Carbon Pricing in Wholesale Electricity Markets—Options for Fossil-Fuel Generators

Thomas N. Russo and Jack Gross

On October 15, 2020, the Federal Energy Regulatory Commission (FERC) announced in a proposed policy statement[1] that it had jurisdiction over carbon pricing mechanisms within the wholesale electricity markets. In that same policy statement, FERC also confirmed it had the authority to approve such rules if brought forward by regional transmission organizations (RTOs) and independent system operators (ISOs).

FERC's announcement ushers in a new era of wholesale electricity market regulation, particularly for fossil-fuel power generators using natural gas, coal, and biomass. These generating resources will no longer be able to rely on inexpensive fuels to remain competitive. Instead, they will have to navigate carbon pricing mechanisms for existing and future power plants if they are to remain competitive in wholesale electricity markets designed to decarbonize the electric power sector. As is the case with any new proposal from FERC, it will take time for RTOs and ISOs to develop carbon pricing proposals with their stakeholders and market participants. This gives companies time to discuss and develop strategies.

Because fossil-fuel power generators consist of regulated electric utilities, electric and gas utilities and independent power producers (IPPs), each of their approaches to dealing with carbon pricing will likely vary. Some companies might take a "business as usual" approach, including operating existing power plants until the end of their existing economic life, even if it's shortened by carbon pricing. Generation owners may also decide to do one or more of the following to address carbon pricing in wholesale electricity:

1. **Strategy 1—Embrace renewable energy generation and storage exclusively,** either by importing hydropower, wind and solar power from Canada and Mexico where feasible or building new hydropower, wind, solar and solar-battery hybrid projects. New pumped storage hydro (PSH) projects[2]

[1] FERC. (2020, October 15). FERC proposes policy statement on state-determined carbon pricing in wholesale markets. Retrieved from https://www.ferc.gov/media/ad20-14-000-0.

[2] Balaraman, K. (2020, October 13). To batteries and beyond: In a high-renewables world, pumped hydro storage could be 'the heavy artillery.' *Utility Dive*. Retrieved from https://www.utilitydive.com/news/to-batteries-and-beyond-in-a-high-renewables-world-pumped-hydro-storage-c/584958/.

Thomas N. Russo has over 30 years of experience in energy regulation, infrastructure, markets, environmental impact assessment, and energy security. Prior to starting Russo on Energy LLC, he worked for over 30 years as a manager and senior energy industry analyst at the Federal Energy Regulatory Commission. He also is an adjunct professor in the Elliott School of International Affairs at The George Washington University in Washington, DC, where he teaches courses in global energy and international energy and environmental regulations. **Jack Gross** is a senior studying at the George Washington University Elliott School of International Affairs, majoring in international affairs with a concentration in environmental studies. He is pursuing careers within the renewable energy industry and has experience working with nonprofits and government affairs.

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could replace retired fossil-fuel power plants, especially if they are closed-loop PSH[3] and don't impact a natural body of water. The Energy Information Administration (EIA) has also reported the cost of utility-scale battery storage has seen a recent decline of 70 percent, making the use of this technology more financially feasible.[4]

2. **Strategy 2—Embrace the new hydrogen economy** by blending H_2 and natural gas in existing and new gas-fired power-generating facilities.
3. **Strategy 3—Embrace a circular carbon economy** that emphasizes reducing, reusing, recycling and removing carbon dioxide and using the IRS 45G tax incentives for using carbon capture, use, and storage (CCUS) technologies at natural gas– and coal-fired power plants.

None of the above strategies need be mutually exclusive. In this article, the authors will discuss the pros and cons of each strategy and whether combustion turbine manufacturers and CCUS technologies can meet the future needs of electric power generators.

GENIE IS OUT OF THE BOTTLE

While FERC Chairman Neil Chatterjee encouraged efforts to develop market rules that incorporate a state-determined carbon price in wholesale electricity markets, he also clarified that FERC will not be proactively setting a carbon price mechanism in wholesale electricity markets. Instead, FERC will await proposals from RTOs and ISOs. FERC is not likely to rubber-stamp such carbon pricing proposals either. While carbon pricing will play a role in its decision on any proposal, FERC will still examine the proposal's effects on reliability, cost to customers and competition to ensure that proposed tariffs are "just and reasonable." However, FERC may give more weight to carbon pricing, subject to potential agency changes following the outcome of the 2020 presidential election. Finally, any final policy statement on carbon pricing might likely be challenged in the courts.

Carbon pricing in the United States is currently limited to California, Washington, and the Regional Greenhouse Gas Initiative (RGGI)[5] among 11 northeast and mid-Atlantic states to cap and reduce CO_2 emissions from the power sector (**Figure 1**). New Mexico and Oregon are considering cap-and-trade programs.[6] The authors expect that RTOs and ISOs within these regions will develop carbon pricing proposals and file them for FERC approval by early next year.

