CO_2 Reduction Options for High Temperature Industrial Combustion

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Abstract

As governments around the world discuss the enforcement of decarbonization, the reduction of carbon dioxide (CO_2) emissions, many are looking at hydrogen (H_2) as a potential low carbon alternative fuel. While some countries are looking to promote the use of hydrogen for industrial heating by adding it at some percent volume to the natural gas supply, others are considering a total switch from fossil fuels to H_2. How might these two approaches differ in terms of environmental impact, compatibility with existing technology, and cost? Are there other cost-effective ways to reduce CO_2 emissions that are comparable to either of the above-mentioned approaches in terms of net reduction of carbon emissions?

In this paper Bloom will review the different ways that H_2 might be used in industrial heating processes and the various results, both environmental and economic. We will also evaluate other ways to minimize CO_2 emissions, such as, optimizing processes to reduce fuel consumption and how those approaches might compare to the use of H_2. Our focus will be on high temperature forced air applications and including findings from new research currently being conducted at our world headquarters in Pittsburgh, PA.

Fuel Options

Historically, when selecting a fuel for high temperature industrial heating applications, the primary factors considered were a fuel’s compatibility with the process or product(s) being heated, the availability of the fuel, and the fuel’s cost. Over time, the environmental impact associated with various fuels has also become a leading factor in their selection. For example, in the United States, electric power generation using coal is being displaced largely by generation methods using natural gas. And, while natural gas costs in the US have dropped over the past decade making its cost per unit of energy comparable with coal, the added benefit of not creating all the hazardous waste products such as ash and SO_2 emissions has helped to accelerate the changeover.

Today, as we try to come up with solutions to combat climate change, industrial heating applications are being pressured to find fuel sources which have a smaller carbon footprint and cause less greenhouse gas emissions, specifically Carbon Dioxide (CO_2). Electricity, biofuels, and non-carbon containing fuels such as H_2 are being considered because of their potential to be low carbon emitting alternatives to traditional fossil fuels, such as natural gas. Below, these three approaches will be evaluated, and will be compared to traditional fossil fuel combustion enhanced with efficiency boosting techniques, to determine the relative benefits of various carbon reduction strategies.

Direct Electrification

For those looking to use electricity for high temperature industrial heating, either through induction or the use of resistive heating elements, it is imperative to understand the source of that electrical power. While using electricity in place of fossil fuels will always reduce or eliminate CO_2 directly emitted from an industrial heating application, the method used to produce the electricity will need to be understood and accounted for to determine the overall carbon footprint associated with this energy source. For example, in the United States, where electricity is generated largely, but not exclusively, through the combustion of fossil fuels (natural gas and coal), an average of 0.92 lbs. of CO_2 is emitted for every kWh of electric produced.[1] This means that adding 1MMBtu (293.1kWh) to a process in the United States using resistive elements, with an assumed power plant to process efficiency (grid efficiency) of 95%, will result in 284 lbs. of CO_2 emissions.

By comparison, burning 1MMBtu (HHV) of natural gas releases about 120lbs. of CO_2 emissions. When compared with the 284 lbs. of CO_2 resulting from the generation and deliver of the same amount energy to a process via resistive heating, natural gas appears to be the clear winner. Unfortunately, this is oversimplified and does not account for the combustion efficiency when using natural gas, which for high temperature heating, can be relatively low. Combustion efficiency is simply the portion of useable energy that goes to the process compared to the total energy supplied. Therefore, if natural gas is to produce less CO_2 than resistive heating the combustion efficiency will need to be high enough so that every 1MMbtu added to the process results in no more than 284/120 = 2.367 MMBtu of fuel being burned. The combustion efficiency percentage that this equates to is 1MMBtu/2.367MMbtu * 100 = 42%. This means that adding 1MMtu to an industrial heating process in the United States through the direct combustion of natural gas will result in less CO_2 than heating done using "average" grid electricity if the combustion efficiency with natural gas is more than 42%.

Although not very common today, one way to decrease the amount of carbon dioxide released into the atmosphere after the combustion of hydrocarbons is to remove it from exhaust gas streams and to store it somewhere. This is often referred to as Carbon Capture and Store (CCS). By chemically removing the carbon from a processes waste gas stream, and then transporting it to a location (generally underground) where it is possible to store it safely away from the atmosphere, it is possible to remove up to 90% of the carbon dioxide emitted. There is an associated "energy penalty" related to capturing, compressing, transporting, and storing the carbon dioxide but progress continues toward making CCS more practical, accessible, and cost-effective through ongoing research efforts and, in the future, it might help to lower average CO_2 emissions per kWh of electric generated in some regions. Unfortunately, due to the large expense in both capital dollars and operational dollars CCS is not practical for all but a few large CO_2 emitting facilities right now.

