9/28/2020

SUBJECT: Review of the KMMEF SSEIS

My name is Mark Uhart and my wife and I live near Kalama. I certainly hope Ecology will read all the written comments, and scrutinize the information in this SSEIS. I read the SSEIS and there are so many bad assumptions, poor application of technical information, and a covert attempt to under report upstream, operational and downstream emissions. I documented my review and I am submitting multiple comments, referencing all my sources.

1. The SSEIS refers to the research by Yu Gan, et al (2020), as referenced in Section 3.4.4.2.1 of the SSEIS (China-based natural gas to methanol),"… the average GHG intensity of the Chinese domestic natural gas supplies is 15.5 grams CO_2eq per megajoule (g CO_2eq/MJ) for conventional methods and 21.5 g CO_2eq/MJ for unconventional methods." It goes on to state, "the average GHG intensity for these supplies is 35.9 g CO_2e/MJ for international pipelines," which is a primary source for Chinese natural gas from Russia. Furthermore, the SSEIS goes on to state that based on the Gan study, both domestic and imported sources of China based natural gas have a higher GHG intensity than US-based sources, which average 12.1 g CO2e/MJ (Table B.5, Appendix B, First SEIS.)

   The Gan study states that the GHG intensities of the 104 shale gas fields, identified in his research, show the range is from 6.2 to 43.3 g/CO_2eq/MJ^{-1}. Due to increasing shares of GHG-intensive supplies from Russia, Central Asia, and domestic shale gas fields, the supply-energy-weighted average GHG intensity of China natural gas is projected to increase from 21.7 in 2016 to 23.3 g CO_2eq/MJ^{-1} in 2030. Unconventional/natural gas has a higher supply-energy-weighted average GHG intensity of 21.4 g CO_2eq MJ^{-1}, primarily driven by extraction-associated emissions. The average extraction-associated GHG emissions of China shale gas was estimated at 19.1 g/CO_2eq/MJ^{-1}. <u>Gas extraction accounts for upward of 60% of the total GHG intensity of the supply chain</u>. Figure Fig. 4, Well-to-city-gate GHG intensity supply curve of natural gas for China in 2030, in the Gan paper, illustrates extraction accounts for around 75%, with processing from 5-10% and transmission 5-15% (Gan et al.)

   With all types of GHGs (i.e., CO_2, CH_4, N_2O) converted to GWP_{100}, methane leakages constitute approximately 50–70% of extraction-associated emissions for tight and shale gas. Because methane GWP_{20} is ~3 times the GWP_{100} the extraction-associated GHG emissions of unconventional gas increase significantly for GWP_{20} compared to GWP_{100}. I know the SSEIS uses the AR4 GWP_{100} calculations in Table

3.5-12 Upstream Emissions from Natural Gas because that is the WAC 173-441-120. The RCW will likely be updated to AR-5 and the GWP_{20} factor foe Methane will be used, thus vastly increasing the GHGs to be reported.

Furthermore, the SSEIS only mitigates GHG emissions within Washington State. This approach doesn't account for the global warming potential of methane over the next 20 years from "well to wheel," a standard more countries are using. Certainly within the 40-year life span of this project Washington's RCWs will change to move more in line other states like California, which includes methane emissions from extraction, processing, storage and transport as well as all the GHGs resulting from the methane being consumes as a fuel, the well-to-wheel approach. Methane leakage during transport over approximately 1,500 miles of pipeline from Ft. St. John to Sumas, to Kalama, should be attributed to this project. GHG emissions from transmission increase as the length of the pipeline delivering the natural gas increases (Gan, et al. 2020.) Was the length of the pipeline delivering natural gas from the fields on BC to the lateral pipeline included in the lifecycle analysis? Although it is stated that the GHG emissions from transmission of natural gas from BC to the lateral pipeline would be included, this was not stated in subsequent Table 3.5-14, whereas upstream GHGs were only calculated for the in-state transmission of the natural gas.

A high proportion of impurities in raw gas (e.g., CO_2, H_2S.) would necessitate intensive energy consumption for gas processing. The CO_2 content, which itself is a GHG, is vented after separation and further increases emissions (Gan et.al. 2020.) Other factors influencing extraction-associated emissions include the estimated ultimate recovery rate (EUR) per well, which is unknown for the BC-sourced natural gas. The supply-energy-weighted average GHG intensity of 2030 is projected to be 23.3 g CO_2eq MJ^{-1}. Johnson Matthey, the supplier of the ULE/GHR + ATR process, discussed later, estimates that a minimum level import of electricity, and a North American Mix, would result in 33.6 g CO_2eq MJ^{-1} for the ULE/GHR + ATR process, much higher than NWIW's estimate.