Many states view FERC's policy statement and decision as long overdue. The authors believe states that have established renewable portfolio standards[7] and/or economy-wide decarbonization goals[8] or targets of 50 percent or greater will pressure RTOs and ISOs to develop proposals for FERC approval quickly. In fact, the New York ISO stakeholders have already introduced such a proposal, and ISO New England and PJM have publicly stated that they would support such a program if the NYISO proposal is ultimately approved. State public utility commissions (PUCs) in non-ISO markets may also take a harder look

[3] Russo, T. N. (2019, August). Pumped storage hydro: Reliable choice for the new electric storage era. *Natural Gas & Electricity, 36*(2), 25–32. Retrieved from https://onlinelibrary.wiley.com/doi/full/10.1002/gas.22138.

[4] Energy Information Administration. (2020, October 23). *Utility-scale battery storage costs decreased nearly 70% between 2015 and 2018.* Washington, DC: Author. Retrieved from https://www.eia.gov/todayinenergy/detail.php?id=45596.

[5] The RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont, New Jersey, and Virginia to cap and reduce CO_2 emissions from the power sector.

[6] See https://priceoncarbon.org/business-society/state-actions/.

[7] Thirteen states—California, Hawaii, Maine, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Oregon, Vermont, and Washington—and the District of Columbia have adopted clean energy or renewable portfolio standards of 50% or greater. See C2ES, US State Electricity Portfolio Standards, https://www.c2es.org/document/renewable-and-alternate-energy-portfolio-standards/.

[8] Nineteen states—California, Colorado, Connecticut, Hawaii, Louisiana, Maine, Massachusetts, Michigan, Minnesota, Montana, Nevada, New Hampshire, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington—and the District of Columbia have adopted economy-wide decarbonization goals or targets of 50% or greater. See C2ES, US State Greenhouse Gas Emissions Targets, https://www.c2es.org/document/greenhouse-gas-emissions-targets/.

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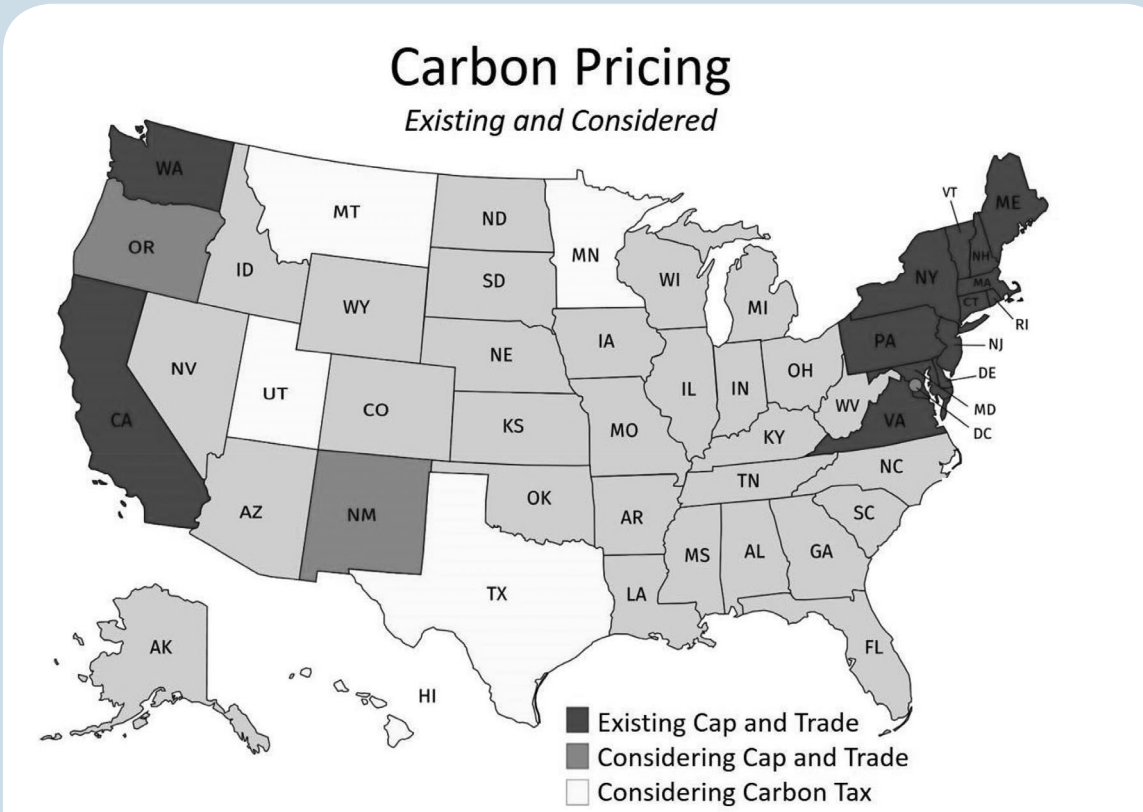
Figure 1. Grid Modernization Roadmap



Note: New Mexico is also considering a carbon tax. States which currently have cap and trade and are also considering carbon tax include: Connecticut, Maryland, New Hampshire, Massachusetts, New York, Rhode Island, and Vermont.