In some countries such as France, electricity is generated largely via nuclear. In others like Sweden, renewables supply the majority of grid electric. Logically the average CO_2 emitted per kWh is much lower in these places, being only 0.12 lbs. per kWh in France and 0.026 lbs. per kWh in Sweden.[2] If electricity generated using low carbon emitting sources (solar, wind, hydroelectric, biomass, or nuclear) is available and practical for an industrial heating application then it can in fact greatly reduce the process's carbon footprint. On the other hand, however, when electricity is predominantly generated using carbon rich fossil fuels such as coal (as is the case in China) the average amount of CO_2 emissions per kWh for that country or region can be as high as 1.3 lb. per kWh or more in which case many heating applications would produce less CO_2 if a less carbon rich fossil fuel such as natural gas was used directly.

Please see **Figure 1** for a comparison between the CO_2 resulting from the addition of 1MMBtu of available heat to an application using natural gas or electric resistance heating in various countries.

CO_2 Generated to Provide 1 MMBtu of Available Heat to a Box Furnace @ 2,050°F					
	Cold Air Combustion - US (100°F, λ = 1.05)	**Electric Resistance Heating - US**	**Electric Resistance Heating - France**	**Electric Resistance Heating - Sweden**	**Electric Resistance Heating - China**
Natural Gas Required (MMBtu - HHV)	2.33	0	0	0	0
Combustion Efficiency (%)	43	-	-	-	-
CO_2 Produced from Fuel (lbs.)	280	0	0	0	0
Electric Required for Heating (kWh)	0.0	293.1	293.1	293.1	293.1
Combustion Air Blower Power Required (kWh)	2.7	0	0	0	0
Grid Efficiency (%)	95	95	95	95	95
Total Electric Required (kWh)	2.8	308.5	308.5	308.5	308.5
Average Grid CO_2 per kWh (lbs.)	0.92	0.92	0.12	0.026	1.30
CO_2 Associated with Electric (lbs.)	2.6	283.8	37.0	8.0	401.1
Total CO_2 (lbs.)	**282**	**284**	**37**	**8**	**401**

Figure 1

Biofuels

Fossil fuels contain carbon that was removed, largely by plants and phytoplankton, from the earth's atmosphere over very long periods of time and in great quantities. Now this carbon is being stored mostly underground and in a form that it is not available to the atmosphere. Extracting and combusting these fossil fuels releases huge amounts of carbon dioxide into the atmosphere far exceeding what plants can quickly reabsorb. The result is an increased concentration of carbon dioxide in the earth's atmosphere.

In contrast, the release of CO_2 thru the combustion of biofuels contributes little or no net carbon (CO_2) to the atmosphere. This is because biofuels are fuels derived from biomass, which has recently absorbed the carbon they contain from the atmosphere during growth. In this way, if the biomass that acts as the feedstock for biofuels is continuously being replaced, the biofuel itself is considered to contribute little or no new net carbon to the atmosphere.

Some biofuels include alcohols (the most common being ethanol), oils, biodiesel, and synthesis gases (syngas). At Bloom Engineering, we have successfully designed burners to run on some gaseous biofuels including syngas and biogas along with many liquid biofuels including biodiesel, bio-oil, methanol (see **Figure 2**), and glycerol. For many of the liquid biofuels, systems designed for their safe delivery and proper introduction to a burner are similar to what would be done for light or heavy petroleum-based oils. One of the main differences being the types of materials used in pumps and other wetted components to ensure that chemical attack is minimized.

