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Hydrogen Blending in Texas Natural Gas Power Plants at Scale

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Introduction

Hydrogen is a potential solution to help decarbonize the economy, including electricity. Once hydrogen is produced, it can be used in industrial processes or to produce electricity from fuel cells and gas turbines. Hydrogen can also be a long-term storage solution for excess electricity produced by other clean sources. Multiple studies have derived deep decarbonization pathways by integrating large amounts of hydrogen into many sectors of the economy.[1,2] These studies generally require large amounts of new capital expenditures and a significant reworking of the energy and transportation sectors to achieve their carbon reductions.

This study sought to assess the carbon emissions reduction value, if any, in utilizing low levels of hydrogen blending in *existing* power plants. This study finds that blending even relatively small amounts of hydrogen in the fuel streams of existing natural gas power plants can reduce carbon emissions. Furthermore, the results suggest that the levels of tax credits currently being considered at the federal level are likely necessary and sufficient to make hydrogen blending economically competitive in the short term.

Significant strides have been made in the development of new power plants, particularly natural gas turbines and combined cycle systems, that have the ability to utilize hydrogen fuel blends.[3] For example, the proposed Orange County Advanced Power Station in Texas is a 1.2 GW natural gas power plant with the ability to blend up to 30% hydrogen.[4] In addition, El Paso Electric is planning to install a similar unit to support its energy grid as part of its decarbonization efforts.[5] Outside the borders of Texas, the power industry also sees growth in hydrogen consumption utilizing gas turbines to help accelerate decarbonization efforts, including the Intermountain Power Project[6] in Utah and the Magnolia project[7] under development in Louisiana.

[1] https://www.sciencedirect.com/science/article/abs/pii/S2542435121004426
[2] https://www.fchea.org/us-hydrogen-study
[3] https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/
[4] https://www.powermag.com/1-2-gw-dedicated-hydrogen-fired-power-plant-starts-taking-shape-in-texas/
[5] https://pv-magazine-usa.com/2021/10/21/el-paso-electric-looks-to-hydrogen-for-future-electric-power-generation/
[6] https://www.ipautah.com/ipp-renewed/
[7] https://kindle-energy.com/about-us/about-kindle-energy/

However, power plant fleet turnover is on the order of decades. While new gas turbines with the ability to consume high hydrogen blends are likely to be deployed in the future, existing power plants (that do not have this ability) will likely outnumber these new technologies in the short term. There are currently about 464 GW of natural gas turbine-driven[8] power plants in the US. About 13% (59 GW) of those power plants are in Texas and many are located in the energy-intensive Texas Gulf Coast region.

The Gulf Coast region is also home to the largest hydrogen hub in the US. Within this regional hydrogen hub, Texas alone consumes about 9 million kg of hydrogen per day, or about 1/3 of the total US consumption. Currently, almost all this hydrogen is used as feedstocks for the chemicals and oil and gas industries and is produced via steam methane reforming (SMR). The Texas Gulf Coast is also home to the most extensive hydrogen pipeline networks in the country, with over 715 km (~440 miles) of pipelines (in Texas) moving hydrogen throughout the region including to and from Louisiana.[9]

This investigation focused on a potential area for early adoption of hydrogen, based on co-located critical infrastructure. The analysis sought to accomplish two goals: 1) determine the spatial relationship between the existing hydrogen pipeline network and the local natural gas power plant fleet and 2) assess the implications for connecting the two. Utilizing historical energy generation and spatial data analysis techniques, the team assesses the suitability of the local natural gas power plant fleet to consume hydrogen, its impacts on power plant economics and emissions, as well as the increased demand for hydrogen in the Gulf Coast region of Texas.

Methods

Data

The initial area of study included power plants that were within 5 km of the existing hydrogen network. EIA 860[10] and EIA 923[11] (2020) were used as the basis for the set of power plants, and data from the Texas Railroad Commission (RRC)[12] for the locations of hydrogen pipelines.

