LNG Response Summary Table

The table shows the distribution of responses to individual questions (column at left), spread across the 17 individual response documents received (row at top), representing a total of 23 organizations. Four of the responding organizations chose to respond with a general narrative rather than providing individual answers specific to the questions. The numbers in several of the cells in the table indicate where the responses aligned specifically with any of the three overarching areas of interest: (1) R&D opportunities identified, (2) government policy considerations, and (3) views on the design and implementation differentiated gas certification frameworks in relation to LNG exports.

	Common wealth LNG	UT Austin	RAND	Project Canary	USLNGAllies	MiQ	GPLNG	GHGSat	IPS-Climate Policy Prgm. MEJC-NJEJA-NYLPI-350.org	Williams Cos.	Sierra Club and Earthjustice	CLNG-API-NGSA	Cheniere	CATF	AXPC	DGCC	ABS
General Response					1, 2, 3				2		2	2				3	
Upstream Environmental Profile																	
1.1										1, 3						2	
1.2						3											
1.3																	
1.4																	
1.5	3	3		3		3	3			3		3	3	3	3	3	
1.6	3			3		3	3			3		3	3		3	3	
1.7	3	2, 3		2, 3		3	3			2, 3		3	3	2, 3	3	3	
Emission Reduction Strategies: Liquefaction																	
2.1			2														
2.2																	
2.3																	
2.4																	
2.5																	
2.6																	
2.7																	
2.8																	
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2.10																	
2.11																	
2.12																	
Emission Reduction Strategies: Loading Transport and Delivery																	
3.1																	
3.2																	
3.3																	
3.4																	
3.5																	
Additional Info																	
4.1																	
4.2																	1
4.3		2				3										2	

Respondent:

Commonwealth RNG

Responses to RFI

By:
Commonwealth LNG

U.S. Department of Energy
Office of Fossil Energy and Carbon Management

Request for Information (RFI)

DE-FOA-0003052

Original Issue Date: April 21, 2023
Modification 000001 Date: May 17, 2023

Topic 1: Environmental Profile of Upstream Supplies –

As a liquefaction company, Commonwealth LNG will not own or operate any upstream production & gas transportation assets.

1.1. What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

Almost all upstream producers have either already achieved or intend to supply Responsibly Sourced Gas (RSG).

1.2. To what extent do exporters request or have access to information about the source (e.g., production basin, transportation pipeline, custody transfers) of the natural gas they are liquefying for export? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means? Do the answers vary by the extent to which the gas is supplied by natural gas marketers or through bilateral contracts?

Commonwealth LNG is aiming to purchase certified natural gas and responsibly sourced natural gas.

1.3. To what extent do exporters request or have access to information about the greenhouse gas emissions and/or practices to limit greenhouse gas emissions of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?

See previous comments in sections 1.1 and 1.2.

1.4. To what extent do exporters request or have access to information on non-greenhouse gas emissions, including criteria air emissions or hazardous air pollutants, and/or other practices to address other environmental impacts (e.g., strategies to protect water quality or limit water consumption) of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?

Commonwealth LNG prefers to purchase certified natural gas / responsibly sourced natural gas. RSG certification includes consideration of certain non-greenhouse gas emissions, including water consumption and stewardship.

1.5. What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?

Upstream producers have a significant appetite for exposure to the global LNG markets and hence they have a vested interest to ensure their gas is certified to be Responsibly Sourced Gas.

1.6. What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?

The key is how upstream producers are "greening" their portfolio of upstream assets to be in line with the overwhelming desire to minimize the carbon footprint across the LNG gas chain.

1.7. What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

Clearly LNG off takers and in particular the Europeans have a desire and expectation to ensure the quality of the gas supply from the upstream operators.

Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities

2.1. What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?

Use of high efficiency aeroderivative turbines to improve efficiency since they have much higher efficiency than the Frame machines.

Use of dual-shaft gas turbines for refrigerant compressor drivers which have pressurized LNG compressor startup capability without a helper motor. This allows gas turbine start-up from settle-out pressure rather than flaring the refrigerant after each trip.

Use of gas turbines that have the capability to burn hydrogen-blended fuel in future which results in CO2 reduction.

Incorporation of waste heat recovery for process heating which results in CO2 reduction.

Use of nitrogen as purge gas for flare lines instead of fuel gas.

Use of carbon adsorption filters and thermal oxidizers on condensate tank vents to prevent VOC/BTEX releases to atmosphere.

Selective Catalytic Reduction and CO catalyst systems installed on gas/turbine exhausts to reduce NOx, CO, and formaldehyde emissions.

Truck loading vapor recovery and Boiloff Gas recovery and recycling.

Best standard operating practices (BSOP) to operate efficiently and further reduce emissions and flaring such as LDAR and efficient maintenance / turnaround cycles.

Use of a sufficient number of gas analyzers and flow meters to maintain proper hydrocarbon accounting of flaring and other hydrocarbon losses.

2.2. In addition to published data sources such as EPA's Greenhouse Gas Reporting

Program and Greenhouse Gas Inventory, are there other data and information available on identification and location of point sources of greenhouse gas emissions within liquefaction facilities?

(1) API's Compendium of GHG Emissions Methodologies for the Oil and Gas Industry (API Compendium 2021)
(2) API's Consistent Methodology for Estimating GHG Emissions - LNG Operations, prepared by LEVON Group.

2.3. What methodologies do operators use to estimate and measure greenhouse gas emissions at liquefaction facilities?

Use of a sufficient number of gas analyzers and flow meters to maintain a proper hydrocarbon accounting and to allow estimating the amount of flaring and other hydrocarbon losses which contribute to GHG emissions.

Use of comprehensive Leak Detection and Repair (LDAR) programs which include drone surveillance to locate fugitive emission sources and estimate leakage rates.

2.4. Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?

Drone/aerial surveys for emissions monitoring and detection will be deployed on the Commonwealth LNG facility.

2.5. When is the decision to select electric, natural gas-powered, or hybrid compressor driven systems made during the facility design process? What are the key factors that influence this design choice?

Major driver selection is made early in the design process (i.e. pre-FEED phase). Cost, site electric power availability, plot space and location, and liquefaction technology are all key factors in addition to owner/operator and EPC experience. Remoteness of the liquefaction site is a significant determinant in the choice to self-generate or import power from the utility transmission system. The availability and reliability of imported power is a critical decision point for LNG off takers as well as banks for financing.

2.6. What data and information are available related to the feasibility of electrifying new facilities or the ability to repower existing liquefaction facilities to use electric motor drives?

The feasibility of new facilities to be designed as all-electric is highly dependent on utility power availability and reliability, electric power pricing and plot space/location. Re-powering existing constructed facilities is typically cost prohibitive as well as resulting a long period of downtime for conversion to electric drive and does not always result in significant environmental gains depending on the source of electric power (e.g., percentage of renewable energy).

Converting refrigerant compressors to electric drives often requires local electric utility improvements or the addition of an onsite combined cycle power plant, reconfiguration of process heating and fuel gas equipment, an additional process heating furnace, and other changes including switching out some of the most critical and expensive equipment on the facility.

2.7. When companies have electrified facilities, what steps have they taken to quantify the emissions associated with purchased electricity?

The critical decision points to utilizing all electric liquefaction facilities is both availability and reliability of transmission power. Therefore, the key points of discussion with the utility power companies are how much power can be supplied, how reliable is the supply and how is that power generated in order to fully map out the carbon footprint of the whole system in its entirety.

2.8. When companies have electrified facilities, to what extent are they reducing consumption of natural gas that would otherwise be used for facility operation? What is the magnitude of such natural gas savings?

Facilities using utility power and electric drivers for refrigerant compressors still consume small amounts of gas for flare lines and pilots, thermal oxidizers, process fired heaters, etc. Natural gas auto-consumption of these facilities is 1% or less, compared with approximately 6-9% for facilities that utilize direct-drive gas turbines for compressors and auxiliary generators.

However, any reductions in Scope 1 emissions using electric drives is offset by resulting Scope 2 emissions from using grid power depending on the mix of renewable electricity that is purchased.

2.9. Do companies have specific plans to deploy carbon dioxide capture at liquefaction facilities in the future on low and high purity CO_2 gas streams? In addition to financial considerations, are there technical or other limitations to deploying carbon dioxide capture at liquefaction facilities?

Liquefaction facilities typically have two primary opportunities to capture CO2:

(1) Native CO2, (in pipeline gas) is high purity and relatively simple to capture. However, this volume of CO2 represents only 10-15% of the facility's total CO2 emissions.

(2) For LNG liquefaction facilities that utilize gas turbines for refrigerant drivers and/or power generation, the post-combustion CO2 represents 85-90% of the facility's total CO2 emissions. However, this CO2 is low in purity and much more complex to separate and treat. The low purity (~3% CO2) also means that treatment is much more complex and very energy intensive.

2.10. Are there data or information available on other technologies or strategies operators could deploy to reduce or avoid greenhouse emissions at liquefaction facilities? Are these technologies or strategies considered experimental or pre-commercial? Are there estimates of emission reductions and/or gas savings associated with implementation of these technologies?

There are constant improvements in the field of emission reduction technologies that LNG facilities can utilize, such drones to detect leaks and track emissions, flare gas recovery system, and improvements in seal technologies for rotating equipment.

2.11. What data and information are available on the co-benefits of practices to limit greenhouse gas emissions at liquefaction facilities (e.g., reductions in criteria pollutants, hazardous air pollutants)?

There are several critical practices that govern the efficiency of a LNG facility as it relates to safety and emissions from a liquefaction facility: (a) Training and development practices for the operations and maintenance staff and the robustness of methods by which the competency of staff is assured; (b) The experience of the EPC contractor in developing LNG facilities is a fundamental requirement when it comes to efficiency of the liquefaction process in terms of emissions; (c) Development and implementation of robust and well thought-out systems and process is a critical success factor when it comes to managing and minimizing emissions; and (d) Development and implementation of fit-for-purpose and appropriate operations and maintenance procedures are critically important.

2.12. What data and information are available to assess potential improvements to local air quality or benefits to communities from mitigation practices implemented at liquefaction facilities?

It is primarily the design and engineering of the LNG facility that ensures minimal flaring that in turn reduces both the visual and air quality impact to the surrounding environment. In addition, depending on the design of the LNG facility, some facilities are more prone to losing refrigerants during upset conditions that affect total emissions.

Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery

3.1. What technologies or strategies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?

Emissions during loading can have several origins and can be in the form of LNG (liquid) and/or natural gas (vapor). Emissions can come from leaks in pipeline connections, vapor return lines and from the flaring of excess boil off vapor generated during the loading process.
Leaking of LNG and/or natural gas vapor from the vessel's containment and associated pipeline system and/or the connection between vessel and shore can easily be observed and rapidly corrected.
Regarding technologies and strategies to reduce GHG emissions:
1. All LNG vessels have gas detection systems that continuously sample various locations on the vessel. Any natural gas leakage detected by the gas detection system would immediately raise an alarm allowing the crew to act swiftly and investigate the area at the location of the gas detector that set off the alarm. Very often a leakage originates from flanged connections that may require tightening or may need a gasket replacement.

2. The manifolds of the vessel connected to the shore loading arms are equipped with an Emergency Shut Down system that protects against emissions through activation of PERCs (powered emergency release couplings) and shutting down of the shore loading pumps.
3. During loading of an LNG vessel,
gas vapors in the vessel's tanks will vent as the LNG is being loaded. The loading operation will utilize vapor balancing equipment to assure that all of the vessel's gas vapors are returned to the facility to be reliquefied back into LNG.

3.2. What approaches do LNG operators use to capture boil off gas (BOG) and limit loss of natural gas when storing, loading, transporting, and unloading LNG?

As operator of a liquefaction facility, Commonwealth LNG will have a boil off gas system to recover all gas vapors from LNG ships during loading operations and from LNG Storage tanks. The gas vapors will be used as a fuel gas supply to power the gas turbines. Any excess gas vapor will be recycled and re-liquefied.

3.3. What approaches do LNG operators use to minimize greenhouse emissions during tanker transport of LNG?

As a liquefaction company, Commonwealth LNG will not own or operate LNG tankers. However, all newer LNG carriers have installed processing equipment that re-liquefies any boil off gas during the sea voyage.

3.4. For contractual agreements that include the transport of LNG, what measures, if any, are taken to assure natural gas is not lost and greenhouse emissions are minimized during shipping?

As a liquefaction company, Commonwealth LNG will not own or operate LNG tankers. However, most newer LNG carriers have equipment on board to re-liquefy any boil-off during the sea voyage.

3.5. Are there data or information available to assess potential improvements to local air quality or benefits to communities from mitigation practices implemented during the loading, transport, and delivery of LNG?

See comment on point 3.4 above.

Topic 4: Additional Information

4.1 What non-US requirements for greenhouse gas performance are LNG exporters being asked to respond to with emissions data? Are emission reduction requirements included in any contracts or other importing country requirements?

Emissions and emission reduction requirements are part of the commercial clauses that Commonwealth LNG is obliged to keep confidential.

4.2 What changes or technology advances does industry think are needed to decarbonize the LNG supply chain from production through delivery? What are the economic benefits or challenges associated with the measures to decarbonize the LNG supply chain? Is there data or information available on the costs or savings associated with implementing these measures?

Commonwealth LNG's comments and explanations in the preceding paragraphs address this question.

4.3 Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?

LNG is considered to be the most reliable, efficient, and cost-effective transition fuel in order to allow global economies to move from fossil fuels to renewables.

Respondent:

The University of Texas at Austin

Response to Request for Information DE-FOA-0003052 on Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports

Submitted by

The University of Texas at Austin

These comments are made by individuals with expertise in methane emissions from oil and gas operations, and the comments do not necessarily reflect the views of any of the organizations they are affiliated with.

Overview

This submission addresses each of the four topics identified in the Request for Information on Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports. Specifically, we provide information on methane emissions measurement across the LNG supply chain from upstream, midstream, and liquefaction facilities, recent progress in the development of models and tools to interpret methane emissions, emissions from shipping, and the need for a comprehensive education and training program to enable measurements and emissions mitigation focused on small operators in the US and other countries around the world that do not yet have comprehensive methane monitoring and reporting programs.

1. Topic 1: Environmental Profiles of Upstream Supplies

1.1. What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

Mitigation strategies should be informed by an understanding of the emissions specific to an asset. Measurement-based studies[1,2] find higher aggregate methane emissions than estimated in generic emission factor based, bottom-up accounting methods such as those currently mandated by the US EPA greenhouse gas reporting program (GHGRP). Furthermore, measurement-based studies suggest that, in addition to the total reported emissions being generally underestimated by generic emission factor-based estimates, in part due to omission of certain sources and under-accounting for malfunctioning equipment, the source attribution (understanding of the relative contribution to the total emissions by source) is also likely inaccurate.

Importantly, asset managers use available emissions source attribution data to inform mitigation strategies.[3] Therefore, publicly available mitigation strategies have focused on reduction of emissions from natural gas driven pneumatic devices[4,5,6,7,8,9,10] and increasing leak detection and

[1] R.A. Alvarez et al. (2018). Science 361,186-188. DOI:10.1126/science.aar7204
[2] J.S. Rutherford et al. (2021). Nat Commun 12, 4715 (2021). https://doi.org/10.1038/s41467-021-25017-4
[3] https://www.chevron.com/-/media/shared-media/documents/chevron-methane-report.pdf
[4] https://www.eqt.com/responsibility/pneumatic-device-replacement/
[5] https://theenvironmentalpartnership.org/what-were-doing/pneumatic-controllers-upgrades/
[6] https://corporate.exxonmobil.com/-/media/global/files/advancing-climate-solutions-progress-report/2022-july-update/methane-spotlight.pdf
[7] https://www.globalmethane.org/documents/m2mtool/docs/ll_pneumatics.pdf
[8] https://www.env.nm.gov/wp-content/uploads/sites/15/2019/08/pneumatic-controllers-and-pumps-9-27-19.pdf
[9] https://methaneguidingprinciples.org/resources-and-guides/best-practice-guides/pneumatic-devices/
[10] https://www.clr.com/environmental-social-and-governance-esg/environmental/air-quality/emissions-management-techniques/

repair (LDAR) programs.[11,12] However, measurement-based studies suggest tanks may present larger cost-effective mitigation opportunities, and tank emissions may be under-estimated. Operators focused exclusively on pneumatics and LDAR, which are typically the largest contributors to emissions inventoried in the GHGRP, may still not achieve the emissions intensities they expect based on GHGRP reporting. Harnessing the burgeoning and readily available ecosystem of measurement technologies available in North America to inform mitigation strategies is critical to cost-effective methane mitigation.

Measurement informed methane emission mitigation can be promoted by LNG exporters. LNG exporters are large volume buyers of US natural gas. For example, data from Department of Energy's Office of Resources Sustainability Environmental Information Agency (EIA) show that Cheniere Energy through its Sabine Pass and Corpus Christi liquefaction terminals exported 2,255 bcf of LNG in a 12-month period (May 2022 – April 2023), corresponding to over 6% of US dry natural gas production [13]. This makes Cheniere one of the largest single buyers of US natural gas, and their market influence, together with their focus on lowering the emissions associated with the gas they deliver, is focusing suppliers on reducing methane emissions. Companies along the LNG supply chain, including upstream producers and midstream operators, have begun to collaborate, producing emissions data sets based on direct measurement of methane emissions through collaboration. Recently, a consortium of universities (University of Texas at Austin, Colorado State University, and Colorado School of Mines) led an LNG supply chain methane measurement campaign funded by Cheniere Energy, through the Quantification, Monitoring, Reporting, and Verification (QMRV) program. The QMRV program conducted multi-scale methane measurements across upstream production facilities and midstream compressor stations across three US oil and gas basins: Permian, Marcellus, and Haynesville. The results of this work have been published in the peer-reviewed literature[14,15,16].

Multi-scale measurements included on-site optical gas imaging (OGI) surveys, drone-based surveys, aerial surveys, satellite detection, and continuous monitoring systems (CMS). Data from these different technologies span a wide range of spatial and temporal resolution – from component-level emissions estimates through OGI surveys to regional emissions estimates from satellites. Furthermore, time scales of measurement varied from a few seconds for satellites to quasi-continuous measurements with CMS technologies. Analysis of data from these systems demonstrates the complementary nature of different measurement approaches. Drone- and aerial surveys provide quantification of emissions at the equipment-level. However, these are snapshot measurements and do not provide information on the frequency or duration of intermittent emissions events. Detailed modeling of CMS data was used to develop distributions of the

[11] https://theenvironmentalpartnership.org/what-were-doing/taking-action/
[12] https://onefuture.us/case-study/
[13] US Department of Energy Office of Resource Sustainability. LNG Monthly (June 2023). https://www.energy.gov/sites/default/files/2023-06/LNG%20Monthly%20April%202023.pdf
[14] J. Wang et al. (2022). Environ. Sci. Technol. 56 14743. https://pubs.acs.org/doi/full/10.1021/acs.est.2c06211
[15] W. Daniels et al. (2023). Just Accepted at Environ. Sci. Technol. Pre-print: https://chemrxiv.org/engage/chemrxiv/article-details/645e690ffb40f6b3ee791411
[16] J. Brown et al. (2023). In review. Pre-print: https://chemrxiv.org/engage/chemrxiv/article-details/646fd2fabe16ad5c57e953b8

frequency and duration of emission events, which can then be used to appropriately scale snapshot emissions information provided by survey-type technologies. OGI-based ground surveys are used for directed leak detection surveys based on aerial survey data and to identify follow up actions. All this information helps focus mitigation activities on the most significant emissions. Expanding such programs to directly measure and transparently report methane emissions across US LNG supply chains in collaboration with exporters can enable the design of cost-effective mitigation strategies.

Other research activities led by UT Austin such as Project Astra have identified the potential for new methane monitoring approaches such continuous monitoring sensor networks, shared among multiple operators, to provide detailed information on spatial and temporal variation in methane emissions. Recent peer-reviewed research has identified the effectiveness of such networks in detecting intermittent emission events and network performance in comparison with conventional optical gas imaging-based emissions detection approaches[17,18].

1.5. What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?

Differentiated natural gas via certification programs[19] may inspire voluntary methane reductions beyond regulation through the provision of a monetization pathway for operators to recoup some or all the costs associated with mitigation projects (or even generate profit). However, both regulatory and certification program changes are necessary to create urgency among buyers to pay the incremental cost (premium) for the cleaner molecules.

In the initial stages of gas certification (beginning in 2020), premiums ranged from $0.07-0.10/mmbtu. Eventually, this slid to $0.03-0.05/mmbtu, and now, the volume of un-retired certificates is so large that they are not expected to trade at any value into the future. The demand for certificates did not keep pace with supply for two reasons.

First, early certification programs did not match buyers' need for confidence in emissions credentials as those early programs were often based on GHGRP generic emissions factor-based emissions estimates and, in some cases, certification schemes lacked transparency. Thus, these programs were not enough to assuage concerns about scientific studies calling out the U.S.'s measured emissions performance.[20]

Second, and more importantly, most buyers did not have an urgent need for certified gas. Certification schemes did not match any established regulatory mandate for differentiated gas. The

[17] Chen et al. (2023). Environ. Sci. Technol. 57 1788. https://pubs.acs.org/doi/abs/10.1021/acs.est.2c06990

[18] C. Schissel et al. (2023). In review. Pre-print: https://chemrxiv.org/engage/chemrxiv/article-details/63e53c7ffcfb27a31f7dd8d4

[19] Responsibly Sourced Gas is a branded product sold by Project Canary, though it released the trademark on this brand in 2022. https://www.projectcanary.com/blog/project-canary-sets-its-rsg-trademark-free/

[20] https://www.nixonpeabody.com/insights/articles/2022/05/20/ferc-rejects-first-of-its-kind-responsibly-sourced-gas-proposal

Inflation Reduction Act will penalize the worst-performing assets on an emissions intensity basis, but it is not designed to differentiate between assets with moderate and low emissions, so it is unlikely to catalyze a market for certificates. Further, while the statute allows for netting of emissions for facilities under common ownership or control, there is no specific provision to enable certificate retirement as a method by which to reduce the emissions charge obligation under the Act. It is possible that either federal or a combination of states adoptions of methane-intensity requirements would create demand for certificates and thereby reward better performance.

Nevertheless, it is possible that a robust market for differentiated natural gas may complement other methane mitigation actions such as the EPA methane rule and the methane fee provisions of the Inflation Reduction Act. Even absent a domestic certificates market, the European Union has proposed requirements for LNG imports to comply with the OGMP 2.0 measurement framework. Such a requirement could create price differentiation by limiting the amount of supply that could access that market. Moreover, once the measurement requirement is in place, the next step would be to limit the methane intensity allowable for imports, thus rewarding cleaner molecules even without a tradable instrument. Defining methane intensity for LNG, however, is much more complicated than for an individual operated asset. It is possible that differentiated gas certification programs could facilitate supply chain methane intensity definition by enabling methane intensity tracking and accounting for assets along the value chain.

Critically, broad acceptance of such differentiated gas certification programs requires certification criteria that (1) ensures credible total emissions for certified volumes and (2) are documented in a clear and consistent framework. Credibility in total emissions can be earned by eliciting buyer trust in underlying measurements, emissions estimates, and verification processes associated with MRV programs. Building that trust in measurements requires a consistent and comprehensive approach to interpretation of measurements. Key features that enable trust are described below:

Shared framework for interpreting measurements: Recent policies such as the proposed EPA methane rule and voluntary initiatives such as OGMP 2.0 will expand direct methane measurements across US oil and gas operations. These measurements often take the form of snapshot emissions data collected through drone-based, aerial, or satellite technologies. Interpreting snapshot measurements to develop useful information such as measurement-informed emissions inventories or supply chain emissions intensities require models and tools that are consistently applied across technologies, operators, and regions. These models and tools must be transparent, scientifically robust, timely, and developed in a manner that enables widespread use and acceptance. The US National Academies of Science, Engineering, and Medicine released a report on developing a framework for evaluating global greenhouse gas emissions information for decision-making that outlines key principles on integrating and interpreting diverse data streams[21].

Early differentiated gas certification focused on differentiation at the point of production rather than the point of sale. Because emissions are generated across the entire natural gas supply chain, buyers, whether domestically or internationally, will need an understanding of the emissions of

[21] National Academies of Science, Engineering, and Medicine (2022). https://www.nationalacademies.org/our-work/development-of-a-framework-for-evaluating-global-greenhouse-gas-emissions-information-for-decision-making

delivered gas, which requires summation of emissions along the entire value chain against a clear and consistent framework. Importantly, this is complicated by the fact that the midstream segment generally does not take title of the gas and so neither the gas purchaser nor the seller (producer) has full visibility on the supply chain emissions. To construct the supply chain emissions, there is a need for a comprehensive public database on methane emissions at high spatial resolution. Such a comprehensive database would allow stakeholders to fill gaps in methane emissions information across the supply chain that are not directly available.

US gridded methane emissions inventory: Differentiated gas certification may be required at spatial resolutions ranging from asset- and operator-level emissions intensities to regional- and basin-level estimates. Gridded emissions inventories that are comprehensive and timely can enable a diverse array of market-based and regulatory initiatives. However, existing gridded inventories developed by the EPA are only available at coarse resolution (0.1° or 10 km) and use outdated emission information (2012 greenhouse gas inventory). Prioritizing publication of higher resolution gridded inventories (1 km, 100 m) in a timely manner can act as a foundational resource for differentiated gas markets. These gridded inventories, developed through detailed GHGRP-type reporting program, can fill gaps in emissions information that are directly available through measurements. Furthermore, any operator or asset claiming emissions significantly lower than that inferred through highly resolved gridded emissions inventories would then be required to demonstrate reported performance through measurements. Thus, a gridded inventory could serve as an independent verification process required for the success of MRV programs.

1.7. What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

Differentiated natural gas products could play a significant role in demonstrating the effectiveness of mitigation efforts through federal regulators (EPA methane rule) and voluntary initiatives. However, for this to be effective, three conditions need to be satisfied.

Need for comprehensive MRV programs: Comprehensive adoption of measurement, reporting, and verification (MRV) programs across the LNG supply chain are needed to empirically demonstrate the emissions intensity of US LNG. Internationally, this effort is coordinated through the International Methane Emissions Observatory (IMEO) through the Oil and Gas Methane Partnership (OGMP 2.0) program that seeks to standardize reporting standards for global oil and gas operators. High resolution domestic programs are needed to complement international programs.

Shared framework for interpreting measurement data: MRV programs collect data on methane emissions using a range of technologies. These data need to be interpreted using a common framework to enable comparability of emissions intensities across operators, regions, and supply chains. A recent peer-reviewed study conducted a controlled release experiment of satellite technology where primary data from a methane detection satellite was given to five different research groups globally for quantification. Despite having the same primary data, the range of estimates provided by the 5 groups ranged from -80% to +300% of the true emission rate (*Sherwin et al. (2023) Scientific Reports 13 3836*). The difference in reported estimates arose from different interpretation framework; the emission estimate strongly depends on assumptions associated with models that convert primary satellite data to emission rate information. Similar conclusions could be drawn for sub-orbital measurement platforms from aircraft-based systems to on-site continuous monitoring systems. **Thus, transparent, peer-reviewed, timely, and publicly available models and tools are needed to interpret methane measurement data to ensure MRV programs are credible**. These principles for developing greenhouse gas emissions information for decision making was recently articulated in a National Academies report[22]. To build credibility in MRV programs that underpin trade in differentiated natural gas, it is critical for the tools to be transparent, scientifically robust, and publicly available for widespread use.

Clearinghouse for methane emissions: To differentiate US LNG supply chains from other global LNG supply chains, a trusted global clearinghouse of high-resolution methane emissions information is necessary. An example of a clearinghouse for methane data in the US is the gridded methane emissions inventory discussed above. Collection of high spatial resolution, measurement-informed emissions information across US oil and gas operations could be included in revisions to the GHGRP program. Making this data available in a variety of formats including gridded emissions inventory at high spatial resolution would provide buyers of US LNG assurance on supply chains' methane emissions. Collaboration with international organizations such as the UN International Methane Emissions Observatory (IMEO) could enable the development of similar datasets for global oil and gas operations.

2. Topic 2: Strategies to Measurement and Reduce Emissions at Liquefaction Facilities

2.2. In addition to published data sources such as EPA's Greenhouse Gas Reporting Program and Greenhouse Gas Inventory, are there other data and information available on identification and location of point sources of greenhouse gas emissions within liquefaction facilities?

No comprehensive public data on point sources of methane emissions at liquefaction terminals currently exists. However, new measurement campaigns that are either currently underway or will be launched soon will make such data broadly available. For example, the Environmental Defense Fund's satellite (MethaneSAT) has committed to make methane emissions data publicly available across the US. That data, along with additional data such as operator data, national inventories, global science studies and additional satellite data will be synthesized within the International Methane Emissions Observatory and made publicly available.

2.3. What methodologies do operators use to estimate and measure greenhouse gas emissions at liquefaction facilities?

The nature of emissions sources at liquefaction terminals varies significantly, requiring different technologies for effective quantification. Potential substantive sources of emissions can include incomplete combustion at flares, LNG storage tanks, compressor units, and other processing

[22] National Academies of Science, Engineering, and Medicine (2022). https://www.nationalacademies.org/our-work/development-of-a-framework-for-evaluating-global-greenhouse-gas-emissions-information-for-decision-making

equipment such as acid gas removal systems. Fugitive emissions from on-site equipment can be detected through new methane measurement technologies such as aerial or drone-based surveys. Repeat measurements will provide an understanding of the temporal variation and intermittency of methane emissions. Exhaust emissions from compressors can be effectively estimated through conventional stack testing methods. While direct measurements of flare destruction efficiency can be challenging, technologies are available to enable quasi-continuous flare monitoring. In addition, process monitoring such as flow metering or measurement of air to fuel ratio in flares can enable continuous evaluation of specific emissions sources.

3. Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery

3.5. Are there data or information available to assess potential improvements to local air quality or benefits to communities from mitigation practices implemented during the loading, transport, and delivery of LNG?

A recent analysis of emissions from LNG transport (to be published as a preprint in July 2023) developed a calculation system, capable of estimating emissions from any vessel in the current LNG fleet, customized by transport distance and schedule[23]. The analysis demonstrates that shipping emission intensities (emissions per kg of LNG delivered) can vary by an order of magnitude for identical trips, depending on the vessel and propulsion technology. Emissions intensity can also vary widely depending on time spent waiting to load or unload.

4. Topic 4: Additional Information

4.3. Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?

Much of the methane emissions information and insights into emissions mitigation is based on data collected in North America over the past decade. Most new technology solutions to detect methane emissions in the oil and gas sector such as aerial systems, drones, satellites, and continuous monitoring systems are from US-based companies. This has led to significant disparities in methane emissions information across global LNG supply chain – even as new field campaigns in the US demonstrate how official inventories underestimate methane emissions, no such extensive measurement data exist outside the US. Thus, there is a need to export knowledge and insights on methane emissions learnt in the US to other like-minded countries through a comprehensive education and training program. This is well aligned with the US' commitment to reduce methane emissions as part of the Global Methane Pledge. One such education and training program is described below.

The Energy Emissions Modeling and Data Lab (EEMDL) at the University of Texas at Austin, in partnership with Colorado State University and the Colorado School of Mines, is developing a comprehensive series of education and training programs on greenhouse gas emissions measurement and reporting in the oil and gas industry. Several short courses and workshops have

[23] C. Rosselot et al. (2023). A time in mode and carrier technology model of emissions of methane and carbon dioxide from LNG shipping. *To be released in pre-print form by July 2023.*

already been conducted for US audiences over the past year, including a workshop on the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model that was used by the EPA in the recently proposed methane regulations.

Part of this initiative is to create a two-part certificate program offered by the University of Texas at Austin through its Texas Executive Engineering Education (TxEEE) program. Participants earn a Certificate in “Fundamentals of Greenhouse Gas Emissions Measurement and Reporting in the Oil and Gas Industry” by completing a 10-hour short course. After completing the 10-hour introductory program, they can earn Master Class completion certificates in a variety of specialized topics. Upon completion of 5 Master Classes, participants earn a Certificate as a “Master of Greenhouse Gas Emissions Measurement and Reporting in the Oil and Gas Industry”. Master classes in specialized topics will be offered to allow participants to focus their training, beyond the material covered in the introductory course. Each offering will be a class followed by hands-on training and will be offered to small groups with similar interests. Offerings will include advanced classes on measurement techniques, advanced classes on emission estimation for specific facility types, software tools used in specific regulatory applications, OGMP reporting, and the use of greenhouse gas emission estimates in risk assessment and financial analysis tools.

The Fundamentals course could be offered to international audiences for nations participating in international consortia involving the US. The Master Class on OGMP reporting would be delivered in partnership with the OGMP and would focus on pathways toward international harmonization of reporting. These international education and training programs could be tailored to individualized country needs and current level of expertise in methane emissions.

Respondent:

RAND Corporation

RAND Corporation Response to RFI related to *Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports*

Submitted to

Office of Fossil Energy and Carbon Management
U.S. Department of Energy

Submitted by

RAND Corporation

June 26, 2023

DE-FOA-0003052

Introduction

The RAND Corporation (RAND) is pleased to provide this response to the Request for Information (RFI) regarding *Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports*. RAND is a nonprofit, nonpartisan institution with a mission to improve policy and decision making through high-quality, objective research and analysis. RAND has broad and deep expertise in energy and environmental policy analysis,[1] technology assessment, data analytics, and program evaluation.[2] In addition, RAND is committed to undertaking research and analysis in the public interest. As such, RAND appreciates the efforts by the Federal Government to advance science policy regarding GHG emissions monitoring and mitigation from a broad spectrum of industries and assets. Developing a more robust system-of-systems for emissions monitoring is critical for the development of evidence-based policy and practice for addressing the challenge of climate change.

Here we provide RAND's responses to three RFI questions, pertaining to Topic 2 in the RFI: *Strategies to Measure and Reduce Emissions at Liquefaction Facilities*. In this context, we would like to use this opportunity to emphasize the importance of enhancing rigorous measurement of methane emissions from facilities such as LNG terminals as an enabling condition for emissions management and mitigation. This is consistent with the draft *Federal Strategy to Advance an Integrated U.S. Greenhouse Gas Monitoring and Information System (GHGMIS Strategy)*. We would be happy to discuss our responses further or provide follow-up clarifications if helpful.

In the meantime, our responses to the three relevant RFI questions are below:

What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?

One useful strategy for reducing emissions is reflected in the growing collaboration between the Federal Government and private sector emitters and data collectors to develop common industry- and sector-specific baselines for emissions from various facilities, particularly those with the potential for significant fugitive emissions. For example, RAND is partnering with Scepter Air[3] and other data providers to enhance not only the collection of atmospheric GHG (particularly methane) data, but also the ability to disseminate data, products, and services that emitters, regulators, and policy analysts can use to monitor emissions at the basin or regional scale in near-real time. Scepter Air's patented approach will provide such capabilities and subsequently enable rapid interventions to address fugitive emissions as well as the validation of the effectiveness of other mitigation interventions. By positioning ourselves between regulated industries and federal regulators and adopting a philosophy of data neutrality that enables exploitation of both public and private data, RAND and Scepter Air will be able to develop trusted emissions profiles and baselines that can be used to monitor emissions and enable emitters to benchmark their own performance. Scepter Air plans to provide a series of information-based products and services offering deeper insight and precision regarding emitter location, emission dispersion, concentration validation, and corrective action abatement protocols. Nevertheless, engagement by the Federal Government in such efforts can

[1] For example, see Regan, Wong, Preston, and Curtright (2021). The economic costs of reducing greenhouse gas emissions under a US national renewable electricity mandate. *Energy Policy* 39(5): 2730-2739.

[2] For example, see Burger, Clancy, Rana, Rudavsky, and Curtright, F. Perez-Arce, and J. K. Yoong (2013). *Outcome Evaluation of US Department of State Support for the Global Methane Initiative*, RAND Corporation.

[3] Scepter is a private firm that simultaneously collects atmospheric data from a global network of satellite-to-terrestrial-level atmospheric sensors across the entire, dynamic vertical air column. See https://scepterair.com/technology/ for more details.

further enhance their relevance and facilitate scaling across regions and industries.

In addition to published data sources such as EPA's Greenhouse Gas Reporting Program and Greenhouse Gas Inventory, are there other data and information available on identification and location of point sources of greenhouse gas emissions within liquefaction facilities?

The U.S. EPA's Greenhouse Gas Reporting Program (GHGRP) is the prevailing federal resource for reporting emissions at different scales. However, it continues to be prescriptive regarding what firms should report owing to technological limitations on the direct measurement of emissions. Furthermore, various gaps have been identified in emissions estimates, particularly with respect to methane,[4,5] resulting in some emissions being overlooked. This ultimately results in biased emissions inventories. More comprehensive reporting of emissions sources would a) improve the accuracy of emission estimates and therefore national inventories; b) support a more ambitious regulatory regime; and c) enable a transition toward performance-based regulations that reduce cost while enhancing comprehensiveness.[6]

Once strategy for addressing these limitations is the development of more integrated observational infrastructure for the direct measurement of atmospheric GHGs. For example, integrating the vertical air column with sensors that include ground, high altitude, and satellite sensors has been proposed as a mechanism for enhancing methane monitoring at LNG facilities.[7,8] Such a capability can be a shared infrastructure with different partners contributing to different elements. Space-based sensors that generate data over large geographic areas can be deployed and sustained by the Federal Government and/or the growing constellation of private sector satellite assets. Meanwhile, other partners could help to provide more bottom-up measurements using other assets for specific locations or regions. This reduces the burden on a single entity to deliver the entire spectrum of observational assets. However, it does depend upon collaboration and coordination among multiple entities including the development of flexible data use agreements and licenses, as well as the implementation of data standards for interoperability.

Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?

Enhancing the capacity to detect, monitor, and report greenhouse gas (GHG) emissions through the acquisition and application of ubiquitous, high-resolution, near real-time atmospheric data is a key enabler of decarbonization efforts. Fortunately, a burgeoning supply of ground, air, and space-based data is now becoming available from new private and public platforms that offer the promise of more precise GHG emissions monitoring data. These include ground-, drone-, balloon-, and satellite-based sensors. For example, Scepter Air deploys stratospheric balloons enabled

[4] Subramanian, R., Williams, L. L., Vaughn, T. L., Zimmerle, D., Roscioli, J. R., Herndon, S. C., Yakovitch, T.I., Floerchinger, C., Tkacik, D.S., Mitchell, A.L., Sullivan, M.R., Dallmann, T.R., & Robinson, A. L. (2015). Methane emissions from natural gas compressor stations in the transmission and storage sector: Measurements and comparisons with the EPA greenhouse gas reporting program protocol. *Environmental science & technology*, *49*(5), 3252-3261.

[5] Johnson, M. R., Tyner, D. R., & Conrad, B. M. (2023). Origins of Oil and Gas Sector Methane Emissions: On-Site Investigations of Aerial Measured Sources. *Environmental Science & Technology*, 57(6), 2484-2494.

[6] Kleinberg, R. (2021). Methane Emission Controls: Redesigning EPA Regulations for Greater Efficacy. *Columbia Center on Global Energy Policy (Commentary)*.

[7] Payne Institute for Public Policy (2020). A Digital Canopy. Getting to Transparency. Colorado School of Mines, April 3, 2020. https://payneinstitute.mines.edu/a-digital-canopy-getting-to-transparency/

[8] Project Canary (2022). Project Canary Measures Facility Level ESG Data with Focus on Methane. https://www.projectcanary.com/press/project-canary-measures-facility-level-esg-data-with-focus-on-methane/

with methane-detection sensors. Such balloons, with lengthy dwell times, can be used to uncover intermittent leaks and fugitive emissions from petroleum production and transportation facilities, such as LNG terminals, and have been successfully deployed to detect emissions from domestic oil and gas basins and facilities. Leveraging such capabilities, along with those of other public and private entities, for the direct measurement of emissions at the facility level would generate a range of benefits in terms of creating realistic and transparent measurements of GHG emissions that create incentives for emissions reductions, designing specific operational interventions to achieve such reductions, and providing a robust empirical foundation for development of broader domestic and international decarbonization policies and practices.

Respondent:

Project Canary

Project Canary, PBC

June 26, 2023

Submitted via email to ReduceGHGE_LNG_RFI@NETL.DOE.GOV

The Honorable Brad Crabtree
Assistant Secretary, Office of Fossil Energy and Carbon Management
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

RE: Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. LNG Exports; Request for Information number DE–FOA–0003052

Submittal by Project Canary, PBC

Dear Assistant Secretary Crabtree:

Project Canary, PBC (Project Canary), is pleased to provide insights and information in response to the Request for Information (RFI) issued by the U.S. Department of Energy (DOE) regarding strategies and technologies to reduce greenhouse gas emissions associated with natural gas within Liquified Natural Gas (LNG) facilities and throughout the supply chain.

Project Canary is a leading provider of continuous emissions monitoring solutions for the oil and gas industry, specializing in methane monitoring and leak detection. Our cutting-edge technology and comprehensive approach have been instrumental in supporting upstream and midstream providers in their efforts to mitigate methane emissions, enhance operational efficiency, and improve environmental stewardship.

Our industry-leading emissions monitoring and quantification technology has helped upstream providers significantly reduce their carbon footprint. By implementing our advanced sensor networks and machine learning algorithms, operators gain real-time visibility into methane emissions across their entire production operations. This enables them to quickly identify and address any leaks or anomalies, reducing methane emissions and preventing potential safety hazards. Our solutions have not only ensured compliance with regulatory requirements but have also provided upstream providers with the data and insights needed to optimize operational processes and maximize resource efficiency.

In the midstream sector, our comprehensive methane monitoring solutions have supported large scale U.S. midstream companies in their commitment to reduce emissions. By utilizing our state-of-the-art sensors, deployed at strategic locations throughout facilities and along the transportation routes, operators can proactively detect and quantify emissions. The integration of our monitoring data with advanced analytics and reporting tools allows for timely corrective actions, minimizing methane emissions and supporting the overall sustainability goals.

As we look towards advancing the technology for application to LNG port facilities, Project Canary is committed to driving innovation and collaboration. We aim to develop and deploy cutting-edge monitoring solutions that address the unique challenges faced by LNG port facilities. Our vision includes:

1. Comprehensive Monitoring Infrastructure: We propose the development of an extensive sensor network utilizing a variety of technologies within LNG port facilities, covering key emission sources such as storage tanks, loading/unloading areas, and compressor stations. This infrastructure will provide real-time data on methane emissions and facilitate prompt response to any detected leaks.

2. Integrated Data Management: By using a combination of emission detection technologies we can collect, analyze, and integrate information from various monitoring locations across the LNG port facility. Operational data can also be integrated to better perform root cause analysis and improve temporal resolution. This holistic approach will enable comprehensive emissions reporting, facilitate regulatory compliance, and support evidence-based decision-making for emissions reduction strategies.

3. Advanced AI and Machine Learning: Leveraging AI and machine learning algorithms, we can further enhance the capabilities of our monitoring technology to identify abnormal methane emissions. The possibility exists to predict methane emissions prior to their occurrence through integrating operational data. Continuous improvement of our algorithms will ensure higher accuracy, reducing false positives and enabling more targeted mitigation efforts.

4. Collaboration and Partnerships: We recognize and value the importance of collaboration with stakeholders, including midstream and LNG operators, regulatory bodies, other technology companies, and industry associations. By establishing partnerships and engaging in knowledge sharing, we can collectively accelerate the adoption of methane monitoring technologies and drive industry-wide sustainability.

U.S. regulatory and policy actions, such as this RFI, can ensure that the U.S. can meet potential requirements in the European Union and continue to play a vital export role for Europe. According to the International Energy Agency (IEA)[1], flexible U.S. LNG has played a crucial role in mitigating the shortfall in Russian piped natural gas supply since Russia's invasion of Ukraine. LNG inflows into the EU rose by 70% or 55 billion cubic meters (bcm) in 2022 compared to the previous year –almost twice the increase in global LNG production. The European Commission plans to ensure, until at least 2030, demand for approximately 50 bcm/year of additional U.S. LNG that is consistent with US and EU net-zero goals.[2] Pending EU methane regulations, expected to be finalized by the end of 2023, will likely require reporting of methane intensity within the Oil and Gas Methane Partnership 2.0 (OGMP2.0) regime.

Project Canary is pleased to contribute to DOE's research and development activities in methane mitigation technologies and point source carbon capture. We believe that by working together, we can achieve ambitious climate goals while ensuring energy security and the competitiveness of U.S. LNG in global markets.

Please find our specific responses to a selection of the RFI questions below.

Topic 1: Environmental Profile of Upstream Supplies

1.1 *What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?*

Greenhouse gas emissions from natural gas are due to multiple reasons such as normal operational emissions, poorly maintained equipment, corrosion, human error and weather conditions. With increasing awareness about climate change, the oil and gas industry is taking steps to reduce these emissions, such as implementing leak detection and repair programs, using high-quality materials, and designing equipment with leak prevention in mind.

Leak detection and repair (LDAR) is a systematic approach to identifying and repairing non-operational emissions from equipment along the production and distribution supply chain. LDAR can be used to detect leaks of methane, a potent greenhouse gas, from upstream natural gas production sites. There are several different technologies that can be used for LDAR, including continuous monitoring (CM) detection systems, drones and satellites that can be used to detect methane leaks from space.

Currently, federal rules require well sites and compressor stations constructed or modified after September 18, 2015, to conduct Optical Gas Imaging (OGI) inspections on a semi-annual basis. This is insufficient as methane leaks are isolated events and can happen at any time. Methane is a colorless and odorless gas, so it is not possible to detect leaks without specialized equipment.

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[1] Natural gas supply-demand balance of the European Union in 2023 (windows.net)

[2] FACT SHEET: United States and European Commission Announce Task Force to Reduce Europe's Dependence on Russian Fossil Fuels | The White House

Continuous monitoring systems are technology agnostic and provide notifications to operators within minutes or hours of a leak, offering accurate data on emissions location, quantity, and potential causes. In addition to leak detection, continuous monitoring systems can help quantify total site emissions from both operational and leak sources, to help operators better understand the true emissions profile of a site and the major emissions contributors. As a result, continuous monitoring enables prompt action, effective mitigation, and better emissions accounting. With continuous monitoring systems, such as those offered by our company, operators can proactively manage emissions, reduce environmental impact, and ensure compliance. Our solutions use a combination of technologies, including near infrared spectroscopy, mid-infrared spectroscopy, metal oxide sensors, OGI, satellite observations, aerial flyovers, drones, and open path laser systems.

Project Canary's quantification algorithm predicts total well pad emissions and identifies an accurate inventory of emissions generated by all sources on the pad and at the same time excluding offsite emissions for more accurate data. Utilizing machine learning models, we look at large amounts of data (CH4, wind speed/direction, environment factors, identified onsite/offsite sources) to detect and quantify all operational and fugitive emissions.

- Total site emissions with stacked group contributions are displayed on a graph over time within the dashboard.
- An overlaid heatmap on the site map allows the users to view each emitting source and its intensity.
- The dashboard provides a breakdown of emissions for each equipment group as a percentage of the total.

Due to the stochastic and intermittent nature of leaks, single point-in-time measurements are not sufficient to understand site- or facility-level methane intensity needed to incentivize lower emissions. Studies have revealed significant underestimation of methane emissions in EPA inventories compared to field measurements, emphasizing the need for more accurate approaches:

- "*This value is ~60% higher than the U.S. Environmental Protection Agency inventory estimate, likely because existing inventory methods miss emissions released during abnormal operating conditions*" Alvarez et al 2018, Assessment of methane emissions from the U.S. oil and gas supply chain.[3]
- "*In the United States, recent synthesis studies of field measurements of CH4 emissions at different spatial scales are ~1.5–2× greater compared to official greenhouse gas inventory (GHGI) estimates*" Rutherford et al 2021, Closing the methane gap in US oil and natural gas production emissions inventories.[4]
- "*We estimate emissions to be 9.4% (+3.5%/–3.3%) of the gross gas production for the region" compared to a 1.18% assumed methane intensity across the entire value chain in GREET*" Chen et al 2022, Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey.[5]

1.2. *To what extent do exporters request or have access to information about the source (e.g., production basin, transportation pipeline, custody transfers) of the natural gas they are liquefying for export? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means? Do the answers vary by the extent to which the gas is supplied by natural gas marketers or through bilateral contracts?*

The technology to measure emissions around the clock is readily available from multiple technology companies, enabling exporters to have real-time visibility into methane emissions. These advanced monitoring solutions allow for continuous measurement and data collection, which can be conveniently loaded onto digital registries. By utilizing this technology, exporters can accurately identify the specific well site from which they are receiving natural gas and assess its methane emissions profile. The availability of comprehensive emissions data empowers exporters to make informed decisions, understand the environmental impact of the natural gas they handle, and take proactive measures to address emissions. This data-driven approach enhances transparency, accountability, and enables exporters to actively contribute to emissions reduction efforts.

The North American Energy Standards Board (NAESB) contracts provide another avenue for the provision of environmental data. NAESB recently developed a Certified Natural Gas Addendum,

[3] https://www.science.org/doi/10.1126/science.aar7204?cookieSet=1
[4] https://www.nature.com/articles/s41467-021-25017-4
[5] https://pubs.acs.org/doi/full/10.1021/acs.est.1c06458

through a multi-stakeholder process, which provides information regarding specific environmental attributes related to gas production.[6]

In addition, several registries provide a platform for differentiated gas trades, ensuring that the environmental attributes associated with a specific volume of natural gas production are appropriately accounted for in transactions. Registries which enable this include EarnDLT, CGHub, and Xpansiv.

1.3 *To what extent do exporters request or have access to information about the greenhouse gas emissions and/or practices to limit greenhouse gas emissions of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?*

The answers to these questions may vary depending on the extent to which the natural gas is supplied by natural gas marketers or through bilateral contracts. Natural gas marketers typically have more access to information about the source of the gas they are selling than companies that purchase gas through bilateral contracts. This is because natural gas marketers typically have a wider range of suppliers and are more likely to ask for information about the source of the gas.

Increasingly, producers providing natural gas for export are keen to provide information related to greenhouse gas (GHG) emissions and practices they have undertaken to reduce them. This includes methane intensity and carbon intensity. Historically, this information has been provided based on estimates, however, more and more producers are undertaking a variety of measurements to inform their emissions inventories. This can include satellites, aircraft, drones, and fixed or CM monitors. Such technologies provide increasingly accurate and reliable information that demonstrates the veracity of operating practices to limit GHG emissions. As measurement informed GHG inventories come into play, driven by regulatory requirements and market expectations, this information will improve with time and become more granular, including tracing environmental attributes to the site from which the molecules were produced. This future will support demonstrated decarbonization and net zero initiatives.

Project Canary's SENSE Platform is an enterprise emissions data management solution that utilizes a variety of technologies to provide extensive emissions monitoring in real time. The platform includes a network of sensors that are deployed at natural gas production sites which collect data on emissions. If emissions are detected exceeding the threshold for that facility, an alert is sent to the concerned parties, and they can take action to repair it.

The SENSE Platform can help to address the challenges of obtaining information about greenhouse gas emissions and practices to limit greenhouse gas emissions in a number of ways. Firstly, the platform provides actionable insights about assets, enabling operators to identify and quantify methane emissions in real-time and pinpoint the specific sources of leaks, such as tanks, separators, and

[6] NAESB Adopts Standardized Addendums For Renewable Natural Gas And Certified Gas, March 16, 2023, *** (naesb.org)

wellheads. Additionally, the platform facilitates the visualization of life cycle emissions, empowering stakeholders to measure and manage their carbon footprint effectively. By leveraging these capabilities, exporters have access to information about natural gas they are liquifying for export. This data can be digitized in blockchain for transmission via registries and certificates for exporters, and then also transmitted to the ultimate purchaser. Registries which enable this include EarnDLT, CGHub, and Xpansiv.

U.S. LNG buyers have explicitly highlighted buying certified natural gas. Several European gas buyers have highlighted this certified, or responsibly sourced gas feedstocks in publicly announced transactions, including SEMPRA, Engie, and RWE.

1.4. *To what extent do exporters request or have access to information on non-greenhouse gas emissions, including criteria air emissions or hazardous air pollutants, and/or other practices to address other environmental impacts (e.g., strategies to protect water quality or limit water consumption) of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?*

Typically, exporters have not requested information from Project Canary on non-GHG emissions. However, data on other environmental attributes and their impacts on land, water and community are readily available in the marketplace. Many producers go to great lengths to limit the impact of their operations and employee best practices designed to mitigate their potential effects. These practices can, and often times are, above regulatory requirements. Exporters are beginning to recognize these attributes and seeking them from producers.

Many European buyers have sought information regarding responsible water practices, specifically as it relates to reporting frequency, reuse potential, and impacts on freshwater sources. Project Canary and researchers at Colorado State University's Center for Energy Water Sustainability announced that *The Journal of Water Resource and Protection* has published the "Technical Analysis of Freshwater Use as a Part of Responsibly Sourced Gas ESG Strategy,"[7] a groundbreaking metric designed to measure and mitigate the effects of operations on local water resources.

The key points of this study are the following:

- Project Canary's Freshwater Replacement Ratio (FR^^{2}) has been validated as an industry best practice and is the only metric to localize the impacts on water resources.
- Several North American producers have achieved the Project Canary Freshwater Verified Attribute through participation in the program.

[7] Carlson, F., Li, H.S., Hanif, A., Zier, J. and Carlson, K. (2022) Technical Analysis of Freshwater Use as Part of a Responsibly Sourced Gas ESG Strategy. Journal of Water Resource and Protection, 14, 292-303. https://doi.org/10.4236/jwarp.2022.143014 Technical Analysis of Freshwater Use as Part of a Responsibly Sourced Gas ESG Strategy (scirp.org)

- First-ever peer-reviewed and published freshwater metric to emphasize reducing competitive water usage in high water stress regions and validating responsible water stewardship across all basins.
- Project Canary and Colorado State University's partnership highlights engineering rigor and expertise alignment. In the report titled "Technical Analysis of Freshwater Use as Part of a Responsibly Sourced Gas ESG Strategy," researchers confirmed the Fresh Water Replacement Ratio as an industry best practice and benchmarking tool for evaluating responsible water performance. The metric quantifies operational impacts on local water supplies by measuring competitive water usage in conjunction with a localized water stress index to quantify operators' effects on water supplies.

1.5. *What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?*

Differentiated natural gas certification programs can play a significant role in ensuring natural gas sourced for export has undergone third-party assessment of critical environmental factors surrounding GHG emissions, water stewardship, community, and safety. Currently, buyers of natural gas use environmental risk assessments and the associated scores to determine whether the natural gas has been responsibly sourced or "certified". Approximately 30% of the U.S. natural gas market is certified in some manner illustrating the market drive and acceptance of differentiated natural gas.[8]

Project Canary's TrustWell ratings are designed to differentiate companies and their assets by evaluating their overall approach to responsible operations, specifically as it relates to operational excellence and environmental stewardship.

The TrustWell assessment is a standard derived from current industry best practices, existing international standards, and academic partnerships focused on engineering and environmental performance. The ratings are tied to specific production well API numbers allowing digital registries to trace the molecule from the wellbore of origin via blockchain.

