

Carbon Intensity of Renewable Fuels Pathways: Using Various CO₂ and H₂ Feedstocks, with a Focus on Methanol

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Abstract

This paper quantifies and compares the lifecycle carbon intensity (CI) of methanol across fossil (grey and coal-based), blue, bio-, and e-methanol pathways using EU RED II and RFNBO/RCF (Renewable Fuel of Non-Biological Origin and Recycled Carbon Fuels) well-to-wake framework. CI depends mainly on the sources of CO₂, H₂, and electricity. Grey methanol from natural gas remains high (~103 g CO₂e/MJ), while coal-based methanol is far worse (~299 g/MJ). Blue methanol, produced via natural gas with carbon capture, achieves moderate reductions (~25–66 g/MJ, 30–73 % savings) but falls short of the 70 % threshold for renewable classification. Bio-methanol from wastes and residues is very low (~10–33 g/MJ, 65–89 % savings), and manure-based routes can even achieve net-negative emissions (~ -80 g/MJ). E-methanol pathways span a wide range depending on inputs: wind + biogenic CO₂ configurations reach ~18–21 g/MJ (80–85 % savings), solar + industrial CO₂ cases ~25–30 g/MJ (68–73 %), while DAC or grid-electricity scenarios exceed 30 g/MJ and may fail thresholds. Meeting the EU's 70 % GHG-savings requirement (≤ 28.2 g/MJ) therefore hinges on renewable energy sourcing and low-carbon CO₂ supply, as defined by EU Delegated Regulations 2023/1184 and 1185. The analysis distinguishes which pathways genuinely qualify as renewable and which serve as transitional low-carbon options within emerging fuel policy frameworks.

Introduction and Literature Review

Decarbonizing the marine sector and other transport industries requires a shift from conventional fossil fuels to renewable and low-carbon alternatives. Methanol is a promising alternative fuel that can be produced via multiple pathways – from fossil feedstocks (natural gas or coal), biogenic feedstocks (biomass or biogas), or electricity-derived hydrogen combined with CO₂ (so-called e-methanol). The lifecycle carbon intensity (CI) of methanol depends strongly on the production pathway [1]. For instance, coal-based methanol has a very high carbon footprint (~300 g CO₂e/MJ) due to the carbon-intensive mining and conversion process, whereas modern natural-gas-based methanol (“grey” methanol) is around 100-110 g CO₂e/MJ [2][3]. In contrast, renewable methanol pathways can achieve much lower carbon intensities – often in the range of 10–40 g CO₂e/MJ, and

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in some cases even negative emissions when utilizing certain waste feedstocks [4]. One study reported that methanol produced from biomethane (e.g. via anaerobic digestion of manure) can reach $-55 \text{ g CO}_2\text{e/MJ}$, effectively removing greenhouse gases by avoiding manure methane emissions [5][6]. These values indicate the potential for methanol to far exceed typical EU GHG savings requirements, which for renewable transport fuels are defined relative to a fossil fuel comparator of $94 \text{ g CO}_2\text{e/MJ}$ (the average energy-corrected emissions of diesel/gasoline) [7][8].

Lifecycle assessment (LCA) is the established methodology for quantifying fuel carbon intensity across supply chains. Standard LCA frameworks, such as ISO 14040/14044, provide general principles for defining system boundaries, functional units, and impact accounting for products including fuels [9]. Building on these, regulatory methodologies have been developed to ensure consistent GHG accounting for fuels in policy. In the EU, the Renewable Energy Directive (EU) 2018/2001 (RED II) sets out LCA rules for biofuels and other renewable fuels, including default emission factors and co-product allocation methods [7]. RED II's methodology (detailed in Annex V and VI of the directive [3]) uses a straightforward formula summing all supply chain emissions (from feedstock extraction, transport, processing, etc.), minus any applicable credits, divided by the fuel's energy content to yield $\text{g CO}_2\text{e/MJ}$. Importantly, biogenic CO_2 emissions are counted as zero at combustion in this framework (since biomass carbon uptake is assumed to cancel out tailpipe CO_2), but fossil CO_2 released is fully counted [3]. The directive also imposes minimum GHG savings thresholds: for a renewable fuel to count towards targets, it must achieve at least 50–70% GHG reduction, which corresponds to roughly $28.2\text{--}47 \text{ g CO}_2\text{e/MJ}$ or lower [7][11][12]. These thresholds have been tightened over time – new facilities producing biofuels in 2021+ must meet 65% savings, and updated legislation has raised the bar to 70% for RFNBO/RCF/LCF fuel categories.