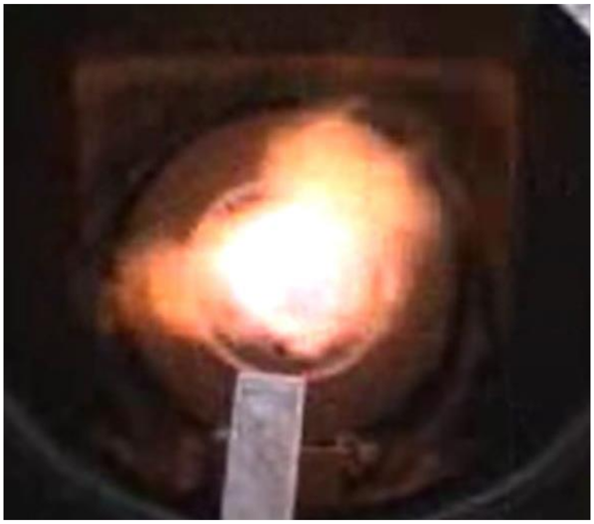

Figure 2 – Bloom 1206 burner firing on Methanol

Unfortunately, the story of biofuels is more complicated than it may first appear. For instance, while the fuel itself may contribute no net carbon to the atmosphere there is often a significant carbon footprint associated with the energy used to plant, fertilize, harvest, transport, and refine the feedstock used to make biofuels. Additionally, as demand for biofuels increases their feedstock become more valuable resulting in more land being dedicated to their production. This is often called direct land use change and can greatly reduce the potential of biofuels derived from some sources, such as wheat[3], to reduce greenhouse gas emissions. Further and even more difficult to quantify are indirect land use changes, a hypothetical example being the clearing of Amazonian rainforest due to increases in corn production in the US Midwest to support ethanol production. Some good news is that nonfood crop based, second generation, biofuels are being developed and some show greater potential than first generation fuels derived from food crops to lower carbon emissions. While precisely quantifying a biofuel's total carbon footprint is often not possible, those who are considering the use of one to lower the carbon footprint of an industrial heating applications should conduct their own careful research to identify the range of reduction factors attributed to that fuel. Only then can they compare the various carbon reduction estimates that they find to their own reduction goals and make a properly informed decision.

Hydrogen

Yet other option for reducing CO_2 is to choose a fuel that does not have carbon in it at all. If there is no carbon in the fuel, then there cannot be any carbon dioxide in the waste gas. One such fuel that has generated quite a bit of interest over the past 30-40 years is molecular hydrogen (H_2). Just like electricity and biofuels, the total carbon footprint of hydrogen will come down to its production source, which will be covered shortly. Before considering the carbon footprint of hydrogen, it makes sense to discuss the practicalities of using hydrogen in industrial heating applications and consider any potential adverse consequences such as increased NOx emissions.

Hydrogen Practicalities

In addition to decades of experience designing combustion systems which run on Coke Oven Gas (COG), that often contains 60% hydrogen by volume, Bloom has successfully fired many of its burner designs using pure hydrogen. **Figure 3** shows a 1610 air staged burner designed by Bloom Engineering firing vertically in a fluid heater using pure hydrogen. Bloom's 1430 small capacity conventional direct fired burner design and both its 1150 and 1650 regenerative burner designs have also been successfully fired using pure hydrogen with great success. One thing that all these burners have in common is the fact that the oxidant (air) and fuel (hydrogen) do not mix until they are in the combustion chamber. Other burner designs that rely on the premixing of air and fuel will likely be susceptible to flashback, especially at turndown, given that the flame speed of hydrogen in air is up to 9 times faster than the speed of natural gas in air. For large burners such as Bloom's 1230 and 1530 that premix the air and fuel prior to them entering the combustion chamber, testing of hydrogen as a fuel has been limited to mixtures of hydrogen and natural gas in which the hydrogen makes up no more than 8% of the total fuel volume. Additional testing would be needed if greater amounts of hydrogen enrichment were desired in Bloom burners of this type.

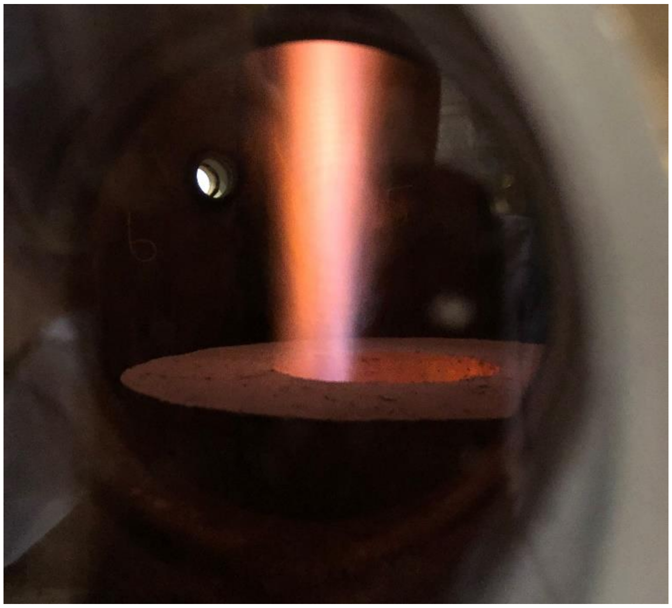

Figure 3 - Air Staged Hydrogen Burner Firing Vertically in a Fluid Heater

One consequence of burning hydrogen in air as opposed to natural gas is the potential for a modest increase in NOx emissions due in part to higher flame temperatures. The magnitude of any NOx penalty when running on hydrogen will depend on the burner design but can likely be minimized by changes to either the burner's fuel nozzle or fuel and air staging. Bloom has already begun to test optimized fuel nozzles for our 1150 regenerative burners and early versions have already been able to reduce or eliminate the NOx penalty (see **Figure 4**).