Source: Price on Carbon (see https://priceoncarbon.org/business-society/state-actions/).

at carbon pricing and begin a dialogue with regulated electric utilities as well.

STRATEGY 1—EMBRACE RENEWABLES

Embracing renewable generation and shifting to solar and wind might be the obvious choices to decarbonize a power generator's fleet. However, a hard look at the time it takes to build new electric transmission to import hydropower from Canada or Mexico or build solar and wind projects may make companies pause. The time required to permit and build purported "clean electric transmission" is roughly 14 years.[9] That's because many electric transmission projects as well as solar and wind projects trigger National Environmental Policy Act (NEPA) reviews because they are located on federal land or cross an international border. The states also duplicate these environmental reviews to comply with state environmental quality and protection statutes.

The President's Council on Environmental Quality's NEPA regulations went into effect September 14, 2020. Rather than expediting project reviews, the new NEPA regulations and changes to regulations governing Section 401 of the Clean Water Act are being challenged in the courts. Therefore, it's questionable whether the new NEPA regulations will expedite approval of large renewable energy projects, which may be controversial.

[9] NEPA Reform and Clean Energy.

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Large renewable energy projects that are located within a single state such as New York will undergo expedited reviews under the Climate Leadership Community Protection Act and Accelerated Renewable Energy Growth and Community Benefit Act. The legislation has created a new state Office of Renewable Energy Siting and promised to reach a decision on a large renewable energy project within six months to one year from the time the application is administratively found adequate. Nevertheless, some counties and municipalities in other states that prefer renewable energy have passed laws limiting the construction of wind and solar projects.[10]

STRATEGY 2—CIRCULAR HYDROGEN ECONOMY

In a two-part series, Russo indicated that using H_2 to decarbonize the natural gas sector was possible. However, actual success largely depends on increasing production of all forms of H_2, especially blue H_2 with CCUS and blending H_2 in the natural gas grid.[11] Both approaches involve incenting gray H_2 producers to take advantage of the IRS 45G tax incentive for CCUS and addressing potential safety and end-user challenges related to the blending of H_2 in the natural gas grid, respectively. The latter requires natural gas pipeline and gas distribution utilities obtaining regulatory approvals from state PUCs and the development of new tariffs for the sale of blended H_2 to retail customers.[12]

In this section, the authors focus on electric utilities, combined electric and gas utilities, and IPPs who own gas-fired combined-cycle power plants (gas CCT) and whether or not they could burn H_2 and become a part of the circular economy. On August 25, 2020, Russo on Energy LLC noted that gas CCT power generators may not wait for years for natural gas pipelines and distribution companies and state regulators to overcome these H_2 blending challenges.[13] Power generators have options and workarounds to decarbonize gas CCTs with H_2 that don't depend on the natural gas grid. Indeed, whether or not gas CCTs take advantage of these H_2 workarounds will depend on each company's ability to compete in the competitive wholesale electricity markets and actions taken by state PUCs in wholesale electricity markets.

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Electric utilities and IPPs are subject to a growing chorus from customers, state regulators, and investors who subscribe to achieving environmental, social, and governance (ESG) goals set by states. ESG investors are increasingly applying these nonfinancial factors as part of their analysis process to identify material risks and growth opportunities.

Many environmental stakeholders are advocating complete decarbonization by retiring natural gas combined-cycle (CC) power plants and replacing their capacity with wind and solar power projects. Electric ratepayers have a large stake in these electric utility decisions and so do state PUCs, as the costs of many gas CCs are included in the rate base for the economic life of the project. Hence, premature retirement would be costly to ratepayers and also reduce the reliability of the grid, especially when the need for capacity peaks during the evening ramp-up or during critical times during winters in the Midwest and Northeast and during heat waves such as California's recent rolling blackouts on August 14 and 15, briefly

[10] Russo, T. N. (2020, July). Hydrogen: Hype or a glide path to decarbonizing natural gas. *Natural Gas & Electricity, 36*(12), 15–21. Retrieved from https://onlinelibrary.wiley.com/doi/full/10.1002/gas.22180.

[11] Russo, T. N. (2020, August). Hydrogen: Hype or a glide path to decarbonizing natural gas—Part 2, *Climate & Energy, 37*(1), 24–32. Retrieved from https://onlinelibrary.wiley.com/doi/full/10.1002/gas.22187.