Differentiated natural gas certification programs have been proven to assist operators in reducing the environmental impacts of operations throughout the natural gas supply chain. Buyers both internationally and domestically are provided with a better and more transparent understanding of the environmental and social impacts of operations. One primary example is, through emphasizing

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[8] Based on anecdotal calculation: MiQ certifies ~17% of the US Gas market: "MiQ currently certifies approximately 4% of the global gas market and 17% of U.S. gas production." https://www.bp.com/en_us/united-states/home/news/press-releases/bp-expands-natural-gas-certification-to-100-percent-of-its-us-onshore-upstream-operations.html. Project Canary certifies approximately 11% of US gas production. EIA puts production at 98.11 BCF/day. https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php#:~:text=U.S.%20dry%20natural%20gas%20production,the%20highest%20annual%20amount%20recorded.

measurement-based methodologies, differentiated natural gas creates the opportunity for emissions reconciliation and a more accurate emissions profile. Encouraging the implementation of differentiated gas provides several benefits for all stakeholders:

- facilitate the development of a low carbon market, incentivizing measured reductions in GHG emissions,
- granular and transparent emissions accounting through the use of empirical data and measurements,
- establish continuously evolving benchmarks for all environmental attributes,
- and incorporation of stakeholder input building trust between suppliers and buyers.

1.6. *What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?*

Certification programs currently available in the market are distinguished by their offerings. As noted in our response to Question 1.5, we analyze over 600 data points and provide a score for each facility as well as a detailed report covering operations from drilling to completion to production. These data points are used to evaluate 28 different categories covering air, land, water, and community environmental attributes. Methane intensity is one key element of the facility's scoring. The buyers of natural gas use our environmental risk assessments and the associated scores to determine whether the natural gas has been responsibly sourced or "certified", as it is sometimes known. In addition, Project Canary also provides a Low Methane Rating (LMR) which is designed to capture insights on an annual basis at both the basin and site level with the following attributes: methane intensity, carbon intensity, emissions best practices, monitoring technology implementation, and producer emission reduction targets/goals. The purpose of the LMR is to provide a robust and quantifiable evaluation of methane emissions performance at the basin and site level. The program includes clear metrics which benchmark operators within the sector and rewards those using the best industry practices and most up-to-date technologies. Operators must meet minimum requirements to qualify for the LMR and additional points are awarded for performance in each category where an operator goes above the minimum requirements[9].

TrustWell is distinguished by its site level analysis, enabling environmental attributes to the actual production site. MiQ, another significant certification supplier, provides an emissions-based offering that is focused on the basin or EPA Subpart W GHG Reporting Program (GHGRP) facility level. The MiQ certification does not afford site level analysis or the ability to trace environmental attributes to the specific production site. Equitable Origin also provides an assessment program which is focused on general enterprise level operating practices, including governance.

There does not appear to be any obvious gaps in the market. There are competing environmental assessment programs providing producers and buyers with relevant data to meet their needs. As the

[9] Project Canary Low Methane Rating Evaluation Protocol for Onshore Production go.projectcanary.com/l/971793/2023-04-28/3w3fm/971793/1682695229dizN0dK2/Project_Canary_LMR_Protocol_APR_2023.pdf

market for differentiated gas grows it is likely that there will be an increased focus on a variety of environmental attributes, the methods for deriving site level measurements, and the process for reconciling different measurements.

1.7. *What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?*

Differentiated natural gas certification programs can play a significant role in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas. These programs can help to demonstrate that U.S. natural gas is produced and transported in a way that minimizes environmental impacts, which can be a valuable selling point for buyers who are looking for sustainable energy sources.

Here are some specific examples of how differentiated natural gas certification programs can help to create a competitive advantage for U.S. natural gas in foreign markets:

- demonstrate that U.S. natural gas has a lower greenhouse gas footprint than other sources of natural gas. This is important to buyers who are looking to reduce their environmental impact,
- help to ensure that U.S. natural gas is produced and transported in a way that minimizes methane emissions. Methane is a potent greenhouse gas, so buyers who are concerned about climate change will be more likely to purchase U.S. natural gas if they know that it is produced and transported in a way that minimizes methane emissions,
- and build trust between U.S. suppliers and foreign buyers. This is important because it can lead to long-term relationships, which can be beneficial for both parties.

Overall, differentiated natural gas certification programs can be a valuable tool for helping to create a competitive advantage for U.S. natural gas in foreign markets. These programs can help to demonstrate that U.S. natural gas is produced and transported in a way that minimizes environmental impacts, which can be a valuable selling point for buyers who are looking for sustainable energy sources.

In addition, U.S. regulatory requirements are rapidly changing. Under the Inflation Reduction Act (IRA) Methane Emissions Reduction Program (MERP) and the associated GHG RP changes, it may be the case in the final rule that estimates will no longer be the method for reporting over time. The IRA requires that the data used to assess the methane under this reporting framework be based on "accurate", "empirical" data. Through the IRA, the U.S. has effectively set a methane intensity target of 0.2%, meaning that only 0.2% of the total methane produced is lost in the production process[10], as companies would soon have to pay an emissions charge for any additional methane that is lost over

[10] https://www.ogci.com/action-and-engagement/reducing-methane-emissions/

that amount. Further, the EU is similarly considering a 0.2% methane intensity target in their new methane regulations.

Taken together, these factors can create, ensure, and enable competitive advantages for U.S. LNG in foreign markets with the most transparent emissions reporting requirement, the most stringent reporting and the market incentives to mitigate and reduce emissions. This can ensure that U.S. molecules are truly differentiated versus others around the globe.

As noted below in Question #4.3, DOE is exploring a best practices framework for monitoring, reporting, verification (MRV) and certification. This is relevant to this RFI as it plays a key role in DOE's goal "to bring transparency and best practices to the U.S. and global natural gas supply chains [… and] help American industry achieve among the lowest emissions profiles of any natural gas producer in the world, demonstrating that natural gas production, consumption and exports from the United States can effectively align our energy security and climate goals.", as was noted in the DOE issuances which included this RFI on April 21, 2023. This initiative can play a key role in ensuring that differentiated natural gas certification programs help to create a competitive advantage for U.S. natural gas.

Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities

2.1. *What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?*

Companies are deploying several technologies and strategies to reduce greenhouse emissions at liquefaction facilities. Two of the technologies where our company are active are below:

- Carbon capture and storage (CCS): This technology captures carbon dioxide emissions from a variety of sources, including liquefaction facilities, and utilizes it in other value creating processes or permanently stores it underground. Adoption of CCS has emerged as one of the best practices for the production of liquefied natural gas (LNG). As the global energy landscape undergoes a transition towards cleaner and more sustainable alternatives, LNG producers have recognized the imperative to mitigate greenhouse gas emissions associated with their operations beyond methane. The processing and liquefaction of natural gas can be energy intensive and generate significant volumes of CO_2. However, the inherent operational design and facility management expertise of LNG activities lend themselves to practical and economic adoption of CCS. Verifiable low emissions LNG is a growing global commodity category currently demanding a premium from international buyers. This demonstrates market-based demand for low carbon intensity LNG that incorporates CCS that further enhances the value of CCS beyond government incentives like 45Q. By integrating CCS into LNG production facilities, companies can significantly reduce their carbon footprint, enhance environmental stewardship, and contribute to global efforts in combating climate change. Adoption of CCS as a best practice in the LNG industry represents a significant step forward in aligning energy production with the goals of a low-carbon future. It also further differentiates U.S. produced LNG as one of the most reliable, secure, and low climate intensity energy sources globally.

- Continuous emissions monitoring (CEM) enables project developers and stakeholders to ensure the highest efficacy and certainty in LNG processing. This technology shift from emission estimates to empirical measurements enhances emissions mitigation, improves stakeholder understanding, and facilitates ongoing improvements in operational performance. To demonstrate emissions measurements with statistical significance (typically at a 90% industry standard), project developers require high-quality empirical data and quantifiable measurements. Spectroscopy-based measurement methodologies should be applied whenever feasible, particularly in situations with a higher likelihood of emissions, to quantify operational efficacy comprehensively. Monitoring solutions based on leak imaging or visualization, while challenging to quantify, should be cross-validated with other measurement methods to ensure a comprehensive understanding of system-level performance. Satellite measurements' spatial resolution currently falls short, making them insufficient as standalone tools for accurately providing actionable information for LNG operations. Therefore, whenever technically and economically feasible, continuous real-time measurement should be prioritized over estimation-based calculations. CEM complimented by independent third-party measurement, data validation, and verification play a critical role in establishing trust and confidence among regulatory, societal, and financial stakeholders which leads to building industry trust and enduring project acceptance. CEM plays a vital role in facilitating improved methane management practices, including detection, repair, and methane recovery, empower LNG facilities to effectively address and mitigate methane emissions, minimizing their environmental impact and maximizing operational efficiency.

As the demand for natural gas continues to grow, it is likely that more technologies and strategies will be developed to further reduce emissions from these facilities.

2.3. *What methodologies do operators use to estimate and measure greenhouse gas emissions at liquefaction facilities?*

There are a number of methodologies that operators use to estimate and measure greenhouse gas emissions at liquefaction facilities. Some of the most common methodologies include:

- Process-based methods: These methods use information about the processes that occur at a liquefaction facility to estimate emissions. This information can include things like the amount of natural gas that is processed, the type of equipment that is used, and the efficiency of the facility.
  Process-based methods are typically used for large, complex liquefaction facilities. These methods can be more accurate than inventory methods, but they require more data and can be more expensive to implement.
- Inventory methods: These methods track the emissions from individual sources at a liquefaction facility. This information can be collected through a variety of means, such as manual monitoring, remote sensing, and continuous emissions monitoring.
  Inventory methods are typically used for smaller, less complex liquefaction facilities. These

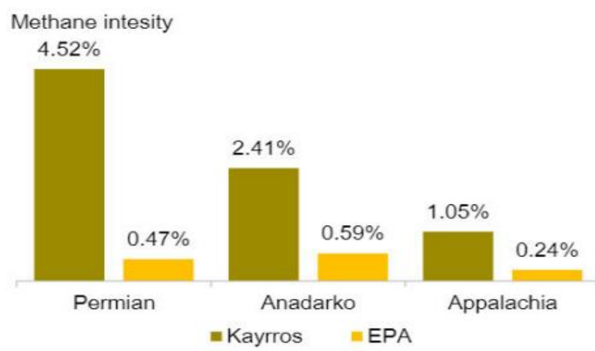
methods are less accurate than process-based methods, but they are less expensive to implement and can be used to track emissions from a wider range of sources.

- Emissions factors: These methods use emission factors to estimate emissions from a liquefaction facility. Emission factors are typically based on the type of fuel that is used, the type of equipment that is used, and the operating conditions of the facility.
  Emissions factors are typically used to estimate emissions from a liquefaction facility when there is limited data available. Emission factors are based on the type of fuel that is used, the type of equipment that is used, and the operating conditions of the facility.

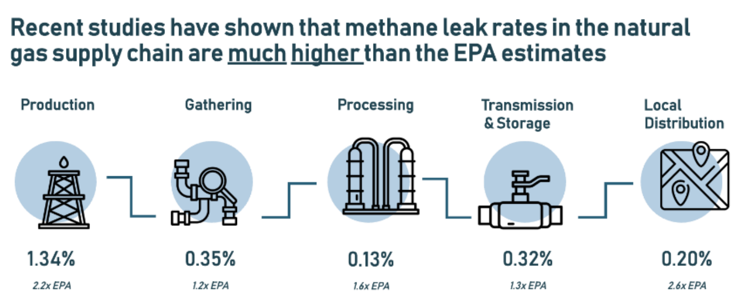
The use of emission estimation-based factors can be problematic because they do not properly consider the variability of emissions over time. The actual emissions from a facility can vary significantly depending on several factors, such as the age and condition of the equipment, the operating practices, the weather conditions, and how humans interact with the equipment. As a result, emission factors can often underestimate or overestimate actual emissions.

For example, emissions from upstream facilities can be higher during periods of peak demand or when there are weather conditions that lead to increased flaring. As a result, emission factors can provide a misleading picture of the actual emissions from a facility.

In the figure below we can see how EPA estimates are much lower than emissions reported by satellite data collected by analytics provider Kayrros.



Source: Kayrros 'full inversion', EPA, BloombergNEF.



Source: AAAS / Science, Assessment of methane emissions from the U.S. oil and gas supply chain (July 2018); American Chemical Society, A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems (June 2020).

Continuous monitoring devices installed on site can solve the problem of estimation and give actual measurement of methane leaking from the site by providing real-time, accurate data on emissions. This data can be used to identify and repair leaks, track emissions over time, and verify the accuracy of emission estimates.

2.4. *Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?*

Companies are deploying advanced technologies, such as drones and ground-based sensors which provide several benefits, including improved accuracy of emission estimates, increased spatial coverage and cost efficiency:

Some of the specific technologies that are being used or planned to be used for monitoring greenhouse gas emissions at liquefaction facilities include:

- Drones can be equipped with sensors that can detect methane leaks. They can also be used to conduct surveys of facilities to identify both potential sources of emissions and operational issues.
- Infrared cameras can be used to detect methane leaks by detecting the unique signature of methane in the atmosphere.
- Spectrometers can measure the concentration of methane in the atmosphere, providing a more accurate measurement of emissions.
- Continuous emissions monitors can measure the flow rate and concentration of methane emissions from both a specific source, and when integrated as a system, for a total site. This provides a more detailed understanding of how emissions change over time.
- Open path laser systems can cover a larger area, potentially the complete facility, with less measurement frequency than continuous emissions monitoring systems but more than more episodic inspection methodologies such as aerial flyovers and satellites.

Some of these technologies are still under development, but they have the potential to revolutionize the way that greenhouse gas emissions are monitored at liquefaction facilities. By providing real-time, accurate data on emissions, these technologies can help to reduce emissions and improve the environmental performance of these facilities.

2.10. *Are there data or information available on other technologies or strategies operators could deploy to reduce or avoid greenhouse emissions at liquefaction facilities? Are these technologies or strategies considered experimental or pre-commercial? Are there estimates of emission reductions and/or gas savings associated with implementation of these technologies?*

While the technology underpinning open path laser systems is well understood, the deployment for many applications, such as at an LNG facility, is still emerging. Through collaboration with other technology companies, Project Canary is researching multiple types of open path laser systems to find the best fit of geographical coverage, sampling frequency, and cost.

These integrated solutions for LNG exporters and buyers could provide comprehensive emission measurements across the entire supply chain, from natural gas production to through the export facility. Our sensors deployed across each stage of the value chain can accurately quantify emissions, enabling users to identify and understand the difference in quantity between production and delivery. With our platform buyers can assess losses incurred at different stages of the supply chain. This product offering could provide unprecedented insights into emissions, facilitating informed decision-making, emissions reduction strategies, and environmental accountability.

Project Canary's Digital Canopy (DC) enables this integrated solution also allowing visualization of methane emissions data from different third-party sensing technologies including satellite, aerial and continuous monitoring. DC is built to be scalable for additional measurement technologies using automated data transfer for ingesting data into the platform. DC aggregates and visualizes top-down methane data, helping to identify sites with uncommon emission patterns across the portfolio and determine where to focus mitigation efforts. It empowers its users with the ability to view methane emissions rate across sensing technologies in one site-specific dashboard and give faster feedback with event annotations feature within the app.

2.12*. What data and information are available to assess potential improvements to local air quality or benefits to communities from mitigation practices implemented at liquefaction facilities?*

As noted in our response to Question 1.5, we analyze over 600 data points and provide a score for each facility as well as a detailed report covering operations from drilling to completion to production. These data points are used to evaluate 28 different categories covering air, land, water, and community environmental attributes. Similar to the production segment and gas processing facilities, LNG facilities could do the same.

Topic 4: Additional Information

4.1 *What non-US requirements for greenhouse gas performance are LNG exporters being asked to respond to with emissions data? Are emission reduction requirements included in any contracts or other importing country requirements?*

We are aware of the following non-US requirements:

Pending EU methane regulations, expected to be finalized by the end of 2023, will likely require reporting of greenhouse gas performance within the Oil and Gas Methane Partnership 2.0 (OGMP2.0) regime. It is also possible that importers to the EU could be required to conform to regulatory requirements that are equivalent to those imposed on EU producers and report this to an EU authority.

According to the joint statement issued during the Japan-U.S. Energy Security Dialogue in December 2022, Japan has emphasized the importance of addressing greenhouse gas (GHG) emissions in the LNG sector. It highlights the commitment to advancing technologies and practices that reduce GHG emissions throughout the LNG value chain. This indicates that emission reduction requirements are a key consideration for LNG exporters, and they are expected to respond to the need for emissions data and align with importing countries' sustainability objectives.[11]

4.3 *Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?*

In a related initiative, DOE has convened a group of countries with the EU to explore a best practices framework for monitoring, reporting, verification (MRV) and certification. This is relevant to this RFI as it plays a key role in DOE's goal "to bring transparency and best practices to the U.S. and global natural gas supply chains [… and] help American industry achieve among the lowest emissions profiles of any natural gas producer in the world, demonstrating that natural gas production, consumption and exports from the United States can effectively align our energy security and climate goals.", as was noted in the DOE issuances which included this RFI on April 21, 2023.

We offer the following comments on this topic.

Improved Measurement and Transparency is Paramount and Fundamental

Best practices focused on improved and advanced methods of methane measurement will address several issues DOE has identified in the draft framework[12]: monitoring, reporting, verification, certification criteria, transparency of claims for buyers, export partners, and the public. Direct measurements at the site-level provide an accurate, transparent, and auditable basis for all that follows in a best practices framework.

Differentiated natural gas is intended to enable operators to demonstrate strong performance and allow markets to reward good environmental performance. The basis of differentiation must stand up to scrutiny and numerous studies have proven that the engineering estimate status quo cannot meet this test. The GREET model (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) and other relatively simple models categorize processes with uniform associated Methane Intensity (MI). They offer a low touch solution but do little to create the necessary incentives to improve emissions performance at an operator and asset level.

As noted above in response to RFI Question 1.1, over the past decade, numerous peer-reviewed studies featuring field measurements of emissions from oil and natural gas facilities have cast doubt on the accuracy of emissions inventories calculated using emission factors in accordance with the EPA GHGI. Continuous events can be easily detected with infrequent sampling; however, intermittent events can go undetected without collecting frequent measurements.

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[11] https://jp.usembassy.gov/japan-us-energy-security-dialogue-joint-statement/

[12] Natural Gas Roundtable Discussion at CERAWeek in Houston, TX | Department of Energy

To put this into perspective, we look at the Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States Report by MJBradley[6] which provides operator-specific methane intensities reported to the EPA under Subpart W of the GHGRP. Assuming a 0.2% methane intensity threshold for differentiated, or certified, natural gas, the MJBradley report suggests that over 70% of natural gas production would qualify as certified natural gas with no action taken. An abundance of scientific evidence suggests that emissions exceed GHGRP inventories, yet the status quo reporting methodologies would recognize nearly three quarters of US oil/natural gas production as below 0.2% methane intensity.

Voluntary industry initiatives, such as OGMP2.0 and GTI Veritas, and regulatory and legislative actions such as the EPA Supplemental Rule and the Methane Emission Reduction Program in the Inflation Reduction Act (MERP IRA), have recognized the need for methane measurement to accurately account for emissions. With these programs and actions highlighting the need for measurement instead of engineering estimates, we strongly recommend any differentiated gas framework guidance from the DOE follow suit.

OGMP2.0 Provides a Best Practice Approach for Harmonizing Monitoring and Reporting

Project Canary agrees that there is high value in harmonizing MRV frameworks. The requirements of OGMP2.0 would provide a ready-made framework that has gained significant support within the operator community and is also widely supported in the EU methane draft regulations. DOE's support of OGMP2.0 could be both for operators joining OGMP or for using the protocols.

A 0.2% MI at the site-level for production should be the goal and there is widespread consensus on this number target. As technologies evolve and operator and site-level performance improve, the bar should get higher (0.2% --> 0.1%) and operators should be encouraged to work towards continuous improvement and enhanced best practices.

Currently, most operators in the U.S. are at OGMP2.0 Level 3 (current GRGRP Subpart W requirements). DOE best practices should encourage attainment of OGMP Level 4 (specific Emission Factors (EFs) and Activity Factors (AFs) for individual sources) in the short-term and transition to OGMP2.0 Level 5 (specific EFs and AFs for individual sources and site-level measurement) within a reasonable timeframe. Level 5 correlates to the ultimate goal of transparent, independently derived data. To ensure continuous improvement, DOE should regularly update their best practices as OGMP2.0 adds higher level protocols.

It is important to note that the OGMP2.0 framework at this stage still lacks clarity regarding measurement technology specifications. For example, limited aircraft flights over a facility in the course of a year are considered a site-level measurement yet lack the temporal resolution necessary to observe intermittent events, which are material and should be included in an annual emissions inventory. Sampling frequency should be considered in order to ensure accuracy in reporting emissions for differentiated natural gas. This approach should be agnostic to the type of technology that is used.

Requiring a transition to site- and source-level data also will improve the outcome of the recently announced joint common tool for life cycle analysis (LCA) of methane emissions for hydrocarbon suppliers and purchasers by the EU-US Energy Council. DOE should consider aligning the transition of best practice from Level 4 to Level 5 with the final EU methane regulations.

The requirements would also be compatible with U.S. private, independent environmental assessments, often referred to as certifications, and registries. These U.S. registries can include adherence to OGMP 2.0 levels as a part of the reported attributes of the imported natural gas.

Monitoring and Measurement Best Practices: Approval of Monitoring Technologies via the EPA Supplemental Process

Measurement-based monitoring frameworks are already in development. Aligning a differentiated natural gas framework with these regulations is a sensible, efficient approach. For example, the EPA Supplemental Continuous Monitoring section of the proposed rule includes a definition for CM that will, if the rule is adopted as proposed, be approved by the EPA. This definition, and other EPA-approved methodologies, could be a standard that consumers and governments point to as an approved methodology for monitoring. This removes the potential for debate. For example, relying on this EPA approved methodology to ensure monitoring is best practice for purposes of verification, auditing, or buyer certainty for purchases of differentiated natural gas.

There are several reasons this approach could be considered best practice:

- Frequency – the EPA Supplemental proposal requires a quantified value for CM leak detection at least once every 12 hours. Methane leaks are largely intermittent thus the best opportunity to measure comes from regular inspection frequency.
- Quantification – EPA-approved Supplemental CM technology must quantify emissions, i.e., in the Supplemental proposed rule, emissions exceedance thresholds (or leaks) are determined by flux values (kg/hr), not concentrations (500 ppm). This implies that CM technology application can be used to measure methane emissions.
- Accuracy – a recent study compares aerial monitoring flyovers with CM and confirms that even frequent flyovers (every 2 days) miss a significant number of emissions events compared to 24/7 monitors.[13]

[13] Towards multi-scale measurement-informed methane inventories: reconciling bottom-up inventories with top-down measurements using continuous monitoring systems | Energy | ChemRxiv | Cambridge Open Engage, Daniels W, Wang M, Ravikumar A, Harrison M, Roman-White S, George F, et al. Towards multi-scale measurement-informed methane inventories: reconciling bottom-up inventories with top-down measurements using continuous monitoring systems. Abstract excerpt: "Specifically, we use CMS to (i) assess the validity of snapshot measurements and determine how they relate to the temporal emissions profile of a given site and (ii) create a near-real time, measurement-informed inventory that can be cross-checked with top-down measurements to update conventional bottom-up inventories. This work presents a real-world demonstration of how CMS can be used to reconcile top-down snapshot measurements with bottom-up

- Affordable – CM measurement technologies are readily available and cost effective.

Reporting Best Practices and Reconciliation

Voluntary initiatives, such as OGMP2.0 and GTI Veritas, require measurement informed inventories to replace inaccurate generic engineering estimates. As noted above, we recommend replacing generic engineering estimates to calculate emissions inventory with measurement and that measurement be technology agnostic, enabling innovation. However, it is critical to understand the nuance in measurement technologies and their implementation as it pertains to generating source and site-level annualized emissions inventories. For example, the lower detection threshold of technologies is critical to understanding which emissions events are detectable. Operators must reconcile emissions to account for events below the measurement detection threshold and to ensure that events are not double counted across various technologies and accounting methodologies.

We recommend alignment with OGMP2.0, the International Methane Emissions Observatory[14] (IMEO) and GTI Veritas frameworks for such reconciliation. It is critical that all technologies are tested rigorously across a wide range of operating conditions and that technology providers are transparent with the results of such testing. Published results should include lower detection threshold, probability of detection across varying operating conditions (e.g., at night or with cloud cover or rain) and confidence intervals for quantified emissions. Testing requirements shed light on the performance of point-in-time measurements but do little to characterize the influence of temporal resolution on derived emissions inventories. Sampling frequency will impact the uncertainty associated with a measurement approach, and it is critical that this be incorporated into any measurement-informed emissions inventory.

Verification by an Accredited Independent Third-Party Best Practices

Relying on an EPA-approved monitoring methodology, independent verifiers can verify that natural gas was produced at a well site that utilized a technology approved by the EPA under the Supplemental program during the time in question and ensure that the required methane intensity was met. This eliminates the need for verifiers to verify the efficacy of a technology methodology. The MERP IRA pending rulemaking will also likely provide a government-approved pathway for methane measurement.

Questions assessed by independent verifiers could include:

- Site – what well site and what wells currently produce into the site?
- Time Period – what time period, i.e., daily, weekly, monthly, quarterly, annual, etc.

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inventories at the site-level. More broadly, it demonstrates the importance of multi-scale measurements when creating measurement-informed emissions inventories, which is a critical aspect of recent regulatory requirements in the Inflation Reduction Act, voluntary methane initiatives such as OGMP 2.0, and corporate strategies."

[14] https://www.unep.org/explore-topics/energy/what-we-do/methane/imeo-action

- Technology deployed – was an EPA-approved technology deployed at this site during the time period?
- Operational – was the EPA-approved technology operating the vast majority of the time period and is the data gathered approximately every 12 hours?
- EPA approved – was the technology approved by the EPA for the application in question?
- Kilograms (Kg) of methane emitted – how much methane was reported over the time period from the technology provider?
- Independence – the technology provider could provide the data directly to the verifier, instead of from the operator.
- Production values – how much methane did this site produce in the given time period and is this confirmed by the last gas composition sample taken?
- Calculation of methane intensity – the verifier can then use the data from third parties (emissions from the technology company and production volume from operator), as described above and can then calculate a reliable MI.

This verification approach will likely rely on environmental consultancies such as ERM, SLR, Geosyntec, Ramboll, and others, by leveraging their existing skills.

All associated data described above that is verified can easily be provided to many registries, thereby allowing natural gas buyers to purchase natural gas that meets their needs or preferences such as produced in a relevant geography, using a preferred technology, or a specific MI.

* * * * *

Thank you for considering our response to this RFI. We look forward to potential collaboration and the opportunity to contribute to the advancement of methane monitoring technologies in the LNG sector.

Respondent:

LNG Allies

U.S. Department of Energy
Office of Fossil Energy and Carbon Management
Request for Information (RFI)
DE-FOA-0003052

Introduction
The Office of Fossil Energy and Carbon Management (FECM) of the U.S. Department of Energy (DOE) issued a Request for Information (RFI) on April 21, 2023, "on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce greenhouse gas (GHG) emissions and other air pollutants associated with natural gas delivered to a liquefaction facility, at liquefaction facilities, and during the loading, transport, and delivery of natural gas to a regasification facility."

The USLNG Association, operating under the global brand of "LNG Allies" is pleased to provide a brief response to the RFI setting forth our suggestions for R&D activities that could be undertaken by FECM to improve knowledge on these subjects. LNG Allies is a 501(c)(6) nonprofit trade association. Our members include USLNG exporters and project developers, U.S. natural gas producers, and allied service companies, including engineering firms, equipment makers, and global gas infrastructure providers.

Responses to Topics in the RFI

Topic 1: Environmental Profile of Upstream Supplies. DOE is currently working with the U.S. natural gas and LNG industries and various international partners to try to harmonize the many private sector and government initiatives to measure, report, verify, and reduce methane emissions. This is an important endeavor that we fully support. Research sponsored by FECM in this arena could be helpful, especially as it pertains to facilitating full life-cycle comparisons of USLNG exports with competing fuels, including gas produced in other countries and coal. Other useful R&D efforts could focus on validating the efficacy of various methane data collection systems and methodologies (especially satellites) and the use of outdated equipment emission factors. As DOE recognizes, efforts to standardize measurement and verification methodologies across companies and even countries is an urgent imperative.

Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities. Many of the questions posed under this topic are answered in detail in the submissions USLNG project sponsors must submit to the Federal Energy Regulatory Agency (FERC) and the Department of Energy in applications to build LNG export facilities (FERC) or export the molecules (DOE). Nonetheless, we encourage DOE to work with the USLNG industry—on a voluntary and 100% confidential (data protected) basis—to gauge actual emission profiles so that life-cycle analyses such as those mentioned above might be based on real measurements rather than estimates as much as possible.

Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery. As USLNG exports continue to grow in the years to come, it will become ever more important to have data on GHG emissions during the loading/unloading and transport stages. Little information is currently available on this subject, and we encourage DOE to support actual measurements on a variety of vessels travelling along different routes and unloading at various international terminals.

We appreciate the opportunity to submit these brief comments and look forward to continuing to work with DOE to reduce the GHG and other emissions associated with USLNG exports.

Respondent:

MiQ

MiQ Response to DoE FECM RFI related to Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports

DE-FOA-0003052

Institution name: MiQ

Organizational Background:
MiQ is a not-for-profit organization that certifies methane performance of oil and gas operators. The organization's mission is to reduce methane emissions from the oil and gas sector. MiQ has certification standards for each section of the natural gas supply chain, including liquefaction, regasification, and LNG shipping.

1.1 What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

MiQ has observed that operators and handlers of natural gas throughout the supply chain, each responsible for upstream emissions ahead of delivery to liquefaction fatalities, are leaning on a plethora of technologies and strategies to mitigate greenhouse gas emissions. Methane emissions throughout the natural gas and LNG supply chain represent a very significant opportunity for greenhouse gas reductions. It is clear that the largest, fastest and lowest cost overall option for emission abatement is related to the elimination of methane emissions from the oil and gas supply chain - potentially responsible for half of the well-to-gate emissions.

MiQ has distilled the most impactful activities for methane leakage reduction into the **MiQ Standards for Methane Emissions Performance**, published for each segment of the natural gas supply chain. These standards were developed with extensive consultant, operator, academic, governmental and civil society feedback and represent the best thinking for the prevention of methane emissions available today. These standards for methane performance can be found at www.miq.org/documents.

The essence of MiQ's standards for methane performance across the natural gas supply chain include, but are not limited to, MiQ being a not-for-profit standard-setting organization, public access to the standards, the use of third-party auditors to verify operator performance, steps to ensure that no double-counting of methane performance certificates occurs, and other steps to eliminate conflicts of interest. While other entities and operators may be tracking methane performance, some of these involve self-certification and others use abbreviated verification practices. Self-certification lends itself to doubts regarding the veracity of both process and results. Any verification program that does not use true third-party auditors (auditors that are independent of both certifier and operator and have no financial interest in the outcome of the certification) raises questions about the credibility and effectiveness of the program.

Improved Company Practices and Control Technologies are an overarching tool for methane emissions abatement. These include:

- Workplace Policies and Practices: A fundamental, but often overlooked, ingredient to methane emissions abatement, are low-tech solutions embedded as part of company culture, much akin to workplace safety requirements. These include operator training around the handling of natural gas, enhanced adoption and skillful training of AVO (audio-visual-olfactory) surveys, improved standard operating procedures (SOPs) for handing natural gas to minimize emissions, corporate KPIs and performance tracking, commitment and support by management to reduce emissions.
- Control Technologies: Control technologies, or capital improvements, can also address major sources of methane emissions according to best available science. These include reduction or elimination of flaring emissions (requiring sufficient take-away capacity for natural gas, properly sized and flow-controlled flares with redundant monitoring systems); elimination of hydrocarbon tank emissions through tankless facilities, control systems on all tanks, engineered controls and monitoring of tank thief hatches; reduction of combustion emissions through electrification.

Monitoring that addresses unintended methane emissions (leaks and fugitive emissions, abnormal process conditions, as well as human error or poor adherence to company practices) benefits from enhanced spatial and temporal coverage. However, there is no single solution that works best for all emission types. Certifications or voluntary initiatives that advance a particular type of technology or require continuous emissions monitoring are often pushing an agenda or a particular business plan - and are not focused on the fit-for-purpose frameworks that are now considered a best practice for emissions monitoring and reductions.

- Some very large emissions are intermittent. These, however, may only occur from a few known sources. Therefore, it makes sense to deploy technologies that target those specific sources. It is important to remember not all methane reduction 'solutions' are high tech. Many emission reduction solutions can involve pressure sensing valves, lower explosive limit detection, and frequent and well executed AVOs. Expensive fence line monitoring that acts as a 'smoke alarm' is sometimes only just as effective or reliable than existing process alarms that cost a fraction of the price.

- Some very large emissions are persistent. These may form plumes or are carried to high elevations through vent stacks and are not easily captured during an AVO or OGI inspection. In these cases, facility-scale or site-wide views of an equipment pad using aerial views or gimbled lasers are critical to finding and targeting specific leaks.
- Some monitoring solutions are effective at distinguishing methane slip from exhaust, some are not – reinforcing that there are no single solutions to identify all major leak types.
- It is important to remember that for monitoring to be effective, it must be matched with sufficient operator personnel and reporting tools to follow up and enact on these monitoring reports. With advanced monitoring solutions, many operators find themselves overwhelmed with data and not enough supporting information (SCADA, maintenance report, operational logs, understanding of intermittency or component level ID, relative size of emission) to prioritize findings, follow-up, and determine if the source is still a risk. As a result, sizable resources can be expended on enhanced monitoring. While valuable data is produced this can sometimes result in inadequate emission reductions due to this disconnect. Performance standards that require root-cause analysis (causal analysis) for all detections, record keeping, sensical follow-up protocols, and verification of repair/cessation of emissions should be a key ingredient of any policy that incentivizes enhanced monitoring.

One of the most proactive first steps available to eliminate an operator's methane emissions is to complete a baseline study or a statistical, measurement-informed review of their emissions profile. From this, they might determine what their biggest risks are and work to engineer or remove these sources all together. This strategy can be achieved cost-effectively as part of an operator's monitoring strategy. It involves applying quantitative monitoring solutions, whose accuracy and uncertainty has been defendably determined through controlled release single blind testing, and whose MDL (lower detection limit) is capable of detecting a majority of an operator's emissions.

Carbon dioxide (CO2) emissions from the natural gas production segments, as well as the full life cycle, are largely attributed to (in order): diesel and natural gas engines that power equipment and provide electricity; associated gas flaring; and process and equipment flaring (such as flaring from tank and compressor vent controls, as well as vented emissions sent to flare from blowdowns, completions/workovers/fracking, well testing and drilling). Remaining value chain CO2 emissions are largely contributed to combustion from power generation, followed by flaring of process emissions (blowdowns and controllers for vented sources).

- CO2 Control Technologies – Flaring: Key control technologies for upstream CO2 reductions for the elimination of flaring should incentivize enhanced off-take capacity for associated gas production, followed by development of tankless operations eliminating the need for tank controls and flaring of captured gas. These solutions may be more economical on newer, centralized footprints.
- CO2 Control Technologies – Upstream: Control technologies in the upstream (production and gathering and boosting segments) focus on the reuse of captured natural gas from process emissions. This is followed by the reduction of combustion emissions for power generation (pneumatics, pumps), namely through the usage of renewable microgrids or installation of new electric transmission lines.

- CO_2 Control Technologies – Combustion Sources: Key control technologies for combustion sources, particularly combustion in the processing and transmission & storage segments, benefit from grid-derived electrification. The location of the facilities is easier to access grid-power compared to more disparate footprints in the gathering and boosting and production segments.
- CCUS: Carbon capture in the midstream segments is highly advisable due to high pressures and high CO_2 concentrations, The costs can therefore be relatively low.

1.2 To what extent do exporters request or have access to information about the source (e.g., production basin, transportation pipeline, custody transfers) of the natural gas they are liquefying for export? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means? Do the answers vary by the extent to which the gas is supplied by natural gas marketers or through bilateral contracts?

Typically, gas marketers and procurement desks do not have any information on the provenance of the gas. Such information would need to be requested specifically through and RFP and/or detailed in a bilateral contract. This information is not commonplace on traditional NAESB contracts. While some contracts may request delivery to specific meter points, there is typically no clear information as to where the gas might have been produced. Some RFPs may request gas from specific locations, although this is also not yet common.

A certification program that allows for true life cycle certification can provide that chain of custody that will allow buyers, exporters, and importers to track the source of the gas, as well as the methane performance of each stage of the supply chain. This ability to do life cycle certification (and subsequent tracking) was specifically designed into MiQ's certification standard program.

1.3 To what extent do exporters request or have access to information about the greenhouse gas emissions and/or practices to limit greenhouse gas emissions of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?

- At this time, and in the absence of a life cycle certification program, operators generally have no defendable or credibly audited information regarding greenhouse gas emissions and/or practices for the natural gas they intend to liquefy and export outside of a certification program tied to a registry.
- A credible certification program utilizes an open-source/transparent, auditable and reproducible metric for evaluating methane and greenhouse gas emissions on an annualized basis through empirical inputs; verifies those emissions through an impartial third-party auditor (which means a prohibition of self-auditing of one's own emissions data (i.e., self-certification), or having no financial interest in the outcome of the audit); and lodging the results of that audit on a registry with information regarding the provenance, volumes, vintage, supply chain segments involved, and reference to the metric or standards used to evaluate the data. At minimum, a credible certification that addresses natural gas lifecycle emissions must utilized standard lifecycle assessment (LCA) protocols that acknowledge all possible emissions from that supply chain segment, including from low-producing or marginal wells or low-pressure gathering lines, and that present data on an annualized basis.
    - Some standards evaluate emissions on a well-by-well or day-by-day basis. This is acceptable, albeit excessive for the purposes of LCA accounting, as long as no wells or pipelines within a given basin or facility are omitted from the rolled-up data outputs, and emissions are calculated on an annualized or rolling 12-month basis to properly address the impact of stochastic, fat tail emission events on a full LCA. If this is not the case, this self-selection of facilities qualifies as cherry picking and casts doubt on the veracity of said results and claims.
- Exporters interested in greenhouse gas emissions information should have access to it through certificate registries. Registries are critical for tracking this data from each owner of the attribute or emissions, until the point of retirement.
    - Some emission tracking schemes invoke block chain technology as a necessary ingredient for tracking either emissions or primary data from meter to meter, delivery point to delivery point, or between physical gas owners. A frequent claim for utilizing this type of technology solution is to enhance data security regarding emissions information. However, there is no evidence that emissions data is at any greater security or corruption risk than any other contracted information. This raises questions about the necessity of such an expensive solution. It should also be noted that the risk of passing on incorrect emissions accounting data due to outdated or opaque metrics, or conflicted audits, vastly exceeds the risk of data corruption in a digital registry. It is in this sense, perhaps, wise to keep in mind one of the oldest foundational notions in computer science

– garbage in, garbage out – when one assesses the newest tech solutions, like blockchain, for use in emissions reductions.

- Other options have been explored by LNG operators and natural gas intermediaries. A number of these, however, contain one or more fatal flaws that do not solve the issue of credible emissions accounting - and may also promote greenwashing. Some of these issues include:
  - Use of and/or over-reliance on emission factor-based methane emission calculations and estimates, which result in inaccurate and underestimated emissions inventories upwards of many factors.
  - Use of black box or opaque emission metrics or calculation techniques, thus preventing calibration or auditability by an impartial third party. This calls into question trust by the exporter and end-user.
  - Use of first-party auditors or verifiers who are responsible for collecting the primary data or selling of equipment that generates the data, or that have a financial or reputational interest in the outcome of the verification process. These auditors include auditors employed or contracted by the certifying organization or operator.
  - Desktop audits: Credible emissions verification must be conducted by auditors with an understanding of oil and gas operations and the challenges posed by methane emissions and must be operational audits. Audits that are not operational and consist only of the review of data provided by the operator raise questions about the veracity and completeness of the verification (and auditing) process.
  - Use of LCA models (such as OPGEE, GREET, and NETL) for estimating full supply chain emissions. Short of certified emission attributes tracked from individual operators and combined through a credible registry, LCA models likely represent the only tested and studied, therefore credible, tools for evaluating upstream emission for LNG exports. For these tools to be effective the metrics must be transparent, the inputs or assumptions auditable, the formulations and results calibrated to actual measurements or measurement-informed studies, must be able to uniquely address the limitations and uncertainties associated with both methane and carbon dioxide combustion emissions, and must fully represent or encompass each natural gas supply chain segment. All this said, unfortunately LCA tools rely on statistical averages, assessing only aggregated emissions. They may therefore have high degrees of uncertainty if applied at the operator level. To determine facility-specific emission inventories, operator-specific inputs to the emission source-level and site-level in a fit-for-purpose standard are necessary.

1.4 To what extent do exporters request or have access to information on non-greenhouse gas emissions, including criteria air emissions or hazardous air pollutants, and/or other practices to address other environmental impacts (e.g., strategies to protect water quality or limit water consumption) of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?

See answer in 1.3 – Provided that open-source/transparent, auditable and reproducible metrics are applied, as well as impartial third-party auditors and credible registries are utilized to track and retire attributes for utilized gas - the same opportunity applies to non-GHG emissions as well GHG emissions and other ESG attributes.

1.5 What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?

Certification programs are designed to ensure verification of environmental claims held by the natural gas sourced and exported in the following ways:

- They maintain transparent, peer-reviewed, frequently updated, and calibrated standards to equitably grade performance on GHG emissions and other environmental attributes, from each operator and segment of the natural gas supply chain. Reliable and applicable metrics must:
    - Be auditable by trained and independent third-party auditors.
    - Focus on the biggest opportunities for emission reduction or reduction of environmental impact based on the most recent studies.
    - Be fit for purpose for each segment of the supply chain or types of operating unit.
    - Allow for any use of technology to accomplish the goals, provided that the technology meets certain guard rails in terms of performance as verified by an auditor.
- Represent complete and comprehensive inputs that cover the entire natural gas supply chain, namely in support of complete life cycle assessments (LCAs). This is accomplished provided that:
    - A life cycle assessment covers each segment of the natural gas supply chain, and credibly conveys how the elements (certificates demonstrating methane or GHG intensity) are connected and metered together.
    - Encompasses the entire "facility" boundary – or according to the EPA definition – all contiguous equipment in a given basin or operational boundary that impacts or handles natural gas. This approach eliminates the potential for biased the self-selection - or cherry picking – of a single site or well or portion of a pipeline. Those programs that claim certification may allow for cherry picking if there is a risk that neighboring assets may contribute to the aggregated environmental impact of the gas handled and delivered to the next supply chain segment and create an unenviable emissions profile. Facility-scale certification is consistent with all credible life cycle assessment programs applying to any energy product or fuel. Furthermore, the unique risk to oil and gas systems is that a single well or piece of equipment can pollute the water or atmosphere of the entire basin – therefore it is imperative that 100 percent of the asset must be included in the facility certification.
    - The metrics are stringent enough to provide meaningful assurance to the accuracy of the GHG or ESG claims using best available technology and focus on the biggest risks unique to each segment of the supply chain. These should not be structured to be so onerous that reasonable usage of the metrics is inhibited.
        - For example, measured or empirically-derived emissions inventories such as OGMP level 4/5, that *de facto* require 90% measurement without

appreciation for the risks to a given segment's inventory, provide diminishing returns towards accuracy and assurance. It can therefore serve as an exceptional barrier to entry.

        - Equally, specific measurement or continuous monitoring requirements are not fit for purpose for all emission sources or the supply chain, when calculations or other types of quantification are better applied and done with higher uptake and emission reduction potential.

- A program guide that requires credible and defendable third-party verification of GHG or ESG attributes towards a common standard. Credible assurance or verification means that:
    - Auditors are subject matter experts to the GHG, or environmental claims being assessed, are trained and accredited to the specific standards against which they are auditing. In the case of methane emissions performance and emission reductions, auditors will need to understand (1) the nature of measurement and engineering calculations to inform an emissions inventory, (2) the use of monitoring technologies and their evolving capabilities to directly support emission identification, reduction and verification, (3) the use of cultural norms to impact awareness and attention to reducing methane emissions inside operations, (4) capital improvements to eliminate methane emission sources in entirety and how these address the largest sources beyond regulatory requirements. These skills and backgrounds are especially necessary for the operational audits necessary to provide credible verification practices for emissions performance.
- Work interchangeably with LNG international industry best practices and principles for emission accounting and environmental claims including:
    - GIIGNL.
    - SBTi.
    - Import ETS schemes, where applicable.
    - Address Specific criteria such as tank controls or zero routine flaring to meet import requirements.
- Utilize a registry for environmental attributes to ensure that claims are issued in alignment with the physical gas, the dates/times/locations are properly tracked, that claims are never double counted or double sold, that claims are properly retired upon usage, and that book and claim systems do not irresponsibly transfer between localities or natural gas grid systems without properly accounting for full life cycle assessments.

1.6 What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?

To our knowledge, as of the date of this RFI submission, there are no credible certification programs being enacted yet in LNG. Some press releases indicate that non-credible certification programs have applied to LNG deals. These should be disqualified due to a combination of opaque metrics, conflicted or first party audits, greenwashing or the use of inaccurate and mis-represented life cycle assessments by allowing cherry picking of certain assets.

Many LNG operators have expressed interest in adopting existing certification programs that do meet the principled criteria found in Question 1.5, above, to support their export goals. For LNG operators and natural gas buyers exporting to Europe, their priorities from certification include:

- Understanding of full GHG profiles of a given cargo of natural gas.
- Understanding of full supply chain GHG and environmental impact, with a focus on production as a priority followed by other segments.
- Use of measurement-informed metrics for assuring accuracy of GHG and methane emissions accounting.
- Addressing key sources of methane emissions such as no-routine flaring of associated gas and hydrocarbon tank controls.
- Address environmental impacts associated with unconventional or fracked natural gas.

1.7.a What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas?

Certification programs in the US provide a foundation for a US competitive advantage for the following reasons:

- GHG emissions from natural gas associated with certain oil-rich systems, as well as coal-bed methane, carry with them the perceptional or real risk of being high emitting – potentially to the point where natural gas scope 1, 2 and 3 emissions are worse than the burning of coal. This undercuts the argument regarding the sustainability benefits of fuel switching – especially from gas exported overseas. Certification of actual, empirically derived emission reductions for natural gas for the comparative analysis of other black, brown or green fuels helps support carbon reduction and goals, particularly from high-risk natural gas producing basins.
- Other environmental impacts from unconventional shale gas or hydraulically fractured gas brings with it actual or perceptual risk in importing regions overseas. Certification of ESG attributes such as water and land usage protections would alleviate concerns around environmental damage from shale gas development. Equitable Origin's certification program credibly captures these attributes. Similarly, a number of operators use joint MiQ and Equitable Origin certification to capture a suite of environmental attributes.
- Regulation and/or emissions reporting inside the US for GHG emissions accounting is often voluntary, self-enforced, not required for smaller operators, and varies depending on the state or provenance. LNG buyers may have little confidence in the environmental integrity of gas sourced from the US based if they are looking to regulatory compliance alone, due to uneven requirements across jurisdiction and the lack of third-party verification (i.e., the preponderance of self-certification programs). Certification programs with credible third-party audits, transparent standards, and provisions to disallow conflicts of interest provide the consistent, standardized and verified extra-regulatory assurance on an operator-by-operator and basin-by-basin basis.
- Some dry gas producing regions in the US have near-zero methane risk due to the nature of the producing geology. Certification programs could validate these total emission claims against transparent standards.
- Certification programs that specifically address and verify zero routine flaring and hydrocarbon tank emission controls would secure access to various EU countries or gas buyers with such requirements.
- Credible, supply-chain certification will provide life cycle emissions verification that can be used for importing programs such as the European Union's Carbon Border Adjustment Mechanism (CBAM). The summed methane intensity can provide, in this instance, European regulators with certainty as to the amount of [carbon] tax that should be levied.
- While European methane emission reduction policies are still under negotiations, there is a likelihood that monitoring requirements will be adopted for all LNG imports into

Europe. Only certification undertaken on a supply chain basis can provide the life cycle emissions profile (or report) that would provide assurance to European regulators. Reporting frameworks – like OGMP 2.0 – are not structured to provide methane emissions life cycle reporting on an LNG shipment-by-shipment basis. OGMP 2.0 provide company-wide reporting, and not the facility-level reporting necessary to satisfy potential EU reporting requirements. Similarly, OGMP 2.0 is not structured to allow for life cycle emissions summation and reporting. Other programs that posit to track emissions for LNG cargoes consist of self-certification and inferred emissions attributions that may not be representative of the actual emissions profile (on a true-life cycle basis) of a given cargo. Such programs do not yield the transparency or provide the credibility to satisfy potential European reporting regulations. Only a transparent certification program that has a publicly accessible standard, is structured to engage life cycle certification, uses independent third-party operational auditors, uses a digital registry, and certifies on a facility-basis can provide credible emissions monitoring that would satisfy potential regulatory import requirements. Finally, European regulators would presumably want a standardized approach to emissions reporting for LNG imports in order to avoid receiving a patchwork of reporting frameworks. U.S. policymakers could respond to this by requiring LNG exports to utilize a consistent set of monitoring, measurement, reporting, and verification (MMRV) criteria. Such criteria, however, should not be established at the 'lowest common denominator' framework that would encompass all U.S. certification or reporting programs – that would eliminate the utility of a credible (and usable) certification, reporting, or MMRV system. Instead, only certification/reporting/MMRV programs that encompass life cycle certification, uses independent third-party operational auditors, uses a digital registry, and certifies on a facility-basis should be promoted by FECM and other policy-makers. Programs that rely on self-certification, or that may be subject to conflicts of interest should not be included in any such U.S. program.

1.7.b Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

Yes, certification program that recognize at least a yearly GHG accounting metric and stringent up-front ESG evaluation metrics may help assert expected GHG and ESG claims for a long-term operating asset. Contracting details for physical gas that allow for flexibility (such as minimum requirements) and recovery mechanisms (such as compliance windows, penalties, or replacement with equal graded gas) with the change of a performance grade, GHG intensity or boundary definition, provide an easy solution to long term physical transactions – and are currently being enacted.

2.1 What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?

MiQ encourages the FECM to review the **Subsidiary Document 2: Company Practices' section** of the MiQ Standard for LNG: liquefaction and regassification. Below is a summary of strategies and tools to reduce methane emissions at liquefaction facilities:

Mandatory General Practices Applied to All Operations from the Natural Gas Supply Chain.

- Operations staff receive annual training that emphasizes the importance of eliminating methane emissions, eliminating or modifying the equipment most likely to leak, identifying signs of methane emissions (including Audial, Visual, and Olfactory (AVO) observations) that may indicate a problem, logging and reporting methane emissions for purposes of annual methane emissions calculations, and taking actions in the event of an observation.
- Operators enact a reporting system accessible to all staff to report methane emissions related to observations or incidents, including those related to incomplete combustion. Such a reporting system contains recordkeeping guidance details for when methane emissions are detected outside routine LDAR inspections and outlines the chain of command and notification processes.
- Operator enacts guidance for measurement methods and calculation of methane emissions.
- Operators enact zero-venting policies and procedures.
- Operators enact a Health, Safety & Environment (HSE) communication plan that includes methane emissions reduction best practices, such as educational material or an emissions incident bulletin program.
- Operators enact a preventive maintenance process, carried out at regular intervals.
- Operators embrace KPI metrics for methane emissions (such as Methane Intensity) that is tracked for the facility and regularly communicated with the staff.
- Operators implement a measurable and actionable methane emissions reduction plan, which may include progress indicators, evaluation of abatement potentials, and cost-free best practices.
- To the extent possible, generation of substantially all electricity on-site, and that imported or purchased electricity used by the facility is generated from renewable sources.
- Operator develops a complete methane emissions profile overview of the facility, which includes a distribution of measured sources and history of failures or super emitting events.
- An operator or third-party vendor conducts Leak Detection and Repair (LDAR) method-specific trainings for Method 21 or Optical Gas Imaging (OGI) or equivalent or alternative program, including proper use of instruments or camera, instrument calibration, and inspection methods.
- The LDAR plan for source-level emissions outlines:

    - The specific equipment and/or components included in the survey (which must include process valves, connectors, compressor seals, open-ended lines, meters, pressure relief valves, regulators, and pneumatic controllers).
    - Leak definition.
    - Monitoring methodology (reference to equipment, frequency, conditions, reporting log).
    - Equipment repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted.
    - First attempt requirements within 24 hours of detection, repair within two weeks and follow up repair verification.
- Directed inspection and maintenance procedures target major equipment (i.e., PRVs, vapor recovery equipment, gas-powered compressor vent sources, flare stacks) and collect cumulative data to develop preventative maintenance and targeted inspections for source based on accumulated historical data.

Strategies for Methane Emission Reduction specific to Liquefaction Facilities

- Operators manage methane emissions from tanks by having policies and procedures in place that address methane emissions during all stages of tank use, including LNG entering tanks, LNG stored in tanks, LNG removal from tanks and maintenance and inspections of tanks. These not only include observation for methane emissions but also require preventative maintenance based on historical problems (including, for example assignment of identification numbers and records on specific problem pieces of equipment).
- Tank monitoring addresses key areas that may be a source of methane emissions including vapor/BOG recovery systems connection points, and pneumatic controllers, as well as contain tank pressure monitoring systems and alarms, and automated tank gauging and reporting.
- To manage fugitive emissions specific to liquefaction components, operators may choose to install reduced-leak connections and components across a minimum of 100 percent of the relevant components or equipment at the facility, such as extreme weather-resistant connections, flange washers with increased elasticity in the bolting system, low-temperature and temperature-fluctuation resistant joints and equipment, gaskets resistant to extreme temperatures, below 75°C, such as flexible graphite and polytetrafluoroethylene (PTFE), or low-emission valves and controllers, such as leakproof cryogenic thermal insulation valves, process control valves, compressor anti -surge valve, or zero-emission pressure relief valves.
- Operator can reduce blowdown (of methane emissions) by enacting policies and procedures for the removal of natural gas and LNG from equipment or systems scheduled for repair to the greatest extent possible minimizing the amount of gas flared, while maintaining safe operations.
- Operators can implement the following practices when returning equipment to service: Address purging the equipment of air prior to restoring operation while minimizing natural gas emitted and gas flaring during purging operations; and, To the greatest

extent possible, use natural gas vented during blowdowns for productive purposes or route it to storage vessels or to a flare to minimize methane emissions.

- Alternatively, an operator might implement automated LNG facility start-up processes to eliminate blowdown emissions or implement policies and procedures under which no gas from facility blowdowns is flared and all gas is used productively.
- Operators utilizing natural-gas-driven pneumatic devices should implement procedures to maintain an accurate inventory of pumps and controllers that is checked annually, at a minimum, and implement policies and procedures to ensure controllers are operating as designed (based on type of service (on/off, throttling) and type of venting (continuous or intermittent)) according to industry equipment standards, and ensure that devices are included in regular inspections in the LDAR plan as emission sources.
- Ideally, operators install non-venting (i.e., no-bleed, electric, mechanical, or instrument air) pneumatic controllers, engines and pumps in place of gas-driven pneumatics for at least 95 percent of the Inventory.
- To prevent venting from compressors, operators should replace natural gas reciprocating compressor rings on a fixed schedule based on run hours unless the vent gas is re-routed to be either recovered or flared, minimize starts and stops from compressor gas starters, have evaluated controls to address compressor seal methane losses, replace all wet seal centrifugal compressors with dry seal centrifugal compressors with nitrogen loop or dry seal centrifugal compressor with vent line recovery, scheduled upgrades for reciprocating compressor packing cups, rings, gaskets, rods as part of the preventive maintenance.
- To prevent emissions from flaring, operators should limit flaring to events such as maintenance, startup, shutdown and emergencies, plus other tightly-defined events, with defined duration limits for each. All flaring must implement procedures that define stable operating ranges for applicable criteria (i.e., combustion zone net heating value, flare gas velocity), considering emergency events, to promote good combustion efficiency, ensure flares are managed and maintained to ensure flare functionality. Flares must be targeted during LDAR surveys, and good combustion efficiency should be achieved through the utilization of staff or consultants for inspections (AVO and engineering & maintenance inspections).
- Operators should have measurable and actionable plans in place to reduce the amount of natural gas that is flared, for example via installation of additional flare gas compression capacity, and have flaring systems installed that have design elements that account for ambient conditions and gas composition to maximize combustion efficiency, as well as have installed flow meters with a maximum uncertainty of 7 percent (as required by the EU-ETS) on flares.
- Operators can manage flare functionality through control and engineering design such as the use of SCADA systems and logic controllers to monitor flare ignition or thermocouples (temperature sensors) to ensure pilots stay lit or flame out, have detection devices installed, use of auto ignition system, or systems to provide checks on flare capacity such that production levels are maintained to ensure the flares' combustion efficiencies match range of production and do not overload.

