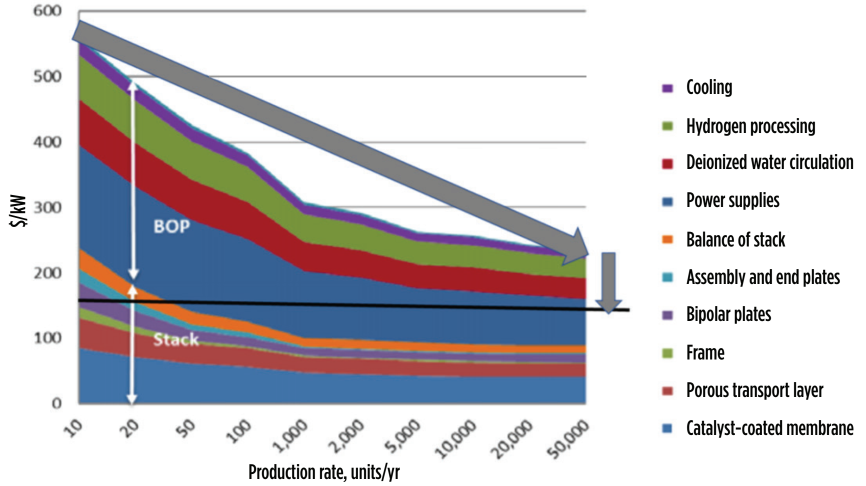


FIG. 2. Pathway for reducing electrolyzer cost.

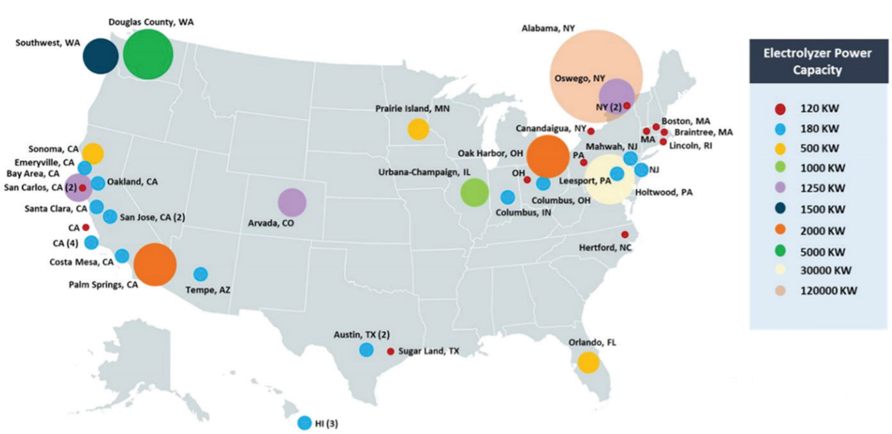


FIG. 3. Planned and installed PEM electrolyzer capacity in the U.S., as of June 2021. Source: DOE HFTO Program Record.

Texas, that is capable of running on a combination of H_2 and natural gas on startup in mid-2026. Entergy is also working to blend H_2 into natural gas at its power plants, and will convert an underground gas storage facility to hold H_2 as part of its long-term decarbonization strategy.

On the **East Coast,** NextEra Energy's Florida Power & Light subsidiary plans to build a $65-MM pilot plant in Florida to produce green H_2 from a 20-MW electrolyzer powered by solar energy, with startup slated for 2023. The H_2 produced would replace a portion of the natural gas that is presently used at the 1.75-GW Okeechobee power plant. If green H_2 becomes economic, Florida Power & Light may retrofit some of its natural gas facilities to run wholly or partially on H_2.

In the **Rocky Mountain region,** Dominion Energy is developing several pilot projects to blend H_2 into its gas distribution system and use H_2 in the generation of clean electricity, renewable storage, transportation and manufacturing. In the first project, Dominion will blend 5% H_2 in a test system at its training facility in Utah before blending it into a larger system that serves more than 1 MM gas utility customers. The company has proposed a similar project for North Carolina.

RenewH2 plans to produce, store and deliver 300 tpd of blue H_2 by reforming biogenic methane from SMR at its Wyoming facility from 2023. Hyzon Motors, which will develop ultra-heavy-duty liquid H_2-fueled trucks, has signed an MOU with RenewH2 to collaborate on H_2 supply and demand logistics.

In the **Midwest,** New Fortress Energy is working with GE and Black & Veatch to introduce H_2 into the natural gas turbines at the 485-MW Long Ridge Energy Terminal power plant in Hannibal, Ohio. The project is slated to begin producing CO_2-free power by the end of 2021. It will be the first purpose-built H_2-burning power plant in North America. The Long Ridge plant's combustion turbine will initially burn from 15 vol%–20 vol% H_2 in the gas stream and transition to burning 100 vol% green H_2 over the next 10 yr.

Mitsubishi Power and Bakken Energy are considering a redevelopment of Basin Electric Power Cooperative's Dakota Gasification plant near Belulah, North Dakota, to produce blue H_2. The coal gasification plant, which has been struggling due to low commodity prices in recent years, already captures 2 metric MMtpy of CO_2. The companies are presently conducting due diligence for the proposed project.

Meanwhile, Nikola is investing $50 MM for a 20% equity interest in a blue H_2 project being developed in West Terre Haute, Indiana. The project will use solid waste byproducts, such as petroleum coke combined with biomass, to produce blue H_2 for transportation fuel and baseload power generation while capturing CO_2 emissions for permanent underground sequestration. Once completed, the project is expected to be one of the largest carbon-capture and clean H_2 production projects in the U.S. The H_2 will be used to fuel Nikola's zero-emissions trucks.

Additionally, Enel Green Power, through its North American renewable subsidiary Enel Green Power North America, and Maire Tecnimont, through its subsidiary NextChem, are building a plant to produce green H_2 via electrolysis at an undisclosed location in the U.S. The plant, which will become operational in 2023, will convert solar energy from an EGPNA installation into green H_2 for use at a biorefinery.

Canada eyes H_2 for net-zero targets.

Canada produces an estimated 3 metric MMtpy of H_2 at present, with the majority of this as gray H_2 for industrial use. Canada's federal government released its Hydrogen Strategy for Canada in December 2020 as part of its national plan to become carbon neutral by 2050.[3] Prime Minister Justin Trudeau has also pledged to cut carbon emissions 45% below 2005 levels by 2030. The country plans to lay the foundation for its H_2 economy through 2025, including the development of new H_2 supply and distribution infrastructure to support the deployment of early H_2 projects in mature applications while simultaneously supporting emerging applications for H_2.

From 2025–2030, Canada will work to diversify its H_2 market into applications such as FCEV cars, buses and heavy-duty trucks, as well as H_2/natural gas blending for industrial and chemical feedstock in regional hubs. As renewables are increasingly introduced into the electricity grid, pilot plants to produce H_2 for use in utility-scale energy storage will be required. In the 2030–2050 time frame, Canada will capitalize on its H_2 supply and distribution infrastructure and realize the full benefits of its growing H_2 economy.

According to the government's estimated potential adoption rates for hydrogen by 2050, H_2 could account for 31% of secondary energy use in Canada by 2050 under a "transformative" scenario, assuming net-zero targets are reached and economic and population growth are offset by efficiency improvements resulting in consistent energy consumption over time. This represents just over 20 metric MMtpy of H_2 demand in 2050 (FIG. 4).[3]

A more conservative "incremental" scenario, based on less aggressive policy assumptions, shows opportunity for 8.3 metric MMtpy of H_2 demand by 2050; however, this scenario is not consistent with meeting net-zero targets in 2050 (FIG. 4).[3] Ultimately, the market will decide where best to deploy H_2 when greater supply becomes available domestically. The main drivers for H_2 market development will be cost competitiveness com-

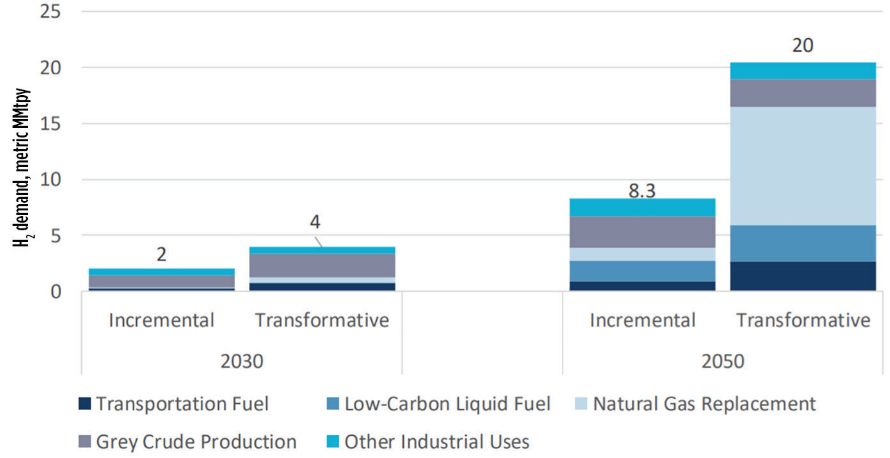


FIG. 4. Canada low-carbon H_2 demand potential through 2050. Source: Government of Canada.

pared to alternative energy sources and decarbonization potential.[3]

According to a report from Alberta's Transition Accelerator, in Canadian provinces that have ample low-carbon electricity from hydropower, nuclear or renewables, electrolysis can produce green H_2 for $2.50/kg–$5/kg. In provinces with low-cost natural gas and geology suitable for permanently sequestering CO_2, blue H_2 can be produced at a cost of $1.50–$2/kg. It is anticipated that by 2030, green H_2 will be cost-competitive in Canada as a result of lower renewable energy costs and the scaling up of electrolyzer technology.

H_2 projects. In Canada, utilities are field testing green H_2 blends with natural gas ahead of the 2021–2022 heating season for the Ontario and Alberta residential markets. A Québec pilot project will employ H_2 to extract ethanol and methanol from landfill sites. Also, British Columbia and Québec have already begun deploying H_2 fueling infrastructure to support FCEV mobility. Furthermore, the country's Hydrogen Strategy acknowledges that significant renewable resources exist to generate green H_2, including existing hydroelectric generation in British Columbia, Québec, Manitoba, and Newfoundland.

The government has also singled out Canada's vast natural gas reserves, primarily in **Alberta,** as a main fuel source for blue H_2 production to exploit inherent competitive advantages. In Alberta, Air Products is building a $1.1-B complex in Edmonton to produce blue H_2 and capture 95% of its carbon emissions. When it opens in 2024, the Net-Zero Hydrogen Energy Complex will be the first of its kind in Canada. Air Products will also build an H_2 liquefaction facility to supply industrial customers and commercial FCEV fleets, as well as an H_2-based power plant.

Canada's Suncor Energy will partner with utility ATCO Ltd. to develop a blue H_2 project near Fort Saskatchewan, Alberta. The project would produce more than 300,000 metric tpy of low-carbon H_2 by capturing carbon emissions from oilsands production. An FID on the project is expected in 2024, with operations projected to start by 2028 if the project is sanctioned. Around 65% of the H_2 produced would be used at Suncor's Edmonton refinery, while another 20% could be used in the Alberta natural gas grid.

In **Québec,** Air Liquide inaugurated the world's largest PEM electrolyzer in Bécancour in January 2021. The 20-MW electrolyzer, which is capable of producing up to 8.2 metric tpd of H_2, increased the capacity of Air Liquide's Bécancour H_2 production complex by 50%.

The potential for H_2 use in power generation, industrial heating and as an industrial feedstock in the U.S. and Canada is high.

Also in Bécancour, Canada's H2V Energies is building a green H_2 plant that will commence production in 2022. The Alpha plant, to be constructed in the Bécancour Waterfront Industrial Park, will deploy a new industrial plasma gasification technology for converting raw residual biomass material into syngas to produce around 49,000 metric tpy of green H_2 without electrolysis.

Meanwhile, the green H_2 division of Thyssenkrupp Uhde Chlorine Engineers was awarded a contract to carry out the installation of an 88-MW electrolysis plant for Hydro-Québec, an energy firm backed by the provincial government. The electricity for the plant, to be built in Varennes, will come from hydropower. The project will generate 11,100 metric tpy of green H_2 on startup in late 2023.

Evolugen, the Canadian operating business of Brookfield Renewable, and Gazifère, an Enbridge company, are collaborating on a $90-MM project to advance the development and use of green H_2, and have announced plans to build and operate a 20-MW water electrolysis plant in the Outaouais region of Québec. An estimated capacity of approximately 425,000 GJ of green H_2 will be produced for injection into Gazifère's distribution network.

In **British Columbia,** Renewable Hydrogen Canada (RH2C) plans to produce green H_2 through water electrolysis powered by wind and hydropower. RH2C's first project, Sundance Hydrogen, is a JV among RH2C, FortisBC and Macquarie Green Investment Group. The project will feature a $200-MM green H_2 plant with a dedicated wind farm. Utility FortisBC will be the offtaker for the plant's production of 60 metric tpd of H_2, which will help it increase the renewable content of its natural gas to 15%, as per a provincial mandate.

In **Ontario,** Enbridge and Hydrogenics were selected by the Independent Electricity System Operator for Ontario for a grid energy storage project. The project will deliver 2 MW of storage capacity and be located in the greater Toronto area. Hydrogenics will supply the facility's next-generation PEM electrolyzers and is partnering with Enbridge to develop, build and operate the energy storage facility.

Furthermore, Enbridge Gas and Cummins are undertaking a $5.2-MM project to pilot the blending of renewable H_2 produced at the Markham, Ontario power-to-gas facility into a portion of the existing natural gas network serving about 3,600 customers. The success of the project in 2021 will support Enbridge Gas in pursuing additional and larger-scale H_2 blending activities in other parts of its distribution system.

Ontario's nuclear industry also has the potential to work synergistically with H_2 by using off-peak electricity for electrolysis or by using excess steam from nuclear reactors (including future small modular reactors) to improve electrolyzer efficiency.

Regional outlook. North America is joining Europe and Asia in starting up blue and green H_2 projects and building out H_2 infrastructure. The potential for H_2 use in power generation, industrial heating and as an industrial feedstock in the U.S. and Canada is high.

Near-term opportunity exists in using blue H_2 to reduce feedstock emissions in refining and ammonia manufacturing. For green H_2 to be competitive at a large scale, substantial decreases in production and storage costs will be necessary over the next decade to bring down the price of green H_2 to $2/kg.

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EXECUTIVE VIEWPOINT

Driving a successful energy transition: From natural gas to H_2 and beyond

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ARJA TALAKAR is Senior Vice President of the Industrial Applications Products business unit at Siemens Energy. As a member of the Siemens Energy leadership team, he is responsible for the new products business, which includes power generation and rotating equipment for the oil and gas industry. Arja Talakar has extensive leadership experience that covers more than 25 years with Siemens in multiple global roles in the U.S., Germany, South Korea and Saudi Arabia.

Previously, he was CEO of Siemens Saudi Arabia, where he led large international JVs with a focus on projects, manufacturing, solutions and services. Over the past decade, jointly with his team, Arja Talakar has worked on several turnarounds and driven the profitable growth of organizations. As CEO in Saudi Arabia, he helped develop close ties and strategic partnerships with the world's leading oil and gas, energy and petrochemical companies. The company he led also succeeded in securing and executing large infrastructure projects.

Arja Talakar started his career with Siemens in the fields of engineering and technology for rotating equipment and automation systems, prior to embarking on assignments with increasing responsibility across the globe. He holds an MBA degree from IMD Business School in Switzerland, as well as an engineering degree from the University of Braunschweig in Germany.

Among the many challenges the world will face in the coming years, there is arguably none greater than reversing the tide of climate change. Global warming threatens to disrupt the ecosystems on which we all depend. At the same time, global energy demand is expected to double over the next three decades. This poses an enormous challenge in and of itself, especially considering that today roughly 770 MM people—more than 10% of the world's current population—lack access to power.[1]

We believe solving this dilemma and driving a successful energy transition will require a diverse range of sources, including cost-competitive renewables, natural gas and hydrogen (as well as other e-fuels). It will also need strong partnerships and collaboration between private and public sector stakeholders to facilitate innovation and accelerate the commercialization of emerging technologies.

Building a bridge to H_2. A large portion of global greenhouse gas (GHG) emissions comes from the energy sector, specifically from fossil fuel-based power generation. In 2018, coal-fired power plants alone represented nearly one third of all CO_2 emissions worldwide.[2]

Although some believe that the growing use of natural gas for power generation is at odds with the buildout of renewables, like solar and wind, it represents the best possible replacement for coal in the near term and can enable significant emissions reductions.

Not only is natural gas abundant and inexpensive when burned in simple-cycle gas turbines, but it also releases up to 50% less CO_2 than coal. Even greater decarbonization opportunities are possible if combined-cycle configurations are used (i.e., incorporation of waste heat recovery and a steam turbine), which can yield another 20%–23% reduction in carbon emissions. In fact, with modern gas turbines in cogeneration applications, it is possible to achieve energy efficiencies as high as 85%.[3]

With natural gas expected to become the largest global energy source in 2026 and to remain so through 2050,[4] the critical question is how to make its lifecycle cleaner—from extraction to transportation to end use.

We are working closely with oil and gas customers across the Americas region to address this issue. One specific example is our recent collaboration with TC Energy Corp. Together, our two companies are implementing a first-of-its-kind waste heat-to-power solution at a pipeline compressor station in Canada. The solution, which Siemens Energy helped commercialize, is licensed under Echogen Power Systems and uses supercritical CO_2 (sCO_2) as the working fluid to capture and convert waste heat from a gas-fired turbine into emissions-free power (FIG. 1). Enough electricity will be generated from the system to power approximately 10,000 homes. It will offset approximately 44,000 t of GHG—the equivalent of taking up to 9,000 vehicles off the road.

I am confident these types of joint efforts will accelerate as we work to make more sustainable options, such as H_2, increasingly economical. In the long term, displacement of natural gas with hydrogen is a viable means of enabling carbon-neutral power plant operation, as H_2 combustion produces no CO_2. Furthermore, if the H_2 being used is "green" or "blue," the entire process—from H_2 production to end use—is entirely emissions-free (FIG. 2).

At present, the major impediment to scaling green H_2 production is the availability of renewable electricity. It is estimated that 4,700 GW of new renewable generating capacity will be needed to fulfill the H_2 demand forecast by 2050 with green H_2—nearly five times the world's current installed base.[5] Blue H_2 production can be scaled more easily and represents the most feasible option over the next decade.

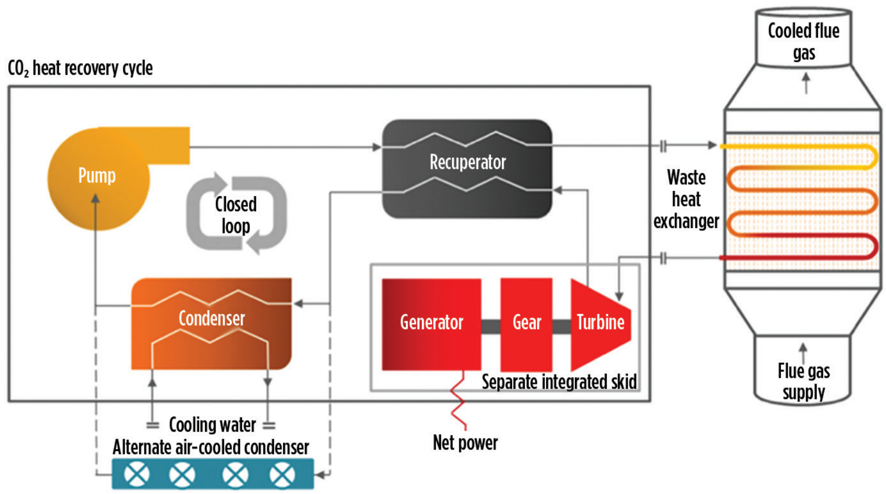

FIG. 1. Process flow for supercritical CO_2-based waste heat-to-power solution.

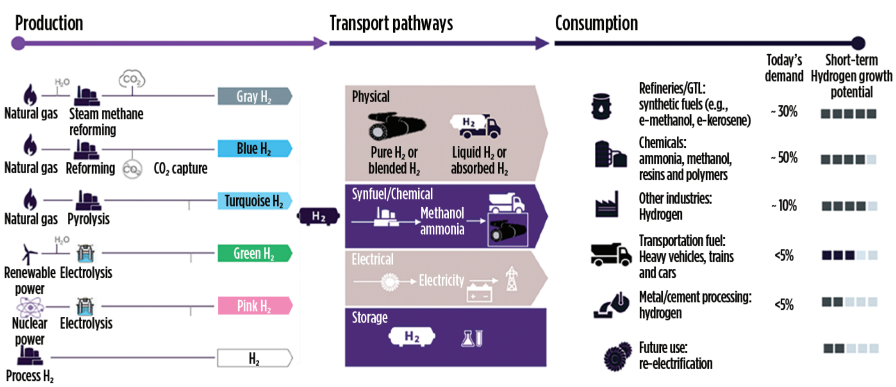

FIG. 2. The H_2 economy will support global decarbonization efforts in myriad ways.

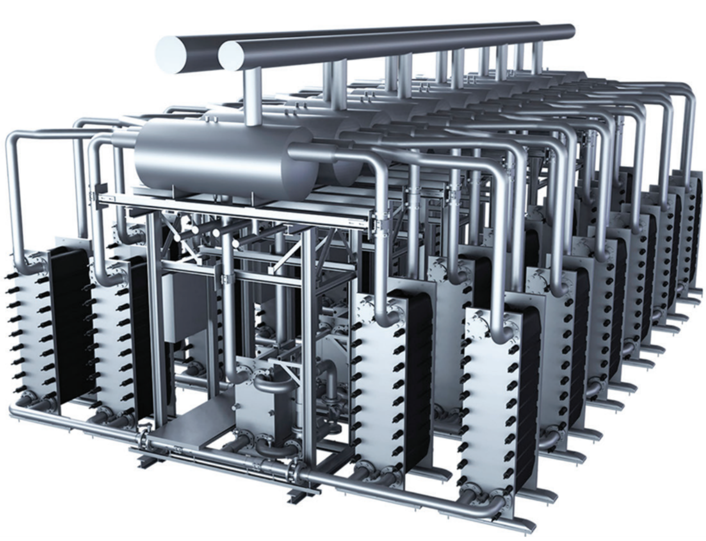

FIG. 3. Siemens Energy Silyzer 300 PEM module array.

Although operating large gas turbines with very high H_2 content fuel mixtures is not economically viable today, it is within reach for smaller gas turbines. However, even blending in small amounts of H_2 with the natural gas fuel stream (i.e., co-firing) can yield impactful emissions reductions. For example, adding just 10% volume of H_2 reduces CO_2 turbine emissions by 2.7%. Although this may not seem significant, for a 600-MW combined-cycle power plant that runs for 6,000 hr/yr at an average 60% efficiency, it would result in a reduction of approximately 1.26 MM metric t of CO_2—the equivalent of taking nearly 275,000 internal combustion engines (ICEs) off the road.[a]

Many of the gas turbines at Siemens Energy are already capable of burning H_2-rich fuel streams. At present, we have 55 gas-H_2 turbines in operation worldwide, which have amassed more than 2.5 MM operating hours since the 1960s. Our goal is for all of our turbine models to be compatible with 100% H_2 fuel by 2030. We are also taking steps to avoid technological obsolescence by ensuring that all new turbine installations can be upgraded to handle 100% H_2 fuel streams. Doing so will enable units that are currently installed (or will be in the near future) to be converted into even more powerful decarbonization agents.

Partnerships to drive innovation. While leveraging existing infrastructure and technologies will be critical to driving a successful energy transition, it is only one piece of the puzzle. The path to an H_2 economy—and, more broadly, to carbon neutrality—will require co-creation and collaboration among diverse public and private industry stakeholders to drive innovation. After all, no single company on the planet can reverse the tide of global warming singlehandedly.

Over the past 12 months, I have been extremely encouraged by the growing number of leaders who have embraced this mindset. Never before have so many companies in the energy space showed a willingness to come together and invest in bringing new emissions-reducing technologies to market.

We have been very active in our efforts to co-create with customers and other technology providers to accelerate decarbonization through innovation—the TC Energy collaboration is one example.

Another is our recent collaboration with Air Liquide. Together, we are working to advance proton exchange membrane (PEM) electrolysis technology and lay the framework for the mass manufacturing of electrolyzers (**FIG. 3**).