[12] Ibid.

[13] DiChristopher, T. (2020, August 26). Why gas utilities could get left behind in the hydrogen economy. *S&P Global Market Intelligence.* Retrieved from https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/why-gas-utilities-could-get-left-behind-in-the-hydrogen-economy-60092835.

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cutting off power to several hundred thousand households.

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STRATEGY 3—EMBRACING THE CIRCULAR CARBON ECONOMY

The circular carbon economy (CCE) is rooted in the idea of closing the loop with resource consumption represented by the four R's: reduce, reuse, recycle, and remove. The more that products are reused and recycled at the end of their life, the more energy is conserved, and in turn it emits less CO_2 emissions.

The King Abdullah Petroleum Studies and Research Center (KAPSARC) is particularly interested in promoting CCE and demonstrating its usefulness.[14] It has partnered with the International Energy Agency (IEA), International Renewable Energy Agency (IRENA), Nuclear Energy Agency, Organisation for Economic Co-operation and Development, and Global CCS Institute. On September 29, 2020, the G20's[15] energy ministers endorsed Saudi Arabia's CCE approach.[16] CCE, which focuses on the flow of CO_2 emissions through the economy, may be one of the best ways to reduce energy consumption and meet climate goals (**Figure 2**).

Rather than work to regulate the amount of hydrocarbons that is burned, the CCE regulates every aspect of the economy and seeks to control CO_2 emissions through the economy to reduce energy consumption and meet climate goals. Similar to the circular economy, the CCE is rooted in the 4 R's. By reducing, reusing, recycling, and removing CO_2, the circular carbon economy seeks to achieve global climate goals.

CCUS FACILITY INVESTMENTS LOSING MOMENTUM

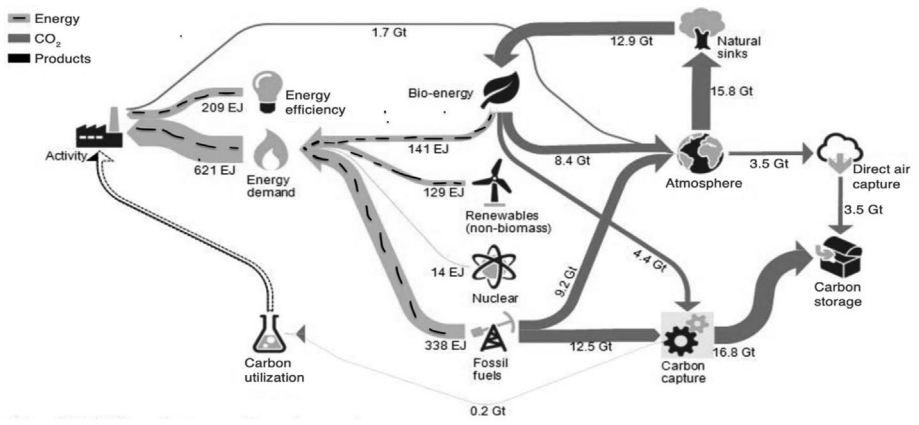
Much of the CCE is dependent on CCUS to remove CO_2 emissions to meet climate goals. Unfortunately, the number of new

[14] Williams, E. (2019, November 6). Achieving climate goals by closing the loop in a circular carbon economy. *Instant Insight*. Retrieved from https://www.kapsarc.org/research/publications/achieving-climate-goals-by-closing-the-loop-in-a-circular-carbon-economy/.

[15] The G20 is an international forum for the governments and central bank governors from 19 countries and the European Union.

[16] Kane, F. (2020, September 29). G20 backs Saudi Arabia's circular carbon economy strategy. *Arab News*. Retrieved from https://arab.news/65uje.

Figure 2. Circular Carbon Economy



Source: Modified from TERI 1.5D low carbon transportation policy scenario; International Energy Agency; KAPSARC analysis.

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CCUS projects has not grown to support the CCE's removal efforts despite widespread government support, tax incentives, and project announcements in a number of countries (**Figure 3**). Today, there are only 21 CCUS facilities worldwide with the capacity to capture up to 40 metric tons (Mt) of CO_2 each year. The nine facilities in the United States use CO_2 for enhanced oil recovery (EOR). Two-thirds of operating CCUS facilities rely on revenue from sales of CO_2 for EOR, and more than one-third of planned projects are linked to EOR.[17] One Texas facility, the Petra Nova coal-fired power generation plant, has temporarily suspended CO_2 capture operations in response to low oil prices. The price paid for CO_2 for EOR is typically indexed to the oil price in commercial contracts, so the recent slump in oil demand and prices will have substantially reduced revenues for CCUS facilities.