2. The SSEIS states, "Thus, based on this study, both domestic and imported sources of China based natural gas have a higher GHG intensity than US-based sources, which average 12.1 g CO_2e/MJ (Table B.5, Appendix B, First SEIS). The problem with this statement is that it refers to Table B.5 in the First SEIS, which was (1) based on the GREET_2017 model, (2) assumed the AR4 100-year global warming potential (GWP) vs. 20-year, and (3) didn't include transmission leakage estimates along the 1,500 plus mile

pipeline from Ft. St. John, BC, to the BC-US border at Suma, WA, and on to Kalama, WA.

3. Section 3.4.4.2.2.1 states, "Due to the high uncertainty, the evaluation of upstream GHG emissions for non-KMMEF importers of methanol assumes that their upstream emission is equivalent to the upstream KMMEF emissions on a per MT of methanol produced basis." This is a bad assumption and contradicts other information in the SSEIS. Yu Gan stated that was why he researched the "Carbon Footprint of Natural Gas Supplies to China (Gan et al. 2020,) to determine the GHG emission intensities of various Asian feedstock inventories supplying China.

4. In Section 3.4.4.2.2.3 Direct Emissions, it is stated the Ultra-Low Emissions (ULE) process will be used instead of the EPA-PSD–permitted combined reforming (CR) process. The actual emissions from the ULE process are unknown. The term "Ultra-Low Emissions (ULE)" is not used in any EPA permits for the use of this technology in the US. The ULE proposed by NWIW uses gas-heated reforming (GHR) + autothermal reforming (ATR), as described by Johnson Matthey (JM). Johnson Matthey's reforming technology is currently being used in Coogee Energy Pty. Ltd.'s small (50,000 mt/yr)gas-to-methanol plant in Laverton, Australia. It was built by BHP Petroleum in 1994. (Methanex, Canadian-owned methanol supplier, is building a GHR + ATR methanol plant in Louisiana.) <u>Has NWIW completed an application for a Prevention of Significant Deterioration (PSD) Permit for GHG emissions to the EPA for the ULE process?</u> What devices or equipment are subject to this PSD GHG permit (reformers, combustion units, boilers, catalytic reduction systems, regeneration heaters, treaters, flares, fugitives processors, pumps, cooling towers, etc.) What are the risks in approving ULE for this project without an approved PSD permit? What if NWIW, or its successor, decides to change to the CR process if the price of electricity makes ULE no longer cost-effective?

5. In Section 3.4.4.2.2.3 Direct Emissions, it is stated, "as described in Appendix B of the First SEIS, it is assumed that the ULE technology provides a 38% reduction in CO_2e emissions relative to combined reforming (process.) However, this author found an article from Oil and Gas Industry News, March 30, 2016 by Marshall Frank (writes for the Methanol Institute), that ULE technology requires additional on-site electric power generation to satisfy the overall energy requirements of the methanol plant. Adding the emissions from the required electric generation facility to its process emissions, ULE still offers a 31.4% reduction in total

emissions. Unless the author of the SSEIS can validate the 38% figure then the lower figure, 31.4%, should be applied.

Based on Johnson Matthey Technical Review 61 (Alan Ingram, 2017), which is attached to the end of these comments, the amount of GHGs, expressed as $gCO_{2e}\ MJ^{-1}$ methanol, is actually greater for GHR + ATR unless a maximum electrical import is used. If a maximum electrical import is used the difference is only about 12%. The only way this plant will see the efficiency stated in the FSEIS would be if they were using maximum electrical import and the electricity is from renewable resources. Ecology should check the data presented in Section 3.5.3.7. of the SSEIS against this JM Technical Review.

6. Section 3.4.5 Economic Analysis, the framework of the analysis was based on: a market analysis if the methanol was used as a fuel; how assumptions about the sources of methanol used influence the emissions analysis; and if the analysis of global GHG emissions can be more flexible based on a wider range of assumptions?

