

Reducing the Carbon Intensity of Methanol for Use as a Transport Fuel

Impact of technology choice on greenhouse gas emissions when producing methanol from natural gas

Alan Ingham

Johnson Matthey, 10 Eastbourne Terrace,
London W2 6LG, UK

Email: alan.ingham@matthey.com

Methanol is increasingly being looked at as a way to reduce the emissions potential of transport fuel. It may be used in place or in addition to gasoline fuel, for example. The amount of greenhouse gas (GHG) emitted in producing methanol can vary hugely according to the syngas generation technology selected and the choice of electrical or steam turbine drive for compressors and pumps. This paper looks at the impact of these technology choices on GHG emissions and how the carbon intensity of methanol used as a transport fuel compares to the carbon intensity of other hydrocarbon fuels. It is found that methanol produces lower well to wheel emissions than gasoline under all production methods studied and can even produce lower GHG emissions compared to ethanol as a fuel supplement. However, the same is not always true if methanol is used to produce gasoline from natural gas.

1. Introduction

Many countries around the world are either using or looking to use methanol as a fuel. China is currently leading the way and in 2015 used as much as 12 million metric tonnes of methanol to fuel its cars, trucks and buses. Methanol now makes up 8% of the Chinese fuel pool and in over a dozen provinces fuel blends such as M15 (15% methanol and 85% gasoline) are sold for

use in existing passenger cars (1). Methanol is an affordable alternative transportation fuel due to its efficient combustion, ease of distribution and wide availability around the globe. Methanol is a high octane fuel that enables very efficient and powerful performance in spark ignition engines. Engines optimised for methanol could provide an energy based efficiency gain of 50% over a standard (port fuel injected, non-turbo) gasoline engine in a light-duty vehicle (2).

Two different methods are used to compare the emissions from the flowsheets, the first is the direct GHG emissions from the methanol plant as a carbon dioxide flowrate per hour and the second is the carbon intensity of producing methanol based on the total carbon emitted from the process per unit of energy, and is expressed as grams of CO₂ equivalent per megajoule of methanol on a lower heating value (LHV) basis (gCO₂e MJ⁻¹ MeOH).

2. Natural Gas to Methanol Flowsheets

To produce methanol from natural gas, the natural gas must first be reformed to syngas before converting this syngas to methanol, further details of the Johnson Matthey reforming options can be found elsewhere (3). In order to generate a syngas with the correct stoichiometry for methanol production there are four main process flowsheets for reforming the natural gas:

1. steam-methane reforming (SMR)
2. SMR with maximum CO₂ addition (SMR + CO₂)
3. combined reforming (CR), with SMR and autothermal reforming (ATR)
4. gas heated reforming (GHR) and ATR (GHR + ATR).

Each of the reforming options listed above has advantages and the choice of flowsheet depends on a number of parameters, with the most influential being the natural gas composition, operating cost and capital cost. There are several other factors that also have a significant influence when assessing the benefits of each process and the environmental impact of the plant is becoming increasingly more important. This is most noticeable in North America where the cheap natural gas price has led to numerous methanol projects being developed, all of which require a Title V environmental permit before construction can begin (4).

Figure 1 is an overview of the flow of carbon and the emission points from the methanol plant for Flowsheets 1 to 3. **Figure 2** shows the same overview but for Flowsheet 4, the GHR + ATR flowsheet, which due to the nature of the reforming section has a different layout.

Using a typical North American pipeline natural gas composition from a recent methanol project in the USA, a comparison of the natural gas efficiency, electrical power consumption and CO₂ emissions for the four flowsheets is shown in **Table I** based on a capacity of 5000 mtpd. These flowsheets are based on driving all compressors and large pumps with steam driven turbines and utilising import electricity to drive the air cooler fans and smaller pumps only. This is the minimal electrical import to the inside battery limit (ISBL) plant without the addition of a turbo generator, where the ISBL plant refers to the methanol unit only and does not

include utilities other than the air separation unit (ASU), where applicable. The natural gas efficiency, on a LHV basis, has been split out to show where the natural gas is used within the ISBL plant and is quoted on a per tonne of methanol basis.

As an alternative flowsheet option, it is also possible to minimise the amount of natural gas burnt in the auxiliary boiler by maximising the number of compressors that are driven by motors, allowing an improvement in the natural gas efficiency of the ISBL plant as well as reducing the CO₂ emissions. The values in **Table II** are based on maximising the import electricity while maintaining the minimum load on the auxiliary boiler.