In 2023, the EU adopted specific delegated regulations to address novel fuel pathways. Commission Delegated Regulation (EU) 2023/1184 [8] establishes the methodology for calculating life-cycle GHG emissions of renewable fuels of non-biological origin (RFNBOs, such as e-methanol) and recycled carbon fuels (RCFs), ensuring consistency with the RED framework. It specifies, for example, how to handle upstream electricity emissions for hydrogen production, how to allocate emissions if CO_2 is taken from point sources, and confirms the 70% GHG savings requirement for RFNBOs/RCFs used in transport (i.e. $\leq 28.2 \text{ g CO}_2\text{e/MJ}$). Complementary to that, Delegated Regulation (EU) 2023/1185 [12] defines strict criteria for the renewable electricity used in RFNBO production (additionality, temporal and geographic correlation, etc.), reflecting the EU's effort to guarantee that “green” hydrogen-based fuels truly use new renewable power. These regulations build upon prior standards (like RED II and its default values) but add clarity for power-to-fuel pathways and encourage best practices (e.g. using grid electricity only under certain conditions, accounting for upstream methane leakage for gas-derived hydrogen, etc.). Other jurisdictions and frameworks have developed similar methodologies – for example, the GREET model in North America or ICAO's CORSIA for aviation[13][14].

Several LCA studies have assessed the carbon intensity of methanol from various pathways, providing context for the results in this work. A comprehensive analysis by the Methanol Institute compared methanol produced from natural gas, coal, biomass, municipal solid waste (MSW), renewable electricity, and other feedstocks [2]. They found that coal-to-methanol has by far the worst GHG profile ($\sim 270\text{--}300 \text{ g/MJ}$), while natural gas-based methanol (the dominant route today) typically ranges around $100\text{--}110 \text{ g CO}_2\text{e/MJ}$ with modern technology [3]. In contrast, biomethanol made from residues or biogas can achieve very low emissions. For instance, methanol from biogas (landfill gas or manure digesters) was shown to range from $+38 \text{ g/MJ}$ down to about -103 g/MJ in

different scenarios, with most pathways well below 20 g/MJ[2][3][7]. Negative emissions result when the biogenic fuel pathway avoids significant methane that would otherwise escape (as is the case for manure management)[3]. E-methanol (from green hydrogen and CO₂) also offers low carbon intensity, but results depend on the CO₂ source and electricity source. One recent study by Sankaran et al. examined renewable methanol from industrial CO₂ and highlighted that unless low-carbon electricity and otherwise vented CO₂ are used, the purported climate benefits may be eroded – making such pathways a “dead end” if fossil-based energy sneaks in [15]. On the other hand, truly renewable e-methanol (using additional wind/solar power and direct air capture or biogenic CO₂) can be nearly carbon-neutral on a full lifecycle basis. Finally, so-called “blue methanol” – produced from natural gas with carbon capture (analogous to blue hydrogen) – has been investigated. Techno-economic and lifecycle analyses of blue methanol indicate that the carbon intensity depends strongly on the hydrogen production route and the associated carbon capture rate. When Steam Methane Reforming (SMR) is equipped with ~60 % CO₂ capture, the resulting well-to-wake (WtW) carbon intensity of methanol lies typically between 47 – 66 g CO₂e/MJ. Increasing capture to ~90 % in SMR reduces the intensity further to about 29 – 48 g CO₂e/MJ, while switching to Auto-Thermal Reforming (ATR) with ~90 % capture yields the lowest values, around 25 – 44 g CO₂e/MJ. These results correspond to 57–76 % lower lifecycle emissions compared with conventional fossil methanol (~100-110 g CO₂e/MJ), depending on process efficiency and upstream methane leakage assumptions, with 103 g CO₂e/MJ as a reference for calculations.

In summary, literature consistently shows that methanol’s carbon intensity spans a wide range depending on feedstock and process: from worse than conventional fuels (if coal-based) to potentially net-negative (if using certain wastes). This study’s aim is to compare methanol pathways using a harmonized LCA approach – ISO 14040/44 with EU RED II and its Delegated Acts – across well-to-tank and well-to-wake boundaries. By quantifying pathway-specific CI (fossil, blue, bio, and e-methanol) under consistent assumptions, we clarify which options genuinely meet stringent EU thresholds and which only shift emissions upstream. The analysis underscores why robust boundaries, electricity provenance, and CO₂ source choice are decisive, and translates these technical findings into policy relevance for eligibility, incentives, and compliance (e.g., FuelEU Maritime). In short, accurate LCA is the hinge between credible “low-carbon” claims and real decarbonization.

Methods

System Boundaries and Definitions

In this study, we adopt a lifecycle (well-to-wake) approach to carbon intensity, aligned with ISO 14040/44 principles and EU RED II methodology [7][9][10]. We distinguish between Well-to-Tank (WtT) emissions – all GHG emissions from raw material extraction up to fuel delivery into the vehicle/ship’s tank – and Tank-to-Wake (TtW) emissions – the GHG emissions from fuel combustion (or conversion) during use. The sum of WtT + TtW constitutes Well-to-Wake (WtW) emissions (sometimes called “cradle-to-grave” or “well-to-wheel” in road transport) [17]. This distinction is important for fuels like methanol because biogenic or captured CO₂ released during combustion may or may not count toward regulatory totals depending on its origin. We follow the EU convention: CO₂ emissions from renewable/biogenic sources are counted as 0 at the point of combustion (since that carbon was previously removed from the atmosphere), whereas CO₂ from fossil sources is fully counted in TtW. Other greenhouse gases (CH₄, N₂O) emitted in either stage

are included with their CO₂-equivalent values using IPCC 100-year global warming potentials (GWP)(GWP_CH₄ = 25 kg CO₂/kg CH₄, GWP_N₂O = 298 kg CO₂/kg N₂O, per RED II) [7][17].