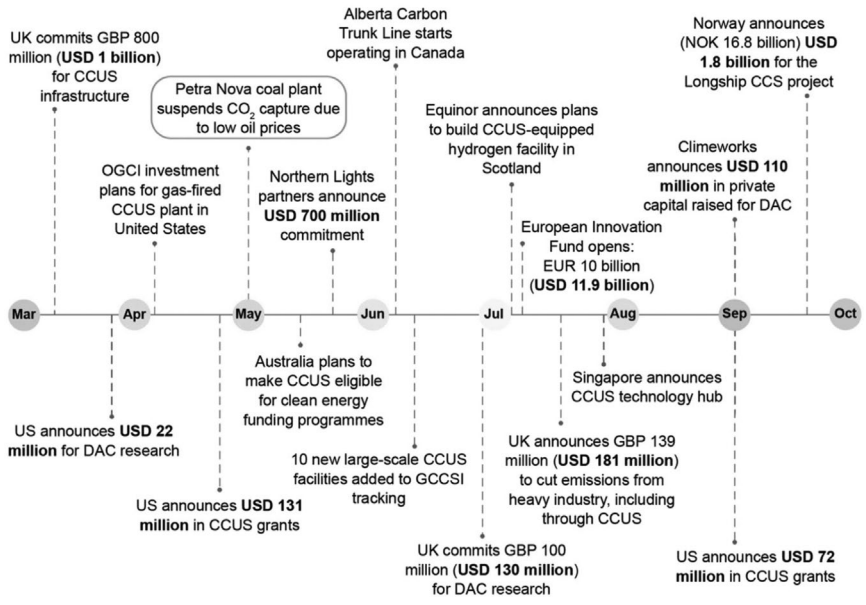
In the United States, the 45Q IRS regulations provide a tax credit of $35 per ton of CO_2 if it is used for EOR or converted into fuels, chemicals, or cement, and $50 per ton if the CO_2 is securely stored in geological formations. Low oil prices, a slump in profits in US shale oil, and the COVID-19 pandemic have delayed some announced CCUS projects. The project delays would also have a significant impact on their eligibility for 45G credits, as facilities must be in construction before January 1, 2024, to qualify under current arrangements. Projects unable to meet this deadline are far less likely to proceed.[18] Prior to the COVID-19 pandemic, the Department of Energy (DoE) estimated that the 45Q regulations would create between 4 and 6 million jobs.[19] The credit

[17] Global CCS Institute. (2020). Facilities database. Retrieved from https://co2re.co/FacilityData.

[18] International Energy Agency. (2020). *CCUS in clean energy transitions.* Paris, France: Author. Retrieved from https://www.iea.org/reports/ccus-in-clean-energy-transitions.

[19] US Department of Energy. (2019, October). *Internal Revenue Code tax fact sheet.* Washington, DC: Author. Retrieved from https://www.energy.gov/sites/prod/files/2019/10/f67/Internal%20Revenue%20Code%20Tax%20Fact%20Sheet.pdf.

Figure 3. Timeline of CCUS Developments, March–September 2020



Source: International Energy Agency. (2020). *CCUS in clean energy transitions.* Paris, France: Author. Retrieved from https://www.iea.org/reports/ccus-in-clean-energy-transitions.

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should also incentivize gray H_2 producers to implement CCUS to produce blue H_2.

FERC's announcement regarding carbon pricing will put pressure on electric utilities and IPPs regarding the continued use of natural gas and coal in their power generation fleets. If carbon pricing does gain traction in wholesale electricity markets, the ability of natural gas– and coal-fired power generators to remain competitive could be jeopardized in the energy, capacity, and ancillary markets. Carbon pricing could actually incentivize fossil-fuel generators to reconsider CCUS or H_2 to decarbonize their facilities.

ELECTRIC UTILITY SENTIMENT TOWARD H_2

S&P Global Market Intelligence's Tom DiChristopher characterized the comments by C-suite electric and gas utility executives on the use of H_2 as "cautious." Some executives, like NextEra's CEO, characterized the company's interest as a "toe-in-the-water approach." Other utilities expressed great interest, but similar to their approach in building utility-scale solar projects years ago. While there is growing interest in using H_2 to decarbonize gas CCTs, many are taking a cautious approach (**Table 1**).