Two important trends are displayed in **Tables I** and **II**. The first is that the CO₂ emissions in **Table I** move in line with the natural gas efficiency of the flowsheet, with the exception of the SMR + CO₂ flowsheet. This stands to reason because, as **Figures 1** and **2** show, again with the exception of the SMR + CO₂ flowsheet, natural gas is the only carbon input into the ISBL plant, with methanol and CO₂ emissions the only output. Therefore, any carbon in the natural gas not converted to methanol will eventually leave the plant as CO₂. The SMR + CO₂ flowsheet is the exception to this rule as additional carbon is added to the process in the form of CO₂ injected upstream of the reformer. This additional carbon helps improve the natural gas efficiency but at the expense of increasing the CO₂ emissions from the ISBL plant. The increase in CO₂ emissions for the SMR + CO₂ flowsheet is due

(a)

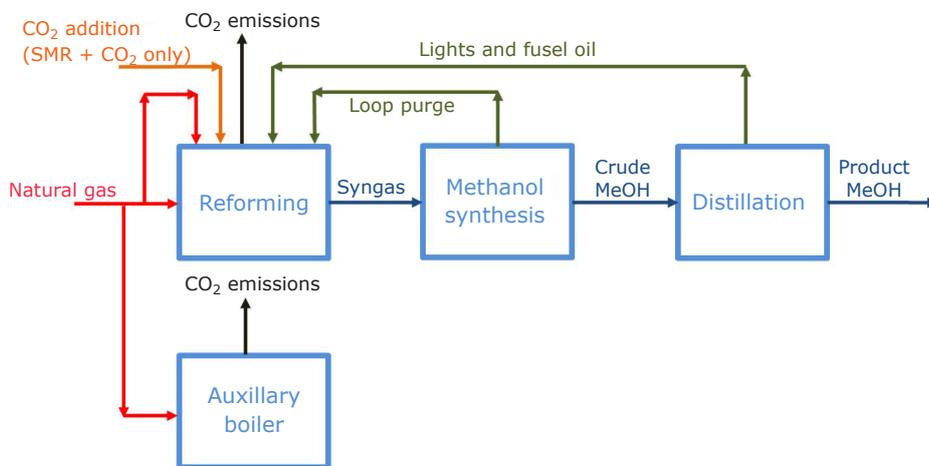


Fig. 1. Methanol plant overview for Flowsheets 1–3: (a) diagram of the unit operations for Flowsheets 1–3; (b) picture of a SMR + ATR used in Flowsheet 3

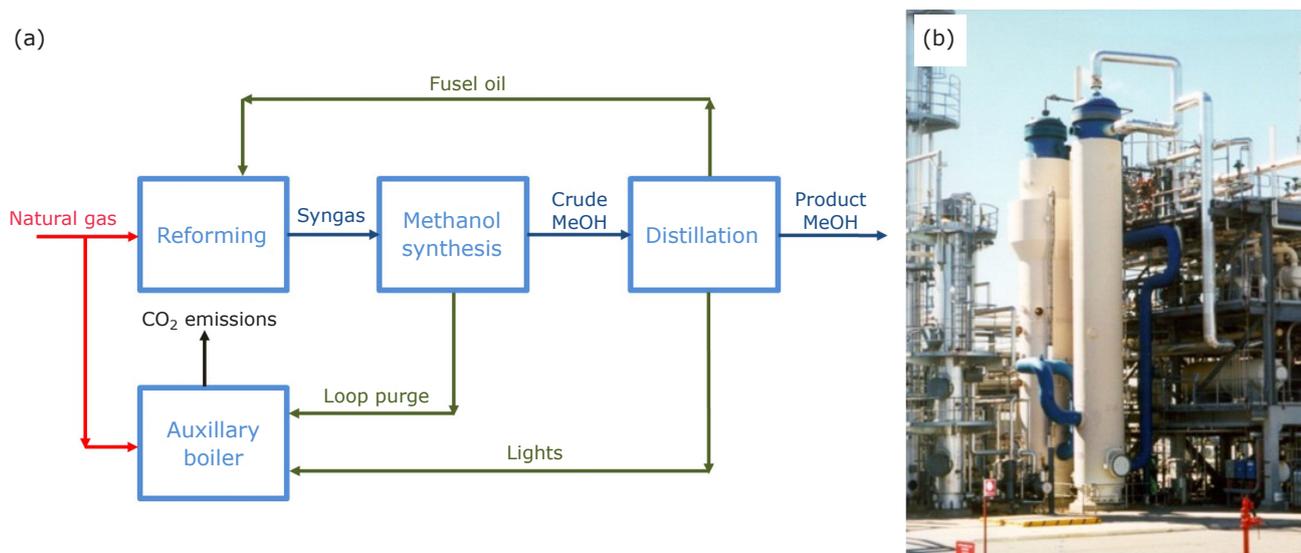


Fig. 2. Methanol plant overview for Flowsheet 4: (a) diagram of the unit operations for Flowsheet 4; (b) picture of a GHR + ATR used in Flowsheet 4