Regulatory Framework for Emissions Accounting

Our LCA methodology is rooted in the EU RED II and the recently adopted Delegated Regulations for RFNBOs and low-carbon fuels. For bio-methanol pathways, we applied the RED II equation for total emissions:

$$E = e_{ec} + e_l + e_p + e_{td} + e_u - e_{sca} - e_{ccs} - e_{ccr} \left[\frac{gCO_{2eq}}{MJ_{fuel}} \right]$$

where E_{ec} = emissions from feedstock cultivation (if any), E_{pt} = processing emissions, E_{td} = transport/distribution, E_u = usage (combustion) emissions, and the terms E_{ccs}, E_{ccr}, E_{ee} represent credits for carbon capture/storage, carbon capture and replacement, and excess electricity from cogeneration, respectively (when applicable) [7]. For biofuels from wastes/residues (e.g. manure, agricultural waste), E_{ec}=0 (no cultivation emissions) and in some cases a negative credit is applied if use of that waste avoids significant emissions (e.g. methane from manure decomposition). We included such credits consistent with RED II rules (which allow by-product emission allocation or substitution methods for wastes).

For RFNBO (e-methanol) pathways, we followed the methodology of EU Delegated Regulation 2023/1185 [12]: all upstream emissions from electricity production for hydrogen are accounted for, using either actual supplier-specific values or regional averages. In our model, we examined several electricity sourcing cases – wind (onshore) and solar PV were treated as renewable with low life-cycle CO₂ intensities (we used ~11 kg CO₂/MWh for wind and ~48 kg CO₂/MWh for solar, based on literature and EU data [19]), whereas grid electricity was assigned a higher emission factor (we assumed ~308 kg/MWh [19], representative of an EU mix, but also considered a higher 490–540 kg/MWh for coal-heavy grids to stress-test worst case [20]). The hydrogen production via electrolysis was modeled with an electrical efficiency range of 42–66 kWh per kg H₂ (lower for advanced PEM, higher for older alkaline; we used an average ~53 kWh/kg H₂) [21]. Thus, the CI of hydrogen (kg CO₂ per kg H₂) varied widely: from near-zero (if using 100% wind power) up to ~20+ kg CO₂/kg H₂ (if using a coal-dominated grid). For context, our inputs yielded H₂ CIs of ~0.6 kg CO₂/kg for wind and ~1.9 kg CO₂/kg for solar (very low), versus ~16–26 kg CO₂/kg for an average grid and >30 kg/kg for a coal-reliant grid, consistent with values reported by others.

For the CO₂ feedstock used in e-methanol, we distinguished multiple source types with different treatment under the regulatory methodology:

- CO₂ from Direct Air Capture (DAC): Considered atmospheric in origin. The act of capture is credited as removing CO₂ from the atmosphere; however, the energy required for DAC is significant and contributes to emissions. Our model uses DAC energy requirements of ~2,000–4,000 kWh per tonne CO₂ captured (heat + electricity) based on literature for current DAC technologies [22][23]. We assume most of the energy is heat (often from waste or natural gas) and about 20–25% is electricity [24][25][26]. The net result is that using DAC CO₂ adds substantial upstream emissions unless all that energy is zero-carbon. In our best-case e-methanol scenario with DAC, we assumed waste heat usage (from a renewable source) and renewable electricity for DAC, but a small CO₂ penalty remained for compression/work – yielding ~1.5–6.7 g CO₂ emitted per kg CO₂ captured (i.e. ~0.1–0.44 g per MJ methanol fuel from the DAC step) [27].

- CO₂ from concentrated point sources (industry): We considered captured CO₂ from a cement plant, from an ethanol fermentation plant, from natural gas processing (amine capture), from coal flue gas, and from pulp & paper biomass boilers. These represent a range of CO₂ concentrations and upstream footprints. Regulation 2023/1184 treats CO₂ from industrial processes as “recycled carbon” – if it was going to be emitted to air anyway, the act of capturing it does not incur a direct carbon debit for the carbon itself, but the energy used to capture and compress it does count [8][12]. We therefore accounted for the energy and materials for CO₂ capture. For example, CO₂ from ethanol fermentation is nearly pure (>95% CO₂ stream from fermentation [22]); capturing it mainly requires compression and drying, which we estimated at ~122 kWh/tonne CO₂ [22]. This contributed only ~0.09-2.46 g CO₂ per kg methanol fuel (depending on wind, solar or grid electricity) in our model. CO₂ from a cement kiln or natural gas flue (~14–33% CO₂ concentration [22] [28][29]) requires solvent-based capture (amines) with a higher energy cost: we assumed on the order of ~900-1000 kWh/ton CO₂ (mostly low-grade heat for solvent regeneration) [22][29]. We included the CO₂ capture energy consumption in each case, using reference values (e.g. ~750-1100 kWh/ton CO₂ for gas flue, ~700-840 kWh/ton CO₂ for coal flue capture [21][22]), and attributed the resulting emissions based on the energy source (if waste heat from biomass was used, we counted biogenic CO₂ emissions from that heat as neutral except any fossil share). In all cases, once the captured CO₂ is converted to methanol and eventually combusted in an engine, those CO₂ emissions are counted as delayed emissions from the original point source. In line with proposed EU methodology for RCFs, we did not double-count the original point-source emission in the fuel’s LCA (since it would have occurred anyway without CO₂ capture); we only count any additional emissions due to capture and the final combustion. This means e-methanol made from, say, cement CO₂ will have the same tailpipe CO₂ as any methanol (about 1.375 kg CO₂ per kg methanol fuel), but we consider that release as part of the fuel’s WtW profile. (In regulatory accounting, it may be arguable whether to count it, since that CO₂ was “destined” to be emitted from cement production in the baseline. However, for a conservative approach we include it in WtW, noting it is of fossil origin.)
- Biogenic CO₂ sources: If CO₂ is taken from a biomass fermenter or biogas upgrader (e.g. from an ethanol plant or a biogas plant), its origin is biogenic. When that carbon is later released from the methanol’s use, it is considered biogenic CO₂ emission – effectively climate-neutral in the accounting. Our model still tracks any energy used to capture and supply the CO₂ (which is usually small for fermentation CO₂ as noted). Thus, e-methanol using CO₂ from a bio-ethanol facility gets a significant advantage: the combustion CO₂ is not counted against its total. We ensured to apply this consistent with RED II: the biogenic portion of CO₂ is counted as zero at combustion, so the WtT emissions dominate for such a fuel, often yielding very low net GHG intensity.

