Co-Pollutant Impacts of Low-Carbon Fuels and Technologies

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Many air pollutants are byproducts of the combustion of carbonaceous fuels, including fossil fuels and most alternative fuels, including fine particulate matter ($PM_{2.5}$) and its precursors nitrogen oxides (NO_x) and sulfur dioxide (SO_2), among others. The use of low-carbon alternative fuels and technologies can improve, worsen, or have similar impacts on air quality compared to their fossil fuel counterparts, depending on the specific fuel, application, and emission controls in place.

The key takeaways below provide a qualitative summary of the impacts of certain low-carbon alternative fuels and technologies on direct, local co-pollutant emissions, which would most directly affect public health. The attached memorandum, *Co-Pollutant Impacts of Low-Carbon Fuels and Technologies—2025 Update*, details the findings of a literature review on these impacts and provides additional information on the fuels and their applications.

Key Takeaways

Fuel or Technology	Application	Overall Air Pollutant Emissions Impacts
Sustainable aviation fuel	All aircraft operation cycles	Reduction in $PM_{2.5}$ and SO_2 emissions compared to fossil jet fuel. No impact on NO_x emissions.
Hydrogen	Electricity generation	Elimination of $PM_{2.5}$, SO_2, and other co-pollutant emissions compared to natural gas. Potential increased NO_x emissions, which could be reduced to within regulatory compliance levels with appropriate system design and/or post-combustion controls.
	Industrial combustion	Elimination of $PM_{2.5}$, SO_2, and other co-pollutant emissions compared to natural gas. Potential increased NO_x emissions without additional controls, with uncertainty depending on the blend level, combustor type, and configuration.
	Hydrogen enriched natural gas (pipeline injection) used in industrial, commercial, and residential appliances	Reduction in $PM_{2.5}$, SO_2, and other co-pollutant emissions roughly correlated to hydrogen energy content compared to pure natural gas. Uncertain changes in NO_x emissions depending on blend level, burner type, and operating conditions.

Fuel or Technology	Application	Overall Air Pollutant Emissions Impacts
Biogas	Electricity generation	Potential increased SO_2 emissions, no change in NO_x emissions, and no data available on $PM_{2.5}$ emissions changes compared to natural gas. If biogas is combusted on-site at a landfill, $PM_{2.5}$ and NO_x emissions may increase or decrease compared to flaring depending on the waste content and combustion device, and there may be additional emission reductions from reduced electricity production elsewhere.
Renewable natural gas	All applications	No change expected compared to natural gas.
Renewable diesel	On- and non-road engines with emission controls	No change expected compared to ultra-low sulfur diesel (ULSD).
	Non-road engines without emission controls	Reduction in $PM_{2.5}$, NO_x, and other co-pollutant emissions compared to ULSD.
	Residential boilers	No data available.
Biodiesel	On- and non-road engines with emission controls	No change expected compared to ULSD. NO_x emissions may vary based on biodiesel feedstock and vehicle speed, engine load, and control technologies.
	Non-road engines without emission controls	Potential reduction in $PM_{2.5}$ emissions and potential increased NO_x emissions, but data is limited.
	Residential boilers	No data available.
Carbon capture and storage	Pre-combustion at coal industrial facilities	Reduction in NO_x, SO_2, and ammonia (NH_3) emissions, but no change in $PM_{2.5}$, compared to coal facilities without pre-combustion CCS.
	Post-combustion at natural gas industrial facilities	Uncertain changes in $PM_{2.5}$, NO_x, and SO_2 emissions compared to natural gas facilities without post-combustion CCS due to limited data. Increased NH_3 emissions without additional emission controls.
	Post-combustion at natural gas power plants	Reductions in $PM_{2.5}$, NO_x, and SO_2 emission compared to natural gas facilities without post-combustion CCS.

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Subject:	**Co-Pollutant Impacts of Low-Carbon Fuels and Technologies—2025 Update**

MEMORANDUM

This memorandum summarizes the findings of a literature review by SC&A, Inc. (SC&A), under subcontract to Industrial Economics, Inc. (IEc) for NYSERDA, on the effects of low-carbon fuels and energy technologies on direct, local co-pollutant emissions, with an emphasis on fine particulate matter ($PM_{2.5}$) and its precursors.

Summary

A literature review was conducted to assist NYSERDA in its efforts to understand the air quality and health effects of decarbonization efforts within New York State. This review focuses on local, co-pollutant emissions from direct combustion associated with fuel swapping from fossil fuels to low- or no-carbon fuels and clean technologies. Additionally, the focus here is on fuels and applications with the most relevance to New York State. Below, we present a brief overview of each fuel or technology, its expected applications, and the associated co-pollutant emission impacts. Table 1 summarizes the impacts of fuel or technology switching on co-pollutant emissions organized by application for each fuel and technology evaluated in this memo.

Sustainable aviation fuel (SAF), a non-fossil fuel replacement for conventional jet fuel, is expected to significantly reduce emissions of $PM_{2.5}$ and sulfur dioxide (SO_2). The magnitude of $PM_{2.5}$ emission reductions varies by SAF blending percentage and aircraft operation cycle (i.e., idling, cruising, or landing/takeoff operations), where $PM_{2.5}$ emission reductions decline as engine load increases. $PM_{2.5}$ emissions reductions increase as the SAF blend percentage increases, although incremental $PM_{2.5}$ emission reductions relative to SAF content decrease at higher level blends. SO_2 emissions are directly related to the sulfur content of the fuel and SAF is expected to meaningfully reduce SO_2 emissions due to its lower sulfur content compared to conventional jet fuel. Emissions of nitrogen oxides (NO_x) from SAF are not likely to be impacted because they are primarily dependent on turbine inlet temperature rather than fuel composition.

Hydrogen can be used as an alternative to natural gas, either alone or blended with natural gas, for electricity generation, industrial combustion, or blended (in limited quantities) in natural gas pipelines for general use. Hydrogen combustion is a cleaner alternative to natural gas because it does not emit $PM_{2.5}$ or SO_2. However, hydrogen fuel burns at higher temperatures than natural gas, and systems not designed for hydrogen can emit higher levels of NO_x compared to natural gas absent sufficient emissions controls.

Hydrogen combustion in unmodified natural gas electricity generation and industrial combustion systems can significantly increase NO_x emissions compared to natural gas combustion, and NO_x control technologies would be needed to maintain or reduce NO_x emission levels. Unlike natural gas, hydrogen combustion for electricity generation or industrial combustion is not expected to emit $PM_{2.5}$, SO_2, volatile organic compounds (VOCs), or carbon monoxide (CO).

If low levels of hydrogen are blended into natural gas pipelines and used in unmodified industrial, commercial, and residential appliances, the impact on NO_x emissions is uncertain and dependent on the appliance, configuration, and blend level. The hydrogen portion of hydrogen enriched natural gas is not expected to emit $PM_{2.5}$, SO_2, VOCs, or CO.

Biogas from landfills and wastewater treatment facilities can be combusted onsite to generate electricity, often using internal combustion engines. Combustion of biogas may have different emission profiles compared to natural gas depending on the feedstock and end-use application. Trace gases and other impurities in the feedstock may increase emissions compared to natural gas. For example, trace amounts of hydrogen sulfide could emit large amounts of SO_2 if not removed before combustion. NO_x emissions from biogas combustion are expected to be similar to those from natural gas combustion. There was insufficient data to compare $PM_{2.5}$ emissions from biogas combustion versus natural gas combustion for electricity generation.

Biogas is often flared at landfills to avoid methane and other emissions, so co-pollutant emissions from onsite biogas combustion for energy uses can alternatively be compared to emissions from flaring. Biogas combustion in boilers or steam turbines for electricity generation would decrease NO_x and $PM_{2.5}$ emissions compared to biogas flaring emissions. However, biogas combustion in internal combustion engines would increase NO_x and $PM_{2.5}$ emissions relative to biogas flaring emissions. In both cases, there could be some additional emissions benefits to the extent that this onsite electricity generation reduces electricity production elsewhere that uses natural gas, renewable natural gas (RNG), or diesel.