Table I 5000 mtpd Methanol Plant Comparison for Minimal Electrical Import					
	Units	SMR	SMR + CO ₂	CR	GHR + ATR
Overall natural gas efficiency (LHV)	GJ mt ⁻¹	32.6	31.6	30.8	31.0
Process		29.6	24.0	27.0	25.5
Reformer		1.7	6.4	3.0	0.0
Auxiliary boiler		1.3	1.2	0.8	5.5
Electricity	MW (MMBtu)	5.0 (17)	5.0 (17)	3.6 (12.3)	4.5 (15.4)
CO₂ emissions^a	mt h ⁻¹ (st h ⁻¹)	92.8 (102.3)	144.9 [80.9] (159.7 [89.2])	71.7 (79.0)	77.3 (85.2)

^aBased on using captured CO₂ as a feedstock, the net CO₂ emissions are shown in [] brackets

Table II 5000 mtpd Methanol Plant Comparison for Maximum Electrical Import					
	Units	SMR	SMR + CO ₂	CR	GHR + ATR
Overall natural gas efficiency (LHV)	GJ mt ⁻¹	32.4	31.4	30.7	25.5
Process		29.6	24.0	27.0	25.5
Reformer		1.7	6.4	3.0	0.0
Auxiliary boiler		1.1	1.0	0.7	0.0
Electricity	MW (MMBtu)	13.4 (45.7)	12.9 (44.0)	8.3 (28.3)	90.5 (308.6)
CO₂ emissions^a	mt h ⁻¹ st h ⁻¹	90.4 (99.6)	142.8 [78.8] (157.4 [86.9])	70.9 (78.2)	13.9 (15.3)

^aBased on using captured CO₂ as a feedstock, the net CO₂ emissions are shown in [] brackets

to both the increase in natural gas fuel required in the reformer because of the reduced LHV of the methanol loop purge gas as well as an increase in CO₂ concentration in the recycled fuel from the methanol loop and distillation. Therefore, with any CO₂ injection flowsheet aside, the better the natural gas efficiency of the ISBL plant the lower the CO₂ emissions. If captured CO₂ is used as a feedstock to the ISBL plant for CO₂ injection flowsheets then **Tables I** and **II** show that the net CO₂ emissions fall back in line with this trend.

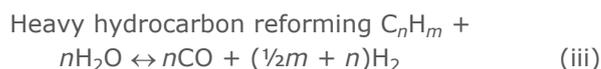
The second important trend is that as the comparison between **Tables I** and **II** shows, for the SMR, SMR + CO₂ and CR flowsheets there is no significant scope to maximise the electrical import while maintaining the minimum auxiliary boiler load. The SMR, SMR + CO₂ and CR flowsheets all generate high pressure (HP) steam as a way of cooling the process gas after reforming. This steam is a useful byproduct of the cooling process because it can be used to power the turbines of the large compressors on the plant. In addition, all flowsheets have an auxiliary boiler, whose primary purpose is for start-up and shut-down. In normal operation the boiler is kept running but it has a minimum turndown and so this steam also has to be utilised within the ISBL plant. After all this steam has been consumed, the additional power requirements of the smaller compressors are minimal and hence there is no real benefit in switching from steam turbine driven to motor driven compressors for reducing the ISBL plant emissions and improving the natural gas efficiency. In contrast, the GHR + ATR flowsheet uses the high temperature process gas to provide heat for the reforming reaction in the GHR, which then allows all the compressors and large pumps to be electrically driven if required. The ability to decouple the power requirement for the compressors and large pumps from the ISBL plant, and the fact that the GHR + ATR flowsheet does not contain a SMR, means that the CO₂ emissions of the ISBL plant can be reduced significantly for normal operation, as shown in **Table II**.

3. Gas Heating Reforming and Autothermal Reforming Flowsheet

To understand why the GHR + ATR flowsheet allows for increased flexibility in choosing the power to drive the rotating equipment, a more detailed description of the flowsheet is given below.

The GHR + ATR flowsheet incorporates a GHR in series with an ATR, with an interchanger on the feed to the GHR, as shown in **Figure 3**.

The GHR consists of a refractory lined vessel containing vertically supported tubes filled with nickel catalyst. The feed gas is preheated by the GHR shell-side effluent gas before it passes down through the tubes where the endothermic reforming reaction takes place (Equations (i)–(iii)).



The heat required to drive the reaction is provided by reformed gas from the ATR which flows counter-currently on the shell-side of the reactor. The partially reformed gas leaves the tube-side of the GHR at approximately 700°C.