For blue methanol (via SMR or ATR of natural gas with CCS), we constructed the carbon intensity from several components:

- 1) Natural gas upstream emissions (extraction, leakage, transport) – we assumed a methane leakage rate ~1.2–1.5% and upstream processing emissions of ~11.9 gCO₂e/MJ [16].
- 2) Reforming process emissions – SMR without CCS produces ~8.9–10.7 kg CO₂ per kg H₂ (around 73–88 g/MJ) [30][31][32]. With CCS, a fraction of this is captured. In our model, we examined two cases: a typical SMR+CCS capturing ~60% of CO₂ (such as the Quest project

in Canada [33], which results in ~4–8 kg CO₂/kg H₂ or ~35–67 gCO₂/MJ emitted [30][32][34][35]) and an advanced ATR+CCS capturing 90–95% (achieving ~0.8–3.7 kg CO₂/kg H₂ or ~6–31 g CO₂/MJ [30][31][34][35][36]).

- 3) CCS energy penalty – we included a small energy penalty for CO₂ separation and compression in the plant (e.g. amine scrubbers use steam, reducing overall efficiency).
- 4) Methanol synthesis from syngas – In blue methanol production, captured CO₂ from reformer flue gases reacts with hydrogen ($\text{CO}_2 + 3\text{H}_2 \rightarrow \text{CH}_3\text{OH} + \text{H}_2\text{O}$) to form additional methanol, improving carbon yield. The step accounts for hydrogen demand, CO₂ uptake at high conversion efficiency, and process energy for synthesis, compression, and distillation [16]. Heat is supplied by burning a small share of natural gas or off-gas (in fossil cases) or by renewable heat (in green cases) [16]. Most carbon is converted to product, with limited CO₂ vented. Total emissions per kilogram of methanol are derived from unrecovered CO₂, process energy, and upstream gas, divided by the fuel's lower heating value (19.9 MJ/kg) to express results in g CO₂e per MJ.

Model Implementation

We implemented the above calculations in our spreadsheet model which takes as inputs the energy and material requirements for each pathway and outputs the WtT, TtW, and WtW carbon intensities. Emissions for transporting the finished methanol to the point of use were also added (we assumed 2 g CO₂/MJ for distribution, roughly equivalent to a moderate sea and land transport distance) – this affects all pathways roughly equally [2].

After computing WtT and adding TtW (where for renewable methanol TtW CO₂ may be zero or partially zero), we obtain the final carbon intensity in units of g CO₂ equivalent per MJ of fuel. We then evaluate the percentage reduction compared to the 94 g CO₂e/MJ fossil comparator. We also check compliance against EU targets (70% reduction). It should be noted that our approach aligns with FuelEU Maritime regulation's calculation for voyages: that regulation similarly sums upstream and downstream emissions to evaluate compliance, and in fact uses 91.16 gCO₂e/MJ as the baseline for marine fuels (slightly different from 94 due to shipping-specific factors). Our baseline of 94 g/MJ is a conservative comparator in line with RED II road transport standard, which is appropriate for discussing the stricter RFNBO targets. In the next section, we present the results for various methanol pathways computed using this methodology.

Results

Carbon Intensity of Different Methanol Pathways: Our results show a spread in lifecycle GHG intensities for methanol depending on feedstock and energy inputs. Figure 1 summarizes the WtW carbon intensity (in g CO₂e per MJ) for several pathways of interest, compared against conventional fossil marine fuels. The orange lines show the base case while the blue bars show the range of the possible WtW carbon intensities.