Biogas can also be further refined to produce RNG, which is chemically similar to natural gas; thus, emissions from RNG combustion would be similar to emissions from natural gas combustion.

Renewable diesel is a biofuel produced from renewable sources that can be used as a drop-in fuel in diesel engines without requiring any modifications. When renewable diesel is used in newer engines equipped with emission controls (e.g., diesel particle filters [DPFs]), such as those found in almost all on-road diesel vehicles (fully phased in by model year 2010) and newer non-road diesel engines ("Tier IV," noting that non-road engines often have extended lifetimes), $PM_{2.5}$, NO_x, and SO_2 emissions are similar to those from fossil diesel (ultra-low sulfur diesel [ULSD]) currently sold for on-road and non-road use. Using renewable diesel in older non-road engines that are not equipped with emission controls (still common in non-road applications) would reduce $PM_{2.5}$ and NO_x emissions compared to fossil diesel. Renewable diesel can also reduce emissions of hazardous air pollutants (e.g., benzene), though diesel vehicles are not a large source of these emissions. No literature was found on the impacts of renewable diesel on emissions from residential boilers.

Biodiesel, a fuel made from vegetable oils, animal fats, or waste grease from restaurants, is currently blended into transportation fuels and heating oil in New York State. Biodiesel combustion in older (uncontrolled) non-road engines may reduce $PM_{2.5}$ emissions but increase NO_x emissions. As with renewable diesel, for on-road and newer non-road engines equipped with emission controls, $PM_{2.5}$, SO_2, and NO_x emissions are expected to be similar to those from fossil diesel, though NO_x emissions may vary based on the biodiesel feedstock and the vehicle speed, engine load, and control technologies. The use of biodiesel in boilers has not been well studied, and there is insufficient information to determine if there are any co-pollutant reductions compared to ULSD, which is already required by New York State.

Carbon Capture and Storage (CCS) refers to the set of technologies designed to capture significant quantities of carbon dioxide (CO_2) from large point sources, including power plants and certain industrial facilities. While CCS technologies are not primarily designed to remove pollutants other than CO_2, they are often paired with other pollutant controls to increase the efficiency of CO_2 capture. Pre-combustion CCS at coal-fueled industrial facilities has been shown to reduce emissions of NO_x, SO_2, VOCs, and ammonia (NH_3), but did not impact $PM_{2.5}$ emissions. Post-combustion CCS at natural gas industrial facilities uses amine scrubbing and has been shown to both increase and decrease emissions of NO_x, $PM_{2.5}$, and SO_2 and significantly increase NH_3 emissions compared to natural gas industrial facilities without post-combustion CCS. Pairing post-combustion CCS with additional control measures could reduce these emissions. Post-combustion CCS at natural gas combined cycle plants using a CO_2 recovery facility has been shown to eliminate $PM_{2.5}$ and SO_2 emissions and reduce NO_x emissions.

Table 1 summarizes the co-pollutant impacts of the alternative fuels evaluated in this review. All changes in co-pollutant emissions presented in Table 1 are on an energy content basis.

Table 1. Impacts of Alternative Fuels on Co-Pollutant Emissions

Fuel and Application	**Change in Co-Pollutant Emissions**
Sustainable Aviation Fuel (compared to jet fuel)	
Aircraft Idling	$PM_{2.5}$ emission reductions of 63-73% from a 50% SAF blend
Aircraft Cruising	$PM_{2.5}$ emission reductions of 55-58% from a 50% SAF blend
Aircraft During Landing/Takeoff Operations	$PM_{2.5}$ emission reductions of 39-80% from a 50% SAF blend
Aircraft Emissions (all Cycles)	No change in NO_x emissions SO_2 emission reductions directly correlated to fuel sulfur content (70-100% reduction in SO_2 emissions for SAF component of fuel)
Hydrogen (compared to natural gas)	
Electricity Generation	Uncontrolled NO_x emissions may increase by up to 4[1] times (100% hydrogen). NO_x emissions can be reduced to within regulatory compliance levels with appropriate system design and/or post-combustion controls. $PM_{2.5}$, SO_2, VOC, and CO emission reductions of 100% (100% hydrogen)
Industrial Combustion	Uncontrolled NO_x emissions may increase by 2-7 times or decrease depending on blend level, combustor type, and configuration $PM_{2.5}$, SO_2, VOC, and CO emission reductions of 100% (100% hydrogen)
Hydrogen Enriched Natural Gas in Industrial, Commercial, and Residential Appliances	NO_x emission changes are uncertain depending on blend level, burner type, and operating conditions $PM_{2.5}$, SO_2, VOC, and CO emission reductions roughly correlated to hydrogen energy content

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[1] This estimate of a 4-fold increase in NO_x emissions is on an energy basis and includes an additional correction from Douglas et al. (2022) discussed in the body of the report.

Fuel and Application	**Change in Co-Pollutant Emissions**
Biogas (compared to natural gas and flaring)	
Electricity Generation	Compared to natural gas combustion: • Data was not available for $PM_{2.5}$ • No significant change in NO_x emissions • SO_2 emission increases of 100% • CO emission increases of 13% Combustion in boilers or steam turbines compared to flaring: • $PM_{2.5}$ emission reductions of 52% • NO_x emission reductions of 13% Combustion in gas turbines compared to flaring: • $PM_{2.5}$ emission increases of 30% • NO_x emission increases of 130% Combustion in internal combustion engines compared to flaring: • $PM_{2.5}$ emission increases of 180% • NO_x emission increases of 150% Note that flaring may also reduce off-site generation emissions that are offset by onsite generation. Additionally, the biogas emission rates used for the flaring comparisons above are variable depending on the specific content of the waste being combusted
Renewable Natural Gas (compared to natural gas)	
Any application	No change expected
Renewable Diesel (compared to ultra-low sulfur diesel [ULSD])	
On-Road Engines and Non-Road Engines with Emission Controls	No change in $PM_{2.5}$ or NO_x emissions No empirical data, but no expected change in SO_2 emissions Some hazardous air pollutant emission reductions
Older Non-Road Engines (without Emission Controls)[2]	$PM_{2.5}$ emission reductions of 22-38% NO_x emission reductions of 5-13% CO emission reductions of 22-32% Total hydrocarbon emission reductions of 40-45%
Locomotives (without Emission Controls)	PM emission reductions of 36% NO_x emission reductions of 17% CO emission reductions of 19% Total hydrocarbon emission reductions of 37%
Residential Boilers	No data available

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2. Studies of non-road engines were focused on agricultural tractors. While effects may be similar for other uncontrolled non-road engines, emissions from non-road engines do vary by load cycle.

Fuel and Application	Change in Co-Pollutant Emissions
Biodiesel (compared to ULSD)	
On-Road and Non-Road Engines with Emission Controls	No change in $PM_{2.5}$ emissions No overall change in NO_x emissions is expected. NO_x emissions may vary based on biodiesel feedstock and vehicle speed, engine load, and control technologies
Older Non-Road Engines (without Emission Controls)	$PM_{2.5}$ emission reductions of up to 40% NO_x emission increases of up to 19%
Residential Boilers	No data available
Carbon Capture and Storage (CCS) (compared to no CCS)	
Pre-Combustion CCS at Industrial Facilities using Coal	No change in $PM_{2.5}$ emissions NO_x emission reductions of 15% SO_2 emission reductions of 55% VOC emission increases of 27% NH_3 emissions reductions of nearly 100%
Post-Combustion CCS at Natural Gas Industrial Facilities	$PM_{2.5}$, NO_x, and SO_2 emissions may increase or decrease and are considered uncertain based on limited data Large increases in NH_3 emissions
Post-Combustion CCS at Natural Gas Combined Cycle Power Plants	NO_x emission reductions of 25% $PM_{2.5}$ emission reductions of 100% SO_2 emission reductions of 100%

Introduction

This memorandum documents the latest scientific understanding and data regarding co-pollutant emissions from alternative low-carbon fuels and technologies. We compare these low-carbon fuels to their fossil fuel counterparts across various end-use applications. This analysis focuses on local combustion emissions of concern for air quality and health assessments, particularly emphasizing fine particulate matter ($PM_{2.5}$) and its precursors, while also summarizing any significant findings on other pollutants where substantial data exist. We focus on local, direct combustion emissions associated with fuel swapping (rather than lifecycle emissions), aligning with NYSERDA's focus on air quality and health impacts related to decarbonization in general, including the potential use of alternative fuels.