Another example is our joint project with Braskem, the largest producer of thermoplastics resins in the Americas and the world's leading biopolymer producer. We are designing a cogeneration plant for Braskem in Brazil fueled with residual process gas with high H_2 content to reduce water use and CO_2 emissions. Our two gas turbines and the advanced combined cycle will generate 38 MW and provide 160 t/hr of steam. Braskem estimates that the upgrade project will reduce the cracking unit's water consumption by 11.4% and decrease CO_2 emissions by 6.3%, mitigating environmental impacts and improving the company's sustainability target achievement.

These are two of many examples that we believe demonstrate what is possible when industry leaders come together and aspire to serve a common cause.

Considering the human element. To date, much of the dialogue surrounding the H_2 economy and the energy transition has been focused on what technologies must be deployed to meet carbon reduction targets. As a result, less attention is given to the human element of the equation. People, however, are the true drivers of change. To be successful, we as energy leaders must attract, develop and unite the brightest minds in a diverse and inclusive environment committed to tackling climate change.

Developing the necessary future-fit workforce will, for the most part, involve directing the existing extensive experience and technological expertise of our existing workforce into new market growth areas through training and upskilling. We may also complement our versatile, vibrant, and experienced workers with specific skill sets in fields such as H_2, decarbonization and digitalization to give us the burst of innovation necessary to tackle climate change.

Leaders and executives will also need to demonstrate that we can unlearn old ways and learn new ones. To this end, we must strive to eliminate siloed thinking. It is only through a willingness to change and collaborate that we will drive a successful energy transition. H2T

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NOTE

[a] Assumes a car with annual emissions of 4.6 metric t of CO_2.

Realize energy and environmental benefits with circular H_2 from waste gasification

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Increasing concerns about environmental pollution related to greenhouse gas (GHG) emissions is promoting the energy transition toward more sustainable energy production systems. These systems are based on renewable energy exploitation and circular economy principles.

The concept of sustainability is often coupled to the concept of waste valorization as a driver for rethinking conventional production systems. Such vision, aiming for a more sustainable use of resources, is also supported by the European Commission through a policy stating that "…waste management should be improved and transformed into sustainable material management with a view to promoting the principles of the circular economy, enhancing the use of renewable energy and providing new economic opportunities."[1]

Circular economy concept. The concept of circular economy is redesigning many industrial fields with the aim of waste stream valorization. In the field of solid waste, municipal and plastic waste management is receiving urgent attention from many governments. As a consequence of the Chinese government's January 2018 ban on the import of waste from foreign countries, many industries in developed countries began to face challenges due to limited installed waste management capacity.[2]

At present, approximately 2 billion metric tons per year (metric Btpy) of waste are globally produced. By 2050, this volume is anticipated to reach 3.4 metric Btpy due to expected increases in population and GDP, which both influence yearly waste production value.[3] This scenario may worsen as increases in living standards will inevitably bring higher consumption and higher waste production.

Both chemical production and waste disposal by incineration imply high GHG emissions. However, combining waste recovery and production of chemicals into one process brings the benefits of synergy and allows for significant reductions in overall emissions. The conversion of waste into a chemical also simultaneously solves the issue of waste disposal and the substitution of fossil feedstock. In this way, waste is valorized as a source of carbon and hydrogen, representing a widely available renewable source without geographical restrictions.

The "waste-to-chemicals" approach is also favored from an economic point of view, as the waste feedstock becomes a source of revenue, rather than a cost. The waste fractions that are taken into account as sources in the waste-to-chemicals process are indeed fractions that alternatively would have been disposed through, at worst, landfilling or, at best, incineration with energy recovery. The waste-to-chemicals process allows carbon and hydrogen recovery—i.e., material and energy recovery.

Refuse-derived fuel (RDF), the dry fraction of unsorted municipal solid waste (MSW) and a fraction of unrecycled, sorted plastic waste (PW) are the types of waste eligible for the waste-to-chemicals process. In this article, an innovative route for circular H_2 production is presented and described from technical, economic and environmental points of view.

High-temperature gasification for waste valorization. Typical compositions for MSW, RFD and PW feedstocks are reported in **TABLE 1.** As shown by the elementary composition, carbon content may vary from 30 wt%–60 wt%, while H_2 is in the range of 4 wt%–7 wt%. If properly converted into syngas, then waste may be used for the synthesis of a wide range of chemicals.[4]

Under this scenario, technology plays a major role in the full implementation of a circular economy around the concept of waste as feedstock for industrial processes. This paradigm implies a robust and reliable technology able to manage the heterogeneous nature of waste, as well as their pollutants content.

The proposed technology allowing the conversion of waste into chemicals is based on a high-temperature gasification process carried out in a pure oxygen (O_2) environment. A schematic view of a gasifier reactor, in which such conversions are performed, is shown in **FIG. 1.**

The gasifier reactor consists of three sections:

1. The melting zone on the bottom of the reactor, where exothermic reactions and melting of inert compounds take place

TABLE 1. Typical elementary composition of PW and RDF and relevant LHV values

Component, wet basis	RDF	PW
C, wt%	33–38	47–61
H, wt%	4–5	5–7
O, wt%	16–18	14–20
N, wt%	0.2–1	0.2–0.5
S, wt%	0.02–0.15	0.02–0.3
Cl, wt%	0.8–1.5	0.8–1.5
Moisture, wt%	17–21	5–9
Inert, wt%	17–25	7–20
LHV wet, MJ/kg	14–16	21–24

2. The gasification zone in the middle, where low O_2 content leads to partial oxidation reactions
3. The stabilization zone on the top of the reactor, where the further introduction of auxiliary fuel and O_2 leads to an increase in temperature, ensuring tar degradation, full decomposition of the long-chain organic molecules and inhibition of dioxins formation.

Multiple injections of O_2 and auxiliary fuel along the reactor help maintain temperature at 1,600°C–2,000°C in the melting zone, at 600°C–800°C in the gasification zone and up to 1,100°C–1,200°C at the top. Such a temperature profile ensures the full conversion of waste into two products: a highly valuable syngas that is rich in H_2 and CO and is free of char, tar, dioxin and furans discharged from the top of the reactor; and an inert vitrified material discharged on the bottom.[5] The high temperature in the melting zone allows for discharge of the inert components of waste (minerals and metals) in a granulated and vitrified state, ideally carbon-free. Depending on local legislation, such material can be valorized into the cement or construction industry, or otherwise disposed as standard waste.

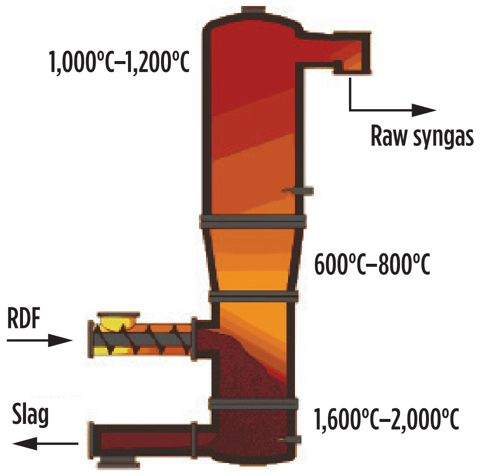

FIG. 1. High-temperature gasification reactor.

As reported by Salladini *et al.*,[6] the syngas yield and relevant composition are mainly affected by the lower heating value (LHV) and the carbon-to-oxygen (C/O) ratio. In general, higher LHV results in higher syngas yield, higher CO and H_2 content and lower concentration of CO_2. Produced syngas contains, as the major components, CO, H_2, CO_2, as well as minor quantities of volatile metals and other particles. **FIG. 2** shows a block diagram of the gasification section, together with the preliminary cleaning and syngas purification section.

As a first step, the hot gas exiting the reactor is routed to an evaporative quench, where temperature is abruptly reduced to 85°C–90°C by direct injection of water. Although a loss of high-temperature heat is observed, this rapid cooling freezes the chemical composition achieved at high temperature, thereby avoiding undesired reactions. The two-phase mixture at the bottom exit of the quench is routed to a sedimentation tank. This unit allows for

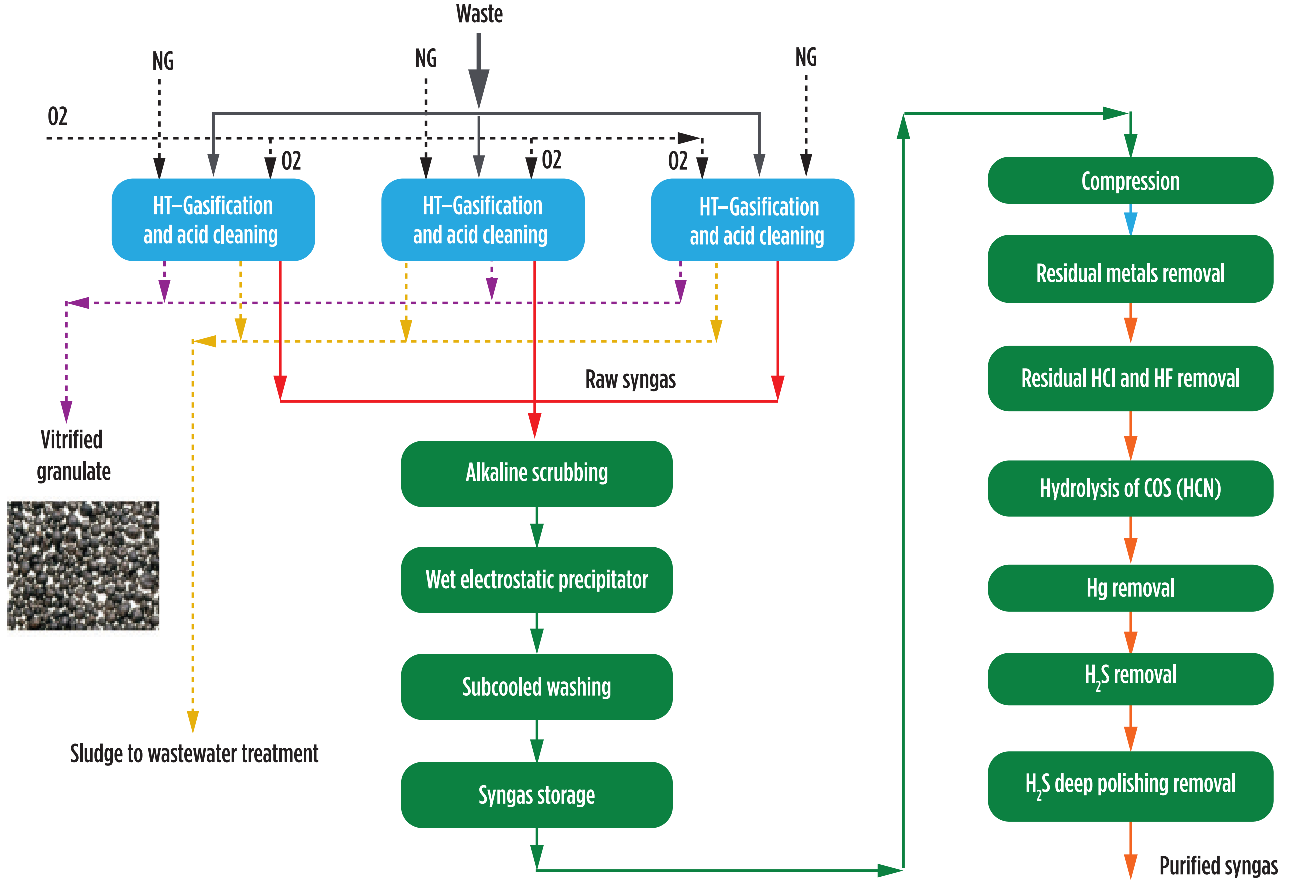

FIG. 2. Block scheme for gasification and syngas preliminary cleaning and purification.

collection of the bottom sludge, which is continuously removed from the system, and clarified water is reused as cooling water in the quench. The sedimentation works under a low-pH condition (1.5–3) to promote the migration of volatile metals in the liquid phase. The syngas exiting the sedimentation tank is routed to an acidic column that further promotes metals removal.

Syngas exiting from the acidic columns of each gasification line is collected and sent to a common section based on an alkaline scrubbing column, wet electrostatic precipitators (WESP) and a subcooling column. The water stream collected from the bottom of the washing columns are routed to the wastewater treatment unit, due to the potential presence of pollutants.

The gasifier works under atmospheric pressure and achieves pressure on the order of a few mbar at the end of the cleaning section. In this scheme, a compression section is needed before routing the syngas to the downstream section. To ensure stable conditions in terms of syngas pressure and flowrate at the suction of the compressors, a gas holder is installed between the gasification and compression sections.

The cleaned syngas still contains sulfur compounds, mainly in the form of H_2S and COS, together with residual chlorine, HCN and traces of Hg. Once compressed, the syngas is routed to the purification section involving the following steps: removal of residual dust and metals, removal of HCl, hydrolysis of the COS and HCN, H_2S removal through an oxy-reduction system and a final polishing step based on zinc oxide absorbents. These steps help reduce sulfur content to ppb, as required by catalyst used in downstream synthesis.

The high temperature regime and the use of waste as feedstock requires dedicated maintenance work around the gasifier to prevent damages to refractory materials and avoid excessive fouling along the quench wall and sedimentation. A plant architecture based on multiple gasification lines working in parallel is recommended to ensure plant availability during maintenance. When a gasification line is shut down for maintenance, the other lines are operated at maximum capacity to ensure continuous syngas production with minimum reduction in productivity.

The described purification procedure delivers a syngas suitable for feeding to catalyst-based synthesis. Depending on the desired end product, a conditioning step to adjust H_2 and CO content may be required.[7,8,9] When applied for H_2 production, the conditioning section consists of a shift section and an H_2 purification section with pressure swing adsorption (PSA).

Waste to H_2 production. The proposed waste-to-H_2 case study is developed around a waste feedstock having an average composition describing a mixture of 50% RDF and 50% PW. The resulting mixture composition is detailed in **TABLE 2.**

By applying the process scheme depicted in **FIG. 2,** the resulting syngas composition at the end of the purification section has a composition as shown in **TABLE 3.** The process architecture for H_2 production from waste is depicted in **FIG. 3.**

To increase H_2 content, a shift reaction (Eq. 1) is carried out in two intercooling steps. To promote the shift reaction, medium-pressure steam is mixed at the inlet of the shift reactor, operating with a steam/dry syngas ratio of at least of 1.5 to maintain the shift exit temperature below 480°C. Due to the high CO content, a two-stage shift reaction is foreseen to properly control any variation of CO content deriving from the heterogeneous nature of waste.

$$CO + H_2O \leftrightarrow CO_2 + H_2 \quad (1)$$

The resulting syngas is cooled through heat recovery and cooling water, sent to a gas-liquid separator for condensate removal and routed to a PSA unit. The latter unit allows for the production of H_2 at a purity of 99.99%, and the purge gas stream is used as fuel in the auxiliary boiler.

A different approach may be adopted when CO_2 capture is required. The high partial pressure of CO_2 in the cooled syngas fed to the PSA allows a less energy-intensive capture compared to CO_2 capture of hot flue gas. The case study analyzed here is based on a plant architecture without CO_2 capture.

In the proposed architecture, three gasification lines are adopted with an overall capacity of approximately 192,000 tpy of waste delivering around 200 $MMNm^3$/y of H_2. Heat and material balance for the proposed scheme were performed using a proprietary simulation program. The key products and byproducts, as well as utilities consumption, are shown in **TABLE 4.**

TABLE 2. Waste used for the case study (mixture of 50% RDF and 50% PW)

Component, wet basis	Value
C, wt%	41.7
H, wt%	6
O, wt%	19
N, wt%	0.7
S, wt%	0.2
Cl, wt%	1.1
Moisture, wt%	13.5
Inert, wt%	17.8
LHV, MJ/kg	17.9

H_2 cost of production. To assess the economic feasibility of the waste-to-H_2 technology, an economic evaluation was carried out to estimate CAPEX and OPEX. The overall CAPEX was estimated at approximately €242 MM. A breakdown of relevant costs is shown in **TABLE 5.**

To evaluate OPEX and the related H_2 cost of production, specific utilities costs have been assumed as outlined in **TABLE 6.** On the basis of utilities consumption derived from heat and material balance (**TABLE 4**), the OPEX has been estimated at approximately €28 MM/y, with the breakdown shown in **FIG. 4.**

The resulting cost of production is strictly related to the waste gate fee. By varying the gate fee from €130/t to €150/t, the resulting H_2 cost of production ranges from €0.102/Nm^3 to €0.083/Nm^3. These values are promising and competitive with the cost of production of a conventional steam reforming process.

CO_2 emissions for waste-to-H_2. For a better understanding of the potential carbon footprint reduction of the proposed waste-to-H_2 technology, a simplified lifecycle assessment (LCA) analysis was performed.

The use of waste as feedstock for chemical synthesis allows for the simultaneous fulfillment of two different services: the

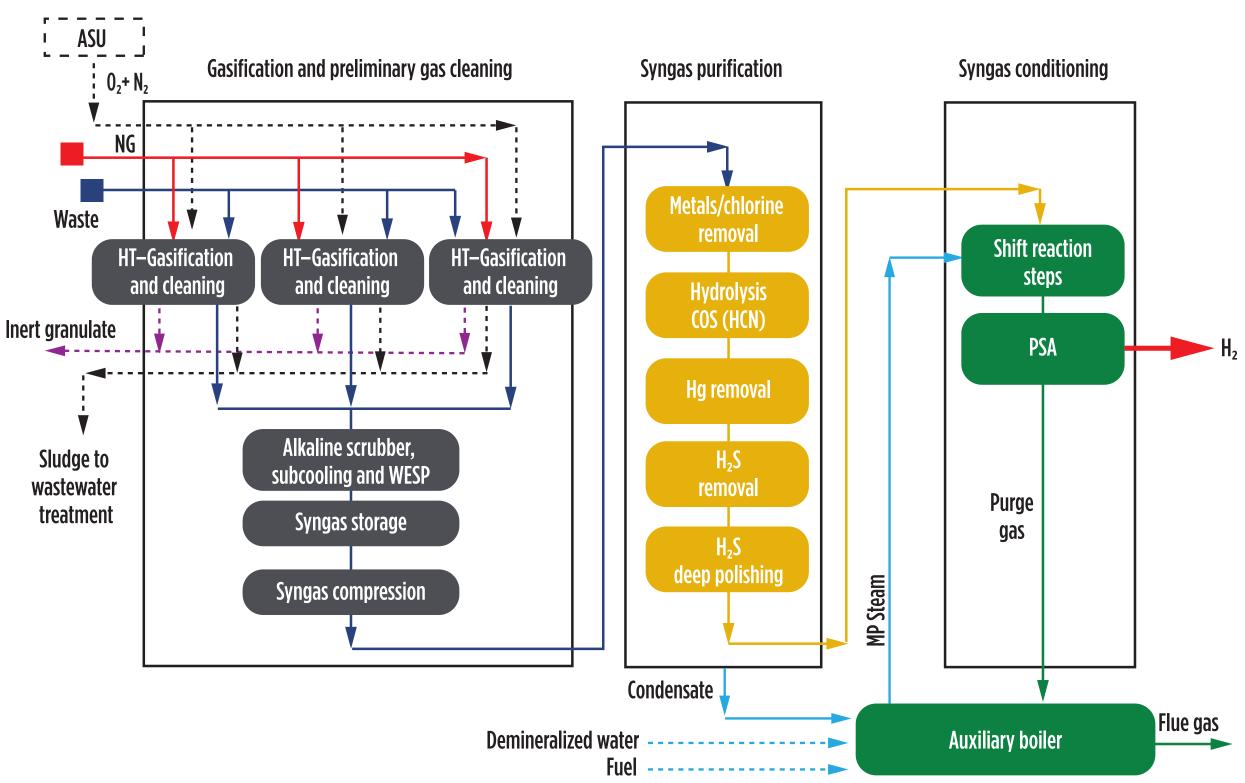

FIG. 3. Waste-to-H_2 block diagram.

recovery of waste on one side, and the synthesis of a chemical (H_2) on the other. Compared with the conventional routes for waste disposal of incineration and chemical synthesis from fossil feedstock, this system allows for better exploitation of carbon and better CO_2 emissions savings. An estimate of CO_2 savings from the waste-to-chemicals approach can be quantified using the formulation shown in Eq. 1:

$$CO_2\ saving = [(CO_{2_{Conv.H_2}}) - (CO_{2_{Waste\ to\ H_2}} - CO_{2_{Incinerator}})] / CO_{2_{Conv.H_2}} \quad (1)$$

An estimate of CO_2 emissions for conventional H_2 production takes into consideration that equivalent emission for feed and fuel consumption is around 75% of overall lifecycle emissions. Average feed and fuel consumption for a conventional H_2 plant equal to 3,500 kcal/Nm^3 of H_2 was assumed. The resulting specific emissions for this assumption are approximately 12.6 t CO_2/t H_2.

Incinerator emissions. The reference value of 2 t CO_2/t waste was adopted for the incinerator. Assuming that the distance from the nearest incinerator is equal to 1,000 km, the overall emissions are on the order of 2.1 t CO_2/t of waste, which is equal to 22.5 t CO_2/t H_2.

To properly account for the equivalent CO_2 emissions from electric power not produced from waste, an electric energy efficiency of 28% is assumed. It can be calculated that 24 tph of waste with a calorific value of 18 MJ/kg and combustion assisted by natural gas (which assumes 2% of energy content of the waste) would produce around 34 MWe. The latter must be replaced by electric energy from the grid.

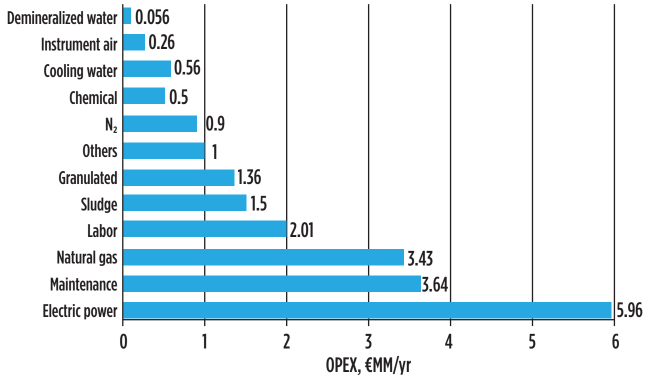

FIG. 4. Estimated OPEX for waste-to-H_2 scheme.

TABLE 3. Syngas composition after cleaning and purification

Component	Value
H_2, mol%	39.1
CO, mol%	42.6
CO_2, mol%	12.8
H_2O, mol%	0.4
N_2, mol%	4.8
CH_4, mol%	0.21
Arg, mol%	–
H_2S, ppm	0.01
COS, ppm	0.1
HCN, ppm	0.1
HCl, ppm	0.1
Hg, ppm	–
PM, ppm	–

TABLE 4. Material balance for the waste-to-H_2 scheme

Feed/product/bioproduct	Quantity/yr
Waste feedstock, tpy	192,000
H_2 production, MMNm^{3}y	200
Granulated, tpy	34,000
Sludge, tpy	7,520
Utilities	**Quantity/yr**
Electric power, MWh/yr	84,000
Industrial water, m^{3}y	50,400
Demineralized water, m^{3}y	130,000
Natural gas, tpy	12,176
Instrument air, MMNm^{3}y	10
N, MMNm^{3}y	11.5
O, MMNm^{3}y	82.5
Cooling water, MMm^{3}y	40

TABLE 5. CAPEX estimate for waste-to-H_2 plant

CAPEX	€ MM
CAPEX inside battery limits	190
CAPEX outsidey battery limits	30
Contingency (10%)	22
Total	**242**

TABLE 6. Utilities cost assumptions for economic evaluation

Cost component	Value
Waste treatment (three gasification lines), tpy	192,000
Vitrified granulate produced, tpy	34,000
Concentrated sludge produced, tpy	7,500
Maintenance cost as % of CAPEX	2%
Depreciation Equity (20 yr and 6% interest) Bank loan (12 yr and 3% interest)	 0.0872 0.0672
Personnel (at company cost), € MM/yr 7 people per shift (7 × 5) = 35 people 3 specialists during working day 1 manager	 1.75 0.24 0.12
RDF plastics price, €/t	150
Electric energy cost, €/MWh	70
Natural gas price, €, sm^3	0.24
O_2 cost, €/Nm^3	0.078
N_2 cost, €/Nm^3	0.078
Instrument air, €/Nm^3	0.028
Industrial water, €/m^3	0.08
Cooling water, €/m^3	0.014
Demineralized water, €/m^3	0.43
Slag disposal cost, €/t	40
Concentrated slag disposal cost, €/t	200

Emissions of waste to H_2. For the waste-to-H_2 plant, the following contributions were taken into account:

1. CO_2 emissions derived from all carbon contained in the waste, which is converted into CO_2 during the process. Considering the reference waste composition, this contribution is on the order of 16.5 t CO_2/t H_2.
2. CO_2 emissions derived from fuel consumption, which considers the direct fuel consumption in the gasifier and auxiliary boiler. This contribution is estimated at 1.9 t CO_2/t H_2.
3. CO_2 emissions derived from fugitive emissions of natural gas used in the project, calculated as 2.5% of natural gas consumption[9] with a methane global warming potential (GWP) equal to 28;[10] the resulting value is calculated at approximately 0.44 t CO_2/t H_2.
4. Equivalent CO_2 emissions to replace electric energy not produced from a waste incinerator. The resulting amount of equivalent CO_2 is on the order of 2.5 t CO_2/t H_2, on the basis of a grid electric emissions factor of 0.245 kg CO_2/kWhe.
5. Indirect CO_2 emissions for electric energy absorbed along the process also take into account O_2 production. The resulting value is approximately 1.9 t CO_2/t H_2, according to a grid emissions factor of 0.245 kg CO_2/kWhe.
6. Equivalent CO_2 emissions derived from the transport of waste from the production facility, assuming a distance between the gasifier and the waste facility of around 100 km. The resulting specific consumption is 0.1 t CO_2/t H_2.