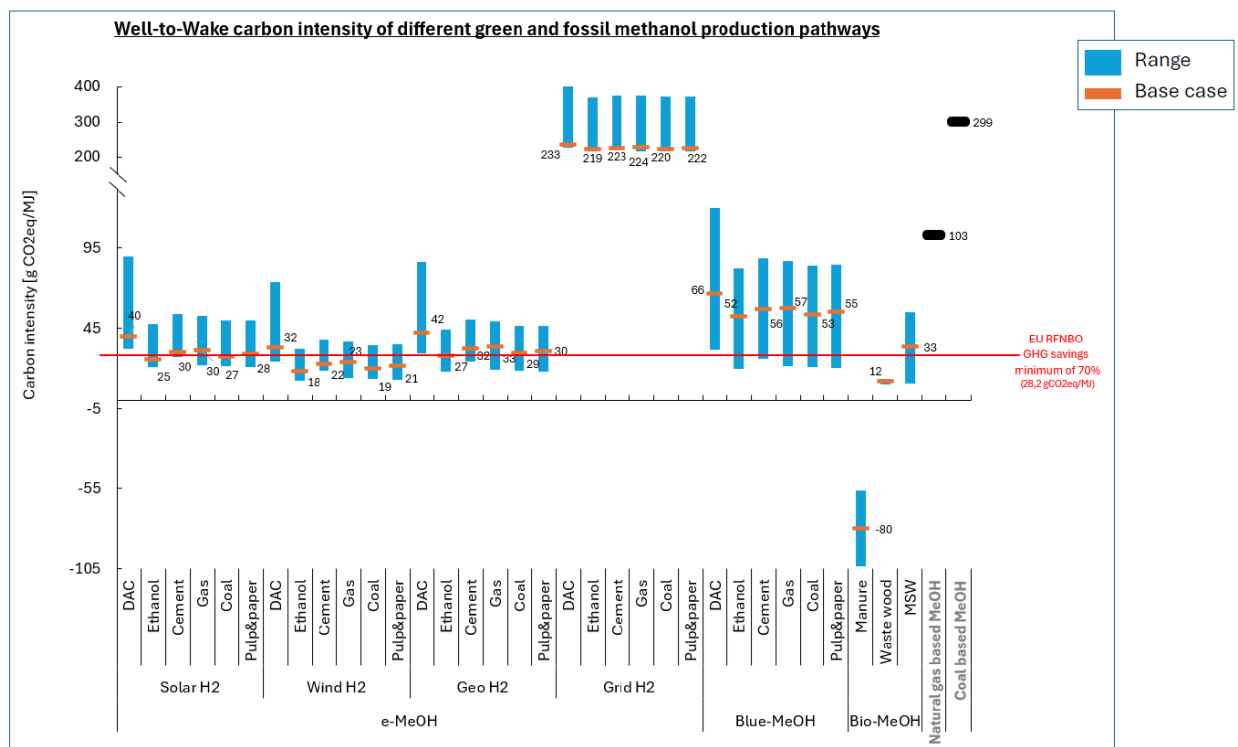


Figure 1: Well-to-wake carbon intensity of methanol pathways, including a comparison to fossil methanol (coal and natural gas based).

As Figure 1 illustrates, conventional fossil fuels like VLSFO or marine diesel oil have WtW emissions around 90 gCO₂e/MJ. Grey methanol produced from natural gas (no CO₂ capture) is actually higher than this: we estimate roughly ~103 gCO₂e/MJ on average for modern plants (range ~100–110 g/MJ), which aligns with literature values; coal-based methanol is far worse at ~299 g/MJ. This is because producing methanol from methane or coal releases most of the carbon as CO₂ (either in syngas production or as off-gas), on top of upstream emissions – without capture, it can even exceed the emissions of refining and burning fuel oil.

By contrast, e-methanol (renewable methanol) can have a much lower footprint, but with important caveats. In a base-case e-methanol scenario where hydrogen is produced from solar electricity and CO₂ is captured from an industrial source, we find carbon intensities on the order of ~25–30 gCO₂e/MJ depending on the source: for example, cement + solar H₂ averages 29.6 g/MJ (26.7–54.0), while ethanol CO₂ + solar H₂ averages 25.1 g/MJ (20.6–47.6). Using wind electricity improves results further for the same CO₂ sources – e.g., cement + wind H₂ averages 22.2 g/MJ (18.5–38.4), and ethanol CO₂ + wind H₂ averages 17.7 g/MJ (12.4–32.0). These values correspond to GHG reductions of roughly ~68–76 % for the solar-cement cases (vs. the 94 g/MJ comparator) and ~76–86 % for the wind cases, respectively. In other words, not all e-methanol pathways automatically meet the 70 % savings threshold (≤ 28.2 g/MJ): the solar + cement case at 29.6 g/MJ narrowly misses it on average, while wind + cement and wind + ethanol generally pass. The main contributors to emissions remain the electricity’s embodied/operational GHG (even renewables aren’t strictly zero) and the energy used to capture CO₂ from lower-purity industrial streams. With completely carbon-free heat for CO₂ capture (or slightly lower PV emissions), the solar-cement pathway could dip below ~28 g/MJ and qualify as RFNBO. This highlights how sensitive e-fuel LCA is

to real-world energy inputs – also emphasized by other research [37][38][39]. Regulators presently require $\geq 70\%$ savings (≤ 28.2 g/MJ), which some solar-based configurations narrowly miss, indicating developers must pay attention to every emission source. Worst-case power assumptions are disqualifying: grid-powered H₂ yields ~ 218 – 233 g/MJ across e-methanol cases (e.g., cement + grid H₂ 223.2 g/MJ; ethanol + grid H₂ 218.6 g/MJ), far worse than fossil fuel.