SC&A, as a subcontractor to IEc, was tasked by NYSERDA to update a previous version of this memorandum, "Effect of Low-Carbon Fuels and Energy Technologies on Co-Pollutant Emissions," and this memorandum replaces that document and incorporates and updates those previous findings along with new information and sources. The previous memorandum (dated October 18, 2022) was prepared for NYSERDA by Abt Global based on literature available at that time.

SC&A reviewed the sources cited in the 2022 memorandum, searched for updated information from these sources and relevant information from other sources, expanded on the analysis of hydrogen combustion, and added SAF. Where no additional information was identified beyond the findings of the 2022 memorandum, those conclusions are restated here. This updated literature review synthesizes information from academic publications, scientific journals, government research, and professional organizations.

Discussion of Findings by Fuel Type

Sustainable Aviation Fuel (SAF)

SAF is a low-carbon replacement for conventional jet fuel. It currently can be blended with conventional jet fuel at a maximum of 50% to ensure safe operation with existing engines (Braun-Unkhoff et al., 2017), although some research testing has been performed on 100% SAF and it is possible that the 50% blend limit would change in the future. SAF can be produced through a variety of methods, including the Fischer-Tropsch (F-T) process, alcohol to jet fuel (ATJ) conversion, and via hydroprocessed esters and fatty acids (HEFA) or fatty acid methyl esters (FAME). The feedstocks for SAF are typically agricultural waste, purpose grown biomass feedstocks, or oils from soybean or corn, but many waste stream feedstock options are also possible.

Jet fuel requires high energy density to keep fuel weight low on long flights. SAF typically has an energy density that is comparable to conventional jet fuel. Three different formulations of SAF (two different FAME biofuels and one fatty acid ester of ethanol) mixed in a 50% blend with conventional jet fuel were found to have an energy content of between 33.6 MJ/L and 33.7 MJ/L (Yakovlieva et al., 2019). Conventional jet fuel has an energy content of 34.3 MJ/L; thus, these 50% SAF blends have an energy content that is between 98.0% and 98.2% of conventional jet fuel. Another study found that one F-T SAF had an energy content that was 1.8% higher on a per gallon basis than conventional jet fuel, while a FAME SAF was 17% lower (Lobo, 2011). The emissions changes reported for SAF in this memo assume the cited studies have reported their results on an energy content basis and have not been further adjusted.

Non-volatile particulate matter (nvPM) from jet fuel combustion is mainly soot and ash (Doliente et al., 2020) that does not further transform either chemically or in terms of particle size in the exhaust plume. Engine exit exhaust has high temperatures such that particulate matter emissions “mainly consist of ultrafine nvPM, [and] the geometric mean diameter of these particles typically ranges from 15 nm to 60 nm” (Owen et al., 2022). Most jet engine emission studies measure only total PM or nvPM, rather than specifically $PM_{2.5}$. Because health modeling relies on estimates of PM(mass), that is the figure that is used here whenever both mass and number figures are provided by the underlying studies.

nvPM emissions from jet engines using SAF depend on the fuel composition, including total aromatics and fuel hydrogen content (Durand et al., 2021). When burning SAF blends, the size of emitted particles decreases, yielding a steeper reduction in mass than in number. SAF typically has lower aromatics and sulfur content compared to conventional jet fuel, which leads to a reduction in PM emissions (Braun-Unkhoff et al., 2017). However, low levels of aromatic compounds in 100% SAF were shown to cause fuel leaks in the aircraft fuel system and tanker trucks because low aromatic content can increase seal swell (Beyersdorf et al., 2014). While many SAF formulations have low aromatics content, some SAF fuels have levels of aromatics that are similar to that of conventional jet fuel. For example, catalytic hydrothermolysis synthesized kerosene fuel with aromatics had aromatics that were only 7% lower than Jet A1, while F-T synthesized paraffinic kerosene had 97% lower aromatics than conventional jet fuel (Chan et al., 2016).

PM emission reductions from SAF vary by aircraft flight cycle. The largest PM emission reductions from 50% SAF blends relative to standard jet fuel are during aircraft idling, and more generally, "an increase in engine power decreased the net effect of the alternative fuel on particulate emissions" (Corporan et al., 2010). PM emissions reductions for idling aircraft on a volumetric basis were measured at 66% (Beyersdorf et al., 2014) and in the range of 63-73% (Corporan et al., 2010) for a 50% SAF blend and 70% for a 32% SAF blend (Durdina et al., 2021) compared to conventional jet fuel. PM reductions for cruising aircraft using 50% SAF blends were found to be in the range of 55% (Corporan et al., 2010) and 58% (Moore et al., 2017). Three studies of PM emissions from aircraft using 50% SAF during the landing/takeoff (LTO) cycle — which includes taxi, approach, take-off, and climb — found PM reductions of 39% (Lobo et al., 2011), 61% (Beyersdorf, 2014), and 80% (Chan et al., 2016). SAF with higher aromatics have higher PM emissions (Chan et al., 2016) and that may explain the wide range in emissions reductions observed across these three studies. From the perspective of local air quality and health impacts, emission reductions from idling and LTO cycles are most relevant. The Appendix provides supplementary information on the impacts of SAF on aircraft engine emissions during specific operation cycles.

The relationship between SAF blend level and PM emission reductions remains unclear. We found no available studies of the impacts of SAF blends between 51% and 99%. While most studies assessed SAF blends of 50%, two studies compared PM emission reductions of a 50% SAF blend and 100% SAF for engines at 100% load (comparable to an LTO cycle). A 2011 study of F-T gas-to-liquid SAF found a 39% reduction in PM mass for a 50% blend, but only a 62% reduction for 100% SAF (Lobo et al., 2011). A 2014 study of F-T gas-to-liquid SAF found a 61% reduction in PM mass for a 50% blend, and an 84% reduction for 100% SAF (Beyersdorf et al., 2014). In addition, a meta-study performed a weighted quadratic function fit on the data points of three similar studies (Chan et al., 2016; Beyersdorf et al., 2014; Lobo et al., 2011) and found that as SAF blend percentage increased between 50 and 100%, PM reductions leveled off (Booz Allen Hamilton, 2019). These studies indicate that incremental PM savings relative to SAF content decrease at higher level blends during the LTO cycle.

For blends below the 50% level, it is also unclear whether PM emission reductions are linear. In one meta-study, a 5% SAF blend reduced PM(mass) by 9% during the LTO cycle, while a 50% SAF blend reduced PM(mass) by 65% (Booz Allen Hamilton, 2019). While the meta-study had significant uncertainty associated with its estimates, it stated that nvPM particle number reductions were directly related to the SAF content in blends up to 50%

SAF (Booz Allen Hamilton, 2019). This meta-study also performed a weighted quadratic function fit of the data points of three similar studies (Chan et al., 2016; Beyersdorf et al., 2014; Lobo et al., 2011), which also showed a relatively linear relationship between SAF blend percentage (up to 50%) and PM mass reductions (Booz Allen Hamilton, 2019). Further study is needed to investigate the relationship between SAF blend level and PM reductions.

For both conventional jet fuel and SAF blends, SO_2 emissions “are found to be directly proportional to the amount of sulfur found in the fuel burned, independent of engine type and operating condition” (Booz Allen Hamilton, 2019; Barrett et al., 2012). Reduction in SO_2 emissions from the use of SAF will similarly be a function of fuel sulfur content (Owen et al., 2022). The fuel sulfur content of conventional jet fuel can vary but is typically in the range of 550 to 750 ppm (Faber et al., 2022; Kapadia et al., 2016). If ultra-low sulfur jet fuel standards were adopted (similar to ultra-low sulfur standards for on-road diesel), then sulfur contents would fall to below 15 ppm, but those standards have not been adopted in the US (Kapadia et al., 2016).