Comparing the NOx Increase from Bloom Burners when Operating on Hydrogen vs. Natural Gas

Bloom Burner Series	PPM NOx Increase Standard Nozzle (% - dry basis)	lb./MMBtu-[LHV] NOx Increase Standard Nozzle (%)	PPM NOx Increase Optimized Nozzle (% - dry basis)	lb./MMBtu-[LHV] NOx Increase Optimized Nozzle (%)
1430*	78	30	-	-
1150**	25	-9.1	-1.6	-28
1650**	13	-16	-	-

* 2200 °F furnace and 600°F air

** 2300 °F furnace

Figure 4

As seen in Figure 4, simply switching from natural gas to hydrogen can cause modest increases in a burner's NOx production as was the case with Bloom's 1430 burner. Further, one can see that NOx generation using 1150 and 1650 regenerative burners went down on a lb./MMbtu basis as these burner designs are much better suited for ultra-low NOx hydrogen firing even without modification. At this point, it is important to point out why it is possible for the ppm of NOx in the exhaust gasses on hydrogen to be greater than when firing on natural gas even though the lb./MMBtu might be the same or lower. The explanation for this comes down to the waste gas volumes of the two fuels. The total waste gas volume when firing hydrogen is lower per MMBtu than it is when firing natural gas. And, when sampling is done on a dry basis the waste gas volume of hydrogen combustion is lower still per unit of energy compared to natural gas resulting in more concentrated NOx (higher ppm) for the same amount (mass) of NOx. For a practical example, please consider two furnaces that are being heated by direct combustion and have the same NOx emissions equal to 0.1 lbs./MMBtu (LHV). If the first furnace is heated using natural gas the concentration of NOx in its flue gasses will be around 75 ppm when corrected to 3% O_2 on a dry basis. Assuming that the second furnace is heated using hydrogen the concentration of NOx in its exhaust gasses will be about 103 ppm when corrected to 3% O_2 on a dry basis. This is very important to note as a few air permits include a maximum concentration (ppm correct to a reference O2) limit and unless corrected would unfairly disadvantage hydrogen compared to natural gas and many other common hydrocarbon fuels (see **Figures 5A & 5B**).