7. The SSEIS still fails to address the potential negative economic impacts from a "business as usual" approach to climate change. Without 100% sequestration of the GHGs for which this project will be responsible, it will contribute to the GHGs that affect climate change. What will be the economic impact to the state of Washington for the following:
    - Fighting wildfires?
      What will be the firefighting and disaster relief costs to the state and those affected by the fires?
    - Lost timber harvests as a result of wildfires?
      How many logging truck drivers, lumber mill and lumber exporting employees will lose their jobs?
    - Decreasing timber harvests as a result of hotter and drier weather?
      How will the lower timber yields affect jobs and revenue from state lands?
    - Loss of commercial fishing revenue, directly and indirectly, as a result of decreasing salmon, steelhead and shellfish harvests?
      How will this affect the fisherman, the processors, resellers, merchants, and state tax revenue?
    - State and Federal disaster monies committed due to extreme weather events and fishery disasters?
      How will this affect the state budget? Higher taxes?
    - Repairs to public roads and utilities as a result of extreme weather events?
      How will this affect our state budget?

Higher taxes?

- o Loss of productivity from extreme weather events?
  Why wasn't there an attempt to quantify these costs?
- o Effects on human health?
  What are the costs associated with extreme weather events and more air and water pollution.
- o Increased healthcare costs?
  Who will bear the healthcare costs from the additional PM2.5 in the air?

8. In Section 3.5.3.1 the SSEIS states, "The ESM recognizes that limitations likely will be placed on coal-based methanol expansion in China in the future. Over time, the ESM predicts an increase in natural gas-based imports to fulfill the methanol demand in China under the alternate cases. This is why the average annual emission values are lower than the initial year values (2020), because over time substitution for coal is slowly reduced, and RC emissions decline." This statement discounts the projected growth in the methanol industry. (See Figure 3.5-8 and Section 3.4.5.3, where it states, "The methanol market is forecast to continue growing, having experienced an average annual growth rate of 4.5 percent per year between 2015 and 2020,… according to the methanol institute.) RC emissions will not decline, they will continue to go up as more methanol plants come online, as projected in this SSEIS.

   This author disagrees with some of the assumptions presented in Section 3.5.3.1. For example: "60 percent of the methanol produced by KMMEF is assumed to be used for olefin production, and 40 percent is assumed to be used for fuel production." The demand for methanol as a fuel is likely to be more because the production of olephin from conventional gas is a less expensive pathway. China's growing fleet of commuter vehicles and methanol-powered ships indicate it is more likely than not that methanol will be used as a fuel.

9. The assumption developed in Section 3.4.5.2, and illustrated in Table 3.4-3, Source Definition Under Three Alternate Cases, are questionable. As shown in the table presented by Yu Gan (2020), on the next page, imports from natural gas pipelines outside of China will increase. The new pipeline from Russia will deliver 12.6% of energy supply by 2030. This author questions the statement, "The RC/best estimate was designed to illustrate the most likely outcome, wherein 60 percent of the production that would come from the KMMEF would potentially be replaced by production from coal-based methanol in China (CCM), 10 percent would be from

natural gas-based methanol from China (CNGM), and 30 percent would come from imports." Based on Gan's research, and the fact that China's growing need for electricity cannot be met with only natural gas and renewable energy, the coal-fired plants will continue to operate. In fact, China continues to build more coal-fired plants based on their 14th 5-year plan (2021-2025.)