- Operators should also install a closed flare or be able to justify that ambient conditions do not require a closed flare to reach sufficient level of combustion efficiency (including factors such as wind and precipitation conditions and gas composition).
- Operators can manage fugitive emissions from the combustion of fuel in on-site power generation by installing reduced-emissions infrastructure, including catalytic converters for gas-driven engines that reduce methane emissions, or implementing engine design features to improve combustion, such as placing the exhaust recycling structure close to the engine or reducing crevice spaces and cool areas to avoid unburnt methane.

(For details on emission reduction strategies for loading and unloading, see section 3.1 below).

2.2 In addition to published data sources such as EPA's Greenhouse Gas Reporting Program and Greenhouse Gas Inventory, are there other data and information available on identification and location of point sources of greenhouse gas emissions within liquefaction facilities?

MiQ recommends the following published metrics be evaluated in line with some best available understanding of emission sources for liquefaction facilities, including:

- Marcogaz (2019). Assessment of methane emissions for gas Transmission and Distribution system operators. Retrieved from www.marcogaz.org/publications/assessment-of-methane-emissions-for-gastransmission-distribution-system-operators/.
- GTI Energy. (2022). GTI Energy Methane Emissions Measurement and Verification Initiative. Retrieved from https://www.gti.energy/veritas-a-gtimethane-emissions-measurement-and-verification-initiative/
- Oil & Gas Methane Partnership 2.0 (2022). Technical Guidance Documents. Retrieved from https://www.ogmpartnership.com/templates-guidance
- American Petroleum Institute (API) Compendium of Greenhouse Gas Emission Methodologies for the Natural Gas and Oil Industry, 2021
- American Petroleum Institute (API) (2015). Liquefied Natural Gas (LNG) Operations: Consistent Methodology for Estimating Greenhouse Gas Emissions, Version 1.0
- Rabeau, P., Paradowski., H., Jocelyne Launois., J. HOW TO REDUCE CO2 EMISSIONS IN THE LNG CHAIN, retrieved form http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2007/fscommand/PS2_7_Rabeau_s.pdf

2.3 What methodologies do operators use to estimate and measure greenhouse gas emissions at liquefaction facilities?

Development of an accurate methane or GHG emissions inventory from a liquefaction facility must take into account both known sources as well as unknown or unintended sources. This is especially true for methane emissions, where estimation techniques may suffer from outdated or inaccurate emission factors and measurement techniques are still evolving in terms of accuracy, understanding of intermittency, and how best to be applied. MiQ's research and involvement in stakeholder-composed methane research working groups suggests that some emission sources are best calculated using primary data inputs and facility-specific engineering calculations, which may be based on component- or equipment-level measurement; while some sources are more difficult to estimate and may need to more heavily rely on measurement. In all cases of inventory development, however, an operator must recognize the impact from "fat tail" emission sources – which often include the unexpected, unintended emissions from abnormal process conditions (such as for flares or storage tanks) or failure to comply with best operating procedures (such as with blowdowns). These unexpected or unintended emissions would naturally exceed facility-specific estimates and potentially equipment-level measurements and may only be realized during monitoring campaigns.

For liquefaction facilities, MiQ encourages FECM to visit Subsidiary Document 1: Methane Intensity in our MiQ Methane Performance Standard to see how MiQ's standard provides guidance on the development of a reconciled inventory. Table 3 in Subsidiary Document 1 of this standard contains a detailed list of methane emission sources and the minimum calculation requirements for each to create a baseline emissions inventory. The assumption is that all detected emission events from advanced LDAR and monitoring surveys are incorporated into such an inventory and their emissions quantified using best available information.

For any measurement-informed emissions inventory, MiQ recommends a measurement strategy that describes how an operator uses direct measurement and indirect measurement data to inform the methane emission inventory and methane intensity estimate. The measurement strategy must define how measurement informs operator reporting of emissions. This should consider the appropriateness of the selected technology's MDL, the representativeness of sites monitored, and the variability of emissions over time including how monitoring frequencies affect assumptions made.

2.4 Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?

Only a limited number of published studies have been conducted at liquefaction facilities in terms of source-level methane measurement and regarding abnormal process conditions informing methane emissions and their contributing sizes. However, based on best available understanding of the equipment involved in a liquefaction plant and the associated process of loading and unloading onto vessels, the following emission sources potentially exhibit the greatest risk: Methane slip from combustion; Unlit or poorly combusted flares; Leaks from compressor units or flanges, connections, meters; Large vented releases from blowdowns. Due to the high-pressure environment of liquefaction facilities, small, pressured fugitive emissions or equipment leaks are not as easily missed as they might be in a low-pressure setting upstream.

In all cases, but especially regarding facilities such as liquefaction units, advanced monitoring technologies should be the last line of defense for identifying leaks, and instead should be preceded by existing solutions such as redundant flare controls, frequent LDAR surveys for hygiene purposes, installation of LELs and CEMs, engine stack testing, directed inspection and maintenance targeting PRVs, vapor recovery equipment, gas-powered compressor vent sources, and flare stacks.

Advanced monitoring technologies, however, have the potential to drive a significant understanding of emission risks in a liquefaction facility and are subsequently being implemented today in the following ways:

- Conducting detailed measurement-based emissions inventory – quantitative (indirect measurement) drone-based or fixed gimbled lasers with low MDLs are proving to be very helpful at evaluating and cataloging liquefaction facility emission profiles.
- Auditing or confirmation of major process leaks – some airborne surveys over LNG facilities (liquefaction, loading, shipping) have identified large emissions, likely associated with blowdowns, boil off or LNG transfers. Such enormous, fat-tail emissions are a high risk and audits could be implemented frequently to evaluate and confirm improved practices and the handling of LNG cargoes.
- Operator conducted LDAR (enhanced AVO) such as handheld acoustic sensors or TDLAS. Vendors and operators claim this allows a quick and easy way to conduct inspections in-house during routine shift inspections. When coupled with appropriate recordkeeping, follow-up, and repair procedures, these practices can lessen the duration of a given leak between formal LDAR surveys.

3.1 What technologies or strategies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?

MiQ encourages the FECM to review the **Subsidiary Document 2: Company Practices' section** of the MiQ Standard for LNG: liquefaction and regassification. Below is a summary of strategies and tools to reduce methane emissions during the loading and unloading of natural gas:

- Operators have processes in place for loading/unloading operations to be carried out according to best industry standards and regulations. These include monitoring methane content in loading and unloading lines, and ensuring that loading and unloading lines contain minimal amounts of LNG before disconnecting transfer equipment, having procedures in place to minimize methane emissions during loading and unloading operations and transfer starts and transfer stops, policies and procedures to limit methane venting to the concentration limit set by the relevant port authority during the gassing up of a LNG tanker, having procedures to limit vapor generation during normal vessel operations with regards to the design limit of boil-off gas compression equipment (i.e. initial cool down procedures, loading rate procedures), monitoring methane content until the concentration lowers to <10,000 ppmv, and using an approved monitoring methodology during loading and unloading.

3.3 What approaches do LNG operators use to minimize greenhouse emissions during tanker transport of LNG?

LNG Shippers currently are currently not incentivized to minimize GHGs, instead prioritizing on financial benefits and safety. MiQ encourages the FECM to review the **Subsidiary Document 4: Estimation of Methane Intensity for LNG Shipping** of the MiQ Standard for LNG for a better understanding of methane emission risks and reduction strategies for tanker transport of LNG.

Research has shown that the most significant source of methane emissions of the LNG shipping fleet is methane slip during combustion of natural gas in vessels' main and auxiliary engines. This is especially the case for LNG carriers with dual-fuel engines whose design is typically adapted from liquid marine fuel use. As a function of their design, therefore, certain engine types exhibit much higher methane slip than others. While engine designers and manufacturers have been working hard to reduce methane slip in recent years, the overall fleet retains a large proportion of older designs. Engine type, therefore, will continue to be a key indicator of the level of methane emissions resulting from the ocean transport of LNG cargoes. This is an achievable outcome as it is known that certain engines have lower methane slip than other engines, see Annex C of MiQ Standard for LNG for more details.

Other potential sources of methane emissions on ships include the venting of boil-off gas and leaks. Classification rules for LNG carriers generally require at least two methods to 'use' boil-off gas. Methods include using the LNG (in gaseous form) in the ship's engines to provide propulsion, to re-liquefy it, to 'waste' the surplus gas either by creating additional steam and dumping it, or by combusting the gas in gas combustion units.

While the technical aspects of the LNG carrier largely determine the rate of emissions, the length of the voyage (in terms of both duration and distance) determines the *period of emissions*, i.e., the period over which the rate of emissions persists. All things equal, the same LNG carrier will emit more methane over a longer voyage that a shorter voyage. There are some subtleties to this generalization (for example, vessel speed, which itself is a function of voyage duration and distance, will impact the rate of emissions – a higher speed may be more efficient, resulting in lower methane emissions per nautical mile), but this simplified view may be helpful to understanding the key determinants of emissions.

The LNG cargo may also remain on the vessel longer due to financial incentives. Examples of this could include a longer shipping route for delivery to a higher priced market or floating the vessel to wait until a higher priced period during the winter months. In some instances, there may even be reloading in some ports due to contractual constraints. For example, if a seller is contracted to deliver to a certain point and this cannot be changed, then the buyer may reload it onto another vessel to then send it to another region for sale there. The additional loading and unloading, as well as the additional voyage all lead to more emissions. Over one third of the LNG market is spot or short-term trading. The main goal, therefore, for these shipments is how to get extra financial value - not GHG management, nor even security of supply.

If the LNG trading was centered on shorter journeys (i.e., exporting markets supplying the nearest importing markets) there would be a resultant decrease in emissions. This, however, is not how the LNG market works.

3.4 For contractual agreements that include the transport of LNG, what measures, if any, are taken to assure natural gas is not lost and greenhouse emissions are minimized during shipping?

See response to 3.3, above. If every producer of LNG shipped LNG to their nearest markets – therefore creating shorter shipping routes - then we would have significantly lower emissions.

Contractually a volume plus or minus a percentage has to be delivered or there is a breach of contract. For example, a contract that specifics, 3,800,000 MTPA +/- 3%. This approach would prevent a large amount of forced boil-off for fuel. Many vessels have reliquefication on board to allow for boil-off gas to be reliquefied. However, the process of reliquefying the vapor takes a lot of energy to cool the gas back down to minus 162C. This, in and of itself, is a significant use of energy (and subsequent emissions) – as liquefaction is not occurring at scale. If the operator is trying to reduce the loss of LNG this would increase the usage of fuel oil to power the onboard liquefaction.

Contractually different regasification terminals where the cargo is being delivered have different chemical composition specifications in the contract. Some import terminals have blending facilities that can be used for a cost for gas that may not meet grid requirement. Some countries, however, have no blending facilities, consequently these import terminals have narrower LNG specifications that must be met. Too much boil-off or loss of LNG is likely to change the chemical composition of the LNG cargo. This could potentially make the LNG off specification for that facility, and thus out of contract. This would result in financial penalties and reputational loss, not to mention additional emissions if the LNG must be transported elsewhere.

As an example of regional specifications, please see the table below for requirements in Greece (https://www.desfa.gr/en/regulated-services/lng/users-information-lng/quality-specifications).

LNG Quality Specifications

Value	Unit	Specification	Notes
Wobbe Index	KWh/Nm^3	13.066-16.328	
Gross Calorific Value (GCV)	KWh/Nm^3	11.131-12.647	The Operator may consider the possibility of accepting a cargo with GCV in the range 11.011 KWh/Nm^3 to 11.131 KWh/Nm^3 or 12.647 KWh/Nm^3 to 12.986 KWh/Nm^3, if after unloading this cargo and mixing with the stored LNG in terminal tanks, the GCV of the resulting LNG will be within the mentioned range.
LNG Density	Kg/m^3	430-478	The Operator may consider the possibility of accepting a cargo in the range 420.3 Kg/m^3 to 430 Kg/m^3 or 478 Kg/m^3 to 483.1 Kg/m^3, if after unloading this cargo and mixing with the stored LNG in terminal tanks, the Density of the resulting LNG will be within the mentioned range.
Molecular Weight	Kg/Kmol	16.52 - 18.88	
Methane	% mol	85.0 min 97.0 max	The Operator may consider the possibility of accepting a cargo with Methane concentration in the range 80 to 85 [% mole] or 97 to 99.8 [% mole], if after unloading this cargo and mixing with the stored LNG in terminal tanks, the value of Methane concentration of the resulting LNG will be within the mentioned range.
i-Butane & n- Butane	% mol	4 max	
i- Pentane & n-Pentane	% mol	2 max	
Nitrogen	%mole	1.24 max	
Hydrogen sulfide (H_2S)	mg/Nm^3	5.0 max	
Total sulphur	mg/Nm^3	30.0 max	
Temperature	^oC	-158 max	The average temperature of LNG in all tanks of LNG vessel before discharging should not be greater than -158^oC. For LNG temperatures higher than -158^oC the method KMK, for the calculation of LNG density, is not valid.

It would be a very simple addition to include one more line to the quality specifications requirements in an LNG contract, so as to include a line on methane management requirement, methane/CO2e intensity, and/or MiQ grade.

4.1 What non-US requirements for greenhouse gas performance are LNG exporters being asked to respond to with emissions data? Are emission reduction requirements included in any contracts or other importing country requirements?

For US LNG exports, European regulations on methane emissions are the important demand drivers. Although other regions are working on similarly-framed MMRV approaches and methane reporting requirements, the European Parliament is due to pass new legislation on methane emissions this year. These would come into force from 2026. The anticipated regulation would be applied to operated assets within the EU, along with imported gas from other countries. Legally-speaking, it is required that the same rules be applied to production as well as imports so that there is no discrimination between the two.

The proposed EU regulation is a prescriptive or qualitative framework, much like the Company Practices and Procedures 'pillar' in the MiQ Standard (one of the three MiQ standard elements). Policies include MMRV, LDAR, routine flaring, and venting.

Following passage of the European regulations, the introduction of an additional regulation to include methane intensity targets may be necessary. These would work alongside the prescriptive regulation. Work on how this could be implemented is underway. That said, methane intensity targets are already working their way into long-term LNG contracts from a European demand side. Given LNG contracts can be created for 20-year terms, we have heard from large European buyers that they are asking for methane intensity restrictions for upstream to be included in contracts from US LNG producers. The OGCI target of 0.2% methane intensity-unallocated (MI is an example of a target being added to long term contracts that would restrict new LNG projects to only use independently certified upstream gas for their liquefaction with a MI of 0.2% unallocated or lower only. Per this example, the end buyer in Europe can be sure they are not creating upstream demand for poor operators in the US. For all reporting requirements it is essential to include and consider emissions for all sections of the supply chain. Given the variation of MI in the US (see MiQ-Highwood Index here) there is a MI limit that can be easily included in contracts concerning the upstream segment. Note MiQ applies the appropriate allocation of emissions to the natural gas phase to calculate methane intensity.

GIIGNL have published MRV and GHG Neutral Framework for the LNG industry (created alongside the LNG industry, who are its members). It requires parties to disclose and share carbon and methane emissions for each section of the supply chain if carbon neutrality is to be claimed. It requires verification for each set of reported GHGs and shares practices for achieving the reported GHGs. To claim carbon neutrality an emission reduction plan is also required. The GIIGNL Framework is a good guideline, but it is not a standard. The standard or methodologies used needs to be stated in the GIIGNL Framework along with the verification.

4.2 What changes or technology advances does industry think are needed to decarbonize the LNG supply chain from production through delivery? What are the economic benefits or challenges associated with the measures to decarbonize the LNG supply chain? Is there data or information available on the costs or savings associated with implementing these measures?

The answers to questions 1.2, 2.1, and 3.1, above, dig deeper into technologies and strategies to "mitigate" greenhouse gas emissions, particularly methane from the LNG value chain. It needs to be underscored that these often low-tech, cultural and procedure-based strategies address the low-hanging fruit that could be implemented today at zero or net-negative costs, according to the IEA marginal abatement cost curves and other studies such as the EPA natural gas star program.

Unfortunately, these solutions do not address the root of the emission sources. True decarbonization of the natural gas value chain will require capital investment in gathering infrastructure, electrification, and marginal well abandonment. The following elements represent the heart of decarbonization, as well as opportunities for federal support for the lowest possible emissions natural gas.

- One of the greatest activities that could be undertaken to decarbonize the LNG supply chain would be to address the emissions from associated gas. Increased take-away capacity and the installation of tankless facilities would eliminate the need for flaring – impacting both the methane and CO2 combustion footprint from gas derived from oil producing basins. The cost, however, of installing take-away gathering systems for associated gas is not trivial. Potential cost levers such as the IRA methane fee, cost-sharing, or DOE loan programs for installing take-away capacity, or mitigating marginal wells, is recommended.

- Low-producing or marginal wells account for a higher rate of methane emissions compared to their higher volume counterparts. Smaller producers do not currently have an economic (or in many times regulatory) incentive to improve emissions performance from vintage production equipment or older wells. Financial incentives to reduce emissions, through hydrocarbon tank controls, or even P&A activities from these riskier assets, should be incentivized.

- Incentivizing electrification for power needs addresses both CO2 combustion sources, as well as the risk of methane slip identified during enhanced top-down measurement campaigns. The cost of electrification, high with longer payback periods (particularly for midstream operators). Such control technologies would greatly benefit from DOE loans or cost recovery programs, or shared financial risk for electrical transmission development.

- Emissions associated with low pressure pipeline leaks (gathering and distribution), equipment leaks, thief-hatches on hydrocarbon tanks, or unlit flares, greatly benefit from advanced monitoring techniques, particularly those with vantage points capable of detecting high elevation plumes. Payback for enhanced LDAR deployment is expected to net positive according to the EIA. DOE FOA 2616: Innovative Methane Measurement, Monitoring and Mitigation Technologies may help build an understanding of which sources must be monitored, how frequently and what the emission reduction opportunities would be. Access to federal cost-sharing mechanisms would enable greater access to enhanced LDAR deployments.

Certification is also considered to be a low-cost and rapid payback opportunity for operators intending to differentiate their product.
Costs to certification include (1) performance an analysis of an operator's methane and GHG performance to a standard (2) hiring a third party, subject matter expert, (3) issuing and transacting certificates on a registry, are expected to be incredibly low and not a barrier to entry.

- Based on operator feedback, the most resource intensive component of certification is the use of operational personnel to evaluate their emissions inventory, company practices and procedures against a standard, and ingest new emissions data from advanced technology solutions. When a US operator simply intends undertake an audit of their emissions performance ***as is***, they might expect a 0.5FTE effort over 2-3 months to gather documents, emissions accounting data, as far as they have been compiled for regulatory efforts, and an additional support (80 hours total) from operators, managers, air compliance teams over an approximate 1 week period to support an onsite audit and interview process.
- If an operator seeks to achieve a higher performance grade by improving their monitoring practices, emissions accounting program to include measurement, enhance training and internal emissions tracking solutions, as well as update and advance standard operating procedures, they might expect a 2.5 FTE effort over 4-6 months to implement improved inhouse solutions.
- If an operator seeks to incorporate advanced monitoring technologies to enable better emissions data collection or a measurement-informed inventory, they might expect an additional $100K or more in the first year for baseline analysis. It should be noted that upstream advanced LDAR costs are anticipated to have a net-negative cost to implement.
- Registry costs are intended to be as low as possible to enable credible issuing, tracking and retirement of attributes, working out to a model average of $20K USD per operating facility or $1/20^{th}$ of a US cent per MMBTU.
- Additional capital improvements to install vapor capture units and tank controls, redundant flare monitoring systems, no bleed pneumatics are also anticipated to have a net-negative cost to implement, according to the IEA.

4.3 Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?

MiQ recommends the following information be considered for assessing emission reporting and reduction frameworks, and ultimately achieving emissions reductions: The temporal and spatial gaps in pending U.S. regulatory programs; The need for a transparent and credible certification and reporting system; Auditor qualifications; Cost considerations. These are discussed in more detail, below.

Pending U.S. Regulatory Programs for Methane Emissions Reductions: A number of federal regulations that are intended to reduce methane emissions have either been proposed (EPA Supplemental Proposed Rules; DOI BLM rule; DOT PHMSA rule) or are being developed (the Inflation Reduction Act's (IRA) methane fee). While it is assumed that these regulations may be effective, they collectively suffer from temporal and spatial issues in terms of implementation. For example, EPA's Supplemental Proposed Rules will affect regulated interests on different time scales. Regulations will go into effect for 'new facilities' or equipment – constructed after November 2021 – 60 days after publication of the final rules. The vast majority of facilities or equipment is considered existing. These facilities are subject to regulation only after EPA has approved state implementation plans modified to the new rules. Approval of these plans can take place up to 4.5 years after publication of the rules. With regards to the proposed IRA methane fee, it only applies to larger emitting facilities – i.e., those that emit more than 25,000 mtCO2e/year – and will be implemented for those facilities at methane intensity levels greater than 0.2%. Therefore, the methane fee will not apply to any smaller emitting facilities, or to large facilities that are emitting at levels of 0.1999% or below. This leaves a sizable number of emission sources untouched by the methane fee – even though it is known that smaller facilities can be major sources of methane emissions.

As a result of the temporal (time for regulations to be implemented) and spatial (set of entities subject to regulations) gaps in regulations seeking to reduce methane emissions, a response is needed on a much shorter time schedule to address methane emissions. Certification – if done effectively, credibly, and transparently – can provide that short-term solution that can dramatically lower methane emissions very efficiently. As a result, methane performance certification serves as an effective – and needed – bridge to methane (along with other greenhouse gases) emissions reductions before regulations are effectively and comprehensively implemented. Also, certification – being a framework that relies on market incentives – can operate concurrently as regulations. For example, a certification program like MiQ grades a 0.2% methane intensity at a grade of C. This means that operators that are not subject to the methane fee could be rated at A or B grades. This means that there are market incentives for these operators to improve their performance – even at the same time that they are not subject to the methane fee. In other words, an operator who has a methane intensity of 0.1999% is not subject to the IRA's methane fee, and in the absence of a voluntary market certification system, will have no incentive to improve performance. Participation in a certification program will provide the incentive for that operator to lower emissions from that 0.1999% level in order to gain (or not lose) market share.

Importantly, MiQ is already certifying nearly 20 percent of U.S. domestic onshore gas operations. All of these certifications have been graded at methane intensities of A (<0.05%), B (<0.1%), or C (<0.2%). Because of this, the United States already has a first-mover advantage of credible methane emissions intensity MMRV (via MiQ certificates) that can be leveraged to export low emission U.S. natural gas overseas (simultaneously gaining market share, as well as replacing higher emissions intensity fuels.)

A Credible Certification Program: Where a certification program for methane performance has the potential to drive down methane emissions, it must be considered credible. This credibility provides assurance to regulators and the public that emissions goals are actually being achieved, and to investors, the financial community, gas buyers, and the oil and gas sector that the attributes included on the certification are actually real. FECM and other state and federal agencies can take steps to ensuring that certification – or MMRV programs – are, in fact, credible. To this end, FECM should develop criteria for an LNG MMRV that results in credible methane intensity reporting. In a similar vein, FECM should not apply the lowest common denominator for an LNG MMRV framework. To do so would erode the credibility of certified gas, generally – and harm the potential competitive advantage of US LNG exports specifically.

A credible methane performance certification program must have the following elements:

1. A transparent and publicly accessible standard. All parties should be able to access the certification standard at any point in order to ascertain how a certification or grade was conducted.
2. Facility-wide certification. Certification must include all wells and equipment in an operating basin or sub-basin. MiQ utilizes EPA's definition of facility in CFR Title 40, Chapter I, Subchapter C, Part 98, Subpart W, Section 98.238 whereby 'a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in a basin would be considered one facility.' The certification of a sub-set of wells or equipment in a facility is cherry-picking and creates confusion for the market, regulators, and other stakeholders as to what is actually being certified, and to what the stated methane intensity actually refers to. In a similar vein, the use of only a company-wide methane intensity is unsatisfactory as this is not the unit of analysis on which gas trades are actually made, along with a company-wide methane intensity can mask a very poorly performing facility within a company's portfolio by the better performance of another company-owned facility. Certifying at the facility-scale eliminates the problems with both individual well certification (cherry picking) and company-wide reporting.
3. Monitoring technology considerations: The certification organization should not sell or provide monitoring equipment. This creates a conflict of interest. A certification entity should allow for the use of technologies chosen by an operator in order to allow for fit-for-purpose monitoring. However, these technologies must have undertaken performance testing and have been approved by a testing entity, such as Colorado State University's Methane Emissions Technology Evaluation Center (METEC). A certification

organization should also not specify which monitoring technologies are used in order to not lock in a particular technology and inhibit future technological innovation.

4. Third-party auditors: Operators should be audited against a certification standard by third party auditors. These auditors should have no contractual or employment relationship with either the certifier with regards to the certification. They should also have no financial interest in the outcome of the certification. Audits should also be operational audits and include verification on-site. Engaging solely in desktop, or spreadsheet, audits do not suffice for this requirement. (Please see the section below on additional audit requirements.)
5. Use of a digital registry: All certificates should be 'stored' or accounted for on a digital registry. Use of a registry ensures that double counting of certificates (and their concomitant environmental attributes) does not take place. Similarly, certificate title changes should be tracked in the registry – allowing for a chain of custody to be developed. Finally, summated methane intensity across the supply chain can occur easily when a registry is utilized. Conversely, if a registry is not utilized in this manner, it is very difficult to provide life cycle emissions reporting – something that is likely to be necessary for LNG imports in the European Union.

In sum, an argument can be made that if a certification or rating program does not include the elements listed above, it should not be considered certified gas.

A credible methane performance certification program should not have the following elements:

A. Proprietary standards: A certification or rating program should not have proprietary standards that are not immediately accessible to the public and other stakeholders. Certification should not hinge on a 'black box.'
B. Self-certification: A certification that involves an operator self-certifying against its own performance standard is not credible. Similarly, self-reporting against a standard that has been developed by that same operator is also not credible.
C. Certification of a sub-set of facilities: Certification of anything less than all wells and equipment in a facility qualifies as the certifier and operator having self-selected particular pieces of wells and equipment. Often, these are the highest performing (in terms of methane emissions) pieces of equipment on the facility. Allegations of greenwashing, in those instances, may well be warranted and cast doubt on the overall methane performance certification space.
D. Non-third-party auditors: Auditors that are employed or have a contractual relationship with the certifier will produce audit reports that may be viewed as not credible.

Auditor Qualifications: MiQ has a well-established, respected, and credible audit program. This entails the use of auditors that have no financial interest in the outcome of the certification, are retained by the operator to conduct the audit, and have no employment or contractual relationship with MiQ. This third-party audit system was developed to minimize and eliminate conflicts of interest and is based on elements of financial accounting and audits.

MiQ recommends that the following elements be taken into consideration with regards to any audit or verification process for life cycle emissions certification, including LNG. More information about MiQ's auditor requirements and program can be found here (https://miq.org/document/miq-introduction-for-auditors/).

Audit Frequency: The audit is conducted by an MiQ Accredited auditor prior to the issuance of any MiQ certificates and is valid for 12 months.

Audit Process: As part of the audit process, the auditor will:

- Verify historical and forecasted data regarding a Facility's methane emissions inventory, including bottom-up and top-down emissions data, for accuracy and completeness to meet the criteria of the Methane Intensity subsidiary document.
- Verify documentation that demonstrates the Facility's compliance with the Company Practices subsidiary document. This documentation may include design standards, operating procedures, equipment inventories, operations training records, maintenance records, and LDAR records.
- Verify documentation related to the Facility's LDAR program and deployment of advanced monitoring technology utilized in reference to the scoring levels of the Monitoring Technology Deployment subsidiary document.
- Interview relevant personnel including operations and environmental management, engineering and environmental staff, lease/site operations, and relevant contractors to confirm documentation, verify data sources, and confirm understanding of operating procedures.
- Conduct onsite field inspections of a representative sample of the Facility's operations to evaluate the implementation and effectiveness of company practices, deployment of monitoring technology, and confirm significant inputs to the emissions inventory.

Conflict of Interest Policy: Auditors must maintain independence and avoid conflict of interest, especially where there is financial conflict, or the auditor is at risk of verifying all or parts of the auditor's own work. Auditors are not permitted to assess their own data or work product, including, but not limited to, primary data collected or processed on behalf of the operator (such as emissions measurement or monitoring data), or prior consulting or emissions management support.
Accreditation Process: All auditors who will audit or verify against the MiQ standard must go through an accreditation process. This consists of a screening process and initial interview, application and submittal of the accreditation application package, MiQ review, and another interview. MiQ then informs the auditor applicants of its accreditation decision for each segment of the MiQ standard to which the auditor nominee has applied.

Auditor Background: Auditors are accredited to specific segments of the supply chain, based on their qualifications, credentials, and relevant experience. Auditors must be subject matter experts, and have experience in GHG auditing, monitoring technologies, natural gas handling and abatement, knowledge of the full natural gas supply chain, and be able to conduct onsite

interviews and onsite verification. The auditor must be a third-party entity of both the certification body and the operator with no financial or contractual ties to MiQ, the operator being audited, or the data provider. Similarly, the auditor can have no financial interest in the outcome of the certification.
The auditor must have substantive experience in each element of the MiQ standard. This experience includes:

- Methane Intensity
  - Demonstrated familiarity with the following:
    - Quality management for environmental systems
      - ISO 9001:2015 [1]
      - ISO 14001:2015 [2]
      - ISO 19011:2018 [3]
      - Similar internal management systems
    - Emissions inventory and information statement development and management
      - ISO 14064-1:2018 [4]
      - ISO 14064-3:2019 [5]
      - ISO 14065:2020 [6]
      - Demonstrated experience with completing, consulting to, or auditing emission inventories and reporting programs for various initiatives including EU ETS [7], CDM [8], CDP [9] and others.
      - Demonstrated experience of top-down and bottom-up methane emission quantification approaches, including developing and coordinating research projects, implementing quantification programs, and analyzing quantification data
      - Developing baseline absolute emissions and emissions intensities
      - Individuals have significant experience developing regulatory emissions inventories for relevant industry segments.
- Company Practices
  - Individuals have experience with the following:
    - Process engineering experience in various oil and gas industry segments.
    - Environmental compliance experience in the oil and gas industry, including but not limited to (For oil and gas specific experience, Individuals should elaborate on specific experiences and specific segments of expertise (i.e., production, G&B, processing, transmission, liquefaction etc.)).
      - Implementing procedures to minimize emissions from critical methane emission sources.
      - Execution of programs to improve oil and gas company culture around methane emissions awareness and management,

        including operator training programs and corporate stewardship programs.
    - Analysis of leak detection and repair (LDAR) program performance and improvement, including the use of advanced technologies such as continuous monitoring systems or intermittent plane/drone-based surveys
    - Experience regarding LDAR program reporting structures.
    - Development of methane reduction programs and emissions management systems in the oil and gas industry o
  - Project management experience
  - Professional engineering experience
  - Professional auditing services experience and accreditation

- Monitoring Technology Deployment
  - Individuals have experience with the following technologies and work practices associated with use of methane emissions monitoring technologies that may be used to comply with the MiQ Standard
    - Source-level leak detection survey technologies and methods including handheld OGI surveys or surveys compliant with USEPA Method 21 [10]
    - Facility-scale leak detection survey technologies and methods including vehicle-based, drone based, fixed-wing aircraft-based, continuous monitoring systems etc.
  - Individuals have experience evaluating methane emissions monitoring technology capabilities through single-blind independent release testing.
  - Individuals have experience evaluating LDAR program components, including but not limited to:
    - Technologies and detection methods used.
    - Frequency and spatial coverage of each detection method
    - Critical environmental parameters that affect detection performance, and mitigation steps taken by company to minimize adverse impacts.
    - Data collection, transfer and alarm systems for captured emissions events o Leak detection and reporting procedures
    - Leak repair procedures
    - Leak repair verification procedures
    - Leak detection and repair recordkeeping procedures
    - Compliance with LDAR repair timelines
    - Equipment training protocols
    - Technology calibration protocols

Cost Considerations: Certification is also considered to be a low-cost and rapid payback opportunity for operators intending to differentiate their product.

Costs to certification include (1) performance an analysis of an operator's methane and GHG performance to a standard (2) hiring a third party, subject matter expert, (3) issuing and transacting certificates on a registry. Costs have been demonstrated to be, and, going forward, are expected to be incredibly low and not a barrier to entry.

- Based on operator feedback, the most resource intensive component of certification is the use of operational personnel to evaluate their emissions inventory, company practices and procedures against a standard, and ingest new emissions data from advanced technology solutions. When a U.S. operator simply intends to undertake an audit of their emissions performance *as is*, they might expect a 0.5 FTE effort over two to three months to gather documents, emissions accounting data (as far as they have been compiled for regulatory efforts), and additional support (80 hours total) from operators, managers, air compliance teams over an approximate one week period to support an onsite audit and interview process.
- If an operator seeks to achieve a higher performance grade by improving their monitoring practices, emissions accounting program to include measurement, enhance training and internal emissions tracking solutions, as well as update and advance their standard operating procedures, they might expect a 2.5 FTE effort over four to six months to implement improved inhouse solutions.
- If an operator seeks to incorporate advanced monitoring technologies to enable better emissions data collection or a measurement-informed inventory, they might expect to spend an additional $100,000 or more in the first year for baseline analysis. It should be noted that, according to the IEA, upstream advanced LDAR costs are anticipated to have a net-negative cost to implement.
- Registry costs are intended to be as low as possible to enable credible issuing, tracking and retirement of attributes, working out to a model average of $20,000 USD per operating facility or 1/20th of a US cent per MMBTU.
- Additional capital improvements to install vapor capture units and tank controls, redundant flare monitoring systems, no bleed pneumatics are also anticipated to have a net-negative cost to implement, according to the IEA.

Respondent:

Golden Pass LNG

Golden Pass LNG

Topic 1: Environmental Profile of Upstream Supplies

1.1 *What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?*

GPLNG has contracted with multiple suppliers for gas supplies, which includes responsibly sourced natural gas verified by multiple independent certification organizations including methane intensity certified by MiQ. As the certification programs mature, align with accepted standards, and become more widely adopted, GPLNG plans to continue to evaluate the impacts on its evolving gas supply portfolio.

1.2 *To what extent do exporters request or have access to information about the source (e.g., production basin, transportation pipeline, custody transfers) of the natural gas they are liquefying for export? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means? Do the answers vary by the extent to which the gas is supplied by natural gas marketers or through bilateral contracts?*

Depending on the contract terms, gas supplier, and receipt point where it takes custody of the gas, GPLNG will have varying degrees of knowledge of the production basin, transportation pipeline(s), and custody transfer points of the gas delivered to the plants. Yet, due to the different business models of suppliers, multiple production basins, and complexities of the transmission system, there are instances where the source of the gas is not transparent.

1.3 *To what extent do exporters request or have access to information about the greenhouse gas emissions and/or practices to limit greenhouse gas emissions of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?*

As stated in response to question 1.1, GPLNG has contracted for some of its supply to be responsibly sourced, certified natural gas. Through open-source information, GPLNG is generally aware of the suppliers that have adopted and who are marketing certified natural gas although much of the certified gas is not produced in basins accessible to GPLNG.

1.4 *To what extent do exporters request or have access to information on non-greenhouse gas emissions, including criteria air emissions or hazardous air pollutants, and/or other practices to address other environmental impacts (e.g., strategies to protect water quality or limit water consumption) of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?*

Responsibly sourced gas that GPLNG has contracted for includes certification by Project Canary and Equitable Origin's EO100 Standard, thus including other measures of responsibly sourced natural gas. Producers that have adopted those certification standards actively market their efforts and GPLNG is thus so informed of the programs.

1.5 *What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?*

Market adoption of differentiated natural gas certification programs is growing and as the certification programs mature, align with accepted standards, and become more widely adopted, GPLNG plans to continue to evaluate the impacts on its evolving gas supply portfolio. The market for those programs is still developing, however, and the certification methods and standards are still evolving such that an imposition of specific methods or certification technologies would stifle innovation that will improve the product offerings from certification companies. As the product offerings become more reliable and are validated and the demand side of the market supports a premium for certified natural gas, more suppliers will adopt the certification programs.

1.6 *What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?*

GPLNG looks to the gas suppliers for the certification programs they are currently using.

1.7 *What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?*

GPLNG has sold 100% of its production and therefore is not marketing its LNG. However, open source market information informs that LNG buyers have been resistant to paying a premium for LNG sourced from certified natural gas. However, once LNG buyers support premium payments for certified natural gas, access to valid, reliable, and transparent certified natural gas could set the U.S. market apart from LNG suppliers that do not have access to certified natural gas.

Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities

2.1 *What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?*

GPLNG is in the process of constructing a new liquefaction facility that has been designed to meet or exceed the current BACT for the Beaumont-Port Arthur (BPA) region. The BPA region is currently classified as attainment. Below is a table detailing the emission controls GPLNG will install and operate at our new liquefaction facility:

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Source	Emissions	Proposed Emission Controls
Gas Turbines/ HRSGs	CO	Post combustion catalytic oxidation
	NO_x	Post combustion selective catalytic reduction
Thermal Oxidizers	NO_x	Low NO_x burners and good combustion practices
	CO	Good combustion practices
Diesel Essential Generators	NO_x	Turbochargers and aftercoolers, good combustion practices
Auxiliary Boiler	NO_x	Low NO_x burners, flue gas recirculation, and good combustion practices
Storage Tanks	VOC	Control by thermal oxidizer and submerged fill pipes
Tank/Truck Loading	VOC	Control by thermal oxidizer and submerged fill pipes
Fugitives	VOC	Appropriate Leak Detection and Repair program

In addition, upon startup of the new Export Terminal, GPLNG will implement a leak detection and repair (LDAR) monitoring program to comply with the Texas Commission for Environmental Quality LDAR programs 28CNTQ (connector inspections) and 28 VHP (piping, valves, connectors, pumps, agitators, and compressors), which meet TCEQ's Tier I BACT. To comply with these standards, GPLNG will procure monitoring services from a third-party who will employ a combination of US EPA Method 21, Audio, Visual & Olfactory (AVO) and Optical Gas Imaging. To eliminate fugitive leaks from operating equipment, GPLNG will be implementing a repair process that will comply with the LDAR standards.

2.2 *In addition to published data sources such as EPA's Greenhouse Gas Reporting Program and Greenhouse Gas Inventory, are there other data and information available on identification and location of point sources of greenhouse gas emissions within liquefaction facilities?*

GPLNG has applied for and received a greenhouse gas PSD permit from the Texas Commission on Environmental Quality (TCEQ). GPLNG will comply with the requirements set forth in that permit (GHGPSDTX100). In addition, the issued permit established enforceable CO2 equivalent ($CO2_e$) emission limits for individual sources onsite.

2.3 *What methodologies do operators use to estimate and measure greenhouse gas emissions at liquefaction facilities.*

GPLNG is designing the operating and monitoring system for its new liquefaction facility with the intent of routinely calculating the $CO2_e$ emissions for stationary fired process equipment.

In addition, as required per applicable regulations and facility permit requirements, GPLNG will implement a leak detection and repair (LDAR) program to identify fugitive emissions sources. Through its permits, GPLNG has the authorization to employ both Method 21 as well as optical gas imaging (OGI) methods to identify potential fugitive leaks for repair.

2.4 *Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?*

Because GPLNG's new liquefaction facility is under construction, we are not currently deploying advanced technologies to monitor for greenhouse gas emissions from the facility.

After the facility completes all startup activities and our LDAR program is fully implemented using either Method 21 or OGI, GPLNG may elect to review additional advanced technologies available to determine if one may be beneficial and provide additional visibility of potential emissions. GPLNG considers the use of OGI cameras, fixed or handheld, to be an advanced monitoring technology.

2.5 *When is the decision to select electric, natural gas-powered, or hybrid compressor driven systems made during the facility design process? What are the key factors that influence this design choice?*

GPLNG is in the process of constructing a new liquefaction facility. The decision to select the power source is made very early in the front end engineering and design process. The choice of power source (grid, site produced or cogenerated) is critical to the ultimate design and layout of the facility. Some key factors are likely to be:

Purchased power would come from the local electrical grid. This option also would require additional equipment (a transformer and a variable speed motor for each compressor). An onsite boiler would be needed to generate process heat. Potential designs using purchased power would result in compressor cycle efficiencies of approximately 39 percent.

Site produced power would likely require a change to the configuration of a facility design to incorporate the additional equipment required to convert and transform steam generated onsite into electricity and back into useable power by the electric motors in the compressors. The additional equipment would include a generator, a variable speed motor, and a transformer for each of the compressors on each liquefaction train. Potential designs using site produced power would result in compressor cycle efficiencies of approximately 50 percent.

Cogeneration: Each train could be equipped a steam turbine generator to provide the necessary power requirements for the refrigeration compressors. The steam turbine generators would produce electrical power through cogeneration by using steam from the heat recovery steam generators that are part of the natural gas-fired turbines in each train. For emission controls like GPLNG is installing, each of the turbines and heat recovery steam generators could be equipped with selective catalytic reduction and oxidation catalysts to reduce NOx and monoxide emissions, respectively. Potential designs using site produced power would result in compressor cycle efficiencies of approximately 50 percent.

2.6 *What data and information are available related to the feasibility of electrifying new facilities or the ability to repower existing liquefaction facilities to use electric motor drives?*

GPLNG is in the process of constructing a new liquefaction facility. There is not data readily available for the feasibility as the analysis would be a site-by-site determination. However, once a site is constructed and operating, the ability for repowering from a different source would likely be infeasible and/or cost prohibitive due to types of equipment required, layout changes necessary for new equipment, loss of efficiency and extended facility downtime to incorporate the significant changes.

2.7 *When companies have electrified facilities what steps have they taken to quantify the emissions associated with purchased electricity.*

GPLNG's liquefaction facility will not be powered from the grid during normal operations.

2.8 *When companies have electrified facilities, to what extent are they reducing consumption of natural gas that would otherwise be used for facility operation? What is the magnitude of such natural gas savings?*

As designed, GPLNG's liquefaction facility will not be electrified.

However, as natural gas is inarguably the cleanest reliable source of fuel available in the current global economy, the use of natural gas in a liquefaction facility is ideal. As some sites operate by using their own product and off gases as fuel, the result is little waste and minimized efficiency loss. The emissions from an LNG liquefaction facility which consumes its own material and off gases have a lower $CO2_e$ impact on the environment than the emissions from older electrical generating units.

2.9 *Do companies have specific plans to deploy carbon dioxide capture at liquefaction facilities in the future on low and high purity CO2 gas streams? In addition to financial* *considerations, are there technical or other limitations to deploying carbon dioxide capture at liquefaction facilities?*

GPLNG is constructing a new liquefaction facility and is considering incorporating carbon capture equipment. Other than the financial considerations, the recent increases in tax credits for carbon oxides capture and sequestration have precipitated significant market activity but also uncertainty. For example, GPLNG cannot now predict or dictate by contract the percentage of carbon in the natural gas delivered to the facility because midstream companies and even producers are evaluating capturing the carbon oxides before natural gas is delivered to GPLNG. As such, GPLNG cannot predict the volume of carbon that would be available to sequester and qualify for the credit. In addition, GPLNG will need to contract with a company to transport and sequester the carbon oxides it captures from the facility. Yet, the several companies considering sequestration in proximity to GPLNG's facility have not reached FID on their projects and have not committed to build a carbon pipeline to GPLNG's fence line. The current uncertainty in the volume of carbon oxide GPLNG will have to offer a sequestration company means that GPLNG is not a strong candidate to be an anchor shipper for a pipeline.

In addition, the technology for installing equipment to remove carbon from combustion exhaust remains uneconomic, even with the increased value of the 45Q tax credits. For all of these reasons, GPLNG has not yet determined whether to incorporate carbon capture equipment in its facility but is positioning itself to do so should the current uncertainties be resolved, and the economics of the project are favorable.

2.10 *Are there data or information available on other technologies or strategies operators could deploy to reduce or avoid greenhouse gas emissions at liquefaction facilities? Are these technologies or strategies considered* experimental *or pre-commercial? Are there estimates of emission reductions and/or gas savings associated with implementation of these technologies?*

GPLNG is constructing a new liquefaction facility using BACT to reduce emissions. GPLNG routinely monitors potential technological solutions to assist in the reduction of losses of primary containment.

2.11 *What data and information are available on the co-benefits of practices to limit greenhouse gas emissions at* liquefaction *facilities (e,g., reductions in criteria pollutants, hazardous air pollutants)?*

Given the design of its new liquefaction facility, GPLNG does not anticipate that the facility will exceed emission thresholds triggering major source for hazardous air pollutants. As previously mentioned in response to Question 2.1, GPLNG has already invested significant capital in emission reduction technologies on the larger fired sources on site.

Additionally, the potential for a financial penalty (Methane Tax) as imposed by the Inflation Reduction Act is an impetus for reducing methane, and therefore $CO2_e$, emissions from GPLNG liquefaction operations.

2.12 *What data and information are available to assess potential improvements to local air quality or benefits to communities from mitigation practices implemented at liquefaction facilities?*

Currently, there is no data available to assess potential improvements to local air quality because the new GPLNG liquefaction facility is still being constructed.

Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport and Delivery

3.1 *What technologies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?*

A vapor arm will be connected between the vessel and the terminal to capture the vessel's vapor while the vessel is loading. All loading arms and vapor arms are designed to prevent leaks and will be tested after the connections are made and prior to commencement of LNG loading operation. Gas detectors will constantly monitor the loading infrastructure for leaks during loading operations. Boil-off gas during loading will be used to supply fuel gas to operating trains. Excess boil-off (if any) is recycled to the inlet pipeline.

GPLNG can only speak to the loading of LNG. Once LNG is loaded at the berth, title is transferred to the buyers, and the buyers are responsible for all transportation and delivery of LNG.

3.2 *What approaches do LNG operators use to capture boil off gas (BOG) and limit loss of natural gas when storing, loading, transporting, and unloading LNG?*

During LNG storing and loading operations, GPLNG's facility is designed to use BOG for fuel gas for the operating trains. Excess BOG (if any) will be recycled to an inlet pipeline. As noted above, GPLNG delivers LNG to its buyers at the berth where title is transferred when the LNG is loaded on the ship, and the buyers are responsible for all transportation and unloading of LNG.

3.3 *What approaches do LNG operators use to minimize greenhouse emissions during tanker transport of LNG?*

GPLNG does not and will not operate any tankers and therefore has no relevant information to respond to this question.

3.4 *For contractual agreements that include the transport of LNG, what measures, if any, are taken to assure natural gas is not lost and greenhouse emissions are minimized during shipping?*

GPLNG delivers LNG to its buyers at the berth where title is transferred when the LNG is loaded on the ship, and the buyers are responsible for all shipping. Therefore, GPLNG has no information to respond to this question.

3.5 *Are there data or information available to assess potential improvements to local air quality or benefits to communities from mitigation practices implemented during the loading, transport, and delivery of LNG?*

Currently there is no data available to assess potential improvements to local air quality during loading of the LNG because GPLNG's liquefaction facility is still under construction. GPLNG is not involved in the transport or delivery of the LNG, and therefore has no information to respond to that portion of the request.

Topic 4: Additional Information

4.1 *What non-US requirements for greenhouse gas performance are LNG exporters being asked to respond to with emissions data? Are emission reduction requirements included in any contracts or other importing country requirements?*

GPLNG has sold 100% of its production and therefore is not marketing its LNG. GPLNG's purchase and sale agreements do not include emission reduction requirements and its buyers have not asked GPLNG to meet any particular non-US greenhouse gas performance requirements. Yet, GPLNG's new liquefaction facility has been designed to meet or exceed the current BACT for the Beaumont-Port Arthur (BPA) region. GPLNG's is also designing the operating and monitoring system for its new liquefaction facility with the intent of routinely calculating the $CO2_e$ emissions for stationary fired process equipment. In addition, as required per applicable regulations and facility permit requirements, we will implement a leak detection and repair (LDAR) program to identify fugitive emissions sources. Through our permits, GPLNG has the authorization to employ both Method 21 as well as optical gas imaging (OGI) methods to identify potential fugitive leaks for repair. Further, GPLNG is actively evaluating the market and technological developments for the potential installation of carbon capture equipment to be sequestered by a third party. Thus, GPLNG anticipates that it will exceed industry standards for low-emission LNG.

4.2 *What changes or technology advances does industry think are needed to decarbonize the LNG supply chain from production through delivery? What are the economic benefits or challenges associated with the measures to decarbonize the LNG supply chain? Is there data or information available on the costs or savings associated with implementing these measures?*

Current technology for eliminating carbon from combustion emissions has not been proven to be technologically and economically feasible for LNG production. The combination of the cost of the equipment, efficiency reductions, and increased operating costs overwhelm all measures of economic benefit given current and projected market conditions for LNG and the value of captured carbon.

4.3 *Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?*

GPLNG routinely monitors potential technological solutions to assist in the reduction of losses of primary containment and evaluates opportunities for further reductions of emissions once its facility begins operations.

Respondent:

GHGSat

June 26, 2023

U.S. Department of Energy
Office of Fossil Energy and Carbon Management
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Subject: Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. LNG Exports (RFI No. DE-FOA-0003052)

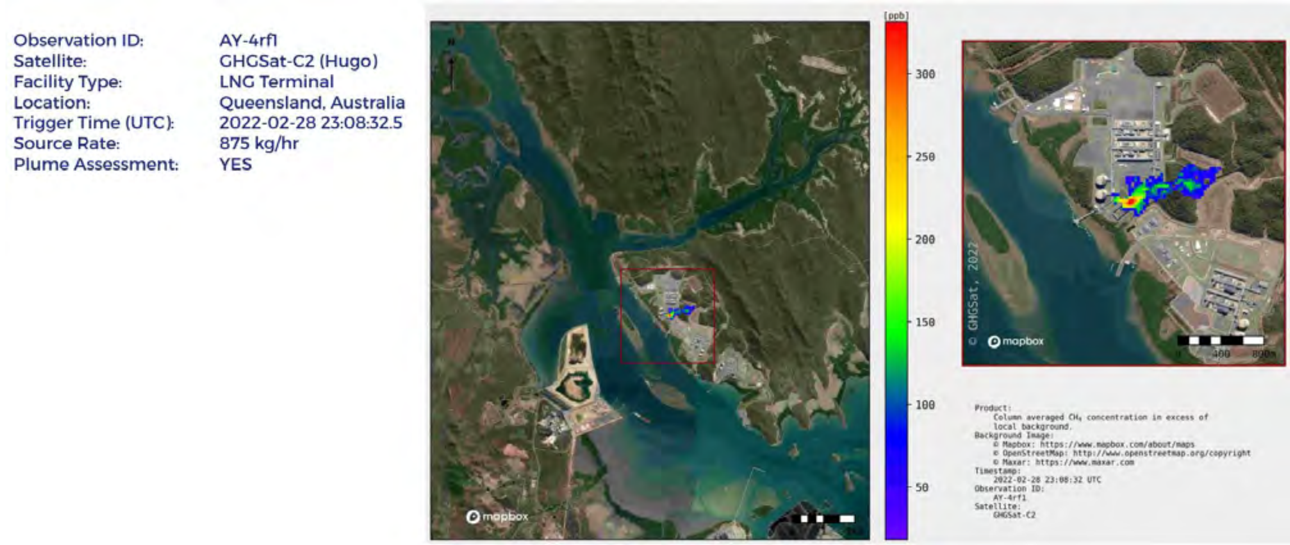
GHGSat appreciates the opportunity to respond to the Request for Information (RFI) No. DE-FOA-0003052 regarding the U.S. Department of Energy's (DOE) Office of Fossil Energy and Carbon Management's (FECM) research and development activities and regulation of natural gas imports and exports under the Natural Gas Act of 1938 as amended. Specifically, GHGSat wishes to address the following RFI questions:

1.3. To what extent do exporters request or have access to information about the greenhouse gas emissions and/or practices to limit greenhouse gas emissions of the natural gas they are liquefying for export prior to delivery at the liquefaction facility?

2.4. Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities?

The short answer to the above questions is that companies are already utilizing advanced technologies to monitor greenhouse gas emissions, not just drones and aerial surveys but also satellites. Today, exporters have extensive access to information from satellites and aerial surveys about greenhouse gas emissions at all phases of the LNG chain from production through transportation of natural gas delivered to a liquefaction facility, at liquefaction facilities, and during the loading, transport, and delivery of LNG to a regasification facility.

Established in 2011, GHGSat operates satellites and aircraft that quantify methane emissions from oil and gas facilities across the United States and around the world, providing the timely and objective data needed by Federal agencies, state and local governments, and companies. GHGSat now has nine satellites in space and will be adding another three before the end of this year, including a new CO_2 sensing satellite. The satellites of the current constellation have a methane detection threshold of 100 kg/hr and a spatial resolution of less than 30 meters, representing a unique ability to quantify point sources like an LNG terminal – a crucial capability for facility-level attribution. Complementary aircraft-based sensors have been performing operational flights since 2020 for oil and gas operators across North America and overseas. GHGSat's technology has been routinely applied to the detection and quantification of methane emissions to support fugitive emissions investigations and mitigations on behalf of end-users in government, industry, and the scientific community. As an example, the following observation was made by a GHGSat satellite in February 2022 and shows a methane emission from an LNG terminal in Queensland, Australia with a source rate of 875 kg/hr.



Objective data that accurately reflects facility-level methane emissions is essential for the success of a differentiated natural gas certification program for U.S. LNG exporters, however, this cannot be achieved with ground-based measurements alone. Numerous scientific studies [Brandt et al., 2016; Zavala-Araiza et al., 2017; Duren et al., 2019] have reported that methane emissions show a skewed distribution in which a small number of super emitters are responsible for the majority of emissions. It is therefore crucial to locate and quantify these super emitters quickly. Incomplete or inaccessible data is also a significant challenge to differentiated natural gas certification programs due to the current reliance on limited field measurements, estimates, and self-reporting that are likely to underestimate emissions, particularly in areas with intense LNG production, transportation, and delivery activities.

Given the nature of the distribution of methane emissions as documented in the scientific literature, GHGSat recommends that DOE review and consider the tiered methane emissions monitoring approach in the Environmental Protection Agency's (EPA) proposed rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources (EPA-HQ-OAR-2021-0317). In such a tiered approach, satellites with a detection threshold of 100 kg/hr could monitor on a monthly basis and detect very large emissions quickly. Airborne instruments with a detection threshold of 10 kg/hr could be dispatched on a bimonthly basis with an emphasis on the high-risk areas identified by satellites. Finally, optical gas imaging (OGI) or Method 21 surveys could be performed on a yearly or year-and-a-half basis to quantify the remaining emissions. Such a tiered approach would prioritize the biggest leaks quickly, increasing transparency through the detection of undeclared and intermittent emissions, and provide the timely and objective emissions data needed for a differentiated natural gas certification program. A recent paper documented the cost-effectiveness and efficacy of a tiered monitoring approach using GHGSat's satellite constellation and aircraft-based instruments in the oil and gas sector [Esparza et al., 2023]. Similarly, a recent modeling study concluded that tiered monitoring using satellites and aircraft will increase emissions reductions when compared to OGI surveys alone [Cardoso-Saldaña, 2023].