The hydrogen pipeline data were down sampled from RRC county-level GIS files that contained pipeline data of all types. The pipelines that mentioned hydrogen in their description were taken from each of the 254 county files and combined into one pipeline dataset.

The EIA data include, among other things, the type of power plant, the amount of fuel it consumed, the amount of energy it generated, and its latitude and longitude. The locational

[8] Natural gas combustion turbines and combined cycles.
[9] This analysis only considered Texas power plants and pipelines, more pipelines an potentially near power plants also exist in Louisiana.
[10] https://www.eia.gov/electricity/data/eia860/
[11] https://www.eia.gov/electricity/data/eia923/
[12] https://mft.rrc.texas.gov/link/d4eda8c4-9ff0-43b7-8f19-da0a57f10fd2

values were used to convert the dataset into a spatial dataset that could be put into reference with the pipeline data using custom Python GeoPandas scripts.[13]

Hydrogen Substitution

Blending hydrogen with natural gas reduces the volumetric energy density of the mixed gas. Thus, a higher volume of hydrogen-blended natural gas is required to deliver the same amount of energy to a power plant. For reference, a 5% volumetric blending of hydrogen with natural gas would only displace about 2% of the natural gas if the blended gas stream is to deliver the same level of energy (MMBTU) to a power plant.

Figure 1 shows a schematic of two methods of delivering hydrogen to power plants. One path is to blend hydrogen into the existing network before reaching the power plant. A different near-term possible pathway would be to deliver hydrogen directly to power plants via dedicated infrastructure. Due to the presumably small, but unknown cost differential, the second pathway, blending onsite at the power plant, was chosen for this study.

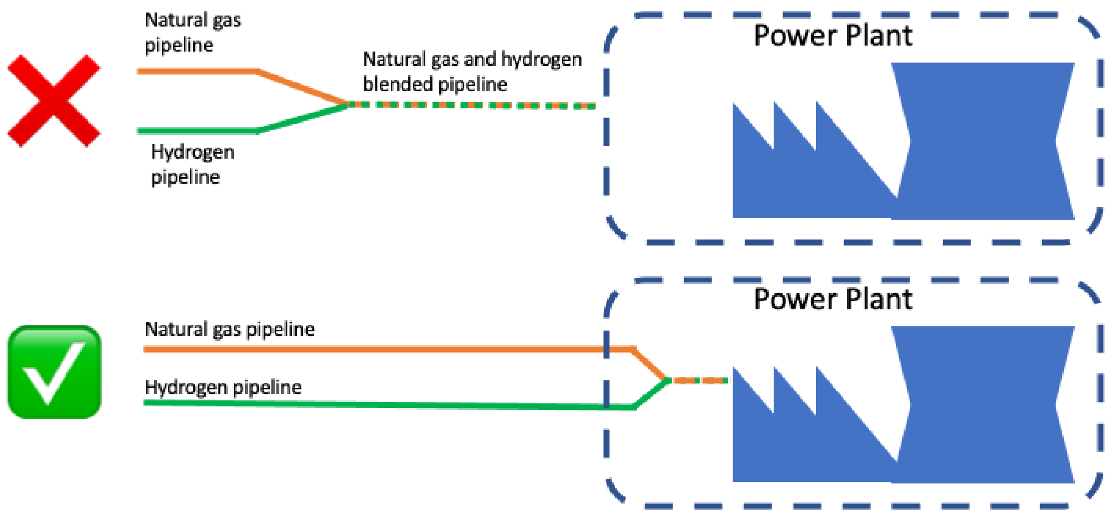

Figure 1: Figure showing the method of getting hydrogen to power plants considered in this analysis. The analysis DID NOT consider blending hydrogen into the bulk natural gas grid (top), but instead utilizing a separate pipeline to deliver pure hydrogen directly to the power plant to be mixed into the fuel stream immediately before combustion (bottom).