The product from the GHR is fed to the ATR, which is also a refractory lined vessel. Oxygen is fed to the burner gun of the ATR and this then mixes with the hydrocarbon feed and burns in the upper section of the ATR. In the middle section the hot gas passes over a fixed catalyst bed, where the temperature drops as the endothermic reactions proceed.

Sufficient oxygen is fed to produce a temperature exiting the catalyst bed of 1020°C and at these conditions the reformed gas contains low levels of methane slippage. The hot reformed gas from the exit of the ATR passes to the shell-side of the GHR where it flows counter-currently to the tubes and

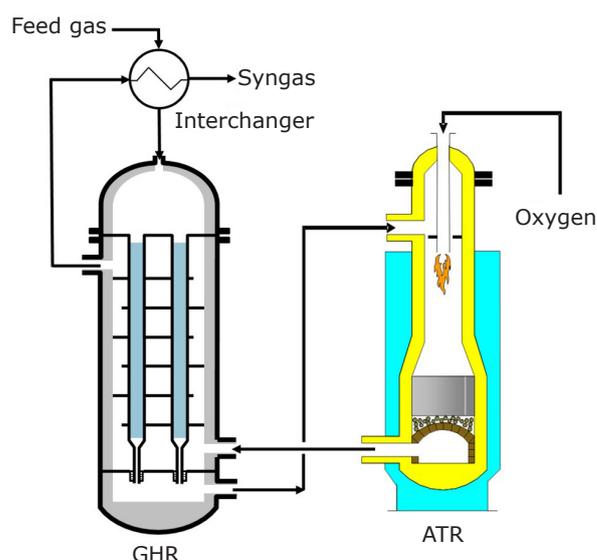


Fig. 3. GHR + ATR flowsheet arrangement

provides sufficient heat for the reforming reaction in the GHR tubes. The reformed gas, now known as synthesis gas (syngas), exits the shell-side of the GHR and passes to the interchanger where it preheats the incoming feed gas. The syngas exits the interchanger then passes to the downstream heat recovery.

No steam generation is required as all the high grade process heat is recycled directly back into the process which provides the ability to decouple the power requirement for the GHR + ATR flowsheet and move it outside battery limits (OSBL). This is an effective method of reducing the emissions and improving the natural gas efficiency of the ISBL plant. However, typically the imported power to the plant will be from the grid, where the electricity is generated from a portfolio of technologies, with the largest contribution generally from fossil fuels burnt in a power plant. A typical North American portfolio of grid electricity is shown in **Figure 4** and this shows that 68% of the electricity is generated through burning carbon fuels.

The imported power means that the source of the CO₂ emissions generated by producing the electrical power is transferred from the ISBL plant to the existing producers, so essentially the emissions are just being moved from one location to another. When building a new methanol plant, this is advantageous as the emissions required for the Title V environmental permit in the USA are only those for the new plant and do not include those for the existing producers supplying the import electricity. Therefore, in areas where GHG emissions are restricted, the GHR + ATR flowsheet with imported power offers the best flowsheet for

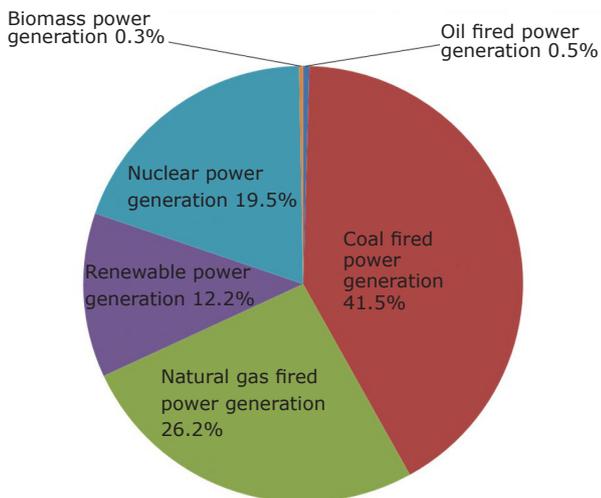


Fig. 4. A typical North American electricity mix (5)

reducing GHG emissions for the ISBL plant and also for providing a natural gas efficient flowsheet.