Taking into account these estimated contributions, the overall CO_2 emissions for the waste-to-H_2 plant are on the order of 23.3 t CO_2/t H_2. The overall savings achieved by the waste-to-H_2 plant, according to a simplified lifecycle assessment, are around 90%, corresponding to approximately 202,000 t CO_2/yr.

Takeaway. Waste such as refuse-derived fuel (RDF), municipal solid waste (MSW) and plastic waste (PW) may be used as feedstock for the synthesis of a wide range of chemicals. This approach fulfills the waste management hierarchy by taking advantage of waste that cannot be recycled or routed to an incinerator or landfill.

The key to utilizing waste as an alternative feedstock is the primary conversion step, which is based on a high-temperature gasification process carried out in a pure O_2 environment and with a temperature profile ensuring certain characteristics for produced syngas.

The case study, based on circular H_2 production from waste, showcased a feasible solution from a technical, economic and environmental point of view. A competitive cost of production may be achieved under a gate fee of approximately €130/t–€150/t, which is the average cost for the disposal of such fractions of waste in Italy.

The simplified lifecycle assessment performed for the waste-to-H_2 scheme shows high CO_2 savings compared to the conventional steam reforming process. The waste-to-chemicals approach also allows for the simultaneous synthesis of a chemical and the recovery of waste. Under the lifecycle assessment scenario, waste enters with a CO_2 emissions credit, having avoided a conventional disposal system based on an incinerator.

Under this scenario, the waste-to-H_2 scheme accounts for a CO_2 emissions savings of approximately 90%. This translates into a potential emissions reduction of around 202,000 t CO_2/yr.

ACKNOWLEDGMENTS

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H_2 value chain analysis comparing different transport vectors—Part 1

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Meeting the anticipated 10-fold increase in hydrogen requirements by 2050 has led to many studies evaluating the most techno-economic means to achieve this target. While fully green, large-scale value chains are still some way off, there is adequate hydrocarbon infrastructure in place where blue H_2 could be produced.

This article assesses the options to convert a portion of the LNG supply chain already in place between Qatar and the UK into blue H_2 and the different transport vectors to convey the H_2. Transporting the H_2 as liquid or in the form of ammonia (NH_3) or other liquid organic H_2 carriers (LOHC), such as methylcyclohexane (MCH), are common comparisons; however, retaining liquified natural gas (LNG) as the energy carrier is also considered. It is shown with available technology that LNG as the transport vector is economic compared to ammonia and LOHC, with liquid H_2 (LH_2) still somewhat more expensive but anticipated to decrease in cost.

Introduction to project study. As a result of global demand for natural gas and the general fact that the resource-rich areas of the world are at significant distances from their markets, well-established production and transportation methods have been developed. Full value chains, from gas wells to regasification terminals, have been put in place with economy of scale, equipment efficiency and optimization of every aspect being developed over the years.

Replacing these value chains with low-carbon and green forms of energy will require significant development of new and large-scale technologies not yet developed or proven. The largest electrolyzer project in development is 24 MW, with an expected carbon dioxide (CO_2) emissions reduction of 0.04 MMtpy,[1] approximately 3% of the scale of this study. The reuse of existing infrastructure should be considered as an interim measure while new technologies are developed if the lower CO_2 emissions targets of 2030 and 2050 are to be achieved.

This article examines a well-established LNG value chain and the options to change a portion of it, limited by downstream infrastructure specifications, to blue H_2. A number of studies and papers compare different transport vectors for delivering H_2 to market, as there is significant cost involved in storage and transportation. However, these studies generally compare only the transportation of LH_2 against either liquid NH_3 or an LOHC, such as methanol or MCH.

The results of the studies vary depending on the export location, the import location and the distance between the two. Therefore, it can be concluded that one solution probably will not fit all situations in the future, and concept feasibility studies will be required for defined configurations. This is not dissimilar to LNG value chains, where the specific project characteristics determine the final detailed configurations.

One aspect to be considered in the production of blue H_2 is the disposal of the CO_2 captured in the process. It is generally assumed to be reinjected and stored permanently at the export location; however, two additional options exist:

1. The CO_2 can be reinjected into permanent storage at the import location
2. The CO_2 can be transported back to the export location for reinjection.

In this article, the second option is considered so that the four transportation vectors can be compared on a reasonably equal basis.

The Qatargas 2 (QG2) project is a fully integrated value chain linking all of the components from wells to market in a single project. Offshore wells in Qatar deliver gas to Ras Laffan, where two LNG mega-trains (Trains 4 and 5) are installed. The LNG is transported in dedicated Q-Max LNG carriers to the South Hook LNG terminal in Wales, UK.

There is consensus that up to 20 mol% H_2 can be mixed with natural gas into the UK gas grid without many complications with respect to pipeline materials and end users receiving the gas.[2] Siting a blue H_2 plant consisting of steam methane reformers (SMRs) with carbon capture at this location is the reference for this study. The CO_2 is liquefied and returned to Qatar by ship for reinjection. All three comparison options have the blue H_2 plant sited at Qatar, where the captured CO_2 is also compressed and reinjected.

Concept basis. This study considers four transportation vectors to convert natural gas from Ras Laffan Industrial City in northeast Qatar into an H_2 product at South Hook LNG terminal in Milford Haven, West Wales, UK.

The product is transported 6,140 nautical mi (approximately 11,371 km) by ship from Qatar to South Hook LNG terminal in the UK.[3] As shown in **FIG. 1,** the sea route is an established route via the Suez Canal,[4] through which a large Q-Max LNG tanker of 266,000 m^3 can pass.[5] In all scenarios considered in this study, the same quantity of H_2 delivery to the injection point on the UK gas grid is targeted.

The LNG regasification terminal in South Hook has a design capacity of 15.6 MMtpy.[6] An H_2 blend with natural gas is considered to be acceptable with an upper limit of 20 mol% concentration H_2 in natural gas.[2] UK National Grid records[7] show an approximately 40% average annual utilization of the South Hook terminal sending natural gas to the grid. Winter peak demand is countered by low energy demand during summer.

In this study, average natural gas usage of 6.24 MMtpy is considered as the baseload, and of this volume 0.541 MMtpy is converted to H_2, corresponding to 0.171 MMtpy of H_2 product at the delivery point. Mixing the H_2 with the resulting natural gas produces 5.871 MMtpy of a 20 mol% H_2 mixture into the export pipeline; the resulting calorific valve is slightly lower at approximately 98.5%. The estimated CO_2 emissions reduction from the gas is 1.183 MMtpy, or approximately 7% compared to that emitted from the 100% natural gas reference flow.

In this study, the estimated CO_2 emissions reduction from the gas is 1.183 MMtpy, or approximately 7% compared to that emitted from the 100% natural gas reference flow.

For all scenarios, the CO_2 produced during the natural gas conversion to H_2 is captured for permanent storage in Qatar. It should be noted that CO_2 is still emitted from various parts of the overall chain, such as power production and shipping.

To ensure a fair comparison between the processing routes, study boundaries were set. For all options, the upstream process boundary was fixed at the point where natural gas feed enters the system. The costs associated with natural gas production, front-end purification to remove impurities such as sulfur, and delivery to Ras Laffan are not included in this study. The downstream process boundary is set at H_2 gas production at 20 bar before compression for distribution in pipelines.

Four scenarios for H_2 transportation to determine the most economically efficient technical solution for transport are compared. All scenarios consider the product in liquid form at atmospheric pressure, based on ship type availability:

- LNG
- LH_2
- NH_3
- MCH.

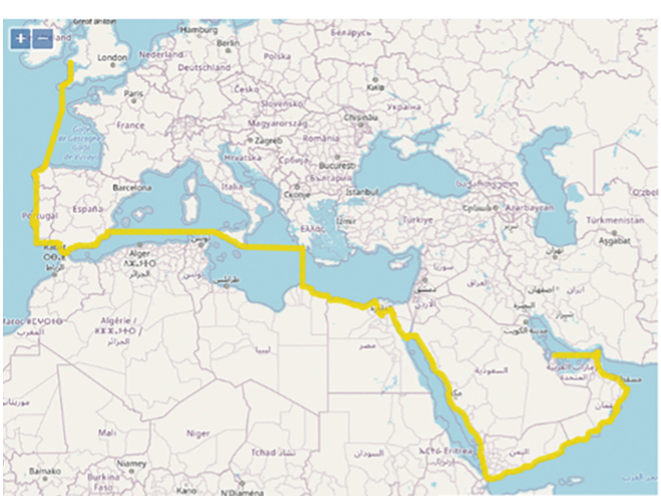

FIG. 1. Transport route for LNG produced at Ras Laffan, Qatar to regasification at Milford Haven, Wales, UK.

Study definitions. Green H_2 is generally defined as H_2 produced from renewable power such as wind, solar or hydroelectricity via electrolysis. No hydrocarbons are used, and no CO_2 is produced in the process.

Gray H_2 is generally defined as H_2 derived from hydrocarbons where CO_2 is produced and emitted to the atmosphere in the process.

Blue H_2 is generally defined as H_2 derived from hydrocarbons where the CO_2 produced in the process is captured and permanently stored. Blue H_2 has a range depending on the percentage of CO_2 captured.

Methodology. Since the purpose of this study is to compare four different H_2 vectors, it is important to ensure that the boundary of each system is the same and the method of costing is comparable, as the resulting differentials are key.

The majority of the data used is obtained from the public domain, papers and other literature available on the internet. This contains an inherent element of uncertainty, since it is not always entirely clear what scope is included in CAPEX figures, or what items are included in total installed costs (TIC). Generally, the CAPEX used was considered to be the cost of equipment required fully installed. In-house CAPEX data is used where available, or as a benchmark against data from literature. Licensing, regulatory and infrastructure interconnections and owners' costs are not included, nor are costs for minor utilities, as all plants need these services.

Where a wide range of data is assimilated for CAPEX vs. capacity for a particular process or storage, the data is plotted graphically, outliers are disregarded, and average or specific data are selected from within the group of data. Where the studied process required a unit capacity larger than presently available or referenced, it was assumed that several units would be required for costing purposes. Since only one full liquid H_2 chain is in operation as a pilot project[8] and at a small capacity, all of the costing data for LH_2 is based on expectation. While gathering data, a noticeable trend was observed for LH_2 liquefaction plant CAPEX reduction, which led to a sensitivity case being produced for the more optimistic data. This case shows potential savings as the technology is developed, scaled up and commercialized.

Operating costs were generated by a fixed percentage of the CAPEX to cover fixed operating and maintenance (O&M), and the major feed streams and utility user annual costs (OPEX) are based on location prices. Generally, this included the cost of the natural gas feed, power, demineralized water, cooling water, fuel gas and transportation (ship) fuel.

Infrastructure to deliver clean natural gas to the first process block in Qatar is not included. Storage tank CAPEX and OPEX are included, as these are different between the four options due to the different energy densities and ship sizes. Loading systems and jetties are not included, as it is assumed that the existing infrastructure in both Qatar and the UK will be used. However, due to the requirement for the LNG value chain to have two types of ships—LNG carriers and CO_2 ships—CAPEX for berthing CO_2 ships was included in both Qatar and the UK.

The system boundary for each option is detailed in the following sections. A simple heat and material balance is developed for each option, resulting in the same quantity of H_2 being delivered into the UK grid. Depending on the various losses of product through the value chain, each option requires a different quantity of natural gas feed.

The study is essentially based on 500 metric tons per day (metric tpd) of H_2 capacity. The resulting individual unit processes are sized based on the best information available for realistic or available equipment. This methodology also applies to typical ship sizes for the different products. LH_2 value chains do not exist at present, so all unit sizes were selected on the most realistic size with accompanying CAPEX data. Included are optimistic, scaled-up unit sizes and optimistic energy reduction targets cited in the literature, so a sensitivity case is included to capture potential savings as the LH_2 value chain is developed.

The same H_2 production configuration was used for all options, and any additional heat integration opportunities in the processes are not considered. For example, "cold" recovery from LNG and LH_2 regasification is not explored, nor is heat recovery from the NH_3 and MCH processes. Therefore, good energy savings may be found in the further development of these processes.

Shipping fuel requirements proved particularly difficult to establish. It was assumed that the LNG, CO_2, NH_3 and MCH ships could run on LNG, and the LH_2 ship would run on LH_2 boil-off gas (BOG). It seems likely that ships can be fueled by NH_3 in the future, but for this study it was decided to keep the fuel consistent between the options with the exception of the LH_2, where BOG reliquefication on the ship is unlikely to be economic. Converting ship power requirements into LNG/LH_2 usage was carried out, using a simplistic method, consistently between the different options.

The Qatargas 2 project[9] LNG value chain capacity includes 2 × 7.8-MMtpy LNG mega-trains (APCI AP-X), 5 × 145,000-m^3 LNG storage tanks, LPG, additional condensate berths, sulfur facilities, a fleet of 14 Q-Flex and Q-Max ships in Qatar, 3 × 220,000 m^3 LNG tanks in the UK and regas facilities with a collective capacity of 15.6 MMtpy. CAPEX and OPEX are costed on a factor of (0.54 ÷ 15.6) for the entire value chain, excluding the byproducts and additional berths. Only one Q-Max ship was considered in the CAPEX.

Storage, loading, unloading and transportation costs are a significant proportion of the overall value chain. The ship size selected for each option is based on typical sizes cited in literature and referenced later; however, this may not give the most optimum or economic solution, as some options have lower ship utilization than others, which is a key parameter for optimization in any future study.

Selecting the ship size and speed defines the voyage duration and number of trips and, therefore, the number of ships required. It also defines the minimum onshore storage capacity required. For the sake of simplicity, the same capacity was assumed in Qatar and the UK. A minimum margin of 7 days of storage is included to allow for shipping delays, such as weather or ship outages.

To determine the number of ships, it is important to identify the number of trips required to transfer the total product from the export terminal to the import terminal. The total number of trips to transport a certain amount of product is calculated using the carrier capacity shown in Eq. 1:

$$\text{Total number of trips} = \text{Transported capacity (metric t} \div \text{yr)} \div \text{Ship capacity (metric t)} \quad (1)$$

The maximum number of trips each ship can make per year must then be determined. This is achieved by calculating the number of days per trip, which depends on the carrier sea speed, calculated as shown in Eqs. 2 and 3:

$$\text{Number of days per trip} = [\text{Distance (km / Ship)} \times \text{speed (km / hr)}] \div 24 \quad (2)$$

$$\text{Number of trips per yr} = \text{Operating days in yr} / \text{Number of days per trip} + \text{turnaround days} \quad (3)$$

Operating days per year is assumed to be 350 days, and turnaround time in port (which consist of loading and unloading hours) is assumed to be 3 days. Therefore, the number of ships can be calculated as shown in Eq. 4:

$$\text{Total number of ships} = \text{Total number of trips} / \text{Number of trips per yr} \quad (4)$$

Eqs. 5–7 are used to determine the storage tank volumes and number of tanks. A margin for the delayed arrival of a ship is considered.

$$\text{Frequency (days)} = \text{Operating days} / \text{Total round trip} \quad (5)$$

$$\text{Working volume (m}^3) = \text{Carrier size (m}^3) + \text{Minimum frequency or 7 days} \times \text{Rundown rate (m}^3 \div \text{day)} \quad (6)$$

$$\text{Number of storage tanks} = \text{Working volume (m}^3) \div \text{Tank capacity (m}^3) \quad (7)$$

Cost estimation. The value chain for each option is defined, and CAPEX and OPEX were calculated for each unit within the process. For each part of the value chain, it is assumed that there are 350 operational days/yr, and the overall lifetime is 30 yr. Data gathered for each unit are scaled up or down, as required for the required unit size, using the standard estimation factor to a power. A geographical estimating factor of 0.9 for Qatar to 1 for the UK was also applied where necessary. Currency conversion factors of pounds sterling (GBP) to U.S. dollars (USD) of 1.32, and euros to USD of 1.14 are used where necessary. Feed and utility costs for each location are detailed in **TABLE 1.**

The approach taken in this study to determine the capital cost of a plant, is calculated based on the scaling factor and corresponding reference capital cost and capacity as outlined in Eq. 8:

$$\text{Capital investment (S)} = \text{Capital investment}_{ref}(S_0) \times [\text{Capacity (C)} / (\text{Capacity}_{ref}(C_0)]^n \quad (8)$$

TABLE 1. Utility costs

Utility	Qatar	UK
Natural gas, USD/kWh[1]	0.0082	0.012
Power, USD/kWh[2]	0.0351	0.064
Demineralized water, USD/metric t	2.5	1.875
Cooling water, USD/m[3]	0.1	0.064
Toluene, USD/metric t[3]	424	–
LNG, USD/GJ[4]	5.93	–
LH_2, USD/GJ[5]	12	–

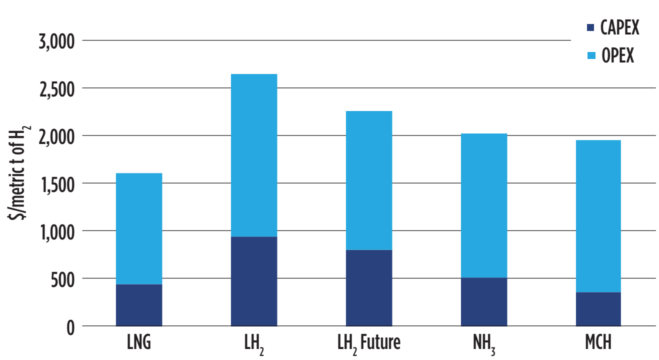

FIG. 2. CAPEX/OPEX comparison.

Here, *n* is the scale factor. In this study, a scale factor of 0.6 is used. Capital investment is typically reported as USD $MM, and the capacity is reported in metric tpy of the corresponding energy vector.

The specific CAPEX per year is calculated by dividing the capital investment (S) by the plant lifetime in years. For a specific capital cost per metric t of H_2, the annual capacity of the target H_2 is considered as shown in Eq. 9:

$$\text{Specific capital cost} = \text{CAPEX (\$MM/yr) / metric t } H_2 \quad (9)$$

As mentioned previously, the OPEX splits into a fixed OPEX, which is represented by a percentage of the CAPEX and variable OPEX, as shown in Eq. 10:

$$\text{Fixed OPEX} = \text{O\&M (\%)} \times \text{Capital investment (S)} \quad (10)$$

Here, fixed OPEX is reported as $MM/yr. Variable operating costs are calculated by multiplying utility data by a corresponding price, as calculated in Eq. 11:

$$\text{Variable OPEX} = \text{Utility data} \times \text{Price} \quad (11)$$

The utility data refers to the feed and utility consumption (e.g., natural gas feed, power consumption, fuel consumption, etc.) in a process reported as kWh or metric t. Prices are represented in various ranges, depending on the type of energy source, typically reported as USD/kWh or USD/metric t. Variable OPEX is then determined as $MM/yr, using Eq. 11.

To determine the specific operating cost per metric t of H_2, the same approach to that of specific capital investment is applied, as shown in Eq. 12:

$$\text{Specific operating cost} = \text{OPEX (\$MM/yr) / metric t } H_2 \quad (12)$$

The total process-specific cost per metric t of H_2 is normally calculated as the sum of the specific CAPEX and OPEX. An exception to this is made for the LNG value chain. Since the LNG value chain is already established on a much larger scale than the 500-metric-tpd H_2 requirement used for this study, CAPEX and OPEX attributed to the LNG capacity was simply prorated on the installed capacity.

The CAPEX and OPEX were calculated for each option, and the specific H_2 value was calculated simplistically by dividing the CAPEX by 30 yr, adding the annual OPEX and diving the result by the final H_2 production (0.171 MMtpy in all cases). This specific H_2 value ($/metric t) is used to compare the overall value chains, as well as individual aspects of each option.

Part 2. This article continues in Parts 2 and 3, to be published in consecutive issues, to illustrate the results shown in **FIG. 2.**

NOTES

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The complete cycle of low-carbon H_2—Part 1

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Hydrogen enjoys enormous attention and acceptance as an energy carrier and a carbon-free solution for the different sectors. The increasing cost of fossil fuels due to depleting resources and growing concerns for climate change require an immediate solution, and H_2 is a feasible, clean, affordable and promising one.

Affordable and sustainable H_2 production is the first and foremost challenge. "Blue" H_2 from steam methane reforming, "green" H_2 from electrolysis and H_2 from biomass [classified by *H2Tech* as "red" H_2] are the three most appropriate methods of low-carbon H_2 production and are key for establishing the H_2 economy. Each technology has a place in the H_2 economy, and the simultaneous integration of all three may prove to be a holistic solution.

H_2 production background. Conventionally, most H_2 is produced through steam methane reforming (SMR) for refinery, fertilizer and petrochemical use. Due to recent technology advances, a number of new pathways have been identified for the production of H_2, for applications like fuel for transportation, the decarbonization of industrial sectors such as steel and cement, alternative production methods for ammonia and methanol, and heat and power generation and backup energy storage.

SMR, a fossil fuel-dependent production route, can encourage the establishment of centralized or distributed H_2 units to decarbonize various sectors when combined with carbon capture. Due to the benefit of the scale of production, technology maturity and affordable price, SMR with carbon capture bridges the gap in the H_2 economy. SMR is more attractive in areas where natural gas is available at a cheaper price and significant production scale.

Biomass conversion through thermochemical and chemical routes is a critical thermal process with an abundance of benefits. As biomass is a carbon-neutral feed, it helps in offsetting carbon emissions. Biomass is more attractive for decentralized production and where steady biomass supply is available at an optimum price. The biomass route has enormous social benefits, as it can boost the agriculture sector and rural economy. Technology proof at a commercial scale is one of the critical challenges of the biomass-based production of H_2.

Electrolysis is the most environmentally friendly process when integrated with a renewable energy source. At present, electrolysis has a high cost of production. In the future, however, capital cost and associated costs for electrolyzers will decrease. Electrolysis is a carbon-free solution, but it has a large water footprint, which is a challenge for the process. Another concern is that the production route is entirely dependent on the surplus availability of renewable electricity, which could be a challenge for energy-deficient countries.

The most prominent end use for H_2 is as a fuel in the transportation sector. Purification, compression, storage, dispensing and control are needed downstream of the H_2 production unit to reach the consumer. The complete H_2 fueling chain is presented in a later case study.

H_2 is a versatile component in production as well as consumption. The real potential recognizes H_2 as an energy carrier for the decarbonization of the transport sector and the fertilizer, iron and steel, and power sectors (**TABLE 1**).

Globally, H_2 production is 120 MMtpy, and H_2 demand is predicted to be 1.37 Btpy by 2050 for a complete energy transition.[3] H_2 demand for different sectors is depicted for worldwide (**FIG. 1**) and for India (**FIG. 2**).

TABLE 1. Summary of H_2 production status

Present production	120 MMtpy (global), 6 MMtpy (India)
Demand by 2050	187 MMtpy–1.37 Btpy (global), 41 MMtpy (U.S.), 28 MMtpy (India)
Form	75% is pure H_2, 25% is in mixed form
Current use	75% in refinery, ammonia and methanol
Present production route	95% of fossil fuel, 5% from electrolysis (as byproduct from the chlor-alkali industry)
Future production route	Fossil fuel, biomass, electrolysis
Color[1,2]	Gray, brown, blue, green, red,[a] turquoise[b]
Feedstock	Fossil fuel (natural gas/coal), biomass, water/electricity
Production cost[c]	\$1.5/kg–\$2/kg (gray), \$2/kg–\$2.5/kg (blue), \$4/kg–\$6/kg (green), \$3.5/kg–\$4/kg (red)
Future use	Transport, heating, iron and steel, ammonia/methanol production, cement, power integration
Emission	Gray (10–12 kg CO_2/kg H_2), blue (2–3 kg CO_2/kg H_2), green (0.3 kg CO_2/kg H_2), red (neutral)
Storage	Gaseous, liquid, solid
Transport	Truck/pipeline, ship
H_2 price as fuel	\$9/kg–\$10/kg (Japan), \$13/kg–\$16/kg (U.S.), \$10/kg–\$15/kg (UK)

[a] H_2 produced from biomass and waste
[b] H_2 produced via methane pyrolysis
[c] Typical production cost for industrial-quality H_2; the actual price is dependent on various factors including geographical location, feedstock availability, process configuration, etc.