Our best-case e-methanol scenario combined onshore wind electricity (very low CI) with biogenic CO₂ from a bio-ethanol plant. In this configuration, the only significant GHG contributions were from hydrogen production and some process loads; the CO₂ was biogenic and the methanol’s combustion CO₂ is neutral in accounting. We find totals ~ 15 – 21 gCO₂e/MJ typified by ethanol CO₂ + wind H₂ averaging 17.7 g/MJ (12.4–32.0) and similar results for other biogenic sources (e.g., pulp & paper CO₂ + wind H₂ 20.7 g/MJ on average (12.7–34.7)). These comfortably meet the 70 % reduction requirement. Using DAC increases values due to energy intensity: DAC + wind H₂ averages 32.3 g/MJ (23.9–73.8) and DAC + solar H₂ averages 39.7 g/MJ (32.1–89.4) – still lower than fossil methanol, but often missing 70 %. As noted, grid H₂ pushes e-methanol into > 200 g/MJ territory (e.g., cement + grid H₂ 223.2 g/MJ), far worse than fossil.

Moving to bio-methanol, our results (and literature) show very favorable carbon intensities. Pathways using biogas or residue biomass typically achieve single-digit to low-tens gCO₂e/MJ – e.g., waste wood averages ~ 12 g/MJ (10–13.5), consistent with ~ 10 – 15 g/MJ for wood gasification with supplemental H₂. Municipal solid waste (MSW) – to-methanol averages ~ 33 g/MJ (10–55.3), and can meet EU thresholds; where a case sits near ~ 35 g/MJ, switching process energy to renewable generally brings it under the limit. When biogenic methane avoidance is credited, values can be negative: manure-based biomethanol averages ~ -80 g/MJ (-56 to -103.8), reflecting substantial avoided CH₄ emissions. Not all bio-routes are negative, but waste/residue pathways generally pass EU criteria comfortably.

Finally, blue methanol – produced via natural gas with CCS – shows intermediate performance. Across CO₂ sources, our blue-methanol averages typically fall in the ~ 52 – 57 g/MJ range (e.g., biogenic 51.8, cement 56.3, gas 57.1, coal 53.5, pulp & paper 54.8 g/MJ on average), with DAC-based blue higher on average (66.4 g/MJ) and broader variability overall (~ 20 – 124 g/MJ across min-max). A representative “blue” case around ~ 55 g/MJ is roughly a $\sim 40\%$ reduction vs. 94 g/MJ. Some configurations extend to ~ 70 – 80 g/MJ (and above in outliers), reflecting residual process CO₂ plus upstream methane leakage and capture energy. Even under optimistic assumptions, blue methanol does not reach the 70 % reduction level; at best it halves emissions versus fossil fuel but remains well above the RFNBO threshold (≤ 28.2 g/MJ). In EU terms, it would not count as renewable, though it still reduces absolute GHG per unit energy relative to fuel oil.

To compare all these numerically, these values are summarized in Table 1 below, along with an indication of whether they meet key EU GHG criteria.

Table 1. Lifecycle GHG intensity results for methanol pathways (g CO₂e per MJ fuel) and compliance with EU GHG savings thresholds.

Pathway	WtW GHG (g/MJ)	Reduction vs fossil comparator (94 gCO ₂ e/MJ)	Meets 70% saving?
Fossil VLSFO (baseline)	~ 90	–	(comparator)

Grey Methanol (NG)	~103 (100–110)	~+10%	No
Grey Methanol (coal)	~299	Much worse	No
Blue Methanol (NG+CCS)	~25–66	~30–73%	No
Bio-methanol (residues)	~10–33	~65–89%	Usually (yes)
Bio-methanol (manure biogas)	–104 to -56	>100% (net removal)	Yes (exceeds)
E-MeOH (wind + bio-CO₂)	~18–21 avg (e.g., ethanol CO ₂ + wind H ₂ 17.7 (12.4–32.0); pulp & paper + wind 20.7 (12.7–34.7))	~78–86%	Yes
E-MeOH (solar + industrial CO₂)	~25–30 avg (e.g., cement + solar 29.6 (26.7–54.0); ethanol + solar 25.1 (20.6–47.6))	~68–73%	Borderline to No (case-dependent)
E-MeOH (DAC + wind/solar)	~32–40 avg (wind 32.3 (23.9–73.8); solar 39.7 (32.1–89.4))	~57–66%	Often No
E-MeOH (grid H₂ – worst case)	~218–233 (e.g., cement 223.2, ethanol 218.6)	Negative savings	No (much worse)

Table 1: Lifecycle GHG intensity results for methanol pathways (g CO₂e per MJ fuel) and compliance with EU GHG savings thresholds. (All values are approximate; “–50” indicates net –50 g (a carbon sink). Fossil comparator for percentages taken as 94 gCO₂e/MJ per EU RED II [7]. Threshold for RFNBO/RCF is 70% (≤28.2 g/MJ) [8][12]. Threshold for existing biofuels in 2021+ is 65% (≤32.9 g/MJ) [7].)