Importing electricity allows the ISBL emissions to be reduced but it doesn't give a complete representation of the carbon intensity of producing methanol using the GHR + ATR process. For certain states in the USA and Canada, for example California, there has been a drive to reduce the carbon intensity of the fuels they use and this has resulted in the implementation of legislation in California called the low carbon fuel standard (LCFS), a summary of which is given in **Appendix A**. This standard looks at the total carbon emissions of a fuel from well to wheels and so tries to capture the total carbon intensity of that fuel over its whole life cycle. So taking gasoline as an example, the LCFS aims to take into account the GHG emissions during the extraction and refining of the crude oil, transporting the gasoline to the pump as well as the emissions from the combustion engine in the vehicle. In order to enable the carbon intensity of these fuels to be determined from well to wheels, software has been developed to calculate the GHG emissions over the whole life cycle of the fuel. This software can therefore also be used to determine the carbon intensity of producing methanol on a well to product basis, thus incorporating the GHG emissions from transporting the natural gas to the plant, the electricity used in the plant and from storing the methanol.

4. The Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model

GREET is the software developed by Argonne National Laboratory, USA, in conjunction with the Californian government's LCFS to enable the calculation of GHG emissions for fuels produced and imported into the state of California (6). The software uses pathways to break each step of the product life cycle down and enables the emissions from each section of that process to be determined.

Using the GREET software, the figures generated below in **Tables III** and **IV** show the well to product values for the four flowsheets based on steam driven turbines for the compressors and large pumps, as **Table I**. The first section of the table is divided into three parts for the GHG emissions. The first is the processing and transportation of natural gas from the well to the methanol plant, the second is the emissions from the ISBL plant and the third is the storage of the methanol. The second section shows the GHG emissions for the

Table III GREET Numbers for Minimum Electrical Import^a

Stage	Units	SMR	SMR + CO ₂	CR	GHR + ATR
(a) Natural gas to plant	gCO ₂ e MJ ⁻¹ methanol	13.0	12.6	12.3	12.4
(b) Methanol plant^b	gCO ₂ e MJ ⁻¹ methanol	23.1	36.0 (20.1)	17.8	19.2
(c) Methanol storage	gCO ₂ e MJ ⁻¹ methanol	1.3	1.3	1.3	1.3
Subtotal^b	gCO ₂ e MJ ⁻¹ methanol	37.4	49.9 (34.0)	31.4	32.9
Electricity					
North America mix	gCO ₂ e MJ ⁻¹ methanol	0.76	0.76	0.54	0.67
Renewable mix	gCO ₂ e MJ ⁻¹ methanol	0.005	0.005	0.003	0.004
Total (North America mix)^b	gCO ₂ e MJ ⁻¹ methanol	38.1	50.7 (34.8)	32.0	33.6
Total (renewable mix)^b	gCO ₂ e MJ ⁻¹ methanol	37.4	49.9 (34.0)	31.4	32.9

^aThe GREET values quoted in **Tables III** and **IV** have been peer reviewed but have not been confirmed as official GREET numbers by the Californian government

^bThe net CO₂ GREET GHG emissions are shown in brackets

Table IV GREET Numbers for Maximum Electrical Import^a

Stage	Units	SMR	SMR + CO ₂	CR	GHR + ATR
(a) Natural gas to plant	gCO ₂ e MJ ⁻¹ methanol	12.9	12.5	12.2	10.2
(b) Methanol plant^b	gCO ₂ e MJ ⁻¹ methanol	22.5	35.5 (19.6)	17.6	3.5
(c) Methanol storage	gCO ₂ e MJ ⁻¹ methanol	1.3	1.3	1.3	1.3
Subtotal^b	gCO ₂ e MJ ⁻¹ methanol	36.7	49.3 (33.4)	31.2	15.0
Electricity					
North America mix	gCO ₂ e MJ ⁻¹ methanol	2.03	1.95	1.23	13.7
Renewable mix	gCO ₂ e MJ ⁻¹ methanol	0.012	0.012	0.008	0.083
Total (North America mix)^b	gCO ₂ e MJ ⁻¹ methanol	38.7	51.3 (35.4)	32.4	28.7
Total (renewable mix)^b	gCO ₂ e MJ ⁻¹ methanol	36.7	49.3 (33.4)	31.2	15.1

^aThe GREET values quoted in **Tables III** and **IV** have been peer reviewed but have not been confirmed as official GREET numbers by the Californian government

^bThe net CO₂ GREET GHG emissions are shown in brackets

distributed electricity to the ISBL plant. There are two figures relating to the import electricity: the first is based on the standard North American electricity mix, as shown in **Figure 4**, and the second is based on a standard renewable energy electricity mix, as shown in **Figure 5**.

As **Figure 6** shows, the USA and China are leading the way in the installation of renewable energy and therefore being able to use electricity where the majority or all of the energy comes from a renewable source is a distinct possibility in the near future. This real possibility of access to electricity from a renewable source is why this option has been considered. In addition, it also gives a good

indication of the total possible reduction in carbon intensity of producing methanol.