Table 1. Summary of Comments From Corporate Officers of Selected Combined Electric and Gas Utilities Regarding Their Interest in Hydrogen as Power Fuel

Company	Project	Timeline	Commentary
NextEra Energy Partners	$65 million investment in Florida Power and Light 20-MW Green Hydrogen Electrolysis System for Okeechobee Clean Energy Center	Okeechobee Clean Energy Center Electrolyzer in service by 2023	"What makes us really excited about hydrogen, particularly in the 2030 and beyond time frame, is that that has the potential to supplement significant deployment of renewables."—Rebecca J. Kujawa
Sempra Energy	Eight to 10 unidentified projects that are being looked at	Noted as still a little early, perhaps in the second half of the coming decade	"Both utilities (San Diego Gas & Electric and SoCal Gas) are working on several exciting hydrogen projects that we will be announcing in the upcoming quarters."—Kevin Cristopher Sagara
Dominion Energy	Pilot project in Utah is in advanced planning stages	LDC system able to handle 5% hydrogen blending by 2030	"We've certainly spent a lot of time studying it. . . . But for the most part, it's still in that study and preparatory planning stage."—Diane G. Leopold
CenterPoint Energy	Natural Gas Distribution Green Hydrogen Electrolysis Project in the Twin Cities Metro area	Minnesota pilot project currently in design phase; plan to be built and online by 2021	"We are also really excited about a pilot program starting next year in Minnesota, which is expected to convert renewable energy to hydrogen that will then be blended with our natural gas supply."—David John Lesar
Southern Co.	Producing hydrogen with a nuclear plant	Working with hydrogen for seven years; all projects still in R&D	"So we've been working on hydrogen now for seven years, roughly."—Thomas A. Fanning
Fortis	Closed-loop system for industrial sites to offset natural gas use; looking into hydrogen blending across the system.	NA	"We are part of working teams with other natural gas utilities in the Canadian context, who are looking at both green and blue hydrogen."—Roger A. Dall'Antonia

Company	Commentary
National Grid	"We are exploring, working with the industry, a number of projects looking at the role that a gas transmission network could use—could be with hydrogen. So we're looking at options with 20% blending, 40%, and up to 100%, and what impact that will have on the network."—John Pettigrew
WEC Energy	"One of the things that we're looking at here relates to the potential use of hydrogen as a mix in our gas distribution lines. . . . We are a long, long way away, in my opinion, from anything being commercialized and readily available. A lot of potential and it could, I think, help all of our companies get to the 2050 carbon goals."—Gale E. Klappa
Eversource Energy	"We're evaluating the possible usage of hydrogen and various aspects of our business, again, whether it be an alternative for transportation or whether it be for some other component of introducing it to our gas distribution infrastructure."—Philip J. Lembo
UGI Corp	"If you look at electrolytic hydrogen, renewable hydrogen produced electrolytically with renewable power, driving that process is definitely of interest. . . . It's an opportunity for us to leverage our infrastructure, leverage our core assets and . . . the connection we have to all the end users we serve to incorporate what would be sort of an alternative or a supplement to our supply portfolio."—John Lawrence Walsh
DTE Energy	"Hydrogen can become a very interesting way to store renewable energy in our pipeline system and storage assets, as you can blend significant amounts of hydrogen into the natural gas stream. So that is something we're starting to think seriously about."—Gerardo Norcia

Source: Summary of US Utility Q2 2020 Hydrogen Commentary from *S&P Global Market Intelligence*.

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With the approval of state PUCs, the authors believe electric utilities will be prudent and use pilot projects to explore H_2 as a fuel that could decarbonize gas CCTs and other fossil-fuel power plants. Also, the level of conversations between state PUCs and electric utilities on H_2 blending and power-generating plants rendered uncompetitive in markets that include carbon pricing will increase. Given recent issues regarding grid operations in California, the need to decarbonize the grid will be tempered with discussions on reliability and system reserves to deal with perceived or actual higher frequency of climate-related events affecting RTOs and ISOs.

COMBUSTION TURBINE SUPPLIERS

Gas combustion turbine suppliers appear to recognize government policies that fight climate change. The ability to run existing and new combustion turbines on hydrogen blended with natural gas is a part of every supplier's business plans. Some suppliers like Siemens have specific goals to enable their gas combustion turbines to burn 100 percent H_2 by 2030, and many CTs currently burn 20 percent H_2 (**Figure 4**).