Case Study Area

This analysis focused on the Gulf Coast region of Texas, including the counties of Texas that border the Houston (Harris County) region and touch the Gulf of Mexico. This area of Texas is home to most of the existing hydrogen infrastructure in the state.

Results

[13] https://geopandas.org/en/stable/

Power Plant Locations

This analysis found that there are 43 natural gas power plants[14] within 5 km (3.1 miles) of existing hydrogen pipelines in Texas, constituting about 18 GW of power plant capacity. Figure 2 shows the location of the existing hydrogen pipeline network on the Texas Gulf Coast, the natural gas power plants within 5 km of those pipelines (green squares), and the natural gas power plants in the region that are farther than 5 km from existing hydrogen pipelines (dark green circles).[15]

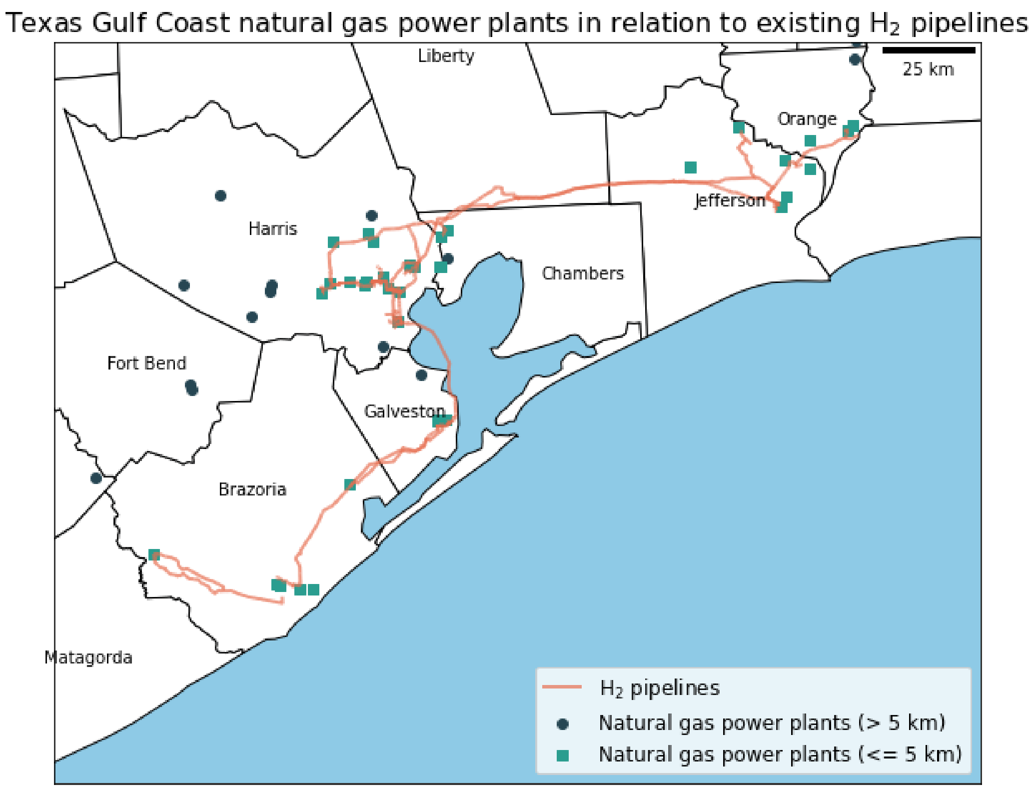

Figure 2: Figure showing the location of Texas Gulf Coast hydrogen pipelines (orange lines), natural gas power plants within 5 kilometers (green squares) of the hydrogen pipelines, and other natural gas power plants in the region that are located greater than 5 km from existing hydrogen pipelines (dark green circles). Note that there are a small number of hydrogen pipelines and natural gas power plants within the same limit in other parts of the state but are not shown here to allow for more local detail to be shown.