Satellites are a validated and operational commercial-scale technology for measuring LNG sector methane emissions that is available right now. In October 2020, GHGSat performed a blind controlled release with TotalEnergies of France to validate the performance of a GHGSat satellite. Analysis of the collected data identified the precise location of the methane release and the satellite rate estimate of 250±140 kg/hr was very close to the ground truth release rate of 234 kg/hr. More recently, a paper led by researchers at Stanford University reported on the single-blind validation of a GHGSat satellite achieving quantification accuracy of better than ±20% for each methane plume that was observed as part of the study [Sherwin et al., 2023].

GHGSat appreciates the opportunity to respond to the RFI and would welcome further discussions with DOE on the role of satellites and aircraft-based remote sensing capabilities in reducing greenhouse gas emissions associated with U.S. LNG exports.

Respondent:

Institute for Policy Studies – Climate Policy Program;

Michigan Environmental Justice Coalition; New Jersey Environmental Justice Alliance; New York Lawyers for the Public Interest; and 350.org

Dear FECM,

Thank you for the opportunity to comment on "Opportunities To Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated With U.S. Liquefied Natural Gas (LNG) Exports." Here are our concerns with the basic premise of incremental reduction in emissions of U.S. LNG exports, which fails to account for the lifecycle greenhouse gas and environmental justice impacts of LNG exports.

Scope 3 Emissions of U.S. LNG Exports are Ignored in Claims of "Green" or "Low-Carbon" LNG

The federal government is requiring corporate entities to investigate and disclose their Scope 3 emissions (the amount of greenhouse gasses emitted along their supply chains) to better prepare investors on the climate risks and impacts associated with those companies and their outputs. If it's good for the goose, it's good for the gander. The federal government should be required to include the end-use climate risks and impacts associated with the greenhouse gas (GHG) emissions of the US' exports of liquified natural gas (LNG). Not including those emissions in the overall picture of the US' climate change impacts is a deliberate obfuscation of how much the US' fossil fuel industry contributes to global warming and climate risk for everyone.

By marketing US-produced LNG as "green" or "responsibly sourced," there is an unsubstantiated attempt by the US federal government to designate their fossil fuel output as less harmful to the planet than other countries' fossil fuel production. However, the US does not include the methane emissions produced by the transportation, liquefaction, and utilization of the exported LNG in their overall picture of how clean US-produced LNG is. For the record, methane is an even greater short term heat-trapping gas than carbon dioxide and fossil gas' primary makeup and GHG emission is methane. The global warming potential of methane is 81 times more than CO2 over a 20-year window, and 28 times more than CO2 over a 100-year window.

This is a grave oversight. Scope 3 GHG emissions, from end-use and supply chain-related activities, are a Securities and Exchange Commission (SEC) requirement for greater transparency of corporate climate risk and the same standard needs to be applied to the federal government. US-produced LNG is not cleaner or greener than any other countries' fossil gas and the methane and carbon dioxide emissions from exported LNG from the US is proof of that. This is why the US should not be exporting any fossil fuels; the entire industry, regardless of initial export location, is harmful to the planet and an extreme contributor to climate change.

U.S. LNG Exports are Driving Increased Gas Production and Associated Environmental Justice Harms

Because the U.S. is the world's largest producer and second largest exporter of fossil gas, this attempt at greenwashing U.S. gas exports is particularly dangerous from the standpoint of contributing to global greenhouse gas emissions, as well as environmental justice impacts within the U.S.

Particularly, U.S. fossil gas exports are the driver of increasing domestic production. Between 2000 and 2022, domestic consumption of fossil gas grew by only about 39%, while production grew by 93%, with the majority of the growth attributable to exports. Consequently, exports are, to a large extent, to blame for the growth of hydraulic fracturing and drilling for fossil gas.

More fossil gas production, in turn, leads to more air and water contamination, disproportionately harming already over-polluted environmental justice communities. The export terminals themselves are sources of toxic pollution which also pose environmental justice risks, including pollution from methane, carbon monoxide, volatile organic compounds (VOCs), nitrogen oxides (NOx), and sulfur dioxide (SO2). The pollution from LNG export terminals has devastating health impacts on the communities around them, damaging the eyes, lungs, organs and causing issues like heart disease and cancer.

It follows that installing carbon capture and storage technology at LNG export terminals is merely an exercise in greenwashing–an inherently harmful activity that poses a serious threat to the health of disproportionately Black, Indigenous, and poor communities, and our planetary future. The only practical solution is to start phasing out U.S. LNG exports instead of investing capital in expensive CCUS technology to facilitate continued fossil gas exports.

Adding CCS to LNG Export Terminals is Not a Climate Solution

Any discussion of the feasibility of adding CCS to LNG export terminals needs to start with the recognition that CCS is a very energy intensive and water intensive process, and that it has a record of failing to meet its goals of capturing CO2. Ultimately, installing CCS at LNG export terminals amounts to relying on an expensive, resource-intensive technology that may not even work, to reduce a small fraction of the lifecycle greenhouse gas emissions associated with LNG exports.

Carbon capture and storage (CCS) for LNG export terminals is not just greenwashing, it's folly. Per the updated site proposal of the Rio Grande LNG (RGLNG) facility in Brownsville, Texas to the Federal Energy Regulatory Commission (FERC), "[t]he CCS system will primarily consist of flue gas cooling, a CO2 absorber, an amine regenerator and reboiler, CO2 dehydration, CO2 compression, and a hot oil system." This entire system has a giant energy and water resource footprint that renders any benefit of CCS practically moot. Additionally, as LNG moves from a pipeline to a shipping container for export, there is a specific process that needs to be followed to capture the carbon released in that process. Therefore, unless a capture facility the size and scope of which has never been built before is included in the overall building plans of an LNG terminal, the expectation is that each distribution line from the pipeline to the compressor for shipping would need its own CCS facility. Once again, any projected carbon capture benefits – which, in practice, have so far been so nominal as to be negligible – are rendered moot because the two separate CCS facilities required (in the case of the Rio Grande LNG terminal) will be so energy, land footprint, and resource intensive that the impacts of the CCS projects, alone, are astronomical.

It's instructive to look at a real-life example of installing CCS at an LNG terminal. Chevron's Gorgon LNG project in Australia, the world's largest CCS facility, is an expensive failure. It was approved on the condition that it capture 4 million tonnes of CO2 a year, but it captured only 1.6 million tonnes last year, down from 2.2 million the previous year.

Finally, as previously stated, LNG's primary makeup and GHG emission is methane, and methane is a more potent planet-warming gas than CO2 in the short term. **Once again, CCS does not capture, nor does it store, methane, which makes CCS a greenwashing process for a fossil gas that is primarily made up of something the process does not contain.** CCS also does not reduce the myriad other pollutants from LNG. In fact, the energy required to run the CCS facility may result in an increase of these pollutants and the devastating health impacts they cause.

This means frontline communities will be footing the bill for an expensive, ineffective process that continues to poison them while claiming to save them.

Recommendation

We urge the Department of Energy to take the only logical course of action possible to cut greenhouse gas emissions from fossil gas exports, which is to stop issuing licenses to export fossil gas to countries with which the U.S. does not have a free trade agreement, by making the determination that such exports are not in the public interest.

Signed,

Institute for Policy Studies, Climate Policy Program
Michigan Environmental Justice Coalition
New Jersey Environmental Justice Alliance
New York Lawyers for the Public Interest
350.org

Respondent:

The Williams Companies, Inc.

Submitted via the "ReduceGHGE_LNG_RFI@NETL.DOE.GOV" email address

June 26, 2023

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Washington, DC 20024

Re: Comments from The Williams Companies, Inc. in response to the Request for Information (RFI) related to Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports. Reference number: DE-FOA-0003052

Assistant Secretary Crabtree,

As requested in the RFI referenced above, please see the contact information below.

- Company/institution name: The Williams Companies, Inc.

The Williams Companies, Inc. (Williams) appreciates this opportunity to submit written comments regarding the U.S. Department of Energy Office of Fossil Energy and Carbon Management's (FECM) "RFI related to Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports" issued on April 21, 2023. Williams is one of the nation's largest energy infrastructure providers. For more than a century, Williams has been providing infrastructure that is essential to our everyday lives and prospering businesses. Today, we are responsible for the transportation of approximately 30% of the nation's natural gas, directly serving over 600 utility and industry customers and indirectly serving over 35 million energy consumers. We have been around for over a century because we embrace change for the opportunity it brings, and we are excited about the latest challenge of meeting the world's demand for reliable, low-cost, and low carbon energy. We believe that running our business in a sustainable manner and doing what is right for the environment and our communities is critical to being here for the next 100 years.

Williams has internal functions and experts focused on both LNG export opportunities as well as deployment of new innovative technologies. As you are aware, the United States is now the world's largest exporter of liquefied natural gas. As countries in Europe and Asia look for clean and reliable energy solutions, global demand for LNG is increasing rapidly. Williams is well-positioned to meet this need. We are integrating a wellhead to water strategy to serve markets domestically and abroad.

In 2021, we launched Williams New Energy Ventures, a business development group focused on commercializing innovative technologies, markets and business models. New Energy Ventures collaborates with talent across Williams to evaluate and implement projects to grow our clean energy business, including our comprehensive "NextGen Gas" certification process to track and measure end-to-end emissions across all segments of the value chain from production through gathering, processing and transmission.

For the purposes of this RFI, we focused on "Topic 1, Environmental Profile of Upstream Supplies." Please see our responses below to the Topic 1 questions that apply to our core business and technology interests.

<u>Topic 1: Environmental Profile of Upstream Supplies</u>

Question 1.1. What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

<u>Williams Response</u>

As the first U.S.-based midstream company to publicly announce a climate commitment, Williams is committed to deploying the latest technology to not only provide new insights into emission reduction opportunities, but also to provide trust and transparency of emissions profiles for gas delivered across our pipeline network. More accurate reporting from various technologies across the entire supply-chain plays an important role in reducing emissions and demonstrating the low-carbon attributes of gas delivered to liquefaction facilities. Current emissions reporting approaches which are anchored in regulatory frameworks, are proven to be inaccurate and fail to instill trust in operators good faith and voluntary efforts to reduce emissions. As more oil and gas operators work to incorporate technology-based solutions and best practice frameworks on emission quantification, such as those prescribed by the United Nations Environmental Programme's Oil and Gas Methane Partnership 2.0 (OGMP 2.0), investors and end-users begin to build trust in emissions reporting that will allow gas supplies to be truly differentiated.

Williams is deploying an advanced QMRV (quantification, monitoring, reporting and verification) strategy to track emissions across our infrastructure network using advanced software and hardware technologies that provide a more detailed view of emissions across the entire value chain. The data generated is allowing Williams to provide customers with transparent emissions profiles for gas delivered to end-users such as LNG buyers, including production, gathering, and transmission pathways, enabling the delivery of natural gas with the lowest carbon profiles for emission conscious buyers. [1] Williams QMRV strategy involves detailed "bottom up" measurement informed calculations of site specific emissions sources that goes above and beyond EPA Subpart W GHGRP requirements with such calculations then supplemented by, and reconciled through, the use of multiple advanced "top down" emissions monitoring technologies and capabilities including on-site monitors, drones, aircraft and satellites – all with the ultimate goal of improving data accuracy and enhancing timely clean energy supply and delivery. This is key to finding opportunities to reduce emissions.

Through Williams New Energy Ventures, Williams has invested in and deployed multiple technology solutions including ground-based optical gas imaging cameras, aerial flyovers, satellite monitoring and internal operational systems which provide up to real-time insights to CO2 and specific sources of methane emissions. This advanced capability allows insights into our emissions footprint, at each site across our infrastructure network, generating an ability to remedy issues and reduce emissions in a more timely manner. This is an important capability that Williams is deploying to optimize our operations and complements our climate commitment efforts. Williams has contracted with satellite-based hyperspectral methane emission monitoring solutions from Satlantis and Orbital Sidekick as well as on-site monitoring solutions from Encino Environmental and LongPath Technologies to provide complementary methane monitoring and detection capabilities to our bottoms-up measurement informed emissions calculations. These technologies allow detection of specific methane leaks. While the technology needed to scale differentiated gas is developing rapidly, the technology is still in an early stage with the primary benefit being leak detection rather than full-site quantification. Advanced detection technologies such as continuous monitors and satellites are lacking sufficient quantification capabilities for all sources of methane emissions, which requires the use of proven technologies such as a high-flow sampler to measure the flow rate of known emission sources to quantify them. To meet industry best practices for emission quantification, our QMRV program has a unique capability of incorporating real-time operational data with robust leak detection and point-source emissions measurement to improve the accuracy and understanding of emission sources and detection technologies. There is not currently a single measurement or solution for accurately measuring and quantifying emissions.

Advanced Software Solution

To put all of this information together and create context, Williams is implementing an industry leading data fabric system through Context Labs' Decarbonization as a Service™ (DaaS™) platform which leverages block-chain, machine learning, and artificial intelligence technology to support asset-based reporting and independent verification of emissions. [2] Through this tool, we will be able to aggregate and reconcile data from multiple technology and data sources to improve the accuracy of emissions quantification, while providing verified emissions profiles of delivered gas. This process will capture the progress of greenhouse gas (GHG) mitigation across the natural gas value chain and provide an end-to-end path-specific emissions intensity

[1] *See* The Williams Companies, Inc. - Williams Executes Agreements with Coterra and Dominion Energy for Delivery of Full-Value Chain Certified Low Emission Next Gen Gas

[2] *See* contextlabs.com.

certification from production to liquefaction facilities across our pipeline system. In addition, Williams will gain new insights into day-to-day operations that enable system optimization and emissions efficiencies across the asset base. The key feature of this advanced software approach is the ability to correlate multiple emissions quantification technologies and bottoms-up emission inventory data, with real-time operational data to pinpoint and correlate multiple measurements to determine root cause and reduce uncertainty. By placing this information directly onto a blockchain carbon ledger, the information can be easily tracked, verified digitally by third-party auditors, automate regulatory emissions reporting, and attribute emissions in near real-time for reporting to end-users and customers across our footprint.

Direct Measurement Technologies

Handheld technologies, primarily OGI cameras and Continuous Flow Samplers, can survey individual equipment and components for methane emissions and allow the direct identification and quantification of very small emissions sources through direct measurement. These tools and practices are widely available to operators, and when performed on a routine basis, provide the most accurate measurement of emissions. OGI cameras are approved as an alternative work practice for surveys required under the Environmental Protection Agency's OOOOa regulation and are the standard way that oil and gas operators conduct methane LDAR programs. Together with real-time operational data, this is the most accurate approach to quantifying routine and small sources of methane emissions that are difficult for newer technologies to detect and quantify. This approach applies a more accurate assessment of emission leak rates, specific to the operating conditions and equipment in use, versus generic factors prescribed by regulation.

On-Site Monitoring Technologies

Fixed sensors that continuously monitor methane emissions are another form of technology being used to potentially enhance and improve the detection and quantification of specific sources of methane. The number and placement of sensors necessary to optimize detection and quantification at a site are typically developed according to a proprietary model and vary by site, geography, and equipment types. A subset of stationary technologies is continuous monitoring systems, which are used to track emissions in real-time. These systems can alert operators to sudden increases in emissions, allowing them to respond quickly and prevent large-scale leaks. Sensors are also used for high-efficiency flare combustion and can significantly reduce methane emissions and steam usage. Operators can verify their flare meters remotely, quickly identify issues, and intervene promptly by having access to real-time combustion efficiency data on the production floor. Advancements are still needed to improve the accuracy in more complex operations, such as those found in midstream operations, to determine the appropriate application of technology by equipment type and improve the accuracy of detection and quantification. Williams is actively deploying continuous monitoring solutions to determine the efficacy of such technologies across our complex treating, processing, and large-scale compression fleet. Technology Williams is using include solutions offered by LongPath Technologies, and Encino Environmental. LongPath uses a patented frequency-comb laser technology deployable in a hub-and-spoke arrangement, covering a radius of up to 2.5 miles at a high detection resolution, enabling economical coverage of large areas. [3] The application of this technology has been well studied in an E&P production environment, and additional testing will be performed by Williams to determine accuracy and applicability to midstream operations. Encino Environmental is

[3] *See* longpathtech.com

another service Williams has deployed, which utilizes a trailer mounted Hyperspectral Imaging camera to detect and quantify methane emissions. [4]

Drone-Based Surveillance:
Unmanned aerial vehicles or drones equipped with sensors and cameras can be used to monitor facilities from the air. These technologies can typically measure methane in three dimensions, including methane concentrations in the vertical atmospheric column within a methane plume. In addition, some can calculate wind speed and direction enabling more data for calculations. The use of drones can enable more frequent inspections and can help identify leaks or other issues that may not be visible from the ground. Limitations of this approach include a lower resolution, not continuous, climate conditions can prohibit coverage, and delays between surveys - all which limit actionable data.

Plane-Based Surveillance:
Manned aircraft, ranging from larger multi-engine research planes to small single-engine general aviation aircraft and helicopters can fly at different altitudes and have a long range. High-altitude flights can target large areas while low-altitude flights can detect and measure methane from a point source. Planes and helicopters can cover a larger area than drones, making them useful for monitoring multiple facilities or large-scale operations such as pipeline rights-of-way. Similar limits to drone-based technologies exist in addition to the limits associated with the time frame captured by this approach, reducing its ability to detect and quantify intermittent events. Williams is actively utilizing plane based aerial surveillance as part of our advanced QMRV program, covering sites quarterly to ensure our bottom-up inventory assessment is not missing unknown leak sources.

Satellite-Based Surveillance:
Satellites can provide a global view of greenhouse gas emissions and are typically used for frequent, low-cost measurements over large areas. They are often used to identify super-emitters, monitor facilities over time, and verify other sources of methane estimates or measurements. Several satellites specifically focused on or relevant to methane are already in operation or planned for launch in the next few years. Sensors on satellites measure methane in the total atmospheric column; they are typically not able to identify a specific emissions source and are limited in detection abilities to include only larger, super-emitter types of events. This can help identify trends and hot spots, and can also be used to provide insight into emissions data reported by individual facilities and are not excluding unknown events from unmanned facilities or pipelines. Williams has deployed services from industry leading satellite-based methane detection technologies, including those from Orbital Sidekick and Satlantis. [5,6]

Williams Market Engagement
Williams has joined together with methane science organizations, industry and academic-led initiatives, and technology providers to help establish industry best-practices across our assets. Partnerships include those with Gas Technology Institute (GTI), through their Veritas initiative, the Collaboratory for Advancing Methane Science (CAMS), the National Petroleum Council

[4] *See* Environmental Testing Services | Emissions Monitoring | Encino (encinoenviron.com)
[5] *See* Orbital Sidekick - Spectral Intelligence
[6] *See* HOME - Satlantis

Natural Gas Greenhouse Gas study, and has joined the United Nations Environmental Programme's Oil and Gas Methane Partnership 2.0. Williams also is a member of the ONE Future coalition, a group of Natural Gas companies working together to voluntarily reduce methane emissions across the natural gas value chain. Williams is also a member of the Differentiated Natural Gas Coordinating Council, a coalition of stakeholders across the natural gas supply chain dedicated to facilitating a pathway and common currency for policymakers, regulators, utilities, and gas consumers to utilize differentiated gas as an important option to meet their climate goals. Through these initiatives Williams will work to establish best practices to identify the most impactful and cost-effective GHG emission reduction opportunities, establish model frameworks for life-cycle emissions analysis, and establish model frameworks for life-cycle emissions reporting.

Question 1.5. What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?

Williams Response

Differentiated natural gas programs, when implemented in a trusted and transparent manner, verified by an independent third party, and done so in accordance with industry best-practices, can serve as a valuable market-mechanism, allowing buyers to better understand the emissions intensity of their gas supplies in support of their clean energy goals. Domestic and foreign buyers of natural gas are becoming increasingly interested in demonstrating the emission profile of their natural gas supplies, and may be willing to pay small premiums for gas that can be proven as having a low-emission profile as measured from production through delivery. Providing transparent emissions profiles for natural gas will lead to greater differentiation in procurement by both domestic and foreign buyers providing a market mechanism to incentivize and drive further emissions reductions. Certification programs that enhance the measurement and accuracy of emissions data across the natural gas supply chain from production through delivery, rather than certification programs that merely seek to differentiate based on reported EPA GHG Subpart W data for the production sector, can increase trust in U.S. natural gas and help demonstrate the low emissions attributes of U.S. LNG in support of European Union and other international emissions reduction initiatives. In summary, low carbon intensity natural gas is an affordable and valuable way for end-users to meet their climate commitments, drives operators towards continuous improvement and collaboration, and stimulates emission reduction investments.

Question 1.6. What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?

Williams Response

There is significant variation between the existing differentiated natural gas certification programs. Currently natural gas certification programs focus almost exclusively on production and provide data that is focused predominantly on methane emissions. This is the first and largest market gap. An end-to-end, full value chain approach is needed to provide trusted and transparent emissions data of gas delivered to LNG facilities. There are multiple certification programs providing this service, but the trust and transparency of data and methodology vary. This is the second gap; a common standard for emissions quantification and reporting. Most certifiers have relied upon factor-based emission models, calling into question the accuracy of emissions intensity being provided to LNG buyers and limiting the value of differentiated gas for the export market.

Context Labs is another certifier whose mission is to improve the reliability of methane emissions detection, quantification, and reporting to enable better-informed business decisions and quantification of end-to-end emissions across the natural gas supply chain by directly ingesting and reconciling information from multiple sources in real-time, including continuous monitoring devices, aerial, satellite, and operational data directly from equipment. With services provided by Context Labs, oil and gas operators can deploy capital more effectively to reduce greenhouse gas emissions and improve their operational efficiency. Although Context Labs has not publicly announced a partnership with any LNG exporters, it is working with a number of leading upstream and midstream operators who are key suppliers to LNG facilities, to ensure that end-to-end full supply chain emissions are accurately measured and verified in accordance with OGMP 2.0 (Level 4/5) and GTI Veritas standards, rather than estimated emissions.

Certifiers often provide additional value by utilizing blockchain carbon ledgers and digital registries. This allows the environmental attributes of an LNG cargo to be transparently audited and communicated to buyers without fear of double counting.

Williams has partnered with Context Labs to provide a full life-cycle solution for natural gas produced and delivered across all segments including production, gathering and boosting, processing, and transmission. [7] By leveraging multiple sources of real-time data, and by following commonly known industry leading methodologies such as OGMP 2.0 Level 5, trusted and transparent information can be provided to the customer each month by leveraging real-time data. KPMG verifies the calculation and data provenance and provides all source information to buyers through a blockchain carbon ledger and digital registry, allowing the environmental attributes of an LNG cargo to be transparently audited and communicated to buyers without fear of double counting. Additionally, through these technology partners, Williams is able to include both industry leading methane emission quantification, but also CO_2 emissions.

Question 1.7. What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

[7] *See* Williams to Partner With Context Labs on Technology to Certify and Optimize Clean Energy Delivery | Business Wire

Williams Response

Differentiated natural gas programs can play an important role in demonstrating that U.S. LNG is the cleanest in the world. Through the deployment of advanced technologies and by following globally recognized measurement and reporting methodologies, differentiated natural gas provides an element of trust in emissions data that demonstrates the low carbon attributes of U.S. natural gas versus other sources of energy. In a world that is increasingly concerned about climate change and emissions reductions, demonstrated low-emissions natural gas should have a competitive advantage in the global marketplace that enables further decarbonization around the globe, particularly with respect to demonstrating the ongoing climate benefits of continued coal to gas conversion.

Differentiated natural gas programs may be especially valuable to European buyers who are seeking to reconcile their need for secure, reliable, and affordable energy with their climate commitments. As discussions continue regarding a Carbon Border Adjustment Mechanism for LNG imported into Europe, differentiated natural gas can play an important role in ensuring that European buyers minimize their financial exposure to potential taxes associated with gas supply emissions while continuing to supply much needed natural gas to their customers. It is possible that differentiated natural gas programs become a requirement of climate conscious buyers internationally and are already becoming a preferred element of long-term LNG supply agreements. The DOE's efforts in establishing a best-practices framework for differentiated gas, using a globally recognized methane measurement and quantification methodology that considers all segments of the value chain, such as OGMP 2.0, is essential to ensuring the strategic benefits of American natural gas are recognized globally.

In conclusion, differentiated natural gas programs can play a crucial role in helping the U.S. gain a competitive advantage in foreign natural gas markets, facilitate long-term contracting by purchasers of U.S. natural gas, and promote continued decarbonization across the globe affordably and reliably. Differentiated natural gas programs represent a unique opportunity to advance U.S. national security, domestic economic vitality, and leadership in climate issues.

Thank you for the opportunity to comment on this RFI. Williams stands ready to further engage with FECM as you look at technologies and solutions, "…to reduce greenhouse gas emissions and other air pollutants associated with natural gas delivered to a liquefaction facility, at liquefaction facilities, and during the loading, transport, and delivery of natural gas to a regasification facility."

Respondent:

Sierra Club

Sierra Club appreciates the Department of Energy's (DOE) request for input regarding ways to reduce lifecycle greenhouse gas (GHG) and non-GHG air emissions resulting from exportation of liquefied methane, or so called "natural," gas (LNG). This letter responds in part to DOE's requests. Critically, however, it is impossible to fully or even substantially mitigate the climate, environmental, and community harm caused by continued expansion of the LNG industry. So while we are encouraged that DOE thinks industry can do better, that doesn't change the fact that continued expansion of this industry's activities will cause massive amounts of climate and other environmental and community harm.

I. Introduction.

Any increase in LNG exports is both unnecessary and unavoidably harmful. In its Net Zero Emissions by 2050 scenario, consistent with a 50% change of limiting global warming to 1.5° Celsius, the International Energy Agency (IEA) finds that there is no need for new LNG capacity beyond terminals already existing or under construction.[1] In contrast, economic projections that show a rise in US LNG export capacity are aligned not with climate stability but with a world where we breach our climate goals and face increasingly devastating climate impacts. Producing LNG is an extremely energy-intensive process that releases huge amounts of greenhouse gas and non-GHG pollutants at every step in the process, even with cutting-edge emission reduction technologies (more detail below). While we support efforts to reduce the lifecycle pollution from LNG exports, any new gas or LNG infrastructure will necessarily

[1] IEA (2022), World Energy Outlook 2022, IEA, Paris https://www.iea.org/reports/world-energy-outlook-2022, License: CC BY 4.0 (report); page 383

increase GHG emissions and local pollution. Moreover, these environmental harms often fall on communities already overburdened with pollution, particularly communities of color and low-income communities.

For any new LNG exports that are approved —and for already-existing gas and LNG infrastructure—we support applying available measures to mitigate environmental harms in a manner consistent with environmental justice best practices. But DOE's current public interest analysis fails to account for the real harms caused by LNG exports.

Every stage in the LNG lifecycle produces dangerous GHG and non-GHG air pollution that harms public health and the environment. LNG is primarily composed of methane, a greenhouse gas that is over 80x more potent than carbon dioxide, and prone to leakage (even with the most advanced technologies). The majority of US gas for export is fracked gas, extracted by a process that pollutes local air and water, in addition to releasing methane. It then travels through pipelines, where common methane leaks poison local communities and supercharge climate change. Then, the gas is compressed and supercooled in giant facilities, an energy intensive process that produces additional GHGs as well as local pollutants, including volatile organic compounds, nitrous oxides, sulfur dioxide, carbon monoxide, and particulate matter, and known human carcinogens like formaldehyde. These pollutants are known risk factors for cancer, respiratory, and cardiovascular disease. Next, the LNG is shipped overseas and regasified in GHG-intensive processes that further increase the fuel's lifecycle emissions. Finally, it is combusted for end use, releasing carbon dioxide (CO_2) and other pollutants. In fact, only 5% of the total lifecycle emissions of US LNG exports occur at the liquefaction site.[2]

II. Even with Necessary Emission Reduction Measures, LNG Exports Will Increase Upstream Domestic GHG and non-GHG Emissions.

LNG export is now the driving force behind increased US gas production, incentivizing upstream extraction by offering companies attractive overseas markets. According to the Energy Information Administration (EIA)'s Issues in Focus 2023, US gas production will rise through

[2] **Life Cycle Greenhouse Gas Emissions From U.S. Liquefied Natural Gas Exports: Implications for End Uses**
Leslie S. Abrahams, Constantine Samaras, W. Michael Griffin, and H. Scott Matthews
Environmental Science & Technology **2015** *49* (5), 3237-3245
DOI: 10.1021/es505617p

2050, driven not by domestic demand but by exports.[3] No matter what happens with LNG export capacity, the EIA expects domestic gas demand to stay flat or decline as renewable energy prices trend downward. However, in its scenario with aggressive LNG buildout, it projects overall gas production to rise in 2050 to levels 17% higher than would be seen in the reference case—evidencing that the increase in production is driven by rising export capacity.

Any analysis of LNG's GHG impacts, therefore, must consider realistic estimates of upstream GHG and non-GHG pollution from production that will be induced by increased LNG exports—pollution that DOE has consistently underestimated. For example, the 0.7% "upstream emission rate" or "leak rate" of U.S. LNG exports—the amount of methane that is emitted to the atmosphere during production, processing, and transportation of gas to the export facility—assumed in the DOE's 2019 analysis[4] drastically underestimates actual upstream leakage rates. One study published by Alvarez, et al., which Sierra Club has previously presented to DOE, estimates an average leak rate of 2.3%.[5] As we explained, there are many reasons to believe that this study's atmospheric measurements, and others like it, are more reliable than the "bottom up" estimates used by DOE—notably, the fact that bottom up estimates poorly represent the rare but severe major leaks that constitute a large fraction of upstream emissions.[6] And this is not an isolated report: multiple studies have shown that actual emissions are at least 60 to 100% higher than EPA's data indicate, and possibly much higher still.[7]

DOE, in its response to this comment, explained the difference between its estimate and this study's by arguing that the "higher leakage rates cited by Alvarez are merely indicative of the type of irregular behavior expected in highly variable natural gas systems, which have many contributors with skewed probability distribution functions (e.g., superemitters)." 85 Fed. Reg.

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[3] U.S. Energy Information Administration, AEO2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market, May 2023.

[4] 2019 Life Cycle GHG Perspective at 27.

[5] Sierra Club, Comment on 2019 Update to Life Cycle Greenhouse Gas Perspective at 6 (discussing Alvarez, et al., Assessment of methane emissions from the U.S. oil and gas supply chain, 361 Science 186 (July 13, 2018)).

[6] Sierra Club, Comment on 2019 Update to Life Cycle Greenhouse Gas Perspective, at 6-8 (Oct. 21, 2019), available at https://fossil.energy.gov/app/DocketIndex/docket/DownloadFile/604.

[7] *See, e.g.*, Rutherford, et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4 (showing that emissions are 1.5 to 2 times higher than official estimates suggest); Robertson, et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54 Environ. Sci. Technol. 13926–13934 (Oct. 15, 2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927.

72, 84 (Jan. 2, 2020). But that's the point: superemitters do skew the overall emission rate for gas production, but that doesn't make superemitters any less real or important, and superemitters are not adequately accounted for in NETL's bottom-up estimates. Subsequent research has consistently affirmed the importance of superemitters and the fact that actual emissions exceed NETL's bottom-up estimates. A 2020 study that found that oil and gas production in the Permian basin, the likely source of supply for many Gulf Coast export projects, had a leak rate of roughly 3.5% or 3.7%.[8]

More broadly, every year, new research further affirms that gas production emits greater amounts of methane than what DOE's analyses have assumed, despite ongoing efforts to reduce methane emissions.[9] DOE should be very leery about claims of "certified" gas or LNG.[10] In addition, upstream inputs for LNG infrastructure result in high emissions of GHGs and other harmful pollutants. Air pollution from US oil and gas production in 2016 resulted in 410,000 asthma exacerbations, 2,200 new cases of childhood asthma and 7,500 excess deaths. The total price tag for these health impacts was valued at $77 billion.

Companies can and should pin down where their gas supplies are coming from,[11] and such specifics would support more precise estimates of upstream emissions. The natural gas inputs that feed into LNG infrastructure are sources of major upstream emissions of many major pollutants, including climate-forcing greenhouse gasses such as methane and carbon dioxide, methane, smog- and soot-forming volatile organic compounds (VOC), and hazardous air

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[8] See Yuzhong Zhang et al., Quantifying methane emissions from the largest oil-producing basin in the United States from space, SCIENCE ADVANCES (Apr. 22, 2020), DOI: 10.1126/sciadv.aaz5120, available at https://advances.sciencemag.org/content/6/17/eaaz5120/tab-pdf;Environmental Defense Fund: New Data: Permian Oil & Gas Producers Releasing Methane at Three Times National Rate (Apr. 7, 2020), available at https://www.edf.org/media/new-datapermian-oil-gas-producers-releasing-methane-three-times-national-rate.

[9] See, e.g., EPA, Inventory of U.S. greenhouse Gas Emissions and Sinks 1990-2020: Updates for Anomalous Events (April 2022), available at https://www.epa.gov/system/files/documents/2022-04/2022_ghgi_update_-_blowouts.pdf; see generally NRDC, Sailing to Nowhere: Liquefied Natural Gas Is Not an Effective Climate Strategy (Dec. 2020), available at https://www.nrdc.org/sites/default/files/sailingnowhere-liquefied-natural-gas-report.pdf.

[10] For more information, see Lorne Stockman et al., Certified Disaster: How Project Canary & Gas Certification are Misleading Markets and Governments, Oil Change International and Earthworks, April 2023; Tim Donaghy, Lorne Stockman and Andy Rowell, Madness Is The Method: How Cheniere is Greenwashing its LNG With New Cargo Emissions Tags, Oil Change International and Greenpeace USA, August 2022.

[11] *See e.g.*, Sierra Club's Supplemental Letter Re: Driftwood Lines 200 & 300 Upstream Sources

pollutants like benzene, xylene, and formaldehyde, which are known human carcinogens. Although efforts to reduce upstream emissions from this sector can help alleviate the problem, even the most stringent regulations and best practices will necessarily leave large quantities of emissions unabated. In other words, even in a best-case scenario, LNG infrastructure creates a demand for a product the extraction, gathering and boosting, processing, transportation, and distribution of which imposes serious costs on our climate and air.

As a case study, it is instructive to look at the specific impacts of upstream greenhouse gas emissions from the oil and gas sector and compare them to expected reductions from pending regulations. Although only gas and not petroleum feeds into LNG infrastructure, it is actually necessary to consider this industry as a unified whole with regard to upstream emissions, rather than attempt to disaggregate the impacts of gas production compared to petroleum production. This is because the substantial majority of oil wells derive revenue from natural gas in addition to oil. In fact, in 2021, 95 percent of all oil produced for sale in the United States came from wells that produced some quantity of natural gas as well.[12] Thus, any expansion in LNG infrastructure incentivizes companies to drill wells that produce *any* quantity of gas—and these include the majority of oil wells.

According to EPA's 2023 Inventory of Greenhouse Gas Emissions and Sinks, U.S. natural gas systems emitted approximately 6.48 million metric tons (MMT) of methane in 2021 while U.S. petroleum systems emitted approximately 1.79 MMT, for a combined total of 8.27 MMT.[13] It is important to note that these figures likely underestimate the true extent of upstream methane emissions from the oil and gas sector; as noted above, multiple studies have shown that actual emissions are at least 60 to 100% higher than EPA's estimates suggest, if not higher.[14] Using a 100-year global warming potential (GWP) of 28 for methane,[15] EPA calculates that its

[12] This statistic is based on analysis on Enverus Prism data of onshore wells with non-zero production in 2021.
[13] EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990–2021*, 3-78 and 3-96 (Apr. 2023), https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.
[14] *See, e.g.*, Rutherford, et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4 (showing that emissions are 1.5 to 2 times higher than official estimates suggest); Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, 361 Science 186 (July 13, 2018), https://www.science.org/doi/10.1126/science.aar7204 (finding emissions 60% higher than EPA's data); Robertson, et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54 Environ. Sci. Technol. 13926–13934 (Oct. 15, 2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927.
[15] EPA, *supra* n. [12], at 1-10.

estimates for the oil and gas sector are equivalent to approximately 231.6 MMT of CO_2.[16] Again, EPA underestimates the true extent of these emissions: methane's 20-year GWP, which rounds to 83,[17] corresponds much more closely than the 100-year GWP to the time during which critical emission reductions must occur in order to avoid the worst impacts of climate change. Thus, the most appropriate CO_2-equivalent figure for these methane emissions is nearly three times what EPA has estimated in its inventory.

Taking a conservative approach and using EPA's figures, we assume that the oil and gas sector emits 8.27 MMT of methane per year. Later this year, the agency is expected to finalize strengthened methane standards for new oil and gas sources and the first-ever nationally applicable methane regulations for existing sources.[18] The agency anticipates that by 2026, these requirements will be fully implemented and will reduce sector-wide methane emissions by approximately 3.5 MMT per year through 2035.[19] If EPA's projections are correct, methane emissions would drop to 4.77 MMT, which calculates at 133.56 MMT in CO_2-equivalent values using (against, conservatively) EPA's preferred 100-year GWP of 28. EPA's methane regulations are not expected to reduce the oil and gas sector's CO_2 emissions, which, in 2021, were 36.2 MMT for natural gas systems and 24.7 MMT from petroleum systems.[20]

All told, then, even with EPA's nationwide methane controls fully implemented, the oil and gas sector is projected to emit approximately 194.5 MMT per year. To put this figure in perspective, it exceeds the national GHG contributions of over 80 percent of the world's countries—more than 150 nations—including Venezuela, Ethiopia, Colombia, the Czech Republic, Sudan, Romania, Peru, New Zealand, Austria, and Greece.[21] And, again, this estimate

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[16] *Id.* at 3-78 (showing 50.2 MMT CO2-e in methane emissions from petroleum systems) and 3-96 (showing 181.4 MMT CO2-e in methane emissions from natural gas systems).

[17] IPCC, *Climate Change 2021: The Physical Science Basis-- Working Group I Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, 7-125 (2021), https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Full_Report.pdf.

[18] *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 Fed. Reg. 74,702 (Dec. 6, 2022).

[19] EPA, *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 49 (Nov. 2022).

[20] EPA, *supra* n. [12], at 3-78 and 3-96.

[21] ClimateWatch, *Data Explorer*, https://www.climatewatchdata.org/data-explorer/historical-emissions?historical-emissions-data-sources=climate-watch&historical-emissions-end_year=2020&historical-emissions-gases=All%20Selected%2Call-ghg&historical-emissions-regions=All%20Selected&historical-emissions-sectors=total-excluding-lucf&historical-emissions-start_year=2020&page=1&sort_col=2020&sort_dir=DESC (last visited June 22, 2023).

is highly conservative: the true extent of upstream emissions from the oil and gas sector are likely much higher—and the climate-forcing impact much more severe—than EPA's official data indicate.

To be sure, more stringent standards and safeguards are possible. Many environmental groups—including a number of the undersigned organizations—strongly support EPA's proposed methane rule, but have urged the agency to implement stricter requirements, including more frequent leak detection and repair inspections and a prohibition on routine flaring of gas at oil wells.[22] Yet even the most ideally stringent regulations cannot eliminate upstream emissions, or even come anywhere near doing so. The simple fact is that oil and gas extraction inevitably entails large emissions of greenhouse gasses, VOCs, and hazardous air pollutants. And any actions that increase demand for natural gas—such as the build-out of LNG export infrastructure opening more U.S.-produced gas to foreign markets—will likewise increase upstream emissions, even with the most stringent regulatory requirements in place. DOE cannot ignore this reality.

III. Increased LNG Exports Are Inconsistent With International and Domestic GHG Reduction Targets.

Globally, avoiding catastrophic climate change by limiting global warming to 1.5° C—or even 2° C—will require drastic reductions in global emissions, which can only be achieved by phasing out fossil fuels as quickly as possible.[23] The world must transition to net-zero emissions by 2050, and reduce global CO_2 emissions by 45 percent by 2030—to do so, we need "rapid, deep and sustained reductions in global greenhouse gas emissions."[24] According to the United Nations Intergovernmental Panel on Climate Change (IPCC), to achieve these reductions, we

[22] *See, e.g.*, Envtl. Def. Fund, et al., *Joint Environmental Comments on New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, Dkt. No. EPA-HQ-OAR-2021-0317-2433 (Feb. 13, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2021-0317-2433/attachment_1.pdf.

[23] See Sierra Club Comments on 2019 Lifecycle Report at 4-5, available at https://fossil.energy.gov/app/DocketIndex/docket/DownloadFile/604; Sierra Club Comments on 2014 Lifecycle Report at 12-15, available at https://fossil.energy.gov/app/DocketIndex/docket/DownloadFile/180

[24] U.N. Framework Convention on Climate Change Secretariat, Glasgow Climate Pact at ¶17, available at https://unfccc.int/sites/default/files/resource/cop26_auv_2f_cover_decision.pdf.

must move to renewable energy as extensively and as quickly as possible.[25] The IEA similarly concludes that, globally, "there is no need for investment in new fossil fuel supply in our net zero pathway."[26] Accordingly, Executive Order 14,008, Tackling the Climate Crisis at Home and Abroad,[27] instructs federal agencies to discourage "high carbon investments" or "intensive fossil fuel-based energy."[28] Peer-reviewed research concludes that US LNG exports are likely to play only a limited role in displacing foreign use of coal.[29] Global LNG export volumes, specifically, must decline below present levels in just the next few years: as the IEA recently affirmed, further expansion of LNG export facilities cannot be part of the path to net-zero emissions.[30]

Multiple sources of evidence enable DOE to reasonably forecast where additional LNG might go. As discussed below, any additional demand from Europe will likely be limited to the short or intermediate term, expiring far before new LNG facilities' 30-year lifespans. In Asia, according to the International Energy Agency, "Demand from traditional LNG buyers, namely Japan and Korea, is likely to be flat or decline gradually depending on use in power generation;"[31] "demand from traditional buyers is expected to be stagnant."[32] Any growth in Asian LNG demand "is being driven by newer importers" or "non-traditional emerging buyers, namely Bangladesh, China, India and Pakistan."[33] Like the IEA, the EIA also uses tools to estimate the extent to which foreign markets are actually likely to buy US LNG.[34] Other evidence also indicates how these receiving markets will shift in response to additional LNG. Peer reviewed research concludes that US LNG exports are likely to play only a limited role in

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[25] Intergovernmental Panel on Climate Change, Special Report: Global Warming of 1.5 C, Summary for Policymakers at 15 (May 2019) ("IPCC 2019"), available at https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_SPM_version_report_LR.pdf.
[26] International Energy Agency, Net Zero by 2050, at 11 (May 2021), available at https://iea.blob.core.windows.net/assets/7ebafc81-74ed-412b-9c60-5cc32c8396e4/NetZeroby2050-ARoadmapfortheGlobalEnergySector-SummaryforPolicyMakers_CORR.pdf.
[27] 86 Fed. Reg. 7619 (Jan. 27, 2021).
[28] Executive Order 14,008, 86 Fed. Reg. 7619, at § 102(f), (h) (Jan. 27, 2021).
[29] Gilbert, A. Q. & Sovacool, B. K., US liquefied natural gas (LNG) exports: Boom or bust for the global climate?, Energy (Dec. 15, 2017), available at https://doi.org/10.1016/j.energy.2017.11.098.
[30] International Energy Agency, Net Zero by 2050, at 102.
[31] International Energy Agency, Global Gas Security Review 2019 (web version) (Sept. 2019), https://www.iea.org/reports/global-gas-security-review-2019; pdf report available at https://webstore.iea.org/download/direct/2832?fileName=Global_Gas_Security_Review_2019.pdf.
[32] *Id.* at 4.
[33] *Id.* at 4, 11.
[34] See, e.g., https://www.eia.gov/outlooks/aeo/assumptions/pdf/natgas.pdf at 4.

displacing foreign use of coal.[35] Thus, the argument that US LNG can serve as a "bridge fuel" abroad falls flat as recent evidence shows how it will be unsuccessful in replacing harmful coal and as a fossil fuel itself, contribute to an overall increase in global GHG.

Thus, the proposed buildout of US LNG infrastructure is far outside of domestic and global carbon budgets, and even operating existing infrastructure through the end of its proposed lifespan jeopardizes our ability to meet climate targets. Lifecycle emissions from full operation of the existing US LNG export facilities are estimated to be 557 million metric tons (MMT) CO_2e annually, equivalent to over 120 million gasoline-powered cars or 149 coal plants.[36] Estimated annual lifecycle emissions for the four projects under construction along with the 32 proposed projects would be equivalent to emissions from 532 coal plants or over 428 million gasoline-powered cars (1,987 MMT CO_2e). That means that existing facilities, proposed expansions, and new LNG export projects could collectively contribute to the climate crisis as much as 681 new coal fired power plants or 548 million gasoline-powered cars (2,544 MMT CO2e) *each year*. Furthermore, the proposed lifespans for these facilities will lock in high GHG emissions for decades, making it virtually impossible to meet global climate goals.

In focusing on whether there are non-US requirements for greenhouse gas performance for US LNG (Topic 4), DOE is asking the wrong question. Instead, mounting evidence demonstrates that Europe—currently the largest importer of US LNG—is seeking to rapidly cut demand for gas. The IEA has concluded that heat pumps, building efficiency, and similar measures can significantly reduce the European Union's gas use within a year, with greater reductions each following year.[37] As the EU and many other regions shifted to US gas from

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[35] Gilbert, A. Q. & Sovacool, B. K., US liquefied natural gas (LNG) exports: Boom or bust for the global climate?, Energy (Dec. 15, 2017), available at https://doi.org/10.1016/j.energy.2017.11.098.

[36] Sierra Club's LNG lifecycle emissions estimates are based on methodology from a Carnegie Mellon study on LNG lifecycle emissions using the 20 year global warming potential of methane, in this case applied to the capacity of LNG terminals.
Life Cycle Greenhouse Gas Emissions From U.S. Liquefied Natural Gas Exports: Implications for End Uses
Leslie S. Abrahams, Constantine Samaras, W. Michael Griffin, and H. Scott Matthews
Environmental Science & Technology **2015** *49 (5)*, 3237-3245
DOI: 10.1021/es505617p
Equivalent emissions from coal plants or gasoline-powered cars are calculated using the EPA's GHG Equivalency Calculator.
Sierra Club's LNG project counts and statuses are based on the FERC LNG Export list, DOE's list of Long Term Applications Received to Export, MARAD Deepwater Port Licensing applications, and projects tracked on the ground by local campaign members and partners. See https://www.sierraclub.org/dirty-fuels/us-lng-export-tracker

[37] International Energy Agency, A 10-Point Plan to Reduce the European Union's Reliance on

Russian gas after the 2022 Russian invasion of Ukraine, the most secure shift would be off gas and towards renewable energy. Some analyses conclude that the EU can entirely eliminate reliance on Russian gas by 2025, with efficiency and renewable energy making up for two thirds of the former Russian supply.[38] Similarly, the United Kingdom's Energy & Climate Intelligence Unit has concluded that all of the UK's gas demand that was recently met by Russian gas could be eliminated through installation of heat pumps and better installation within five years.[39] European Energy Commissioner Kadri Simson has emphasized that Europe remains committed to renewable energy goals, and is looking to additional gas imports only for the short term.[40] Members of the U.S. Congress and the European Parliament have emphasized that, notwithstanding the need to assist Europe in transitioning off of Russian gas, no new gas infrastructure or exports should be approved.[41]

Even considering only the emissions that occur on US soil, the proposed LNG buildout also prevents the US from meeting domestic climate goals. The US's own emission reduction goals, and international climate agreements to which the US is a party, specifically call on the US to address territorial emissions, regardless of whether domestic emission increases might be offset by foreign emission reductions. Compliance with commitments made under the Paris Accord is evaluated based on "greenhouse gas emissions and removals taking place within national territory and offshore areas over which the country has jurisdiction."[42] Moreover,

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Russian Natural Gas (March 3, 2022), available at https://www.iea.org/reports/a-10-point-planto-Reduce-the-european-unions-reliance-on-russian-natural-gas.

[38] https://www.e3g.org/publications/eu-can-stop-russian-gas-imports-by-2025/ or https://9tj4025ol53byww26jdkao0x-wpengine.netdna-ssl.com/wp-content/uploads/Briefing_EUcan-stop-Russian-gas-imports-by-2025.pdf

[39] Harry Cockburn, Heat Pumps and Insulation 'Fastest Way to End Reliance on Russian Gas," the Independent, March 9, 2022, available at https://www.independent.co.uk/climatechange/news/heat-pumps-russian-gas-north-sea-b2032017.html; *see also* Energy & Climate Intelligence Unit, Ukraine Conflict and Impacts on UK Energy, https://eciu.net/analysis/briefings/uk-energy-policies-and-prices/briefing-ukraine-conflict-andimpacts-on-uk-energy.

[40] https://www.politico.com/newsletters/morning-energy/2022/04/28/doe-declares-an-energywar-00028380.

[41] Jared Huffman et al., Letter to U.S. President Biden and E.C. President Von der Leyen (May 19, 2022), https://huffman.house.gov/imo/media/doc/Letter%20Regarding%20the%20EUUS%20Joint%20Energy%20Security%20Statement_5.19.22.pdf

[42] Intergovernmental Panel on Climate Change, 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 8: Reporting and Tables, at 8.4 available at https://www.ipccnggip.iges.or.jp/public/2019rf/pdf/1_Volume1/19R_V1_Ch08_Reporting_Guidance.pdf.

Executive Order 14,008 affirms that "Responding to the climate crisis will require … net-zero global emissions by mid-century or before."[43] As an interim step, President Biden has announced a "commitment to reduce US emissions by 50-52% from 2005 levels in 2030."[44]

Increased LNG exports are entirely inconsistent with these domestic reductions. In Figure 1 below, the yellow wedge represents business-as-usual emissions, using projections developed by Rhodium (which include the benefits of the Inflation Reduction Act), modified to include only LNG export capacity currently operating as of 2023.[45] Under this scenario, the US will make some progress toward reducing climate emissions by 2030, reducing emissions 28% below 2021 levels by 2030. However, if planned and under-construction LNG terminals come online (represented by the gray and red wedges), one-third of that progress is wiped out, with emissions reductions of only 18% from 2021 to 2030.[46] This is compared to the blue line, which represents the Biden administration's aforementioned 2030 emissions reduction commitment, as well as the goal to reach net zero emissions by 2050. Under the business-as-usual scenario, US emissions are projected to overshoot the 2030 goal by 21%. If the slate of currently planned and under-construction LNG terminals comes online, the US will overshoot the 2030 goal by 36%.

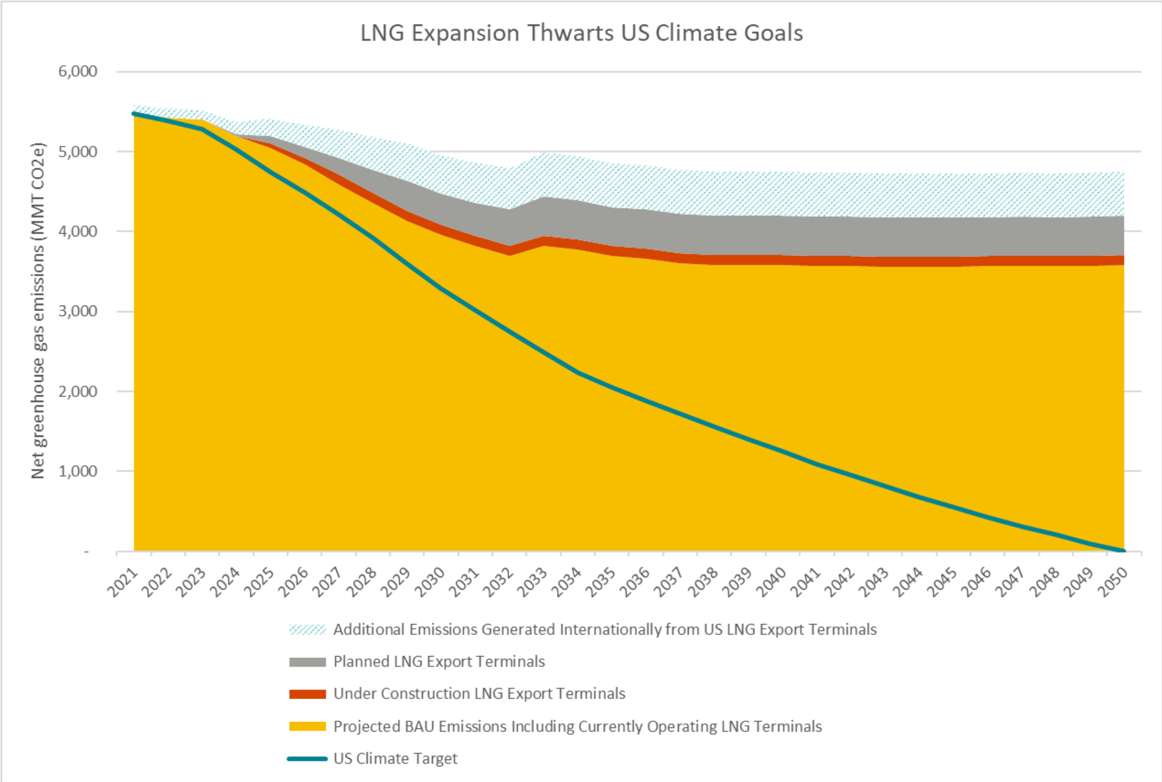
[43] Id. § 101, 86 Fed. Reg. at 7619.

[44] https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/13/fact-sheetrenewed-u-s-leadership-in-glasgow-raises-ambition-to-tackle-climate-crisis/.

[45] Using projections from the Central scenario https://rhg.com/research/climate-clean-energy-inflation-reduction-act/

[46] See footnote 15.

Figure 1. Net GHG emissions including LNG buildout compared with US climate target



IV. LNG Export Facilities Exacerbate Non-GHG Air Pollution.

LNG exports result in unavoidable and extensive non-GHG air impacts where LNG infrastructure is located, most often in communities already overburdened by pollution. While DOE should insist on emission reduction methods—such as electrification of onsite power and refrigeration turbines, onsite renewable energy production to power LNG operations (including these electric turbines), selective catalytic reduction (SCR), and catalytic oxidizers to destroy waste gasses—even those strategies will not eliminate air pollution from LNG facilities. DOE can and must evaluate air pollution, public health, and environmental justice impacts in any public interest analysis for new LNG export authorizations.[47]

To do so, DOE must conduct its own evaluation of air pollution from the LNG buildout and cannot simply defer to analyses conducted by state agencies (or the EPA) under the Clean

[47] See, e.g., Exec. Order No. 12,898, 59 Fed. Reg. 7629 (Feb. 16, 1994) (directing federal agencies to identify and address "disproportionately high and adverse human health or environmental effects" of their actions on minority and low-income populations (i.e., environmental justice communities)).

Air Act. This is because, among other things, the “significance” analysis under the Clean Air Act’s prevention of significant deterioration (PSD) program does not guarantee that LNG facilities will have zero emissions, nor is it intended to. And serious concerns about abuse of the “significant impact levels” thresholds undermine confidence that states are ensuring compliance with the health-based National Ambient Air Quality Standards (NAAQS).[48]

Under the PSD program, new sources in areas currently in compliance with the NAAQS must “demonstrate” that their emissions will “not cause or contribute” to any violation of the NAAQS.[49] An applicant “demonstrate[s]” compliance with the NAAQS with standardized computer modeling.[50] If that modeling demonstrates that the source causes or contributes to a NAAQS violation, the permitting authority cannot issue a PSD permit unless the source reduces its impacts or mitigates the predicted NAAQS violation.[51] Even if modeling indicates that an area will violate the NAAQS, however, air permitting agencies may issue a permit if the source’s modeled impacts are below the significant impact level (SIL).