The H_2 cycle. The complete cycle of H_2—including feedstock, production route, transformation, transport, storage and use—is depicted in **FIG. 3.**

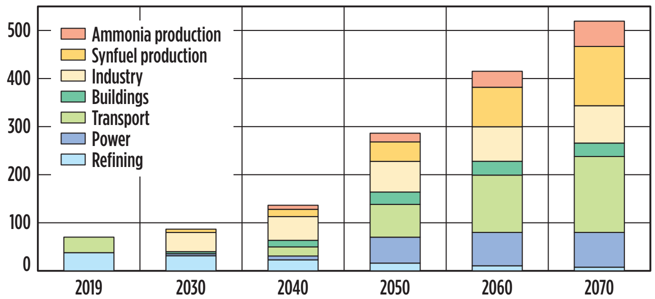

FIG. 1. Global H_2 demand, 2020–2050 (estimated), MMtpy.[4]

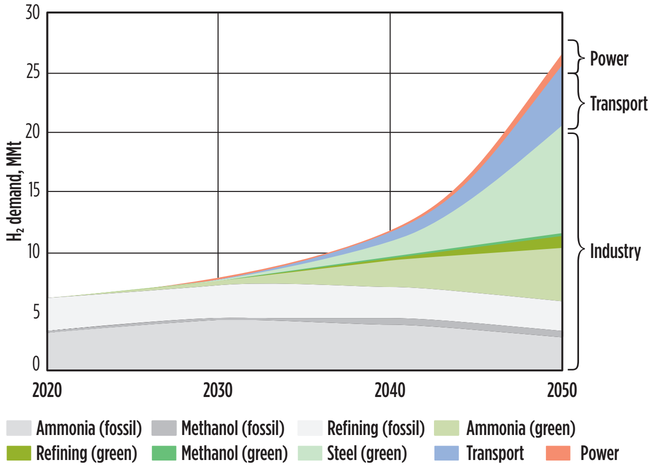

FIG. 2. H_2 demand in India, 2020–2050 (estimated), MMtpy.[5,6]

H_2 has a tremendous role to play, not only in the transport sector but also in the decarbonization of other sectors like steel, cement, fertilizer, power, methanol derivatives, heating and many more. Greater use of H_2 is foreseen in hard-to-electrify areas including steel, cement, chemicals, long-haul road transport, marine industry and aviation.

- **Iron and steel:** Steel is the main driver for H_2, where it replaces coal for use as a reducing agent. The technology is still at pilot scale and moving toward commercial scale.
- **Cement:** The cement industry is responsible for 7% of global CO_2 emissions. Cement kilns mainly use fossil fuels like coal. The effective use of H_2 will convert "gray" cement into "green" cement.
- **Heat:** H_2 can be used for heating homes in the same manner as natural gas, both in pure form and in natural gas blends.
- **Power/grid stabilization:** H_2 can be used for energy storage and flexible power generation to overcome the intermittent availability of renewable energy. H_2 stores the renewable energy during times of peak demand, and this energy is used when renewable energy is not available. The overall process efficiency is 20%–35%, but it enhances the applicability of renewable energy through around-the-clock supply.
- **Transportation:** The fastest-growing use of H_2 is in the transportation sector. H_2 is used in its pure form in fuel cell electric vehicles (FCEVs) as a fuel for transportation. Every country is focusing on different production routes and different forms of H_2 in the transportation sector—e.g., California in the western U.S. is focusing on FCEVs, while Germany is focusing on converting natural gas infrastructure to H_2.
- **Fertilizer:** H_2, along with nitrogen separated from atmospheric air, is converted into "green" ammonia

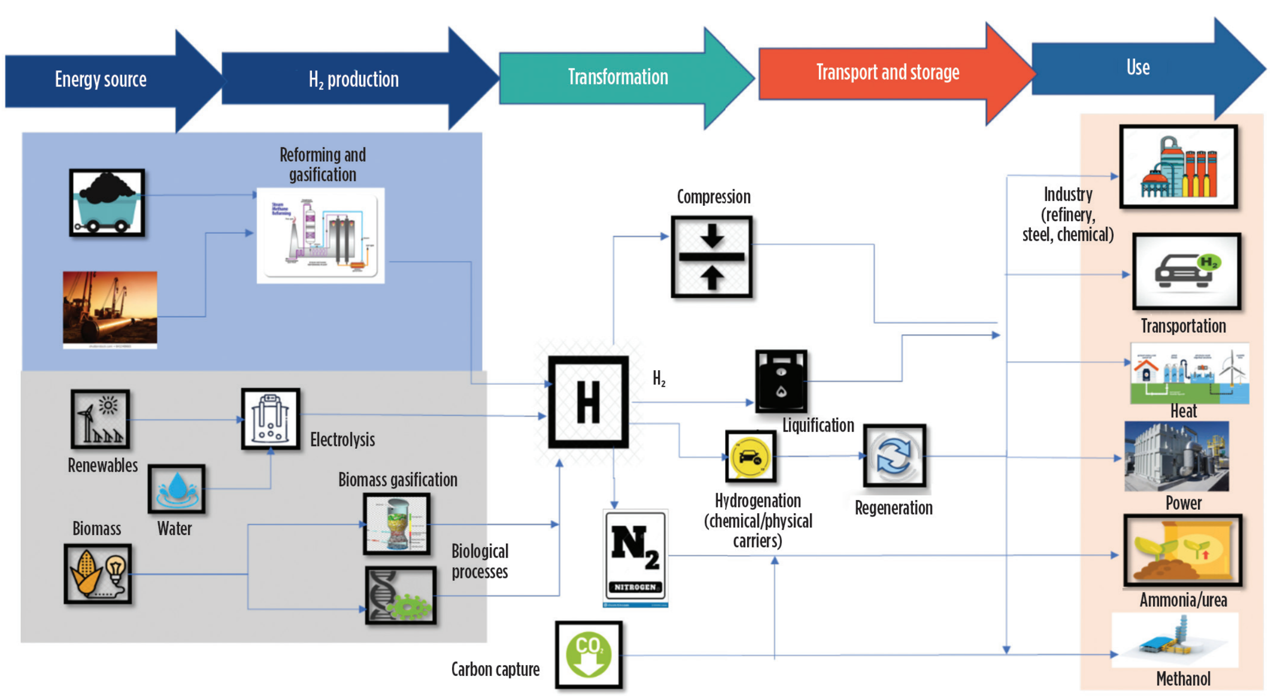

FIG. 3. The complete cycle of H_2 production.

through the Haber process. The ammonia is further converted into urea with the use of captured CO_2 from different sources. At present, the cost of green ammonia is estimated at 2–3 times the cost of "gray" ammonia; by 2030, however, green ammonia is expected to be more cost-competitive with gray ammonia. Middle East Gulf countries are focusing on green H_2 for the production and export of green ammonia.

- **Methanol:** Green methanol can be produced using captured CO_2 from a power plant, refinery or any other CO_2-emitting process plant. At present, the cost of green methanol is estimated at 3–4 times that of conventional "gray" methanol. The methanol can be further converted into olefins, giving a more comprehensive range of products.

The world is committed to keeping the global temperature increase in this century well below 2°C. To achieve this goal, it will be necessary to limit CO_2 emissions. The reduction of CO_2 emissions is emphasized alongside the effective utilization of captured CO_2. H_2 has greater application when joined with CO_2 capture, as shown in FIG. 4, for the production of synthetic fuels like diesel, gasoline, synthetic natural gas, and synthetic chemicals such as methanol and urea.

H_2 production routes. Low-carbon H_2 production is the foremost requirement to establishing a sustainable H_2 economy. Various routes for H_2 production exist or are under development or study. Among these routes, steam reforming of natural gas with carbon capture, biomass conversion and water electrolysis are frontrunners.

SMR route. The most reliable and efficient H_2 production process is the steam reforming of fossil fuels.[1] The SMR process is widely divided into the following steps: feed pretreatment, steam reforming, shift process, synthesis gas cooling and purification (FIG. 5). The primary reaction of reforming is strongly endothermic, meaning it requires heat to drive it forward. That heat is usually supplied by burning the natural gas, which produces CO_2. The carbon monoxide (CO) in the output stream from the primary reaction is generally converted to CO_2 via the water-gas shift reaction (WGSR) for increasing H_2 production, as shown in Eqs. 1 and 2:

$$CH_4 + H_2O + \text{Heat} \leftrightarrow CO + 3H_2 \quad (1)$$

$$CO + H_2O \leftrightarrow CO_2 + H_2 + \text{Heat} \quad (2)$$

The reformed gas is cooled and routed to the shift reactor to maximize the H_2 content. The produced syngas is further cooled, and the process condensate is separated out. The reformed gas has a primary composition of H_2 (74 mol%), CH_4 (7 mol%), CO (1 mol%) and CO_2 (18 mol%), which depends on feed composition and the selected process scheme. The gas is purified in the pressure swing adsorption (PSA) section to remove CO, CO_2 and CH_4 impurities and to produce gray H_2.

The key to the success of blue H_2 is selecting the right carbon-capture technology and carbon-capture location in the process. There are varied technologies for capturing carbon. Carbon capture through absorption technology is implemented in various syngas plants. Overall carbon-capture rate is 53%–90%, depending on the method used and the carbon-capture location.

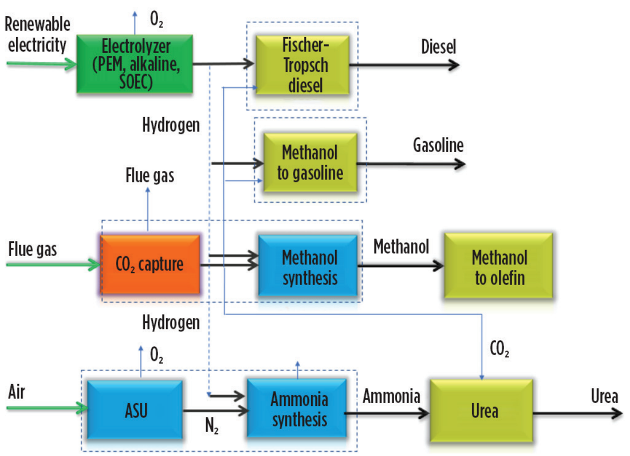

FIG. 4. H_2 can be integrated with CO_2 capture and converted into a range of chemicals and fuels.

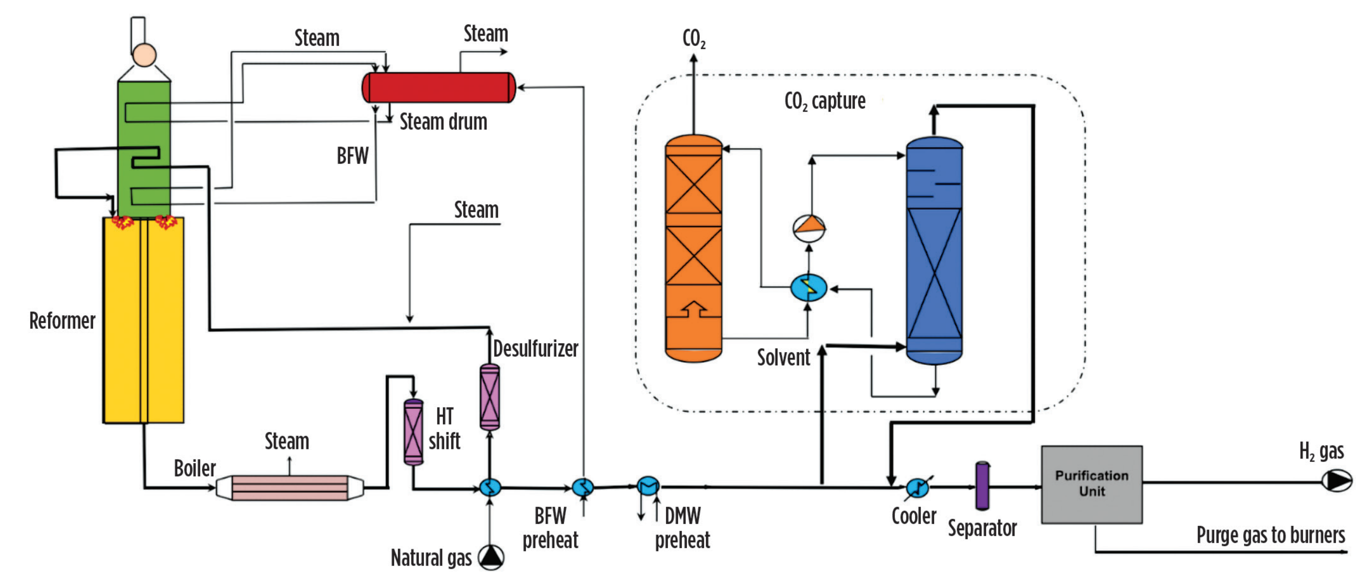

FIG. 5. H_2 production via SMR.[1]

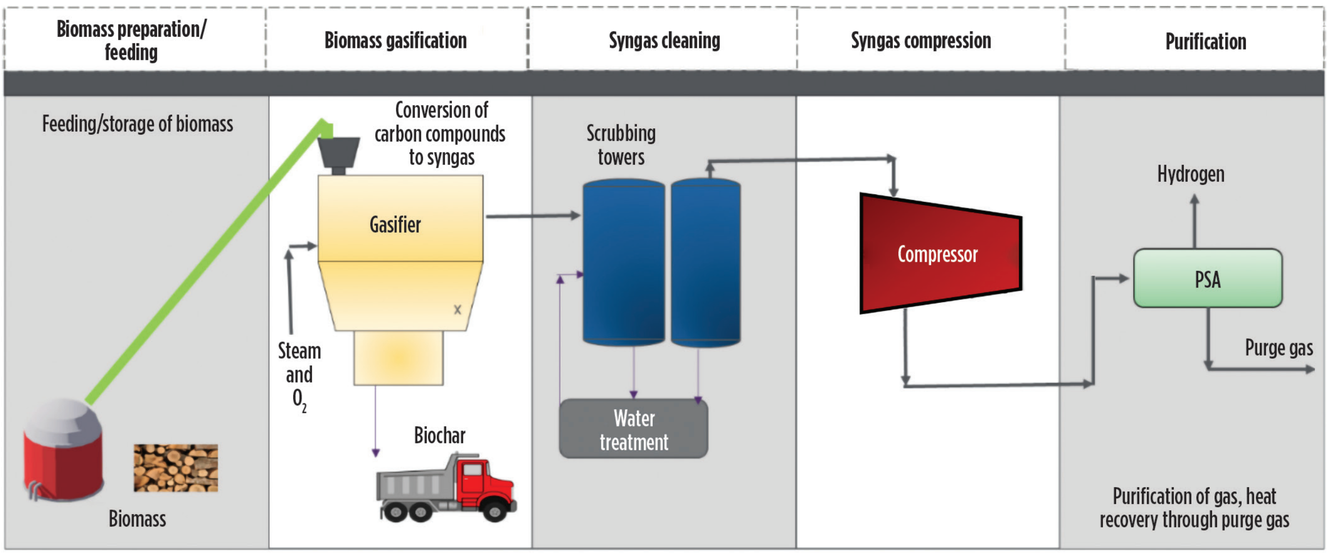

FIG. 6. H_2 production via biomass gasification.

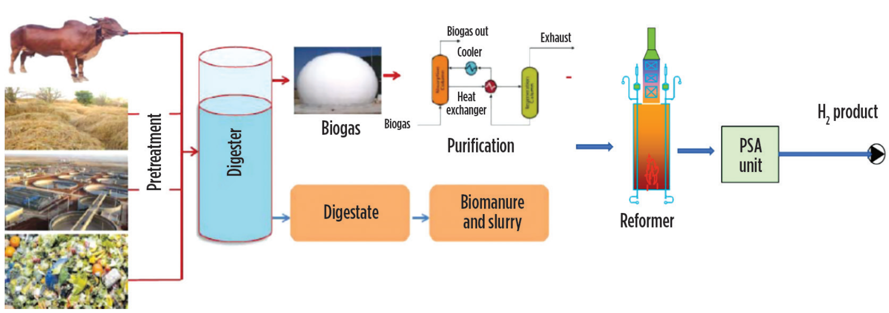

FIG. 7. H_2 production via biogas upgrading.

Biomass route. H_2 from biomass, or red H_2, is one of the promising routes for low-carbon H_2 production. H_2 is produced from biomass through biomass gasification, biogas upgrading (where biogas is produced via the anaerobic digestion of biomass), dark fermentation and other methods. Biomass gasification and biogas upgrading are primarily covered in this article. Here, biomass is considered as plant-based material and animal waste that is otherwise dumped, landfilled or burned.

The **biomass gasification** process for the production of H_2 is shown in FIG. 6. The oxy-steam gasifier processes biomass in the presence of O_2 and superheated steam in a fixed ratio. At controlled conditions in the oxy-steam gasifier, thermo-chemical conversion of biomass takes place to produce syngas. The syngas produced contains undesirable material—identified as contaminants, mostly tar and particulate matter—that require removal from the syngas before the final purification process via PSA for the production of pure H_2. The syngas is cleaned and cooled with gas scrubbers, using cooling water and chilled water. Dry syngas is then routed to PSA for final purification, and pure H_2 is generated. The gasification reactions are defined in Eqs. 3–6:

$$\text{Steam gasification: } C + H_2O \rightarrow CO + H_2 \quad (3)$$

$$\text{Boudouard: } C + CO_2 \rightarrow 2CO \quad (4)$$

$$\text{Hydrogasification: } C + 2H_2 \rightarrow CH_4 \quad (5)$$

$$\text{WGSR: } CO + H_2O \rightarrow CO_2 + H_2 \quad (6)$$

Here, the syngas is generated from biomass gasification, and the same syngas can be generated from waste gasification. The biomass gasification route is well-proven at the pilot scale, although it needs to be brought up to commercial scale.

The **biogas upgrading** process offers another production route. Biogas is produced from biomass and is used for combined heat and power (CHP) and mobility applications. It is generated from the anaerobic digestion of biomass and comprises > 60% of methane. Raw biogas is purified and reformed to produced H_2, as shown in FIG. 7. The process is the same as natural gas reforming, with the only difference being the feedstock, which is carbon neutral in the case of biogas. This production route benefits from the reforming process, which is efficient, reliable, well-proven and cost-effective.

The main challenge associated with biomass technologies is scalability due to biomass availability and cost of transport. The biomass route is most promising for agriculture-based countries like India, which has an abundance of biomass and looks to strengthen the rural economy through the effective use of biomass.

Electrolysis route. H_2 produced through water electrolysis using renewable electricity is "green" H_2. Water electrolysis is an electrochemical process that splits water into H_2 and O_2, using electricity. The H_2 produced from the electrolysis of water is purified in the de-oxy and dehumidification units. The process scheme of electrolysis is shown in FIG. 8, which covers the three major types of electrolyzer technology: alkaline, polymer electrolyte membrane (PEM) and solid oxide electrolyzer cell (SOEC).[7,8]

PEM is an acidic polymer membrane that requires no liquid electrolyte, which significantly simplifies the design. PEM electrolyzers potentially can be designed for operating pressures of up to several hundred bar and are suited for both stationary and mobile applications.

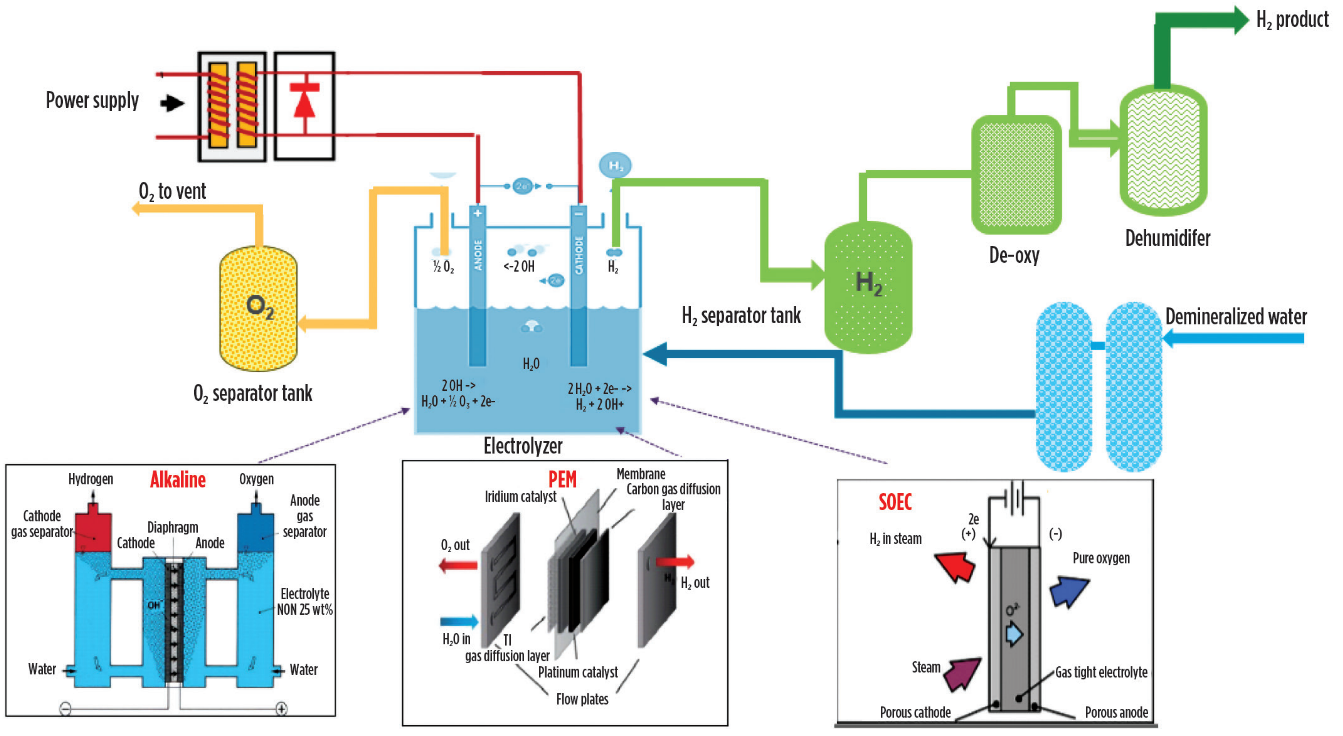

FIG. 8. Flow diagram of the electrolysis process.

The significant advantages of PEM over alkaline electrolyzers are higher turndown ratio, increased safety due to the absence of KOH electrolyte, more compact design due to higher current densities, and higher differential pressures. The system cost of PEM electrolyzers is approximately 1.3–1.8 times that of alkaline systems. The main drawbacks of this technology are the limited lifetime of the membranes and the high cost of the electrolyzers.

Alkaline electrolysis is a mature technology for H_2 production up to MW scale and is the most widely used type of electrolysis technology. The electrodes consist of non-noble metals like nickel with an electrocatalytic coating. The alkaline electrolyzer is relatively lower cost, as less rare material is required and water purity is less stringent. Zero-gap alkaline electrolyzers hold the key to cheap and efficient renewable energy storage. They use concentrated lye solution as the electrolyte and require a gas-impermeable separator to prevent the product gases from mixing.

The advantages to the bipolar (filter press) design are reduced stack footprint, higher current density and the ability to produce higher-pressure gas. Pressurized alkaline electrolyzers have lower efficiency and produce a lower-purity product than atmospheric alkaline (AEL). The foremost advantage of pressurized AEL compared to atmospheric AEL is that pressurized AEL produces compressed H_2 (either for grid injection or further use) with less additional energy input. This happens because the reduction in electric efficiency of the electrolysis with increased pressure is lower than the energy needed to compress the produced H_2.

Nevertheless, alkaline electrolyzer cells do not operate well at very low-current densities. They are limited in terms of flexibility in the load-following operation required for use with renewable energy sources. In alkaline electrolyzers, gases can blend across porous separators when the current fluctuates, making them unsuitable for powering directly from intermittent renewable power sources.