Figure 3 shows a histogram of the distances of these near (≤ 5 km) power plants to existing hydrogen pipelines. The average power plant in this subset is about 1.3 km (0.8 miles) from an existing hydrogen pipeline, with almost 80% (34 natural gas power plants) within 2 km (1.2 miles) of existing hydrogen pipelines.

[14] Many power plants have multiple generators within the plant location, so the actual number of turbines and/or boilers (units) is higher.

[15] There are two very short hydrogen pipelines located in other parts of the state, but they are not shown here in order to be able to better see the bulk of the system on the Texas Gulf Coast.

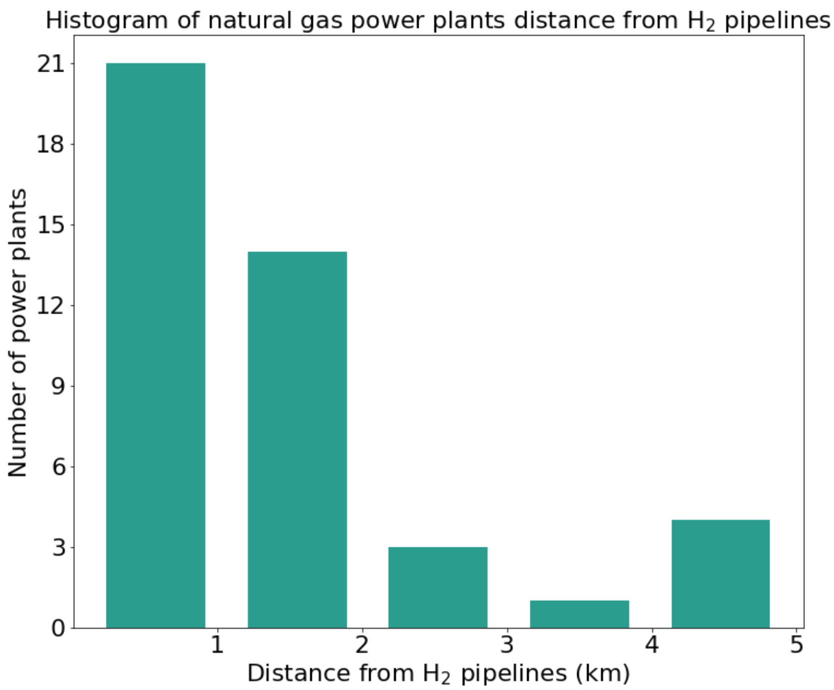

Figure 3: Histogram of the number of power plants within 1 km bins from hydrogen pipelines. For example, there are 21 natural gas power plants that are between 0 and 1 kilometers from existing hydrogen pipelines in the Texas Gulf Coast region.

In 2020, these near facilities produced about 71.5 TWh, or about 15% of the total generation from all types of power plants (474.6 TWh) across the entire state.[16] This set of power plants constitutes about 18 GW, or about 13% of all the total power plant capacity in Texas (of all technology types). In 2019, these power plants produced about 28.7 million tons of CO_2 emissions, about 13% of all power plant carbon emissions in Texas (219.7 million tons).[17]

Thus, the set of natural gas power plants that are close to existing hydrogen pipelines in Texas could represent a low-risk, large opportunity to test the deployment of low-level hydrogen blending at-scale while also reducing carbon emissions in a large part of the power sector.

Natural Gas and Hydrogen Demand Impacts

Table 1 shows results for blending 5%, 10%, or 30% hydrogen by volume for natural gas power plants within 5 km of existing hydrogen pipelines in Texas (Figure 2). Most of the analysis and discussion focuses on the 5% and 10% blends, as these levels are generally considered more compatible with existing natural gas power plants. The 30% hydrogen blend case is included as a forward-looking, hypothetical case study since some newer gas turbines are available with up to 30% hydrogen blend capabilities. Some future turbine technologies are also expected to be 100% hydrogen capable.