This approach is insufficient for DOE’s purposes because the PSD significant impacts analysis looks *only* at a source’s pollution contribution to potential NAAQS violations at a specific location in “time and space” that the model predicts will exceed the NAAQS.[52] The analysis says nothing about the source’s maximum pollution contribution. Nor does a SILs analysis say anything about the cumulative pollution impacts of the proposed project in areas that are already suffering from unhealthy air quality. In conducting any NEPA review of new LNG facilities, by contrast, DOE must evaluate all of the direct, indirect, and cumulative effects that

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[48] SILs petition

[49] See 42 U.S.C. § 7475; Alaska Dep't of Env’t Conservation v. EPA, 540 U.S. 461, 470 (2004); Ala. Power Co. v. Costle, 636 F.2d 323, 362 (D.C. Cir. 1979).

[50] See 40 C.F.R. Part 51, App. W §§ 8.1, 8.3, 9.2.

[51] See, e.g., 40 C.F.R. § 51.165(b)(2) (requiring a major stationary source that contributes to the violation of the NAAQS to “reduce the impact of its emissions upon air quality by obtaining sufficient emission reductions to, at a minimum, compensate for its adverse ambient impact where the major source or major modification would otherwise cause or contribute to a violation . . . .”).

[52] EPA guidance indicates that “the significant contribution analysis should be based on a source’s contribution to the modeled violation paired in time and space.” EPA, Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2, National Ambient Air Quality Standard at 3 (Mar. 1, 2011) (hereinafter “NO2 Modeling Guidance”).

[5]

project may have on environmental justice communities, even if the project's air emissions do not exceed the SIL at the precise time and location of any predicted NAAQS violation.

Nor can DOE adopt the unlawful position that air pollution is of no concern so long as a facility's share of pollution is below the so-called SILs used by state permitting agencies to assess whether a source contributes to a violation of the NAAQS. Courts have rejected the use of SILs as a blanket exemption from the requirement to fully evaluate and mitigate harmful air pollution impacts. The Clean Air Act requires each proposed LNG facility to demonstrate that its emissions "will not cause or contribute" to "*any*" exceedance of the applicable air quality standard.[53] It is clear—"no" means no[54]—and, as shown by the repeated use of "any," the statutory mandate must be given broad, sweeping effect.[55] Indeed, this is the very sort of "rigid" statutory language that forecloses *de minimis* exemptions.[56] Reliance on SILs to avoid consideration of alternatives or minimize pollution impacts is also contrary to the core purposes of the Clean Air Act: to *prevent* incremental, cumulative additions of pollution from deteriorating air quality.[57] Consistent with those principles and statutory text, in 2013, the D.C. Circuit vacated EPA's SILs regulation for fine particulate matter ("$PM_{2.5}$"), recognizing EPA's "lack of authority to exempt sources from the requirements of the Act."[58] The court specifically rejected the premise that a source does not contribute to violations of the NAAQS simply because "a proposed source or modification's air quality impact is below the SIL." *Id*.[59]

Finally, even if the SILs were relevant to DOE's air pollution inquiry (and they are not), EPA has made clear that use of the SILs "may not be appropriate" and may be "misuse[d]"

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[53] 42 U.S.C. § 7475(a)(3)(A)-(B) (emphasis added).
[54] See United States v. Clintwood Elkhorn Mining Co., 553 U.S. 1, 7 (2008).
[55] See Consumer Electronics Ass'n v. FCC, 347 F.3d 291, 298 (D.C. Cir. 2003) ("the Supreme Court has consistently instructed that statutes written in broad, sweeping language should be given broad, sweeping application."); see also Clintwood Elkhorn Mining, 553 U.S. at 7 ("Five 'any's' in one sentence and it begins to seem that Congress meant the statute to have expansive reach."); Massachusetts v. EPA, 549 U.S. 497, 528-29 (2007) ("repeated use of the word 'any'" demonstrated that statutory language was "sweeping" in its protective reach).
[56] See Public Citizen v. Young, 831 F.2d at 1111-13 (quoting statutory language whose "natural—almost inescapable—reading" requires certain action and finding that language is rigid).
[57] Alabama Power, 636 F.2d at 362.
[58] Sierra Club v. EPA, 705 F.3d 458, 465–66 (D.C. Cir. 2013).
[59] See also Rise St. James et al. v. Louisiana Dep't Envtl. Quality, Docket No. 694,029, Sec. 27 (19th Dist. La. Sept. 8, 2022) (vacating a PSD permit and the agency's environmental justice analysis, in part, based on the agency's arbitrary reliance on SILs to conclude that no harm would occur, despite impacts below the SIL).

where modeling shows that the area is already exceeding the NAAQS.[60] In such cases, "[a]dditional discretion may need to be exercised in such cases to ensure that public health is protected."[61] That is because pollution increases within the SIL can still cause or contribute to nonattainment.[62]

By way of example, if a proposed source will emit NO_2 that has a potential contribution of 37.7 µg/m^3, or more than 20% of the NAAQS (as FERC's modeling for the Commonwealth LNG facility outside of Lake Charles, Louisiana projects),[63] it plainly has the potential to tip an area that is at or near the NAAQS (like Lake Charles, Louisiana) into nonattainment, and therefore adversely affect public health in those communities. Around Lake Charles, the high concentration of existing and proposed LNG infrastructure will result in and exacerbate violations of health-based National Ambient Air Quality Standards for at least nitrogen dioxide.[64] Specifically, FERC's modeling for the Commonwealth LNG facility outside of Lake Charles, Louisiana, shows that the maximum 1-hour NO_2 concentration in the area is 229 µg/m^3—exceeding the NAAQS by more than 20%. EIS at 4-229. That estimate almost certainly underestimates the extent and scope of NO_2 exceedances in the area. Using Commonwealth LNG's own PSD modeling inputs, and after expanding the size of the receptor grid and number of receptors in the area, Wingra Engineering conducted an updated, independent modeling analysis demonstrating a maximum NO_2 concentration of 1,537 µg/m^3 in Cameron and Calcasieu Parishes—approximately eight times the NAAQS.[65]

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[60] 75 Fed. Reg. 64,864, 64,894 (Oct. 10, 2020); EPA, Guidance on SILs for Ozone and Fine PM in the PSD Program, p. 3 (2018) (citing 75 FR 64864, 64892 and Memorandum from Stephen D. Page, EPA OAQPS, to EPA Regional Air Division Directors, "Guidance for PM2.5 Permit Modeling," May 20, 2014), available at https://www.epa.gov/sites/production/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf (attached).

[61] NO2 Modeling Guidance at 1, 10; see also EPA, Guidance Concerning the Implementation of the I-hour NO NAAQS for the Prevention of Significant Deterioration Program at 5 (June 29, 2010) (Where "the applicant can show that the NOx emissions increase from the proposed source will not have a significant impact at the point and time of any modeled violation, the permitting authority has discretion to conclude that the source's emissions do not cause or contribute" to an exceedance of the NAAQS) (PSD Guidance).

[62] See 75 Fed. Reg. at 64,892, 64,894/2.

[63] EIS at 4-227, Table 4.11.1-8; see also Final EIS, App'x I.

[64] CITE to Commonwealth LNG comments & modeling

[65] Modeling Comments of Steven Klafka, P.E., BCEE, Wingra Engineering, S.C., Commonwealth LNG Commonwealth Parish, Louisiana, Evaluation of Compliance with the 1-hour NAAQS for NO2 (Mar. 18, 2022) (Klafka Report), filed in this docket as an attachment to Sierra Club et al. Comments on DEIS, Accession 20220525-4151 (starting at pdf page 119 of 131 of the attachment "Sierra Club PSD Comments").

Commonwealth LNG is, by itself, responsible for as much as 37.7 $\mu g/m^3$ of NO_2 pollution, or approximately 20 ppb—well above the SILs and above the levels at which EPA has found to result in adverse health impacts.[66] Although those impacts do not occur at the precise time and location of modeled violations of the NAAQS, the SILs do not represent a threshold below which there is zero-risk. In fact, EPA and courts have recognized that adverse effects from NO_2 may occur at any ambient concentration, and there is no "threshold" NO_2 concentration below which respiratory health effects do not occur.[67] Thus, even if Commonwealth LNG's individual pollution impacts do not exceed the SIL at the precise time and location of any NAAQS exceedance, that does not demonstrate that the direct and cumulative effects of Commonwealth LNG's air pollution on human health will be insignificant, or that such disproportionate impacts are not cause for concern.

Moreover, for environmental justice communities in and around Lake Charles where petrochemical facilities, heavy industry, and other emissions are already contributing to air quality that is violating or projected to violate the NAAQS, *any* increase in NO_2 will cause the violation to persist and make it harder to cure. Those very real, cumulative contributions to unhealthy air quality in environmental justice communities cannot be reasonably characterized as insignificant or *de minimus*, even if, for the purposes of PSD permitting evaluation, Commonwealth LNG itself is not projected to exceed the "significant impact level" at a violating modeling receptor location.[68]

Reliance on the SILs for NO_2 impacts also fails to address or evaluate environmental justice communities' cumulative exposure to multiple pollutants. This risk of multiple exposure may not be captured by the NAAQS because EPA sets the NAAQS in a context of assessing "acceptable" risks, not eliminating all risk. *Murray Energy Corp. v. EPA*, 936 F.3d 597, 609 (D.C. Cir. 2019). Moreover, NO_2 pollution also contributes to the formation of harmful

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[66] CITE

[67] EPA Integrated Science Assessment for Oxides of Nitrogen—Health Criteria at 5-92 (Jan. 2016), available at https://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=310879; see also NAAQS for Nitrogen Dioxide, 75 Fed. Reg. 6,474, 6,480, 6,500 (Feb. 9, 2010); Am. Trucking Ass'n, Inc. v. EPA, 283 F.3d 355, 359-360 (D.C. Cir. 2002) (NO2 is recognized as a pollutant for which no threshold of exposure fully protects human health).

[68] EPA guidance indicates that "the significant contribution analysis should be based on a source's contribution to the modeled violation paired in time and space." EPA, Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2,National Ambient Air Quality Standard at 3 (Mar. 1, 2011) (hereinafter "NO2 Modeling Guidance").

particulate matter and ozone pollution, for which EPA has similarly found that there are no zero-risk thresholds below which adverse health effects will not occur.[69] DOE must not myopically focus on the SILs because doing so would fail to account for the cumulative pollution impacts of NO_2, including ozone and particulate matter formation that may disproportionately affect environmental justice communities.

Commonwealth LNG is not the only facility where abuse of the SILs raises serious air pollution, environmental justice, and public health concerns. Frontline groups and allies recently submitted a petition asking the EPA to address the systematic abuse by Louisiana and Texas of EPA's SILs Guidance.[70] The result of these states' abuse is to permit massive concentrations of air-polluting sources that threaten or exceed the National Ambient Air Quality Standards (NAAQS) and disproportionately harm Black, Latino, Indigenous, and low-income residents of the States with criteria air pollution. Emissions from LNG facilities are exacerbating these issues.

Again, we are encouraged to see this request for information from DOE regarding ways to reduce lifecycle greenhouse gas (GHG) and non-GHG air emissions resulting from LNG exports. We must reiterate how critically important it is that DOE not allow industry greenwashing to distract from its obligations to scrutinize whether additional LNG exports are in the public interest in the first place. DOE must reject any premise that LNG can be "net zero" or "environmentally friendly." The production, liquefaction, transport, and consumption of LNG from the buildout of additional infrastructure will inherently result in more pollution for communities and the climate.

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[69] EPA, Policy Assessment for the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter at 3-25, 3-30, 3-31, 3-33, 3-51 (May 2022), available at https://www.epa.gov/system/files/documents/2022-05/Final%20Policy%20Assessment%20for%20the%20Reconsideration%20of%20the%20PM%20NAAQS_May2022_0.pdf; see also 80 Fed. Reg. 65,292, 65,355/2-3 (Oct. 26, 2015) (EPA's ozone NAAQS); accord 80 Fed. Reg. 65,334/2-3.

[70] Petition for Action on Louisiana's and Texas' Clean Air Act Programs for Abuse of the Significant Impact Levels Guidance and Violations of the Clean Air Act, State Implementation Plans, and Title VI of the Civil Rights Act (Attached).

EARTHJUSTICE

BEFORE THE ADMINISTRATOR OF THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

PETITION FOR ACTION REGARDING DEFICIENCIES IN THE LOUISIANA AND TEXAS CLEAN AIR ACT PROGRAMS BY ABUSING SIGNIFICANT IMPACT LEVELS, IN VIOLATION OF THE PREVENTION OF SIGNIFICANT DETERIORATION PERMITTING PROGRAM, NATIONAL AMBIENT AIR QUALITY STANDARDS, AND TITLE VI OF CIVIL RIGHTS ACT

I. INTRODUCTION

RISE St. James, Vessel Project of Louisiana, For a Better Bayou, Deep South Center for Environmental Justice, Healthy Gulf, Louisiana Bucket Brigade, and Sierra Club ("Petitioners") petition the Administrator of the Environmental Protection Agency Region 6 ("Administrator" or "EPA"), pursuant to the Administrative Procedure Act, 5 U.S.C. § 551 *et seq.*, the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7401 *et seq.*, and the Act's implementing regulations, to address the failures of the State of Louisiana and the State of Texas (the "States") to implement properly the Act's Prevention of Significant Deterioration ("PSD") permitting, National Ambient Air Quality Standards ("NAAQS") requirements and protections, and specifically their abuse of EPA's "significant impact levels" ("SILs") guidance.

The States, which each administer the Act's air pollutant emission permitting programs through an EPA-approved State Implementation Plan ("SIP") and related State regulations, regularly fail to comply with the Act and SIP requirements when issuing PSD permits based on EPA's 2018 Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (the "SILs Guidance").[1] They instead use the SILs unlawfully as a tool to permit large concentrations of heavy-emitting industry to build in areas where modeling shows the air may no longer meet the NAAQS. They do it without exercising the case-by-case discretion that the SILs Guidance requires or complying with the Clean Air Act's prohibition on causing or contributing to such violations. And in nearly every instance we describe, the resulting harm—air that is dangerous to breathe—falls most heavily on the predominately Black, Latino, or Indigenous, as well as low-income communities that live closest to these industrial facilities. This is how sacrifice zones are created.

The States' failings are not simply the product of poor individual permitting decisions. These errors and omissions are repeated in permit after permit and reflect statewide policies that ignore the mandates of the CAA, misapplying their respective SIPs, abusing EPA's SILs

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[1] EPA, "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program" (Apr. 17, 2018), https://www.epa.gov/sites/production/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf.

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Guidance, and brutalizing environmental justice.[2] Specifically, our experience and the evidence and examples below show that the States are systematically committing the four following legal violations: ***1)*** omitting the exercise of case-specific discretion despite using SILs in areas at risk of violating or increasing violations of the public-health-based NAAQS; ***2)*** issuing PSD permits to construct when modeling shows the new sources will cause or contribute to NAAQS violations, contravening the PSD permitting program's core purpose; ***3)*** failing to take any other remedial measures to cure the NAAQS and increment violations that appear in new sources' air quality modeling or to collect and account for SILs use data. Further, each of these three kinds of Clean Air Act violations ***4)*** harm, disproportionately, frontline Black, Latino, Indigenous, and other communities of color and low-income communities, in violation of environmental justice and civil rights mandates.

In enacting the CAA, Congress foresaw that states would be tempted to subvert PSD requirements to advance other policy objectives, and Congress wisely provided EPA with ample authority to remedy exactly the kind of illegal action now prevalent in the States' programs.

II. REMEDIES REQUESTED

Consequently, the Petitioners petition EPA to use its statutory authority to address the States' abuse of the SILs Guidance. EPA possesses a wide range of legal authority empowering, and in some instances requiring it, to correct this harm, under both the Clean Air Act and Title VI of the Civil Rights Act.

A. Clean Air Act.

We first ask EPA Region 6 to act in its oversight role under the Clean Air Act to correct Louisiana Department of Environmental Quality's ("LDEQ") and Texas Commission on Environmental Quality's ("TCEQ") failures to comply with the Act, and properly implement the States' SIPs, in their air permitting programs. Namely, we ask EPA Region 6 to: ***1)*** find and issue notice that States are failing properly to implement the Clean Air Act and their SIP permitting provisions by allowing new sources to "cause or contribute" to NAAQS violations or avoid cumulative air quality modeling altogether, *see* 42 U.S.C. §§ 7410(k)(5), 7413(a)(2), (5), 7509(a)(4); ***2)*** prohibit the use of SILs to permit new or modified major stationary sources in Louisiana and Texas, under 42 U.S.C. § 7413(a)(5); ***3)*** enforce the Act and SIP by amending permits that were issued based on abuse of SILs Guidance, including in the examples described below, under 42 U.S.C. § 7413(a)(2), ***4)*** impose sanctions on the States, under 42 U.S.C. §§ 7509(b) and 7410(m), and ***5)*** keep these prohibitions and enforcement measures in place for each State until it comes into compliance with the Act. Petitioners also request that ***6)*** EPA exercise its oversight authority under 42 U.S.C. § 7413(a)(2), (5), *inter alia*, to investigate ***A)*** each State's use or abuse of the SILs guidance and ***B)*** the cumulative air pollutant emissions associated with the use or abuse of the SILs guidance throughout Region 6, including revising the SIPs as necessary to address the violations, *see* 42 U.S.C. § 7410(k)(5).

[2] This Petition focuses on the States' abuse of the SILs Guidance, as applied. Nothing in this Petition is meant to suggest, and the Petitioners do not concede, that the SILs Guidance itself is a lawful policy under the Clean Air Act. *See Sierra Club v. EPA*, 955 F.3d 56 (D.C. Cir. 2020) (raising facial challenge to SILs Guidance). Petitioners are simply not raising that issue at this time.

In addition, to ensure the States meet the Clean Air Act requirements when applying the existing guidance on SILs, Petitioners call for EPA Region 6 to direct LDEQ and TCEQ on the factors that constitute a "basis for concern" under the SILs Guidance, and so disqualify the application of SILs at the preliminary screening level to forego cumulative modeling and full impacts review.[3] As this Petition demonstrates, such bases for concern arise, for example, ***a)*** where modeling for a criteria pollutant shows an exceedance of NAAQS or increment, ***b)*** where an "attainment area" compliance status is not based on monitoring; and ***c)*** where a facility would impact environmental justice communities or other communities carrying (or slated to carry) a disproportionate pollution burden.

B. Title VI of the Civil Rights Act.

Further, because many of the States' abuses of the SILs Guidance meet the four factor disproportionate impacts test, the Petitioners request that EPA ***6)*** perform a Title VI compliance review and exercise its full authority under the Civil Rights Act of 1964 to reverse and remedy the attendant environmental injustices; and ***7)*** consider this Petition to also constitute a Title VI complaint and initiate investigation on LDEQ's ongoing practice of violating the Civil Rights Act of 1964, including within the last 180 days by its decisions on ***A)*** December 5, 2022 to extend the Formosa Plastics major source air permits' deadlines to commence construction, and ***B)*** March 28, 2023 to grant the Commonwealth LNG major source air permits.[4]

III. PETITIONERS

A. **RISE St. James** is a faith-based grassroots organization dedicated to environmental justice and ending the proliferation of petrochemical industries in St. James Parish, Louisiana. Its leaders are descended from people who were enslaved in the area. They have lived in the 5th District of St. James all their lives and have been exposed to heightened levels of carcinogens, and a dramatically increased risk of cancer and other diseases attendant to heavy industrial sitings in those Districts, as a result of LDEQ's ongoing practice of violating the Clean Air Act and Civil Rights Act of 1964. There are 12 industries within a 10-mile radius in the 4th district (district directly across the Mississippi River from the 5th District) and 5th District of St. James Parish.

B. **The Vessel Project of Louisiana** is a grassroots mutual aid and disaster relief organization founded in Southwest Louisiana in response to several federally declared

[3] SILs Guidance, *supra* note 1, at 18 ("However, upon considering the permit record in an individual case, if a permitting authority has a basis for concern that a demonstration that a proposed source's impact is below the relevant SIL value at all locations is not sufficient to demonstrate that the proposed source will not cause or contribute to a violation, then the permitting authority should require additional information from the permit applicant to make the required air quality impact demonstration.").

[4] 42 U.S.C. § 2000d; 40 C.F.R. § 7.35(b). LDEQ is a recipient of federal funding forbidden from administering its permitting program to have discriminatory effects, i.e., "the effect of subjecting individuals to discrimination because of their race, color, national origin, or sex." 40 C.F.R. § 7.35(b); *see also id.* §§ 7.115(a) (authorizing EPA to initiate compliance reviews); 7.120(a) (requiring EPA to undertake prompt investigation of all Title VI complaints).

disasters, including hurricanes Laura and Delta, winter storm Uri, and the May flood of 2021. The Vessel Project aims to create horizontal pathways for people in communities to help one another without a hierarchical bureaucratic structure. The violation of air pollution permitting standards in Louisiana not only harms the health of children and families, but it also hinders the mission of The Vessel Project of Louisiana. As Vessel Project strives to help the most vulnerable communities, including black, indigenous, people of color, and low-income individuals, we are faced with the challenge of addressing the emergency needs of those affected by the harmful effects of air pollution and the industries that cause it. These violations create additional barriers for our efforts to be efficient and barrier-free, making it difficult for individuals to maintain their dignity and advocate for themselves. We must continue to fight for environmental justice to ensure that these communities are protected from the harmful effects of pollution and have access to the resources they need to thrive.

C. **For A Better Bayou** is a community-based organization in Southwest Louisiana that is raising awareness and building a community-based movement to ensure protections for a sustainable bayou and environment. For A Better Bayou educates community members on the world-wide climate crisis and how that impacts Southwest Louisiana and the bayous in the region which provide a myriad of benefits to the surrounding communities. With outings like bird walks and other events in the Lake Charles area, For A Better Bayou also educates the community on the value of a robust and diverse ecosystem. LNG, petrochemical, and other major industry construction and operation in the Lake Charles produce harmful air and water pollution that impact For A Better Bayou's community, employees, and members, and also interfere with For a Better Bayou by deterring engagement in outdoor activities in the region.

D. **Deep South Center for Environmental Justice** is a fully independent, nonprofit entity dedicated to improving the lives of children and families harmed by pollution in the Gulf Coast Region and rising to meet to the unique challenges of climate change facing communities of color and poor communities in the South.

E. **Healthy Gulf** is a 501(c)(3) organization based in Louisiana whose mission is to collaborate with and serve communities who love the Gulf of Mexico by providing the research, communications, and coalition-building tools needed to reverse the long pattern of over exploitation of the Gulf's natural resources. Healthy Gulf has staff, as well as thousands of members, in Louisiana and Texas. Healthy Gulf fights for people of Gulf communities to live and work in Louisiana free from the sights, sounds, and dangers of industry. Healthy Gulf also fights for the ability for everyone to benefit from the use and enjoyment of the wetlands, waters, and coastal areas in the Gulf.

F. **Louisiana Bucket Brigade** is a nonprofit membership organization dedicated to preserving and enhancing the environment of Louisiana as well as promoting environmental justice and protecting the people, communities, and public resources of the Louisiana Gulf Coast.

G. Sierra Club is a not for profit organization whose mission is to explore, enjoy and protect the wild and beautiful places of the Earth; to practice and promote the responsible use of the Earth's ecosystems and resources; to educate and enlist people to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. Sierra Club has tens of thousands of members in Louisiana and Texas, including in the areas of those states most burdened by the abuse of EPA's SILs Policy.

IV. LEGAL BACKGROUND

A. Environmental Injustice in Louisiana and Texas Air Pollutant Emissions.

Environmental injustice and the disproportionate burden of industrial pollution on Black, Brown and low-income communities in Louisiana and Texas is well established. EPA's own October 2022 Letter of Concern to Louisiana's Department of Environmental Quality ("LDEQ") and its Department of Health ("LDH") chronicles the ongoing history of environmental injustice in Louisiana. For example, its initial fact findings "indicate[ ] that census tracts with the highest cancer risks from air toxics in Louisiana are almost exclusively within the Industrial Corridor and also have a high percentage of Black population."[5] Similarly, EPA cites "significant evidence suggesting that the Departments' actions or inactions have resulted and continue to result in disparate adverse impacts on Black residents of St. John the Baptist Parish, St. James Parish, and the Industrial Corridor."[6] Now, data confirms that LDEQ's permitting practices result in discrimination against Black and other environmental justice communities throughout Louisiana.[7]

In Texas, communities of color and low-income communities are also disproportionately hurt by industrial air pollution that is permitted by TCEQ. A ProPublica study showed that the cities of Freeport, Port Arthur, Longview, Port Lavaca, and Laredo in Texas were hotspots for hazardous industrial air pollution that causes cancer.[8] In each of these cities the percentage of Hispanic/Latino, Black/African American, and/or low-income populations exceed that of the

[5] EPA Title VI Letter of Concern regarding LDEQ and LDH (Oct. 12, 2022), p. 5 ("EPA Oct. 2022 Title VI Letter of Concern"), https://www.epa.gov/system/files/documents/2022-10/2022%2010%2012%20Final%20Letter%20LDEQ%20LDH%2001R-22-R6%2C%2002R-22-R6%2C%2004R-22-R6.pdf, attached as **Exhibit 1**.

[6] *Id.* at 2.

[7] Kimberly A. Terrell & Gianna St. Julien, *Discriminatory outcomes of industrial air permitting in Louisiana*, 10 Journal of Environmental Challenges (Jan. 2023), https://doi.org/10.1016/j.envc.2022.100672), attached as **Exhibit 2.**

[8] Al Shaw, *et al.*, *The Most Detailed Map of Cancer-Causing Industrial Air Pollution in the U.S.*, ProPublica (Nov. 2, 2021, updated March 15, 2022), https://projects.propublica.org/toxmap/, attached as **Exhibit 3**; *see also* Lylla Younes, *et al.*, *Poison in the Air*, ProPublica (Nov. 2, 2021), https://www.propublica.org/article/toxmap-poison-in-the-air (explaining significance of map), **Exhibit 4**.

State of Texas.[9] The ProPublica study also identified the city of Houston as a hot spot for cancer-causing industrial air pollution.[10] An independent study confirmed that communities of color and low-income communities experience a disproportionately high level of this air pollution in the Houston area.[11] Similar concerns have been raised about air pollution in other environmental justice communities across the state, from Corpus Christi's Refinery Row[12] to West Dallas,[13] and Brownsville[14] to El Paso.[15]

B. The Clean Air Act, Its Public Health Based Protections, and State Implementation Plans.

The Clean Air Act ("CAA" or the "Act") is designed to protect and improve the nation's air quality and public health into the future.[16] As part of its scheme to accomplish its expansive

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[9] In Texas 12.9% of the population is Black/African American, 39.7% is Hispanic/Latino, and 13.9% lives in poverty. By comparison, in Freeport 17.6% of the population is Black/African American, 64% is Hispanic/Latino and 25.5% of the population lives in poverty. In Port Arthur 42.2% of the population is Black/African American and 26.7% of the population lives in poverty. In Longview 22.6% of the population is Black/African American and 18.6% of the population lives in poverty. In Port Lavaca 64.4% of the population is Hispanic/Latino. In Laredo 95.5% of the population is Hispanic/Latino and 23.9% of the population lives in poverty. U.S. Census Bureau, Quick Facts: Laredo, Port Lavaca, Longview, City, Port Arthur, and Freeport, Texas, https://www.census.gov/quickfacts/fact/table/laredocitytexas,portlavacacitytexas,longviewcitytexas,portarthurcitytexas,freeportcitytexas,TX/PST045221, **Exhibit 5**.

[10] Al Shaw, *supra* note 8.

[11] Sustainable Systems Research, LLC, *Evaluation of Vulnerability and Stationary Source Pollution in Houston* (Sept. 2020), https://www.nrdc.org/sites/default/files/houston-stationary-source-pollution-202009.pdf; *see also* Yukyan Lam *et al.*, *Toxic Air Pollution in the Houston Ship Channel: Disparities Show Urgent Need for Environmental Justice*, NRDC (Aug. 31, 2021), https://www.nrdc.org/resources/toxic-air-pollution-houston-ship-channel-disparities-show-urgent-need-environmental (explaining significance of study), **Exhibit 6**.

[12] Aman Azhar*, In Corpus Christi's Hillcrest Neighborhood, Black Residents Feel Like They Are Living in a 'Sacrifice Zone'*, Inside Climate News (July 4, 2021), https://insideclimatenews.org/news/04072021/corpus-christi-texas-highway-infrastructure-justice/, **Exhibit 7**.

[13] Darryl Fears, *Shingle Mountain: How a pile of toxic pollution was dumped in a community of color, Washington Post* (Nov. 16, 2020), https://www.washingtonpost.com/climate-environment/2020/11/16/environmental-racism-dallas-shingle-mountain/, **Exhibit 8**.

[14] Carmen Rocco & Dolly Lucio Sevier, *Air Pollution a concern if LNG comes to the Valley*, Rio Grande Guardian (Sept. 7, 2016), https://riograndeguardian.com/roccosevier-air-pollution-a-concern-if-lng-comes-to-valley/, **Exhibit 9**; Gus Bova, *Bridge to Nowhere*, Texas Observer (Sept. 16, 2019), https://www.texasobserver.org/liquefied-natural-gas-rio-grande-valley-endangered-pollution/ (discussing concerns about air pollution impacts if three proposed LNG export terminals are built near the low-income *colonia* of Laguna Heights, which is home to many Mexican immigrants who work in the area's hotels and restaurants), attached as **Exhibit 10**.

[15] Isa Gutierrez, *et al.*, '*Like a Dumping Ground': Latina moms in Texas border city are fighting air pollution*, NBC News (Feb. 22, 2022), https://www.nbcnews.com/news/latino/-dumping-ground-latina-moms-texas-border-city-are-fighting-air-polluti-rcna16789, **Exhibit 11**.

[16] 42 U.S.C. §§ 7401(b), 7410(a)(2)(C), 7475, 7503.

and forward-looking environmental and public health goals, the Act requires sources of air pollution to obtain permits that limit emissions of pollution to levels that are protective of public health. The CAA allows states to issue federal air pollution permits as long as the state's permitting program meets minimum federal standards and is approved by the EPA in a State Implementation Plan ("SIP").[17] States develop SIPs to attain and maintain health- and welfare-based National Ambient Air Quality Standards ("NAAQS") promulgated by EPA and meet other requirements under the CAA. *See* 42 U.S.C. § 7410(a). But Congress also entrusted EPA to take an active role overseeing state implementation and enforcing state compliance when necessary. The Act vests EPA with authority to revoke or modify the SIP, to prohibit permitting new or modified major source facilities, to enforce compliance both from , as well as to issue sanctions when a SIP does not meet the requirements of the Act, or a State is not implementing its SIP in compliance with the Act. *See*. *e.g.*, 42 U.S.C. § 7410(k)(5) (authority to order revisions to SIPs that fail to attain or maintain NAAQS); 42 U.S.C. § 7413(a)(5) (authority to prohibit new or modified permits); 42 U.S.C. § 7413(a)(2) (authority to enforce or order compliance with SIP and Act); 42 U.S.C. § 7509(b) (authority to issue sanctions); 42 U.S.C. § 7410(m) (authority to issue sanctions). EPA has authority to order states to perform air quality modeling and supply data on potential violations of the Act or disproportionate harm from air permitting. *See* 42 U.S.C. § 7410(a)(2)(K).[18]

Congress also placed EPA in charge of ensuring that state agencies comply with Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d; 40 C.F.R. § 7.30. Title VI states that "[n]o person in the United States shall, on the ground of race, color, or national origin . . . be subjected to discrimination under any program or activity receiving Federal financial assistance." *Id.* These EPA regulations prohibit discrimination by recipients of federal funds, such as LDEQ and TCEQ, whether intentional or not. *See* 40 C.F.R. § 7.35. A state agency's mere compliance with federal environmental law—were that the case—does not assure compliance with Title VI's prohibition on disparate harm.[19] To protect civil rights, permitting agencies should incorporate civil rights and environmental justice reviews into their individual permitting, from the very start of the process.[20] Agencies should identify environmental justice communities and account for

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[17] 42 U.S.C. § 7407(a).

[18] EPA, *EPA Legal Tools to Advance Environmental Justice*, 21 (May 2022) (describing historical uses of this power and explaining that "on case-by-case bases, EPA could . . . require states to conduct ambient air quality modeling in areas where communities with environmental justice concerns may be disproportionately impacted by high ambient concentrations of NAAQS pollutants, and use responsive data to determine whether to issue SIP Calls"),https://www.epa.gov/system/files/documents/2022-05/EJ%20Legal%20Tools%20May%202022%20FINAL.pdf; *see also id.* at 22 ("EPA has recommended that states also conduct 'unmonitored area analyses' to consider air pollution impacts in areas that have no ambient air monitors, especially where the state or EPA has reason to believe that violations of the NAAQS may be occurring in unmonitored areas.").

[19] *See* EPA, *Interim Envt'l Justice & Civil Rights in Permitting FAQs*, p. 6 (Aug. 2022) ("State, local, and other recipients of federal financial assistance have an independent obligation to comply with federal civil rights laws with respect to all of their programs and activities, including environmental permitting programs."), https://www.epa.gov/system/files/documents/2022-08/EJ%20and%20CR%20in%20PERMITTING%20FAQs%20508%20compliant_0.pdf.

[20] *Id.* at 4, 15.

cumulative impacts and disproportionate harm to those communities.[21] This includes assessing the risks from existing sources of air pollution when data suggest these sources might already present a risk of harm.[22] When state agencies falter, EPA should avail itself of the full array of tools available to it to ensure environmental justice and protect civil rights in air permitting.[23]

The National Ambient Air Quality Standards are at the core of the Clean Air Act. The NAAQS put public health first. *See* 42 U.S.C. § 7409(b)(1) (requiring EPA to set NAAQS at levels "requisite to protect the public health," with "an adequate margin of safety"). They are meant to ensure that everyone in the United States breathes air that at least meets health-based limits set by the EPA for six harmful "criteria" pollutants. 42 U.S.C. § 7409; *see* 40 C.F.R. pt. 50 (listing pollutants). As an additional measure to ensure the air stays within the NAAQS, EPA also sets "increments" that cap allowed growth in criteria air pollution from new industrial sources. 42 U.S.C. § 7473(b)(2). We refer to the NAAQS and increments collectively here as the "federal air standards."

The Act's Prevention of Significant Deterioration ("PSD") permit program is designed to enforce these federal air standards against violations in individual permitting decisions in those areas of the country treated as in "attainment" for the NAAQS. 42 U.S.C. § 7475(a) (forbidding new major sources of air pollution from constructing without a PSD permit). Sources with potential pollutants emissions level above tons-per-year (*i.e.* total mass) thresholds set out in the law, called the "significant emissions" levels, trigger PSD review for those pollutants.[24] EPA delegated to Louisiana and Texas, as well as other States in Region 6, the authority to issue PSD permits. *See* 42 U.S.C. § 7410(a)(l)-(2) (allowing state agencies to administer program, with EPA approval and oversight); 40 C.F.R. § 52.970(c), 52.2270(c) (identifying EPA-approved PSD permit regulations for both states). Each state's permitting program must meet or exceed the Act's minimum requirements. *See* 42 U.S.C. § 7410(k)-(l); *Luminant Generation Co. v. EPA,* 714 F.3d 841, 846 (5th Cir. 2013).

The PSD permitting program achieves these ends by requiring each applicant to do an "Air Quality Analysis" for each pollutant above the mass-based "significant emissions" level.[25] (This is the only "significance" test written into the PSD regulations that applies directly to an Air Quality Analysis.) The "Air Quality Analysis" uses a computer model that, for an applicant

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[21] *See, e.g.*, EPA Office of Air and Radiation, Memorandum, *EJ in Air Permitting – Principles for Addressing Environmental Justice Concerns in Air Permitting*, 2–4 (Dec. 2022), https://www.epa.gov/system/files/documents/2022-12/Attachment%20-%20EJ%20in%20Air%20Permitting%20Principles%20.pdf; EPA, *EPA Legal Tools to Advance Environmental Justice*, *supra* note 18, pp. 45–47; EPA, *Interim Envt'l Justice & Civil Rights in Permitting FAQs*, *supra* note 19, pp. 6, 8–22.

[22] EPA, *Interim Envt'l Justice & Civil Rights in Permitting FAQs*, *supra* note 19, at 9 (calling for assessing existing environmental data and noting that "[a]n area with an above average number of sources, especially if those sources are large or close to people in the area, is a sign of concern.").

[23] *See generally* EPA, *EPA Legal Tools to Advance Environmental Justice*, *supra* note 18.

[24] 40 C.F.R. § 52.21(b)(23), (m).

[25] 40 C.F.R. § 52.21(m). The PSD permitting program also requires applicants to install the best available pollution control technology ("BACT"). The estimated emissions after installation of BACT serve as the basis for the Air Quality Analysis. Determination of BACT is not at issue for this Petition.

to proceed, must "demonstrate" that the project will not "*cause, or contribute to*," violations of the NAAQS or increments when its emissions combine with other existing and proposed sources. 42 U.S.C. § 7475(a)(3); 40 C.F.R. § 52.21(m)(1)(3) (emphasis added). In other words, the law requires a cumulative impact air pollution analysis for each of those pollutants. Both Texas and Louisiana transpose the federal Act's Air Quality Analysis requirement directly into their state regulations as part of their SIPs. *See* LAC 33:III.509.K–M; 30 TAC § 116.160.

If a source fails the Air Quality Analysis, it cannot receive a PSD permit. *See, e.g.*, LAC 33:III.519.C.5; 30 TAC § 116.161. This is in keeping with the statute's purpose to defend the NAAQS and increments, as "the emphatic goal of the PSD provisions is to prevent those thresholds from being exceeded." *Alabama Power Co. v. Costle*, 636 F.2d 323, 362 (D.C. Cir. 1979); H.R. REP. 95-294, 9, 1977 U.S.C.C.A.N. 1077, 1087 (articulating the same purpose for the Air Quality Analysis provisions). To move forward, the source must either cut its own emissions (or secure binding commitments from other sources to curtail theirs) enough "to eliminate the predicted exceedances of the NAAQS." 30 TAC § 116.161. And if data show an area no longer meets the NAAQS, the Act charges either the state or EPA to redesignate the area as "non-attainment" for the standard in question. 42 U.S.C. § 7407(d)(3).

C. EPA's Significant Impact Levels Guidance.

Over the years, EPA has provided non-binding guidance with an additional threshold for routine situations when there is little to no threat to the Act's goal of maintaining federal air standards to simplify the Air Quality Analysis. Ironically (and confusingly), although the PSD Air Quality review is triggered by pollutants already at or above "significant emission" levels, EPA named this non-statutory threshold, based on airborne concentration of each criteria pollutant, "Significant Impact Levels," or "SILs."[26] SILs are expressed in parts per billion or micrograms per cubic meter of air. They are not health-based measures or indicative of relevant pollutant exposure levels.[27] Instead, SILs are based on the potential day-to-day variability in the pollution measured at air quality monitors due to factors like shifts wind.[28] They express a margin of error that may be acceptable where there is little or no threat of exceeding the NAAQS

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[26] *See*, *e.g.*, SILs Guidance, *supra* note 1, at 1 nn.1–4, 5 (reissuing SILs guidance and citing to prior guidance documents).

[27] *United States v. Ameren Mo.*, 421 F. Supp. 3d 729, 817-18 (E.D. Mo. 2019), aff'd in part, overruled in part on other grounds, 9 F.4th 989 (8th Cir. 2021) ("[T]he SILs do not establish a level below which there is no risk of harm from a facility's pollution."). To the contrary, "EPA has emphasized *ad nauseum* that there is no known safe threshold below which incremental increases in $PM_{2.5}$ exposure do not create incremental increases in risk to human health and welfare." *Id.* at 817.

[28] SILs Guidance, *supra* note 1, at 10–13; *Ameren Mo.*, 421 F. Supp. at 787 ("SILs were derived from a statistical analysis of the limits of monitoring data, based on a finite network of variably-placed monitors.") This discrepancy is heightened by the fact that the significance levels began as a tool to measure compliance with a different part of the Clean Air Act. *See* SILs Guidance, *supra* note 1, at 8–10. Further, the speculative nature of the SILs Guidance's adopted "confidence intervals" and its acknowledged potential for "false negatives" confirm the inherent uncertainty of relying on the SILs. *See id.* at 13.

public health-based standards. SILs are not designed to protect against incremental harm from new air pollution.

The SILs Guidance indicates that if a permitting agency finds that a source's emissions of a criteria pollutant would result in airborne concentrations below the SIL, the agency might in its discretion conclude that the applying source is unlikely to cause or contribute to violations.[29] The benefit to the applicant is that it could avoid further modeling in such situations.[30] But the risk of unswerving reliance on the SILs in permitting is legally and practically significant. Sometimes, even small amounts of new pollution, less than a SIL, could bring an area to violate the federal air standards or aggravate existing violations, or would clash with Title VI and environmental justice. *Cf.* 42 U.S.C. § 7475(a)(3) (forbidding new sources from causing or contributing to these violations). For instance, when EPA tried to enshrine the SILs in binding regulations that Sierra Club challenged in court, the D.C. Circuit vacated the regulations. The court reasoned that requiring permitting agencies to use the SILs could circumvent "a cumulative air quality analysis for sources that are below the SIL, but could nevertheless cause a violation of the NAAQS or increment." *Sierra Club v. EPA*, 705 F.3d 458, 465 (D.C. Cir. 2013) (*Sierra Club I*). And by the time of the court's ruling, EPA itself had conceded that using the SILs in such a situation could be unlawful. *Id.* at 464 (pointing to EPA statement that "notwithstanding the existence of a SIL, permitting authorities should determine when it may be appropriate to conclude that even a *de minimis* impact will 'cause or contribute' to an air quality problem and to seek remedial action from the proposed new source or modification.").[31] Despite EPA's concession, industry-intervenors who favored the SILs regulation persisted in mounting a full facial defense in the suit, even arguing for use of the SILs when the federal air standards could be under threat. *Sierra Club I*, 705 F.3d at 464–66. The court rejected these industry arguments, but LDEQ's and TCEQ's policy and approaches nonetheless now closely match industry's effort, as outlined below. *See id.*

Following the D.C. Circuit ruling, EPA during the Trump administration reissued the SILs Guidance, this time confining use of the SILs as modeling thresholds to non-binding memoranda: the 2018 SILs Guidance.[32] Nothing in this SILs Guidance could alter the language of the Clean Air Act, of course, as enforced by the court in *Sierra Club I* and other decisions—a reality the Guidance itself acknowledges. Fundamentally, the Guidance presents itself not as a fully-formed rule, but more modestly as an experiment, meant to gather information about its own implementation:

[29] *See* SILs Guidance, *supra* note 1, at 17–18.

[30] SILs Guidance, *supra* note 1, at 1–5, 17–18.

[31] EPA's statement is at *Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)*, 75 Fed. Reg. 64864, 64 892 (Oct. 20, 2010).

[32] SILs Guidance, *supra* note 1, at 1.

> [T]he EPA believes it should first obtain experience with the application of these values in the permitting program before establishing a generally applicable rule.
> …
>
> First, the **EPA is providing non-binding guidance so that we may gain valuable experience and information as permitting authorities use their discretion to apply and justify the application of the SIL values** identified below on a case-by-case basis in the context of individual permitting decisions.[33]

And as the quote above references, EPA's guidance requires agencies to justify each use of any SIL on a "case-by-case" basis, "in the record for each permit."[34] Indeed, EPA instructs that, if a permitting authority "has a basis for concern" in an individual permitting case, then a demonstration of a proposed source's impact below the relevant SIL "is not sufficient to demonstrate that the proposed source will not cause or contribute to a violation."[35]

The D.C. Circuit has concluded the same, stating: "The SILs Guidance is *not sufficient* to support a permitting decision—simply quoting the SILs Guidance is not enough to justify a permitting decision without more evidence in the record, including technical and legal documents."[36] Permitting agencies cannot simply rest on EPA's SIL values alone, without also considering "any additional information in the record that is relevant" to whether the SILs are appropriate for the context.[37] Indeed, while expressing openness to more expansive use as part of this regulatory experiment, EPA's 2018 SILs Guidance recalls its past warnings against applying the SILs when data show that the air around the source could be at risk of violating the NAAQS or increment in question.[38]

V. ARGUMENT

"Experience and information," under the 2018 SILs Guidance now shows that Louisiana and Texas are abusing their discretion and misapplying the SILs Guidance by applying the SILs to authorize sources to cause or contribute to federal air quality standards violations, as a matter of routine. This is not what the SILs Guidance allows or could lawfully allow, because permitting NAAQS violations undermines a key purpose of the Act and can contribute to violations of Title VI of the Civil Rights Act, when done with discriminatory effect.

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[33] SILs Guidance, *supra* note 1, at 2 (emphasis added, footnotes omitted).

[34] *Id.* at 19.

[35] *Id.* at 18.

[36] *Sierra Club v. EPA*, 955 F.3d 56, 63–64 (D.C. Cir. 2020) (*Sierra Club II*) (relying on express agency discretion requirement to find SILs Guidance not final decision reversible on its face).

[37] SILs Guidance, *supra* note 1, at 19.

[38] *See* SILs Guidance, *supra* note 1, at 10 ("To guard against the improper use of the 2010 SILs for $PM_{2.5}$ in such circumstances, the EPA later recommended that permitting authorities use those SILs only where they could establish that the difference between background concentrations in a particular area and the NAAQS was greater than those SIL values. This approach was intended to guard against misuse of the SILs in situations where the existing air quality was already close to the NAAQS.").

In Part V.A., we first summarize the four kinds of legal violations that LDEQ's and TCEQ's policies and practices implicate when applying the SILs in their PSD permitting schemes: ***1)*** failure to perform case-specific review despite documented bases of concern when using SILs to avoid a full Air Quality Analysis; ***2)*** failure to withhold or condition PSD permits where modeling shows the source causes or contributes to NAAQS exceedances, violating the plain language of the Clean Air Act; ***3)*** failure to cure NAAQS and increment violations that appear in new sources' air quality modeling or even to collect data and maintain records of these and other potential cumulative violations; and ***4)*** failure to protect the frontline Black, Latino, Indigenous, and other communities of color, as well as low-income communities, from disproportionate harm in violation of environmental justice and civil rights mandates.

Part V.A. references specific case examples of these abuses, which we describe in detail in Part V.B.

A. Abuse of the SILs Guidance in Violation of the Act and Contrary to Environmental Justice.

If a State does not justify its application of SILs to forego a cumulative impacts modeling Air Quality Analysis, it violates its delegated responsibility under the Clean Air Act, as well as its administrative obligations to support its decisions on the record.[39] We have observed LDEQ and TCEQ abuse the SILs consistently, creating and preserving air pollution hotspots that exceed the NAAQS, like in Cancer Alley, Louisiana. As the examples below illustrate, the agencies accomplish this in four interrelated and unlawful ways.

First, in contrast to EPA's SILs Guidance's instruction, the States do not exercise case-specific discretion to justify their use of the SILs. Rather, they apply the SILs uniformly, even when there is a "basis for concern." This is not just their practice, as our examples show (*see all examples below*); the States have enshrined this practice as written or confirmed policy. For instance, take LDEQ's most recent Air Quality Modeling Procedures Manual.[40] Instead of calling for the case-by-case analysis and justification that EPA's SILs Guidance requires, LDEQ's manual equates compliance with the SIL as compliance with the Clean Air Act as follows, without mention of surrounding context:

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[39] *See*, *e.g.*, *Save Ourselves, Inc. v. La. Env't Control Comm'n*, 452 So. 2d 1152, 1159 (La. 1984) ("This court has held that for the purposes of judicial review, and in order to assure that the agency has acted reasonably in accordance with law, in a contested case involving complex issues, the agency is required to make basic findings supported by evidence and ultimate findings which flow rationally from the basic findings; and it must articulate a rational connection between the facts found and the order issued."); LAC 33:III.509.Q.2.g-h (requiring agency to consider all public comments and issue written final PSD permit decision).

[40] *See* LDEQ, Air Quality Modeling Procedures (Aug. 2006 ed.), https://deq.louisiana.gov/assets/docs/Air/ModelingProcedures0806.pdf, attached as **Exhibit 12**. While this 2006 manual is clearly outdated, and while for years LDEQ has said that the manual "is currently under review," nonetheless, the agency has not replaced it with updated air modeling guidance. LDEQ maintains the 2006 manual on its website, and permit-writers and -applicants continue to apply it in PSD permitting. *See* LDEQ, Air Modeling Resource, *Current Version Draft Modeling Protocol*, https://www.deq.louisiana.gov/page/air-modeling-resource (visited May 29, 2023).

> If the modeled concentration is less than the significance level [i.e., the SIL], the project's impact *is insignificant* (i.e., the project increases *will not* cause or significantly contribute to an exceedance of the NAAQS or PSD Increment standards); therefore, *no further analysis is required*.").[41]

While LDEQ states it has been reviewing its Modeling Procedures Manual for years now, its permitting decisions remain consistent with this policy (*see examples below*). Indeed, the authors are unaware of any matter where LDEQ exercised discretion and chose *not* to rely on the SIL to abbreviate a proposed permit's impacts review.

Similarly, TCEQ's Air Quality Modeling Guidelines specify that if the new source will "not make a significant impact for a criteria pollutant of concern, the demonstration is complete."[42] And TCEQ adheres to this approach in individual permitting cases. Under oath in a recent contested case hearing, a TCEQ permit writer confirmed that the agency uses the SIL "regardless" of surrounding air quality, and that the agency views compliance with the SIL as compliance with the Air Quality Analysis requirement "by definition."[43]

The States' consistent failures to perform case-by-case reviews means they are not performing cumulative modeling or otherwise demonstrating that permitted facilities will not cause or contribute to violations of NAAQS and increments.

Second, these States issue major source permits even where the applicants' modeling demonstrates that they ***will***, in fact, contribute to violations of NAAQS and increments. (*For examples, see Formosa Plastics, Plaquemines LNG, and all Louisiana facilities below in Part V.B*.) And, despite the SIL Guidance clarification that a "culpability analysis" may only be appropriate "in some cases," LDEQ, at least, applies it as if it is required or *per se* exculpatory (*see, e.g., Plaquemines LNG example below*). As we demonstrate below, LDEQ and TCEQ assert that the source's contribution is not significant enough to warrant analysis if it falls below the SIL. But these agencies fail to reconcile their assertion with the plain language of the law, which forbids a source from "contribut[ing]," without qualification as to whether the contribution is more or less "significant" standing alone. *See Sierra Club I*, 705 F.3d at 465–66; *Bluewater Network v. EPA*, 370 F.3d 1, 13 (D.C. Cir. 2004) (holding that the phrase, as used analogously in another part of the Clean Air Act, means either to cause, or "to have a part or share in producing," pollution in excess of the NAAQS and that "contribute," "has no inherent connotation as to the magnitude or importance of the relevant 'share' in the effect; certainly it does not incorporate any 'significance' requirement.").

[41] LDEQ, Air Quality Modeling Procedures (Aug. 2006 ed.), p. 2–3 (emphasis added), https://deq.louisiana.gov/assets/docs/Air/ModelingProcedures0806.pdf, **Exhibit 12**.

[42] TCEQ, Air Quality Modeling Guidelines, APDG 6232, p. 20, App'x A (Nov. 2019), https://www.tceq.texas.gov/assets/public/permitting/air/Modeling/guidance/airquality-mod-guidelines6232.pdf, attached as **Exhibit 13**.

[43] Transcript of Hearing on Merits, Feb. 8, 2021, Texas State Office of Administrative Hearings, Application of Jupiter Brownsville, LLC for PSD Permit (hereinafter "Jupiter Hearing Transcript"), pp. 244:4-245:10 (Justin Cherry), excerpt attached as **Exhibit 14**.

Not only are such agency interpretations contrary to the plain language of the statute, a SIL is not a measure of what is "small," or "insignificant" in terms of the Act's public-health-protective aim. The SILs are a device for permitting convenience that "do not establish a level below which there is no risk of harm from a facility's pollution," and that "are not a valid means of determining the significance of downwind health effects." *United States v. Ameren Mo.*, 421 F. Supp. 3d 729, 817 (E.D. Mo. 2019). Moreover, the purpose of the PSD permitting provisions is to protect against the aggregation of such increases in air pollution that could collectively endanger public health when air quality fails to meet the NAAQS. *See Ala. Power Co. v. Costle*, 636 F.2d at 362.

If Congress had meant to limit prohibited contributions under the Air Quality Analysis test to significant contributions, it easily could have. Elsewhere in the Clean Air Act, the law uses a version of the phrase, "significantly contribute." *See Bluewater Network*, 370 F.3d at 13–14 (noting same); *see e.g.*, 42 U.S.C. §§ 7506a(a), 7492(c)(1), 7426(a)(1)(B), 7547(a)(1), (4) (explicitly requiring significant contributions). The Act's PSD provisions do not. The SILs Guidance might make permitting more efficient when there is no concern for causing or contributing to NAAQS violations, but it cannot function in circumstances where federal air standards could be under threat.

Third, despite being on notice of modeled NAAQS exceedances from an Air Quality Analysis, the States fail to take other legally available—sometimes required—measures to mitigate the impact of these exceedances on surrounding populations and the environment. For instance, LDEQ and TCEQ have an obligation to require the applicant and other sources in the area to lower their emissions to eliminate any modeled increment violation.[44] And the agencies have an obligation to determine whether to declare areas where these violations occur as non-attainment for the NAAQS, adopting SIP revisions to bring the area into compliance and for existing and proposed sources to meet more stringent permitting requirements. 42 U.S.C. § 7407(a), (d)(3) (giving states primary responsibility to assure compliance with NAAQS by submitting and updating designations and implementation plans); *see also id.* § (d)(3)(A), (C) (stating that EPA Administrator may, "on basis of air quality data" and other considerations, "at any time notify the Governor of any State that available information indicates that the designation of any area or portion of an area within the State or interstate area should be revised," and empowering EPA to redesignate on its own if state fails to do so). But LDEQ and TCEQ do nothing to protect against the public health standard exceedances that they acknowledge and permit under their application of the SILs.

Further, the States fail to account for the cumulative impacts that result from their repeated reliance on SILs—both at the prescreening and cumulative modeling stages (*see Commonwealth LNG example and footnote 118, below in Part V.B.*). There is no apparent record keeping of how many times a State relies on the SILs or of the cumulative emissions they have discounted through that process. Rather than address contributions or recognized exceedances,

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[44] *See, e.g.*, EPA, 1990 Draft New Source Review Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, pp. C.2 to C.53, https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf ("In situations where a proposed source would cause or contribute to a PSD increment violation, a PSD permit cannot be issued until the increment violation is entirely corrected," by obtaining emissions reductions sufficient to avoid the violation.).

the States' effectively wipe their slate clean as if starting from zero each time. This is especially problematic in areas where there is no ambient monitoring.

This failure to account interferes with collecting the "experience and information" that the SILs Guidance states is its goal to be able to evaluate whether the SILs are even appropriate.[45] Moreover, the failure to account compounds the harm of using SILs without case specific review and exacerbates a main error highlighted in President Biden's executive order on environmental justice: "[G]aps in environmental and human health data … conceal these harms [like poor health outcomes and lower life expectancies] from public view, and, in doing so, are themselves a persistent and pernicious driver of environmental injustice." Exec. Order 14096, 88 Fed. Reg. 25251, 25252 (Apr. 26, 2023).

Worse still, the States' casting a blind eye to the emissions and impacts they permit not only means cumulative pollutant emissions that exceed SILs and cause or contribute to violations of federal standards and law, it also means other new sources can build in the same area and worsen these violations even further (*for examples, see Formosa Plastics, Commonwealth LNG below in Part V.B.*), all while disingenuously treating the air as "unclassifiable" or in attainment with the NAAQS.