Another issue is that it takes 30 min–60 min to restart the system following a shutdown. The most significant disadvantage of AEL electrolyzers is that the utilized electrolytes (alkaline solution, e. g. 20%–30% KOH solution) are highly corrosive, necessitating high maintenance costs. A general overhaul of the system is necessary every 56,000 hr–90,000 hr of operation. AEL electrolyzers also have a large footprint and low output pressure.

SOEC electrolyzers operate at high temperatures of 800°C–1,000°C. SOEC has the highest overall efficiency of 70% and utilizes waste heat. It runs in regenerative mode to achieve water electrolysis using solid oxide/ceramic electrolyte to produce H_2 and O_2. Energy demand from SOEC is reduced due to Joule heating of an electrolysis cell, which is utilized in the electrolysis process at high temperature.

Advantages of SOEC include long-term stability, fuel flexibility, low emissions and low operating costs. However, a disadvantage is the high operating temperature, which results in long startup times and break-in times. The high operating temperature also leads to mechanical compatibility issues, such as thermal expansion mismatch and chemical instability, such as diffusion between layers of material in the cell. The cost of an SOEC electrolyzer is 2–4 times higher than alkaline, and the operating pressure range is approximately 1 bar.

AEM electrolyzers are equipped with an anion exchange membrane (AEM) and are also known as alkaline PEM electrolyzers. They require pure water feed and cheap components, such as platinum group metal-free catalysts and stainless steel bipolar plates. AEM electrolyzers are simple, robust and easy to operate. No water is transported to the cathode, and there is no need for an H_2-water separator, which makes for a simpler system and a lower cost module than both PEM and AEL. The AEM stack creates a physical barrier between H_2 and O_2 so that they never mix in an explosive ratio.

The significant advantage of AEM technology is that it works very well with intermittent power sources like solar and wind. AEM electrolyzers can work with filtered tap water and rainwater. Total annual maintenance costs are much less than for other technologies. AEM is an emerging technology; as such, few companies are developing AEM electrolyzers, and limited commercial products are available.

Balance of plant (BOP) for all types of electrolyzers includes the transformer, rectifier, control system, water purification, H_2 dryer and H_2 purification. A comparison of PEM and alkaline electrolysis technologies is offered in **TABLE 2.**

The quality of product H_2, the plant's scale, available utilities and heat input methods decide the electrolyzer selection and configuration. Major utilities required for an electrolyzer are power, demineralized water and cooling water. The major gaseous effluent is O_2.

Comparison of major H_2 production routes. Key parameters for all three major H_2 production routes are shown in **TABLE 3** for an H_2 production capacity < 1,000 Nm^3/hr and India as the geographical location. The cost of natural gas used for this case study is assumed at \$9/MMBtu–\$10/MMBtu, biomass feedstock prices are \$27/t–\$70/t, and electricity prices are \$25/MWh–\$107/MWh.

Electricity cost is assumed at \$50/MWh for renewable electricity. In the case of the SMR and biomass routes, the grid electricity cost is assumed at \$100/MWh for the cost of production. As evident from **TABLE 3,** the overall CAPEX of electrolysis is more than 40%–50% compared to SMR, and the overall cost of production is lowest in the case of SMR plus carbon capture. Furthermore, the CAPEX of the SMR plus carbon capture route decreases drastically as the scale of production increases—e.g., for capacity > 50,000 Nm^3/hr, the CAPEX is \$1,000/tpy H_2–\$2,000/tpy H_2.

At present, SMR is the most efficient process, while biomass is the least efficient. However, the biomass route has the highest net energy ratio as the only inputs are power and steam, and feedstock biomass does not account for energy input since it is waste.

Conversely, electrolysis requires a considerable amount of water for operation, and it will increase further if the water requirement for cleaning solar photovoltaic (PV) is considered. However, recycling of cleaning water will optimize the water uses for solar PV. The SMR and biomass routes are in the same range of water consumption. In reality, the biomass route is a net water production process, as it captures water from organic matter. Biomass gasification requires a good amount of utility water to clean syngas, which can be further optimized.

The least amount of power is required in SMR, while electrolysis requires much more power than the SMR and biomass routes.

Land use has a broad range in the biomass route due to the large footprint required for conveyor and biomass storage, which can be further optimized. The lowest land use is for SMR because of the compactness of layout, which has improved over the years. Land use by the electrolysis route increases greatly (> 100-fold) when accounting for the solar PV footprint.

CO_2 emissions are lowest in the electrolysis route since a renewable source of electricity is used. However, the biomass route is actually carbon negative, considering that some carbon is inevitably fixed in the char extracted during the process.

In electrolysis, two main options exist for estimation. One is to select a large-capacity electrolyzer and a large-capacity H_2 storage to maintain continuous H_2 production. The second is to consider renewable energy with battery storage. In the second option, the electricity cost will be 2–3 times greater than the first option, but a smaller electrolyzer and storage would be required. A third, less desirable option is mixed-origin power (renewable energy with fossil-fuel grid electricity), but this results in some CO_2 emissions and is not considered a "green" process

TABLE 2. Comparison of PEM and alkaline electrolyzers[7,8]

Electrolyzer type	PEM	Alkaline
Investment, \$MM/MW*	1.6–2.7	1.2–1.5
Product purity, mol%	> 99.995	> 99.5
Stack life expectancy, hr	60,000	90,000
Pressure, barg	0–40	0–3
Demineralized water, μS/cm	< 0.1	0.5
Turndown, %	10	40–50
Maintenance	Less	More
System size range, kW	0.2–1,150	1.8–5,300

* Investment varies with the size of the unit; the comparison basis is literature survey and in-house data

TABLE 3. Key parameters for different low-carbon H_2 production routes[a]

Parameter	SMR plus carbon capture	Biomass	Electrolysis
CAPEX, \$1,000/tpy H_2	10–16	8–10	10–50
Cost of production, \$/kg	2–2.5	3.4–3.9	3.5–6
Specific energy, Gcal/1,000 Nm^3 H_2	3.5–4.2	5–5.5	4.9–5
Carbon footprint, kg CO_2/kg H_2	0.2–4	Neutral	0.3–0.9[b]
Water footprint, l/Nm^3 of H_2	0.9–1.7	0.5–1.1	5.6–6
Power consumption, kW/Nm^3 of H_2	0.01–0.04	0.4-0.45	5.5–6
Land use, m^2/tpy H_2	0.15–0.2	0.5–3.4	1–3[c]

[a] Values presented in the table are typical and depend on many factors including geographical location, size of the unit, feedstock price, utility cost, etc.
[b] Carbon footprint when the source of electricity is renewable only
[c] Land use is for the electrolyzer without accounting for the renewable source footprint

Part 2. To be published in the Q4 issue, Part 2 will present a sensitivity analysis of H_2 production cost and a case study for FCEVs.

LITERATURE CITED

Complete literature cited available online at www.H2-Tech.com.

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HYDROGEN STORAGE

Long-duration H_2 storage in solution-mined salt caverns—Part 1

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Hydrogen storage in solution-mined caverns can provide utility-scale, long-duration energy storage to support grid integration of renewable energy generation and H_2 fuel management. An H_2 energy storage ("HES") facility consists of:

1. An H_2 production plant using electrolysis, steam reforming and/or other methods
2. Underground storage caverns created in a salt formation
3. An energy distribution facility that delivers H_2 gas to a combustion gas turbine, gas engine, or fuel cell for power generation; gaseous H_2 truck load-out to supply industrial or mobility fuel markets, and/or an interconnection to a load-serving H_2 pipeline.

Electrical utilities and other large industrial and commercial energy consumers are adopting goals to increase the use of renewable energy in response to government mandates and customer preference. As a result, renewable generation capacity (primarily wind and solar) now constitutes 23.4% of generation capacity in the U.S.

However, matching intermittent and scattered renewable energy supply with variable, often concentrated, demand is difficult for several reasons:

- Solar is a diurnal resource
- Wind is weather-dependent
- Extreme hot or cold weather conditions that drive peak demand are commonly associated with stagnant air masses and low wind conditions.

The design requirement to reliably serve peak demand with intermittent resources requires greater gross generation capacity, a diversity of resources with lower utilization, and/or combustion peaking capacity fired with carbon-based fuel. The excess of capacity during seasonal low demand, peak solar generating hours or transmission congestion increasingly results in renewable energy being curtailed. These intermittent, curtailed resources can produce "green" H_2, via electrolysis, for the industrial gas and mobility fuel markets, if sufficient long-duration storage is available to provide a rateable, reliable supply at a predictable cost.

Salt caverns are ideal for long-duration H_2 storage for a number of reasons:

1. Withdrawal, or "discharge," of H_2 is highly flexible in rate, duration and volume
2. With the proper surface facilities, HES can simultaneously deliver stored energy to multiple physical markets
3. Caverns are a mature, financeable storage technology that have been successfully used for storage of compressed gases for over 75 yr, and for H_2 specifically at six locations since 1972
4. At scale, solution-mined caverns have the lowest unit cost of available storage technologies
5. The conditions appropriate for high-quality renewable generation in much of the U.S. and Europe, such as the western parts of the regions, are coincident with areas of suitable salt deposits.

Consequently, H_2 generation by electrolysis coupled with salt caverns is uniquely suited to meet the market need to shift excess off-peak energy to meet dispatchable on-peak demand, and to match intermittent, often low-value, renewable generation resources with stable, rateable, higher-value demand in industrial and mobility markets.

Why hydrogen? H_2 is increasingly viewed as the fuel of the future (**FIG. 1**) because it is carbon-free, readily substituted into electrical, mobility and chemical markets presently served by natural gas, and meets the increasing need for dispatchable power generation to match intermittent renewable generation with asynchronous demand.[2,3]

HES uses electrolysis to convert surplus electricity to H_2, stores H_2 in the subsurface, and then uses H_2 as fuel for power generation, mobility applications or petrochemical feedstock. However, due to H_2's small molecular size and high chemical reactivity, it is more difficult to store than hydrocarbon natu-

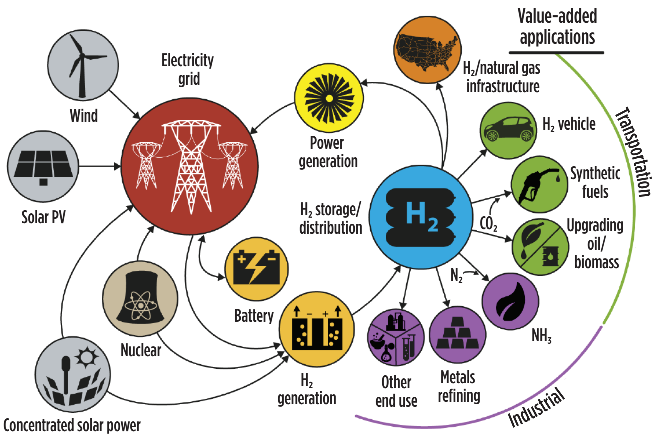

FIG. 1. Future H_2 at-scale energy system.[1]

ral gases. All materials used must be effectively impermeable to H_2 at operating conditions, materials must be resistant to H_2 embrittlement and corrosion, greater care must be taken to make gas tight connections in piping and joints, and possible microbial activity requires mitigation. Consequently, the limitations of H_2 storage technologies have been an impediment to deployment of H_2 as a utility-scale fuel.[4]

A variety of methods are available for storing H_2;[5] however, the primary storage technologies in commercial use are liquefaction, compressed gas in aboveground tanks, and salt cavern storage. For vehicle refueling and light industrial applications, multiple tube tanks (3–15 tanks of 0.5 m or 3.3 ft in diameter × 6 m–12 m or 19.7 ft–39 ft in length), or spherical tanks are manifolded together to provide storage. Typical maximum pressure is 200 bar (2,900 psi). Some commercially available tube tanks are encased in steel-wire-wound, composite sleeves to increase the operating pressure to 275 bar–690 bar (3,988 psi–10,000 psi). At an operating pressure of 275 bar (3,988 psi), an 8.8-m (26-ft) tank can store (+/–) 34 kg of H_2. However, for HES to support the ramping requirements of wind and solar power generation, load shifting at a utility scale requires tens to hundreds of MWs.[6] **TABLE 1** shows the storage requirement for various-sized gas turbines, which is substantially greater than the capacity of aboveground, compressed gas tank capacities.

Liquefaction storage is a technically viable solution and a comparatively mature technology that still has opportunities for cost reduction.[5] For a liquefaction H_2 storage system, 40%–50% of the CAPEX is the liquefaction plant and 50%–60% is the cost of the tank(s). The OPEX includes the energy costs of liquefying the H_2 and managing the H_2 that warms and boils off (0.1 vol% or less per day), which then needs to be reliquefied or used in operations. Worldwide, installed H_2 liquefaction capacity is (+/–) 355,000 kg, but approximately 10% of that capacity is a single, 34-metric-tpd liquefaction facility operated by NASA. The NASA facility also contains the world's two largest cryogenic H_2 tanks with a capacity of 3,218 m^3 each (+/– 225,260 kg).[7]

As shown in **TABLE 1,** the combined volume of both tanks is sufficient to support a 44 MW–138 MW peaking turbine. Arguably, the cost of liquefied storage can come down, and facilities can be scaled up, as it has happened with liquefied natural gas (LNG), but the cost and complexity of liquefaction and storage is likely to remain substantially greater than geologic storage.

Other near-surface underground compressed gas storage solutions may be viable for H_2, such as mined rock caverns, abandoned mines and buried pipe,[8] but they have significant size limitations, substantial technical risks and high construction costs.

Although H_2 differs in many respects from natural gas, the fundamentals of how to store utility-scale volumes of H_2 parallel natural gas. The costs of underground storage of gas in a salt cavern, excluding compression facility costs, are approximately 1/25th the cost of cryogenic (liquid) tanks and about 1/10th the cost of compressed gas for storage of 400,000 sft^3 (11,326 m^3) and larger. Consequently, geologic storage of H_2 is presently, and is likely to be in the future, the most economic method for storing H_2 and supporting dispatchable generation capacity at a utility scale.

The need for dispatchable energy. The intermittency of wind generation and the daylight limitation of photovoltaic (PV) solar generation require energy storage to mitigate weather-driven fluctuations in wind and solar resources, time shift excess power generation output to resource-constrained low- to no-sunlight hours, and mitigate extreme weather events (cold and warm) resulting from stagnant air masses, where demand peaks and renewable generation are curtailed.

Daily time-shifting. An hourly bar graph of the annual average locational marginal price (LMP) for electric power ($/MWhr) at a California independent system operator (CAISO) price node outside of San Francisco, California is shown

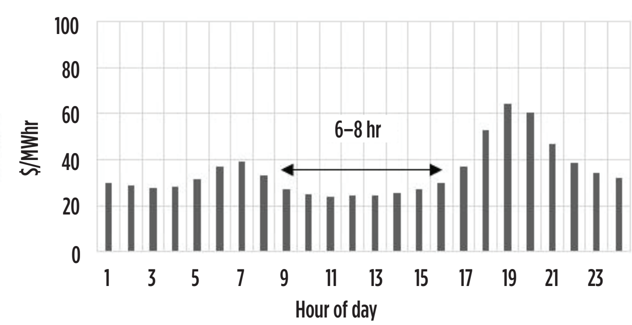

FIG. 2. Average location marginal price (LMP) by hour of day.

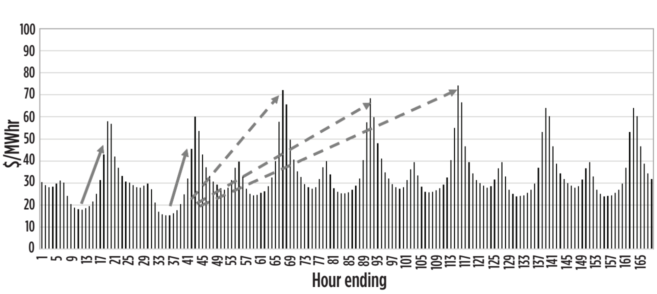

FIG. 3. Weekly locational marginal power price by hour.

TABLE 1. Storage requirement and technology by generator size

Net output, MW	Duration, hr	Fuel rate, kg/MWhr	Storage with 10% reserve, H_2 kg	Type of storage
0.08	1	375	34	Single tube tank
1.7	1	375	695	15-pack 12-m tubetank
0.2	8	375	695	
1.8	8	375	5,040	Subsurface containment storage
20.8	8	375	68,640	
32	8	375	105,600	
44.4	8	375	146,487	Salt cavern
91.4	8	375	301,587	
138.4	8	375	456,687	
185.4	8	375	611,787	
232.4	8	375	766,887	

in **FIG. 2.** Pricing data is a strong indicator of the value of storage, since prices reflect, in real time, the mismatch of supply and demand with the price the market is willing to pay to balance the mismatch. This area has substantial renewable power generation (both solar and wind), hydroelectric and gas-fired generation, and installed battery capacity, so it provides insight as to how longer-duration storage can create value.

The lowest-priced power is in the daylight hours, where high PV solar output dampens pricing. There are two price peaks: evening (1700–2100 hr) and morning (0600–0700 hr). Battery storage is effective in time-shifting surplus daytime power to evening peaks. Batteries generally start discharging at 1800 hr and have a 4-hr discharge cycle. The 25% drop in power price at 2100 hr is a result of falling demand and continued discharge of batteries to the grid. The morning peak occurs in the early daylight hours just prior to and during sunrise, when PV solar capacity is still ramping up and battery resources are limited in output due to the prior evening discharge.

Weekly time-shifting. An hourly bar graph is shown in **FIG. 3** for 1 wk of the annual average $LMP/MWhr for the same price node from 2400 hr Friday through 2400 hr the following Friday (e.g., the weekend hours are hours ending 1–48). The daily pattern repeats (solid arrows), with the lowest prices during the daylight hours, an evening peak lasting 3 hr–4 hr, prices falling in the final evening hour, and an early morning peak where demand increases while PV solar capacity is still ramping up.

The notable difference in the weekly profile is that the lowest prices are Saturday and Sunday afternoon, and the duration of the "trough" on weekends is 8 hr–11 hr vs. 4 hr–8 hr on weekdays. The day-to-evening peak spread during the week is 15%–20% higher than the daily spread on the weekend. Consequently, the highest-value storage technology shifts power 74 hr (+/–) from Sunday afternoon (hours 33–40) to Wednesday evening (hours 114–116) (dashed arrows), or longer.

Seasonality. As in the natural gas markets, seasonal weather also significantly impacts the price of electrical power (**FIG. 4**). Summer pricing volatility is driven by the longer solar day, air conditioning load, and late-summer (August–September) extreme heat events lasting 3 d–6 d. Winter peaks (mostly in February) are driven by extended-duration (6 d–8 d), cold weather events combined with shorter solar days. Volatile weather conditions during the "shoulder" months (April–June and October–November) can result in negative power pricing demand, which is less predictable and which makes scheduling resources by the system operator less reliable.

FIG. 4 shows 3 yr of price data in southern California. In 2018, both winter (February–March) and summer (July–August) weather-driven peak pricing (e.g., prices are 10 times the daily mean) events occurred. In 2019, both summer and winter conditions were mild. In 2020, no winter events occurred, and no significant price volatility was seen from December 2019–May 2020; however, five multi-day summer events with peak prices over $300/MWhr were recorded. Note the concurrence of negative power prices in August 2019 with peak prices of $700/MWhr and the frequency of negative pricing from December 2019–early March 2020.

Short-duration storage (< 8 hr discharge) can mitigate many of the short-duration (< 8 hr) events, but it cannot mitigate multi-day events. The highest prices (**FIG. 5**) are seen during multi-day weather events where the limitations of battery storage result in unmet demand.

Winter events. Hourly power prices for two winter weather events in February 2019 are shown in **FIG. 6.** Event 1 starts at hour 120 and lasts until hour 264, and Event 2 starts at hour 403 and lasts until hour 513. Peak prices are up to 3.5 times

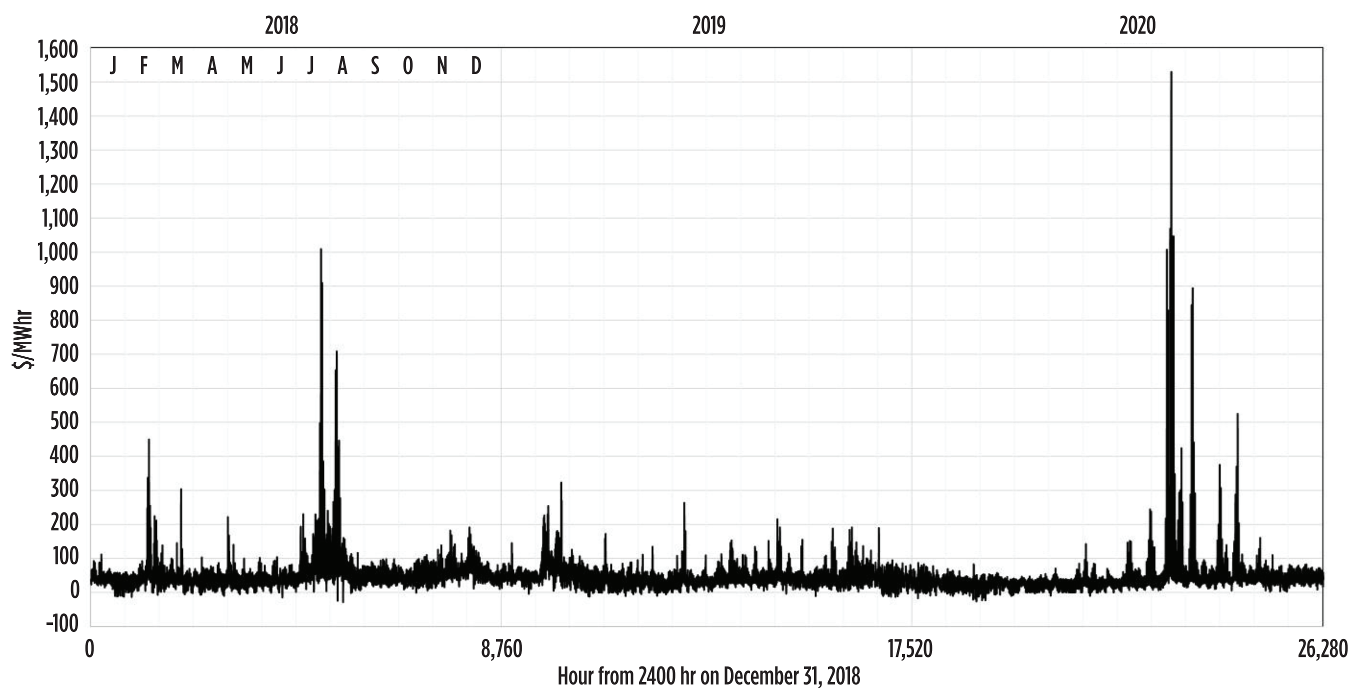

FIG. 4. Locational marginal power prices for 2018–2020.

the annual mean peak price. Evening peaks can last longer than 7 hr, and the daily price "trough" shortens from 6 hr–8 hr to 2 hr–4 hr. HES would allow "charging" in anticipation of a weather event (0–115 hr), which would provide the ability to shave more efficiently the 2 hr–3 hr needle peaks over the following 250 hr on an hourly dispatch basis, vs. the battery duty-cycle of 4 hr–6 hr.

In the same winter event, the absence of longer-duration, dispatchable generation exacerbated price volatility (**FIG. 7**). The extended evening peak, greater than 4 hr, results in a greater dispatch of reserve battery storage resources. Due to the battery duty cycle, demand falls suddenly and prices collapse around midnight (hours 24, 48, 72, 120 and 144) until the reserve battery sources fully discharge. The exhaustion of battery resources coincident with the lack of PV solar generation in the early morning results in a morning peak price that can exceed the evening peak. This is the only time of year when the morning peak price is of similar magnitude to the evening peak price.

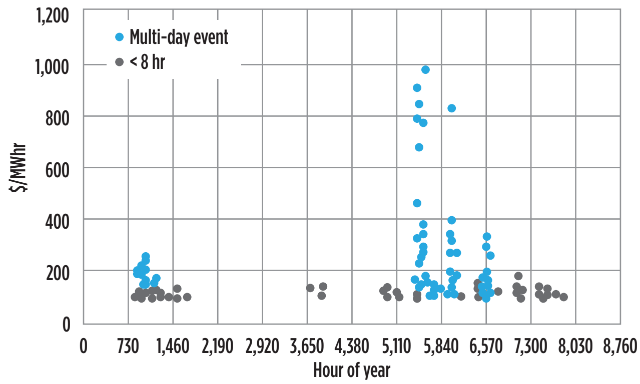

FIG. 5. Seasonality of major price spikes (> $100/MWhr) and duration in 2019.

