Hydrogen in Combustion Turbine Electric Generating Units

Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

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Introduction

Hydrogen does not contain carbon and therefore emits no carbon dioxide (CO_2) when combusted. There is increasing interest in hydrogen as a viable, potentially low-greenhouse gas (GHG) fuel source for stationary combustion turbines in the utility power sector. The direct benefit of combusting hydrogen to produce electricity is zero CO_2 emissions at the stack.

The use of hydrogen in the United States (U.S.) to date has been primarily limited to certain applications in industrial sectors. The nation produced approximately 10 million metric tons (MMT)[1, 2] of hydrogen in 2018 and 70 percent of that total was used by refineries to remove sulfur from petroleum products[3] and 20 percent was used to produce ammonia in the manufacture of fertilizer.[4] The remaining 10 percent was used for treating metals, processing foods, and other miscellaneous applications.[5] Hydrogen is also used in the transportation sector, currently in light duty hydrogen fuel cell vehicles.[6, 7, 8] The fact that hydrogen emits no CO_2 when combusted is the key to its potential for reducing GHG emissions in hard-to-decarbonize industries that require a high heat source, such as cement and steel manufacturing.[9] For example, hydrogen can replace the metallurgical or coking coal and other fossil fuels used in a traditional blast furnace to reduce iron oxides to iron in the direct reduction of iron (DRI) process.

Potential Emissions Reductions from the Use of Hydrogen in Combustion Turbines

Industrial combustion turbines have been burning byproduct fuels containing hydrogen for decades, and combustion turbines have been developed to burn syngas from the gasification of coal in integrated gasification combined cycle units.[10] There are several noteworthy physical

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[1] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production.

[2] U.S. DOE (2018). *Fact of the Month May 2018: 10 Million Metric Tons of Hydrogen Produced Annually in the United States*. Accessed at https://www.energy.gov/eere/fuelcells/fact-month-may-2018-10-million-metric-tons-hydrogen-produced-annually-united-states.

[3] U.S. Energy Information Administration (EIA) (2016). *Hydrogen for refineries is increasingly provided by industrial suppliers*. Accessed at https://www.eia.gov/todayinenergy/detail.php?id=24612.

[4] New York State Department of Health (2005). *The Facts About Ammonia*. Accessed at https://www.health.ny.gov/environmental/emergency/chemical_terrorism/ammonia_tech.htm.

[5] National Renewable Energy Laboratory (NREL) (2022). *Hydrogen 101: Frequently Asked Questions About Hydrogen for Decarbonization*. Accessed at https://www.nrel.gov/docs/fy22osti/82554.pdf.

[6] Via U.S. Department of Energy, *Alternative Fuels Data Center*: In mid-2021, there were 48 open retail hydrogen stations in the United States. Additionally, there were at least 60 stations in various stages of planning or construction. Most of the existing and planned stations were in California, with one in Hawaii and 14 planned for the Northeastern states. Accessed at https://afdc.energy.gov/fuels/hydrogen_infrastructure.html.

[7] U.S. DOE (n.d.). *Alternative Fuels Data Center Alternative Fueling Station Locator*. Accessed at https://afdc.energy.gov/stations/#/find/nearest?fuel=HY&lpg_secondary=true&country=US&hy_nonretail=true.

[8] U.S. Energy Information Administration (EIA) (2022). *Hydrogen Explained.* Accessed at https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php.

[9] Bartlett, J., Krupnick, A. (2021). *The Potential of Hydrogen for Decarbonization: Reducing Emissions in Iron and Steel Production*. Resources. Accessed at https://www.resources.org/common-resources/the-potential-of-hydrogen-for-decarbonization-reducing-emissions-in-iron-and-steel-production/.

[10] Goldmeer, J. & Catillaz, J. (2021). *Hydrogen for power generation*. Retrieved July 13, 2021, Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.

characteristics of hydrogen that differ from natural gas (*i.e.*, methane) when used as a fuel in utility combustion turbines.