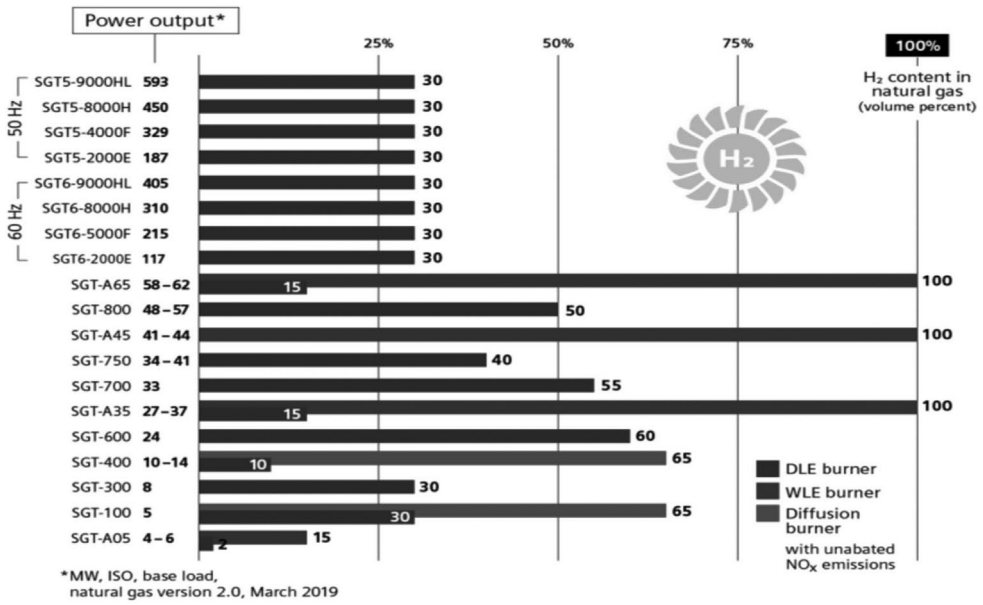
General Electric

General Electric has more than 70 gas turbine technologies that have operated (or continue to operate) on fuels that contain H_2. This fleet has accumulated more than 4 million operating hours and over 300 terawatts of power generation. This fleet also includes a set of 25 gas turbines that have operated on fuels with at least 50 percent (by volume) hydrogen; these units have accumulated more than 1 million operating hours over the last 20+ years (**Figure 5**).[20]

On October 15, 2020, GE, Long Ridge Energy Terminal, and New Fortress Energy

[20] Goldmeer, J. (2019, February). *Power to gas: Hydrogen for power generation, fuel flexible gas turbines as enablers for a low or reduced carbon energy ecosystem.* GEA33861. Atlanta, GA: GE Power.

Figure 4. Gas Combustion Turbines Offered by Siemens Able to Burn Hydrogen With Natural Gas



Source: Siemens Power to X website and report (*Power-to-X: The crucial business on the way to a carbon-free world*, 2020 White Paper).

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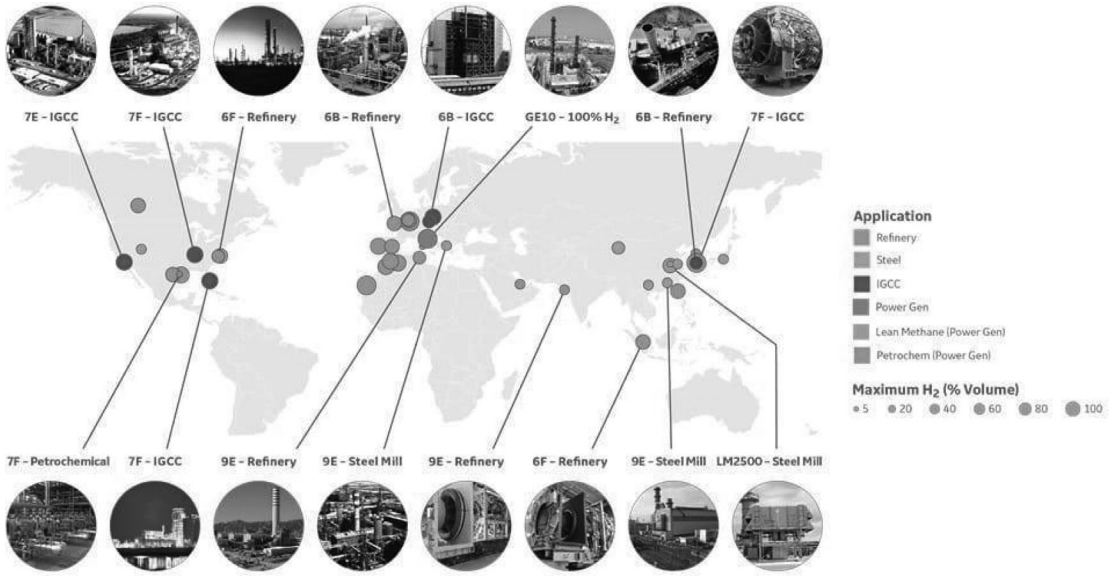
Figure 5. General Electric Global Fleet of Combustion Turbines That Burn Hydrogen



Source: Goldmeer, J. (2019, February). *Power to gas: Hydrogen for power generation, fuel flexible gas turbines as enablers for a low or reduced carbon energy ecosystem.* GEA33861. Atlanta, GA: GE Power.

will transition their 485-MW combined-cycle power project to operate on carbon-free H_2. It will be the first purpose-built H_2-burning power project in the United States and worldwide to incorporate H_2 in GE H-class gas turbines. The facility will burn between 15 and 20 percent H_2 by volume in the gas stream in November 2021 and 100 percent over time.