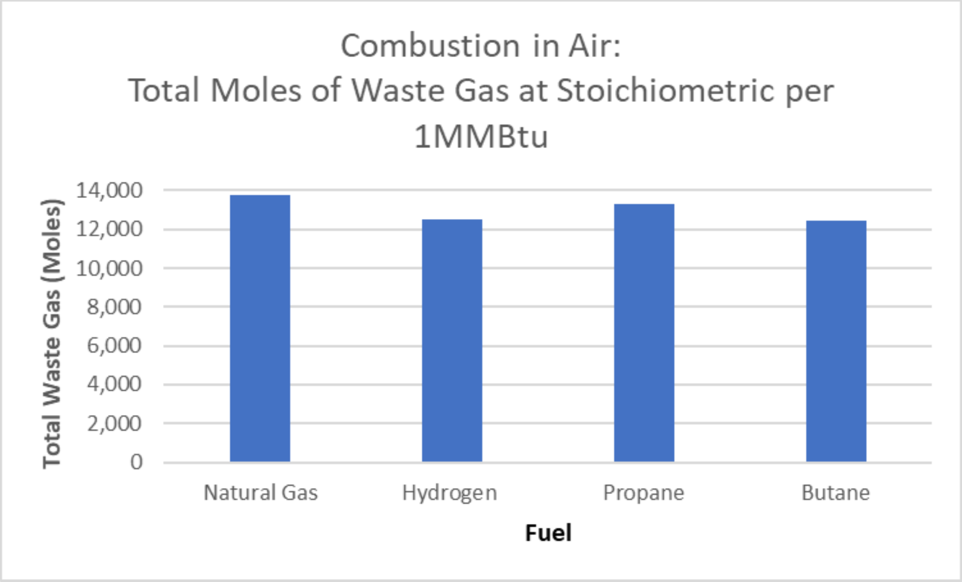

Figure 5A

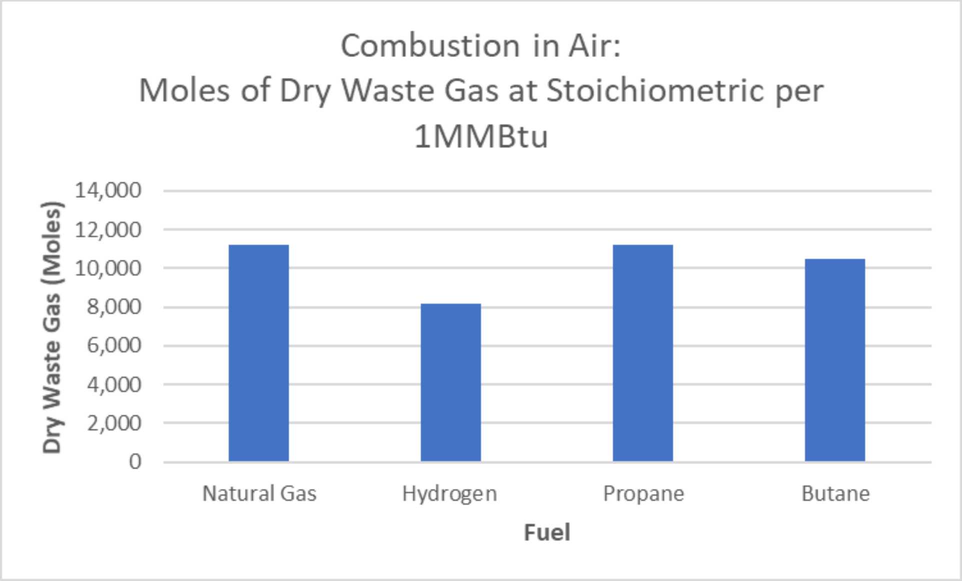

Figure 5B

Looking again at Figure 4, it also shows that Bloom was able to eliminate the NOx penalty associated with changing the fuel in an 1150 burner from natural gas to hydrogen even when NOx was being evaluated on the basis of ppm [dry] through fuel nozzle optimization. Interestingly, the optimized 1150 nozzle ended up being very similar to what is standard in a 1650 showing that Bloom's 1650 not only offers world class NOx performance on natural gas but is also a near optimal design without the need for modification for Ultra-Low NOx hydrogen combustion in high temperature applications.

In terms of combustion system design one advantage that hydrogen has is its Wobbe Index which can be very similar to some varieties of natural gas (see **Figure 6**). This means that in some instances metering equipment currently being used with natural gas will be able to handle enrichment or complete conversions to hydrogen with very little modification. It is not always a simple matter, though, to make a direct conversion to hydrogen. Its small molecule size which makes it prone to leakage. Amplifying the leakage issue is the fact that, due to hydrogen's high flame speeds, it is not uncommon for hydrogen burners to be run with higher fuel velocities which require higher static pressure in the delivery system. When talking about pure hydrogen, some common materials used for natural gas piping such as cast-iron pipe and fittings are prohibited by relevant codes including NFPA 54. For these reasons, if any existing fuel delivery system is to be converted over to hydrogen it should be thoroughly reviewed by a qualified combustion engineer.

	Higher Heating Value (Btu/SCF)	**Lower Heating Value (Btu/SCF)**	**Specific Gravity**	**Wobbe Index - HHV**	**Wobbe Index - LHV**
Natural Gas	1000	901	0.6	1291	1163
Hydrogen	325	275	0.07	1228	1039

Wobbe Index is equal to the heating value divided by the square root of the specific gravity

Figure 6

Hydrogen's Carbon Footprint

Today hydrogen can be broken into at least three distinct environmental impact categories, and each has a different price point. First, there is grey hydrogen which is generated by separating the carbon atoms in methane from their bonded hydrogen atoms through a two-step process called steam methane reforming (SMR). With this method, all resulting CO_2 is released into the atmosphere. Because steam is needed to drive SMR and assuming that the extra energy required to produce the steam ultimately comes from combustion, the final CO_2 tally for grey hydrogen as a fuel source shows that there is up to a 40% penalty over the direct combustion of natural gas. Further, at a current price point of up to $13 per gross MMBtu ($1.80 / kg H_2), there is no global environmental or cost justification to switch from natural gas to grey hydrogen.