The sulfur content of SAF can vary. A 2025 study of HEFA found fuel sulfur content was less than 1% of conventional jet fuel (Rohkamp et al., 2025). Another study found SAF sulfur contents of less than 1 ppm (Gladstein, Neandross & Associates, 2020). One meta-study found that hydroprocessed SAF had a fuel sulfur content of 0.02% by weight, compared to 0.08% for conventional jet fuel. Thus a 50% SAF blend reduced SO_2 emissions by 38% compared with conventional jet fuel (Booz Allen Hamilton, 2019). Another study found a 72% reduction in fuel sulfur content between a FAME from rapeseed oil and conventional jet fuel (Yakovlieva et al., 2019). Overall, the SO_2 emissions reductions expected from a 50% SAF blend varies from 36-38% at the low end (Booz Allen Hamilton, 2019; Yakovlieva et al., 2019) up to 49-50% on the high end (Rohkamp et al., 2025; Gladstein, Neandross & Associates, 2020) (this translates to 72-100% SO_2 emission reduction from the SAF component of the fuel).

NO_x emissions from SAF are expected to be similar to conventional jet fuel (Schripp et al., 2022; Booz Allen Hamilton, 2019; Corporan et al., 2010) because NO_x emissions are primarily dependent on turbine inlet temperature rather than the fuel composition (Schripp et al., 2022; Yakovlieva et al., 2019). In general, NO_x emissions would increase with increasing turbine inlet temperature (Yakovlieva et al., 2019). One study reported a small reduction in NO_x emissions from 10% and 20% SAF blends, which was attributed to a decrease in turbine inlet temperature in engines under high loads and suggested that the SAF blends result in lower turbine inlet and jet pipe temperatures compared to conventional jet fuel (Yakovlieva et al., 2019). Other studies did not find a change in turbine inlet temperature from SAF use (Schripp et al., 2022; Beyersdorf, 2014).

Hydrogen

Hydrogen can be combusted as a fuel to replace natural gas for electricity generation, industrial applications, and other uses and can be blended into natural gas pipelines at low levels resulting in use in connected industrial, commercial, and residential applications. Discussion of additional applications is included in the Appendix.

When combusted, hydrogen does not directly emit $PM_{2.5}$ or other pollutants such as SO_2, VOCs, or CO. Because SO_2 emissions result from sulfur in the fuel, there would be no SO_2 emissions from 100% hydrogen combustion, and while natural gas contains low levels of sulfur, it does contain trace amounts.

However, combusting hydrogen can result in higher flame temperatures compared to those used in the combustion of natural gas, which can increase NO_x emissions in systems not explicitly designed for hydrogen combustion. While hydrogen has only about 30% of the energy content of natural gas, the emission changes reported in this section are on a volume basis unless otherwise noted.

Douglas et al. (2022) notes that when comparing changes in measured NO_x emissions from natural gas blends with different percentages of hydrogen, studies that use volume-based measurements (e.g., emissions measured in parts per million by volume) may overstate NO_x emissions changes. Douglas et al. (2022) recommends applying corrections to improve estimates of NO_x emissions from hydrogen combustion: 7% correction for a 50% hydrogen blend by volume, 17% for an 80% hydrogen blend by volume, and 37% for 100% hydrogen. Studies that use a volume-based measurement approach and do not apply a correction may find higher NO_x emissions than would be measured from the combustion of the same mass of 100% hydrogen. Given the timing of the studies cited in this section, it is likely that the literature reviewed did not include such a correction. Since we have not adjusted the values reported by studies in our discussion below, we expect that most of the studies demonstrating higher NO_x emissions associated with hydrogen combustion overstate the increase.

Electricity Generation

Hydrogen combustion can be an alternative to natural gas in electricity generation. At lower blend percentages of hydrogen in turbines, NO_x emissions are minimal, but at up to 50% hydrogen (by volume), NO_x emissions could increase by as much as 35% when used in unadjusted natural gas turbines, which suggests that uncontrolled NO_x emissions could potentially double in existing turbines operating with 100% hydrogen on a volume basis (Goldmeer et al., 2022). When the adjustment mentioned above by Douglas et al. (2022) is applied and then adjusted to an energy equivalent basis, these NO_x emission increases observed by Goldmeer et al. (2022) are comparable to about a 4-fold increase in NO_x when combusting 100% hydrogen in an unadjusted natural gas turbine.

To ensure that replacing natural gas with hydrogen does not significantly increase NO_x emissions, systems can be designed explicitly for 100% hydrogen combustion. For example, changes to the combustor flow design, operational controls to adjust the air to fuel ratio, lean pre-mixed combustion, or staged combustion can be used to reduce NO_x emissions (USDOE, 2022). In addition, post-combustion NO_x controls can be incorporated, such as selective catalytic reduction (SCR) systems (Zhou et al., 2024). Implementation of such control measures can substantially lower NO_x emissions to design levels, similar to existing natural gas systems with SCR under New York State permit requirements.

The studies reviewed make no mention of SO_2 or $PM_{2.5}$ in the uncontrolled exhaust from hydrogen combustion. It is expected that these pollutants are not emitted from the combustion of 100% hydrogen for electricity generation.

Industrial Combustion

Literature on the combustion of hydrogen in industrial applications found that NO_x emissions are dependent on a variety of factors, including blend level, system design, and operating temperature. As a result of this variety of factors influencing NO_x emissions, some studies noted only increases in NO_x emissions from hydrogen combustion while others noted increases or decreases.

Cellek and Pinarbaşi (2017) studied uncontrolled industrial low swirl burner-boilers and found that NO_x emissions increased as the hydrogen blend level increased. At 100% hydrogen, the study noted that NO_x emissions increased by 659% compared to combustion of 100% natural gas. The study found that with hydrogen blends of 25%, 50% and 75% (with blend percentage based on the energy content of the fuel, such that at a 50% blend, each fuel is providing 50% of the needed energy to achieve a desired temperature), the NO_x emissions increased by 93%, 220%, and 360% respectively. The study notes that these increases in NO_x emissions are attributable to the higher flame temperatures when hydrogen is combusted.

Colorado et al. (2017) studied NO_x emissions for a variety of industrial burner types with varying hydrogen blends of up to 70% hydrogen by volume and observed that the porous materials used for surface-stabilized combustion burners and infrared burners make the premixed flow laminar, which avoids the recirculation of combustion products. For these two burner types, the study observed NO_x emission reductions as the hydrogen fraction increases. The reactions in these burner types enhance radiative heat transfer from the reactions to the thermal load by using extended surface areas and materials with excellent emissivity. This reduces the temperature of the reactions and increases radiative heat out of the reaction zone. Thus, this study attributes the NO_x reductions that are observed for these burner types to the enhanced reaction heat losses. Other burner types—including low swirl burners, micro-turbine combustors, oxygas burners, high speed jet burners, radiant tubes, and slot burners—are typically expected to increase NO_x emissions as the hydrogen fraction increases.

These results demonstrate that variable changes in NO_x emissions can occur when combusting hydrogen in industrial burner systems designed for natural gas, and therefore, attention to design and operation are needed to avoid increasing NO_x emissions when designing industrial systems for hydrogen combustion or transitioning existing systems to hydrogen.

Hydrogen Enriched Natural Gas (HENG) in Pipeline Delivery

HENG is generally compatible with existing natural gas transmission and distribution infrastructure and with end-use equipment with minimal system modifications at low blending levels.[3] If hydrogen were to be blended into pipeline-delivered natural gas, it would be used by all applications downstream of the injection point. This includes industrial, commercial, and residential applications.

The addition of hydrogen to natural gas would generally reduce $PM_{2.5}$ and other pollutant emissions associated with natural gas such that emission reductions of $PM_{2.5}$ and SO_2 from HENG blends would likely correlate with the hydrogen blend level. Available literature on HENG shows evidence of NO_x emissions increases, decreases, and no change as a result of HENG combustion in systems not designed or retrofitted for the blended fuel. The literature indicates that the magnitude and direction of changes in NO_x emissions resulting from HENG combustion are dependent on the specific application and combustion conditions.