Category	Country	Gas fields[a]	% of supply energy[b]		
			2016	2020	2030
Domestic conventional	China	Shuangyushi & Jiulongshan (1), Chunxiao (2), Liwan & Liuhua (3), Anyue-longwangmiao (4), Datianchi (5), Panyu & Huizhou (6), Wolonghe (7), Mahe (8), Kelameili (9), Qingshen (10), Zhongba (11), Sebei (12), Tainan (13), Kekeya (14), Dongping (15), Luojiazhuai (16), Lingshui (17), Donohue (18), Longgang (19), Tieshanpo (20), Bozhong (21), Ya (22), Hetianhe (23), Wenchang (24), Yuanba (25), Puguang (26), Dina2(27), Kela (28), Yingmai7 (29), Tahe (30), Tazhong (31), Ledong (32), Changling & Songnan (33), Dongfang (34)	32.6	30.3	20.9
Domestic unconventional	China	Juggar CBM (35), Qingshui CBM (36), Bishuixing CBM (37), Ordos CBM (38), Qiongxi (39), Sulige (40), Guangan (41), Yingtai (42), Hechuan (43), Yulin (44), Zhaotong (45), Daniudi (46), Bajiaochang (47), Changning & Weiyuan (48), Wushenqi (49), Jingbian (50), Yanchang (51), Mizhi (52), Zizhou (53), Shenmu (54), Xinchang (55), Luodai (56), Fuling (57), Dabei (58), Keshen (59)	29.0	28.2	28.6
International pipeline	Myanmar	Shwe (60)	1.9	1.2	1.9
	Russia	Chayandinskoye (61), Kovyktinskoye (62), Urengoi (63), Nadym (64)	—[c]	5.6	12.6
	Uzbekistan	Karakul (65)	2.0	1.5	0.9
	Turkmenistan	Bagtiyarlyk (66), Galkynysh (67)	14.0	8.8	12.0
Overseas LNG	Qatar	Qatargas North Field (68)	3.2	3.4	2.1
	Oman	Khazzan (69), PDO block 6 (Saih Nihayda, Saih Rawl & Barik, 77)	0.1	0.06	0.04
	Russia	South Tambey (70)	—[c]	1.2	0.8
	Australia	Jansz-lo (71), APLNG fields (72)[d], QCLNG fields (76)[e], Gorgon (89)	7.5	8.8	5.6
	Papua New Guinea	Hides (73), Angore (74), Juha (75)	1.4	1.1	0.7
	Nigeria	Niger Delta (78)	0.2	0.1	0.07
	Trinidad&Tobago	Amherstia (79)	0.1	0.06	0.04
	Indonesia	Tangguh (80)	2.2	1.3	0.9
	Norway	Snohvit (81)	0.1	0.09	0.06
	Malaysia	Central Luconia (82)	1.9	1.2	0.7
	United States	Gulf of Mexico-offshore (83), Gulf Coast-conventional (84), Central-CBM (85), TX-LA-MS Salt-conventional (86), Central-conventional (87), Gulf Coast-tight (88), Illinois-conventional (90), North Central-conventional (91), Appalachian-conventional (92), Central-tight (93), TX-LA-MS Salt-tight (94), Appalachian-CBM (95), Fort Worth-shale (96), Central-shale (97), Appalachian-tight (98), Illinois-shale (99), Illinois-tight (100), Appalachian-shale (101), West Texas-shale (102), North Central-tight (103), North Central-shale (104)	0.2	1.5	1.4
Total			96.3	94.5	89.4

[a]Numbers in parentheses correspond to the gas field numbers in Fig. 1. [b]Detailed shares of supply from individual gas fields and data sources are presented in Supplementary Data 1. [c]— means no gas supply to China for the gas fields in 2016, and the fields are expected to start gas delivery later than 2016. [d]APLNG fields are gas fields of the Australia Pacific LNG project, which include fields of Spring Gully, Talinga, Combabula, Condabri, Peat, Orana, Reedy Creek, Jordan, Ruby Jo, Kenya, Bellevue, Fairview, Arcadia, Roma East, and Ironbark in the Surat and Bowen basin of Queensland Australia. [e]QCLNG fields are gas fields of the Queensland Cutis LNG project, which include fields of Bellevue, Berwyndale, Charlie, Jordan, Kenya, Ruby Jo, and Woleebee Creek.

10. At the end of Section 3.4.5. it the SSEIS states, "Because methanol will increasingly replace higher-emission transportation fuels such as gasoline and bunker fuel for ships, it is likely that the increases in methanol production through time will also result in lower global emissions when compared with a future scenario that excludes methanol-based fuels." This might be true if the world population doesn't increase, but we know it will, thus driving the need to consume fossil fuels. It is more likely than not that there will be increased demand for all fossil fuel energy feed stocks.