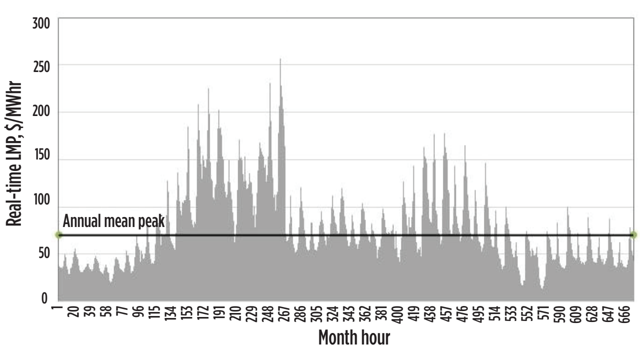

FIG. 6. Locational marginal power prices for February 2019 winter events.

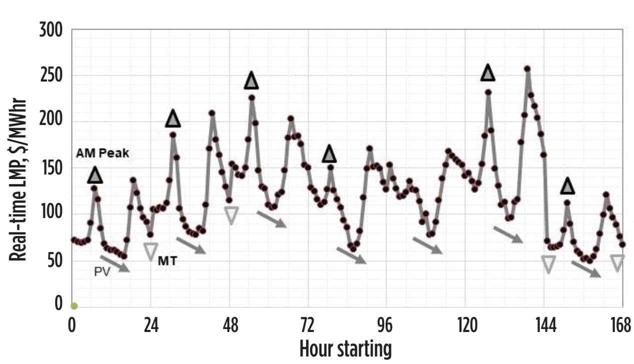

FIG. 7. February 2019 first winter event.

Summer events. Price behavior during an 8-d summer heat event in 2020 is shown in **FIG. 8.** Note the log scale on the price axis. Large price peaks (> $750/MWhr) are the result of shorter daily troughs and fewer cheap hours for charging storage, due to air conditioning adding to load starting in late morning and overnight price peaks (> $100 MWhr) with 6 hr–9 hr of duration. Prices of > $500 MWhr generally occur later in the evening and last for 1 hr–3 hr. As in the winter scenario, HES can build H_2 fuel inventory in anticipation of the weather event and then selectively discharge to shave the needle peaks.

Seasonal charging, dispatch and capacity.

As in the natural gas markets, the electrical power markets benefit from having a mix of storage alternatives, particularly those that are dispatchable and can retain energy efficiently over long time periods. The natural gas markets benefit from a combination of fast response, low-volume line pack, large seasonally cycled aquifer storage, multi-cycle depleted reservoir, high-cyclability salt cavern storage and liquefaction peakshaving. The authors view batteries as being analogous to line pack. Pumped hydraulic storage is analogous to aquifer storage in that it is expensive, has a long lead time to construct and has unique siting challenges, but also has a low variable cost once in service.

HES can fill the role of multi-cycle storage that, unlike other commercially available energy storage technologies, can time-shift energy weekend-to-weekday, month-to-month and seasonally. **TABLE 2** describes a two-cycle, seasonal operation plan for varying size of generators. It assumes that outside summer and winter peak months, the facility is charging constantly. During the peak seasons, it discharges at a rate of 4 hr/d–4.5 hr/d. The base project "charges" with a 20.8-MWe electrolysis facility that can produce 415 kg/hr of H_2 with a ramp time of less than 5 min, with water consumption of 90.8 l/min (24 gal/min). On discharge, a gas-fired, simple-cycle turbine fueled with 100% H_2 is assumed. To improve ramping speed, the unit can fire on 85% H_2 and 15% methane during

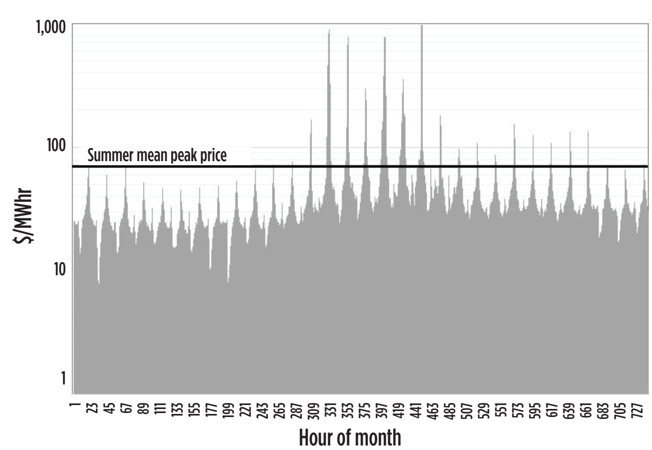

FIG. 8. Eight-day summer event, 2020.

startup. The resulting storage capacity required is on the order of 0.5 Bft^3–4 Bft^3 (14.2 MMm^3–113.3 MMm^3), which is well within the cavern feasibility range of most salt deposits.

With additional electrolysis capacity, cycling time can be increased to whatever a cycling plan may require, assuming that the economics support the additional capital expense.

Round trip efficiency. TABLE 2 also illustrates the weakness of HES that its low round-trip efficiency makes HES uncompetitive with batteries for short-duration service (< 10 hr). Existing battery technologies are very efficient (75%–90%) across their design basis duty cycles of 4 hr/d–8 hr/d, depending on technology and configuration. Batteries are increasingly less efficient as the duration of storage period increases beyond 8 hr–10 hr due to self-discharge over time, degradation of performance with use, and depending on ambient temperature conditions. The economic round-trip efficiency of batteries decreases further if the economic discharge period is less than the discharge duty cycle.

H_2 in storage does not degrade with time. Also, since the energy content of H_2 does not change with time, its energy efficiency remains constant indefinitely. The only loss of efficiency with time is due to volumetric losses due micro-permeation of H_2 through containment materials over long time periods (months to years). Depending on generation technology choice, the resource can be rapidly ramped up and down (e.g., has a more flexible duty cycle), giving it a more competitive round-trip efficiency for needle peakshaving.

H_2 in storage does not degrade with time. Also, since the energy content of H_2 does not change with time, its energy efficiency remains constant indefinitely.

Also, round-trip efficiency is primarily dependent on choice of combustion technology. TABLE 3 compares round-trip efficiency for the component technologies in various equipment combinations. Note that the increase in round-trip efficiency of the waste heat from the generation cycle can be captured and used beneficially (e.g., combined heat and power, or "CHP").

Preliminary studies of the levelized cost of energy (power), or LCOE,[9] show the comparative cost impact of round-trip efficiency, using fuel cell generation, vs. duration of storage (FIG. 9). H_2 fuel cells, coupled with geologic storage, have a flat to slightly declining levelized cost of energy from 0 d–7 d. Batteries, due to self-discharge, are advantaged below a storage duration of 13 hr. Over 13 hr, H_2 technologies are increasingly favored.[9]

Cycling limitations. The rate of HES cycling is constrained by the rate at which H_2 inventory can be replaced (e.g., charging), the variable cost of generation equipment maintenance affected by starts and stops, and the ramping characteristics of the generation technology.

Ramping characteristics vary with electrolysis technology and standby condition. PEM electrolyzers can reach full power in 1 sec ("hot standby") to 5 min (from off condition). Other electrolysis technologies, which operate at higher temperatures and pressures, can take up to 30 min to reach full power.

TABLE 2. Seasonal operating scenario

Injection/generation periods	Days	Hr/d	20.8 MWe[a]	47.3 MWe	236.5 MWe
Spring injection	92	24	2,156 hr	2,208 hr 55,862 MWhr	2,208 hr 248,842 MWhr
Summer dispatch Power generation Injection 	 122 122 	 4.5 14 5.5	501 hr 10,410 MWhr Standby	550 hr 23,523 MWhr 1,708 hr 43,212 MWhr Standby	550 hr 101,601 MWhr 1,708 hr 192,491 MWhr Standby
Fall injection	61	24	1,540 hr	1,464 hr 37,039 MWhr	1,464 hr 164,992 MWhr
Winter dispatch Power generation Injection	 90 90	 4 20	390 hr 8,112 MWhr	360 hr 18,330 MWhr 1,800 hr 45,540 MWh	360 hr 79,100 MWhr 1,800 hr 202,860 MWh
Ratio of charging to dispatch			4.15	7.9	7.9
Total energy shifted (generated)/yr			18,522 MWh	41,854 MWh	180,772 MWh
Total energy consumed (load)/yr			85,008 MWhr	181,653 MWh	809,185 MWh
H_2 storage capacity (Bft^3 at 60°F – 1 atm)			65,000 kg H_2 (0.027 Bft^3)	2,408,000 kg H_2 (1 Bft^3)	9,632,000 kg H_2 (4 Bft^3)
Round trip (charge/discharge) efficiency[b]			21.8%	23%	22.3%

[a] Variance in charging and discharging due to use of standard containerized equipment packages vs. field-erected facilities for smaller sizes
[b] Assumes simple-cycle gas turbine; combined-cycle and use of larger units would increase efficiency by 5%–32%

TABLE 3. Range of round-trip efficiency for varying configurations

Performance	PEM electrolyzer, %	Storage, %	Generator, %	Round trip, %	Generation technology
Low	48.5	97.5	24.1	11	Radial turbine
Average	75	98.2	29.5	22	Simple-cycle E-class
High	75	99	37.8	28	SC aeroderivative
High	75	99.8	51.5	39	Combined-cycle F-class
Maximum	82	100	57.7	47	CC H-/J-class
			Fuel cell		
Low	60	97.5	40	23	PEM fuel cell
Average	70	98.2	45	31	PEM fuel cell
High	75	99	60	45	PEM fuel cell
Maximum	90	99.8	80	72	PEM fuel cell
			With waste heat recovery (CHP)		
Low	60	97.5	55	32	Radial turbine CCGT
Average	75	98.2	65	48	Turbine gas engine
High	80	99	70	55	Fuel cell
Maximum	90	99.8	90	81	Fuel cell
			Notes		
Electrolyzer	Low (60%) = Maximum de-rated average, per vendors				
	Average (75%) = Typical, as per Blanco and Faaij, 2018)				
	High (75%) = Maximum reported by vendors without heat recovery				
	Maximum (82%) = Maximum without heat recovery				
Storage (depth dependent)	Low = 2.5% round-trip fuel				
	Average = 1.8% round-trip fuel				
	High = 1% round-trip fuel				
	Maximum = Electrical compression with solar + battery				
Fuel cells	Low (60%) = Lowest PEM fuel cell efficiency				
	Average (70%) = Median of PEM fuel cell range				
	High (75%) = Highest reported from vendors				
	Maximum = High plus 20% heat recovery (maximum reported by vendor)				

Discharge limitations. Discharge cycling is constrained by the selection of generation equipment and desired ramp time (ramp time equals time from cold start to full power). Fuel cells ramp up and down very quickly (sec to min, depending on standby conditions) without meaningful degradation of performance.

Combustion technologies are more mature and available at scale; however, they have longer duty cycles than fuel cells. H_2 has less energy content than methane, so it can do less work instantaneously. A cold turbine firing on 100% H_2 has a longer ramping time than a comparable natural gas unit. This can be mitigated by co-firing with natural gas during startup, but doing so results in carbon emissions.

Combustion engine and turbine duty cycles encompass four gross time periods:

1. Ramp-up time
2. Minimum runtime (time between generator breaker close and reopen)
3. Ramp-down time
4. Minimum downtime (time the generator must be offline before restarting).

As an example, a gas engine with a startup ramp-up of 30 min, a minimum run time of 60 min, a ramp-down of 30 min, and 120 min of minimum downtime would have a minimum duty cycle of 240 min (4 hr), and would be limited to a maximum of six starts per day.

For combustion technologies, the cost of operating and maintenance due to frequent starts and stops is also a consideration.

Degradation and variances in capacity. Charge and discharge capacities of HES may vary due to transient weather conditions, progressive wear and tear, and discharge loading.

De-rating for ambient weather. There is no derating of the electrolysis or a fuel cell facility for elevation, or within ambient temperature of 5°C–45°C (41°F–113°F), and relative humidity of 0% to 95% (non-condensing).

Due to changes in air density with temperature and humid-

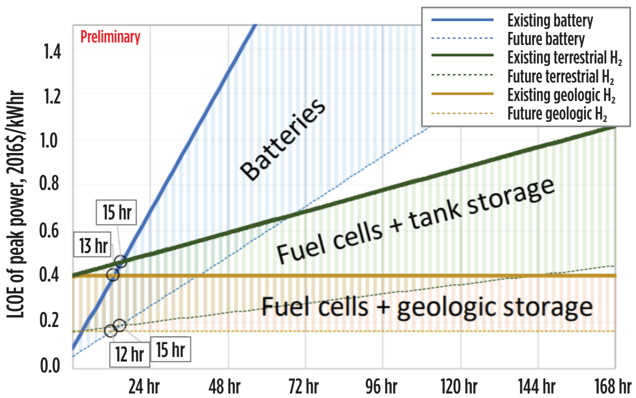

FIG. 9. Preliminary comparison of the LCOE for peak power for battery and H_2 energy storage systems.[9]

ity, combustion generation output varies with weather conditions. **TABLE 4** shows the variance in output across a range of peak summer temperatures in a location in the western U.S. for a 50-MW gas turbine running a simple cycle with 80% H_2 and 20% natural gas fuel.

Degradation to due wear and tear. Both the charging/electrolysis and discharge/combustion or fuel cell technologies degrade with run hours. The degradation rate for PEM electrolysis is (+/–) 2.3 μV/hr, but varies by specific technology and vendor. This is equivalent to a performance degradation of 0.1%–0.15% per 1,000 hr and, depending on the vendor, results in a projected operating life of 60,000 hr–80,000 hr (at 90% or higher nominal efficiency) before stack replacement.

The primary cause of degradation is trace calcium and magnesium fouling the membrane. Degradation can be partially mitigated by ensuring the quality of the demineralized water and selective scheduled replacement of the stacks—the generating modules that make up an electrolyzer—during annual maintenance. H_2 fuel cells exhibit similar degradation with use. The output of combustion technologies also degrades with use. **TABLE 5** shows the heat rate degradation by operating period for the combustion turbine in **TABLE 4** across a major maintenance cycle.

Part 2. The second part of this article, to be published in the Q4 issue, will examine the environmental impacts and sustainability of H_2 storage, as well as opportunities for process and facility integration.

TABLE 4. Variance in output and heat rate with ambient temperature

	Ambient temperature		
Specification	120°F/48.9°C	105°F/40.6°C	85°F/29.4°C
Turbine output, kW	47,129	49,013	50,798
Parasitic loads, kW	–792	–803	–812
Net power output, kW	46,337	48.210	49,986
Turbine heat rate, kW	10,265	10,159	10,080

TABLE 5. Degradation of output with use during one major maintenance cycle

Period start, hr	Period end, hr	Degradation, %	Heat rate, Btu/kWh
0	1,000	0%	10,310
1,000	8,000	1.5%	10,465
8,000	16,000	2%	10,516
16,000	24,000	2.5%	10,568
24,000	32,000	1.5%	10,465
32,000	40,000	2%	10,516

NOTE

This paper was first presented at *H_2Tech's* H2Tech Solutions virtual conference on May 19, 2021.

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SAFETY AND SUSTAINABILITY

Key safety considerations for the rollout of H_2 infrastructure

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The international hydrogen economy is set to boom in the next few years with Europe emerging as the clear leader in investment and policy support for the sector. Despite the COVID-19 pandemic heavily impacting economies, 2020 saw six European countries, as well as the European Commission, release H_2 strategies as part of a green recovery plan.[1] Annual global investments are expected to exceed $1 B by 2023, with spending increasing rapidly after that year. With lofty goals of 55% decarbonization by 2030 and net-zero carbon emissions by 2050, five key European countries (France, Germany, Italy, Portugal and Spain) are predicted to invest more than $44 B in blue and green H_2 projects.

In the U.S., major oil companies, automakers, H_2 producers and fuel cell manufacturers are pushing policymakers to follow Europe's lead in making a major commitment to H_2 infrastructure. In a recent report by McKinsey & Co., "Roadmap to a U.S. hydrogen economy," forecasts show that H_2 for low-carbon sources could supply approximately 14% of the country's energy needs by 2050.[2] The report goes on to state that the U.S. already has an H_2 industry valued at about $17.6 B. Reaching the outlined targets could result in $140 B/yr in revenue by 2030 and $750 B/yr by 2050.

The factors driving this rapid acceleration are the decreasing costs of H_2 production technology and transportation, and increases in public and government support. To date, government incentives and investments have been instrumental in assisting with the advancement of H_2 fueling technology and infrastructure. However, research suggests that state aid to co-fund the H_2 network is not enough to drive the buildout of the technology, meaning that costs will need to shift to private industry and public investment. Industry has reported challenges with small stations remaining profitable due to the large capital and operating costs, as well as the limited opportunity to generate income through fuel sales.[3] To grow public adoption of H_2 technology, education on the safety aspects of H_2 and successful mitigation of the risks associated with the technology are of utmost importance.

One aspect of H_2 that is under-appreciated outside of the industry is that the technology is well established, which sometimes is not thoroughly understood with increasing interest in new applications of H_2 technologies. H_2 has been an industrial gas for a long time, and the production, transport and storage logistics are well established. However, for H_2 to be used widely as a consumer product, the existing infrastructure must be modified and expanded.[1] With falling costs and a push for clean energy, new companies are entering the H_2 value chain. These rapidly evolving companies, unlike traditional producers and sellers, may not fully appreciate the unique safety challenges posed by H_2.

Recent H_2 incidents. As stated previously, it is essential that safety remains an integral part of the aggressive rollout of H_2 technology and infrastructure. H_2 has unique characteristics and must be handled differently than traditional fuels. Integrating a rigorous approach to risk management early in the process may prevent incidents from happening that disrupt networks, slow the acceptance of H_2, or derail the industry indefinitely. The following H_2 incidents occurred within a month of one another, each with an important lesson to be learned:[4]

- Limitations of H_2 vehicle fueling infrastructure were demonstrated by the network impacts following the Santa Clara, California explosion
- Poor public perception of H_2 safety was evident in protests following the explosion in Gangneung, Korea
- Lack of confidence in technology caused multiple station closures across Europe following the station explosion in Baerum, Norway.

Santa Clara, California. On June 1, 2019, an H_2 explosion occurred at the Air Products chemical, gas storage and transportation facility in Santa Clara. In this incident, an H_2 tanker truck was being filled when a leak occurred. During the shutdown of the H_2 transfer to the tanker truck, an explosion occurred that damaged the emergency shutoff panel and valve near the tanker. While two valves were shut off, the valve closest to the tanker truck could not be closed, and the fire continued to burn for nearly 2 hr. This fire, which was not visible to the human eye, resulted in the shutdown of the Air Products facility through September 2019.

As the only provider of H_2 for H_2 fueling in the Bay Area region, the shutdown of the Air Products facility resulted in a disruption to the distribution network that lasted for months. While a small supply was available from southern California, the limited availability of fuel was not enough to meet demand. By the time the facility reopened in September 2019, left with no reasonable choice but to abandon their vehicles until fuel supplies returned, many local FCEV owners traded in their cars for low-carbon options such as electric vehicles and hybrids.

Gangneung, Korea. In May 2019, an H_2 tank explosion destroyed a complex half the size of a soccer field, killing two people and injuring six more at Gangwon Technopark. Preliminary investigations suggest that the explosion resulted from a spark after oxygen found its way into the tank. This event hampered South Korea's goal of 1 MM-plus FCEVs on the road when resident groups began protesting stations both planned and under construction around the country (**FIG. 1**).

South Korea was significantly behind the goal of 114 stations by the end of 2019, with only 29 built. The country has a lot of ground to make up to hit the 310 stations targeted by 2022. Further slowdowns from public protests and a refusal to incorporate H_2 technology into existing stations by station owners have been recognized as a show of resistance due to safety concerns.

Baerum, Norway. An Uno-X fueling station experienced an explosion event on June 10, 2019, due to a leak from an improperly installed plug on a high-pressure storage tank. The explosion resulted in two airbag-related injuries from a nearby car and a subsequent fire that burned for approximately 3 hr. Not only did this incident result in a distribution network interruption in Norway, but also the closure of 10 similar stations throughout the Uno-X distribution network. The public, which did not understand or trust the technology, were reluctant to accept the similar stations as safe until an inspection and integrity testing scheme was completed. Knock-on effects continued with Toyota and Hyundai both halting sales of FCEVs in Norway, virtually eliminating the market since they were the only two vehicle providers in the country.

How do regulators and owner-operators cultivate public support and adoption? Looking to other alternative fuel safety regulations may provide a framework for proactively addressing safety and network concerns, rather than reactively addressing public concerns and implementing lessons learned. If a reactive approach is taken (which is common practice for regulatory agencies), H_2 technology may hit a significant roadblock in the future.

H_2 fueling safety concerns. It is essential that in the accelerated buildout of H_2 infrastructure, the focus on safety is not left behind. An area where this is of particular importance is for planned H_2 vehicle fueling stations, which if added to existing diesel/gasoline stations, could be near busy intersections or in close proximity to other businesses. However, stations sited based on safe distances for gasoline/diesel may not be safe for alternative fuel infrastructure due to the differences in safety characteristics of the fuel sources requiring larger safety margins.

The key to H_2 safety is to be aware of all hazards related to the handling and use of the material. Due to historical incidents such as the Hindenburg disaster (**FIG. 2**) and the public's perception of H_2 bombs (**FIG. 3**), it is a commonly held belief that H_2 is much more dangerous than gasoline/diesel or natural gas. While the worst-case consequences of H_2 may be more severe than those of traditional fuels, with a proactive approach to design, infrastructure and safeguards using information learned from incidents and testing programs, H_2 can be utilized as fuel at an acceptable level of risk.

H_2 safety concerns are simply different from other fuel sources. The primary H_2 hazard is the production of a flammable or explosive mixture in air. H_2 has a low minimum energy for ignition (0.02 mJ), meaning that it is easily ignited. H_2-air mixtures have nearly an order of magnitude lower ignition energy and a wider flammability range than methane-air mixtures, while the MIE for gasoline and diesel vapors in air are higher than methane-air mixtures. Therefore, major emphasis must be placed on containment, leak detection and ventilation of areas where H_2 can accumulate. In chemical processing facilities, safety measures such as elimination of likely sources of ignition, frequent inspection and maintenance, and formal operator training can significantly improve safety. Despite these best practices, leaks, fires and explosions still occur. This inevitability becomes increasingly problematic for H_2 vehicle fueling due to the involvement of the public as the primary "operators."

Lessons learned from existing fueling regulations.

While H_2 fueling is "new" technology, vehicle fueling is not. The most common vehicle fuels are gasoline and diesel, both of which are readily accepted materials for internal combustion engines (ICEs). Individuals do not question driving to the nearest fueling station and "filling up" with a material that is flammable and capable of forming explosive mixtures in air. We should take a step back to remember that there are inherent risks associated with gasoline and diesel fueling operations, as demonstrated throughout history. As incidents occurred, governments began instituting regulatory requirements such as the Environmental Protection Agency (EPA) Fuel Handling and Storage Regulations in the U.S., and the Petroleum (Consolidation) Regulations and Dangerous Substances and Explosive Atmosphere Regulations in the UK. Even with these regulations, material releases do occur and accidents do happen (**FIG. 4**).

With respect to H_2 fueling, one can look to the propane fueling market for lessons learned. In Canada, automotive propane is the most popular alternative fuel. Demand for automotive propane increased dramatically in the 1980s due to the government's introduction of CA-400 in 1981 to encourage conversion of vehicles to propane fuel. The automotive propane fueling infrastructure naturally followed the bulk storage and loading infrastructure for traditional propane markets.

FIG. 1. South Korea protests against H_2 fuel cell technology.[5]

FIG. 2. The 1937 Hindenburg Disaster.[6]

FIG. 3. The 1946–1958 Marshall Islands testing.[7]

On August 10, 2008, a boiling liquid expanding vapor explosion (BLEVE) at the Sunrise Propane facility rocked Toronto. This explosion was the result of the illegal practice of swapping propane loads between trucks, which was faster than unloading to and loading from storage tanks. The event forced 12,000 residents to evacuate and resulted in two deaths and dozens of injuries. Houses and businesses near the blast site were destroyed, and the total cleanup bill was approximately C$1.8 MM, with an additional multimillion-dollar class-action lawsuit settlement.[9] The Sunrise Propane event caused a significant reaction from regulators and the public, ultimately resulting in new regulations (**FIG. 5**).