The units for the values in **Tables III** and **IV** are grams of CO₂ equivalent per megajoule of methanol on a LHV basis (gCO₂e MJ⁻¹ MeOH).

The GREET GHG emission values in **Table III**, for flowsheets with the minimum electrical import, follow the same trend as the CO₂ emissions in **Table I**. This is because for the minimum electrical import flowsheets the contribution to the GHG emissions from the import electrical power is minimal and so the total emission figures are dominated by the emissions from transporting the natural gas to the ISBL plant and from the ISBL plant itself.

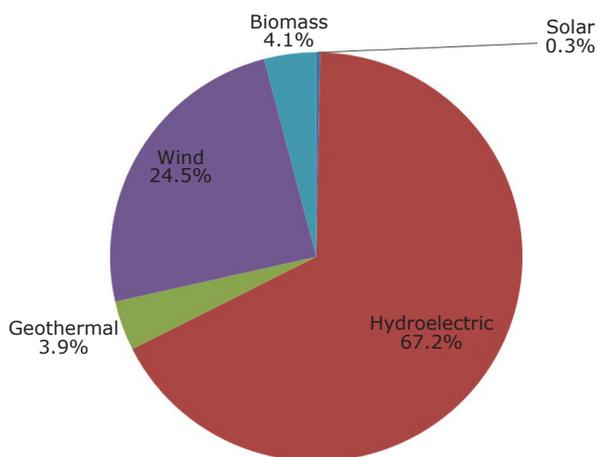


Fig. 5. Standard renewable energy mix (7)

However, the GREET GHG emission values in **Table IV**, for flowsheets with the maximum electrical import, show a different trend. For the SMR, SMR + CO₂ and CR flowsheets, moving to the maximum electrical import actually increases the overall well to product GHG emissions compared to the values in **Table III** when using the typical North American electricity mix and only a small reduction when using the renewable electricity mix. This is compared to the GHR + ATR flowsheet which shows a reduction in GHG emissions of 15% and 54% when using the typical North American electricity mix and the renewable electricity mix respectively. The reason for the increase in GHG emissions for

the SMR, SMR + CO₂ and CR flowsheets when using the typical North American electricity mix compared to a reduction in emissions for the GHR + ATR flowsheet centres around the plant heat integration and utilisation of the steam from the auxiliary boiler. For the SMR, SMR + CO₂ and CR flowsheets the generation of HP steam in the reformed gas cooling train means that there is only sufficient heat remaining in the reformed gas to provide approximately 55% of the distillation duty, with the remaining duty provided by low pressure (LP) steam. There is therefore a large LP steam demand, which typically has been satisfied by using medium pressure (MP) steam in back pressure turbines, with the LP steam header topped up by letting down a small amount of MP steam. This therefore maximises the amount of work performed by the MP steam. When, however, the compressors driven by these turbines are switched to motor driven, the LP steam demand remains the same and so the shortfall in LP steam is made up by letting down more of the MP steam. This then results in the use of MP steam becoming less efficient and so the GHG emissions for the combined ISBL plant and import electricity actually increase. For the GHR + ATR flowsheet, the LP steam demand is small because all the distillation duty is provided by the reformed gas train cooling so the flowsheet does not need to incorporate backpressure turbines to satisfy the LP steam demand. Therefore, switching the compressors from turbine to motor driven does