[16] This includes Texas power plants that are not in ERCOT.
[17] 2019 EPA eGrid data: https://www.epa.gov/egrid/download-data

Table 1. Table showing how the amount of natural gas, hydrogen, and carbon emissions would change if all power plants within 5 km of hydrogen pipelines were to use a 5%, 10%, or 30% blend by volume of hydrogen in their fuel. Fuel use data for power plants based on 2020 EIA 923 data. Note that "MMT" stands for a million metric tons, or 1,000,000,000 kg. Note that emissions reduction percentages only apply to the fleet of power plants within 5 km of hydrogen pipelines, not the entire electricity grid.

	Units	No H_2	5% H_2	10% H_2	30% H_2
Natural gas	Million MMBTU	806.3	788.3	770.3	698.2
Natural gas	MMT	16.1	15.8	15.4	14.0
Hydrogen	Million MMBTU	-	18	36	108
Hydrogen	MMT	-	0.161	0.322	0.965
*CO_2**	MMT	79.6	77.8	76.0	68.9
*CO_2 reduction**	%	0%	2%	4%	13%
Annual H_2 increase	%	0%	5%	10%	29%
*Breakeven H_2 price***	$/kg	-	$0.40	$0.40	$0.40
Hydrogen pipeline cost	$/kg	-	$0.23	$0.12	$0.04
*Break even electricity PTC***	$/MWh	-	$5	$10	$30
*Implied cost of carbon***	$/metric-ton	-	$195	$195	$195

* Assuming zero-carbon hydrogen
** Calculated at a natural gas price of $3.50/MMBTU and hydrogen delivery price of $2.55/kg

Hydrogen Cost

The analysis indicates that, for a 5% blending rate, these power plants would consume about 160,000 metric tons of hydrogen per year, which is approximately a 5% increase in the current annual hydrogen consumption in Texas.

The average price of natural gas delivered to power plants in 2020 was about $2.48/MMBTU.[18] However, natural gas prices in 2021 were higher at about $4.46/MMBTU[19] and global energy shortages could keep prices above recent historical levels. Thus, in Table 1 a price of $3.50/MMBTU for natural gas is used, which leads to a break-even hydrogen price of $0.40/kg. That is, if a power plant were able to source hydrogen at $0.40/kg, it would choose to do so if natural gas prices were at or above $3.50/MMBTU. However, this $0.40/kg value is low compared to current hydrogen production cost estimates of $0.87/kg[20] for SMR, $1.55/kg[21] for SMR with 90% carbon capture (SMR+CCS), and $1.90/kg[22] for electrolysis using grid electricity. However, it might be possible to achieve lower hydrogen costs if the input electricity or natural

[18] https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm
[19] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/081021-high-natural-gas-prices-lead-to-increased-coal-generation-2021-carbon-emissions-eia
[20] Assuming about $3.50/MMBTU for the natural gas.
[21] https://sites.utexas.edu/h2/files/2021/07/H2-White-Paper_Market-Competetive-Electrolysis-in-ERCOT_Updated.pdf
[22] https://sites.utexas.edu/h2/files/2021/07/H2-White-Paper_Market-Competetive-Electrolysis-in-ERCOT_Updated.pdf

gas were otherwise stranded, such as curtailed wind and/or solar energy or flared wellhead gas.[23]

Hydrogen Pipeline Cost

Using a cost of \$1.86M/km[24] for a new hydrogen pipeline, the average natural gas power plant (at 1.3 km from a hydrogen pipeline) would cost about \$2.5M to connect to the hydrogen pipeline system, or \$212,000 per year[25] if amortized for 20 years at 6%.[26] This amortized pipeline costs results in an average \$0.23 per kg[27] of hydrogen to build and operate the hydrogen spur line to deliver a 5% hydrogen blend to the power plant. Considering that most pipeline siting and construction costs are for the right-of-way, a pipeline that delivered enough hydrogen for a 10% blend might cost roughly the same but be able to deliver hydrogen for about \$0.12/kg. Similarly, for a 30% hydrogen blend, the hydrogen delivery cost would be about \$0.04/kg.