- "Low natural gas prices are presumed to persist in North America." What does "persist" mean? I agree that a price will a price, any price, will persist. But if this means the "low" natural gas pricing will persist then I don't agree. The higher demand for natural gas in SW Washington, as a result of the new KMMEF, could increase natural gas prices. What is the capacity of the Williams pipeline and how will it factor into the cost?
- "Oil prices are assumed to remain stable at present levels – about $40/barrel." Again, this might be a good assumption for the short-term, but prices will rise when demand goes back up and the supply goes down.
- "The upstream methane emission rate is 0.97 percent for KMMEF." This is shown in Table 3.4-1b for the "Medium" scenario. The SEIS also states in footnote 3. of Table 3.5-14, "Upstream natural gas emissions in Washington State calculated by multiplying the transmission emissions from GHGenius or GREET (depending on scenario) by the fraction of the total pipeline miles from the natural gas source region that are within Washington State.
  The 0.97 percent is very low based on this author's research (Atherton, Risk et al. 2017, Zavala-Araiza, et al. 2018, Alvarez , et al. 2018, Howarth, 2019, Burnham 2019, and Gan, et al. 2020.) After reviewing the GREET 2019 table, this author believes the "Upper" scenario is the best for this facility based on the operating conditions and the author's review of many studies on upstream fugitive methane (production, processing, and distribution). The leakage rate should be between 2.5% and 3.1% of the amount of natural gas consumed. As part of that the leakage rate during transmission must include transportation from processing facilities in BC at Ft. St. John, to the BC-WA border at Sumas, to the KMMEF lateral pipeline, not just "within Washington State." This is approximately 1,500 pipeline miles.

11. The "Net Emissions" for the KMMEF shown in Table 3.5-10, and discussed in Section 3.5.3, should not be considered in the decision on the shoreline permit. It is not relevant as it is based solely on the displacement theory, and the assumption that most of the methanol will be used for the production of olefins, which is unlikely, cannot be assured and validated throughout the 40-year life of this project.

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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

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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 CO_2 equivalent per megajoule of methanol on a lower heating value (LHV) basis ($gCO_2e\ MJ^{-1}$ 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 CO_2 addition (SMR + CO_2)
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 CO_2 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 CO_2 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 CO_2 emissions in **Table I** move in line with the natural gas efficiency of the flowsheet, with the exception of the SMR + CO_2 flowsheet. This stands to reason because, as **Figures 1** and **2** show, again with the exception of the SMR + CO_2 flowsheet, natural gas is the only carbon input into the ISBL plant, with methanol and CO_2 emissions the only output. Therefore, any carbon in the natural gas not converted to methanol will eventually leave the plant as CO_2. The SMR + CO_2 flowsheet is the exception to this rule as additional carbon is added to the process in the form of CO_2 injected upstream of the reformer. This additional carbon helps improve the natural gas efficiency but at the expense of increasing the CO_2 emissions from the ISBL plant. The increase in CO_2 emissions for the SMR + CO_2 flowsheet is due

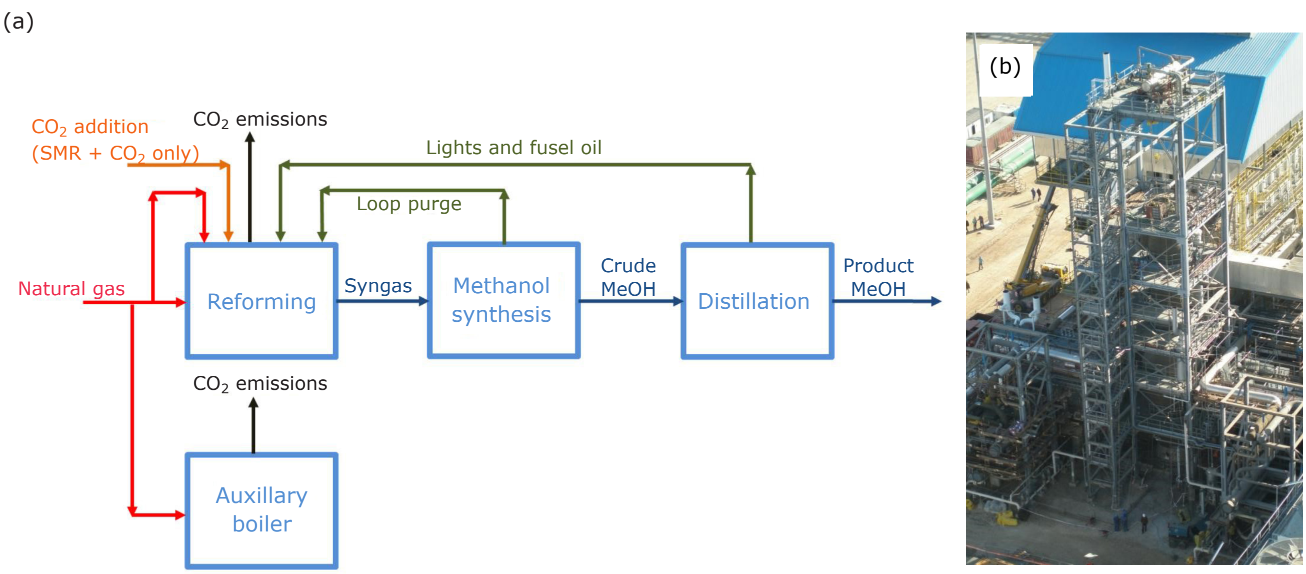

Fig. 1. Methanol plant overview for Flowsheets **1–3**: (a) diagram of the unit operations for Flowsheets **1–3**; (b) picture of a SMR + ATR used in Flowsheet **3**