One of the differences between hydrogen and natural gas is the energy density by volume of the gases. To achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas. Blending or combusting such high volumes of hydrogen presents challenges to fuel availability because of limited production and demand from other sectors, infrastructure (*i.e.*, distribution and transportation pipelines, storage), turbine design capabilities, and safety. High hydrogen blends by volume also have the potential to increase nitrogen oxide (NO_X) emissions from the combustion turbine as well as increase any upstream GHG emissions associated with the hydrogen production process. Since hydrogen and methane have different volume energy densities, when blending natural gas and hydrogen, the CO_2 emissions reduction is smaller than the percentage by volume of hydrogen in the mixture. For example, to achieve a 50 percent reduction in EGU stack emissions of CO_2 requires a fuel blend that is approximately 75 percent hydrogen by volume; a 75 percent CO_2 reduction requires a blend of 90 percent hydrogen by volume. As a result, hydrogen-enriched fuels have a lower GHG intensity than typical natural gas fuels. To visualize, estimates of the CO_2 emissions reductions as a function of percent hydrogen by volume for the working fuel is shown in Figure 1.

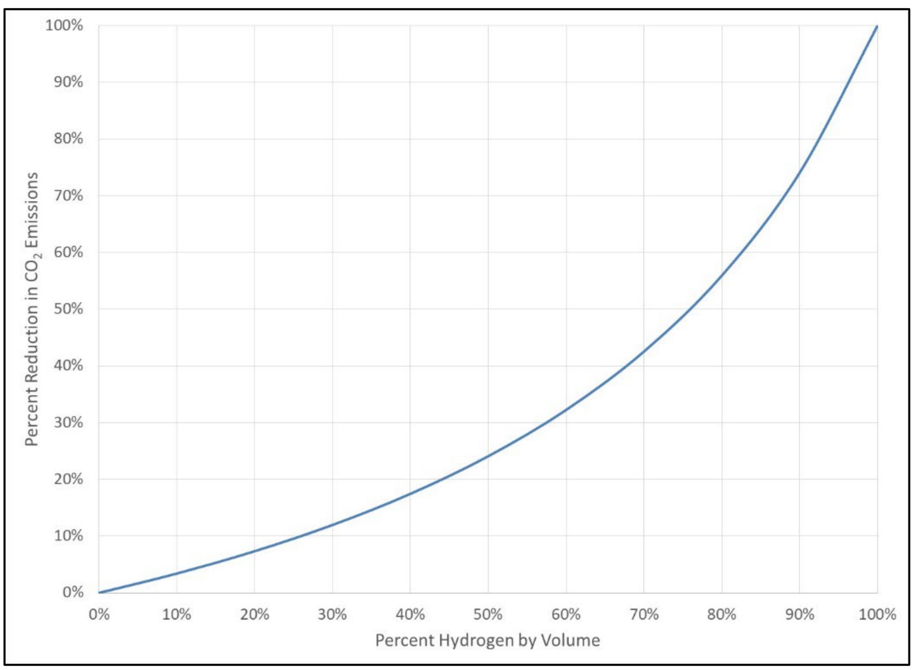

Figure 1: CO_2 Emission Reductions and Percent Hydrogen by Volume

It should also be noted that in a literature review white paper[11] released by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) in August 2022, the actual percentage by volume of hydrogen used as fuel and correlated CO_2 emission reductions depend on the specific model of combustion turbine, the type or model of combustor (NO_X controls), the combustion system, overall fuel consumption, and other factors.

Technical Feasibility of the Use of Hydrogen in Combustion Turbines

Overview

As discussed in greater detail below, certain models of combustion turbines that are currently available can combust up to 100 percent hydrogen. These are generally smaller industrial or aeroderivative units. Several larger models of new and existing combustion turbines have demonstrated the ability to co-fire up to 30 percent hydrogen by volume without modification. For certain new larger models, combustor upgrades are available from manufacturers that allow the combustion turbines to increase their hydrogen co-firing to as high as 50 percent. In addition, many new facilities have announced plans to initially co-fire up to 30 percent hydrogen by volume and up to 100 percent in approximately 10 to 20 years. According to combustion turbine manufacturers, certain new models can be constructed at present that will, in the near future, be able to install pre-planned upgrades that will align to turbine compatibility and allow up to 100 percent hydrogen combustion. In addition, the world's three largest turbine manufacturers have made commitments to develop advanced technologies by 2030 or sooner that will enable additional models of new heavy-duty combustion turbines to fire 100 percent hydrogen while limiting emissions of NO_X. For certain existing larger models, manufacturers are developing retrofits that will allow those units to safely increase their levels of hydrogen co-firing up to 100 percent.