Adding the delivery cost for a 5% blend to the production costs above and including a 20% contingency, results in an average delivered cost[28] of hydrogen for SMR of \$1.32/kg, SMR+CCS of \$2.14/kg, and electrolysis of \$2.55/kg.

Emissions Tradeoffs of Different Hydrogen Sources

Table 1 also shows the carbon emissions reductions for the blended fuel scenarios. These scenarios assume that hydrogen is produced using zero-carbon intensity technologies, such as electrolysis powered with renewable electricity. A 5% by volume hydrogen blend would reduce power plant carbon emissions[29] by 2.2%. A 10% blend would double these results and a 30% blend would increase their values by a factor of six.

However, not all production methods produce zero-carbon intensity hydrogen. Thus, when considering the carbon intensity of the input hydrogen as it displaces natural gas, it is estimated that the embedded carbon emissions of the hydrogen must be below 6 kg-CO_2 per kg-H_2 for the overall power plant emissions to be lower than burning 100% natural gas.

A SMR facility with no carbon capture produces hydrogen with a carbon intensity of about 9 kg-CO_2 per kg-H_2, not including any upstream fugitive methane emissions. A new SMR+CCS facility (with 90% carbon capture) would produce hydrogen at about 1 kg-CO_2 per kg-H_2, also not including any upstream fugitive methane emissions or post capture fugitive CO_2 emissions. The

[23] https://sites.utexas.edu/h2/files/2021/07/H2-White-Paper_Market-Competetive-Electrolysis-in-ERCOT_Updated.pdf
[24] https://sites.utexas.edu/h2/files/2021/08/H2-White-Paper_Hydrogen-Pipelines-versus-Power-Lines.pdf
[25] About \$163,000/km-year.
[26] https://sites.utexas.edu/h2/files/2021/08/H2-White-Paper_Hydrogen-Pipelines-versus-Power-Lines.pdf
[27] With a range of \$0.004 to \$2.89 per kg of hydrogen, depending on length of line and how much hydrogen is used.
[28] To the considered fleet of natural gas power plants. This cost will vary for any individual project.
[29] Inclusive of natural gas system fugitive methane emissions assumptions of 1%.

marginal carbon intensity of electricity in the Houston region varies between 175 and 345 kg-CO_2/MWh.[30,31] Thus, hydrogen generated via centralized electrolysis in the region would have an average carbon emissions footprint of about 3.5 kg-CO_2 per kg-H_2.

Utilizing hydrogen via SMR+CCS and electrolysis would offer a carbon benefit to the electricity produced by the natural gas power plants. The SMR+CCS hydrogen scenario realizes about 83% of the total carbon benefit as compared to zero-carbon hydrogen, while the electrolysis hydrogen (using the current grid electricity mix) realizes about 42% of the total possible carbon benefit. Table 2 summarizes the emissions benefits of these hydrogen production methods.

Table 2. Table showing the annual emissions reductions if all natural gas power plants within 5 km of existing hydrogen pipelines were to blend 5% hydrogen, by volume, into their fuel supply for different hydrogen production methods.

H_2 production method	**CO_2 intensity**	**CO_2 reduction with 5% H_2 blend***	
	$\left[\frac{kg_{CO_2}}{kg_{H_2}}\right]$	[MMT CO_2]	[%]
SMR	9.	-0.9	-50%
SMR+CCS (90%)	1.	1.5	83%
Electrolysis – grid electricity	3.5	0.75	42%
Electrolysis – zero carbon electricity	0.	1.8	100%

* As compared to the total reductions from using electrolysis powered by zero-carbon electricity. Negative reductions imply increased emissions.

Carbon Abatement Costs

In the zero-carbon hydrogen case with hydrogen delivered to power plants at $2.55/kg, the effective price of the carbon reductions is about $195/t-$CO_2$. If the delivered cost of hydrogen declines or the price of natural gas increases, the effective price of carbon reductions would fall. For example, if the price of natural gas were $5/MMBTU and the delivered cost of hydrogen were $1.50/kg, the effective price of carbon reductions would be about $85/t-$CO_2$.