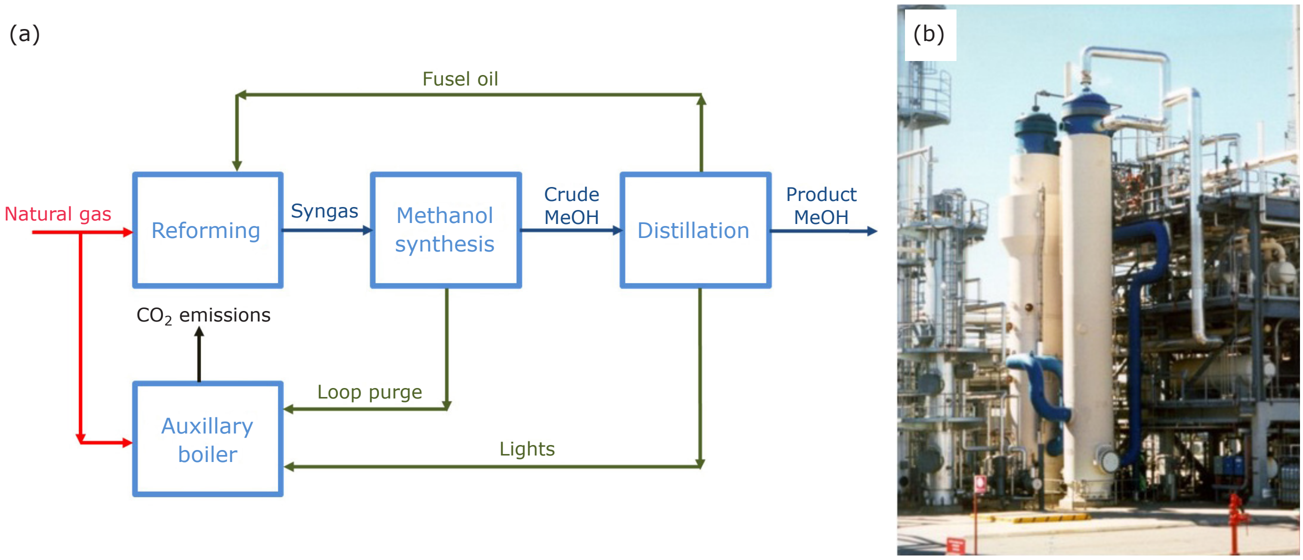

Fig. 2. Methanol plant overview for Flowsheet **4**: (a) diagram of the unit operations for Flowsheet **4**; (b) picture of a GHR + ATR used in Flowsheet **4**

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)
CO_2 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)

[a]Based on using captured CO_2 as a feedstock, the net CO_2 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)
CO_2 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)

[a]Based on using captured CO_2 as a feedstock, the net CO_2 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 CO_2 concentration in the recycled fuel from the methanol loop and distillation. Therefore, with any CO_2 injection flowsheet aside, the better the natural gas efficiency of the ISBL plant the lower the CO_2 emissions. If captured CO_2 is used as a feedstock to the ISBL plant for CO_2 injection flowsheets then **Tables I** and **II** show that the net CO_2 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 + CO_2 and CR flowsheets there is no significant scope to maximise the electrical import while maintaining the minimum auxiliary boiler load. The SMR, SMR + CO_2 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 CO_2 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)).

$$\text{Reforming } CH_4 + H_2O \leftrightarrow CO + 3H_2 \qquad \text{(i)}$$

$$\text{Water-gas-shift } CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \text{(ii)}$$

$$\text{Heavy hydrocarbon reforming } C_nH_m + nH_2O \leftrightarrow nCO + (½m + n)H_2 \qquad \text{(iii)}$$