***Fourth**,* and finally, the States' routine abuse of SILs and misapplication of the SILs Guidance result in an insidious and enduring set of environmental injustices and civil rights violations that demand a Title VI compliance review and EPA's investigation of LDEQ's abuses, including its most recent permitting decisions concerning Formosa Plastics and Commonwealth LNG.

EPA recently expressed concern that LDEQ lacks any procedure or policy for evaluating environmental justice.[46] Similarly, EPA is currently assessing several Title VI complaints related to TCEQ's air permitting decisions, in which the complainants cite TCEQ's repeated refusal to conduct any environmental justice review in its air permitting decisions.[47] Moreover, a recent

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[45] SILs Guidance, *supra* note 1, at 2–3.

[46] EPA Oct. 2022 Title VI Letter of Concern, *supra* note 5, at 51 ("EPA was unable to find any published policies, guidance, criteria, or procedures regarding when and how LDEQ conducts EJ analyses or its Title VI analyses nor did LDEQ provide any.").

[47] *See, e.g.*, *Petition for Action Regarding Deficiencies in the Texas Air Permitting Program Related to Environmental Justice and Public Participation*, 12 (June 28, 2022) ("In response to concerns raised by Texas residents from Port Arthur to Manchester to Brownsville to El Paso that the TCEQ's permitting practices are disproportionately harming environmental justice communities across Texas, TCEQ repeatedly asserts that environmental justice concerns have no place in its permit reviews."), attached as **Exhibit 15**; Title VI Complaint, *Complaint against the Texas Commission on Environmental Quality for Actions Related to Rulemaking Amendment to the Concrete Batch Plant Standard Permit*, EPA No. 06RNO-22-R6, https://www.epa.gov/system/files/documents/2022-06/06RNO-22-R6%20Complaint_Redacted.pdf; Title VI Complaint, *Complaint regarding the Texas Commission on Environmental Quality's Issuance of Federal Operating Permit No. O1493 to Oxbow Calcining LLC*, EPA No. 02R-21-R6 (Aug. 2021), https://www.epa.gov/system/files/documents/2022-06/02R-21-R6%20Complaint_Redacted.pdf.

scientific study demonstrates both that industrial air pollution disproportionately burdens communities of color in Louisiana and that LDEQ permitting decisions drive that disparity:

> We found that the Louisiana Department of Environmental Quality (LDEQ) has permitted a pattern of industrialization wherein reported emissions of common industrial pollutants are 7 to 21-fold higher among industrialized communities of Color compared to industrialized White communities …. This disparity can be primarily attributed to the Chemical Manufacturing Industry, which represents more LDEQ-reporting facilities and more emissions in predominantly Black communities - and in Louisiana overall - than any other industry subsector. [48]

Almost all of the examples described in Part V.B. below, directly affect environmental justice communities—and disproportionately so. The Formosa facility that LDEQ permitted, for example, is in an area of St. James Parish that EPA's October 2022 Letter of Concerns highlights for its history of environmental racism. Similarly, in the case of Plaquemines LNG, LDEQ permitted emissions of nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and fine particulate matter ($PM_{2.5}$) despite modeling that showed NAAQS exceedances for those pollutants in an area where six of the seven surrounding communities are majority people-of-color, low-income, or both. What is clear from the examples that follow is that the abuse of the SILs Guidance occurs near or at the fence-line of people-of-color and low-income communities, as well as in areas already disproportionately burdened by industrial pollution.

Notably, examples below demonstrate *prima facie* cases of disparate impact discrimination, including because they allow EPA to (1) identify the specific policy or practice at issue; (2) establish adversity/harm; (3) establish disparity; and (4) establish causation.[49] (*For examples, see Formosa Plastics and Commonwealth LNG (within the last 180 days), as well as Plaquemines LNG, and Jupiter Brownsville below in Part V.B.*) This creates an unfair and dual system: regions of the country where the NAAQS and increments are enforced, compared to industrial "sacrifice zones" that jeopardize the health and well-being of people historically and continuously marginalized by American society and government at all levels.

B. Examples of State Abuses of the SILs Guidance.

In this section, we document prominent examples of LDEQ's and TCEQ's failures. While we lack the capacity in this Petition to survey every single permitting decision of LDEQ and TCEQ that implicates the SILs, the examples below are typical of undersigned counsel's practice in front of these two agencies.

We begin with lengthier descriptions of two cases that exemplify the States' abuse of the SILs, Formosa Plastics, in St. James Parish, Louisiana, and Plaquemines LNG, in Plaquemines Parish, Louisiana. We follow these with less detailed summaries of other recent examples,

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[48] Kimberly A. Terrell & Gianna St. Julien, *Discriminatory outcomes of industrial air permitting in Louisiana*, Journal of Environmental Challenges (vol. 10, Jan. 2023), https://doi.org/10.1016/j.envc.2022.100672, attached as **Exhibit 2**.

[49] EPA*, Interim Envt'l Justice & Civil Rights in Permitting FAQs*, *supra* note 19, at 12–13 (laying out factors for disparate impact analysis).

providing what we hope is enough information for context and to grasp the pervasiveness of the problem in both States—but without undue repetition. In addition, we provide a table summarizing these examples at Figure 1.

Figure 1, Table of Examples

Facility	**State Applied SILs w/o Case by Case Review?**	**Basis of Concern: No In-Zone Monitoring for Pollutant Above PSD Significance Level & Below SILs (at Prescreening)?**	**Basis of Concern: Existing Modeling Shows NAAQS / Increment Exceedance or Less than SIL to Exceedance?**	**Basis of Concern: Environmental Justice Communities Impacted?**	**Where Pollutant Emissions Above SILs, State Applied SILs to Allow Despite Data Showing Contribution to NAAQS Exceedance?**	**State Required Mitigation to Offset Contribution to Exceedance?**
Formosa Plastics	Yes	Yes	Yes	Yes	Yes	No
Plaquemines LNG	Yes	Yes	--	Yes	Yes	No
Calcasieu Pass LNG	Yes	Yes	--	Yes	Yes	No
CP2 LNG	Yes*	Yes	Yes	Yes	Yes	No
Commonwealth LNG	Yes	Yes	Yes	Yes	Yes	No
Cameron LNG	Yes	Yes	--	Yes	Yes	No
Lake Charles Methanol	Yes	Yes	Yes	--	Yes	No
Mitsubishi Chemical**	Yes	Yes	Yes***	--	Yes	No
Jupiter Brownsville LLC	Yes	No	Yes	Yes	No	No

*Based on Venture Global application to LDEQ and FERC DEIS; LDEQ proposed permit not yet published.
**Based on Mitsubishi Chemical's permit application to LDEQ; LDEQ proposed permit not yet published.
***Ascension Parish had been in nonattainment for ozone until 2016, and is still in maintenance status.[50]

Our examples focus on newly proposed petrochemical and LNG facilities. This is no coincidence. These are some of the largest sources recently permitted and a regular focus of our work. These buildouts often overlap with existing industry and impact the same frontline communities over and again. This focus on new facilities should not diminish the importance of reviewing SILs abuses relating to existing and re-permitting major source facilities of all types, in all areas of the States. Because other agencies, including federal licensing agencies like Federal Energy Regulatory Commission ("FERC"), rely on LDEQ and TCEQ air permitting to satisfy their separate environmental reviews of the same projects, these same diseased decisions can spread to infect other permitting processes, as we note below.

[50] *See* EPA website, at https://www3.epa.gov/airquality/greenbook/anayo_la.html.

1. Formosa Plastics, St. James Parish, Louisiana.

The Formosa Plastics case illustrates all four sets of failures to meet the law when implementing the SILs Guidance described above: ***a)*** LDEQ failed to perform a case-specific review before relying on the SILs in a compromised airshed that presented bases for concern; ***b)*** LDEQ invoked the SILs to issue air permits despite modeling showing the applicant would worsen ongoing violations of the NAAQS and increments; ***c)*** LDEQ has not taken any other action to address the violations of the federal air standards in St. James Parish that Formosa Plastics' modeling revealed; and ***d)*** LDEQ's decision will disproportionately harm Black and low-income communities.

In 2020, LDEQ granted a PSD Permit and fourteen Title V/Part 70 Air Operating Permits to FG LA LLC ("Formosa Plastics")[51] to construct and operate a mega-complex of chemical plants in St. James Parish, Louisiana.[52] For the PSD Permit, LDEQ first allowed Formosa Plastics to avoid cumulative modeling altogether for four federal air standards based solely on preliminary screening that showed those emissions below the SILs.[53] Had LDEQ conducted the necessary case-specific review, it would have had to account for the bases of concern described below, any one of which should have triggered cumulative impact modeling to gauge the full impacts of Formosa Plastics' air pollution on top of existing sources'.

One basis of concern is the absence of air monitors in highly industrialized St. James Parish for any pollutant, other than ozone.[54] LDEQ nonetheless treats the Parish as if it is in attainment of all NAAQS, resting on the assertion that the air quality is "unclassifiable" due to the agency's own decision not to locate air monitors there.[55] This lack of data means LDEQ cannot say with certainty whether the air in the Parish in fact meets federal air standards, let alone whether it would if Formosa Plastics operates.

Existing modeling in the area, by the nearby Nucor Steel plant, established a second basis of concern because it showed that the air in the Parish actually failed to meet the NAAQS for

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[51] FG LA LLC, the entity to which LDEQ issued the Permits, is part of Formosa Plastics Group, a Taiwanese-based conglomerate.

[52] Jan. 6, 2020, LDEQ Basis for Decision and Response to Public Comments on FG LA, LLC PSD and Title V Air Permits, AI No.198351, EDMS Doc. No. 11998452, https://edms.deq.louisiana.gov/app/doc/view?doc=11998452 (hereinafter "Formosa Basis for Decision"), excerpt attached as **Exhibit 16**.

[53] *Id.* at 12–13, 45–47. LDEQ's summary dismissal of further review included 1-hour SO_2, where Formosa Plastics' emissions came within a small fraction of the SIL (7.49 v. 7.8 μ/m^3); Jan. 6, 2020, Formosa Plastics PSD Permit No. PSD-LA-812, 69 of 126, AI No.198351, EDMS Doc. No. 11998450, https://edms.deq.louisiana.gov/app/doc/view?doc=11998450, excerpt attached as **Exhibit 17**.

[54] *See* LDEQ, Current Monitoring Data & AQI in the New Orleans Area (May 22, 2023), https://airquality.deq.louisiana.gov/Current/Region/NewOrleansArea, attached as **Exhibit 18**.

[55] *Id.* LDEQ treats the Parish as "unclassifiable" for the NAAQS, a status which under the Clean Air Act allows LDEQ to apply attainment-area permitting rules for new sources. *See* 42 U.S.C. § 7407(d)(1)(A)(iii) (defining unclassifiable area as one in "cannot be classified on the basis of available information as meeting or not meeting" the federal air standard); 40 C.F.R. § 81.319 (listing designations for St. James Parish).

$PM_{2.5}$, PM_{10}, NO_2, and SO_2 standards.[56] Indeed, EPA Region 6 has critiqued LDEQ's failure to address the NAAQS violations evidenced in Nucor's modeling.[57] But LDEQ has failed to take action since. LDEQ should have, at a minimum, required Formosa Plastics to model each of these pollutants' standards to ensure the chemical complex would not worsen the violations further.

A third basis of concern is the facility's impact on environmental justice communities. St. James Parish is at the heart of the region from Baton Rouge to New Orleans, often called "Cancer Alley" or "Death Alley,"[58] known for the disproportionate environmental harm its residents face from the petrochemical industry.[59] Formosa Plastics aims to build in an area where more than 90 percent of the nearest residents identify as Black[60] and where residents are disproportionately low-income.[61] Those residents are already overburdened with pollution, because nearly all existing, large industrial emitters in St. James Parish are in majority-Black census tracts like theirs, despite the fact that parish's population is 50 percent white.[62] These existing, industrial emissions place residents in the area closest to Formosa Plastics' site at greater risk of developing cancer from air toxics than 99.6 percent of people living in the United States, according to EPA screening data.[63] EPA's October 2022 Letter of Concern explained that "LDEQ's methods of administering its air permitting program" may be a major contributor to this harm, and confirmed that the "risks appear to be borne disproportionately by the Black residents in St. James Parish, especially those who live closest the proposed Formosa facility."[64] Additionally, EPA's EJScreen tool shows that, among other hazards, the nearby community

[56] Jan. 7, 2011, EPA Comments submitted to LDEQ re: Nucor Steel Louisiana, 10 of 11, AI No. 157847, EDMS Doc. No. 7830225, https://edms.deq.louisiana.gov/app/doc/view?doc=7830225, attached as **Exhibit 19**.

[57] *Id.*

[58] EPA Oct. 2022 Title VI Letter of Concern, *supra* note 5, at 8–9 (explaining that what LDEQ terms the "Industrial Corridor" along the Mississippi River in the state is "sometimes referred to as Cancer Alley" and collecting reports that describe the "Cancer Alley"/ "Death Alley" region in more detail).

[59] Tristan Baurick, *et al.*, *Welcome to "Cancer Alley," Where Toxic Air Is About to Get Worse*, ProPublica (Oct. 2019), https://www.propublica.org/article/welcome-to-cancer-alley-where-toxic-air-is-about-to-get-worse, attached as **Exhibit 20**.

[60] EPA Oct. 2022 Title VI Letter of Concern, *supra* note 5, at 53.

[61] EJSCREEEN results for Welcome, La., 1-mile radius (Population: 849), https://ejscreen.epa.gov/mapper/, attached as **Exhibit 21**.

[62] Deep South Center for Environmental Justice, *The More Things Change, the More they Remain the Same: Living and Dying in Cancer Alley (1990 to 2023)*, 13, 28 (2023) (hereinafter "DSCEJ Report"), https://fluxconsole.com/files/item/211/171496/DSCEJ-CancerAlley_Report.pdf, attached as **Exhibit 22**.

[63] Lylla Younes, *What Could Happen if a $9.4 Billion Chemical Plant Comes to "Cancer Alley,"* ProPublica (Nov. 18, 2019), https://www.propublica.org/article/what-could-happen-if-a-9.4-billion-chemical-plant-comes-to-cancer-alley, attached as **Exhibit 23**.

[64] EPA Oct. 2022 Title VI Letter of Concern, *supra* note 5, at 5.

ranks nationally in the 93rd percentile for environmental justice burden from particulate matter generally and 98th percentile from respiratory hazards.[65]

LDEQ failed to address any of this crucial context before allowing Formosa Plastics to exploit the SILs to forego cumulative air quality modeling for nearly every standard. Instead, LDEQ required cumulative-source modeling only for those standards where Formosa Plastics modeled emission concentrations above the SILs.[66] This modeling, perhaps unsurprisingly, showed Formosa Plastics would add to violations of federal air standards for 24-hour $PM_{2.5}$ and 1-hour NO_2, as depicted in Figure 2 below. For instance, maximum concentrations of NO_2 would be *more than double* the NAAQS 1-hour standard (422.53 µg/m^3 versus 188 µg/m^3).[67] But LDEQ ignored the additional burden on public health and, instead, invoked the SILs a second time, relying on them—despite the Clean Air Act's prohibition—to argue that Formosa Plastics' emissions "insignificant" contributions to the NAAQS and increment violations.[68]

Figure 2[69]

	Formosa Plastics' Max Modeled Contribution (µg/m^3)	**Total (µg/m^3)***	**Standard (NAAQS/ increment) (µg/m^3)**
$PM_{2.5}$ (24-hour NAAQS)	8.94	51.16	35
NO_2 (1-hour NAAQS)	74.05	422.53	188
$PM_{2.5}$ (24-hour increment)	7.97[70]	12.96	9

**Sum of Formosa Plastics' contribution, plus assumed background concentration, plus all industrial sources' modeled concentration.*

These violations have real-world implications for human health and the people living, working, or visiting nearby. According to LDEQ's map, several of the $PM_{2.5}$ violations would take place in or around the historic, Black, Burton Lane neighborhood of St. James Parish, which

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[65] EJSCREEN results for Welcome, La., *supra* note 61. EJSCREEN shows that the Welcome census tract is in the 89th percentile nationally for low-income, meaning only 11 percent of U.S. census tracts have residents with lower incomes on average than Welcome. *Id.*

[66] Formosa Basis for Decision, *supra* note 52, at 13.

[67] *Id.*

[68] *United States v. Ameren Mo.*, 421 F. Supp. 3d 729, 817 (E.D. Mo. 2019) ("[T]he SILs do not establish a level below which there is no risk of harm from a facility's pollution.").

[69] Formosa Basis for Decision, *supra*, note 52, at 13; Formosa Plastics Final PSD Permit, *supra* note 53, at 69.

[70] Formosa Plastics Air Quality Analysis (July 2018), at 42 of 424, AI No. 198351, EDMS Doc. No. 11246153, https://edms.deq.louisiana.gov/app/doc/view?doc=11246153, excerpt attached as **Exhibit 24**.

is already surrounded by oil-terminal tank farms.[71] But LDEQ arbitrarily concluded that because Formosa Plastics' emissions would be below the SILs in some areas where it modeled NAAQS exceedances, the company could receive a PSD permit stating: "the modeled exceedances exist irrespective of the FG LA Complex, and LDEQ has determined that the FG LA Complex's contribution to these exceedances will be insignificant."[72] LDEQ cited to EPA's SILs Guidance as legal justification in to conclude that Formosa Plastics could increase these NAAQS exceedances.[73]

When RISE St. James, Louisiana Bucket Brigade, Healthy Gulf, Sierra Club, and several other groups challenged LDEQ's permit decision in state district court, including on the grounds of LDEQ's abuse of the SILs,[74] LDEQ vigorously defended its blanket use of the SILs in briefing.[75] Far from attempting to argue that it uses case-specific discretion that the SILs Guidance requires, LDEQ argued that the complex's emissions below the SILs, either in preliminary screening or at the point of a NAAQS- or increment-violating receptor, mean that "FG LA will not cause or contribute to a violation."[76] The district court rejected LDEQ's argument, ruling in favor of petitioners, RISE St. James *et al.*, and holding that LDEQ violated the Clean Air Act and Louisiana law in abusing the SILs.[77] The district court issued an order vacating Formosa Plastics' air permits, including the PSD permit that relied on the SILs.[78] But LDEQ appealed the district court's ruling "suspensively," staying the effect of district court's determination during the still-pending appeal.[79]

While the state court's decision is a positive step, it is far from sufficient. EPA has correctly recognized that the state court's ruling in Formosa Plastics on the SILs has not yet changed LDEQ's conduct.[80] After staying the district court's vacatur of Formosa Plastics' PSD

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[71] Reasons for Judgment at 15, *RISE St. James*, *et al. v. LDEQ*, 19th Judicial District Court Parish of East Baton Rouge ("La. 19th JDC") Docket No. 694,029, Sept. 8. 2022 ("Sept. 8, 2022, Reasons for Judgment"), attached as **Exhibit 25**; Formosa Basis for Decision, *supra* note 52, at 16.

[72] Formosa Basis for Decision*, supra* note 52, at 16.

[73] *Id.* at 45–47.

[74] *See* Sept. 8, 2022, Reasons for Judgment, *supra* note 71.

[75] *See* LDEQ Opp. Br. at 46, *RISE St. James*, *et al. v. LDEQ*, La. 19th JDC, Docket No. 694,029, Dec. 6, 2021, attached as **Exhibit 26**.

[76] *Id.* at 46.

[77] Sept. 8, 2022, Reasons for Judgment, *supra* note 71, at 5, 14, 16.

[78] Judgment, *RISE St. James*, *et al. v. LDEQ*, La. 19th JDC, Docket No. 694,029, Sept. 12, 2022, **Exhibit 27**.

[79] *See* FG LA, LLC, Suspensive Appeal Bond, *RISE St. James*, *et al. v. LDEQ*, Docket No. 694, 029, Sec. 27, La. 19th JDC (filed Sept. 29, 2022) (explaining that court signed order of appeal) attached as **Exhibit 28**; LDEQ, Mot. for a Suspensive Appeal, *RISE St. James*, *et al. v. LDEQ*, La. 19th JDC, Docket No. 694, 029 (filed September 27, 2022), attached as **Exhibit 29**; La. Code Civ. Proc. art. 2123(A) (authorizing suspensive appeals in certain cases); La. R.S. 13:4581 (authorizing state agencies to take suspensive appeals without providing bond).

[80] EPA Oct. 2022 Title VI Letter of Concern, *supra* note 5, at 42 (stating as to Title VI complaint relating to the Formosa Plastics matter, "EPA has continued to investigate this matter as it relates to the Formosa permits since the lower court's decision—which EPA has reviewed carefully and taken into account for

permit through its appeal, on December 5, 2022, LDEQ extended that permit's deadline to construct and reasserted its view—ruled unlawful by the district court—that Formosa Plastics' Air Quality Analysis complied with the Clean Air Act.[81] Meanwhile, residents in St. James continue to face an industrial buildout with air that the modeling shows fails to meet federal public-health-based air standards.

2. Plaquemines LNG, Plaquemines Parish, Louisiana.

Another example set of LDEQ's abuse of the SILs Guidance to allow massive emissions that contribute to NAAQS exceedances in communities already suffering environmental injustices is LDEQ's 2019 air permit decisions for the Plaquemines LNG liquefied "natural" gas methane export terminal, as well as its 2021 permit modifications. For both decisions, LDEQ failed to meet SILs Guidance requirements and abused its discretion by permitting criteria pollutant emissions below SILs without any case-by-case review (and despite bases of concern indicating that that modeling was warranted). The agency similarly unlawfully permitted criteria pollutant emissions above SILs—like NOx, SO_2, and $PM_{2.5}$ where predictive modeling showed NAAQS exceedances. Moreover, since FERC relied on LDEQ's permitting decision to meet its federal National Environmental Policy Act ("NEPA") review, Plaquemines LNG also demonstrates how a State's unlawful use of SILs can be incorporated into federal agency decision making—and highlights the broad scope of abuse that EPA can relieve with action on this Petition.

First, LDEQ failed to use case-specific discretion and summarily relied on SILs to avoid any modeling for emissions levels not strictly at or above SILs, despite having ample bases for concern that doing so could frustrate the Act's requirements.[82] For example, LDEQ did not perform a case-by-case review for Annual and 24-hour PM_{10}, Annual $PM_{2.5}$, 24-hour and Annual SO_2. Instead, it merely pointed to the SILs levels for its basis not to model or perform further review: [83]

> **preconstruction monitoring is required for these pollutants. Screening analysis indicated that annual and 24-hour PM_{10}, annual $PM_{2.5}$, 24-hour and annual SO_2, and 1-hour and 8-hour CO are below their significant impact levels. Therefore, no increment analysis or refined modeling is required for these pollutants.**

But this "individual case" included more than one "basis for concern," so that a demonstration of the proposed source's impact below the relevant SIL "is not sufficient to demonstrate that the

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purposes of this Letter—did not finally resolve the concerns related to the issuance of the Formosa permits.").

[81] Dec. 5, 2022, Letter from LDEQ Granting Extension of Deadline to Commence Construction, AI No. 198351, EDMS Doc. No. 13579554, https://edms.deq.louisiana.gov/app/doc/view?doc=13579554, attached as **Exhibit 30**. In the letter, LDEQ notes that the court's "Judgment remains suspended," and asserts that "a substantive reanalysis of air quality impacts is not warranted at this time." *Id.* at 3–4.

[82] *See* April 25, 2019, Plaquemines LNG PSD Permit, PSD-LA-808, pages 6–7 of 226, AI No. 197379 EDMS Doc. No. 11624911 (hereinafter "Plaquemines LNG 2019 PSD Permit"), https://edms.deq.louisiana.gov/app/doc/view?doc=11624911, attached as **Exhibit 31**.

[83] *Id.* at 7 of 226.

proposed source will not cause or contribute to a violation."[84] Instead, "the permitting authority should require additional information from the permit applicant to make the required air quality impact demonstration."[85]

A patent basis of concern for this major source is the lack of air monitoring. Plaquemines LNG is currently under construction in Plaquemines Parish, on the Mississippi River about 30 miles southeast of New Orleans. LDEQ designates Plaquemines Parish "attainment/unclassifiable" because, despite the Parish having two oil refineries, large grain and coal export terminals, extensive oil production, and other air polluting facilities, LDEQ has chosen to place ***none*** of its ambient air quality monitoring network stations in Plaquemines Parish.[86]

Another basis of concern: the terminal site is located near several communities that suffered catastrophic damage in Hurricane Ida, in August 2021, and that are still struggling to recover, such as the historic Black communities of Ironton and West Pointe à la Hache.[87] A recent FERC "environmental justice" review for a proposed capacity expansion of the Plaquemines LNG terminal recognized that 6 out of 7 communities in the area it deemed "impacted" by the terminal's air pollutant emissions qualify as environmental justice communities.[88] Notably, FERC chose a 17.92-kilometer "radius of impacts" from the terminal for its environmental justice review because that "is the distance from the center of the facility to the furthest [point] … that is equal or greater than the Significant Impact Level" for the 1-hour NO_2 NAAQS.[89]

So, when LDEQ found that Plaquemines LNG's "predicted modeled concentrations exceeded the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS,"[90] yet still permitted it to

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[84] *See* SILs Guidance, *supra* note 1, at 18.

[85] *Id.*

[86] *See* 40 C.F.R. § 81.319; LDEQ Air Monitoring Sites map, https://experience.arcgis.com/experience/1bc3c0ad43be455ab7224f0324aabaf2/, attached (with excerpt of relevant area) at **Exhibit 32**.

[87] *See*, *e.g.*, Stacey Plaisance, *Hurricane Ida Devastation Lingers in Louisiana 1 Month Later*, AP News (Sept. 29, 2021), https://apnews.com/article/hurricane-ida-environment-and-nature-louisiana-storms-hurricanes-9f305dd811e9d8fea248b5e514c9aaf1, attached as **Exhibit 33**.

[88] FERC Jan. 6, 2023, Environmental Assessment for proposed Plaquemines LNG uprate amendment, Docket No. CP22-92-000, Accession No. 20231006-3019, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230106-3019 ("FERC Plaquemines LNG EA"), attached as **Exhibit 34**.

[89] *See* FERC Plaquemines LNG EA, *supra* note 88, at 20, n.13 ("[The] Terminal is within … an environmental justice community. An additional six block groups are within the 17.92-kilometer radius [environmental justice review area] for the Terminal site. Out of seven total block groups within this radius, six are identified as environmental justice communities …. One of the block groups is identified as an environmental justice population based on the minority threshold alone …; two are based on the low-income threshold alone …; and three are identified as an environmental justice population based on both the minority and low-income thresholds ….").

[90] *See* Plaquemines LNG 2019 PSD Permit, page 8 of 226, https://edms.deq.louisiana.gov/app/doc/view?doc=11624911, **Exhibit 31**.

emit 966.02 tons per year (tpy) of NOx, 371.86 tpy of $PM_{2.5}$, 114.86 tpy of SO_2, along with other pollutants,[91] it did so in an area surrounded by (and disproportionately affecting) communities that are predominantly minority, low-income, or both. And LDEQ did the same again in 2021, when it modified the air permits, increasing allowed NOx emissions to 1,103.47 tpy.[92]

Further, finding NAAQS exceedances for 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2, created another basis of concern warranting modeling for the remaining federal standards for those pollutants. Moreover, for two of the pollutants where LDEQ found NAAQS violations (24-hour $PM_{2.5}$ and 1-hour SO_2), the reported screening level was just barely below SILs. Preliminary screening for Annual $PM_{2.5}$ was 0.29 and the SIL is 0.3 and preliminary screening for 24-hour SO_2 was 4.99 and the SIL is 5.0, as this chart from the permit shows:[93]

Screening Modeling

Pollutant	Averaging Period	Preliminary Screening Concentration ($\mu g/m^3$)	Level of Significant Impact ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)	Preconstruction Monitoring Required?	Refined Modeling Required?
PM_{10}	24-hour	3.3	5	10	No	No
	Annual	0.4	1	-	No	No
$PM_{2.5}$	24-hour	2.8	1.2	4	No	Yes
	Annual	0.29	0.3	-	No	No
SO_2	1-hour	8.9	7.8	-	No	Yes
	3-hour	75.4	25	-	No	Yes
	24-hour	4.99	5	13	No	No
	Annual	0.1	1	-	No	No
NO_2	1-hour	21.2	7.5	-	No	Yes
	Annual	1.5	1	14	No	Yes
CO	1-hour	1,709.2	2,000	-	No	No
	8-hour	156.2	500	575	No	No

Second, LDEQ abused the SILs Guidance by permitting the facility despite modeling that showed NAAQS exceedances for 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2. When issuing the permit, LDEQ acknowledged it found these exceedances and that Plaquemines LNG's emissions would contribute to them, if at levels below SILs:[94]

> **Refined modeling indicates compliance with the 3-hour SO_2 and annual NO_2 NAAQS. Although the predicted modeled concentrations exceeded the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS, the required culpability analyses demonstrate that when and where a modeled exceedance occurs, Plaquemines LNG's maximum contribution is insignificant (i.e., below the respective pollutant's significant impact level).**

LDEQ's claim that it is merely applying the "required culpability analyses" to excuse these contributions to violations is audacious and incorrect. Far from "required," the SILs Guidance,

[91] *See id.* at 6 of 226. Additional permitted pollutants include as well as 133.88 tpy of VOCs and 8,144,463 tpy of CO2e. *See id.*

[92] *See* May 28, 2021, Plaquemines LNG Modified PSD Permit No. PSD-LA-808(M-2), page 13, 17 of 43, AI No. 197379, EDMS Doc. No. 12738653 ("Plaquemines LNG 2021 Modified PSD Permit"), https://edms.deq.louisiana.gov/app/doc/view?doc=12738653, attached as **Exhibit 35**.

[93] Plaquemines LNG 2019 PSD Permit, at 7 of 226, https://edms.deq.louisiana.gov/app/doc/view?doc=11624911, **Exhibit 31** (screening model table).

[94] *See id.* at 8 of 226.

which includes a so-called culpability analysis, cautions agencies to exercise discretion in each case, and—in any event—cannot overcome the Clean Air Act's prohibition on any new major source contributing to a NAAQS violation.[95] In short, contrary to the Clean Air Act, LDEQ permitted the Plaquemines LNG facility to contribute to three known public health standard violations based on EPA's SILs Guidance to do so.

In 2021, LDEQ doubled down on these abuses when it allowed Plaquemines LNG to modify its permit to increase emissions of NO_x, SO_2, and $PM_{2.5}$ even further, despite modeling that again showed the facility would add to violations of the NAAQS. Although the Clean Air Act prohibits any contribution to a NAAQS exceedance, and LDEQ acknowledged that "predicted modeled concentrations exceeded the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS," the agency nevertheless approved the increase, asserting that "Plaquemines LNG's maximum contribution [for each pollutant] is significant (i.e., below the respective pollutant's significant impact level)."[96]

Among other things, Plaquemines LNG exemplifies how LDEQ's unlawful use of SILs can snowball and disproportionately impact already overburdened communities: In 2019, FERC first allowed Plaquemines LNG to be built and to contribute to NAAQS violations based on LDEQ's unlawful reliance on SILs. Since then, in 2021, LDEQ allowed Plaquemines LNG to increase emissions of pollutants already exceeding NAAQS.

3. Other Louisiana LNG Terminals.

The impact of these LDEQ's abuse of the SILs Guidance is particularly problematic for LNG facilities, not just because of their enormous physical size, massive pollutant emissions, and disproportionate impact on environmental justice communities, but also because FERC's reliance on LDEQ's permitting decisions means the federal government is effectively adopting a position contrary to the Clean Air Act and EPA's guidance on point. FERC has exclusive jurisdiction to approve the terminal's location, among other things. But the States still issue underlying permits, including for air pollutant emissions, and FERC looks to those permits and their applications for its NEPA environmental review. Louisiana is the primary site for much of the recent LNG terminal buildout, accounting for hundreds of millions of tons per year of permitted greenhouse gas ("GHG") and other pollutant emissions in Louisiana. (Most of the other half is happening in Texas.) And FERC appears to simply adopt LDEQ's unlawful SILs application for its own.

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[95] SILs Guidance, *supra* note 1, at 18 (noting it believed the culpability analysis could be sufficient in "most," but not all cases).

[96] Plaquemines LNG 2021 Modified PSD Permit, 17 of 43, https://edms.deq.louisiana.gov/app/doc/view?doc=11624911, **Exhibit 35**; *see also* May 28, 2021 Plaquemines LNG Part 70 Permit, page 21–22 of 100 (note 3 to chart), AI No. 197379, EDMS Doc. No. 12738655, https://edms.deq.louisiana.gov/app/doc/view?doc=12738655, excerpt attached as **Exhibit 36** ("The Project did not significantly contribute to any of the modeled [NAAQS] exceedances because none of the Project contributions to modeled NAAQS exceedances were above the relevant SIL. Hence, for all pollutant and averaging periods requiring full modeling, the Project was shown to be in compliance with the NAAQS.").

With LDEQ's support, LNG terminals are consistently relying on abuse of the SILS Guidance to circumvent the Clean Air Act and push through a huge build out of LNG export terminals and related infrastructure in areas of Louisiana already exceeding the NAAQS public health-based standards. Unsurprisingly, this build out is having a disproportionately large impact on environmental justice communities. For example, no less than six of the eight census block groups within 15 miles of three terminals at the mouth of the Calcasieu River (Calcasieu Pass) in Cameron Parish—including the existing Calcasieu Pass LNG, the recently approved Commonwealth LNG, and the proposed CP2 LNG—are majority-minority and/or low income communities.[97] Those same communities are also near other approved and proposed LNG export terminals in the Lake Charles area, like Cameron LNG among others. Importantly, LDEQ's regular and unchecked reliance on SILs to avoid full review of emissions and to allow contributions to existing NAAQS exceedances from individual sources also means there are cumulative contributions to NAAQS exceedances that are not being accounted for—emissions from more than one facility where prescreening or modeling shows each facility's levels is below SILs for a pollutant, but together they exceed SILS and NAAQS. In other words, the agency is also allowing Clean Air Act violations through cumulative contributions. This is particularly so in Cameron Parish, as well as in adjacent Calcasieu Parish, where LDEQ is permitting in or near the same "attainment" areas, as the examples below show:

- *Calcasieu Pass LNG in Cameron Parish*. Venture Global, the same company that owns Plaquemines LNG, is currently constructing and operating a 12 million tonnes per annum (MTPA) capacity LNG terminal in southwest Louisiana, south of Lake Charles—and with increasing NAAQS and Clean Air Act violations. LDEQ relied on SILs to permit this facility in 2018, skipping a full air quality analysis for all PM_{10}, for 1-hour, 24-hour, and Annual SO_2, and for 8-hour carbon monoxide (CO) NAAQS solely on the basis that emission levels would be below SILs and, further, allowing NOx emissions despite modeling that showed exceedances of the 1-hour NOx NAAQS.[98] The original 2018 PSD permit allowed 680.52 tpy of NO_x and provided only a one-sentence "culpability analysis" to justify the expected 1-hour NO_x exceedance contributions: "when and where a modeled exceedance occurs, Venture Global's maximum contribution is 5.58 $\mu g/m^3$ which is insignificant [or] below the level of significant impact of 7.5 $\mu g/m^3$."[99]

  In February 2021, LDEQ approved a permit modification with NO_x emissions at 707.93 tpy, such that modeling showed 1-hour NO_x emissions at 878.36 $\mu g/m^3$, *i.e.* more than 4

[97] *See* FERC Jan. 19, 2023, CP2 LNG Draft Environmental Impact Statement ("CP2 LNG DEIS"), p. 4–202, Docket Nos. CP22-21-000 & CP22-22-000, Accession No. 20230119-3072, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230119-3072, excerpt attached as **Exhibit 37**; *see also id.* at 4-393 (map of potential cumulative impacts), *infra* Figure 3.

[98] *See* Sept. 21, 2018, Calcasieu Pass LNG PSD Permit No. PSD-LA-805, 7–8 of 235, AI No. 194203, EDMS Doc. No. 11322607 ("Calcasieu Pass 2018 LNG PSD Permit"), https://edms.deq.louisiana.gov/app/doc/view?doc=11322607, attached as **Exhibit 38**.

[99] *See id.* at 7 of 235 (LDEQ's 2021 permit modification included the "or," clarifying the sentence, *infra* note 100).

times the 188 μg/m^3 NAAQS limit.[100] Remarkably, LDEQ took the position that approval was required, asserting in response to comments that "a major source ***shall not*** be considered to cause or contribute to a violation of a NAAQS unless such source would, at a minimum, exceed a significance level (i.e., SIL)."[101] LDEQ's "culpability analysis" to allow these exceedances was, again, only one sentence, stating: "when and where a modeled exceedance occurs, Venture Global's maximum contribution is 4.41 μg/m^3, which is insignificant or below the level of significant impact of 7.5 μg/m^3."[102] LDEQ did not explain how, while allowing NOx emissions to ***increase*** from 680.52 tpy to 707.93 tpy since the 2018 permit, it also calculated that Venture Global's Calcasieu Pass LNG contribution to the modeled NAAQS exceedance had ***decreased*** from 5.58 μg/m^3 to 4.41 μg/m^3.[103]

- *CP2 LNG in Cameron Parish*. Venture Global is proposing a third LNG terminal, CP2 LNG, with 20 – 28 MTPA capacity immediately adjacent to its Calcasieu Pass LNG terminal. Venture Global's application indicates all criteria pollutants exceeding PSD

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[100] *See* Feb. 2, 2021, Calcasieu Pass LNG Modified PSD Permit No. PSD-LA-805 (M-3), 6, 8 of 254, AI No. 194203, EDMS Doc. No. 12563559 ("Calcasieu Pass LNG 2021 Modified PSD Permit"), https://edms.deq.louisiana.gov/app/doc/view?doc=12563559, excerpt attached as **Exhibit 39**.

[101] Feb. 2, 2021, LDEQ Response to Public Comments and Notification of Final Permit Action, 13 of 14, AI. No. 194203, EDMS Doc. No. 12563557 (emphasis added), https://edms.deq.louisiana.gov/app/doc/view?doc=12563557, attached as **Exhibit 40** (responding to comment on air pollution adverse health impacts by, among other things, incorporating SILs Guidance)

[102] *See* Calcasieu Pass LNG 2021 Modified PSD Permit, 8 of 254, https://edms.deq.louisiana.gov/app/doc/view?doc=12563559, excerpt at **Exhibit 39**.

[103] More recently, Venture Global applied to further increase NOx emissions without additional modeling, stating "[a]ir dispersion modeling was determined not to be necessary due to the minimal increase in NOx emissions (+0.14 tpy)." *See* May 13, 2021, Calcasieu Pass LNG Application to Modify Title V Permit No. 0560-00987-V3 and PSD Permit No. PSD-LA-805 (M-3), 9 of 69, AI No. 194203, EDMS Doc. No. 12718901, https://edms.deq.louisiana.gov/app/doc/view?doc=12718901, attached as **Exhibit 41**. Notably, LDEQ approved this May 13, 2021, request for a NOx increase in July 2021, but its permit failed to acknowledge that it required no additional modeling and instead re-adopted the 2020 modeling and 4.41 μg/m^3 NOx contribution culpability analysis as if it were up to date. *See* July 1, 2021, Calcasieu Pass LNG Modified PSD Permit, PSD-LA-805 (M-4), AI No. 194203, EDMS Doc. No. 12782238, https://edms.deq.louisiana.gov/app/doc/view?doc=12782238, excerpt attached as **Exhibit 42**.

review levels and NO_x emissions as high as 1,152.87 tpy, *i.e.* more than 160% higher than the Calcasieu Pass LNG's NO_x emissions next door:[104]

Table 1-3. Facility-Wide Emissions Summary for All Scenarios, tpy

Pollutant	Phase 1 Scenario 1	Phase 1 Scenario 2	Phase 2 Scenario 3	Phase 2 Scenario 4[1]
PM_{10}	168.80	194.91	342.77	368.88
$PM_{2.5}$	168.80	194.91	342.77	368.88
SO_2	109.16	127.64	235.81	254.29
NO_X	710.93	460.28	1,152.87	908.10
CO	1,201.91	738.78	1,844.50	1,428.66
VOC	82.81	96.85	159.97	175.14
Carbon dioxide equivalent (CO_2e)	3,217,036	4,274,682	7,556,201	8,528,260
Total HAPs[2]	16.18	20.59	35.03	39.45
Total TAPs[2]	33.21	190.06	213.54	370.40

[1] The facility-wide PTE emissions are based on Phase 2 Scenario 4 (All permanent sources in operation).
[2] Refer to Appendix B for detailed calculations, including speciation of individual HAPs/TAPs.

Although LDEQ has not yet published a proposed permit, FERC is moving forward with its permitting process and environmental review—and appears to be adopting LDEQ's bad practices on the SILs Guidance. For example, like LDEQ permits, FERC summarily dismissed modeling or other review for any criteria pollutant below SILs, stating: "For all other pollutants and averaging periods evaluated, the maximum model-predicted impacts were below the associated SILs; therefore, NAAQS compliance was demonstrated for those pollutants and averaging periods and no further analyses are required for the Terminal Facilities."[105]

Similarly, FERC pinned EPA and the SILs Guidance with responsibility for Venture Global's Clean Air Act violation when it accepted Venture Global's "culpability analysis." FERC stated the analysis "showed that the contribution by the Terminal Facilities sources to each exceedance concentration at the same point in space and time is not significant (*i.e.*, the contribution is less than the EPA-designated SIL of 7.5 µg/m3). ***Therefore, the Terminal Facilities are not considered, by the EPA, to cause or contribute to this exceedance***."[106]

Moreover, CP2 LNG emissions combined with its sister terminal, the adjacent Calcasieu Pass LNG, CP2's emissions would more than double Venture Global's contribution to the area's NAAQS violations, far exceeding the 7.5 µg/m3 SILs—not only at LDEQ's previously determined point of exceedance, but likely in the more immediate area as well. And this is without considering the addition of the FERC-approved Commonwealth LNG terminal immediately across the Calcasieu River, discussed below. It is notable, too, that FERC's Draft Environmental Impact Statement ("DEIS") also considers separately

[104] July 29, 2022, CP2 LNG Modified Title V Permit and PSD Permit Application – Vol. 1, page 1–6, AI No. 232172, EDMS Doc. No. 13411196, https://edms.deq.louisiana.gov/app/doc/view?doc=13411196, excerpt attached as **Exhibit 43**.

[105] CP2 LNG DEIS, *supra* note 97, at 4–261.

[106] *Id.* at 4–262 (emphasis added).

the NO_x emissions from a related compressor station north of Lake Charles, such that it does not consider what their combined modeling would show at any point of exceedance.

- *Commonwealth LNG in Cameron Parish*. In March 2023, LDEQ approved air pollutant emissions permits for another LNG terminal in Cameron Parish, across the River from Calcasieu Pass LNG and the proposed CP2 LNG terminals and, again, impacting environmental justice communities.[107] Here again, LDEQ first avoided a full impacts review for pollutant emissions above PSD review standards, but that preliminary screenings indicated would be below SILs.[108] LDEQ did not consider bases of concern, like the lack of monitoring in the Cameron Parish attainment zone, existing modeling showing a NAAQS exceedance in the zone,[109] and the disproportionate impacts to environmental justice communities when choosing to forego further review.[110] Instead, contrary to the SILs Guidance's terms, LDEQ avoided reviewing whether emissions would cause or contribute to an exceedance of NAAQS solely based on prescreening levels compared to SILs.[111]

[107] *See* March 28, 2023, Commonwealth LNG PSD Permit No. PSD-LA-841 (the "Commonwealth LNG 2023 PSD Permit"), AI No. 221642, EDMS Doc. No. 13750537, https://edms.deq.louisiana.gov/app/doc/view?doc=13750537, excerpt attached as **Exhibit 44**; *see* Oct. 14, 2022, EPA Letter to FERC re: Commonwealth LNG, Accession No. 20221014-5139, Docket No. CP19-502-000 & CP19-502-001 (commenting on need for increased review and mitigation of Commonwealth LNG's adverse and disproportionate impacts on environmental justice communities), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221014-5139, attached as **Exhibit 45**.

[108] *See* March 28, 2023, Commonwealth LNG 2023 PSD Permit, page 35 of 46, https://edms.deq.louisiana.gov/app/doc/view?doc=13750537, excerpt at **Exhibit 44** (refined modeling "was required" for only 4 pollutant concentrations (24-hour PM 2.5, 1-hour SO2, annual NOx, and 1-hour NOx) and "not required"—and in fact omitted—for other pollutant concentrations solely because they did not "exceed respective significant impact levels (SILs)").

[109] In addition to the modeling for Calcasieu Pass LNG that showed existing NAAQS exceedances of the 1-hour NOx standard, Sierra Club submitted comments with modeling for Commonwealth LNG that showed NAAQS exceedances of 1-hour NOx standard for the facility. *See* April 12, 2022, Sierra Club Amended Comments to LDEQ with Modeling Report at exhibit B, attached at **Exhibit 46**; April 12, 2022, Sierra Club email, AI No. 221642, EDMS Doc No. 13222977, https://edms.deq.louisiana.gov/app/doc/view?doc=13222977 (submitting comments with the documents at Exhibit 46).

[110] *See*, *e.g.*, March 28, 2023, LDEQ Basis of Decision for Commonwealth LNG Permits, page 11–13 of 191, AI No. 221642, EDMS Doc. No. 13750539 ("LDEQ Commonwealth LNG Basis of Decision"), https://edms.deq.louisiana.gov/app/doc/view?doc=13750539, excerpt attached as **Exhibit 47**.

[111] *See*, *e.g.*, *id.* at 11–13, n. 44 of 191. It is notably backwards that, where LDEQ included an "environmental justice review," the agency pointed to its air quality analysis that relied on SILs to find no adverse impact to environmental justice communities instead of pointing to the presence of environmental justice communities (and other bases of concern) to inform whether it should apply the SILs at all. *Id.* at 25 of 191 ("potential emissions of PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, and TAPs from the LNG facility will not cause or contribute to a violation of a NAAQS or AAS based on modeling conducted using AERMOD, EPA's required dispersion model. Accordingly, the LNG facility will not result in 'adverse' impacts in the surrounding area.").

LDEQ also then allowed emissions to contribute to an acknowledged 1-hour NO_x NAAQS exceedance on the finding that Commonwealth's contribution to that exceedance would be less than SILs at the point where its modeling shows a NAAQS violation:

> 1-Hour concentrations of NO_2 will exceed the NAAQS. However, the contribution of NO_2 emissions from the proposed facility to the exceedance will be no more than 0.07 μg/m^3, which is less than the SIL of 7.5 μg/m^3.[112]

It is not clear how LDEQ can conclude that Commonwealth LNG, with NO_x emissions at more than 50% of the neighboring Calcasieu Pass LNG's NO_x emissions,[113] would contribute only 0.07 μg/m^3 to the 1-hour NO_x NAAQS exceedance when Calcasieu Pass would contribute at least 4.41 μg/m^3.[114] Similarly, LDEQ's conclusion appears contrary to its record that shows the facility's 37.7 μg/m^3 1-hour NOx emissions contribute a large portion of the 1-hour NAAQS violation in the attainment zone:

Pollutant	Averaging Period	Background (μg/m^3)	Modeling Results (μg/m^3)	Total (μg/m^3)	NAAQS (μg/m^3)
$PM_{2.5}$	24-hour	19.8	2.18	21.98	35
SO_2	1-hour	57.1	8.14	65.24	195
NO_2	1-hour	46.7	182	228.7	189
	Annual	6.6	4.36	10.96	100

Specifically, preliminary screening showed Commonwealth LNG's 1-hour NOx emissions would contribute 37.7 μg/m^3 and the modeled cumulative contribution (including Calcasieu Pass LNG) would be 182 μg/m^3 in an airshed with 46.7 μg/m^3 background for a total of 228.7 μg/m^3 1-hour NO_x. In other words, Commonwealth LNG would contribute nearly a quarter of the modeled cumulative contribution to the exceedance (37.7 μg/m^3 of 182 μg/m$^{3)}$ and almost the whole measure of the exceedance itself (37.7 μg/m^3 of the 39.7 μg/m^3 above the 189 μg/m^3 NAAQS).

Importantly, LDEQ relies on its abuse of the SILs Guidance—as well as its exclusion of more than a thirty-mile radius of impacted communities—to evade consideration of expected air pollutant impacts on existing, disproportionately impacted communities. There is a lot wrong with LDEQ's purported environmental justice review, including its omission of more than 100 impacted census block groups: Where FERC considered air

[112] Commonwealth LNG PSD Permit, 36 of 46, https://edms.deq.louisiana.gov/app/doc/view?doc=13750537, excerpt attached as **Exhibit 44.**

[113] Commonwealth LNG's permit allows 375.63 tpy of NO_x emissions where Calcasieu Pass LNG's current permit allows 707.93 tpy of NO_x emissions. *Compare id.* at 5 of 46 *with* discussion of Calcasieu Pass LNG *supra* page 26–27.

[114] *See* Commonwealth LNG PSD Permit, 36 of 46, https://edms.deq.louisiana.gov/app/doc/view?doc=13750537, excerpt at **Exhibit 44**; Discussion on LDEQ's Calcasieu Pass LNG permitting, *supra* at page 26–27.

impacts within a 54-kilometer radius from the terminal (about 33.5 miles), LDEQ considered only a three-mile radius for its review (and offered no explanation for that limited scope).[115] So, LDEQ ignored almost all of the 91 census tract block groups (out of 148) that FERC "identified as environmental justice communities," including 24 "based on poverty levels, 18 based on the minority threshold, and 49 based both on both the poverty and minority thresholds."[116]

But LDEQ's reliance on SILs to reject any environmental justice impact on the assertion that "the air quality analysis demonstrates that the LNG facility will not cause or contribute to a violation of NAAQS or AAS"[117] is a failure to consider that there will be some impact—*i.e.* the terminal will put additional pollutants into these communities and the air that people live in and breathe. It is also a failure to consider that, in many areas, those additional pollutants will be piled onto an airshed that already violates the NAAQS and so already exceeds federal public health standards. Whether or not the additional pollutant load is over SILs at the place and time of any existing NAAQS exceedance not the same to whether these pollutants will add to the disproportionate burden on these communities. In short, LDEQ is further abusing the SILs to allow additional and unlawful impacts on the communities it is charged to protect under the Civil Rights Act of 1964.

- *Cameron LNG in Cameron Parish near the border of Calcasieu Parish*. For years, LDEQ has allowed Cameron LNG's emissions in an area whose residents are predominately people of color and/or with low-income.[118] And it has done so despite modeling that both established NOx NAAQS exceedances and confirmed Cameron LNG would contribute to those NAAQS exceedances, if at levels below SILs.[119] Currently, LDEQ is processing

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[115] *Compare* FERC Sept. 9, 2022, Commonwealth LNG Final Environmental Impact Statement ("Commonwealth LNG FEIS"), Docket No. CP19-502-000 & CP19-502-001, Accession No. 20220909-3017, page 4–190, map at page 4–193, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220909-3017, excerpt attached as **Exhibit 48**, *with* March 28, 2023, LDEQ Basis of Decision for Commonwealth LNG Permits, https://edms.deq.louisiana.gov/app/doc/view?doc=13750539, excerpt **Exhibit 47**.

[116] Commonwealth LNG FEIS, page 4–191, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220909-3017&optimized=false, excerpt at **Exhibit 48**.

[117] March 28, 2023, Basis of Decision for Commonwealth LNG Permits, 28 of 191, https://edms.deq.louisiana.gov/app/doc/view?doc=13750539, excerpt at **Exhibit 47**.

[118] *See*, *e.g.*, Affidavit of Dr. Kimberly Terrell, attached as exhibit B to October 15, 2021, Comments of Sierra Club & Healthy Gulf re: Cameron LNG Part 70 Renewal, Permit No. 0560-00184-V10/PSD Permit PSD-LA-766 (M3), AI 99407, EDMS Doc. No. 12947536 ("October 15, 2021 Comments on Cameron LNG"), https://edms.deq.louisiana.gov/app/doc/view?doc=12947536, excerpt attached as **Exhibit 49** Map at Figure 3, *infra* page 31, CP2 LNG DEIS, dated Jan. 19, 2023, page 4–393, Figure 4.14.1–1 ("Projects with Potential to Contribute to Cumulative Impacts").

[119] *See* Dec. 12, 2019, Cameron LNG Title V Permit Modification, 0560-00184-V10, 5 of 49, AI No. 99407, EDMS Doc. No. 11978646 https://edms.deq.louisiana.gov/app/doc/view?doc=11978646, excerpt attached as **Exhibit 50** (modifying to allow switch from LNG import to LNG export and increase

Cameron LNG's permit renewal request. The proposed permit overlooks bases of concern, like the existing modeling that shows NAAQS exceedances and the over-burdened communities nearby. Instead, it summarily relies on SILs to avoid any modeling or other review of pollutants such as NO_2, $PM_{2.5}$, PM_{10}, and CO that screening models showed exceeded PSD significance levels, asserting: "Preliminary screening indicates that the impacts of PM_{10}, $PM_{2.5}$, and NO_x, and CO emissions … will be below their respective SILs. Refined modeling is not required."[120]

Notably, Cameron LNG has a history of failing to meet its emissions limitations and reporting requirements, at least some of which LDEQ acknowledged in 2020,[121] 2021,[122] 2022[123] and 2023.[124] Also, at least one expert report describes that its permits underestimated emissions.[125] As a result, Cameron LNG's contributions to NAAQS exceedances are likely much higher and above SILs.

Other LNG terminals are operating, under construction or proposed in the immediate Lake Charles area,[126] as well as nearby offshore and in Louisiana near the Sabine Pass. FERC's

permitted NO_x emissions in area exceeding NO2 1-hour NAAQS, with rationale in footnote only: "Project's maximum contribution to an exceedance of the NAAQS is 3.68 $\mu g/m^3$. Project's maximum contribution to the maximum concentration of 3,113 $\mu g/m^3$ is 0.00014 $\mu g/m^3$."); *see also* Wingra Engineering Report Air Modeling for Cameron LNG, AI No. 99407, EDMS Doc. No. 12947537, https://edms.deq.louisiana.gov/app/doc/view?doc=12947537, attached as **Exhibit 51** (submitted to LDEQ as exhibit J of October 15, 2021 Comments on Cameron LNG, excerpt at **Exhibit 49**, https://edms.deq.louisiana.gov/app/doc/view?doc=12947536).

[120] *See* Feb. 1, 2023, LDEQ Material associated with proposed Cameron LNG Permit for Public Review, 0560-00184-V11; PSD-LA-766 (M4), page 8 of 580, AI No. 99407, EDMS Doc. No. 13650143, https://edms.deq.louisiana.gov/app/doc/view?doc=13650143, excerpt attached as **Exhibit 52**.

[121] March 26, 2020, LDEQ Warning Letter to Cameron LNG (regarding 2019 violations), AI No. 99407, EDMS Doc. No. 12121119, https://edms.deq.louisiana.gov/app/doc/view?doc=12121119, attached as **Exhibit 53**.

[122] Feb. 22, 2021, two (2) LDEQ Warning Letters to Cameron LNG (regarding 2020 violations), AI No. 99407, EDMS Doc. Nos. 12585627 & 12585621, respectively https://edms.deq.louisiana.gov/app/doc/view?doc=12585621 and https://edms.deq.louisiana.gov/app/doc/view?doc=12585627, attached as **Exhibit 54.**

[123] July 18, 2022 LDEQ Warning Letter to Cameron LNG (regarding 2019 and 2020 violations), AI No. 99407, EDMS Doc. No. 13385903, https://edms.deq.louisiana.gov/app/doc/view?doc=13385903, attached as **Exhibit 55**.