A second option is to combine CCS with SMR and produce what is often called blue hydrogen. With this strategy about 80% of the carbon is removed from the waste stream. Unfortunately, CCS is not free and will increase production costs on the order of 25%. Recently, some analysts have put the cost of blue hydrogen at as high as $2.40 / kg or $17.50 per gross MMBtu.[4]

The third option for generating hydrogen is to produce it by splitting water molecules into oxygen and hydrogen. This can be done using electricity through a process called water electrolysis. If powered by renewable electricity, electrolysis has the potential of making hydrogen production nearly carbon free. Green hydrogen is the term being used when discussing hydrogen produced using electrolysis powered by renewable energy. Two major disadvantages of green hydrogen are the current low availability of renewable electric to produce it and its high cost. Sources in Europe have recently said that the cost of green hydrogen is between $3 and $6.55 / kg ($21.90 – $47.81 / gross MMBtu).[5]

Apart from hydrogen's high cost, currently there is simply not sufficient production capacity or distribution infrastructure to supply blue or green hydrogen in sufficient quantities to support the energy demands of industry. Even for companies looking to produce their own green or blue hydrogen, large capital investments would be necessary.

One method that governments have considered using to introduce some hydrogen into an economy is to mix it in with another fuel, such as natural gas, that already has a distribution network. If done across the entire distribution network, including industrial and residential customers, the amount of hydrogen that could be added would likely be limited to somewhere between 5 to 20% by volume due to the potential of higher flame speeds causing flashback in residential appliances whose designs largely rely on fuel/air premixing or natural draft. In time, new appliance designs could be developed that might allow for higher concentration of hydrogen to be added. **Figures 7A and 7B** show how much CO_2 could be mitigated via enrichment of natural gas up to 20% if it is assumed that the hydrogen used was obtained from green sources.

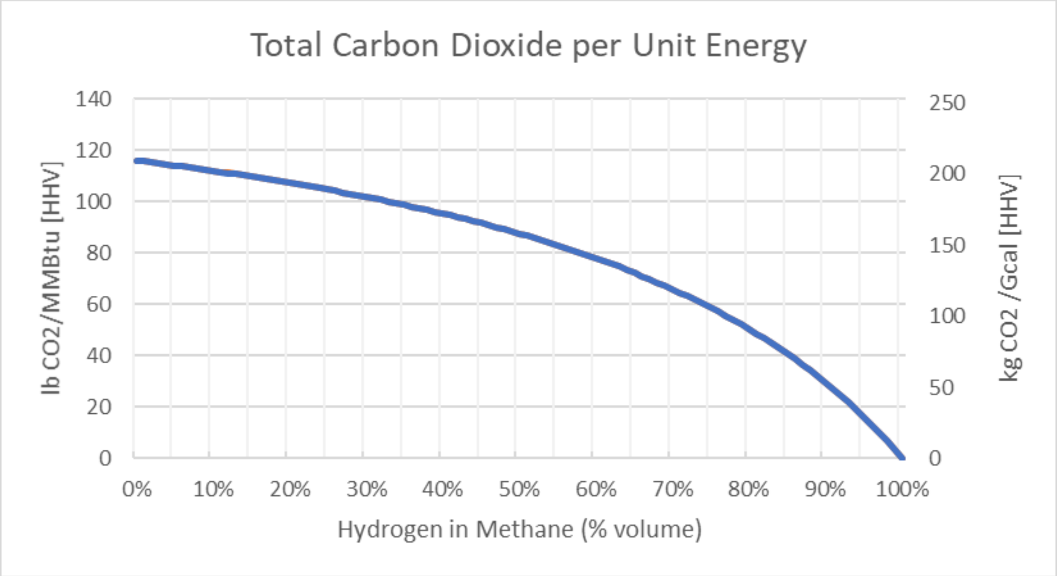

Figure 7A

Combustion of Natural Gas in Air with Various Levels of Hydrogen Enrichment								
				Stoichiometric Products of Combustion (POC)				
	Btu/SCF (HHV)	Btu/SCF (LHV)	Fuel Volume per MMBtu - LHV (SCF)	CO_2 per MMBtu (SCF)	H_2O per MMBtu (SCF)	N_2 per MMBtu (SCF)	CO_2 in Stoich. POC (%)	CO_2 Savings (%)
Natural Gas	1000	901	1110	1110	2164	8309	9.58	-
Natural Gas with 5% H_2	966	870	1149	1092	2187	8283	9.44	1.44
Natural Gas with 10% H_2	932	839	1192	1073	2211	8254	9.30	2.97
Natural Gas with 15% H_2	899	807	1239	1053	2240	8234	9.14	4.65
Natural Gas with 20% H_2	865	776	1289	1031	2268	8202	8.96	6.46
100% H_2	325	275	3636	0	3636	6836	0.00	100.00