Discussion

The technical challenges of co-firing hydrogen in a combustion turbine EGU result from the physical characteristics of the gas. Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas.[12] A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NO_X emissions.[13, 14] It is necessary in

[11] National Energy Technology Laboratory (NETL). (August 12, 2022). *A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOX Control*. A white paper by NETL and the U.S. Department of Energy (DOE). Accessed at https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf.

[12] National Energy Technology Laboratory (NETL). (August 12, 2022). *A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOX Control*. A white paper by NETL and the U.S. Department of Energy (DOE). Accessed at https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf.

[13] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. Accessed at https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/.

[14] Douglas, C., Shaw, S., Martz, T., Steele, R., Noble, D., Emerson, B., and Lieuwen, T. (2022). Pollutant Emissions Reporting and Performance Considerations for Hydrogen-Hydrocarbon Fuels in Gas Turbines. *Journal of*

combustion for the working fluid flow rate to move faster than the rate of combustion. When the combustion speed is faster than the working fluid, a phenomenon known as "flashback" occurs, which can damage injectors or other components and lead to upstream complications.[15]

Other differences include a hotter hydrogen flame (4,089 °F) compared to a natural gas flame (3,565 °F) and a wider flammability range for hydrogen than natural gas.[16] It is also important that hydrogen and natural gas are adequately mixed to avoid temperature hotspots, which can also lead to formation of greater volumes of NO_X.

Combustor modifications or retrofits have the potential to limit NO_X emissions. For example, a larger selective catalytic reduction (SCR) unit inside the heat recovery steam generator (HRSG) is an option for combined cycle turbines. For combined cycle plants planning to co-fire higher volumes of hydrogen over time, it is important to estimate the increased NO_X emissions when sizing the SCR unit.[17]

The industrial and aeroderivative combustion turbines currently capable of co-firing greater than 30 percent hydrogen by volume are generally simple cycle turbines that utilize wet low-emission (WLE) or diffusion flame combustion. In terms of larger, heavy-duty combustion turbines that can co-fire up to 30 percent hydrogen, these models generally utilize WLE, dry low-emission (DLE), or dry low-NO_X (DLN) combustors.

As mentioned earlier, most turbine manufacturers are working to safely increase the levels of hydrogen combustion in new and existing turbine models while limiting emissions of NO_X. This is true of the three largest turbine manufacturers in the world: GE and Siemens both have goals to develop 100 percent DLE or DLN hydrogen combustion capability in their turbines by 2030.[18, 19, 20] Mitsubishi is targeting development of 100 percent DLN hydrogen combustion capable turbines by 2025.[21]

GE's most recent combustor design, the DLN 2.6e, allows hydrogen gas to be pre-mixed safely and reduces the risk of premature combustion. Turbine models such as the GE 7HA.02 can co-

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Engineering for Gas Turbines and Power. Volume 144, Issue 9: 091003. Accessed at https://asmedigitalcollection.asme.org/gasturbinespower/article/144/9/091003/1143043/Pollutant-Emissions-Reporting-and-Performance.

[15] Inoue, K., Miyamoto, K., Domen, S., Tamura, I., Kawakami, T., & Tanimura, S. (2018). *Development of Hydrogen and Natural Gas Co-firing Gas Turbine*. Mitsubishi Heavy Industries Technical Review. Volume 55, No. 2. June 2018. Accessed at https://power.mhi.com/randd/technical-review/pdf/index_66e.pdf.

[16] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines*. Accessed at http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf.

[17] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.

[18] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030.* Accessed at https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.

[19] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines.* Accessed at https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.

[20] de Vos, Rolf (2022). *Ten fundamentals to hydrogen readiness*. Accessed at https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.

[21] Power Magazine (2019). *High Volume Hydrogen Gas Turbines Take Shape.* Accessed at https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.