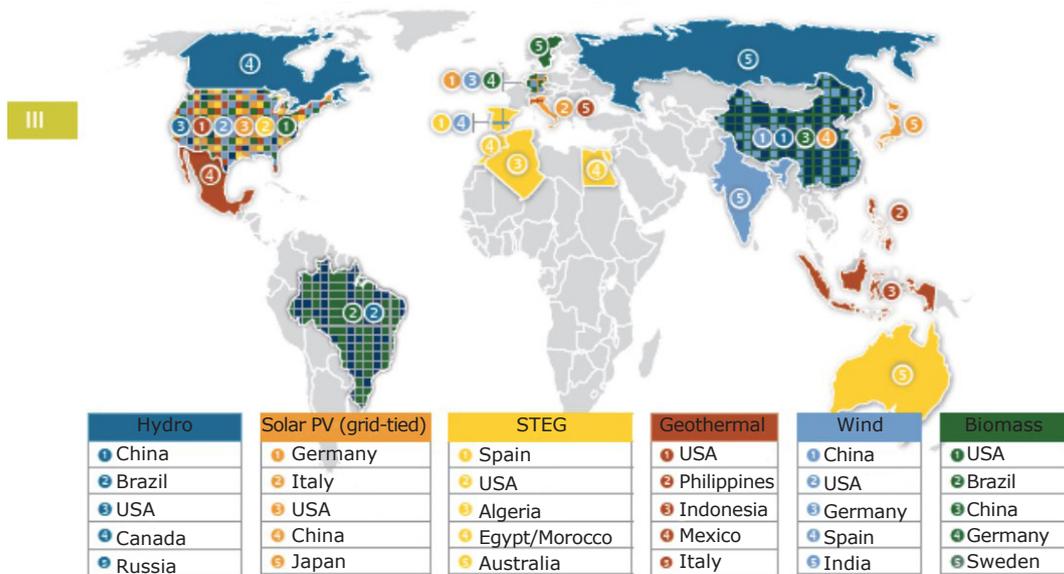


Fig. 6. Top countries with installed renewable electricity by technology in 2012 (8). PV = photovoltaic; STEG = solar thermoelectric generator

not mean additional MP steam has to be let down to the LP steam level and so removing the steam driven turbines has a direct impact on the load of the auxiliary boiler, in proportion to the increase in electrical load and hence allows a total reduction in emissions.

For the GHR + ATR flowsheet, running all the compressors, pumps and air coolers on imported electricity shows a modest saving on the GHG emissions if the supplied electricity is from the grid with a typical North American electricity mix. However, using a renewable energy source to provide the electrical import power to the plant has a significant impact on the GHG emissions for producing methanol from natural gas, with the

emissions over half that of the CR flowsheet, which has the second best emission figures. The GHR + ATR flowsheet is the only flowsheet that doesn't generate HP steam as a byproduct of the process, allowing a large portion of the energy requirement of the ISBL plant to come from electricity import. This in turn allows a large portion of the energy required to make methanol to come from a renewable source.

In addition to calculating the well to product GHG emissions using GREET it is also possible to go one step further and calculate the well to wheels value which allows methanol as a fuel to be compared to all the other available transportation fuels. **Table V** shows the comparison between the methanol well

Table V Well to Wheel Greenhouse Gas Emissions (9)

Fuel	Vehicle	Vehicle operation	Well to product	Total
		gCO ₂ e MJ ⁻¹	gCO ₂ e MJ ⁻¹	gCO ₂ e MJ ⁻¹
Methanol (85%) + Reformulated gasoline E10 (15%). Methanol produced using maximum North America mix electrical import (Notes (i) and (ii))	Methanol flexible-fuelled car	26.6	(a) 36.7	(a) 63.2
			(b) 47.3	(b) 73.9
			(33.8)	(60.4)
			(c) 31.3	(c) 57.9
Methanol (85%) + Reformulated gasoline E10 (15%). Methanol produced using maximum renewable mix electrical import (Notes (i) and (ii))	Methanol flexible-fuelled car	26.6	(a) 35.0	(a) 61.5
			(b) 45.7	(b) 72.3
			(32.2)	(58.7)
			(c) 30.3	(c) 56.8
(d) 16.6	(d) 43.1			
Reformulated Gasoline E10 (100%)	Gasoline car	66.3	25.0	91.3
Low sulfur diesel (100%)	Diesel car	75.7	17.1	92.8
Compressed natural gas (100%)	Compressed natural gas car	57.6	18.6	76.2
Liquefied petroleum gas (100%)	Liquefied petroleum gas car	64.7	12.5	77.2
Ethanol E85 (100%) (Note (iii))	Ethanol flexible-fuelled car	12.6	57.7	70.4
Gaseous hydrogen (100%)	H ₂ car	0.8	94.5	95.3
Fischer-Tropsch diesel (100%)	Fischer-Tropsch diesel car	73.1	36.5	109.6
Electricity (100%) (Note (iv))	Electric car	0	174.4	174.4

Notes for Table V

i) The numbering for well to product and total GREET GHG emissions refers to the following flowsheets:

1. SMR
2. SMR + CO₂
3. CR
4. GHR + ATR

The GREET values quoted for the methanol (85%) + reformulated gasoline E10 (15%) fuel have been peer reviewed but have not been confirmed as official GREET numbers by the Californian government

ii) The net CO₂ GREET numbers are shown in brackets

iii) Based on USA ethanol produced from corn

iv) Electricity based on typical North America mix

to wheels carbon emissions and some of the other standard fuel types.

What **Table V** shows is that methanol as a fuel has a lower carbon intensity than gasoline over its full life cycle, irrespective of which flowsheet is used to produce the methanol. It also highlights that methanol as a blend stock for gasoline is less carbon intensive than using ethanol, unless non-captured CO₂ injection is used on the flowsheet.