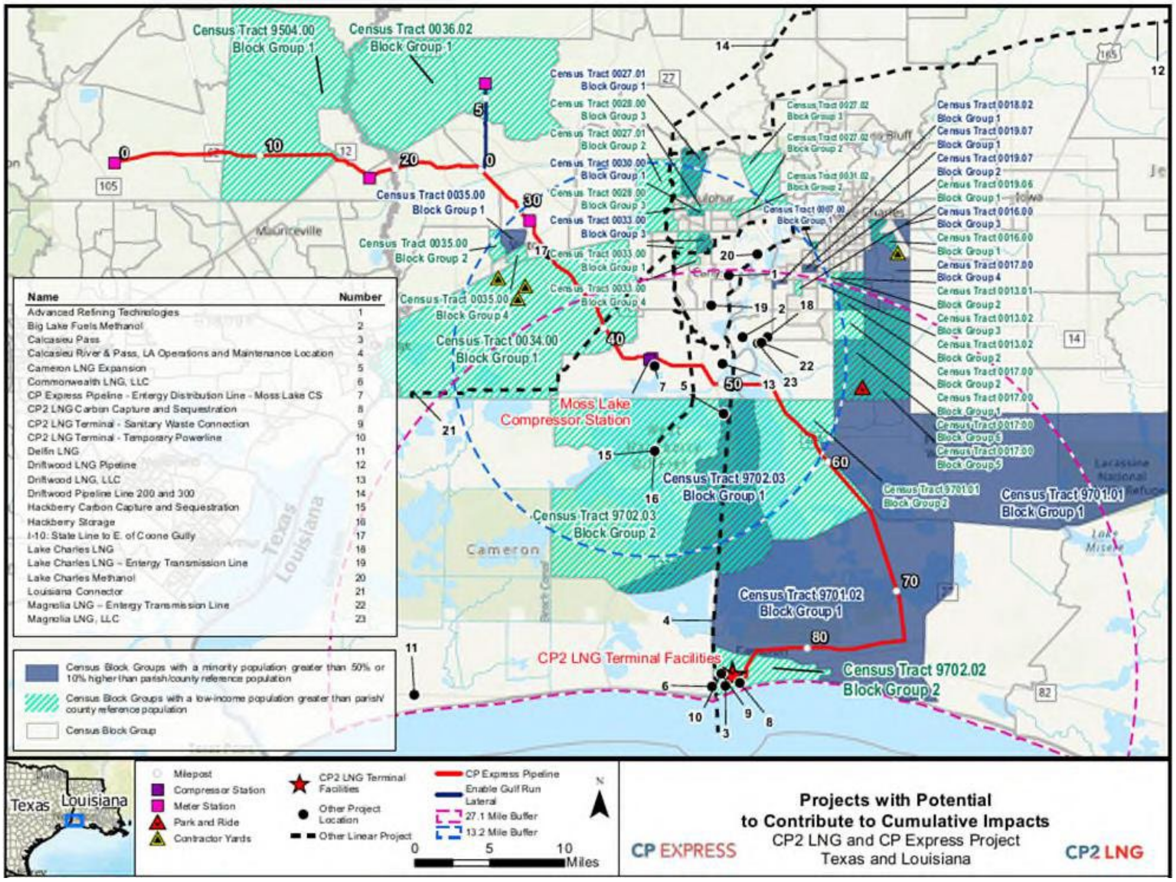
[124] Feb. 24, 2023, LDEQ Warning Letter to Cameron LNG (regarding 2020 violations), AI No. 99407, EDMS Doc. No. 13702093, https://edms.deq.louisiana.gov/app/doc/view?doc=13702093, attached as **Exhibit 56**.

[125] *See* October 15, 2021, Comments on Cameron LNG, page 47 of 175, https://edms.deq.louisiana.gov/app/doc/view?doc=12947536, excerpt at **Exhibit 49**; EDMS Doc. No. 12947536 (with report of Dr. Ranajit (Ron) Sahu).

[126] *See*, *e.g.*, Mar. 21, 2016, Magnolia LNG, PSD Permit PSD-LA-792, AI No. 185639, EDMS Doc. No. 185639, https://edms.deq.louisiana.gov/app/doc/view?doc=10127848.

recent map in its DEIS for CP2 LNG documents some of those LNG facilities, as well as some of the impacted environmental justice communities:

Figure 3, Map from CP2 LNG DEIS, p. 4-393[127]



Upon information and belief, most or all of these LNG facilities rely on an abuse of EPA's SILs Guidance for their permits. The result is a demonstration of Louisiana's systematic failure to apply the Clean Air Act's Prevention of Significant Deterioration provisions and the public health protections of the NAAQS.

Further, the accumulated burden of SILs abuses on air quality and the people—so patent in the rapid LNG build out LDEQ is permitting in Cameron and Calcasieu Parishes—demands EPA's attention. LDEQ accepted modeling protocol appears to aim to avoid finding NAAQS violations and, once emissions are below SILs somewhere, treats them as if they do not exist at all cumulatively, as the proposed permit for Commonwealth LNG admits:

> The objective of cumulative modeling is to show that the Project does not cause or contribute to violations of the NAAQS. Therefore, receptors from the significant modeling analysis that are shown to be below the SIL will not be

[127] CP2 LNG DEIS, *supra* note 97, page 4-393, Figure 4.14.1-1 ("Projects with Potential to Contribute to Cumulative Impacts").

included in the cumulative analysis because it has already been shown that the Project does not cause or contribute to a violation at those receptor locations.[128]

Notably, the "objective" for cumulative modeling should not be to exonerate major sources from causing or contributing to NAAQS violations. Instead, its objective should be to avoid and remedy potential NAAQS violations when modeling indicates an area is in or near such a violation. The upshot is that LDEQ systematically allows NAAQS violations and, further, fails to account for the extent of those violations when it declines to require modeling for emissions below SILs or consider multiple "less than significant" contributions to NAAQS violations. As the LNG terminals in Louisiana demonstrate, the result is permitted violations of the Clean Air Act and unsafe air for the public and, especially, vulnerable communities.

4. Other Louisiana Petrochemical Plants.

As with LNG terminals, LDEQ has used SILs systematically to greenlight enormous emissions from the buildout of petrochemical plants in overburdened communities. Formosa Plastics, above, is just one example. Below are two more pending cases:

- *Lake Charles Methanol, Calcasieu Parish, Louisiana*. In January 2022, LDEQ again improperly relied on the SILs Guidance to allow increased NAAQS violations, this time while attempting to renew Lake Charles Methanol's PSD permit.[129] Lake Charles Methanol proposed to construct a petcoke-to-methanol plant in heavily industrialized Sulphur and Westlake, an area of refineries, chemical plants and other large emitters near the city of Lake Charles. LDEQ, once again, had ample basis for concern before using the SILs. For example, the area within three miles of the site is in the 95th percentile in the nation for risk from respiratory-harming air toxic pollution.[130] Moreover, the data we describe above for Cameron LNG, located south of the site in Calcasieu Parish, showed LDEQ that the area's air could be far above the NAAQS for at least NO_2. Ignoring this case-specific data, the agency erred first by using the SILs to avoid cumulative modeling for the majority of the facility's pollution.[131] Lake Charles Methanol exceeded the Air Quality Analysis' preliminary screening thresholds for five criteria pollutants, $PM_{2.5}$,

[128] Feb. 1, 2023, LDEQ Material associated with proposed permit for Public Review; 0560-0097-V0; PSD-LA-841, page 322 of 851 ("Commonwealth LNG Proposed Permit"), AI No. 221642, EDMS Doc. No. 13105777, https://edms.deq.louisiana.gov/app/doc/view?doc=13105777, excerpt attached as **Exhibit 57**.

[129] Jan. 20, 2022, LDEQ Materials Associated with Lake Charles Methanol, Permit No. 0520-00492-V2, AI No. 196978, EDMS Doc. No. 13083217 (hereinafter "Lake Charles Methanol Draft Permit Package"), https://edms.deq.louisiana.gov/app/doc/view?doc=13083217, excerpt attached as **Exhibit 58**; *see generally* Healthy Gulf, *et al.*, Comment Letter re Lake Charles Methanol's Title V and PSD Air Permits, AI No. 196978, EDMS Doc. No. 13178149 (Feb. 25, 2022), attached as **Exhibit 59**.

[130] *See* EPA, EJSCREEN Risk from Respiratory-Harming Air Toxic Pollution Report for Lake Charles Methanol Site (3464 Bayou D'Inde Rd, Sulphur, LA), https://ejscreen.epa.gov/mapper/, attached as **Exhibit 60**.

[131] Lake Charles Methanol Draft Permit Package, 67 of 350, https://edms.deq.louisiana.gov/app/doc/view?doc=13083217, excerpt at **Exhibit 58 (**Draft Statement of Basis).

PM_{10}, CO, SO_2, and NO_2.[132] But in violation of the Clean Air Act's requirement to perform a full Air Quality Analysis, the company only performed the required cumulative source modeling for just two of those pollutants, SO_2 and NO_2, and only for those standards where Lake Charles Methanol's contribution was greater than the SIL.[133]

Figure 4. Air Quality Analysis Table[134]

TABLE II: AIR QUALITY ANALYSIS SUMMARY (μg/m³)

Pollutant	Averaging Period	Preliminary Screening	Significant Monitoring	Level of Significant Impact	Background	Maximum Modeled	Modeled + Background	NAAQS	Modeled PSD Increment Consumption	Allowable Class II PSD Increment
PM_{10}	24-hour	0.60	10	5				150		30
$PM_{2.5}$	24-hour	0.39	4	1.2				35		-
	Annual	0.07		0.3				15		-
SO_2	1-hour	17.6		7.8	49.7	859.5	(a) 909.2	196		-
	3-hour	11.97		25				1300		512
	24-hour	7.03	13	5	50.2	(c) 564.65	614.85	365	(c) 567.89	91
	Annual	0.73		1				80		20
NO_2	1-hour	19.67		7.5	70.9	328.70	(b) 399.60	188		-
	Annual	0.83	14	1				100		25
CO	1-hour	188.80		2000				40,000		-
	8-hour	28.04	575	500				10,000		-
NAAQS = National Ambient Air Quality Standards										

(a) Lake Charles Methanol contributes 6.69 μg/m³
(b) Lake Charles Methanol contributes 5.11 μg/m³
(c) Lake Charles Methanol contributes 5.26 μg/m³ (2015).

Where Lake Charles Methanol performed the required cumulative model, circled in Figure 4 above, the company found that the new plant would contribute to large air quality violations for each federal air standard. In other words, Lake Charles Methanol failed the regulatory test.[135] As Figure4 above shows, 1-hour SO_2 concentrations (under the column "Modeled + Background") could be more than quadruple their NAAQS.[136] 24-hour SO_2 would greatly exceed both the NAAQS and increment, and 1-hour NO_2 would be more than double the NAAQS.

But contrary to the requirement to perform an Air Quality Analysis, LDEQ issued a draft PSD permit anyway. Healthy Gulf, Louisiana Bucket Brigade, Sierra Club and a local resident in their individual capacity, commented on the draft PSD permit, outlining LDEQ's failure properly apply the SILs Guidance or adhere to the Clean Air Act, among

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[132] *See id.*; LAC 33:III.509.B (setting out the modeling thresholds in defining "*Significant*").

[133] *See* Lake Charles Methanol Draft Permit Package, 68 of 350, https://edms.deq.louisiana.gov/app/doc/view?doc=13083217, excerpt at **Exhibit 58 (**Draft Statement of Basis).

[134] *Id.* at 53 of 350 (red circles added for emphasis).

[135] *See* LAC 33:III.509.K.

[136] *See* Lake Charles Methanol Draft Permit Package, 68 of 350, https://edms.deq.louisiana.gov/app/doc/view?doc=13083217, excerpt at **Exhibit 58 (**Draft Statement of Basis).

other things.[137] LDEQ still has not responded concerning its abuse of the SILs. Although we understand that Lake Charles Methanol now intends to submit a new permit application to account for changes to its production process, LDEQ's conduct indicates that it will continue to invoke the SILs to permit this plant, without performing cumulative air quality modeling and without addressing the large NAAQS and increment violations.

- *Mitsubishi Chemical, Ascension Parish, Louisiana*. In June 2022, LDEQ repeated the same abuses of the SILs Guidance in approving the Air Quality Analysis submitted by Mitsubishi Chemical America, Inc. ("Mitsubishi"), which plans to build a new major-source petrochemical plant in Ascension Parish, Louisiana to make methyl methacrylate monomer and other toxic products.[138] Mitsubishi would emit five criteria pollutants beyond the law's "significant emission rate" modeling thresholds.[139] But LDEQ approved Mitsubishi's decision not to perform a cumulative air quality model for any NAAQS or increment, other than the 1-hour NO_2 NAAQS, claiming that the plant's emissions were below the SIL for all other pollutants.[140] LDEQ's decision to approve this abbreviated Air Quality Analysis failed to take into account any case-specific factors giving basis for concern.[141] For instance, the Geismar area of Ascension Parish already is packed with heavy emitting industry,[142] and the Parish previously spent years as part of the East Baton Rouge nonattainment area for ozone and remains in "maintenance" status—illustrating basis for air quality concerns, especially for an ozone-forming pollutant like NO_2.[143] In addition, the Parish is experiencing a rapid industrial buildout, with nine proposed or under-construction petrochemical plants.[144] Moreover, Mitsubishi's offsite pollution comes within a rounding error of the SIL for several standards that Mitsubishi did not

[137] Healthy Gulf *et al.*, Comment Letter re Lake Charles Methanol's Title V and PSD Air Permits, AI No. 196978, EDMS Doc. No. 13178149, https://edms.deq.louisiana.gov/app/doc/view?doc=13178149, **Exhibit 59**.

[138] June 24, 2022, LDEQ Approval of Mitsubishi Air Quality Modeling Protocol), AI No. 234532, EDMS Doc. No. 13355920, https://edms.deq.louisiana.gov/app/doc/view?doc=13355920, attached as **Exhibit 61**.

[139] Oct. 2022, Mitsubishi Air Permit Application, App'x H, Mitsubishi Air Quality Dispersion Modeling Report, 3, AI No. 234532, EDMS Doc. No. 13517255, (hereinafter "Mitsubishi 2022 Air Modeling Report"), https://edms.deq.louisiana.gov/app/doc/view?doc=13517255, excerpt attached as **Exhibit 62**.

[140] *Id.* at 22–25.

[141] *See id.*; June 24, 2022, LDEQ Approval of Mitsubishi Air Quality Modeling Protocol, AI No. 234532, EDMS Doc. No. 13355920, https://edms.deq.louisiana.gov/app/doc/view?doc=13355920, **Exhibit 61**.

[142] Mitsubishi 2022 Air Modeling Report at 1, https://edms.deq.louisiana.gov/app/doc/view?doc=13517255, excerpt at **Exhibit 62** (listing the industrial air pollution sources near the facility); *see also* DSCEJ Report, *supra* note 62, at 5 (explaining that Ascension Parish has twice the volume of toxic air pollution emissions reported in the Toxic Release Inventory as the next highest parish in the Cancer Alley area).

[143] *See* EPA Green Book on National Ambient Air Quality Attainment Status, Louisiana https://www3.epa.gov/airquality/greenbook/anayo_la.html.

[144] DSCEJ Report, *supra* note 62, at 6.

model cumulatively: 24-hour $PM_{2.5}$ (1.15 μ/m^3 versus 1.2 μ/m^3) and annual $PM_{2.5}$ (0.18 μ/m^3 versus 0.2 μ/m^3), and close to 8-hour CO (457 μ/m^3 versus 500 μ/m^3).[145]

Remarkably, the one cumulative air quality model Mitsubishi submitted, for 1-hour NO_2, showed disturbing results. The model shows that 28 different receptors in the area recorded NAAQS violations, with maximum concentrations nearing double the NAAQS (345 μ/m^3 versus 188 μ/m^3).[146] But Mitsubishi, with LDEQ's apparent blessing, claims it is entitled to a permit anyway because "the contribution of the project sources does not exceed the SILs."[147]

5. Texas Petrochemical and LNG Plants.

Texas' abuse of EPA's SILs Guidance is exemplified by its permitting in Brownsville, Texas, an area along the border with Mexico of almost entirely Latino and Indigenous population and, at least until recently, with high-quality, low-pollution ambient air. Brownsville is 94 percent Hispanic or Latino, with high rates of people below the federal poverty line and existing health disparities.[148] There, TCEQ is facilitating an industrial buildout on sites sacred to the Carrizo/Comecrudo Tribe,[149] and on sensitive undeveloped coastal wetlands,[150] using unjustified applications of SILs to allow deterioration of the air quality at or over the brink of NAAQS public-health standards, including for ozone.

First, TCEQ's permitting of the Jupiter Brownsville, LLC ("Jupiter") oil refinery illustrates Texas' systematic failure to engage in any case-by-case review when relying on SILs to avoid a full air quality analysis.[151] TCEQ gave no justification or review of the past the

[145] Mitsubishi 2022 Air Modeling Report at 22, https://edms.deq.louisiana.gov/app/doc/view?doc=13517255, excerpt at **Exhibit 62**.

[146] *Id.* at 27.

[147] *Id.*

[148] *See* Save RGV from LNG, *et al.*, *Rio Grande Valley: At Risk from Fracked-Gas Export Terminals*, 8 (2019 Update), https://www.ran.org/wp-content/uploads/2019/07/RGV_LNG_2019_vF_1.pdf, attached as **Exhibit 63**.

[149] *See id.* at 7; Dylan Baddour, *Indigenous Leaders Fight to Keep Natural Gas Pipelines Off Sacred Lands*, Texas Observer (Oct. 18, 2022), https://www.texasobserver.org/carrizo-comecrudo-natural-gas-indigenous/, attached as **Exhibit 64**.

[150] *See* Gus Bova, *Bridge to Nowhere*, Texas Observer (Sept. 16, 2019), https://www.texasobserver.org/liquefied-natural-gas-rio-grande-valley-endangered-pollution/, attached as **Exhibit 10**.

[151] TCEQ generally uses the term "de minimis values" whereas EPA uses the term "significant impact levels" (SILs), but TCEQ agrees these are interchangeable terms. *See* Jupiter Hearing Transcript, *supra* note 43, at 243:1-13 ("In our guidance we actually specify that SILs and de minimis levels are the same.").

conclusions of Jupiter itself that its emissions were below the SIL, when it summarily declined further analysis for PM_{10} and CO:[152]

> 38. Jupiter conducted an air quality analysis (AQA) for NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and ozone. De minimis analysis modeling indicated that PM_{10} (24-Hr and 1-Hr) and CO (8-Hr) did not exceed the de minimis concentrations and therefore did not require PSD increment analysis.

Indeed, TCEQ has admitted that this unauthorized application of SILs, *i.e.* omission of any case-by-case review, is part of its practice and policy.[153] When asked at an administrative hearing on Jupiter's air permit to confirm, if "emissions are below the relevant SIL, then the applicant never needs to do the full impacts analysis," a TCEQ representative responded "Correct."[154] This means that TCEQ systematically does not consider background pollutant levels if the proposed emission is below the SILs threshold because, as the TCEQ representative explained: "if it's below that threshold, it will not contribute to any background degradation."[155] When asked to clarify whether Texas applies SILs without consideration of background even where "the background levels are getting very close to the NAAQ Standards," the representative responded: "I mean, it -- yeah, it's true regardless. That's by definition."[156]

TCEQ's inflexible approach was particularly objectionable in Jupiter because of the recent permitting history in the area. TCEQ had also summarily allowed Jupiter to avoid a full Air Quality Analysis for ozone where preliminary screening showed levels below SILs.[157]

In the years leading up to the Jupiter decision, TCEQ had granted air permits to three LNG export terminals along the Brownsville Ship Channel near where Jupiter intends to construct – Rio Grande LNG, Annova LNG, and Texas LNG.[158] Relying on TCEQ's air permitting, FERC found that, collectively, the ozone impacts for those three LNG terminals would be 12.76 parts per billion (ppb). Because background ozone levels in the area were 56.7 ppb, this meant total ozone concentrations could be 69.48 ppb when the LNG terminals were operating.[159] This is only a hair's breadth less than the NAAQS for ozone, which is 70 ppb.[160] And it meant that projected ozone levels in the region were already closer to the NAAQS than

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[152] *See* Oct. 19, 2021, TCEQ Order Granting the Application by Jupiter Brownsville, LLC for Proposed Air Quality Permit Nos. 147681, PSDTX1522, and GHGPSDTX172; TCEQ Docket No. 2020-1080-AIR; SOAH Docket No. 582-21-011, at p. 5 (hereinafter "TCEQ Oct. 19, 2021, Order Approving Jupiter"), excerpt attached as **Exhibit 65**.

[153] Jupiter Hearing Transcript, *supra* note 43, at 244:14-245:10 (admitting that so long as the predicted impacts are below the ozone SIL of 1 ppb, TCEQ never requires a full impacts analysis.).

[154] *Id.*

[155] *Id.* at 245:13.

[156] *Id.* at 245:4-7.

[157] *See* TCEQ Oct. 19, 2021, Order Approving Jupiter, *supra* note 157, at 5.

[158] FERC, Order on Rehearing and Stay, Rio Grande LNG and Rio Bravo Pipeline Company, 170 FERC P 61046, 2020 WL 408934 at *16 (January 23, 2020), excerpt attached as **Exhibit 66**.

[159] *Id.*

[160] EPA, Review of the Ozone Natural Ambient Air Quality Standards, 85 Fed. Reg. 87256-01 (Dec. 31, 2020).

the SIL, separated by 0.52 ppb when the SIL is 1 ppb. Worse still, when FERC included the mobile source emissions from LNG tanker vessels associated with the projects, the air did exceed the NAAQS for ozone.[161]

In other words, TCEQ's permitting of the three LNG terminals had already brought the Brownsville region to the brink of ozone NAAQS violations, if not past that point. And the fact that the air may be closer to the NAAQS than the SIL value of 1 ppb is exactly the scenario that EPA has warned provides "basis for concern" against using the SILs at all. Nonetheless, TCEQ ignored that warning sign and discounted additional ozone pollution based on the SILs again with Jupiter anyway.

Second, TCEQ permitting of Jupiter also demonstrates the agency's maneuvering of data to hide behind SILs and so avoid finding exceedances on paper rather than to find whether there are NAAQS exceedances in fact. Jupiter's initial analysis estimated that the refinery could contribute as much as 3.3 ppb of ozone on its own, over three times the SIL and mandating a cumulative air quality analysis.[162] But TCEQ instead allowed Jupiter to revise downward its estimate of the refinery's ozone contribution to just 0.58 ppb,[163] *i.e.* less than the 1 ppb SIL, and so found Jupiter need not perform cumulative modeling (called a "full impacts analysis" by TCEQ).[164] TCEQ did not require Jupiter to use a source- and site-specific air quality model to determine either Jupiter's or cumulative ozone concentrations. It instead allowed Jupiter to rely on a tool to estimate ozone formation based on the volume of Jupiter's emissions of NO_x and VOC compared to a source near Houston, TX.

On its face, TCEQ appears to have erred on the side of not protecting public health when it relied on the second analysis. But even if we were to assume the second, ozone emissions estimate was legitimate , the initial 3.9 ppb finding served as a "basis of concern" (on top of the LNG terminals' ozone levels showing near-exceedance of the NAAQS) such that TCEQ abused any discretion when it allowed Jupiter to avoid cumulative modeling. Rather than act out of conservativism to protect public health and ask Jupiter to model using or considering the higher-end estimate, TCEQ shielded the company in relying on a low-end estimate of ozone emissions.

Remarkably, even if Jupiter's 0.58 ppb ozone contribution were accurate and appropriate, Jupiter would still cause or contribute to a NAAQS violation. Added to the background readings

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[161] FERC, Order on Rehearing and Stay, Rio Grande LNG and Rio Bravo Pipeline Company, 170 FERC P 61046, 2020 WL 408934 at *16 (January 23, 2020), excerpt at **Exhibit 66**.

[162] Excerpt from Jupiter's Air Dispersion Modeling Protocol, 1724 (Oct. 2017); attached as **Exhibit 67** (formerly known as Centurion Brownsville project).

[163] TCEQ Interoffice Memo on Air Quality Analysis Audit – Jupiter Brownsville, LLC, 3 (0113) (Feb. 27, 2019), attached as **Exhibit 68**.

[164] *See id.*; Transcript of Hearing on the Merits, filed Jan. 20, 2021, Texas State Office of Administrative Hearings, Application of Jupiter Brownsville, LLC, Excerpt of Justin Cherry's Pre-Filed Testimony on Jupiter Brownsville LLC Permit, 21:34-22:5, attached as **Exhibit 69** ("the applicant did not need to evaluate off-property emissions (*i.e.*, Rio Grande LNG) in the 8-hr ozone analysis as the project emissions were below the de minimis value and a full impacts analysis was not required.").

and the LNG terminals' contributions, total concentrations could still exceed the 70 ppb NAAQS:

56.7 ppb	+	12.78 ppb	+	0.58 ppb	=	**70.04 *ppb***
(background levels)		*(three LNG terminals)*		*(Jupiter)*		

Thus, in this situation, even where TCEQ found Jupiter might have "met" the SIL, the company failed to "demonstrate" that it would not "cause or contribute" to a NAAQS violation as the Clean Air Act demands. Here, the evidence actually showed the opposite. This perverse outcome threatens predominately Latino and Indigenous communities, who would lose recently pristine air quality and suffer air that may no longer meet the NAAQS—all in the span of a few short years from consecutive TCEQ air permitting decisions including the new LNG terminals and Jupiter.

VI. CONCLUSION

EPA must take action to halt the abuse of its SILs Guidance now that "experience and information" show that LDEQ and TCEQ are consistently misapplying it to allow violations of the Clean Air Act's plain language. EPA wrote the SILs Guidance in the wake of *Sierra Club I*, where the D.C. Circuit vacated regulations that would have applied the SILs as a compulsory exemption from performing a full Air Quality Analysis. But despite EPA's call for case-by-case reviews and its warning that SILs do not apply in areas where there is a "basis for concern," we see now that LDEQ and TCEQ are using the SILs in the same way that the petitioners in *Sierra Club I* feared and the court aimed to avoid. Specifically, Louisiana and Texas are limiting their PSD review to compliance with a SILs threshold in areas close to or exceeding the NAAQS and avoiding their obligation to assess whether a new major source could "cause or contribute to" violations of the federal public health-based air standards—an outcome EPA has acknowledged can result from adding pollution even less than the SILs. *See* 705 F.3d at 463–66 (noting EPA had conceded the same flaw with the SILs by the time the litigation reached the D.C. Circuit). Indeed, these permitting agencies have shown that they will use the SILs to permit new facilities even where the data show the added pollution *will* cause or contribute to such a violation in the airshed.

Moreover, these abuses of the SILs Guidance have disproportionate and detrimental impacts on communities that these agencies are obligated to consider and protect under Title VI of the Civil Rights Act. The States have transformed the SILs from a tool to streamline uncontroversial permitting scenarios into an all-purpose shield against Air Quality Analysis compliance for new sources entering areas where air quality has already deteriorated to near or exceeding the NAAQS. They do not keep track of, let alone correct, the NAAQS and increment violations that applicants' Air Quality Analysis modeling reveal. The result is disproportionate harm to Black, Indigenous, and Latino communities, and low-income communities, near industrial corridors in Louisiana and Texas. Put simply, state agency abuse of the SILs helps enable "sacrifice zones" for air quality in our region.

It is time for EPA to curb Louisiana and Texas' abuses and to protect frontline and other impacted communities, using the array of legal tools and the oversight mandate Congress gave it under the Clean Act and Title VI of the Civil Rights Act. *See* Section II. We strongly urge EPA to follow through on its charge and to make use of its ample authority. We look forward to discussing this Petition and the States' abuses described here and to assisting in a resolution.

Earthjustice

Counsel for Petitioners, RISE St. James,
Vessel Project of Louisiana, For a Better Bayou,
Deep South Center for Environmental Justice,
Healthy Gulf, Louisiana Bucket Brigade,
and Sierra Club

INDEX OF EXHIBITS

Exhibit No.	Description	Date
1	EPA Title VI Letter of Concern regarding Louisiana Department of Environmental Quality ("LDEQ") and Louisiana Department of Health	Oct. 12, 2022
2	Kimberly A. Terrell & Gianna St. Julien, *Discriminatory outcomes of industrial air permitting in Louisiana*, Journal of Environmental Challenges (vol. 10)	Jan. 2023
3	Al Shaw, *et al.*, *The Most Detailed Map of Cancer-Causing Industrial Air Pollution in the U.S.*, ProPublica	Mar. 15, 2022
4	Lylla Younes, *et al.*, *Poison in the Air*, ProPublica	Nov. 2, 2021
5	U.S. Census Bureau, Quick Facts: Laredo, Port Lavaca, Longview, City, Port Arthur, and Freeport, Texas	Jul. 1, 2022
6	Yukyan Lam, *et al.*, *Toxic Air Pollution in the Houston Ship Channel: Disparities Show Urgent Need for Environmental Justice*, NRDC	Aug. 31, 2021
7	Aman Azhar, *In Corpus Christi's Hillcrest Neighborhood, Black Residents Feel Like They Are Living in a "Sacrifice Zone*," Inside Climate News	July 4, 2021
8	Darryl Fears, *Shingle Mountain: How a pile of toxic pollution was dumped in a community of color*, Washington Post	Nov. 16, 2020
9	Carmen Rocco & Dolly Lucio Sevier, *Air Pollution a concern if LNG comes to the Valley*, Rio Grande Guardian	Sept. 7, 2016
10	Gus Bova, *Bridge to Nowhere*, Texas Observer	Sept. 16, 2019
11	Isa Gutierrez, *et al.*, *'Like a Dumping Ground': Latina moms in Texas border city are fighting air pollution*, NBC News	Feb. 22, 2022
12	LDEQ Air Quality Modeling Procedures	Aug. 2006 ed.
13	TCEQ Air Quality Modeling Guidelines APDG 6232	Nov. 2019
14	Excerpt of Transcript of Hearing on Merits, Texas State Office of Administrative Hearings, Contested Case re: Application of Jupiter Brownsville, LLC for PSD Permit	Feb. 8, 2021
15	Petition to EPA for Action re: Deficiencies in the Texas Air Permitting Program Related to Environmental Justice and Public Participation	June 28, 2022
16	Excerpt of LDEQ Basis for Decision on FG LA LLC ("Formosa Plastics") Air Permits, AI No. 198351, EDMS Doc. No. 11998452	Jan. 6, 2020
17	Excerpt of Formosa Plastics PSD Permit No. PSD-LA-812, AI No. 198351, EDMS Doc. No. 11998450	Jan. 6, 2020
18	LDEQ Current Monitoring Data & AQI in the New Orleans Area	May 22, 2023
19	EPA Comments submitted to LDEQ re: Nucor Steel Louisiana, AI No. 157847, EDMS Doc. No. 7830225	Jan. 7, 2011
20	Tristan Baurick, *et al.*, *Welcome to "Cancer Alley," Where Toxic Air Is About to Get Worse*, ProPublica	Oct. 2019

21	EPA EJSCREEN, results for Welcome, La., Census Block Grp. No. 220930405002	May 29, 2023
22	Deep South Center for Environmental Justice, *The More Things Change, the More they Remain the Same: Living and Dying in Cancer Alley (1990 to 2023)*	May 8, 2023
23	Lylla Younes, *What Could Happen if a $9.4 Billion Chemical Plant Comes to "Cancer Alley,"* ProPublica	Nov. 18, 2019
24	Excerpt of Formosa Plastics Air Quality Analysis, AI No. 198351, EDMS Doc. No. 11246153	July 17, 2018
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28	Suspensive Appeal Bond, *RISE St. James et al. v. LDEQ*, 19th Judicial District Court Parish of East Baton Rouge, Docket No. 694, 029	Sept. 29, 2022
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32	LDEQ Air Monitoring Sites Map	May 23, 2023
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34	FERC Environmental Assessment for proposed Plaquemines LNG Uprate Amendment, Docket No. CP22-92-000, Accession No. 20231006-3019	Jan. 6, 2023
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37	Excerpt of FERC Draft Environmental Impact Statement for Venture Global's CP2 LNG terminal and CP Express pipeline system, Docket Nos. CP22-22-000 & CP22-21-000, Accession No. 20230119-3072	Jan. 19, 2023
38	Calcasieu Pass LNG PSD Permit No. PSD-LA-805, AI No. 194203, EDMS Doc. No. 11322607	Sept. 21, 2018
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40	LDEQ Response to Public Comments and Notification of Final Permit Action on Calcasieu Pass LNG, AI. No. 194203, EDMS Doc. No. 12563557	Feb. 2, 2021
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43	Excerpt of CP2 LNG Modified Title V Permit and PSD Permit Application, AI No. 232172, EDMS Doc. No. 13411196	July 29, 2022
44	Excerpt from Commonwealth LNG PSD Permit No. PSD-LA-841, AI No. 221642, EDMS Doc. No. 13750537	Mar. 28, 2023
45	EPA Letter to FERC re: Commonwealth LNG, Accession No. 20221014-5139, Docket No. CP19-502-000 & CP19-502-001	Oct. 14, 2022
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47	Excerpt of LDEQ Basis of Decision for Commonwealth LNG Permits, AI No. 221642, EDMS Doc. No. 13750539	Mar. 28, 2023
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52	Excerpt of LDEQ, Material associated with proposed Cameron LNG permit for Public Review 0560-00184-V11, PSD-LA-766 (M4), AI No. 99407, EDMS Doc. No. 13650143	Feb. 1, 2023
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56	LDEQ Warning Letter to Cameron LNG, AI No. 99407, EDMS Doc. No. 13702093	Feb. 24, 2023
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Respondent:

Center for LNG;
American Petroleum Institute;
and
Natural Gas Supply Association

June 26, 2023

U.S. Department of Energy
Attn: Jared Ciferno
Office of Fossil Energy and Carbon Management
Forrestal Building
1000 Independence Ave. SW
Washington, DC 20585
VIA Email

RE: <u>Notice of Request for Information on Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas Exports (No. DE–FOA–0003052)</u>

To the Department of Energy ("DOE") Office of Fossil Energy and Carbon Management ("FECM"):

Pursuant to the notice announcing a *Request for Information (RFI) on opportunities to reduce greenhouse gas emissions and other air pollutants associated with U.S. Liquefied Natural Gas (LNG) exports* published by the U.S. Department of Energy (DOE) in the Federal Register on April 26, 2023, 88 Fed. Reg. 25393, the Center for LNG (CLNG), the American Petroleum Institute (API), and the Natural Gas Supply Association (NGSA) (collectively, the Associations) submit the following comments.

I. Interest of CLNG, API and NGSA

CLNG advocates for public policies that advance the use of liquefied natural gas (LNG) in the United States, and its export internationally. A committee of NGSA, CLNG represents the full LNG value chain, including large-scale LNG export facilities in the United States, shippers, and multinational developers, providing it with unique insight into the ways in which the vast potential of this abundant and versatile fuel can be fully realized.

API represents all segments of America's natural gas and oil industry, which supports more than 11 million U.S. jobs and is backed by a growing grassroots movement of millions of Americans. API's approximately 600 members produce, process and distribute most of the nation's energy, and participate in API Energy Excellence®, which is accelerating environmental and safety progress by fostering new technologies and transparent reporting. As highlighted in the API *Climate Action*

Framework[1], API and its members are committed to delivering solutions that reduce the risks of climate change while meeting society's growing energy needs.

Founded in 1965, NGSA represents integrated and independent energy companies that produce, transport and market domestic natural gas and is the only national trade association that solely focuses on producer-marketer issues related to the downstream natural gas industry. NGSA's members trade, transact and invest in the U.S. natural gas market in a range of different manners. NGSA members transport and/or supply billions of cubic feet of natural gas per day on interstate pipelines.

Collectively, the Associations' value the opportunity to provide input on DOE's *RFI on opportunities to reduce greenhouse gas emissions and other air pollutants associated with U.S. Liquefied Natural Gas (LNG) exports***.** Our industry stands ready to work with DOE to reduce emissions, achieve our nation's climate commitments, and continue America's role of providing reliable, ever-cleaner energy to our allies around the world.

II. Comments

a. The Associations' members are committed to reducing emissions and want to ensure that industry innovations, technologies, and initiatives can continue to develop without prescriptive limitations.

The natural gas and LNG industry has always been an industry of great innovation. Their commitment to research and development has revolutionized not only the United States' energy landscape, but the way natural gas is used and distributed around the world. Two decades ago, domestic natural gas production was quickly declining, and the United States was slated to become one of the largest importers of LNG in the world—making U.S. consumers dependent on foreign countries for our energy needs. Thanks to the shale revolution and bipartisan support of American energy—including from this Administration—the United States is now a top exporter of LNG, while simultaneously maintaining a well-supplied domestic market. America has become a stabilizing force for global energy security, and, at home, the growth of the U.S. natural gas industry has created thousands of jobs, spurred economic development, and supported local communities.

As technology has evolved, groundbreaking innovations have helped reduce greenhouse gas (GHG) emissions in operations, services, and products. Increased industry investment in research and development has enabled the U.S. to lead the world in emissions reductions. The industry has embraced digitalization and new technologies like cloud computing, robotics, and 3-D imaging. Natural gas and LNG companies are developing and refining technologies to capture, store and reuse carbon. They are pioneering ways to recycle and reuse produced water and are developing smarter and safer ways to transport products. These innovations and others improve the quality of life and the environment in the U.S. and worldwide.

The Associations' members are committed to reducing GHG emissions and continuing to develop new and innovative ways to advance emission reductions. The Associations' members are eager to support DOE in their efforts to understand how the industry is working to reduce emissions along their

[1] American Petroleum Institute, *Climate*, https://www.api.org/climate.

value chain. Members also want to ensure that industry innovations, technologies, and initiatives are allowed to continue to develop, so that they can assist economies around the world in reaching their climate goals while helping maintain an affordable and reliable energy supply.

The Associations suggest that it would be unproductive for DOE to use this RFI to mandate specific technologies or emission reduction tools because it will likely hinder the development, deployment, and investment in new abatement innovations. Technology in the energy sector is constantly changing and improving, often rapidly. Without the flexibility for companies to pursue their individual emissions reduction strategies and investments in technological innovations, a company or industry sector could easily be left disadvantaged, with limited ability to contribute to U.S. climate goals and economic development.

Further, each LNG and natural gas project is unique, with varying geologic, economic and demographic considerations. The type of emission abatement tools appropriate for one project won't necessarily work for another because of these factors and differences in individual projects' size, scope, and objectives. Additionally, LNG producers have a range of business models and corporate structures with varying degrees of control over the gas that is processed in their facilities—making a potential one-size-fits-all type requirement problematic. Requiring specific technologies or tools to reduce emissions would signal that DOE values those technologies over others, potentially slowing investment in other valuable emissions reduction technologies.

b. The RFI and its received responses should not indicate a license to begin imposing requirements on LNG projects that go beyond DOE's legal mandate under the National Environmental Policy Act of 1969 (NEPA).

Exporting natural gas requires authorization from DOE and from the Federal Energy Regulatory Commission (FERC). FERC is responsible for authorizing the siting, construction, and operation of onshore LNG facilities under Section 3 of the Natural Gas Act (NGA). FERC is also responsible for preparing an environmental assessment or an environmental impact statement for proposed LNG facilities, as required by NEPA. FERC is the Lead Federal Agency in preparing the overall NEPA documentation for LNG facilities. As the Lead Federal Agency, FERC has invested significant resources into ensuring a robust NEPA review.

Upon request of the Lead Federal Agency, any other federal agency which has jurisdiction by law shall be a cooperating agency. DOE is a cooperating agency to FERC regarding the NEPA review for LNG. DOE, under Section 3 of the NGA, authorizes the export of natural gas unless it finds that the export is not consistent with the public interest.

DOE's jurisdiction rests solely with the export of LNG. DOE lacks the authority to approve the construction or operation of the LNG facility itself, that authority rests solely with FERC. DOE does not need to review potential environmental impacts from the construction and operation of the LNG facility (as enunciated in the United States Supreme Court in *Public Citizen* and the D.C. Circuit in *Sierra Club*[2]),

[2] *See* Department of Transportation v. Public Citizen, 541 U.S. 752 (2004); Sierra Club v. Federal Energy Regulatory Commission, 827 F.3d 36 (D.C. Cir. 2016). When making a determination based on the NEPA analysis, only the information that is useful to the environmental decisionmaker need be presented. NEPA analysis has limits and, as enunciated in *Public Citizen* and *Sierra Club,* the "rule of reason" limits agency obligation under NEPA. The agency need only consider the environmental information

which will continue to be reviewed by FERC. Instead, DOE's review should be limited to the potential environmental impacts that are within DOE's authority, namely the impacts that occur at or after the point of export.

Further, DOE should keep in mind that upstream and downstream emissions are already regulated by multiple layers of federal and state regulations. Congress imbued the Environmental Protection Agency (EPA) with the authority to regulate air emissions, including GHGs, through the Clean Air Act (CAA). The CAA established a strong regulatory program, supervised by the EPA, to comprehensively address interstate air pollution.[3] As the Supreme Court explained, "Congress designated an expert agency, here, EPA, as best suited to serve as primary regulator of greenhouse gas emissions."[4] The EPA has taken significant steps to regulate GHG emissions from pipeline facilities and other sources and has a proposed rule under the CAA to further limit emissions of methane from facilities in the oil and natural gas sector, which it has been regulating since 2011.[5]

States also play an important role in regulating air emissions under the CAA. Congress intended for states to have a significant role in establishing measures to mitigate emissions from stationary sources. The CAA acknowledges state authority to issue permits to regulate stationary sources related to upstream and downstream activities. Many states have also taken significant steps to regulate GHG emissions by enacting laws aimed at reducing GHG emissions.

As described above, natural gas facilities' emissions are subject to extensive regulations from the EPA and the states. And while one can debate whether NEPA's intended scope of review includes indirect GHG emissions, the fact is that activities and facilities upstream and downstream of the LNG project are in many cases already covered by the regulations of other federal and state agencies. Further, the U.S. natural gas industry is committed to reducing emissions and advancing climate solutions. Industry supports well-designed regulation of methane from new and existing sources. Along with preparing to comply with these regulations, the natural gas industry is making significant voluntary efforts to reduce methane emissions. With continued technological innovation and concerted industry efforts, methane emissions decreased nearly 60 percent across all seven major U.S. producing regions from 2011 to 2021.[6]

In reviewing this RFI, we ask DOE to consider existing climate regulations. Creating duplicative procedures could cause confusion, create potential regulatory contradictions, and add new hurdles to an already lengthy permitting process for LNG facilities, ultimately preventing the timely deployment of emission reduction technologies and chill LNG infrastructure development. Further, any action taken by DOE as a result of this RFI should be done through the proper process with opportunities for comment and redress. DOE should always provide regulatory certainty to the greatest extent possible. Prudent, well-thought-out regulation is necessary for companies to consider investing in expensive new

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that is of use and relevant to the decisionmaker. An agency does not need to evaluate an environmental effect where it "has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions."

[3] Massachusetts v. EPA, 549 U.S. 497, 532 (2007)

[4] Am. Elec. Power Co. v. Connecticut, 564 U.S. 410, 428 (2011).

[5] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63,110 (Nov. 15, 2021).
Supplemental Update, 87 Fed. Reg. 74,702 (Dec. 06, 2022).

[6] U.S. EPA Greenhouse Gas Reporting Program (GHGRP), https://www.epa.gov/ghgreporting.

technologies. Companies are less likely to make such investments without government agencies' commitment to the proper regulatory process.

c. LNG exports have global environmental benefits and influence decisions other countries make regarding their energy mix.

The natural gas industry is a partner in the transition to a lower-carbon future, and exporting U.S. LNG is one of the ways the industry is working to reduce emissions on a global scale while meeting the energy demands for a growing population. As countries choose to increase their use of natural gas for power generation, they can reduce their GHG emissions through fuel switching from coal to natural gas while simultaneously increasing the deployment of renewable energy. Accordingly, U.S. LNG is central to helping to ensure countries around the world can responsibly meet their climate and energy security goals.

The energy crisis in Europe has demonstrated the importance of the U.S. LNG industry and a robust global LNG market. Although U.S. LNG is not the sole solution to the EU's energy supply crunch, the U.S. has been the EU's largest supplier of LNG throughout their energy crisis. After Russia's February 2022 invasion of Ukraine, U.S. LNG exports to Europe increased by 141% from 2021—staving off the worst-case scenarios for our European allies.[7] Further, having a robust supply of LNG on the global market is critical to helping developing nations reduce their GHG emissions. Natural gas power generation is an ideal partner to intermittent renewable energy resources, given its ability to quickly provide real-time reactions to changing power supply and demand responses. However, without a sufficient supply of LNG on the global market, developing countries will struggle to create a sustainable decarbonization strategy.

Global energy and climate conversations often proceed as though coal has already been eliminated from the global energy system and that gas is engaged in a zero-sum competition with renewable energy development. However, this is false, last year the world burned more coal than at any point in recorded history, and approximately 40 gigawatts of new coal plants were approved—almost all of which are in China. This trend may continue through this year; the International Energy Agency (IEA) expects investment in coal supply to rise by 10 percent in 2023.[8]

As a responsible and reliable supplier of natural gas to global markets, the U.S. can play a primary role in reducing GHG emissions in these countries by decreasing reliance on coal for power generation. America has led the world in emissions reduction since 2005 largely due to the shift in power generation fuel from coal to natural gas[9] – providing a template for countries looking to replicate similar emission reductions. DOE should recognize the benefits that U.S. LNG can provide after the point of export. Any action taken by DOE in response to this RFI must consider the value and emissions reductions that U.S. LNG provides to countries around the world.

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[7] "Europe Was the Main Destination for U.S. LNG Exports in 2022." U.S. Energy Information Administration, 22 Mar. 2023, www.eia.gov/todayinenergy/detail.php?id=55920#:~:text=In%202022%2C%20Europe%20increased%20LNG,according%20to%20data%20from%20Cedigaz.

[8] "World Energy Investment 2023." International Energy Agency, May 2023, https://www.iea.org/reports/world-energy-investment-2023.

[9] "Electric power sector CO2 emissions drop as generation mix shifts from coal to natural." U.S. Energy Information Administration, 9 June 2021. https://www.eia.gov/todayinenergy/detail.php?id=48296.

III. DOE RFI Topic 1: Environmental Profile of Upstream Supplies

a. *1.1 What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?*

Reducing the emissions intensity of LNG begins with upstream production. Broadly, upstream producers are utilizing many different strategies to reduce emissions from their operations.

- Electrification: upstream producers are electrifying their operations at natural gas production sites by using lower-emission power, which may include wind, solar, hydro, and natural gas.
- Flaring reductions: upstream producers are employing programs to eliminate and reduce routine flaring.
- Methane detection and monitoring: upstream producers are reducing methane emissions through detection and mitigation technology, such as the use of forward looking infrared (FLIR) handheld gas detection scanners, drone/aerial technologies, and in-plant gas monitoring systems in leak detection and repair programs. Detection of fugitive emissions enables operators to quickly identify and repair leaks.
- Pneumatic devices: pneumatic devices are used to control the conditions of natural gas and are powered by natural gas. During normal operations, some natural gas is vented into the atmosphere. Transitioning from high-bleed pneumatic devices to low- or no-bleed devices or electrical pumps or controllers can reduce vented emissions associated with these devices.
- Commercializing and scaling carbon capture and storage (CCS): investing in CCS and assessing the potential to implement CCS at natural gas processing facilities will greatly reduce emissions.
- Offsetting emissions: employing high-quality carbon credits to offset emissions that cannot be reduced through operational changes.

b. *1.5 What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?*

Certified natural gas can complement efforts already underway to directly reduce methane emissions both voluntary and regulated. To be effective, certified gas must be a voluntary market-based solution that is inclusive, liquid, and transparent.

c. *1.6 What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?*

LNG and natural gas companies use both in-house and independent measurement protocol programs:

- Companies such as Project Canary, MiQ, and Equitable Origin have measurement protocol programs that are used by LNG operators.
- The International Group of Liquefied Natural gas Importers ("GIIGNL") and its 84 member companies of LNG importers have developed measurement and independent verification (MRV) and GHG Neutral LNG Framework which has a reporting format for both full cycle and individual stage reporting.
- Some LNG operators are working independently with producers to understand the full emissions profiles of the natural gas they are exporting. They are providing that information to their customers voluntarily.

d. 1.7 What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

LNG buyers and natural gas consumers around the world are showing increased interest in transparency around the GHG emission profile associated with the energy they purchase. Certified natural gas programs are only in the early stages of development and have had little if any impact on the global LNG market to date.

The Associations support the development of voluntary and transparent differentiated natural gas data to inform markets; however, prematurely imposing shortsighted requirements on U.S. producers could put U.S. LNG exporters at a serious disadvantage against global competitors.

IV. DOE RFI Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities

a. 2.1 What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?

LNG companies are employing a variety of strategies to reduce emissions at liquefaction facilities, depending on their individual facilities and strategic plans. Described below are a variety of technologies that LNG companies are employing to reduce emissions at their facilities.

- High efficiency gas turbines*:* the use of high efficiency gas turbines requires less natural gas, reducing emissions from the liquefaction process.
- Electrification: electrification of components of the liquefaction process can reduce facility emissions. Operators are also committing to sourcing renewable energy to power their electrified processes.
- Waste heat recovery: for waste heat recovery, liquefaction facilities capture heat that is emitted from liquefaction processes before it enters the atmosphere. This heat can then be used in other processes or to generate electricity.
- Seal gas recovery: compressors used at liquefaction facilities can result in small amounts of natural gas into the atmosphere. Seal gas recovery captures this gas before it can be emitted.
- Leak detection and repair (LDAR): LDAR programs allow operators to quickly identify and repair leaks, minimizing the emissions associated with the leaked gas entering the atmosphere. As

discussed below in Section 2.4, companies are employing innovative technologies to support improved LDAR programs and minimize emissions.

- Pressure safety valve monitoring: these valves are intended to manage pressure in production processes, releasing gas when needed. However, leaky valves may result in unintentional emissions. Increased monitoring of these valves improves leak detection, minimizing subsequent gas leaks.
- Compressed air valve control: LNG facilities may use compressed air to control valves (instead of using natural gas), which reduces vented emissions.
- Pneumatic devices: pneumatic devices are used to control the conditions of gas and are powered by natural gas. During normal operations, some of this gas is vented into the atmosphere. Transitioning from high-bleed pneumatic devices to low- or no-bleed devices or electrical pumps or controllers can reduce vented emissions associated with these devices.
- Pipe flange management: using specific types of pipe flanges and ensuring regular inspection and maintenance can reduce vented emissions.
- Flaring reductions: companies are implementing flaring reduction programs to reduce emissions associated with the venting and flaring of gas. This may include supporting the elimination of routine flaring.
- Carbon capture and storage: as discussed in Section 2.9, companies are developing CCS projects for liquefaction facilities or are assessing the potential of CCS project development.

Supply Chain Emissions Reductions

Along with pursuing emissions reductions within their own operations, LNG companies are making efforts to decarbonize their supply chains. Companies are engaging with their upstream suppliers on sustainability issues through supplier codes of conduct and sustainability programs. Companies also work with their value chain to support emissions data collection and monitoring efforts.

Climate Reporting

LNG companies report on their emissions and decarbonization strategies to promote transparency and a better understanding of how the industry addresses climate change. This includes reporting on company GHG emissions, emissions reductions initiatives, climate goals, and other relevant information. Such reporting efforts demonstrate industry's commitment to better understanding and quantifying their GHG emissions, enabling them to make informed decisions regarding their climate strategies.

Many LNG companies are utilizing voluntary frameworks to guide their climate disclosures. Frameworks such as the Taskforce on Climate-related Financial Disclosures (TCFD), Global Reporting Index (GRI), and the Sustainability Accounting Standards Board (SASB) guide companies in disclosing relevant climate information to support stakeholder needs. Transparently reporting climate-related issues allows stakeholders to understand industry emissions and reduction efforts and enables companies to develop individual emissions reduction strategies tailored to their operations and impacts.

Cross-Industry Collaboration

Along with their individual efforts, many LNG companies are collaborating with other organizations and academic institutions to support emissions reductions across the industry. For example, GTI Veritas is a methane emissions measurement and verification protocol developed with industry support. GTI Energy also administers the Collaboratory to Advance Methane Science (CAMS) - an industry-led research collaboration dedicated to improving the understanding of methane science by evaluating new tools and technologies to detect, measure, and quantify methane emissions. The Energy Emissions Modeling and Data Lab (EEMDL) is also supported by industry in its efforts to develop a global data and analytics hub to support improved GHG emissions accounting across energy supply chains.

Additionally, LNG companies are working across industry and with academia on lifecycle analyses and studies to assess industry emissions, such as a first-of-its-kind study on the emissions from LNG carrier ships.[10]

b. *2.4 Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?*

Companies are exploring the use of advanced monitoring and detection technologies at liquefaction facilities. Forward looking infrared handheld gas detection scanners, or optical gas imaging (OGI) cameras, are being used to detect natural gas leaks, which can then be repaired to prevent further emissions. Companies are also assessing the potential to employ advanced monitoring technologies such as drones, aerial surveys, satellites, and continuous monitors at their facilities. These technologies can improve facility monitoring, enabling operators to identify leaks which can then quickly be repaired.

c. *2.9 Do companies have specific plans to deploy carbon dioxide capture at liquefaction facilities in the future on low and high purity* CO_2 *gas streams? In addition to financial considerations, are there technical or other limitations to deploying carbon dioxide capture at liquefaction facilities?*

LNG companies are exploring the complementary use of CCS for their liquefaction facilities. High purity CO_2 streams are the best candidate for carbon capture. Liquefaction's place in the value chain often comes after the bulk of CO_2 has been performed in upstream producing and processing operations. Some LNG companies are implementing CCS projects to capture and store emissions from their liquefaction operations, while others are assessing potential opportunities to utilize CCS for their facilities. In addition to financial limitations, the regulatory and technical landscape are currently driving the timeline and ability to implement specific plans to deploy CCS. Permitting timelines create significant obstacles to efficiently deploying CCS and CO_2 pipelines. Operators planning to inject and geologically store CO_2 must obtain a Class VI permit through EPA's Underground Injection Control (UIC) program. However, the timeline and requirements for obtaining a Class VI permit are significant. To date EPA has approved six total Class VI permits, two of which are active.[11] There are currently over 80 Class VI permit applications waiting for EPA approval.[12]

Deploying CCS will also require significant infrastructure buildout, including CO_2 pipelines needed to transport captured CO_2 to geological storage. The construction of CO_2 pipelines may require

[10] "Total Methane and CO2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements," Environmental Science &Technology, June 2022, https://pubs.acs.org/doi/10.1021/acs.est.2c01383.
[11] "Letter to Congress Regarding EPA Class VI Permitting Report," U.S. Environmental Protection Agency, https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%.20to%20Congress.pdf
[12] "Class VI Wells Permitted by EPA," U.S. Environmental Protection Agency, *https://www.epa.gov/uic/class-vi-wells-permitted-epa.*

additional permits with lengthy, unclear timelines for approval. The uncertainty associated with the permitting process for both injection wells and CCS infrastructure may limit companies' willingness to invest, hindering CCS implementation.

Alongside regulatory obstacles, the ability for facilities to implement CCS is limited by their local geology. Existing facilities may not have local geology suitable for CO_2 storage, and therefore may be unable to currently implement CCS. To retrofit these facilities, CO_2 transport infrastructure would need to be developed to allow them to transport the captured CO_2 to a suitable geologic site.