Hydrogen Policy Pathways

This analysis has examined the cost and emissions implications for blending hydrogen into the fuel streams of natural gas power plants. The next section considers some potential policy pathways, such as clean hydrogen tax credits, which are currently under consideration at the federal level as well as a modified production tax credit such as that utilized by the renewable energy industry.

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30 https://sites.utexas.edu/h2/files/2021/07/H2-White-Paper_Market-Competetive-Electrolysis-in-ERCOT_Updated.pdf

31 The 2020 ERCOT grid mix was about 46% natural gas, 23% wind, 18% coal, 11% nuclear, and 2% other, largely solar. Source: https://www.ercot.com/files/docs/2021/11/23/ERCOT%20Fact%20Sheet.pdf

Clean Hydrogen Production Tax Credit

Proposed federal legislation would provide a \$3/kg hydrogen production tax credit (H-PTC) for hydrogen if the lifecycle greenhouse gas emissions of that hydrogen are at least 40%[32] lower than current SMR technology. This results in PTC-qualifying hydrogen needing a carbon footprint of 5.4 kg-CO_2 per kg-H_2 or less, when compared to current SMR technology (9 kg-CO_2 per kg-H_2).[33] Thus, the analysis indicates that electrolysis hydrogen production in Houston at 3.5 kg-CO_2 per kg-H_2 would qualify for the H-PTC, as would SMR+CCS hydrogen at 1 kg-CO_2 per kg-H_2.[34]

As shown previously, hydrogen produced through electrolysis in the ERCOT grid has an estimated delivery cost of \$2.55/kg. With a \$3/kg clean hydrogen production tax credit, this reduces the delivered costs to about -\$0.45/kg, which is below the power plants break even costs (~\$0.40/kg) for hydrogen. The profit spread of roughly \$1/kg of hydrogen would likely drive some firms to enter such a market. The same could hold true for qualifying SMR+CCS units where an even larger profit spread might exist.

Blended Hydrogen Electricity Production Tax Credit

Mirroring today's production tax credits for renewable electricity, it is possible that a tax credit for the electricity produced using clean hydrogen blends could offset some of the additional fuel costs of the hydrogen blending. If clean hydrogen can be delivered to the power plants at about \$2.55/kg, the average break-even electricity production tax credit needed, for a 5% H_2 blend, is about \$5.60/MWh[35], depending on the individual power plant's heat rate. If the delivery cost for clean hydrogen is \$4/kg, the needed break-even tax credit is, on average about \$9.70/MWh .

This average is considerably lower than the current wind power production tax credit of ~\$23/MWh. Thus, if a similar PTC for hydrogen blend produced electricity were to match that for wind, natural gas power plants would have an economic incentivize to adopt hydrogen blends and reduce emissions. However, the \$23/MWh PTC for wind produces 100% carbon-free electricity, whereas the electricity from the natural gas power plant burning a clean hydrogen fuel blend produces reduced carbon emissions based on the blend percentage.

Conclusions

This analysis indicates that, if all natural gas power plants within 5 km of the existing hydrogen pipeline network blended 5% of their fuel (by volume) with zero carbon hydrogen, CO_2 emissions for those power plants would fall by about 2.2%, or 1.8 million metric tons per year –

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[32] https://www.congress.gov/bill/117th-congress/house-bill/5192?r=5&s=1
[33] https://sites.utexas.edu/h2/files/2021/07/H2-White-Paper_Market-Competetive-Electrolysis-in-ERCOT_Updated.pdf
[34] https://sites.utexas.edu/h2/files/2021/07/H2-White-Paper_Market-Competetive-Electrolysis-in-ERCOT_Updated.pdf
[35] with a range of \$3-\$20.50/MWh (\$11.25/MWh avg., \$6-\$41/MWh for 10% hydrogen blending)

the equivalent of taking 386,000 cars[36] off the road. Correspondingly, at a 30% hydrogen blend, the equivalent cars off the road would be 2,316,000, or about a 20% reduction in the 11 million vehicles registered in the Houston area.[37]