When producing gasoline from crude oil, the well to product value for reformulated gasoline E10 in **Table V** is 25.0 gCO₂e MJ⁻¹. Therefore, to reduce the carbon intensity the well to product GHG emissions for producing gasoline from natural gas *via* methanol would need to be below 25.0 gCO₂e MJ⁻¹. As **Tables III** and **IV** show, with the exception of the GHR + ATR flowsheet, the GHG emissions for producing methanol from natural gas range from 31.2–51.3 gCO₂e MJ⁻¹ which is already higher than the 25.0 gCO₂e MJ⁻¹ for refining crude oil. Therefore, even if the carbon intensity of producing gasoline from methanol was zero, it would not be possible to produce gasoline with a lower carbon intensity from natural gas *via* methanol. The only exception to this is the GHR + ATR flowsheet using the maximum electrical import from a renewable energy source which has a well to product value of 15.1 gCO₂e MJ⁻¹ and there are companies that are currently developing novel flowsheets, incorporating the GHR + ATR process and renewable energy sources to produce low carbon intensity gasoline from natural gas.

Conclusions

Through raising HP steam in the SMR, SMR + CO₂ and CR flowsheets it is not possible to easily

incorporate renewable electrical energy into the process to enable a reduction in carbon intensity of methanol. The heat integration in the GHR + ATR flowsheet allows the flexibility to significantly increase the electrical power input into the ISBL plant. This not only allows a large reduction in the GHG emissions from the ISBL plant but also allows a total reduction in the carbon intensity of the process over its entire life cycle and significantly so if the source of electricity is from renewable energy.

From well to wheels, methanol produced from natural gas provides a significant reduction in GHG emissions when compared to standard gasoline. Even when compared to ethanol, methanol shows a modest reduction in GHG emissions and emphasises why methanol is such a good supplement to gasoline fuel for the reduction of GHG emissions.

If the intended destination of the gasoline is to a state or country that has implemented a LCFS, then in general making gasoline from natural gas *via* methanol does not reduce the overall carbon intensity of the gasoline and in fact would increase the carbon intensity over the whole life cycle. The exception would be processes that are able to utilise both renewable energy and the GHR + ATR flowsheet in order to produce a low carbon intensity gasoline.

Acknowledgements

This article is an extended and updated version of the International Methanol Technology Operators Forum (IMTOF) London 2015 presentation (10). Amelia Cook, Process Engineer at Johnson Matthey, is acknowledged for her contribution to the data collection and processing.

Glossary

CR	Combined reforming, with steam methane reforming and autothermal reforming
GHG	Greenhouse gas
GHR + ATR	Gas heated reforming and autothermal reforming
LCFS	Low carbon fuel standard
M15	15% methanol and 85% gasoline fuel blend
MTPD	Metric tonnes per day
OSBL	Outside battery limits
SMR	Steam methane reforming
SMR + CO ₂	Steam methane reforming with maximum CO ₂ addition

Appendix A

What is the Low Carbon Fuel Standard?

As further background surrounding the LCFS, the following is a summary (11). In California, USA, they have developed a method for determining the carbon intensity of a fuel for the whole of its life using the concept from well to wheels. In January 2010 the Californian state government implemented the LCFS which calls for a minimum 10% reduction in emissions per unit of energy by 2020. The policy focuses on decarbonising fuels for transportation and is a performance standard that is based on the total amount of carbon emitted per unit of energy. This crucially includes all the carbon emitted in the production, transportation and use of the fuel.

In America, transportation accounts for two-thirds of all the oil consumed and causes approximately one-third of all the GHG emissions. In an attempt to address this, the LCFS assigns a company (for example an oil refiner, importer or blender) a maximum level of GHG emissions per unit of fuel energy it produces. This level then declines each year with the intention of putting the state on a path to reducing total emissions.

There are several ways that regulated parties can comply with the LCFS and in the Californian model there are three compliance strategies available:

- (a) Refiners can blend low GHG fuels, for example biofuels made from cellulose or wastes, into gasoline and diesel.
- (b) Refiners can buy low GHG fuels, for example natural gas, biofuels, electricity and hydrogen.
- (c) Refiners can buy credits from other refiners or use banked credits from previous years.

The LCFS in California is not the only fuel standard that has been implemented. A similar scheme is in place in British Columbia in Canada and others have been proposed in Ontario, Canada, several other states in North America as well as the European Union.

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The Author



Alan Ingham is a Licencing Manager for Johnson Matthey's methanol technology. Before assuming this role he spent over 10 years working in the methanol department as a chartered Senior Process Engineer undertaking roles as both a Lead Process Engineer and Site Commissioning Engineer. Alan graduated from Nottingham University, UK, in 2005 with a first class Masters' degree in Chemical Engineering, following which he joined Johnson Matthey Process Technologies and has been working for the company ever since.