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

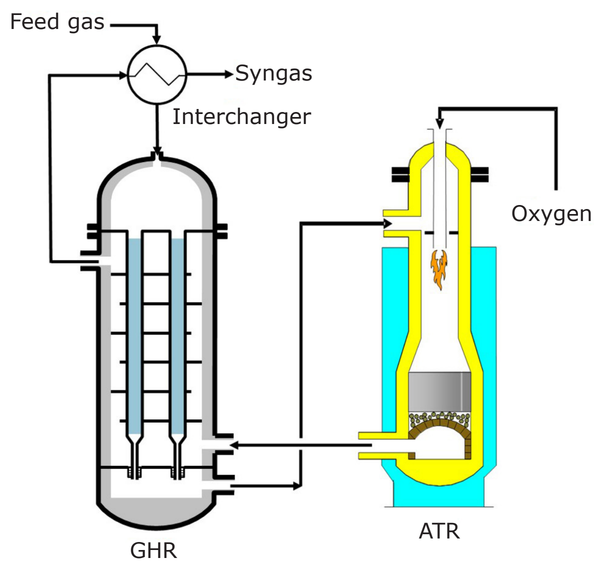

Fig. 3. GHR + ATR flowsheet arrangement

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 CO_2 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 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.

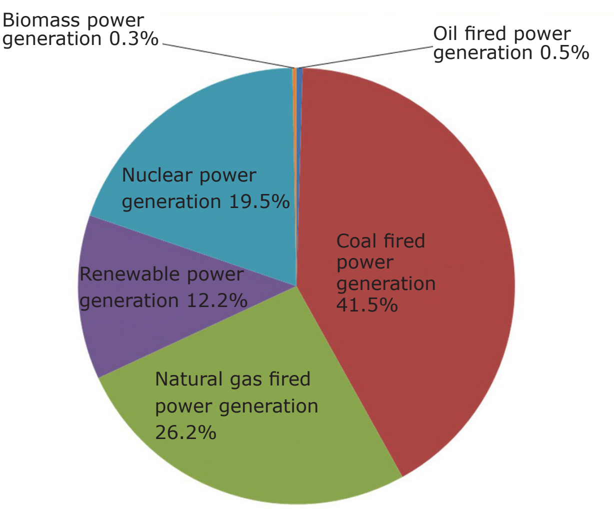

Fig. 4. A typical North American electricity mix (5)

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_2e MJ^{-1} methanol	13.0	12.6	12.3	12.4
(b) Methanol plant[b]	gCO_2e MJ^{-1} methanol	23.1	36.0 (20.1)	17.8	19.2
(c) Methanol storage	gCO_2e MJ^{-1} methanol	1.3	1.3	1.3	1.3
Subtotal[b]	gCO_2e MJ^{-1} methanol	**37.4**	**49.9 (34.0)**	**31.4**	**32.9**
Electricity					
North America mix	gCO_2e MJ^{-1} methanol	0.76	0.76	0.54	0.67
Renewable mix	gCO_2e MJ^{-1} methanol	0.005	0.005	0.003	0.004
Total (North America mix)[b]	gCO_2e MJ^{-1} methanol	**38.1**	**50.7 (34.8)**	**32.0**	**33.6**
Total (renewable mix)[b]	gCO_2e MJ^{-1} methanol	**37.4**	**49.9 (34.0)**	**31.4**	**32.9**

[a]The 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

[b]The net CO_2 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_2e MJ^{-1} methanol	12.9	12.5	12.2	10.2
(b) Methanol plant[b]	gCO_2e MJ^{-1} methanol	22.5	35.5 (19.6)	17.6	3.5
(c) Methanol storage	gCO_2e MJ^{-1} methanol	1.3	1.3	1.3	1.3
Subtotal[b]	gCO_2e MJ^{-1} methanol	**36.7**	**49.3 (33.4)**	**31.2**	**15.0**
Electricity					
North America mix	gCO_2e MJ^{-1} methanol	2.03	1.95	1.23	13.7
Renewable mix	gCO_2e MJ^{-1} methanol	0.012	0.012	0.008	0.083
Total (North America mix)[b]	gCO_2e MJ^{-1} methanol	**38.7**	**51.3 (35.4)**	**32.4**	**28.7**
Total (renewable mix)[b]	gCO_2e MJ^{-1} methanol	**36.7**	**49.3 (33.4)**	**31.2**	**15.1**

[a]The 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

[b]The net CO_2 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 CO_2 equivalent per megajoule of methanol on a LHV basis (gCO_2e MJ^{-1} MeOH).