Figure 7B

Figure 7B shows that adding Hydrogen to natural gas even at levels as high as 20% result in quite modest reductions in CO_2 and at 10%, which seems to be a common level talked about, CO_2 savings is only about 3%. Now, consider the cost of adding 10% green hydrogen to natural gas. If we assume a commodity cost for natural gas of $4.10 per MMbtu gross and a cost for green hydrogen of $35 per MMBtu gross the commodity fuel cost for a blend of 90% natural gas and 10% hydrogen will be $7.19. This equates to a commodity cost increase of 75% for a CO_2 reduction of only 3%. Could there be a better way to reduce CO_2?

Another way that Hydrogen might help reduce global greenhouse gas emissions, without requiring as much new distribution infrastructure to deliver broadly across industry for direct heating, is by offering a means to store excess renewable energy. Unlike traditional batteries, hydrogen can effectively store renewable energy for long periods of time and allow for its relatively clean release during times of high demand. To do this, renewable electric would be used to make hydrogen through electrolysis during times of excess supply. In this instance, the surplus supply would likely be seasonal otherwise more traditional battery technology would be more practical. Energy converted to hydrogen could then be stored in large quantities until needed. At this point the hydrogen could be converted back to electricity by gas turbines. Projects to do this are already being proposed and an example is the partnership between Mitsubishi Power Americas and Magnum Development to use salt domes in Utah to store green hydrogen that would then be used to generate electricity during times of low renewable production.

Combustion with Efficiency Boosting

There has been intense research to find economically viable and sustainable ways to minimize atmospheric carbon dioxide emission, especially as it relates to combustion. Perhaps the most straightforward way to do so would be simply to burn less fuel either through improvements in combustion efficiency, process efficiency or both. Three common types of combustion equipment that can increase combustion efficiency when properly applied are recuperators, regenerative burners, and oxy-fuel technology.

Take for example a box furnace that is heated using natural gas. If the combustion of this natural gas occurs with just 5% excess air using cold (100°F) combustion air the available heat (gross heat input minus the flue losses) will be about 43% of the fuel's heating value. This means that a process requiring 1MMBtu of available heat would need 1/.43 = 2.33 MMBtu of natural gas. Combusting this amount of natural gas would release 2.33 MMBtu natural gas * 120 lbs. CO_2 / MMBtu = 280 lbs. CO_2. A recuperator is a heat exchanger that is used to recover some heat from a furnace's exhaust gases by preheating incoming combustion air. If a recuperator were applied to this example furnace and an air preheat of 750°F was achieved the available heat would increase to about 55% of the fuel's gross heating value thus reducing CO_2 emissions to 221 lbs. (a 20% reduction in carbon dioxide!).

If properly designed regenerative burners (**Figure 8**) or oxy-fuel technology were applied to this same furnace running at the same temperature and level of excess oxygen the available heat would increase to about 75% of the fuel's gross heating value. With this higher efficiency, CO_2 emissions per MMBtu of available heat drop to 160 lbs. or less than 60% of what resulted from cold air combustion. However, when trying to reduce carbon emissions it becomes important to consider how changing one parameter may lead to increases somewhere else. For instance, there is the potential for CO_2 emissions associated with the electricity being used to run the combustion air blowers of any forced air systems. The amount of blower power needed is lowest for the oxy-fuel system followed by ones using cold air. Recuperated air and regenerative system blower power requirements trend upward respectively. But, to run at 5% excess oxygen the oxy-fuel system must be supplied with concentrated O_2 in an amount of 175 lb. / MMBtu of natural gas burned which requires significant amounts of power to produce. **Figure 9** provides a summary showing the total CO_2 required to provide 1 MMBtu of available heat to the example box furnace when both total fuel burned and electricity use is accounted for.