The Technical Standards and Safety Authority (TSSA) for the Ontario Province responded to the incident with Ontario Regulation 211/01: Propane Storage and Handling, which requires propane facilities to have risk and safety management plans (RSMPs) in place to ensure public safety.[11] The Propane RSMP requires strict risk criteria to be met for offsite impacts as part of a detailed site risk assessment. Unfortunately, because this standard was reactive instead of proactive, it meant that a portion of the propane autofilling infrastructure was not compliant and either had to be taken out of the network (shut down) or brought into compliance, with heavy investment, to make stations safety compliant.

FIG. 4. Petrol station fire in St. Louis.[8]

FIG. 5. Sunrise Propane BLEVE.[10]

Practices for assessing risk. Regardless of location, safety requirements tend to incorporate one or more of the following approaches to siting: spacing distances, HAZOP/LOPA and/or select detailed modeling. With regard to spacing distances, a number of international standards exist for various parts of the H_2 technology process. These standards are often supplemented by local regulatory requirements for minimum design spacing for facility layouts. The problem with spacing distances is that they are not site specific and tend to focus on minimizing equipment damage and business interruption due to small, more likely accidental releases, and they fail to address more severe accidents that could occur with impacts to nearby populations.

Countries with specific regulatory and permitting requirements tend to also require a qualitative hazard review process, such as a hazard and operability study (HAZOP) or layers of protection analysis (LOPA). Using these methodologies to apply order of magnitude consequences and frequency to hazardous events can be challenging with emerging technology in potentially densely populated areas, such as H_2 fueling stations. This often involves defining one or more "maximum credible events" (MCEs) and has the unintended consequence of missing low-frequency, catastrophic events as well as high-frequency, low-impact events. As a result, safeguards are identified and selected based on MCEs rather than a thorough range of potential events and the associated risk profile. This is especially troubling for a technology with a lack of historical data on the likelihood of human errors associated with filling activities—a traditionally applied HAZOP/LOPA methodology may struggle to account for these risks in a meaningful way.

In rare instances, detailed modeling is conducted to quantitatively address the hazard and/or risk impacts of a facility. Many of the up-and-coming fueling station owner-operators are utilizing free, open-source software codes with inherent simplifications to conduct risk assessments. While these may be good for a quick answer in some situations, companies should be wary of using any code that they do not fully understand when making important safety and infrastructure decisions. A good rule of thumb is that if it is not readily apparent what calculations are being done and what the model limitations are, then expensive and life-impacting decisions should not be based on those answers.

Key takeaways for safe rollout of H_2 infrastructure. To date, the availability of publicly accepted and mandated hazard and risk criteria is limited; therefore, risk assessments are compared to company guidelines or applicable best practices rather than reviewed critically against a given standard. Due to the unique properties of H_2 with respect to ignition and explosion characteristics, care must be shown when undertaking detailed hazard and risk modeling to ensure that results are representative of current knowledge and technology. Be wary of falling into the trap of using readily available tools without understanding their basis and limitations. Pitfalls to watch out for include:

- Spacing distances that consider only small hole sizes or are focused on fire events and are generally intended to limit property damage or minimize the likelihood of fire propagation
- Qualitative, experience-based reviews have inherent bias and may lack sufficient knowledge when dealing with new technology and applications without verifying with quantitative analysis
- Assuming that safety shutdown or isolation systems ensure safe operations:
    - History has shown us that these systems have limitations and limited reliability
    - High-pressure H_2 releases form a dangerous flammable vapor cloud, or could lead to a jet fire with lethal impacts faster than the release could feasibly be detected and isolated
- Using models without understanding the basis and limitations of those models (i.e., lack of flexibility to model site-specific conditions, buildings and scenarios)
- Models that do not take into account the surroundings; if the results are the same regardless of the location and neighboring properties, then the answers may not reflect the actual environment and should be investigated further

- Failing to recognize that investing early in safety saves significant money and time over the lifetime of the project and operations.

Companies involved in the aggressive growth of H_2 fueling infrastructure should look to the propane fueling industry in Ontario, Canada as an important historical lesson. In this case, one large incident resulted in strict, risk-based regulations. The most cost-effective way to maintain sustainability over the long term is to ensure that risk management keeps pace with infrastructure rollout. This includes a risk-based approach for siting fueling stations by looking at impacts on facility users and nearby populations, as well as evaluating aggregate fueling risks on a yearly basis (i.e., fueling risks on a national level or broader applicable population).

Safe spacing distances and HAZOP/LOPA studies lack the ability to defensibly estimate potential consequences and do not tell an owner-operator about the risk exposure for surrounding areas. Furthermore, because H_2 poses more severe jet fire and vapor cloud explosion hazards than gasoline or diesel, assuming the safe siting of gasoline stations is adequate for a station that also handles high-pressure H_2 may lead down a dangerous and unsafe path.

Finally, it is recommended to look to traditional H_2 producers for guidance on safely operating H_2 installations. These long-term companies have learned over years of experience the rigor that should be used when properly managing H_2 risks. Companies that have produced and sold H_2 understand that H_2 can be handled safely, but it requires thoroughly examining risk exposure early and often. Those knowledgeable of H_2 hazards can help navigate the challenges of safely and aggressively pursuing H_2 infrastructure growth.

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How H_2 production technology will enable the transition to a green economy

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The promise of safe and reliable hydrogen generation and distribution can be both exciting and daunting. On one hand, H_2 is a sustainable answer to growing energy demands across the globe. On the other hand, clean H_2 production is still limited, mainly due to high costs and the need for more advanced technologies in the production chain. Looking to the future where H_2 is a stable and renewable fuel source, the first step will be developing and improving existing processes, tools and infrastructure to handle this challenging application. Only then will it be possible to embrace an H_2-fueled world.

H_2 is dispensed at extremely high pressures compared to other fuels. The main design criteria when creating instruments and equipment for H_2 fuel is to be able to withstand these incredibly high-pressure ratings. If existing infrastructure can be updated to accommodate these challenges, then the industry will be better equipped to safely produce, store, move and use H_2 in a cost-effective way. Investments in these technologies made today will be critical in shaping opportunities for a smooth transition to alternative fuels in the future.

Unique challenges of H_2. H_2 fuel is comparable to fossil fuels but three times as powerful and useful as gasoline. Internal combustion engines that use H_2 operate at higher efficiency levels, too—80% compared to 25% of most other combustion engines. Energy-efficient hybrid vehicles today could travel twice the distance on a full tank of fuel vs. a regular passenger vehicle. This begs the question: Why is H_2 not already being used as a primary fuel source?

H_2 must be kept compressed under high pressures to be useable as an efficient energy source. This makes transportation, storage and distribution especially difficult. Not only will the existing infrastructure need to be overhauled to accommodate it, but also dispensing compressed H_2 at the fuel pump can be a safety hazard if special equipment to withstand the high pressure is not used.

Refineries already use large amounts of H_2 as part of their hydrocarbon processing. For example, H_2 is necessary for the process of removing sulfur from crude oil. Refineries, therefore, have much experience producing H_2 from natural gas. From this experience, we know much about manufacturing what is known as blue H_2. These experiences have aided the development of sophisticated tools and technologies that can withstand these higher levels of pressure, like high-pressure Coriolis flowmeters and non-invasive, wireless monitoring solutions that will aid the journey to fully embracing H_2 fuel.

The path to zero emissions is paved with various colors in H_2 value chains (**FIG. 1**). Green H_2 is ideal, as it is created using renewable energy instead of fossil fuels. It will take some time to get to the point where green H_2 is the norm. In the meantime, adaptions to existing infrastructures with the technologies developed for the production of blue H_2, ready and available today, will bring that reality closer to being realized.

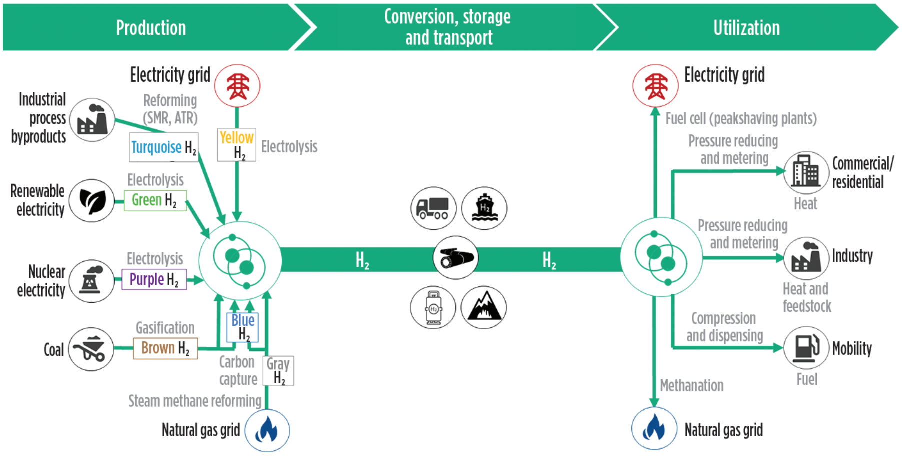


FIG. 1. A graphic overview of the H_2 value chain.

Generating H_2 from electrolysis. Sustainable H_2 production begins with electrolysis, a zero-emissions process using an electric current to split water into H_2 and oxygen. Electrolyzers are the systems that producers use to perform electrolysis to create H_2 on a large scale. Proton exchange membrane (PEM) electrolyzers are the frontrunner for industrialized electrolysis because implementation is simple, there is no corrosion factor and maintenance is more straightforward.

However, to be considered fully "green," the energy used to drive the electrolysis process must come from renewable sources. This requirement drives up the cost of PEM electrolysis and the costs of logistics when that energy source is not co-located with the H_2 generation itself.

Although these systems are in their early design stages, progress is being made to discover operational efficiencies and in scaling up for production-chain manufacturing. Further process improvements like increasing current density, improving water purification and enhancing safety and reliability are still necessary to drive down the expense of these operations and to maximize returns in these large-scale H_2 plants.

Digital twin technology has been instrumental in facilitating the advancement of this process in a safe and controlled environment. By creating a virtual replica of the production process, including all equipment, instrumentation and controls, this software enables operators to simulate the process in real time for training and optimization purposes. These software-based, risk-free environments are already helping manufacturers design and test improvements to H_2 electrolysis projects.

Blended streams: Natural gas and H_2. Another step forward lies in blending H_2 into natural gas streams. By injecting H_2 into natural gas networks, the amount of natural gas being used can be offset without losing any of its energy output. Early studies show that up to 30% of a natural gas stream can be blended with H_2 without significant modifications to downstream equipment at the point of combustion. It is one of the most promising opportunities for decarbonization for the natural gas industry. Still, it comes with a few key obstacles: corrosion from H_2 embrittlement, H_2 leaks through rubber parts due to the small dimensions of the molecule, and lower energy per volume delivered.

Cutting-edge, noninvasive corrosion monitoring systems can be deployed along pipelines to detect issues and alert operators before corrosion becomes a more significant problem. The latest corrosion detection tools help ensure pipeline integrity with sensing technologies designed with the specific needs of H_2 blended pipelines in mind. Wireless monitoring and autonomous capabilities will assist in identifying leaks remotely, enhancing safety and environmental protection.

Transmitter-style gas chromatographs will be valuable in these applications, as well. Utilizing advanced gas composition analysis, these field-mountable devices will continuously analyze the components of the blend to ensure that the correct ratio of H_2 to natural gas is being delivered.

The new H_2-fueled industry will significantly benefit from digital transformation, especially as IIoT-powered devices and practical, scalable digital solutions are on the market and ready to be deployed.

High-pressure H_2 dispensing applications. Proper flow measurement solutions will make a significant difference in H_2 fuel dispensing stations. As mentioned earlier, the high pressure of H_2 applications can create safety issues. When these dispensing applications are in the public domain, safety regulations are incredibly stringent—for good reason. Pumping H_2 fuel into a personal vehicle should not be a risky maneuver.

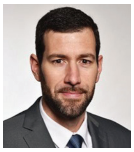
Forward-thinking flowmetering technology designed specifically for the 350-bar and 700-bar, high-pressure H_2 dispensing applications is the answer. High-pressure Coriolis flowmeters have already been tested in the most demanding oil and gas applications in the world, and are some of the safest and most accurate devices for high-pressure environments on the market. This technology has been used in the design of fit-for-purpose technology to tackle high-pressure H_2 fuel dispensing at the pump.

The demand for H_2 vehicles is growing. By 2040, the U.S. alone is expected to have around 10,000 H_2 fuel dispensing stations. The industry requires leading-edge measurement solutions that can handle changing pressures at high levels without compromising safety or accuracy. Fortunately, these instruments are available today. These compact Coriolis flowmeters provide a direct inline measurement of mass flow and temperature from a single device. Innovative additions to the design, such as rupture disks, keep operations and customers safe. Digital enhancements, like onboard diagnostics and continuous monitoring software, will help prevent unplanned shutdowns and under- or over-dispensing, saving producers money.

A digital ecosystem to accelerate adoption. Data analytics and software technologies will be crucial to making H_2 fuel more affordable and accessible. Producers benefit from computational power that helps them accurately predict dispensing levels to mitigate maintenance costs and better manage operational efficiencies.

Connected devices in a full-scale digital ecosystem are becoming the standard across the energy industry. Operators with integrated systems and state-of-the-art analytics, modeling and simulation tools have crucial insight into their processes, which drives better decision-making and leads to operational improvements. The new H_2-fueled industry will significantly benefit from digital transformation, especially as IIoT-powered devices and practical, scalable digital solutions are on the market and ready to be deployed.

Scalable approach to a renewable future. H_2 is poised to transform the energy infrastructure. Although the transition will not happen all at once, the tools and technologies are available today to take a scalable approach to embracing H_2 that will reduce risk during the transition to a more sustainable future. The challenge will be selecting the right tools and processes to generate early successes while remaining flexible enough to adapt as technology advances over time.



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CCUS measurement for low-carbon H_2 production

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The UK has committed to drastically reducing its emissions of carbon dioxide (CO_2) and other greenhouse gases and achieving net zero emissions by 2050. To meet this target, substantial changes to the ways in which energy is generated, stored, transported and consumed are required. One potential route to decarbonization involves the use of hydrogen (H_2) as an energy vector, to power low-emissions vehicles, for heating homes and buildings, and for industrial applications.

Decarbonization with H_2 and CCUS. The H_2 pathway, as it is described in the UK Government's Clean Growth Strategy, is attractive for several reasons. First and foremost, H_2 is clean-burning, producing only water as a byproduct, whether it is used in direct combustion or with fuel cells to generate electricity. It should be noted that H_2 itself is not a primary energy source (i.e., naturally occurring) and must be produced; however, it can be considered as a means of storing energy. For the overall process to be climate neutral, the H_2 must be produced with net zero emissions. This can be achieved in several ways, including the electrolysis of water, provided the electricity used is generated from clean sources such as solar or wind. The H_2 produced in this way is often referred to as "green" H_2.

It could be argued that using the renewable electricity directly would be more energy efficient, rather than producing green H_2, to subsequently convert it back into water. In many cases this is true, but it is important to consider that the supply of renewable electricity is generally intermittent. Solar and wind power are both subject to diurnal and annual fluctuations. At times, the supply will be insufficient to meet demand, and during periods of peak generation there can be an excess, leading to production being curtailed. Producing H_2 via electrolysis would provide an energy buffer for when demand cannot be met and could even act as a long-term storage mechanism for energy.

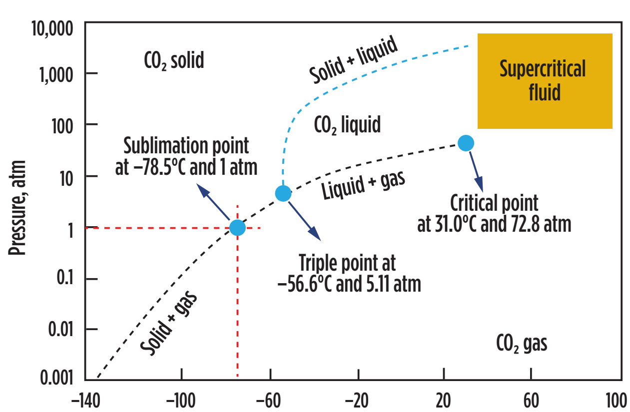


FIG. 1. CO_2 phase envelope.

In some processes, it may be preferable to use H_2 produced from renewable electricity rather than to use electricity directly. Electric battery vehicles are increasingly common and represent a major step toward the decarbonization of transport. This works well for light-duty vehicles, but the weight and charging times of lithium ion batteries are prohibitive for use with heavy-duty vehicles and long-distance transportation. H_2 has a gravimetric energy density of 140 MJ/kg, which is higher than natural gas (53.6 MJ/kg) and diesel (45.6 MJ/kg), and much higher than lithium ion batteries (< 5 MJ/kg). However, in volumetric terms, H_2 is the least-dense gas and takes up more space than both natural gas and diesel. When stored as a compressed gas, the volumetric energy density of H_2 (2.7 MJ/L at 350 bar or 4.7 MJ/L at 700 bar) is still greater than that of a lithium ion battery (2.2 MJ/L), making it a serious contender for use with larger vehicles, such as HGVs.

Similarly, for the decarbonization of domestic heating, one option is to use heat pumps and electric cooking appliances. However, the replacement of natural gas with H_2 in the gas grids is also being considered in many countries, including the UK. This could potentially minimize disruption to end users and allow the gas network infrastructure, and the cumulative skills and experience of its work force, to be repurposed. It would also negate the need to upgrade the UK electricity grid to accommodate the increased electricity generation required. The Clean Growth Strategy estimates that under the electricity pathway, 647 TWh/yr of electricity would need to be generated, a 93% increase compared to the 335 TWh generated in 2018. Under the H_2 pathway, the annual electricity requirement would be similar to today, at 339 TWh. The use of H_2 could also decarbonize industrial direct flame applications, which are essential to provide many chemical products but cannot be replaced with an electrical equivalent.

A strong case can be made for the use of green H_2 in the decarbonized energy supply of the future. However, at present, most H_2 is not produced from electrolysis but from a chemical process called reforming, typically either steam methane reforming (SMR) or autothermal reforming (ATR). In these processes, methane reacts with high-temperature steam in the presence of a catalyst and at elevated pressures. Syngas is produced, which is a mixture of H_2 and carbon monoxide (CO), before a water-gas shift reaction is used to convert the CO into CO_2 and more H_2.

In the final step, H_2 is separated from the CO_2 and other impurities by pressure swing adsorption (PSA), a process that exploits the differing tendencies of pressurized gases within a mixture to adsorb to solid surfaces.

Measurement challenges in CCUS. Since the feedstock includes a fossil fuel and the products include CO_2, this process is neither renewable nor carbon neutral. It is, however, a viable route to producing vast amounts of H_2, enabling the use of H_2 vehicles and appliances while the infrastructure to produce green H_2 at the scale required is developed. The key question then is how to deal with the CO_2 produced? Carbon capture, utilization and storage (CCUS) can be used to create a net-zero emissions process. The UK Government Clean Growth Strategy envisions that 700 TWh of energy could be produced from H_2 in 2050, with most H_2 produced from reforming, coupled with CCUS to keep the process carbon neutral. The H_2 produced from this route is known as "blue" H_2.

With CCUS, many potential measurement challenges are expected due to both the physical properties of CO_2 and the processes involved in CCUS projects. Crucial to the implementation of large-scale CCUS is the method by which it will be monetized, with numerous different approaches being considered, from taxation through to credit-based systems. Whichever mechanism prevails, monetization requires accurate knowledge of how much CO_2 has been sequestered, much the same as custody transfer metering in the oil and gas industry. For context, the UK Oil and Gas Authority requires measurement uncertainty of ±1% for fiscal metering of natural gas, while uncertainties of ±2.5% or less for the total mass of CO_2 measured are required under the EU Emissions Trading System (EU ETS).

In addition to the pecuniary aspects, the ability to accurately measure the flowrate of process streams at various points and reconcile this data to provide a holistic mass balance across the entire system will be important for two other reasons. The first is reservoir management, which will require knowledge of the amount of CO_2 and other process stream components fed into the geological formation. The second is safety; CO_2 is a heavy, asphyxiant gas that can readily pool upon leakage if conditions are correct, and so any breach of system integrity will need to be detected and located quickly.

CO_2 is unusual because of the closeness of its triple point and critical point to the temperatures and pressures commonly found in industrial processes. Compared to other substances that are transported by pipeline (e.g., oil, natural gas and water), the critical point of CO_2 lies close to ambient temperature. This means that even small changes in pressure and temperature may lead to rapid and substantial changes in the physical properties of CO_2 (e.g., phase, density, compressibility) (**FIG. 1**).

In CCUS applications, tightly regulating the temperature and pressure can be a difficult undertaking, particularly over long distances. Pipelines can span hundreds of miles and be subjected to various climates and conditions that affect operating pressure and temperature. When operating near a phase boundary line, there is a risk that the fluid will change phases, or even that multiphase flow conditions will arise. If this occurs at measure-

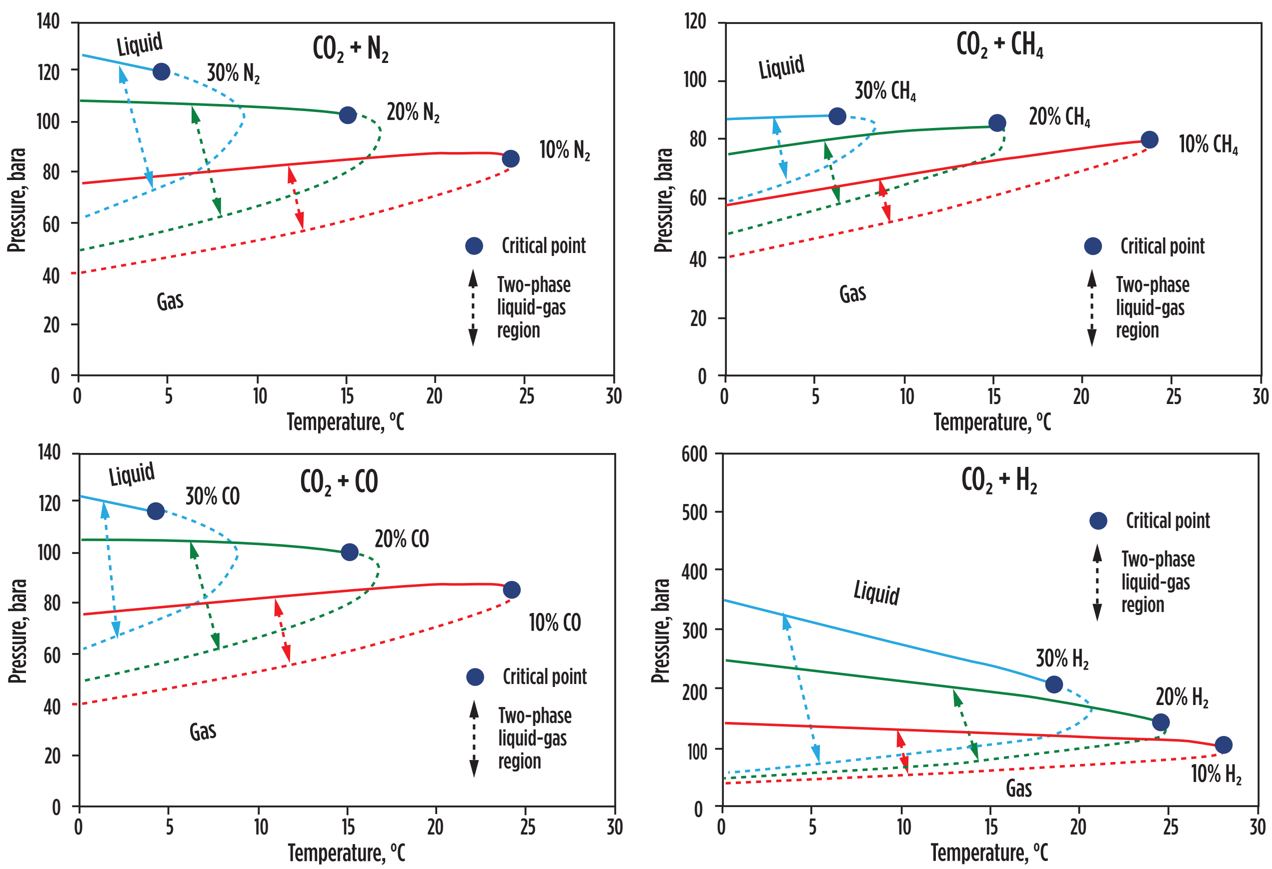


FIG. 2. Phase envelopes for CO_2 with impurities.

ment points, it will have a significant detrimental effect on measurement accuracy, where flowmeters are designed to operate in one specific phase.