Industrial HENG Applications

Emissions from HENG used in industrial processes will depend on the burner type and operating conditions. As described above in the "Industrial Combustion" section, NO_x emissions from low level blends would vary, including increases and decreases relative to pure natural gas, depending on the burner, combustor type, and configuration.

For example, Mac Kinnon et al. (2025) found that for a 20% hydrogen blend by volume: an unaltered surface stabilized natural gas combustion burner on a boiler using premixed gas and on-surface flame reduced NO_x emissions by 50% compared to natural gas; an unaltered oxygas burner on an incinerator using non-premixed gas and a flat flame increased NO_x emissions by 17% compared to natural gas; and an unaltered low-swirl burner on an oven heater with premixed gas and a divergent flow flame structure increased NO_x emissions by 60%.[4] It should be noted that existing equipment that has not been specifically designed or modified for hydrogen combustion is more likely to see results comparable to the low swirl burners.

Commercial and Residential HENG Applications

When HENG is used in commercial and residential appliances such as gas ovens and cooktop burners, NO_x emissions may increase, decrease, or show no change. As with industrial sources, much of this variability depends on the burner or combustor type and configuration.

McDonell et al. (2020) studied the effect of hydrogen blends on NO_x emissions in appliances including cooktops and oven burners. In addition, the researchers identified the

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[3] Hydrogen-enriched natural gas typically contains up to 20% hydrogen by volume (7% by energy content). However, due to the heterogeneity of the natural gas pipeline system in the US, there are uncertainties in the conditions under which blending is compatible at different hydrogen levels (Topolski et al., 2022).

[4] The Mac Kinnon (2025) study notes that there is an uncertainty of about 11% for all the reported emission levels in this study associated with the analyzers and the measured flow rates (Mac Kinnon et al., 2025).

blend levels (by volume) at which operability issues occur, including ignition failure and flame flashback. With cooktop burners, the upper limit was 20% hydrogen for ignition and 55% hydrogen for cooking, while the upper limit was 30% hydrogen blends for oven burners. The study generally found that NO_x emissions decreased with increasing levels of hydrogen, up to the blend level of these operability issues. The results from tests of 50% hydrogen blends by volume in the unaltered cooktop burners showed decreases in NO_x emissions on the order of 20%. The researchers noted that NO_x emission results from the oven burners were unclear due to variation within the analyzer. Another study on domestic cooking stoves typically used in China found that as the percentage of hydrogen to natural gas increases, NO_x emissions remain almost the same compared to stoves using pure natural gas (Fang et al., 2023).

These emission reductions from cooktop burners are of note for their potential contribution to reducing indoor air pollutant concentrations. Due to the large population of residential appliances in use in New York which likely cover a broad range of appliance ages and types, it does not seem appropriate to extrapolate these results based on a small number of appliance tests. Further research and testing are needed on the use of hydrogen in a broader range of appliances. Thus, overall, changes in NO_x emission from hydrogen blends used in commercial and residential appliances are considered uncertain.

Biogas

Biogas is an energy-rich waste by-product and is typically composed of 45-65% methane, carbon dioxide, and other trace gases including siloxanes, hydrogen sulfide (H_2S), aromatic hydrocarbons, and VOCs (USEPA, 2024, Li et al., 2019), though its content will vary by source. Biogas is mostly consumed onsite at the waste facility for electricity generation (or combined heat and power). Biogas has approximately 61% of the energy content of natural gas.

Methane emissions from larger waste sources can also be collected and further refined to produce renewable natural gas (RNG). RNG is processed to be chemically similar to fossil natural gas so emissions from RNG combustion are not expected to be significantly different from natural gas combustion. Therefore, this section focuses on biogas. Information on the use of RNG in engines is presented in the Appendix.

Note that for concentrated sources of biogas such as landfills or wastewater plants, the alternative to combusting biogas for energy use is often flaring to avoid more potent co-pollutant and greenhouse gas (methane) emissions; therefore, the emissions from onsite biogas combustion for energy can also be compared to flaring, in addition to natural gas combustion.

Combustion of biogas in engines may have different emission profiles depending on the feedstocks used and the application of the gas. One study (Kuo & Dow, 2017) compared an internal combustion engine (ICE) fueled by biogas and natural gas for electric power generation and found that the NO_x emission rates from both biogas and natural gas were essentially the same on an energy basis (0.55 g/hp-hr for natural gas vs 0.54 g/hp-hr for biogas). The average CO emissions from biogas combustion were approximately 13%

higher than natural gas on an energy basis, and SO_2 emissions were about 100% higher for biogas combustion compared to natural gas on an energy basis (Kuo & Dow, 2017). The same study also conducted hazardous air pollutant and VOC testing on the biogas-fueled ICE. Of note regarding the measured hazardous air pollutants, the measured formaldehyde concentration was 32 ppbv, naphthalene had the highest concentration of the detected polycyclic aromatic hydrocarbons, and additional hazardous air pollutants including benzene and toluene were also observed in measurable quantities (Kuo & Dow, 2017). However, no comparable measurements of hazardous air pollutants were provided for natural gas combustion. Higher SO_2 emissions from biogas engines are likely due to incomplete removal of H_2S and other reduced sulfur compounds during the pre-treatment stage. H_2S is a byproduct of sulfur compounds in biogas feedstocks undergoing anaerobic digestion. While several studies have looked at PM emissions from biogas combustion (Kleeman et al., 2020, Xue et al., 2018), they do not present sufficient evidence at this time to compare PM emissions from electric generation using biogas versus natural gas.

In addition to comparing emissions from biogas combustion to natural gas, biogas combustion emissions can also be compared to those from flaring biogas waste feedstock — both of which would occur onsite. Using stationary source emissions rates from US Environmental Protection Agency (EPA) (2025), biogas combustion using boilers or steam turbines to generate electricity would decrease NO_x and $PM_{2.5}$ emissions by approximately 13% and 52%, respectively, compared to flaring. In contrast, biogas combustion in a gas turbine or ICE would likely increase emissions of both NO_x and $PM_{2.5}$ compared to flaring; specifically, NO_x emissions could increase by approximately 130% and $PM_{2.5}$ emissions could increase by approximately 30% for gas turbines, and NO_x emissions could increase by approximately 150% and $PM_{2.5}$ emissions could increase by approximately 180% for ICEs compared to flaring. EPA cautions that these rates are very variable, depending on the specific content of the waste being combusted.

Renewable Diesel

Renewable diesel, a biofuel produced from renewable sources, can be used as a drop-in fuel in diesel engines without any engine modifications, as well as in residential boilers.

On-Road Engines

Almost all on-road diesel vehicles are equipped with emission controls, which were fully phased in by model year 2010. Thus, $PM_{2.5}$ emissions from renewable diesel in newer on-road engines are typically similar to $PM_{2.5}$ emissions from fossil diesel. Two California Air Resources Board (CARB) studies found for heavy-duty on-road engines equipped with DPFs, there was no significant difference in $PM_{2.5}$ emissions from renewable diesel and ULSD (Durbin et al., 2023; Durbin et al., 2021).

One of the CARB studies also found no significant difference in NO_x emissions from renewable diesel compared to ULSD in new on-road diesel engines equipped with SCR (Durbin et al., 2021). A study of UPS local delivery trucks found renewable diesel reduced NO_x emissions by 4% compared to ULSD (Kelly & Ragatz, 2018). However, there is uncertainty based on duty cycle, as renewable diesel in UPS long-haul tractors showed mixed results with respect to NO_x emissions. No clear relationship between the use of renewable diesel and overall NO_x emissions in UPS on-road vehicles could be established in this study (Kelly & Ragatz, 2018).

While limited information is available on the effect of renewable diesel on SO_2 emissions from on-road engines, SO_2 emissions will be directly correlated with fuel sulfur content. Renewable diesel has very low sulfur content, comparable to ULSD (Durbin et al., 2021). Since New York State requires the use of ULSD, SO_2 emissions from renewable diesel are likely to be similar to those from fossil diesel currently in use in the state.