Figure 8
Pair of Regenerative Burners

CO_2 Generated to Provide 1 MMBtu of Available Heat to a Box Furnace with 2,050°F Flue Gasses

	Cold Air (100°F)	Recuperated Air (750°F)	Regenerative Air (1,775°F)	Oxi-fuel
Natural Gas Needed (MMBtu)	2.33	1.82	1.33	1.33
CO_2 Produced from Fuel (lbs)	280	218	160	160
Blower Power Needed (kWh)	2.7	2.6	5.4	-
Grid Efficiency (%)	95.0	95.0	95.0	95.0
Cryognenic Seperator Power (kWh)				23
Total Electric Required (kWh)	2.8	2.7	5.7	24.5
CO_2 Associated with Oxidant (lbs)	2.4	2.4	5.0	21
Total CO_2 (lbs)	**282**	**221**	**165**	**181**

* Based on the use of a cryogenic air separator that requires 200kWh/ton O_2[6]

**Calculated using the US average of 0.417 kg CO_2 (0.92 lbs. CO_2) emitted for every kWh of electricity produced

Figure 9

In the above example we saw that regenerative burner technology was able to reduce the carbon emissions from this box furnace running on natural gas by more than 41%. If this level of CO_2 reduction was to be achieved using hydrogen enriched natural gas, more than 70% of the fuel's total volume would have to be green hydrogen. If we assume, as we did earlier, that the commodity cost of natural gas is $4.10 per MMBtu and that green hydrogen is $35 per MMbtu, then the price of the combined fuel would be nearly $26!

In addition to adopting more fuel-efficient technology, another simple but sometime overlooked approach to reducing CO_2 is to minimize excess combustion air if the process and products will allow. **Figure 10** below shows that our box furnace, when running on cold air, produces about 15% less CO_2 when running with only 5% excess air compared to 20% excess air. This is 5 times more CO_2 than would be mitigated by adding 10% H_2 to the natural gas supply. Further, unlike adding H_2 to the fuel, reducing the excess air to the furnace will reduce fuel cost and likely not require any more expense than some basic tuning service and furnace maintenance**.**

CO_2 Generated to Provide 1 MMBtu of Available Heat to a Box Furnace with 2,050°F Flue Gasses		
	Cold Air (100°F, λ = 1.05)	**Cold Air (100°F, λ = 1.20)**
Natural Gas Needed (MMBtu)	2.33	2.68
CO_2 Produced from Fuel (lbs)	280	322
Blower Power Needed (kWh)	2.7	3.1
Grid Efficiency (%)	95.0	95.0
Cryognenic Seperator Power (kWh)		
Total Electric Required (kWh)	2.8	3.2
CO_2 Associated with Oxidant (lbs)	2.4	2.8
Total CO_2 (lbs)	**282**	**324**

Figure 10

One final point to discuss related to combustion efficiency is CO_2 taxes. In some jurisdictions, fossil fuels such as natural gas are being taxed based on the CO_2 that their combustion will release. These taxes are not universal, but as efforts intensify to reduce global climate change, it is likely that they will be applied in more places. If imposed, these taxes will increase fuel costs as shown in **Figure 11**. Reducing fuel consumption will be the only way to limit the added cost of these taxes, especially for those heating processes without access to other alternative sources of low carbon energy discussed earlier.

Added Cost of CO_2 Taxes per MMBtu Burned			
	Tax Rate ($/Ton CO_2)		
	$ 8.00	**$ 51.00**	**$125.00**
LHV	$ 0.53	$ 3.40	$ 8.32
HHV	$ 0.48	$ 3.06	$ 7.50

Figure 11

Final Thoughts

Reducing global carbon emissions will likely involve most, if not all, the above approaches. As renewable electricity sources become more abundant, some heating processes looking to reduce their carbon footprint might decide to skip combustion entirely and move to resistive or inductive heating. Others may turn to second or later generations of biofuels to satisfy their energy needs. Green hydrogen might also play its part when electric heating and biofuels are not viable options for a specific application.

Obviously, hydrogen is getting a lot of attention lately for its potential as a low carbon fuel; however, as discussed above, just like electricity and biofuels, its source must be carefully selected, or overall carbon emissions attributed to its use in an industrial heating application could increase compared to combustion with natural gas. While the options discussed above offer promise, most are still expensive and, in many cases, not capable of being produced in sufficient quantities to represent a real solution to excess CO_2 emissions today. Until then, improving process efficiency or adopting high efficiency combustion technology such as regenerative burners offer an immediate way to reduce carbon emissions. As was shown in Figure 9, when properly applied, regenerative technology can drastically increase available heat compared to cold air combustion and decrease fuel use. Also, the fuel saving potential of regenerative technology is not limited to just hydrocarbon fuels but could also be applied when burning other fuels including hydrogen and biofuels, which regardless of how they are produced, could be quite expensive.

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