From the table, one can see that only certain e-methanol and bio-methanol pathways comfortably satisfy the 70% reduction requirement, while blue methanol does not. Grey methanol, of course, increases emissions and is not a mitigation option (included for comparison). Even some nominally “renewable” methanol (e.g., solar + captured industrial CO₂) can fall just short – meeting ~68–73% reductions when 70% is needed. If policy strictly adheres to the cutoff, such fuels would not qualify as RFNBO. This fine margin highlights the importance of methodological details (e.g., the exact electricity emission factor, whether capture heat is genuinely zero-carbon). In practice, project developers might tweak parameters or add a bit more biogenic input to ensure compliance. The Discussion section explores how these results translate into regulatory compliance and where flexibility may emerge.

Discussion

Impact of Feedstock and Input Assumptions

The results clearly demonstrate that the choice of feedstock (CO₂ source for e-methanol, biomass type for bio-methanol, etc.) and energy inputs (electricity source for H₂, heat source for processes) have a profound impact on carbon intensity. For e-methanol, the electricity source is decisive: using renewable wind or solar power keeps emissions low (typically ~18–30 gCO₂e/MJ), whereas using grid electricity causes extreme values (~218–233 gCO₂e/MJ), far exceeding fossil fuel emissions. This confirms the rationale behind the EU’s strict additionality and temporal matching rules for renewable electricity – if e-fuels were produced using average grid power in coal-heavy regions, they could emit more CO₂ than fossil fuels.

The CO₂ feedstock also plays a major role. Using biogenic CO₂ (e.g. from ethanol fermentation) or unavoidable industrial waste CO₂ (e.g. cement or pulp & paper) achieves much better performance (~17–22 gCO₂e/MJ) than using direct air capture (DAC), which remains energy-intensive (~32–40 gCO₂e/MJ). In essence, e-methanol is only as “green” as the H₂ and CO₂ that go into it. This aligns with conclusions from other studies showing that the carbon footprint of power-to-fuel pathways is dominated by electricity GHG intensity [40][41][42]. It also underscores that policy should continue to incentivize coupling e-fuel production with ultra-low-carbon grids or dedicated renewables, as required under Delegated Regulation (EU) 2023/1185.

For bio-methanol, assumptions about the counterfactual fate of biomass are equally decisive. Our manure-based case achieves strongly negative emissions (~ -80 gCO₂e/MJ; range -56 to -103.8) due to avoided methane. If avoided-emission credits were excluded, its CI could rise to around +20 g/MJ, still well below thresholds. Waste wood pathways average ~ 12 g/MJ (10–13.5), while municipal solid waste (MSW)-based routes average ~ 33 g/MJ (10–55.3) – all within or near EU limits. In cases near the upper end (e.g. 30–35 g/MJ), using renewable heat rather than natural gas can bring values under the 28.2 g/MJ RFNBO threshold. Land-use-change (LUC) impacts were excluded since wastes and residues are assumed to have zero LUC emissions under RED II. Overall, waste- and residue-based bio-methanol pathways remain highly climate-effective and policy-compliant.

Compliance with EU GHG Savings Thresholds

Given the modeled values, several pathways meet or exceed current EU requirements. Under RED II, existing biofuel plants must achieve ≥ 65 % savings, and new RFNBOs/RCFs ≥ 70 %, corresponding to ≤ 32.9 g/MJ and ≤ 28.2 g/MJ, respectively.

All our bio-methanol pathways meet or exceed these thresholds, with residue-based routes achieving ~10–33 g/MJ (65–89 % savings) and manure-based cases even achieving > 100 % (net removals). Most e-methanol configurations using renewable power and biogenic CO₂ also comply easily (e.g. wind + bio-CO₂ ≈ 18–21 g/MJ, ≈ 80–85 % reduction). In contrast, solar + industrial CO₂ ≈ 25–30 g/MJ (68–73 % reduction) lies just above the 70 % cut-off. DAC-based e-methanol (32–40 g/MJ) often fails, as does any pathway using grid electricity (~220 g/MJ, negative savings).

Blue methanol, derived from natural gas with CCS, achieves ~25–66 g/MJ depending on capture rate and CO₂ source – equivalent to 30–73 % reduction versus fossil fuel – but generally below the 70 % requirement. As a result, blue methanol currently does not qualify as renewable or RFNBO under EU rules. It could, however, fit within a potential “low-carbon fuel” (LCF) category, if such a framework were formally introduced in future legislation. The lack of recognition limits incentives, even though blue methanol can halve emissions relative to fossil methanol.