Mitsubishi Power

Mitsubishi Power, formerly Mitsubishi Hitachi Power System, has a fleet of J-Series gas turbines with approximately 1 million hours of operating experience. The company's newest-generation JAC air-cooled dry low NO_x combustion system with H_2-rich fuel capability. Mitsubishi gas turbines have more than 3.5 million hours of high-hydrogen operating experience, accumulated over 40 years and across 29 facilities. The company has announced several projects that will use green H_2 for power generation:

- On September 23, 2020, Mitsubishi Power and Entergy Corporation signed a joint development agreement in which they will collaborate to bring decarbonization projects to Entergy's utility businesses in Arkansas, Louisiana, New Orleans, Mississippi, and Texas. While Mitsubishi has developed a gas turbine that is able to blend 30 percent H_2 with natural gas, it has successfully proven that their existing turbines are capable of blending up to 20 percent H_2 without technological improvements. Mitsubishi's 30 percent blending is compatible with 700-MW turbines but requires some maintenance, manufacturing, and technology costs.
- Balico's 1,600-MW Chickahominy Power Project in Virginia; EmberClear's 1,084-MW Harrison Power Project in Cadiz, Ohio; and Danskammer Energy's 600-MW plant in Newburgh, N.Y., will spend $3 billion on Mitsubishi's green hydrogen technology in projects expected to go into operation in 2022 and 2023.[21]

[21] Heidorn Jr., R. (2020, October 20). Hydrogen: 21st century's 'oil'? *RTO Insider*. Retrieved from https://rtoinsider.com/eba-hydrogen-21st-century-oil-176433/.

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- The Intermountain Power Agency (IPA) awarded a contract for two M501JAC power trains for the 840-MW Intermountain Power Plant in Delta, Utah. The power plant will sequentially transition from coal to natural gas and finally to renewable H_2 fuel. This transition will start in 2025, when the turbines will be commercially guaranteed capable of using a mix of 30 percent H_2 and 70 percent natural gas fuel. Between 2025 and 2045, the H_2 capability will be systematically increased to 100 percent. The renewed generation facility will be owned by IPA and operated by the Los Angeles Department of Water and Power and other communities in California.

EVERY STRATEGY HAS RISK

Electric utilities and IPPs owning coal- and gas-fired power generation appear to be betting more on a H_2 economy strategy than the CCE strategy that relies more on carbon capture. The authors see this as more than a "toe-in-the-water" approach, as evidenced by the recent contracts signed with several combustion turbine suppliers. It is more like a hedging strategy that appeases states and other stakeholders who are demanding decarbonization. At the same time, it satisfies others who want the reliability that dispatchable gas-fired power generation is known for. Companies that embrace this strategy are hoping that the transition from natural gas to H_2 will be successful and enable their facilities to remain competitive in future markets that embrace carbon pricing. Even the RGGI doesn't incentivize CCUS as much as other strategies to reduce CO_2 production. While carbon sequestration is supported as an offset method to cap CO_2 emissions, offset allowances can only help companies meet 3.3 percent of their compliance obligations under the RGGI's current model.

The strategy, though, is inherently risky, especially those that are embracing green H_2, as the production of green H_2 depends on the availability of inexpensive renewable energy and lower future costs of electrolyzers. If green H_2 is not available, utilities and IPPs operating such projects may have to resort to burning gray or blue H_2 if available and, ultimately, natural gas if sufficient volumes of H_2 are not available.

The CEC strategy with heavy emphasis on CCUS sounds pragmatic, and in cases where it is applicable, the authors believe it should be implemented. However, the mere announcement of CCE and CCUS projects and support by governments, KAPSARC, and other international energy organizations may not translate into actual projects. In addition, the overreliance of enhanced oil recovery by most of the existing 21 CCUS facilities is symptomatic of a large issue (i.e., creating usable products and uses for). Clearly more funding and research is needed in this area to enable more CCUS facilities to monetize CO_2 well beyond enhanced oil recovery. Given the impacts of COVID-19 on economic activity and specifically in the oil and gas sector, Congress should consider expanding the construction deadline, as few projects will be able to start construction before the January 1, 2024, deadline to qualify for the current 45G tax credits.

CONCLUSIONS

Fossil-fuel power generators will be facing some form of carbon pricing in electricity markets in the next decade. FERC's announcement that it has jurisdiction with respect to carbon pricing is only the beginning of what may be a decade of experimentation that RTOs/ISOs and market participants will be subjected to. Nevertheless, companies operating in non-ISO markets will not be able to ignore carbon pricing that will likely be raised by state PUCs. Companies with large fossil-fuel generating plants would be wise to establish relationships with combustion turbine suppliers and CCUS facility companies to explore how to decarbonize their generating assets and to be able to compete in future markets that will have some form of carbon pricing. All companies should follow the progress being made on using H_2 and the CCE, especially with CCUS facilities.

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