Impurities in CO_2 streams. Another major challenge for measurement is coping with impurities in the CO_2 stream, which vary depending on the capture process, capture technology and fuel source used. Without knowing the exact phase envelope and physical properties of the CO_2 stream, it can be extremely difficult to control the CCUS processes and undertake accurate flow measurement (**FIG. 2**).

Three main measurements are essential to monitor CO_2 across the CCUS chain:

1. Composition measurement of the CO_2 mixture
2. Determination of physical properties
3. Flow measurement.

Sampling of the CO_2 stream is necessary to determine the CO_2 concentration and for the regulatory reporting of other non-CO_2 components in the stream. As the composition of the stream will vary continuously, sampling points are necessary at the capture plant and at various points throughout the transportation network where the composition can vary.

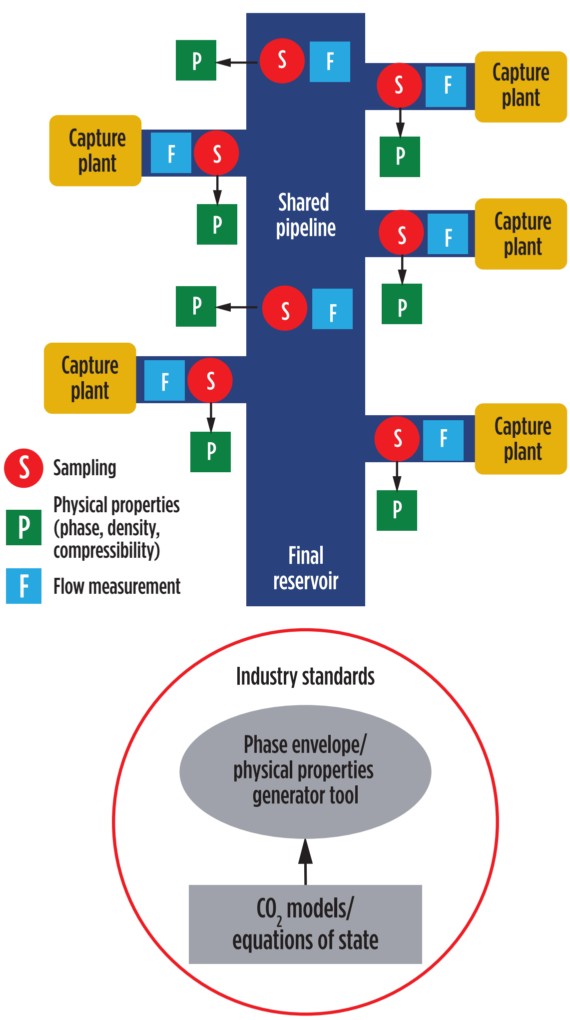


FIG. 3. An integrated measurement system in a shared pipeline.

Ensuring flow measurement certainty. After the composition of the stream has been measured, the physical properties can be calculated to provide the necessary data for handling and transporting the CO_2 throughout the different parts of the CCUS network and for flow measurement purposes. New equations of state and phase diagrams must be established to accommodate the many different CO_2 mixtures that are likely to arise in CCUS schemes.

Physical properties software modeling packages can be used to generate new data for the different CO_2 mixtures. However, wide variation in results can exist between different software packages and algorithms when used to model the same CO_2 mixture. It may be necessary, therefore, to establish validated industry standards and tools to minimize inconsistencies and ensure a uniform approach. This is particularly important in cases where different parties are sharing the same CCUS network (**FIG. 3**).

Flow measurement, in conjunction with the CO_2 concentration derived from the sampling of the CO_2 stream, is required to calculate the transfer of CO_2 on a mass basis across the CCUS chain. To meet the EU ETS required measurement uncertainty of ±2.5% for the total mass of CO_2 measured, it is essential to install the correct type of flowmeter at locations along the network where the flow conditions are stable, and in the specific phase under which the flowmeter is designed to operate. This may necessitate the use of gas meters at certain locations and liquid meters at other locations along the network.

To ensure and maintain a traceable measurement uncertainty for the purpose of regulatory reporting, flow measurement systems should be calibrated, maintained and inspected at regular intervals. Flowmeters should be calibrated at traceable laboratories, using CO_2 at the conditions and ranges under which they will be required to operate. Any secondary instruments used to convert into mass flow, such as pressure, temperature and density instruments, should be calibrated and traceable to national standards and located as close as possible to the flowmeter.

The ability to accurately measure the amount of CO_2 sequestered will be a fundamental foundation of large-scale CCUS, but this presents some interesting technical challenges that require an integrated approach to resolve, such as real-time determination of process stream composition, bulk flowrate and fluid properties. The essential technologies exist, but the challenges of integration and economic viability should not be underestimated.

TÜV SÜD National Engineering Laboratory operates a traceable H_2 calibration facility for domestic gas flowmeters, and a primary flow standard for validating H_2 refueling station dispensers is in development. In addition, capabilities developed for CCUS include gas flowmeter calibration with CO_2 and CO_2/N_2 mixtures at up to 1,000 m^3/hr at 25 bar, as well as a facility for testing densitometers, sampling systems and various sensors with CO_2 and CCUS mixtures in liquid, gaseous or supercritical states. As the energy transition progresses, it is essential that the UK's National Measurement System has the capability to support industry needs to meet the target of net zero emissions by 2050.

DALE ANDERSON is a Clean Fuels Engineer at TÜV SÜD National Engineering Laboratory (NEL), where his primary focus is understanding the flow measurement challenges for H_2, CO_2 and LNG. Since joining NEL, he has been involved in various projects related to the design and uncertainty assessment of physical testing facilities. Part of the TÜV SÜD Group, NEL is the UK's Designated Institute for Flow and Density Measurement.

A. BLUME, Editor-in-Chief

Inaugural H2Tech Solutions draws over 2,000 registrants with strong technical program

H2Tech's first H2Tech Solutions virtual conference, the must-attend event for sustainable H_2 technology, was held on 18–19 May 2021. H2Tech Solutions drew over 2,000 registrants from 82 countries and over 1,000 attendees during the live event, which was held from 10 a.m. UTC–4 p.m. UTC to serve as many time zones as possible.

The conference program featured three tracks with 40 high-level speakers, live Q&As with technical experts and business leaders, networking breaks and meeting tools to facilitate attendee interaction. Please visit www.H2-TechSolutions.com to register for the on-demand version of the 2021 conference, which is available online for one year post-event, and to view the full agenda.

Technical program highlights. H2Tech Solutions was conceived to bring together engineers, technologists and managers working to advance fuel, chemical and industrial applications for H_2. The technical program reflects this goal, with insightful presentations on topics including:

- Blue and green H_2 production
- H_2 mobility solutions
- Advances in electrolyzer technology
- Advances in H_2 compression
- H_2 storage solutions
- H_2 technology optimization
- Integration of low-carbon H_2 in infrastructure
- Regional H_2 buildouts
- Safety and sustainability.

Presenters hailed from leading operating and technology companies, industry associations, engineering firms, equipment manufacturers, solutions providers and consultancies. Additionally, most speakers were from the executive, director or group manager level, lending heavy expertise and authority to the technical program.

The Day 1 opening keynote was given by **DNV** Vice President and Head of Energy Transition, Graham Bennett, who spoke on the role of H_2 in the energy transition and the market outlook for key applications. On Day 2, the President of the **Fuel Cell & Hydrogen Energy Association** (FCHEA), Morry Markowitz, offered perspective on how to drive the growth of H_2 and fuel cells in the U.S.

H2Tech Solutions was supported by several generous sponsors, many of which also presented at the conference. CEO of **Nel Hydrogen,** Jon André Løkke, gave a keynote talk on Day 2 about scaling up green H_2 to help decarbonization efforts, and Senior Vice President of Nel Hydrogen's Electrolyzer Division, Filip Smeets, presented on the company's advances in electrolyzer technology. **Chart Industries'** Director of Hydrogen Sales for the Americas, Reid Larson, spoke about moving liquid H_2 from production to end use.

Also contributing to the technical program, **NextChem's** Fabio Brignoli, Business Development Specialist, informed attendees about the company's drop-in solution for green H_2 for renewable diesel production, while Michele Colozzi, Vice President of Carbon and Emission Reduction Technology, spoke about NextChem's Electric Blue Hydrogen for industry decarbonization. Simon Batt, Head of Performance Engineering and Analytics at **Siemens Energy,** presented on the company's complete power-to-X solution.

Haldor Topsoe's Technology Licensing Manager, Muhammad Ilyas, discussed the company's SynCOR ATR technology for high-capacity blue H_2 production, while **Cummins'** Global Business Development Leader for Electrolyzers, Denis Thomas, educated attendees about PEM electrolyzer solutions for very large power-to-X projects. Rounding out the sponsor presentations, **Howden's** Value Stream Director, Niek Albers, discussed advanced solutions for H_2 compression.

Industry support. Supporting organizations for H2Tech Solutions include Fuel Cells and Hydrogen Joint Undertaking (FCH JU), Gas Infrastructure Europe, GPA Europe, Dii Desert Energy/MENA Hydrogen Alliance, Fuel Cell & Hydrogen Energy Association (FCHEA), Green Hydrogen Coalition (GHC), and Renewable Hydrogen Alliance (RHA).

Gulf Energy Information and *H2Tech* extend sincere thanks to the industry organizations that lend their support to the H2Tech Solutions conference and to *H2Tech*.

Future H_2 conferences. *H2Tech* plans to host the second iteration of the H2Tech Solutions conference as a live event in 2022. More details on location, timing and program agenda will be made available in the coming months.

For questions about sponsorships and speaking opportunities for H2Tech Solutions 2022, please contact Melissa Smith, Events Director, Gulf Energy Information, at Melissa.Smith@GulfEnergyInfo.com. For questions about the H2Tech Solutions agenda, please contact Adrienne Blume, Editor-in-Chief, *H2Tech*, at Adrienne.Blume@H2-Tech.com.

First Element. Gulf Energy Information is also hosting the First Element conference from 7–9 September 2021. The first iteration of the conference will be offered as a virtual event, with plans for a live event in 2022. First Element will address the growing need for information on H_2 markets, policy and regulations, innovative technologies and trends.

With content developed by Gulf Energy's leading brands reaching an audience of 500,000 globally, the conference will offer three tracks over three days, with more than 75 high-level speakers. Confirmed keynotes include Andrew Marsh, CEO of Plug Power; Jon André Løkke, CEO of Nel Hydrogen; Jillian Evanko, President and CEO of Chart Industries; Caroline Hillegeer, Executive VP of Hydrogen Business at Engie; and others.

Please visit www.FirstElementConference.com to view a preliminary agenda and to register for the conference. For questions about the program or sponsorships for First Element, please contact Melissa Smith at Melissa.Smith@GulfEnergyInfo.com.

GLOBAL PROJECTS DATA

A. BLUME, Editor-in-Chief

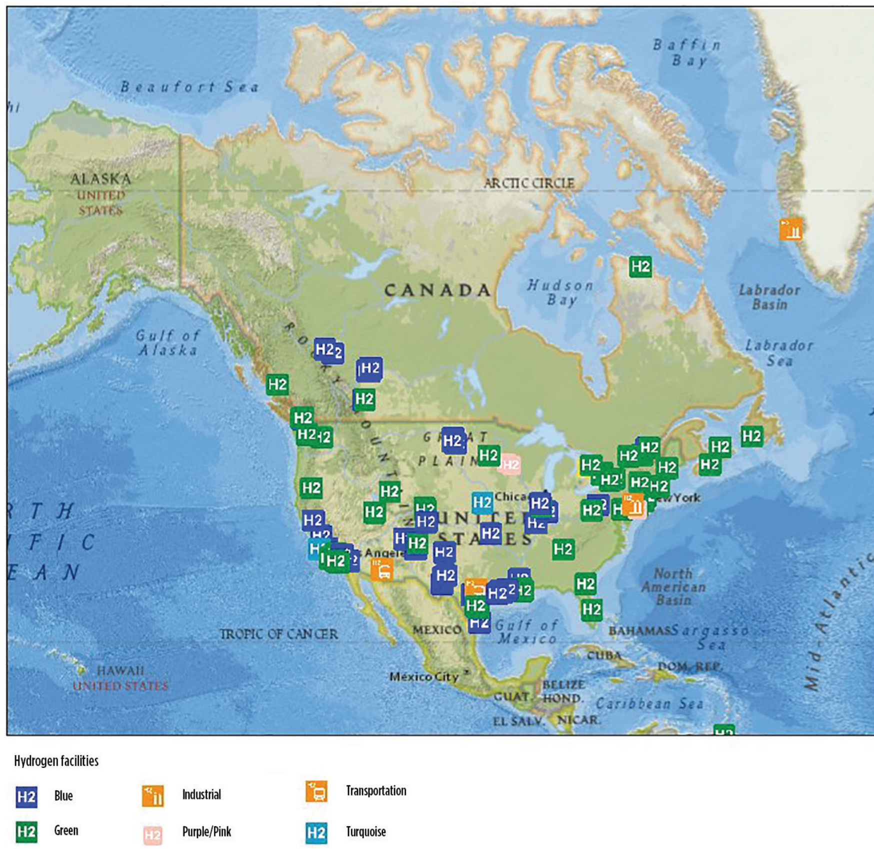
Gulf Energy Information's Global Energy Infrastructure (GEI) Database and Construction Boxscore Database are tracking 413 active and operating carbon-neutral and low-carbon H_2 production and utilization projects around the world.

Among green, blue, yellow, pink and turquoise H_2 production projects that will produce and/or use H_2 as a carbon-free, climate-friendly energy carrier, the vast majority—around 71%—are located in Europe; North America is in second, with around 20% of the project count. Breakdowns of active and operating project market share and project numbers by region and H_2 production type are shown below.

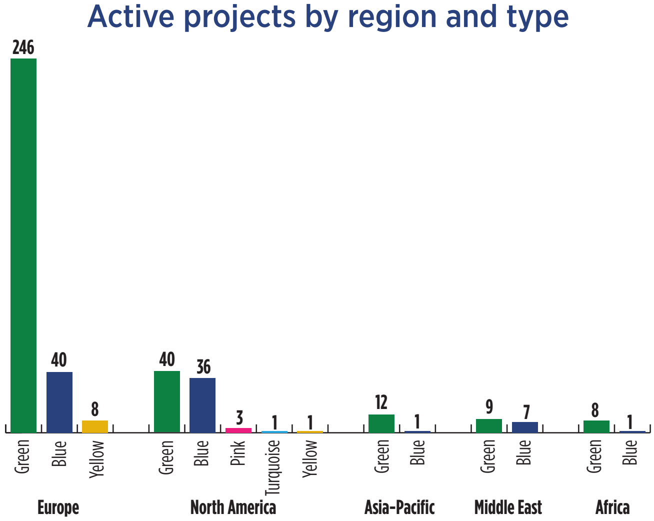
The map, provided by GEI's Energy Web Atlas, shows the distribution of active and operating H_2 projects of various types throughout North America. As shown on the map, green and blue H_2 projects are taking off in the U.S. and Canada for low-carbon chemical and industrial feedstock, energy storage, power generation and mobility applications.

Blue H_2 projects have significant momentum, especially in the U.S., as a lower-cost way of producing low-emissions H_2 for industrial and other needs in the transition to greener technologies. For more information on active low-carbon H_2 projects in North America, please see this issue's Regional Report.

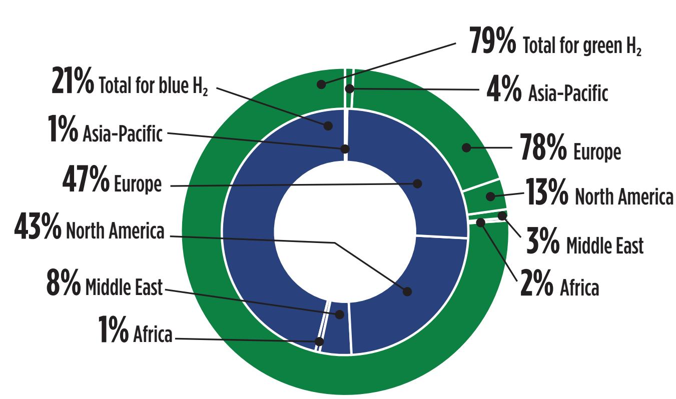
Active and operating H_2 projects in North America



Active projects by region and type



Active project market share by region, green and blue H_2



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HYDROGEN COLOR LEGEND BY *H2TECH*

Feedstock type	H_2 production type	Production technology	Power source/ feedstock	Emissions	Notes
Renewable	Green	Water electrolysis	Renewable electricity	None	Also referred to as clean H_2 or carbon-neutral H_2
	Pink	Water electrolysis	Nuclear power	None	
	Red	Biomass gasification	Forestry and agricultural crops and residues, animal residues, municipal solid waste	Low CO_2 emissions	Heat, steam and O_2 inputs are used to convert biomass to H_2 in a non-combustion process
	Olive	Algal or bacterial photosynthesis (via bioreactor)	Green microalgae or cyanobacteria provide enzymatic pathways; water and sunlight provide power	None	Holds promise for future large-scale, eco-friendly H_2 production
Renewable/ non-renewable	Yellow	Water electrolysis	Mixed-origin grid energy	Low CO_2 emissions	Electricity source can be a mix of renewable power and fossil fuels
Non-renewable	Blue	Methane reforming + CCUS* Gasification + CCUS	Natural gas Coal	Low CO_2 emissions	Also referred to as low-carbon H_2
	Turquoise	Methane pyrolysis	Natural gas	Solid carbon byproduct	
	Gray	Methane reforming	Natural gas	Medium CO_2 emissions	Accounts for 70% of present H_2 production
	Brown	Coal gasification	Lignite coal	High CO_2 emissions	Highly polluting
	Black	Coal gasification	Bituminous coal	High CO_2 emissions	
	White/ Clear	Generated by raising the temperature of oil reservoirs, or naturally occurring	Few viable exploitation strategies exist	Low/no CO_2 emissions	One technology injects O_2 into spent oilfields to generate H_2 and extract it using a downhole filter

*Carbon capture, utilization and storage (CCUS)

EVENTS CALENDAR

A. BLUME, Editor-in-Chief

The H_2 Events Calendar keeps readers updated on hydrogen sector and related industry events that are accessible by the industry public. These events may be virtual and/or live, and are hosted by industry associations and trade organizations, governmental organizations and companies.

Please visit the websites and contacts below for more information on these events, and please email Editors@H2-Tech.com to alert our editorial team of upcoming industry events.

SEPTEMBER

International Hydrogen Aviation Conference (IHAC 2021)
Sept. 2, DoubleTree by Hilton Strathclyde, Glasgow, Scotland
www.hy-hybrid.com/ihac-2021
E: info@hy-hybrid.com
P: +44 0-74-2431-2756

First Element
Sept. 7–9
Virtual Event
Gulf Energy Information Events
(See box for contact information)

ECC Annual PerspECCtives Conference
Sept. 8–11, Gaylord Texan Resort, Grapevine, Texas
www.ecc-conference.org
E: info@ecc-conference.org

RENMAD Hydrogen
Sept. 14–15, Virtual Event
www.atainsights.com/hydrogen
E: manuelbernaudo@ata.email
P: +34 634-409-084

Gastech Exhibition & Conference/Gastech Hydrogen
Sept. 21–23
Dubai World Trade Centre, Dubai UAE
www.gastechevent.com
E: info@dmgevents.com
P: +44 0-203-615-5916

f-cell Stuttgart
Sept. 14–15, Haus der Wirtschaft, Stuttgart, Germany
www.f-cell.de
E: natalie.vollbrecht@messe-sauber.de
P: +49 711-656-960-5708

2021 International Hydrogen Conference
Sept. 12–15
Jackson Lake Lodge, Moran, Wyoming
www.conferences.illinois.edu/hydrogen
E: mmarqua2@illinois.edu
P: +1 217-244-8174

Electric & Hybrid Marine World Expo Virtual Live
Sept. 13–15, Virtual Event
www.electricandhybridmarinevirtuallive.com
E: oliver.taylor@ukimediaevents.com
P: +44 1306-74-3744

Hydrogen+Fuel Cells International at SPI 2021
Sept. 20–23
Ernest N. Morial Convention Center, New Orleans, Louisiana and Virtual Event
www.solarpowerinternational.com/hydrogen
E: spi@xpressreg.net
P: 800-748-4736 / +1 508-743-8522

International Conference on Hydrogen Safety
Sept. 21–23, McEwan Hall, University of Edinburgh, Edinburgh, Scotland
www.ichs2021.com
E: ichs@hysafe.org

International Hydrogen & Fuel Cell Expo
Sept. 29–Oct. 1
Tokyo Big Sight, Tokyo, Japan
www.fcexpo.jp/en-gb.html
E: visitor-eng@wsew.reedexpo.co.jp
P: +81 3-3349-8576

OCTOBER

World Hydrogen Conference
Oct. 4–6
Amsterdam, the Netherlands
www.worldhydrogencongress.com
E: oliver.sawyer@greenpowerglobal.com
P: +44 20-7099-0600

ees Europe
Oct. 6–8
Messe München, Munich, Germany
www.ees-europe.com
E: krucker@conexio.expert
P: +49 723-158-598-186

Hydrogen Online Conference
Oct. 8–9
Virtual event (24 hr)
www.hydrogen-online-conference.com
E: silke.frank@mission-hydrogen.de
P: +49 71-95-904-3900

Connecting Green Hydrogen APAC
Oct. 11–13
Melbourne Convention and Exhibition Center, Melbourne, Australia
www.greenhydrogenevents.com
E: amy@leader-associates.com
P: +86 21-3417-3967

Hydrogen Middle East Summit
Oct. 12–14, Virtual Event
www.hydrogen-middle-east.com
E: MiddleEast@sustainableenergycouncil.com
P: +44 20-7978-0080

Gas Infrastructure Europe 2021 Annual Conference (GIE 2021)
Oct. 12–13, Lucerne, Switzerland and Virtual Event
www.gie.eu/index.php/events-diary/gie-annual-conference
E: gie@gie.eu
P: +32 2-209-0500

Hydrogen Technology Conference & Expo co-located with Carbon Capture Conference
Oct. 20–21, 2021
Messe Bremen, Bremen, Germany
www.hydrogen-worldexpo.com
E: info@trans-globalevents.com
P: +44 1483-330-018 / +1 404-737-8307

HyVolution
Oct. 27–28
Paris Event Center, Paris, France
www.hyvolution-event.com
E: pierre.buchou@gl-events.com
P: +33 47-817-6216

All-Energy Australia 2021
Oct. 27–28, Melbourne Convention & Exhibition Centre, Melbourne, Australia
www.all-energy.com.au/en-gb.html
E: info@all-energy.com.au
P: +61 2-9422-2955

NOVEMBER

UN Climate Change Conference (COP 26)
Nov. 1–12, Scottish Event Campus, Glasgow, Scotland, UK
Note: Open only to representatives of parties to the convention and observer states, representatives of observer organizations and the media
www.ukcop26.org
E: cop26media@cabinetoffice.gov.uk

AIChE Annual Meeting
Nov. 7–11
Hynes Convention Center, Boston, Massachusetts and Virtual
(See box for contact information)

HYdrogen POwer THeoretical & Engineering Solution International Symposium (HYPOTHESIS XVI)
Nov. 8–10
Sultan Qaboos University, Muscat, Oman
www.hypothesis.ws
E: ab.aljanabi@squ.edu.om

ADIPEC
Nov. 15–18
Abu Dhabi National Exhibition Center, Abu Dhabi, UAE
www.adipec.com
E: adipec.enquiry@dmgeventsme.com
P: +971 2-444-4909

CCSHFC 2021: Hydrogen and Fuel Cells—The Time Is Now
Nov. 16
National Exhibition Center, Birmingham, UK
www.climate-change-solutions.co.uk
E: jacqui.staunton@climate-change-solutions.co.uk
P: 07-86-655-2833

European Zero Emission Bus Conference
Nov. 17–18
Maison de la Chimie, Paris, France
zeroemissionbusconference.eu

AIChE's Center for Hydrogen Safety Asia-Pacific Conference
Nov. 30–Dec. 2
Virtual Event
www.aiche.confex.com/aiche/chsc2021/cfp.cgi
E: aiche@confex.com
P: 800-242-4363 / +1 203-702-7660

MARCH 2022

World Hydrogen Summit & Exhibition
March 8–10
World Trade Center, Rotterdam, the Netherlands
www.world-hydrogen-summit.com
E: CHugall@sustainableenergycouncil.com
P: +44 20-7978-0080

NOTE: Due to the COVID-19 pandemic, industry event dates are constantly changing, while others are being postponed or canceled. Please consult the appropriate association or organization to confirm event dates, locations and details.

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