Additionally, this level of hydrogen demand would increase the Houston-area annual hydrogen demand by about 5%, or by about 161 million kg per year. This analysis indicates that it might be possible to deliver electrolysis-based hydrogen to this fleet of power plants for about $2.55/kg, but the power plant breakeven costs for hydrogen are between $0.25 and $0.50 per kg, depending on the prevailing price of natural gas. However, a clean hydrogen PTC of at least $2.00/kg or an electricity PTC about half that available for wind power could bridge this gap.

Further Considerations

While beyond the current scope of work, the following considerations would be useful to further extend this work.

Capacity Limitations

The ability of the existing hydrogen pipelines to be able to convey the extra hydrogen needed was not assessed. However, informal discussion with industrial gas suppliers has indicated a 5% increase in hydrogen demand within the Houston area would likely be viable with existing assets.

It is also possible that sending higher blends of hydrogen to some power plants might result in a derating of their capacity if they are not able to handle the higher volumes of fuel due to the blended gas stream's lower energy content. However, discussions with industry experts[38] indicated that these lower levels of blending are unlikely to impact even existing equipment. Thus, those impacts as part of the scenario analysis were not considered. It is also possible that, in a real electricity market, these power plants would be dispatched less often since it is likely that hydrogen fuel prices would be higher than the above-mentioned break-even price, thus increasing the price of the electricity produced by the power plants. However, it is also possible that tax credits could reduce their costs and thus see them deployed more often.

Emissions

Emissions impacts beyond CO_2 were also not considered. However, the higher flame temperature of hydrogen can produce more NOx emissions. Although, most emissions concerns are around older technologies and are less of a concern for more modern power plant designs and can generally be mitigated through combustion parameter tuning.[39]

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[36] Assuming the typical passenger vehicle emits about 4.6 metric tons of carbon dioxide per year. https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle

[37] http://www.dot.state.tx.us/apps-cg/discos/default.htm?dist=HOU&stat=vr

[38] Personal communication with Jan Mertens of ENGIE.

[39] https://www.power-eng.com/gas/hydrogen-substitution-for-natural-gas-in-turbines-opportunities-issues-and-challenges/#gref

Blending Into the Gas Infrastructure

This analysis did not consider the blending of hydrogen into the existing natural gas pipeline network but looked instead at the possibility of sending hydrogen directly to natural gas power plants that are located within 5 km of existing hydrogen pipelines. It is possible that some parts of the natural gas network could take hydrogen blends at the levels considered here and bypass the need to deploy dedicated hydrogen pipelines directly to power plants.

Hydrogen Contracts

This analysis assumes the ability to access the existing hydrogen pipeline network in the Gulf Coast region. Hydrogen markets are still a developing concept and the current system is a series of privately owned pipelines with a few connection points. Hydrogen contracts are typically long-term, and a power plant could be an attractive customer for the current contracts model. If the power plants have a reasonable estimate of their hydrogen consumption needs over time, they might be better able to hedge their fuel prices as their production costs would not be tied to a single fuel.

Hydrogen Economy Scale

Hydrogen has the potential to help decarbonize significant portions of the economy. A significant and steady increase in hydrogen demand could help the Texas hydrogen system achieve new economies of scale that would bring down the price of clean hydrogen and possibly drive additional demand in other sectors. The impact of deploying hydrogen at significant scale was not accounted for in this study.

Disclaimer and Acknowledgement

This non-peer reviewed report is based on information developed during a more comprehensive investigation, which is intended to be published as a peer-reviewed document. Comments and suggestions for improvements are welcome and should be sent to the technical leader of this task, Michael Lewis, mclewis@cem.utexas.edu.

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