While this literature search was focused on emissions of criteria pollutants and their precursors, our research did identify some literature suggesting that a blend of 20% renewable diesel with 80% fossil diesel could substantially decrease hazardous air pollutant emissions, including reductions in benzene (0.6-14%), toluene (24-27%), and xylene (23-36%) compared to 100% fossil diesel (Liu et al., 2020). However, EPA's 2017 National Emissions Inventory shows that less than 5% of the emissions of these hazardous air pollutants are from diesel vehicles nationally; the majority of hazardous air pollutant emissions are from gasoline combustion (USEPA, 2020). Therefore, the potential benefit of reduced hazardous air pollutant emissions from renewable diesel is not expected to be significant.

Non-Road Engines

Renewable diesel can reduce criteria pollutant emissions in older engines not equipped with emission controls, more common in the non-road sector. Two CARB studies of agricultural tractors compared emissions from pure renewable diesel with ULSD in older non-road diesel engines without SCR or DPF control technologies (Durbin et al., 2021; Durbin et al., 2023). These studies found that renewable diesel reduced $PM_{2.5}$ emissions by 22% (Durbin et al., 2023) and 38% (Durbin et al., 2021) compared to ULSD, and reduced NO_x emissions by 5% (Durbin et al., 2021) and 13% (Durbin et al., 2023). Renewable diesel reduced CO emissions by 22% (Durbin, 2021) and 32% (Durbin, 2023) compared to ULSD and total hydrocarbon emissions were reduced by 40% (Durbin et al., 2023) and 45% (Durbin et al., 2021).[5] Durbin et al. (2023) studied agricultural tractors but indicated that similar emission reductions could be expected from other older non-road engines in other sectors not equipped with emission controls.

A different CARB study found that pure renewable diesel in a tier 3 switcher locomotive reduced PM emissions by 36%, NO_x emissions by 17%, CO emissions by 19% and total hydrocarbons by 37% compared to diesel fuel (Stroos, 2021). This study refers only to PM,

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5. Total hydrocarbons are a broad family of reactive and nonreactive chemicals containing carbon and hydrogen. VOCs are organic chemicals that evaporate into the atmosphere at room temperature and are defined by EPA to exclude less-ozone forming compounds. While many hydrocarbons are VOCs, the two categories of chemicals are not identical. While studies on renewable diesel only measured total hydrocarbons, reductions in VOC emissions are also expected where reductions in total hydrocarbon emissions were measured.

rather than $PM_{2.5}$ specifically, although the difference in size distribution is not expected to have much impact on emissions.

Residential Boilers

No studies were found on the impact of renewable diesel on emissions from residential boilers.

Biodiesel

Biodiesel, made from vegetable oils, animal fats, or waste grease from restaurants, can be blended with diesel and renewable diesel and is currently used in the transportation sector and blended in heating oil in New York State.

On-Road and Non-Road Engines

$PM_{2.5}$ emissions from biodiesel combustion in ICEs are similar to fossil diesel, although in certain cases (e.g., engines without DPFs) emissions reductions are observed (da Silva et al., 2017). Two CARB analyses found no significant difference in $PM_{2.5}$ emissions from biodiesel compared to ULSD in heavy-duty on-road and non-road engines equipped with DPFs (Durbin et al., 2021; Durbin et al., 2011). However, in a 1998 small engine meant for non-road use not equipped with a DPF, the CARB study found $PM_{2.5}$ emissions reductions of up to 7% for 20% biodiesel blends and emission reductions of 40% for 100% biodiesel (Durbin et al., 2011). A separate meta-analysis comparing B20—a diesel blend containing 20% biodiesel—to fossil diesel found total PM emission reductions of up to 6% (O'Malley & Searle, 2021), although this meta-analysis includes a mix of older and new engines. Biodiesel is a mature technology, and few studies are still being done on the impacts of biodiesel on criteria pollutant emissions in the on-road sector.

While some studies of non-road engines indicate that biodiesel increases NO_x emissions, the differences are heavily dependent on vehicle speeds and engine loads. For example, one study of a common rail engine found that biodiesel decreases NO_x emissions in engines at low and medium speeds compared to fossil diesel, but NO_x emissions increased by 15% or more at higher speeds (Chen et al., 2018). A CARB study found a 2% NO_x emission increase for 20% biodiesel blends and a 19% NO_x emission increase from 100% biodiesel in a 1998 small engine meant for non-road use (Durbin et al., 2011).

Studies of on-road engines have found both increases or no change in NO_x emissions from biodiesel compared to ULSD depending on the biodiesel blend level, vehicle speed/load, and the feedstock used to produce the biodiesel (Nabi et al., 2009; Zheng et al., 2008; Pereira et al., 2007). In addition to these variables, emission control technologies will also impact NO_x emissions from on-road diesel engines. In the mid-2000s, the EPA introduced several heavy-duty on-road vehicle emissions standards to reduce NO_x emissions, which required the use of emission control technologies (O'Malley & Searle, 2021). A 2021 meta-analysis examined the impact of the primary emission control technologies used in heavy duty vehicles, such as DPFs, diesel oxidation catalysts (DOCs), and exhaust gas recirculation (EGR) systems. This meta-analysis found that NO_x emissions were higher when using biodiesel than when using fossil diesel for engines equipped with DPFs, DOCs, or EGRs (O'Malley & Searle, 2021). The analysis did include the caveat that this could be confounded by the presence of selective catalytic reduction systems (SCRs) which were phased in around the same time as the other emission control technologies. The NO_x mitigation of SCRs has been found to degrade with biodiesel (O'Malley & Searle, 2021), but there was not sufficient data to estimate the impact of SCRs separately in the meta-analysis. Overall, the meta-analysis found that B20 increased NO_x emissions by 2-4% compared to fossil diesel (O'Malley & Searle, 2021), but this conclusion does not distinguish between engines with or without emission controls.

Other studies found that for vehicles with engine emission controls, biodiesel blends would not have any impact on NO_x emissions compared to fossil diesel. One study of on-road heavy-duty vehicles with DPFs installed found that B20 had no significant impact on NO_x emissions when compared to fossil diesel (Sharp, 2023). In addition, CARB's low carbon fuel standard analysis found that the use of biodiesel in older on-road and non-road engines (without SCR) results in an increase in NO_x emissions relative to use of conventional diesel, while new engines with emission controls resulted in no change in NO_x emissions (CARB, 2018).

There are many variables, such as the biodiesel feedstock and vehicle speed, engine load, and control technologies, that can influence on-road NO_x emissions from biodiesel blends. Overall, fossil diesel and biodiesel blends are expected to have similar NO_x emissions from on-road engines equipped with emission controls. There is limited information on the impact of biodiesel blends on NO_x emissions from newer non-road engines with emissions controls, although the impact is expected to be minimal, similar to the on-road engine findings.

Boilers

A research gap exists regarding biodiesel use in boilers. All studies identified assessed the impacts of boilers using biodiesel compared to commercial #2 heating oil (Lee et al., 2004) or #6 fuel oil (Krishna, 2010). No available studies compare biodiesel and ULSD in boilers.

Carbon Capture and Storage (CCS)

While CCS technologies are primarily designed to reduce CO_2 emissions, they are often paired with air pollution emission controls that can provide secondary air quality benefits. Notably, SO_2 and $PM_{2.5}$ must be largely scrubbed from flue gases before carbon capture in order to make these systems cost-effective (Waxman et al., 2024). At present, there are three primary types of CCS technologies: pre-combustion, oxy-fuel combustion, and post-combustion.

Empirical data on emissions reductions from CCS is limited, reflecting limited CCS implementation at commercial-scale facilities (Furlanetto et al., 2024). Some researchers have used real-world data from CCS installations and retrofits to supplement previous studies that relied on modeling or lab simulations; these findings are summarized below (e.g., Waxman et al., 2024). While CCS technologies are often envisioned for use at coal plants (see Appendix for additional information), the focus of this section is on potential applications that are relevant to New York State such as natural gas power plants and industrial facilities, as well as coal-fired industrial facilities.