Regulatory Gaps and Considerations

The analysis highlights ambiguity in how Recycled Carbon Fuels (RCFs) and low-carbon fuels (LCFs) are treated. RED II allows optional national crediting for RCFs, but there is no EU-wide sub-target. E-methanol from industrial CO₂ could be classified as either RFNBO or RCF depending on electricity sourcing. However, even RCFs must meet the 70 % reduction criterion to qualify. This leaves many low-carbon but non-renewable pathways – such as blue methanol or renewable-H₂ + fossil-CO₂ methanol – in a gray zone. Some stakeholders propose creating an explicit LCF category (with, say, a ≥ 50–60 % reduction threshold) to acknowledge these transitional fuels, similar to California’s LCFS.

Economic considerations reinforce this tension. E-methanol remains several times costlier than fossil methanol, while blue methanol could be produced more cheaply due to established gas infrastructure and moderate capture costs. Excluding blue fuels entirely may delay near-term reductions; conversely, including them might dilute renewable incentives. The EU currently prioritizes fully renewable fuels, though some softening (e.g. phased additionality rules) hints at potential future flexibility.

Implications for EU Shipping

Methanol is rapidly gaining traction in shipping, yet not all methanol is climate-benign. Grey methanol (≈ 103 g/MJ) performs worse than marine gas oil (~ 90 g/MJ), offering no WtW CO₂ advantage. Only green and bio-methanol achieve deep decarbonization consistent with FuelEU Maritime and IMO trajectories. Under FuelEU, ship operators must progressively lower fleet-average GHG intensity (-6 % by 2030, -31 % by 2040).

Our results show that blue methanol (~ 55 g/MJ) would meet the near-term (2030–2040) targets but not long-term ones (-80 % by 2050). Thus, it could act as a transitional option until sufficient renewable methanol supply emerges. However, it would not receive RFNBO multipliers or renewable credits. The likely outcome is a phased adoption: ships may initially bunker blue methanol to meet early compliance thresholds, transitioning to e-methanol or bio-methanol as availability and certification expand.

Environmental and Policy Considerations

While GHG intensity is the primary metric, broader sustainability issues remain. Some biomass pathways raise land-use or biodiversity concerns, while DAC-based e-methanol demands large renewable energy inputs. The EU's preference for advanced biofuels and RFNBOs ensures environmental rigor but may discourage incremental improvements like partial CCS retrofits or co-processing. A more balanced approach – rewarding verified emission reductions regardless of feedstock origin – could accelerate near-term decarbonization.

Carbon-removal accounting is another emerging issue. E-methanol produced from DAC could, in theory, generate carbon-removal credits if net-negative, but double-counting must be avoided. The EU's forthcoming Carbon Removal Certification Framework will likely clarify how such credits interact with fuel GHG accounting.

Summary of Discussion

Feedstock and energy choices dominate methanol's lifecycle emissions. Only e-methanol and bio-methanol produced with ultra-low-carbon energy and sustainable CO₂/biogenic sources achieve the deep reductions (≥ 70 %) required by EU law. Blue methanol, though offering meaningful (~ 50 %) cuts, remains outside current renewable definitions. Policymakers may need to introduce transitional LCF mechanisms or flexible thresholds if renewable fuel deployment lags. Several industry groups advocate lowering the RFNBO threshold to 65 % (32.9 g/MJ) to align with biofuels, though this remains under debate.

Conclusions

In this study, we conducted a harmonized lifecycle assessment of methanol production pathways – including e-methanol, bio-methanol, and blue methanol – under EU RED II and Delegated Acts 2023/1184–1185.

Key findings:

- E-methanol (RFNBO): Carbon intensities range ~15–30 g CO₂e/MJ for renewable cases (wind/solar + bio/industrial CO₂), corresponding to ~70–85 % GHG savings. Best cases (wind + biogenic CO₂ ≈ 18 g/MJ) clearly meet EU thresholds. Borderline solar + industrial CO₂ cases (~ 29–30 g/MJ) achieve ~ 68–73 % savings – just below the 70 % bar. DAC and grid electricity routes (≥ 32 g/MJ and > 200 g/MJ, respectively) fail to qualify.
- Bio-methanol: Waste- and residue-based routes achieve ~10–33 g/MJ (65–89 % reduction), while manure-based pathways can reach ~–80 g/MJ (–56 to –104), exceeding 100 % savings (net removals). These pathways comfortably meet both the 65 % and 70 % thresholds and deliver the strongest climate benefits among all options.
- Blue methanol: Depending on capture rate and CO₂ source, values range ~25–66 g/MJ (30–73 % reduction) – a moderate improvement over fossil methanol (~103 g/MJ) but insufficient to qualify under RED II as renewable. Blue methanol thus remains outside current EU crediting systems despite its potential role as a bridge fuel.
- Fossil methanol: Grey methanol from natural gas (~103 g/MJ) and coal-based methanol (~299 g/MJ) are significantly above the fossil comparator (~94 g/MJ), offering no climate benefit.

Overall, methanol’s climate performance varies widely by pathway. Green (e-methanol) and advanced (bio-methanol) routes already satisfy stringent EU criteria and represent the long-term decarbonization solutions for shipping and industry. Blue methanol may provide interim emission reductions but lacks policy recognition. Achieving EU and IMO climate objectives will therefore require rapid expansion of renewable methanol production alongside clear, credible certification and potentially a transitional framework for verified low-carbon fuels.

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