The GREET GHG emission values in **Table III**, for flowsheets with the minimum electrical import, follow the same trend as the CO_2 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.

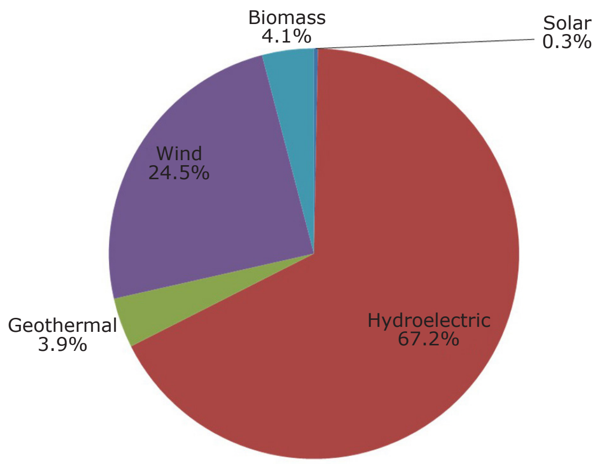

Fig. 5. Standard renewable energy mix (7)

However, the GREET GHG emission values in **Table IV**, for flowsheets with the maximum electrical import, show a different trend. For the SMR, SMR + CO_2 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 + CO_2 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 + CO_2 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

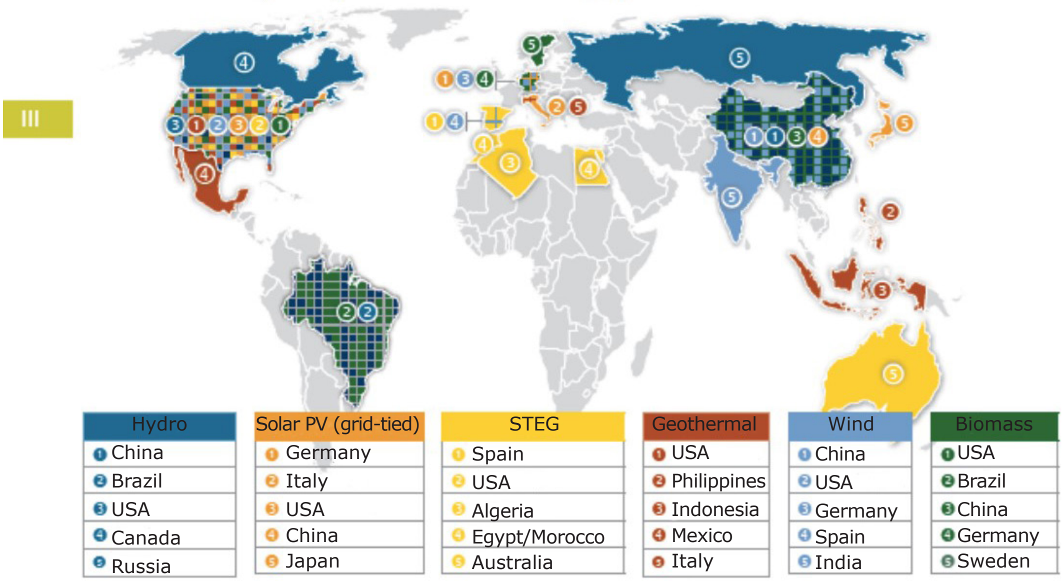

Fig. 6. Top countries with installed renewable electricity by technology in 2012 (8). PV = photovoltaic; STEG = solar thermoelectric generator

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
		$gCO_2e\ MJ^{-1}$	$gCO_2e\ MJ^{-1}$	$gCO_2e\ MJ^{-1}$
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 (b) 47.3 (33.8) (c) 31.3 (d) 28.1	(a) 63.2 (b) 73.9 (60.4) (c) 57.9 (d) 54.7
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 (b) 45.7 (32.2) (c) 30.3 (d) 16.6	(a) 61.5 (b) 72.3 (58.7) (c) 56.8 (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 + CO_2
   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 CO_2 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 CO_2 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 $gCO_2e\ MJ^{-1}$. 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 $gCO_2e\ MJ^{-1}$. 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 $gCO_2e\ MJ^{-1}$ which is already higher than the 25.0 $gCO_2e\ MJ^{-1}$ 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 $gCO_2e\ MJ^{-1}$ 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 + CO_2 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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