Pre-Combustion CCS at Coal Industrial Facilities

Pre-combustion CCS involves the conversion of solid hydrocarbons (typically coal, which is still used by the industrial sector in New York State) into synthesis gas, a combination of CO_2 (which can be directly captured) and hydrogen (which can be used as a carbon-free fuel source). Industrial facilities that have used pre-combustion CCS in the United States include fertilizer/ammonia and hydrogen production facilities (Waxman, et al., 2024).

Researchers compared similar coal-fuel industrial facilities with and without pre-combustion CCS and found that the installation of pre-combustion CCS resulted in average SO_2 emissions reductions of 55%, average NO_X emissions reductions of 15%, near-elimination of ammonia (NH_3) emissions, no change in $PM_{2.5}$ emissions, and VOC emissions increases of about 27% (Waxman, et al., 2024).

Oxy-Combustion CCS

Oxy-combustion CCS involves combusting fuel using pure oxygen to remove impurities present in the air, namely nitrogen gas, to increase the efficiency of CO_2 removal from the flue gas after combustion, which is achieved through condensation. Waxman et al. (2024) notes that this technology is "not yet economically feasible at scale." There is one demonstration oxy-combustion natural gas power plant in the United States, but no facilities operating at commercial scale (Waxman et al., 2024). No studies were found regarding oxy-combustion CCS at industrial facilities.

Post-Combustion CCS at Natural Gas Power Plants and Industrial Facilities

Post-combustion CCS involves capturing flue gases from furnaces or boilers and processing them to extract CO_2. Post-combustion CCS is currently the most common CCS technology because it's the easiest to add as a retrofit to an existing facility (Waxman et al., 2024).

Post-combustion CCS has only been applied to a small set of natural gas-powered industrial facilities in the US at commercial scale (Waxman, 2024). At six natural gas-fired industrial facilities that have applied post-combustion CCS in the US, emission changes were variable. Both increases and decreases in NO_x, $PM_{2.5}$, and SO_2 emissions were reported: NO_x emissions ranged from 90% increases to 40% decreases, $PM_{2.5}$ emissions ranged from 15% increases to 10% decreases, and SO_2 emissions ranged from up to 18% increases to decreases by as much as 70%. Emission reductions were determined based on reported historical emissions before and after installation of CCS at facilities in the ethanol, fertilizer, gas processing, and hydrogen industries (Waxman, 2024). Because of the large variations in reported results from a small number of facilities, the emissions changes from post-combustion CCS at natural gas powered industrial facilities are considered uncertain.

Large increases in NH_3 emissions are expected from post-combustion CCS due to the amine solvent that is used to absorb CO_2. Increased emissions of ammonia would oxidize in the atmosphere to form ammonium, which would contribute to secondary $PM_{2.5}$ formation (Furlanetto et al., 2024; Rochelle, 2024; Waxman et al., 2024; Heo et al., 2015). These increases in NH_3 emissions could be reduced, though not eliminated, by an acid wash, which can reduce NH_3 emissions by 67% or more (Rochelle, 2024) or by a water wash (Waxman et al., 2024).

Schmitt et al. (2023) evaluated natural gas combined cycle (NGCC) power plant units with and without 90% and 95% post-combustion CCS. Testing performed for this study found PM emissions were eliminated during the capture stage by the CO_2 recovery solvent. The NGCC units already used low NO_x combustion technology and SCR post-combustion such that NO_x emissions were low in the base case. The post-combustion CCS further reduced NO_x emissions by 25%. Any SO_2 emissions remaining following the combustion controls (scrubber) were nearly eliminated in the CO_2 recovery absorber vessel. The net power output of the units decreased as the rates of CO_2 capture increased, compared to units without CCS. It is unclear whether similar emission reduction results would be obtained for other types of natural gas power plants.

The use of post-combustion CCS requires additional energy to power the CCS system. This is sometimes referred to as an energy penalty—the impact of the additional energy needed to power the CCS system—which can result in increased emissions at power plants. Rubin et al. (2012) defines this penalty as the additional energy input per net electricity output (e.g., kilowatt hour) of a plant. DOE/NETL (2013) states that CCS itself does not significantly change non-GHG emissions at NGCC power plants. However, when pre- and post-CCS emissions are compared based on the same amount of delivered electricity (i.e., accounting for the energy penalty), emissions of NO_x, PM, SO_2, and NH_3 all showed increases. Koornneef et al. (2010) also showed small increases in NO_x emissions at NGCC facilities (on an equivalent delivered energy basis) and determined that the energy penalty for NGCC units applying post-combustion CCS ranges from 11 to 22%. Thus, accounting for the energy penalty would mean the post-combustion CCS emissions would increase by the same percent as the energy penalty increase. Emission increases are expected to be small, due to the likely application of emission controls by units that would apply post-combustion CCS. Further discussion of the energy penalty can be found in the Appendix.

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Appendix

This appendix contains additional information obtained from the literature review about the fuels discussed. Some of the information contained here is not relevant in New York State (e.g., applications related to coal power plants), addresses applications that are not currently envisioned for use in the state, or are not yet commercially available; they are included here for completeness. In other cases, the appendix provides additional detail on information in the main body of this memorandum.

Sustainable Aviation Fuel (SAF)

Additional information is provided here on PM emissions from SAF in helicopters, additional blend types, and an additional study on 100% SAF.

A study based on emissions from helicopters found that at ground-idle, 100% SAF reduces the nvPM number by more than 81% compared to regular Jet A-1 fuel (Rohkamp et al., 2025). During take-off, the reduction in PM number is 24%. A reduction in engine PM mass emissions of 88% was measured at take-off and PM mass emissions reductions of almost 92% were measured at ground idle. This is because PM emissions from SAF are smaller than in conventional jet fuel, and thus there are greater reductions in PM mass than in PM number (Rohkamp et al., 2025).

Additional SAF blend types include HEFA-synthesized paraffinic kerosene (SPK) and ATJ-SPK blends. Over the LTO, nvPM mass was reduced by 20%, using a 32% HEFA-SPK blend (Durdina et al., 2021). A 53% reduction in total PM mass was observed for a 50% ATJ-SPK blend at high engine operation load (Kurzawska & Jasiński, 2021).

Regarding emissions at ground idle when using 100% SAF, Schripp et al. (2022) measured a 70% reduction in nvPM mass emissions while the engine was at an intermediate level of fuel consumption per hour (assumed to be for idling or taxiing). At the highest rates of fuel consumption, a 37% reduction in nvPM mass was measured, which is assumed to represent LTO (Schripp et al., 2022).

Hydrogen

Information is included here on potential use of ammonia as a blend with hydrogen and uses of hydrogen combustion in the transportation sector. These are not considered to be expected uses in New York in the near term but are presented here as supplemental information related to hydrogen.

Ammonia-Hydrogen Blends

Ammonia is being considered as a potential hydrogen carrier due to its high volumetric energy density and low storage pressures. However, ammonia combustion does have a propensity for high NO_x emissions and a low combustion efficiency (USDOE, 2022). Available studies have examined the application and combustion characteristics of ammonia when combined with other reactive fuels such as hydrogen and methane. Although ammonia-hydrogen combustion offers advantages in internal combustion engines, it also leads to NO_x and unburned NH_3 emissions compared to fossil diesel and gasoline engines (Qi et al., 2023). In furnaces, combustion of ammonia blends with hydrogen or methane resulted in increased emissions of CO, NH_3, and NO_x compared to fossil fuels; however, these emissions are below set national standards (Valera-Medina et al., 2024). More research and development are needed on combustion of ammonia blends.

Engines

In the transportation sector, unlike hydrogen fuel cells, hydrogen internal combustion engines (HICEs) share similarities with diesel and natural gas engines but combust hydrogen. One study found that when 75% of diesel was displaced by hydrogen in a natural gas-diesel dual fuel combustion engine, NO_x emissions increased while CO emissions significantly decreased (Guo et al., 2023). Since NO_x production is associated with high temperatures, reducing combustion temperature using techniques such as exhaust gas recirculation and lean combustion are efficient ways to reduce NO_x emissions in HICEs (Zhou et al., 2025).

Regarding non-road applications, a diesel compression ignition engine could use a fuel blend of diesel, natural gas, and hydrogen. Depending on the temperature, load, and speed of a compression ignition engine, NO_x emissions from the use of hydrogen-enriched natural gas may decrease or increase by 13% for certain fuel blends (diesel + 80% natural gas + 20% hydrogen) (Arslan & Kahraman, 2022). Of the conditions studied in Arslan & Kahraman (2022), NO_x emissions increased by the largest percentage compared to 100% diesel in the high engine speed, no load case. In contrast, at the lower engine speed, no load case, NO_x emissions were reduced by about 50% compared to diesel. As engine load increased, in both the high and low engine speed conditions, NO_x emissions increased for the blended fuel whereas NO_x emissions from 100% diesel were relatively constant with changes in engine load.

Renewable Natural Gas (RNG)

As mentioned above, RNG is biogas that has been refined to be chemically similar to natural gas. This section provides additional information on co-pollutant emissions from RNG. After treatment, RNG generally has a methane content between 96-98% (USEPA, 2024). RNG can be used in thermal applications, electricity generation, or vehicle engines.

Emissions from RNG are expected to be similar to natural gas because they are processed to be chemically similar. For example, RNG processing removes impurities such as H_2S meaning SO_2 emissions from RNG would be similar to those from natural gas (USDOE, 2025). We found few studies that compared $PM_{2.5}$ emissions from RNG to fossil natural gas.

Engines

We did not find specific studies on $PM_{2.5}$ emissions from RNG in engines, but available literature suggests that PM emissions from RNG are expected to be similar to natural gas combustion. Additionally, one study found that a light-duty RNG-powered vehicle, with about 25,000 miles, emitted 30% less NO_x than fossil natural gas, while hydrocarbon and CO emissions were similar (Cignini et al., 2022). The testing was performed on a chassis dynamometer simulating the Worldwide Harmonized Light Vehicles Test Cycle (WLTC).

Biodiesel

Additional studies related to the use of biodiesel are presented here. These studies do not compare biodiesel to ULSD, making them less relevant to potential New York State applications.

In a study comparing B100 (100% biodiesel) used in industrial boilers with #2 fuel oil (with 1,000 ppm of sulfur), investigators found that CO emissions declined by 19% while NO_x emissions increased by 34% (Komariah et al., 2013).

There was an additional study comparing biodiesel with Efecta diesel, which is a Czech diesel blend (Szyszlak-Bargłowicz, 2023). The study did not specify the sulfur content of the fuel, although other studies indicate that Efecta diesel fuel has a maximum of 10 ppm sulfur, lower than the US requirements for ULSD (Borowik et al., 2024). When comparing biodiesel with Efecta diesel, PM emissions decreased in industrial boilers, although the decrease varied by engine size and load factor. PM emission reductions between 40% and 61% were observed (Szyszlak-Bargłowicz et al., 2023).

Carbon Capture and Storage (CCS)

CCS is not expected to be significant as a means of reducing CO_2 emissions in New York. In particular, the use of CCS at power plants using coal is not relevant to New York. However, additional information on the use of CCS in general and for coal-fired power plants in particular is provided here. This section also includes a discussion of the energy penalty associated with the CCS applications (i.e., the additional energy needed to run the CCS system).

Stages of CCS

CCS is typically divided into three stages: capture, transportation, and storage. Most academic research on CCS—and thus this literature review—focuses on the capture stage, where most emissions are produced, although there are signs that researchers are increasingly interested in finding ways to improve the efficiency of, and reduce emissions from, the transportation and storage stages as well (see e.g., Gimeno et al., 2018).

Pre-Combustion CCS at Coal-Fired Power Plants

Pre-combustion CCS at coal-fired power plants can have significant effects on the pollutants emitted per unit of fuel input compared to plants without CCS. SO_2 emissions can be reduced by 40-50%, and NO_x emissions can be reduced by 70-80%. These reductions (which do not account for the energy penalty) are partially due to the fact that SO_2 and NH_3 are almost completely removed prior to combustion (Rao & Phadke, 2017; Koornneef et al., 2010). Emission reductions of SO_2 and NH_3 may reduce secondary $PM_{2.5}$ formation.

Oxy-Combustion CCS at Coal-Fired Power Plants

Compared to facilities without CCS, oxy-combustion technologies can reduce $PM_{2.5}$ and SO_2 emissions by 90% or more and NO_X emissions by 50% or more because virtually no nitrogen is present during combustion (Mukherjee et al., 2019; Spigarelli & Kawatra, 2013;

Koornneef et al., 2010). In addition, flue gas from oxy-combustion is smaller in volume due to the absence of nitrogen, making the exhaust more concentrated with pollutants. Under these conditions, pollution control technologies for removal of SO_2, NO_x, and $PM_{2.5}$ are more effective (NETL, 2020).

Post-Combustion CCS at Coal-Fired Power Plants

As discussed above for natural gas power plants and industrial facilities, post combustion CCS technologies use an amine solvent to separate CO_2 from other components of the flue gas, which can lead to large emissions of NH_3. Various interventions and control technologies, such as water washes, fabric filters, and pretreating flue gas, could all help to minimize gaseous ammonia and ammonium aerosol emissions from coal-fired power plants with post-combustion CCS (Rochelle, 2024).

CCS in Industrial Settings

While most research focuses on CCS at coal-fired power plants, its use in industrial settings, such as oil refineries, cement plants, metal refineries, and similar facilities is beginning to attract more attention, and may be relevant to air quality.

The industrial sector can use the same CCS technologies as the electricity sector, although some industries can implement CCS more easily than others, and the specific approach to CCS may vary by subsector (Bains et al., 2017). For example, the chemicals subsector already separates CO_2 as part of many chemical production processes, such as ethanol production (IEA, 2019). On the other hand, CCS in the industrial sector can be more complex than in the electricity sector because CO_2 emissions can result from non-combustion processes. Cement production facilities, for example, tend to emit more "process emissions" of CO_2 than combustion emissions (Bains et al., 2017). However, current research on CCS in industrial settings continues to focus on combustion emissions, leaving a gap in the literature regarding CCS applications to non-combustion emissions.

Energy Penalty

Across various sectors and applications, a common concern is the "energy penalty" of CCS; that is, a portion of generated electricity that must be used to power the CCS system instead of going onto the grid, which lowers the overall efficiency of the power plant. Rubin et al. (2012) explains, "Lower plant efficiency means that more fuel is needed to generate electricity relative to a similar plant without CO_2 capture" (p. 7). The Intergovernmental Panel on Climate Change recommends defining the energy penalty in terms of the additional energy input (%) per net kWh output of a plant (Rubin et al., 2012). In an industrial CCS setting, this would be expressed as increased electricity consumption resulting in increased emissions from power production, if that power is not fully renewably resourced.

Estimates of this energy penalty range from 11-77%, but mostly fall within the lower end of that range (Furlanetto et al., 2024; Rochelle, 2024; Waxman et al. 2024; Wang et al., 2021; Rubin et al., 2012). Furlanetto et al. (2024) calculate that the penalty is approximately 26% for coal plants, 13% for gas plants, and 20% for combined cycle plants. Alternatively, Waxman et al. (2024) use values of 11% for coal plants and 22% for natural gas plants and hold that the penalty is larger for natural gas plants due to “the fact that coal combustion produces a purer stream of CO_2, which requires less energy to treat and capture” (p. 14). The penalty is also typically greater for post-combustion than pre-combustion CCS (Waxman et al., 2024); specifically, amine scrubbing with CO_2 compression carries a penalty of 15-30% (Rochelle, 2024).

Sector-Wide Impacts of CCS

Some analysts note that the deployment of CCS may result in increased emissions in the long term, as it prolongs the life of fossil fuel power plants, may cause some power generation to shift back to coal, and delays the transition to renewable sources of electricity (Liu et al., 2025; Furlanetto et al., 2024). Liu et al. (2025) states that these emissions can be partially mitigated; however, “end-of-pipe measures lead to much more notable reductions in SO_2 and NO_x than do those for PM, given the limited potential of abating [primary] PM emissions. Therefore, in-depth PM controls depend primarily on energy transitions and thus, extra PM emissions pose a major challenge for the deployment of [CCS].”