For more information on the deployment of CCS at liquefaction facilities, DOE may consider coordinating with the federal agencies that are actively regulating CCS. As discussed above, EPA regulates underground injection for storage. Information on the LNG production process and mitigation planned at liquefaction facilities is discussed as part of the FERC environmental assessment process. DOE may wish to engage with these agencies to further understand the current status and potential for future CCS deployment at liquefaction facilities.

VI. DOE RFI TOPIC 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery

a. 3.1 What technologies or strategies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?

LNG companies are employing a variety of practices and technologies to reduce emissions from the loading, transport, and delivery of LNG.

- Boil-off and ship vapor recovery: use of boil-off gas (LNG that is vaporized during normal operation as well as during ship loading) and returning it for liquefaction instead of flaring it.
- Efficiency initiatives: various initiatives to promote efficiency of LNG transport, including switching to higher-efficiency engines for LNG carriers, hull coatings to reduce friction, and efficient propeller selection. LNG companies may seek to charter the most efficient LNG carriers to reduce their emissions from shipping.
- Natural gas fuel propulsion: using natural gas propulsion in LNG carriers, replacing more emissions-intensive diesel engines.
- Tracking shipping emissions: cross-industry collaboration on a study to directly measure methane emissions of an operating LNG vessel, enabling LNG carriers to identify opportunities for environmental performance improvement.[13]
- Study of alternative fuels: research into alternative fuels for shipping can lay the foundation for future emissions reductions. Alternative fuels such as hydrogen, biofuels, and ammonia are currently being researched to assess feasibility.

In addition to these industry efforts, the International Maritime Organization is working extensively to reduce emissions from international shipping broadly. IMO has established emissions reduction goals for the shipping industry, aiming to reduce the industry's total emissions by 2050. Their strategy for achieving this goal includes energy efficiency measures, development of low- and zero-carbon fuels, and

[13] "Total Methane and CO2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements." Environmental Science &Technology, June 2022, https://pubs.acs.org/doi/10.1021/acs.est.2c01383.

additional emissions reduction innovations.[14] The IMO's work will continue to support emissions reductions within LNG shipping.

V. Conclusion

The Associations appreciate the opportunity to comment on the DOE's RFI. We hope to work with DOE as the industry continues to develop new technologies to reduce emissions and reach our nation's net zero goals.

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[14] "Achieving the IMO decarbonization goals", DVN, July 2020. *https://www.dnv.com/expert-story/maritime-impact/How-newbuilds-can-comply-with-IMOs-2030-CO2-reduction-targets.html#.*

Respondent:

Cheniere Energy, Inc.

CHENIERE
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Cheniere.com

June 26, 2023

Comment on Request for Information
U.S. Department of Energy
Office of Fossil Energy and Carbon Management
"RFI related to Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports"

RE: DE-FOA-0003052: Response to Request for Information

Cheniere Energy, Inc. ("Cheniere") is the largest producer of liquefied natural gas ("LNG") in the United States and the second largest LNG operator in the world. Cheniere owns and operates natural gas liquefaction facilities in Louisiana and Texas, procures and transports natural gas from producers and multiple pipeline systems across North America to those facilities, and has produced over 2,800 LNG cargoes which have been delivered to 39 markets worldwide since 2016. Cheniere is pleased to submit the following comments related to strategies to measure and mitigate greenhouse gas ("GHG") emissions along the LNG value chain. Our comments below are organized by the topics and questions from the request for information.

Topic 1: Environmental Profile of Upstream Supplies
1.1. What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

In 2021, Cheniere initiated an upstream quantification, monitoring, reporting, and verification ("QMRV") research and development ("R&D") project with researchers from University of Texas at Austin, Colorado State University, and Colorado School of Mines along with a select group of natural gas supply companies (producers and midstream operators). Cheniere's QMRV R&D program aims to deploy novel technologies to more accurately measure supply chain GHG emissions. This will help to inform our climate strategies and mitigation programs, as well as those of our natural gas supply chain partners and other stakeholders. The QMRV program develops and employs multi-scale, multi-technology measurement methodologies including ground, drone, aerial and satellite, along with assessments of operational and maintenance practices, to develop measurement-informed data sets and inventories of facilities.

We refer DOE to three technical papers[1] that outline the QMRV protocol employed, along with the measurements, results, and observations from the project:

- Wang, J. L.; Daniels, W. S.; Hammerling, D. M.; Harrison, M.; Burmaster, K.; George, F. C.; Ravikumar, A. P. *Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting*. Environmental Science & Technology 2022, 56, 14743–14752.
- Daniels, W. S.; Wang, J. L.; Ravikumar, A.P.; Harrison, M.; Roman-White, S.A.; George, F.C.; Hammerling, D.M. *Towards Multi-Scale Measurement-Informed Methane Inventories: Reconciling Bottom-Up Inventories with Top-Down Measurements using Continuous Monitoring Systems*. DOI: 10.26434/chemrxiv-2023-jp5nt.
- Brown, J., Rufael, T., Harrison, M., Roman-White, S., Ross, G., George, F., & Zimmerle, D. (2023). *Informing methane emissions inventories using facility aerial measurements at midstream natural gas facilities.* ChemRxiv. doi:10.26434/chemrxiv-2023-dq01m-v3

The key findings of the technical studies are summarized below:

- Multi-scale measurements can develop measurement-informed estimates that account for both persistent and intermittent emissions, but the development of measurement informed inventories at midstream assets requires additional analysis.
- Quantification using measurement-informed inventories should be conducted using peer-reviewed or scientifically robust tools/models and methods.

A key observation from Cheniere's QMRV program is that the combination of snapshot measurements, high-frequency continuous emissions monitoring systems data, and operational data requires detailed analysis. Independent, third-party analysis of this data can provide verification of the accuracy of the measurements, as well as credibility in the eyes of third-party stakeholders.

One such initiative launched in 2023, with Cheniere's financial support, is the Energy Emissions Modeling and Data Lab ("EEMDL"), which is a collaboration between the University of Texas at Austin, Colorado State University, and the Colorado School of Mines.[2] EEMDL's goal is to develop transparent models and datasets for accurate GHG emissions accounting across global oil and gas supply chains. EEMDL will develop methods for assessing a facility's measurement-informed emissions profiles for both snap-shot measurements like aerial or drone, and continuous monitors employing tools and models that are transparently and freely available for all. Models and tools developed by EEMDL will be agnostic to reporting standards and measurement technologies and will focus on the technical approaches to reconciliation across various spatial and temporal scales.

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[1] Cheniere provided financial support for these studies.

[2] Additional information on the Energy Emissions Modeling and Data Lab is available at https://www.eemdl.utexas.edu/.

1.5. What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?
1.6. What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?
1.7. What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

Several voluntary initiatives related to measurement, reporting, and verification ("MRV") of natural gas – so-called "differentiated" natural gas, "certified" natural gas, or "responsibly sourced" natural gas – have emerged in recent years. A paper published this month by MRV company Validere summarizes these voluntary initiatives.[3] Many claims on differentiated or certified gas are based on experiences or commitments from production companies. Garg et al[4] indicates that 20 billion cubic feet per day of U.S. gas production is certified. Currently most differentiated gas programs rely on generic engineering inventory methods such as EPA's Greenhouse Gas Reporting Program ("GHGRP") or a slight expansion of GHGRP such as the ONE Future protocol to cover all assets and computation of methane emission intensities. Recent updates from the EPA[5] and the Inflation Reduction Act seek to utilize emission measurement technologies that could potentially improve the accuracy of methane emissions measurement and mitigation in the United States. The credibility and transparency of the U.S. regulatory system, including GHG emissions reporting requirements, creates a competitive advantage for U.S. natural gas in foreign markets.

Among voluntary initiatives, we believe the Oil and Gas Methane Partnership ("OGMP 2.0")[6] provides the appropriate framework[7] for measurement and reporting of methane emissions data at an international level. OGMP 2.0 is the United Nations Environment Programme's oil and gas methane emissions reporting and mitigation initiative. OGMP 2.0 is a comprehensive, measurement-based reporting framework for the oil and gas industry that seeks to improve the accuracy and transparency of methane emissions reporting. OGMP 2.0 has a multi-tiered quantification approach starting with conventional inventory methods – e.g., level 3 involves the estimation of asset-level emissions through generic, source-specific emissions factors, similar to EPA's GHGRP – to measurement-based quantification at levels 4 and 5. As of June 2023, OGMP 2.0 has over 100 member companies in more than 60 countries representing over 70% of LNG flows. In addition, the role of OGMP 2.0 as an international standard has been endorsed by the U.S.-EU Energy Council.[8]

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[3] https://www.validere.com/reports/voluntary-initiatives-for-natural-gas
[4] Sankalp Garg et al 2023 Environ. Res. Lett. 18 023002
[5] https://www.federalregister.gov/documents/2022/06/21/2022-09660/revisions-and-confidentiality-determinations-for-data-elements-under-the-greenhouse-gas-reporting
[6] https://ogmpartnership.com/
[7] https://ogmpartnership.com//wp-content/uploads/2023/02/OGMP_20_Reporting_Framework.pdf
[8] https://www.state.gov/joint-statement-on-the-u-s-eu-energy-council-2/

The Cheniere-sponsored QMRV studies have illustrated the complexities with not just measuring emissions across the LNG supply chain but translating the same into measurement-informed inventories. A key finding from Wang et al (2022) was that verification must go "beyond satisfying a checklist of operator actions but involve academic experts who can provide independent evaluation." We believe quantification using measurement-informed inventories should be conducted using peer-reviewed or scientifically robust tools/models and methods from entities such as EEMDL and aligned in general with the OGMP 2.0 framework.

Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities
2.4. Are companies deploying advanced technologies, such as drones or aerial surveys, to monitor greenhouse gas emissions at liquefaction facilities? If so, what technologies are they using or planning to use?

In 2022, Cheniere initiated our QMRV program at our Sabine Pass and Corpus Christi LNG export facilities. This program is on-going and technical findings are not yet complete. We can offer the following qualitative insights from our observations to date. Liquefaction terminals are large, complex facilities with thousands of individual components that process gas. Given their size, whole facility measurements employing aerial measurement technologies along with ground-based measurement technologies can support quantification and monitoring of methane emissions.

2.5. When is the decision to select electric, natural gas-powered, or hybrid compressor driven systems made during the facility design process? What are the key factors that influence this design choice?

The Federal Energy Regulatory Commission ("FERC") has exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of onshore or near-shore LNG import or export terminals in the United States. FERC regulations require proposed LNG projects to complete a "pre-filing" process, during which prospective applicants provide to FERC staff for its review and comment 13 separate draft "resource reports" ("RR") with detailed information on the project to begin the scoping process required under the National Environmental Policy Act. This mandatory pre-filing process comes before formal applications under the Natural Gas Act for FERC facility authorization and with DOE for export authorization. In addition to the other reports, RR 11 consists of design and engineering drawings of the principal project facilities while RR 13 requires more detailed engineering and design materials, including details of the liquefaction design. Prospective applicants make design decisions prior to beginning the front-end engineering and design ("FEED") process. Applicants must then make progress in the pre-FEED process in order to provide FERC with the information required for RR 13. Therefore, in terms of timing, the main facility design decisions are made prior to the submission of formal applications under the Natural Gas Act to FERC and DOE.

An important consideration in all LNG projects is the safe and reliable production of LNG to meet contractual customer commitments and ensure the efficiency and longevity of the liquefaction facilities. Characteristics of individual projects influence the choice of electric, natural gas-powered, or hybrid compressor driven systems. Not all possible system alternatives may be technically or economically feasible for a given project, or able to meet its purpose and need. One key consideration is access to a sufficient, reliable, and continuous supply of electricity to ensure the liquefaction facilities ability to run safely and efficiently 24 hours a day, 7 days a week, 365 days a year. Depending on the location of an LNG facility, sufficient electric generation and transmission capacity may not be available, especially in remote locations, and the required construction of the electric infrastructure may not be feasible or environmentally preferable.

Projects on the Gulf Coast must consider the potential impacts of severe weather including hurricanes on the availability and reliability of offsite electric power and the resulting impacts on the reliability of their LNG production. The real-world impacts of these considerations were noted by the Energy Information Administration following Hurricane Laura in 2020.[9] Cost, process efficiency, availability of equipment, and GHG emissions can also be factors that influence design choices. With respect to GHG emissions, the net comparison between systems must be viewed holistically with a lifecycle assessment approach, given the potential GHG intensity of the grid interconnection (i.e., offsite power generation) servicing electric or hybrid compressor driven systems.

Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery
3.1. What technologies or strategies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?

The GHG emissions of loading, transport, and delivery - or shipping – of LNG is primarily dependent on the LNG vessel engine type. A strategy for reducing GHG emissions from LNG shipping is to utilize modern LNG vessels with more efficient engine technologies. Newer LNG ships can run on fuel or "boil-off LNG" — LNG that warms back into a gas as a routine part of the transportation process — which has a significantly lower carbon dioxide emissions profile than typical marine fuels. In addition, many of these new vessels are fitted with new technologies such as reliquefaction units, which can reliquefy excess boil-off gas and inject it back into the containment system, and an air lubrication system, which injects air under the ship to create a continuous layer of bubbles between the hull and the seawater, reducing drag and further improving fuel efficiency.

In 2021, researchers from Queen Mary University London, with support from Cheniere, the Collaboratory to Advance Methane Science and Enagas SA, completed a study that directly

[9] https://www.eia.gov/todayinenergy/detail.php?id=45397

measured methane emissions from an operating LNG vessel. We refer DOE to the resulting technical paper, which describes the methodology and results:

- Balcombe, Heggo, and Harrison (2022), "Total Methane and CO2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements." Environmental Science & Technology 2022 56 (13), 9632-9640 DOI: 10.1021/acs.est.2c01383.

We appreciate your consideration of these comments.

Respondent:

Clean Air Task Force

*RFI response attachments are included as objects in this PDF file.

June 26, 2023

Office of Fossil Energy and Carbon Management,

Department of Energy

Submitted via email to: ReduceGHGE_LNG_RFI@NETL.DOE.GOV

Re: Comments of Clean Air Task Force on Request for Information on Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated With U.S. LNG Exports, number DE–FOA–0003052, 88 Fed. Reg. 25393 (Apr. 26, 2023)

Clean Air Task Force ("CATF") is pleased to provide comments on the Department of Energy's ("DOE") Request for Information ("RFI") on Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas ("LNG") Exports. CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. With over 25 years of internationally recognized expertise on climate policy, science, and law, and a commitment to exploring all potential solutions, CATF is a pragmatic, non-ideological advocacy group focused on climate change and the clean energy transition. CATF has offices in Boston, Washington, D.C., and Brussels, with staff working remotely around the world.

As the world seeks to decarbonize, it is expected that natural gas will continue to play a role in meeting energy needs in some way for the foreseeable future. It is also anticipated that demand will increase for exports of US-produced natural gas. While such exports could potentially aid global decarbonization efforts under certain scenarios, to meaningfully contribute to greenhouse gas ("GHG") emission reductions they must accompanied by both well-implemented and enforced GHG emissions standards and by import standards in the purchasing jurisdictions (including the European Union, Japan, and the Republic of Korea). In the responses provided below, we describe the relevant approaches and strategies that can be used today to reduce methane and carbon dioxide emissions from the full value chain of LNG. We appreciate the opportunity to provide comments on this RFI and invite you to reach out if you have any questions.

Topic 1: Environmental Profile of Upstream Supplies

> **1.1.** What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

A wide variety of technologies and strategies have been deployed by a number of oil and gas operators in jurisdictions both within the US and abroad to reduce emissions of methane and other air pollutants. These technologies – which we briefly describe below – are required by some jurisdictions within the US and abroad, are proven to reduce emissions, available at low cost, and are readily available to use at almost any oil and gas site. Below we provide a summary of these mitigation efforts currently being deployed.

- Leak detection and repair ("LDAR"): LDAR programs are proven to be effective and affordable mitigation strategies. In addition to addressing typical leaks in components like valves and connectors, LDAR programs are essential for identifying emissions from upset conditions and malfunctions that commonly occur at oil and gas sites and are very likely constitute a large portion of total industry emissions.[1] Consequently, they are mandated by regulators in a growing number of jurisdictions.[2] LDAR programs involve frequent periodic surveys and monitoring of oil and gas infrastructure to detect leaks and other problems using instrument-based technologies such as infrared cameras, drones, and sensors, and requirements to promptly repair all leaks or problems.[3]
- Upgrading vent-by-design equipment: Replacing normally venting equipment with zero- or low-emissions technologies, such as zero bleed pneumatic controllers and tankless production sites, has greatly reduced air pollution – including methane, smog-forming volatile organic compounds, and air toxics like benzene – from upstream sites. In other cases, methane emissions vented from process equipment and maintenance operations can be routed to vapor recovery devices to capture and recycle the gas that would otherwise be released into the atmosphere.[4] Replacing some common types of emitting equipment at oil and gas sites with non-emitting designs can readily reduce nationwide methane emissions by over one million metric tons of methane per year.
- Flaring reduction: Prioritizing capture of associated gas from well sites for sales or utilization can eliminate or significantly reduce flaring. Additionally, upgrading current flaring equipment with flares adequately sized to properly combust gas at the needed flowrates and with adequate pilots/auto-ignitors to keep flares lit in all conditions can minimize or reduce unintentional emissions of methane from flares, reducing climate impacts.[5]
- Reduced emissions completions: Many operators have adopted green completions practices that have allowed for effective management of associate gas released during exploration and production operations, by routing the gas to a vapor recovery unit or

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[1] EPA, *2011-2021 Greenhouse Gas Reporting Program Industrial Profile: Petroleum and Natural Gas Systems* (2021), https://www.epa.gov/system/files/documents/2022-10/subpart_w_2021_sector_profile.pdf.
[2] Colorado Air Quality Control Commission Regulation Number 7, Colo. Code Regs. § 1001-9 https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9417); Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector), SOR/2018-66 (Can.), https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/FullText.html; Disposiciones Administrativas de carácter general que establecen los Lineamientos para la prevención y el control integral de las emisiones de metano del Sector Hidrocarburos, Diario Oficial de la Federación [DOF], 06-11-2018 (Mex.), https://www.dof.gob.mx/nota_detalle.php?codigo=5543033&fecha=06/11/2018.
[3] Arvind P. Ravikumar et al., *Repeated leak detection and repair surveys reduce methane emissions over scale of years*, Env't Rsch. Letters, Feb. 26, 2020, https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1.
[4] EQT, *Pneumatic Device Replacement*, https://www.eqt.com/responsibility/pneumatic-device-replacement/ (last visited June 26, 2023).
[5] *Vapor Recovery Units Reduce Flaring by 70%*, Oil Gas Leads (Apr. 9, 2022), https://oilgasleads.com/vapor-recovery-units-reduce-flaring-by-70-%EF%BF%BC/.

pipeline for further use of gas or to a combustion device as a last resort to minimize emissions.[6]

- Using energy-efficient equipment and electrification: Technologies that improve energy efficiency and optimize processes are both cost effective and can reduce overall emissions of facilities. Implementing energy-efficient practices such as using energy-efficient engines, emission control devices with high destruction efficiency, and waste heat recovery units have seen increased investment by operators for their co-benefits.[7] Electrifying processes such as natural gas compression can have clear CO_2 reduction benefits, especially when grid power has a lower carbon intensity and/or purchased or purpose-built dedicated clean electricity is used to power electrified equipment. As discussed below, electrification has a large additional benefit of reducing methane emissions associated with incomplete combustion.
- Well decommissioning: Properly plugging wells at the end of their productive life – *before* they become orphaned or abandoned, using industry best practices – is the most effective way to reduce greenhouse gas emissions and other air pollution associated with orphaned and abandoned wells. This also provides significant environmental benefits by preventing leaks into groundwater aquifers and other environmental resources.[8]

These approaches can dramatically, and rapidly, reduce methane pollution from this industry. The International Energy Agency estimates that 77% of emissions reductions in the U.S. can be achieved with existing technology.[9] In 2020, we demonstrated that national standards under section 111 of the Clean Air Act, *based solely on state level regulatory approaches already proven to work and be feasible and reasonable cost*, would reduce US nationwide methane emissions from oil and gas by about 65% based on 2012 levels.[10]

> **1.5.** What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?

Because emissions of methane and other air pollutants from oil and gas operations are substantial, harmful, and readily reduced using the technologies and practices we describe above, it is essential that regulators put in place and implement enforceable emissions standards for facilities across the upstream oil and natural gas value chain. However, because it is often

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[6] EPA, Natural Gas Pollution Prevention STAR Program, *Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells*, https://www.epa.gov/sites/default/files/2016-06/documents/reduced_emissions_completions.pdf (last visited June 26, 2023).

[7] Ron Bousso, *Top Energy Companies Prepare to Launch New $1 BLN Clean Tech Fund -Sources*, Reuters (Mar. 11, 2022), https://www.reuters.com/business/energy/top-energy-companies-prepare-launch-new-1-bln-clean-tech-fund-sources-2022-03-11/.

[8] Liz Hampton, *In Colorado, Oil Firms Fix Leaky Wells Ahead of New Rules*, Reuters (Nov. 17, 2022), www.reuters.com/business/energy/colorado-oil-firms-fix-leaky-wells-ahead-new-rules-2022-11-14/.

[9] IEA, *Global Methane Tracker 2023* (2023), https://www.iea.org/reports/global-methane-tracker-2023.

[10] Clean Air Task Force, *Oil & Gas Methane: Mapping the Path to a 65% Reduction* (2021), cdn.catf.us/wp-content/uploads/2021/03/21092232/CATF_Methane_2Pager_06.24.21.pdf.

possible to reduce emissions faster or more deeply than is required by even the most protective regulations, we strongly support differentiated natural gas certification programs *provided* that they are based on robust measurement and transparent reporting. A strong certification program can allow buyers to purchase natural gas with confidence that low levels of methane emissions are associated with its production and transportation—in this way the market mechanism can drive deeper reductions, on top of the baseline set by regulations.

However, certification programs that base estimates of emissions intensity for natural gas on equipment counts and emissions factors, rather than measured emissions, will not be useful. Numerous studies, in many jurisdictions, have demonstrated that bottom-up inventories based on equipment counts and emissions factors typically substantially underestimate emissions. A certification program based on this approach to emissions quantification would not provide reliable information to consumers or importers about the emissions associated with purchased natural gas.

> **1.7.** What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

Differentiated gas certification programs can play an important role in creating a competitive advantage for U.S. natural gas, but only if other supporting efforts are continued and/or taken. Natural gas produced within the U.S. is, to some extent, currently subject to effective policies to reduce emissions from the oil and natural gas industries. This includes a legal and regulatory framework that can allow for meaningful implementation of these policies, including information about emissions and better transparency on legal matters than many other jurisdictions. However, even with those policies, we believe that differentiated natural gas certification programs can help create a competitive advantage for U.S. natural gas only *if*: (1) The U.S. continues to successfully promulgate and implement regulatory standards that reduce emissions and require accurate emissions reporting; *and* (2) trading partners implement meaningful import standards for natural gas, including in Europe as well as Japan and Korea.

Differentiated certification programs are only useful if trading partners agree to implement and enforce import standards. Without robust international demand for lower-emissions gas created by an import standard, certification schemes will not provide the U.S. with any significant competitive advantage.

Topic 2: Strategies to Measure and Reduce Emissions at Liquefaction Facilities

> **2.2.** What technologies or strategies are companies deploying to reduce greenhouse emissions at liquefaction facilities?

Advancements in technologies have made it possible to significantly reduce emission intensity of liquefaction facilities. Below, we first discuss the primary sources of CO_2 from these sites, together with approaches to reduce emissions from those sources. Then, we discuss the main sources of methane emissions and the approaches to reduce those emissions.

We attach to this submission two reports, which are extensively cited below. The first is an analysis by Hensley Energy Consulting of several of the CO_2 emissions reduction opportunities, including cost estimates, available to new LNG facilities ("Hensley Report").[11] The second is a report Clean Air Task Force commissioned in 2021 from Carbon Limits, an environmental and oil and gas consultancy, which summarized the methane emissions sources and best practices for methane emissions reductions in the LNG supply chain.[12] The findings of the report are summarized below (and in the responses to questions 3.1, 3.2, and 3.3).

Carbon Dioxide. There are four major sources of CO_2 emissions in liquefaction facilities:

1. Flue gas from gas turbines: Natural gas turbines used for refrigeration and power generation are the largest contributor of CO_2 emissions in liquefaction facilities.[13] Ongoing efforts focus on enhancing engine efficiency, adding waste heat recovery units, and implementing carbon capture and storage ("CCS") systems to reduce CO_2 emissions from these turbines. Some companies are also planning to transition from natural gas-driven engines to electricity-driven engines and using renewable energy sources to meet the energy demands of the liquefaction process.[14] If the renewable energy is additional to the grid (that is, if utilizing this renewable energy for LNG liquefaction does not have the effect of increasing the use of fossil-fuel fired generation on the grid), this can substantially lower emissions associated with liquefaction. The attached Hensley Report quantifies the carbon reductions achievable if zero emission electricity is used compared to use of today's Texas grid power. In addition, the Report illustrates how the cost of switching to electric drive varies depending on the cost of electricity and natural gas.

   Ultimately, electrification of these facilities or use of carbon capture will be needed to achieve the required level of decarbonization. This means that any LNG facility should be planning to use electric compressors and should plan on purchasing or building lower carbon electricity or should include carbon capture on combustion turbines as well as other sources like the acid gas removal unit. Even use of today's grid power would produce a benefit compared to unabated gas turbines and over time the benefit should improve as the carbon intensity of the grid declines further. But purchase or construction of dedicated clean electricity would produce greater the greatest reductions.

   Existing LNG producers should be making plans today to reduce the carbon intensity of their facilities by transitioning to electrification, adding carbon capture, and purchasing of

[11] Report Summarizing LNG Export Terminal CO2 Reduction Options, Hensley Energy Consulting LLC (June 24, 2023) (included as Attachment A).
[12] Carbon Limits, *Methane emissions from LNG Best practices from liquefaction to gasification*, at 17 (2021) [hereinafter Carbon Limits, *Best practices*], https://cdn.catf.us/wp-content/uploads/2021/09/21091747/LNG-Methane-best-practice-29-Sept-2021.pdf (included as Attachment B).
[13] Delphi, *LNG Emissions Benchmarking* (2013), https://www2.gov.bc.ca/assets/gov/environment/climate-change/ind/lng/lng_emissions_benchmarking_-_march_2013.pdf.
[14] ConocoPhilips, *ConocoPhillips Continues Advancing Optimized Cascade® Process Capability by Offering New Operational and Control Technologies*, (Nov. 3, 2020), https://lnglicensing.conocophillips.com/conocophillips-continues-advancing-optimized-cascade-r-process-capability-by-offering-new-operational-and-control-technologies/.

low-carbon electricity and CCS. To the extent possible, operators should work to ensure that purchased low-carbon power is additive (i.e., financing new projects), rather than consuming existing or already planned low-carbon generation in a manner that has the effect of pushing other consumers to increase consumption of fossil-generated power.

Electrification provides additional significant advantages for operators, such as lower capex and simplified operations.[15] Electric, grid-powered LNG facilities are being built in the U.S.,[16] and almost all of the planned liquefaction capacity in Canada will be grid-powered electric driven.[17]

Given the long timeline for electrification, however, existing LNG operators should also examine approaches to improve system efficiency with gas-fired equipment to reduce near-term emissions.

Finally, we recommend that DOE undertake additional analysis to further compare use of carbon capture on combustion turbines with the electrification option. The analysis conducted by Hensley Consulting was not able to fully compare potential benefits and costs of carbon capture alongside the electrification option.

2. Fired Heating Equipment: Fired equipment such as boilers, heaters, and furnaces play a crucial role in meeting the heating and power needs of the facility. Although hot oil systems are favored by some operators due to their lower cost, implementing cogeneration of steam-based heating and power systems can significantly reduce CO_2 emissions from fired equipment and improve process efficiency.[18]
3. Flares: Minimizing flaring by capturing and utilizing the gases for other purposes within the facility can reduce emissions and prove economically beneficial. Alternatively, when flare gas recovery is infeasible, technologies with higher combustion efficiency and improved control systems can also be deployed to reduce greenhouse gas emissions from flaring by avoiding large methane slip.[19] More detail on reducing methane emissions from flaring is provided below.
4. Acid Gas Removal Units (AGRUs): AGRUs are responsible for removing CO_2 from natural gas prior to liquefaction. In some cases, AGRUs vent the extracted CO_2 directly into the atmosphere. Where this is the case, CO2 vented from the AGRU can be responsible for 20% of LNG facility CO2 emissions. (Hensley Report) To reduce greenhouse gas intensity, operators can utilize Carbon Capture and Storage (CCS), by compressing the pure CO_2 stream from AGRU vents and directing it to pipelines and

[15] Will Owen, *The future is electric*, LNG Industry (July 8, 2020), https://www.lngindustry.com/liquid-natural-gas/08072020/the-future-is-electric/.
[16] General Electric, *Decarbonizing the LNG industry: Full electric solution for LNG liquefaction trains* (Sept. 21, 2022), https://www.gepowerconversion.com/case-study/full-electric-solution-for-LNG-liquefaction-trains.
[17] Jan Gorski & Jason Lam, *Squaring the Circle: Reconciling LNG expansion with B.C.'s climate goals*, at 26, Pembina Institute (May 11, 2023), https://www.pembina.org/pub/squaring-circle.
[18] GE Gas Power, *Heat Recovery Steam Generators (HRSG): GE Gas Power*, www.ge.com/gas-power/products/hrsg (last visited June 26, 2023).
[19] Michael Koo, *A Flair for Cutting Flaring*, Control (2016), www.emerson.com/documents/automation/a-flair-for-cutting-flaring-cs-cz-2362382.pdf

wells for underground injection. Because the additional costs to capture CO_2 from the AGRU are relatively low, the 45Q tax credit should provide an adequate incentive for both new and existing LNG facilities.[20] Vent gas capture technology can also be applied to other equipment that routinely vent greenhouse gas emissions to the atmosphere, including nitrogen removal units.[21]

Methane. Methane emissions are also significant at liquefaction facilities. There are 5 main sources of methane emissions at gas liquefaction facilities:

1. Fugitive leaks from equipment wear and tear;
2. Venting of boil-off gas ("BOG") for pressure control;
3. Incomplete combustion of fuel for generating power for equipment; and
4. Incomplete combustion of excess or off-specification gas in flare stacks, incinerators and other process heat generators;
5. Maintenance and irregular emissions.[22]

Fugitive leaks from equipment wear and tear

Leaks from equipment and components can make up a large percentage of total methane emissions from a liquefaction facility. All natural gas installations in general (including LNG facilities in any part of the supply chain) should be systematically and regularly surveyed to identify potential emissions points and address them as part of a comprehensive leak detection and repair ("LDAR") program. See response to question 1.1 for more details on LDAR programs.

In addition to regular LDAR inspections, several maintenance and operational practices can reduce leaks at LNG facilities that handle gas in high pressure/low temperature situations.[23]

- Valves: A number of companies produce cryogenic valves specifically designed to minimize the risk of leaks in extreme cold conditions.[24] Also on the market are thermal insulation for cryogenic values, which helps prevent freezing that can make the valve inoperable and lead to leaks.[25]
- Flange torque: Operators can minimize leaks from flanges by ensuring that flanges are connected with the correct torque value and that installation and maintenance is done properly.[26]

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[20] Costain, *Capturing the value of LNG* (June 2018), https://www.costain.com/media/598559/hydrocarbon-engineering-reprint-june-2018.pdf.
[21] Delphi, *supra* note 13.
[22] Carbon Limits, *Best practices*, *supra* note 12.
[23] *Id.* at 20-21.
[24] *See, e.g.,* ValvTechnologies. *Cryogenic Valves for LNG Service* (2019), https://www.valv.com/wp-content/uploads/2019/07/329_Cryogenic-valves_July-2019_reduced.pdf; Habonim, *Cryogenic Valves*, https://habonim.com/valves/cryogenic-valves/ (last visited June 20, 2023).
[25] *See, e.g.,* Thermaxx Jackets, Cryogenic Insulation Jackets for LNG Valve components, https://www.thermaxxjackets.com/products/cryogenic-lng-insulation-jackets-2/ (last visited June 26, 2023).
[26] Chett Norton & Ron Frisard, *Sealing for Extreme Cold: Best Practices for Static Seals*, July 2018 Pumps & Systems 66.

- Flange sealant material: Advanced sealant materials that do not become brittle and crack in low temperatures can also reduce methane leaks from flanges gaskets. Such temperature-resilient sealants include flexible graphite and polytetrafluoroethylene (PTFE).[27]
- Flange washers: Leaks can also be avoided if flange washers are selected for their ability to be resilient in low temperatures and high pressures found in LNG facilities.[28]

Venting of BOG for pressure control

The process of liquefying natural gas cools and condenses the product so that the liquid takes up roughly 600 times less space than the gas. Once the product is in liquid form, even in the most well-insulated storage vessel, a certain amount will boil off (convert from liquid to gas). This BOG must be vented or managed to prevent excessive pressure buildup. Venting can be avoided through reliquification of gas or utilization of gas for energy production at the facility.

See the response to question 3.2 for more details on BOG management.

Incomplete combustion of fuel for generating power for equipment

Many liquefaction facilities produce their own power using natural gas combined-cycle or combined heat and power plants. While the main GHG from these plants is CO_2, methane is also emitted due to incomplete combustion (also known as methane slip), particularly from certain types of engines. Methane emissions are particularly significant during low-temperature combustion and during start-up and shut-down of process drivers.[29]

Methane emissions from exhaust gas can be reduced using catalytic oxidation[30] and various types of engine tuning, retrofits, and post-combustion treatment.[31] Notably, Environment and Climate Change Canada has committed to regulations which would require substantial reductions in engine exhaust methane emissions.[32]

Alternatively, methane slip from combustion can be avoided altogether if power to run the facility is from the grid rather than on-site power production. As discussed above, this can also reduce overall CO_2 emissions, with the extent of the benefit depending on the sources providing power to the grid. Policies to electrify upstream compression are developing in North America,

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[27] *Id.*

[28] Solon Manufacturing, Inc., *Flange Washers Reduce Fugitive Emissions in LNG Applications*, https://www.solonmfg.com/case-studies/lng (last visited June 20, 2023).

[29] EPA, *Ch: 3 Stationary Internal Combustion Sources*, in I AP 42 (5th ed. 2000), https://www.epa.gov/sites/default/files/2020-10/documents/c03s01.pdf.

[30] Yu Zhang et al., *A Rhodium-Based Methane Oxidation Catalyst with High Tolerance to H2O and SO2*, 10 ATS Catalysis 1821 (2020), https://pubs.acs.org/doi/10.1021/acscatal.9b04464.

[31] DOE's ARPA-E REMEDY program has funded a number of groups developing technologies to reduce methane from engine slip, as has DOE's FECM FOA 2616. Financial Assistance Funding Opportunity Announcement, Innovative Methane Measurement, Monitoring and Mitigation Technologies, DOE-FOA-0002616.

[32] *See Proposed regulatory framework for reducing oil and gas methane emissions to achieve 2030 target*, Government of Canada (Nov. 10, 2022), https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions/proposed-regulatory-framework-2030-target.html.

in Colorado[33] and in Canada (where the Federal Government's emissions cap for oil and gas cannot be met without electrification of upstream compression[34]).

Incomplete combustion of excess or off-specification gas in flare stacks, incinerators, and other process heat generators

Flaring can be a significant source of both CO_2 and methane emissions at liquefaction facilities. Flaring can be used to manage the pressure in equipment and tanks in the facility in cases of emergency shutdown or scheduled maintenance. Flaring may also be used in emergency situations in which a compressor or valve shuts down or malfunctions and gas must be routed to flare system to prevent pressure build-up in the pipelines.[35] In order to minimize flaring, operators must understand and address the root causes of the flaring and adjust operations to minimize flaring.

Operators can utilize flare gas recovery systems to capture and reuse waste gases that would otherwise be flared.[36] To avoid flaring as much as possible, excess gas can be re-routed to the nearest consuming equipment or facility[37] (by switching those devices away from their normal fuel source).

In cases where flare gas cannot be recovered and utilized, despite diligent application of best practices for facility design and operations to avoid flaring, then the best practice is to improve the combustion efficiency of flaring. A certain amount of methane slip will always occur in a flare, but a well-designed and well-maintained flare can have combustion efficiency of at least 98% if operated within the range of the flare's design specifications (input flow rates and heating value of gas, etc.).[38] Flare technology vendors have developed new technologies (including closed flares, staged flares etc.) to flare gas in a safe manner, and do so in a manner that is as environmentally benign as possible. The design of the flare needs to be site specific and depends on the gas composition and the range of volume and pressure of the gas flow.[39]

Maintenance and irregular emissions

Significant amounts of methane emissions can occur during start up, emergency shut-downs, routine- and non-routine maintenance at liquefaction facilities.

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[33] CODPHE, Midstream Steering Committee,
[34] Jan Gorski & Janetta McKenzie, *Decarbonizing Canada's oil and gas supply* (Mar. 21, 2022), https://www.pembina.org/pub/decarbonizing-canadas-oil-and-gas-supply.
[35] Carbon Limits, *Best practices*, *supra* note 12, at 44.
[36] *Vapor Control,* Zeeco, https://www.zeeco.com/products/vapor (last visited June 26, 2023).
[37] Methane Guiding Principles, *Reducing Methane Emissions: Best Practices Guide Flaring* (Nov. 2019), https://methaneguidingprinciples.org/wp-content/uploads/2019/11/Reducing-Methane-Emissions-Flaring-Guide.pdf.
[38] Carbon Limits, *Final Report: Assessment of flare strategies, techniques for reduction of flaring and associated emissions, emission factors and methods for determination of emissions from flaring* (2014), https://www.carbonlimits.no/wp-content/uploads/2015/06/Assessment-of-flare-strategies-techniques-for-reduction-of-flaring-and-associated-emissions-emission.pdf.
[39] *Id*.

During start-up (both when the facility is first built and after a maintenance shutdown), equipment must be pre-cooled, resulting in large amounts of BOG. In particular, the "cold box" must undergo a multi-stage cooling process before it is ready to commence the liquefaction process. Methane emissions from this process can be reduced by recovering the BOG (for example, for recycling the BOG via a small compressor dedicated to compressing BOG[40]) or routing it to a flare.[41] Even further reductions can be achieved by using systems that automate the cooldown process for the cold box, which increase the efficiency of the cooldown process and results in significantly lower BOG, reducing the need for BOG handling or flaring.[42] Depending on the frequency of start-up of the facility and the volumes of LNG used to cool down the facility, gas captured during these processes could be stored for later use in on-site power generating equipment.[43]

Methane emissions from blowdowns due to emergency shut-downs, routine- and non-routine maintenance at liquefaction facilities can be captured and routed to an onsite compression unit. Then, it can either be pumped back into the product stream or utilized for on-site power generation.[44]

Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery

> **3.1.** What technologies or strategies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?

In 2021, Clean Air Task Force commissioned a report from Carbon Limits, an environmental and oil and gas consultancy, which summarized the methane emissions sources and best practices for methane emissions reductions in the LNG supply chain.[45] There are 6 main sources of methane emissions during the loading, transport, and delivery of LNG:

a) fugitive leaks from equipment wear and tear;
b) gas freeing from connection hoses and points during loading/offloading;
c) venting of BOG for pressure control;
d) Incomplete combustion of fuel from power generating equipment;
e) Incomplete combustion of BOG (during operations) and blowdown gas (maintenance/emergency shutdown) from flare systems; and
f) Maintenance and irregular emissions.[46]

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[40] Carbon Limits, *Best practices*, *supra* note 12, at 49.
[41] *Id.* at 46-7.
[42] Theodore Sabram et al., Air Products and Chemicals, Inc., *Less in more: Flare minimization during cooldown* (2019), https://www.gti.energy/wp-content/uploads/2019/10/153-LNG19-03April2019-Sabram-Ted-paper.pdf. *See also, e.g.*, Air Products, *AP-AutoCool*™, https://www.airproducts.co.uk/services/automated-mche-cooldown-ap-autocool (last visited June 26, 2023).
[43] Carbon Limits, *Best practices*, *supra* note 12, at 44, 48, 50.
[44] *Id.* at 49-50.
[45] *Id.* at 12.
[46] *Id.* at 17.

a) Fugitive leaks from equipment wear and tear

Leaks from equipment and components can make up a large percentage of total methane emissions from loading, transport, and delivery of LNG.

See response to question 1.1 for details about leak detection and repair, and see 2.1.(a) for specific operational and maintenance practices to reduce leaks at facilities that handle gas and LNG at extremely low temperatures and high pressures.

b) Gas Freeing from connection hoses and points during loading/ offloading

Methane emissions from gas freeing can occur any time the gas is transferred from one place to another, including from export terminals to LNG carriers and from LNG carriers to import terminals. There is a risk of leaks from the connection hose if the system is not tightly sealed. In addition, as LNG is transferred to a pipeline or carrier that formerly held inert gas (like nitrogen), a certain amount of gas results that is a mixture of inert and methane. This mixed gas is either vented to the atmosphere or managed, for example, by compressing back to the source tank, the receiving terminal, or consumed in a gas combustion unit.[47]

Several best practices can minimize methane emissions during LNG transfer:

> "Before transfer starts, the transferring parties should agree on procedures. In particular, this includes how to properly dispose of the mixtures of natural gas and nitrogen from purging.
>
> Both the source tank and the receiving tank must operate within a specified maximum pressure and should be closely monitored during transfer. If the pressure exceeds this level, the pressure release valve will open to vent methane vapor to the atmosphere. Multiple conditions could lead to methane emissions through the pressure release valve: The pressure increase from the cooldown process could exceed the maximum tank pressure and trigger the pressure-release valve. If the receiving tank is not sufficiently cold, filling it with new LNG will cause a high rate of vapor return, increasing the tank pressure.
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> A newer development is the increased use of dry-disconnect couplings for LNG transfer, allowing connections to be made quickly and securely. Shut-off mechanisms on dry disconnect couplings can eliminate emissions and the danger of methane spillage after the loading and offloading procedure has been completed.[48]

[47] *Id.* at 23-24.
[48] *E.g.* European Maritime Safety Agency, *Guidance on LNG Bunkering to Port Authorities and Administrations* (2018), http://emsa.europa.eu/about/financial-regulations/download/5104/3207/23.html.

If dry-disconnect couplings are not used, gas measurement should be performed before the transfer hose is disconnected.

Draining of the hoses should be ensured by avoiding U-shapes in the hose where LNG can remain. (Exterior ice caps on the hose can indicate remaining liquid.)"[49]

c) Venting of BOG for pressure control

See the response to question 3.2 for more details on BOG management during the loading, transport, and delivery of LNG.

d) Incomplete combustion of fuel from power generating equipment

See response to question 2.1 (c).

e) Incomplete combustion of BOG (during operations) and blowdown gas (maintenance/emergency shutdown) from flare systems

See response to question 2.1 (d).

f) Maintenance and irregular emissions

Significant amounts of methane emissions can occur from blowdowns associated with emergency shut-downs, routine- and non-routine maintenance during loading, transport, and delivery of LNG.

Blowdown is carried out by isolating the section of equipment or pipeline which needs to be blown down using isolation valves, followed by opening of blowdown valve to release natural gas for depressurization. The amount of methane released by a blowdown depends on the volume of the equipment blown down and the pressure of natural gas in the pipe. This process is required in emergency situations and for routine and non-routine maintenance.

Instead of venting, it is a better practice to use flares and incinerators to combust methane. However, flaring combustion efficiency varies with environmental conditions and methane slip from flare stacks can become significant in cases where flare system malfunctions.[50] An even better option is to use a either blowdown minimization techniques or blowdown gas recovery techniques. Blowdown minimization entails efforts to reduce the volume of equipment blown down and removing as much gas as possible from that volume prior to blowdown.[51] Blowdown gas recovery entails the use of compression units that can capture and compress the gas that

[49] Carbon Limits, *Best practices*, *supra* note 12, at 24.
[50] *Id.* at 47-8.
[51] M.J Bradley & Associates LLC, *Pipeline Blowdown Emissions and Mitigation Options* (2016), https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf.

would otherwise be vented or flared so that it can be transferred to equipment which does not need to be depressurized.[52]

3.2. What approaches do LNG operators use to capture BOG and limit loss of natural gas when storing, loading, transporting, and unloading LNG?

In 2021, Clean Air Task Force commissioned a report from Carbon Limits, an environmental and oil and gas consultancy, which summarized the methane emissions sources and best practices for methane emissions reductions in the LNG supply chain.[53]

BOG is an issue that must be managed at all stages of the LNG process. Even with well-insulated storage tanks, the LNG will warm and a certain amount will continuously revert to gas. Thus, the BOG must be managed or released. Boil off will be even more significant at any transfer point in which warm transfer equipment comes into contact with the LNG.[54]

At LNG storage, loading, and offloading facilities, the best practice is to utilize excess BOG as much as possible, for example by re-routing vent gas to generators or engines.[55] While utilization of vent gas for powering the facilities may not reduce the combustion emissions from flaring of that same gas directly, it can reduce the need for fuel that would normally be used by power generating equipment and hence reduce overall GHG emissions at the site. Typically BOG compressors can be used to compress the gas and export the gas to use it as fuel, use it as make-up gas for the storage tank (to maintain tank pressure), or capture BOG from the tanks and re-liquefy and return it back into the storage tank.[56]

To manage BOG on an LNG carrier, the gas must be either reliquefied or utilized. Gas that is reliquefied can be returned to the storage tanks onboard. Other ships utilize gas as a primary or secondary fuel for the ship's engines. This can be a good option, but care must be taken to detect and repair leaks in the lines that carry the BOG to the engines. BOG must be handled and should not be vented to the atmosphere when an LNG carrier is not at full cruise, i.e. ramping up and ramping down during navigation, while waiting to approach a harbor, or when docked.[57] Ship operators should have a plan for useful handling BOG (without flaring) during these periods, including supplemental reliquification pumps or directing the gas to onboard power generating equipment.[58]

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[52] Carbon Limits, *Best practices*, *supra* note 12, at 50.
[53] *See generally*, *Id.*
[54] *Id.* at 12.
[55] Methane Guiding Principles, *supra* note 37.
[56] Carbon Limits, *Best practices*, *supra* note 12, at 31-32. *See also, e.g.,* Amir Sharafian et al., *A review of liquefied natural gas refueling station designs*, 69 Renewable & Sustainable Energy Revs. 503 (2017), https://www.sciencedirect.com/science/article/abs/pii/S1364032116309406?via%3Dihub.
[57] Carbon Limits, *Best practices*, *supra* note 12, at 16.
[58] *Id.* at 32.

3.3. What approaches do LNG operators use to minimize greenhouse emissions during tanker transport of LNG?

In 2021, Clean Air Task Force commissioned a report from Carbon Limits, an environmental and oil and gas consultancy, which summarized the methane emissions sources and best practices for methane emissions reductions in the LNG supply chain.[59]

There are 4 main sources of methane emissions during the tanker transport and delivery of LNG:

a) fugitive leaks from equipment wear and tear;
b) venting of BOG for pressure control;
c) Incomplete combustion in engines, generators and turbines;
d) Maintenance and irregular emissions.[60]

a) Fugitive leaks from equipment wear and tear;

Leaks from equipment and components can make up a large percentage of total methane emissions from tanker transport of LNG.

See response to question 2.1 (a) for details about leak detection and repair as well as specific operational and maintenance practices to reduce leaks at facilities that handle extremely cold temperatures.

b) Venting of boil BOG for pressure control

See the response to question 3.2 for more details on BOG management during tanker transport of LNG.

c) Incomplete combustion in engines, generators and turbines

As noted in the response to question 3.2, many carriers use BOG as a primary or secondary fuel for the ship. However, methane slip can be high in certain types of engines, and over a long journey this can add up to a significant amount of methane emissions. A recent study measured rates of methane slip from the engines on an LNG carrier, and it found an average methane slip rate of 3.8% from carrier engines was one of the most significant emissions sources on the carrier. The 3.8% was an average of all 6 engines on the GasLog Galveston LNG carrier, including two dual-fuel main engines for propulsion and four dual-fuel generator engines to produce power for other ship demands.[61]

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[59] *Id.* at 12.
[60] *Id.* at 17.
[61] Paul Balcombe et al., *Total Methane and CO2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements*, 56 Env't Science & Tech., 9632 (2022), https://doi.org/10.1021/acs.est.2c01383.

Engine manufacturers have developed and are in the process of developing engines with optimized designs to ensure lower methane emissions.[62] See also response to question 2.1 (c).

d) Maintenance and irregular emissions

Dry-dock maintenance of LNG carriers can result in a significant amount of methane emissions. Before the maintenance can occur, the operator must flush out all equipment, lines, and tanks with an inert gas.[63] In the absence of emission reduction efforts, the LNG vapor would be vented to the atmosphere. However, the vaporized LNG can be captured and routed to a mobile vapor recovery unit and then recovered natural gas can be used as fuel for nearby power generating equipment or reliquefied and stored in a small storage tank.[64] If handling methane and/or inter gas mixtures becomes infeasible, methane should always be combusted rather than vented.

Conclusion

CATF appreciates the opportunity to share these comments with the Department of Energy regarding opportunities for reducing greenhouse gas emissions and other pollution associated with U.S. LNG exports, and we look forward to continued engagement with the Department on this important topic.

Respectfully submitted,

Clean Air Task Force

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[62] Carbon Limits, *Best practices*, *supra* note 12, at 41. *See also, e.g.,* Sergey Ushakov et al., *Methane slip from gas fueled ships: a comprehensive summary based on measurement data*, 24 J. Marine Science & Tech. 1308 (2019); *See also*, *WIN GD, X-DF2.0 Technology*, https://www.wingd.com/en/technology-innovation/engine-technology/x-df-dual-fuel-design/x-df2-0-technology/ (last visited June 26, 2023). For more on low methane slip engine and retrofitting, see, e.g., Wärtsilä Corporation, *Cutting greenhouse gas emissions from LNG engines* (Apr. 6, 2020), https://www.wartsila.com/media/news/06-04-2020-cutting-greenhouse-gas-emissions-from-lng-engines.

[63] Liquefied Gas Carrier, *Drydocking preparation for a liquefied gas carrier*, http://www.liquefiedgascarrier.com/drydocking.html (last visited June 26, 2023).

[64] Carbon Limits, *Best practices*, *supra* note 12, at 48-50. *See also, e.g.*, Wartsila, *A reliquefaction system is used to control LNG tank pressure by liquefying boil-off gas (BOG)*, https://www.wartsila.com/marine/build/gas-solutions/liquefaction-bog-reliquefaction/wartsila-bog-reliquefaction (last visited June 26, 2023); Edge Energy, https://edgelng.com/ (last visited June 26, 2023).

Respondent:

American Exploration and Production Council

AMERICAN EXPLORATION & PRODUCTION COUNCIL

June 26, 2023

U.S. Department of Energy
Office of Fossil Energy and Carbon Management
ReduceGHGE_LNG_RFI@NETL.DOE.GOV

Subject: Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. LNG Exports (DE-FOA-0003052_RFI)

Dear Madam or Sir:

The American Exploration and Production Council (AXPC) appreciates the opportunity to provide input responsive to the Department of Energy's (DOE) Request for Information (RFI) related to Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports.

Please find input below, organized by bolded category and sub-numbers as requested in the RFI.

Background

Prior to the Shale Revolution, the U.S. was in the process of building LNG import terminals in anticipation of needing increased imports of natural gas. The Shale Revolution changed that, as it became clear that the U.S. was producing more natural gas than it could consume domestically. The U.S. first started exporting LNG in February 2016,[1] and exports have continued to increase every year while prices in the U.S. have remained low and stable. As of 2021, the U.S. became the largest LNG exporter.

Approximately 90 percent of the natural gas produced in the U.S. remains in the US for domestic consumption, which is why prices remain much lower than other markets and have been more stable than the rest of the world, who must compete for LNG cargoes.

Notably, U.S. production continues to exceed domestic demand – meaning that we have more than enough natural gas to meet domestic needs and support allies' energy needs through the delivery of liquefied natural gas. Even with the significant growth in exports over the past five years, U.S. natural gas prices have stayed relatively stable – and significantly more affordable than global prices due to the significant supply resulting from innovations in shale drilling.

Natural gas is a critical, on-demand, low-emissions energy source globally and is projected to remain a key part of the energy mix into the future.[2] Natural gas provides energy stabilizing services that are difficult to decarbonize such as peak winter heating, supply/demand balancing, seasonal energy storage, and high-temperature industrial heat[3] as well as serves as a feedstock for low-carbon hydrogen.[4] Compared to coal, electricity generation from natural gas produces about half the CO_2 per million BTU.[5] Minimizing the methane emissions intensity of a given natural gas source is critical to realizing the climate benefits of natural gas.[6]By January 2022, the United States had become the largest producer of oil and natural gas.[7]

Figure 1 shows a comparison of IEA-developed Methane Emission Scaling Factors. These factors are based on a country's age of infrastructure, types of operators within each country (international oil companies, independent companies, or national oil companies) and average flaring intensity. Only 7 other producing countries have a marginally lower Methane Emission Scaling Factor. The United States produces almost as much oil and gas as those 7 producing countries *combined*.

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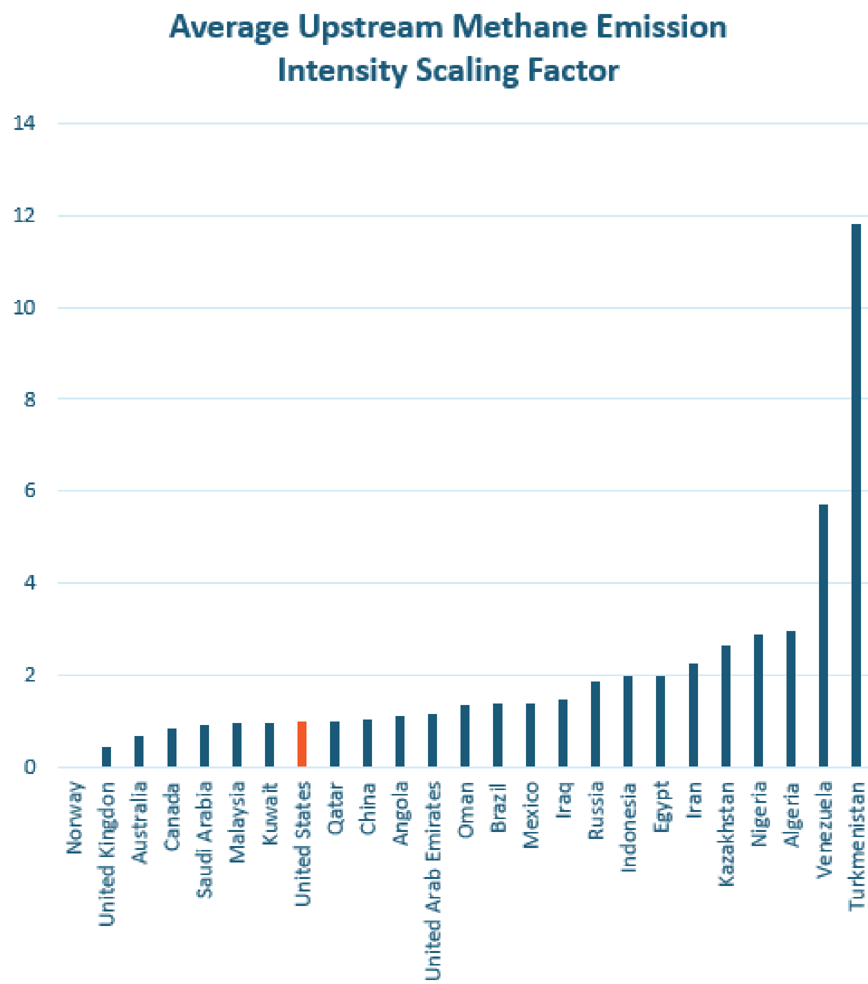
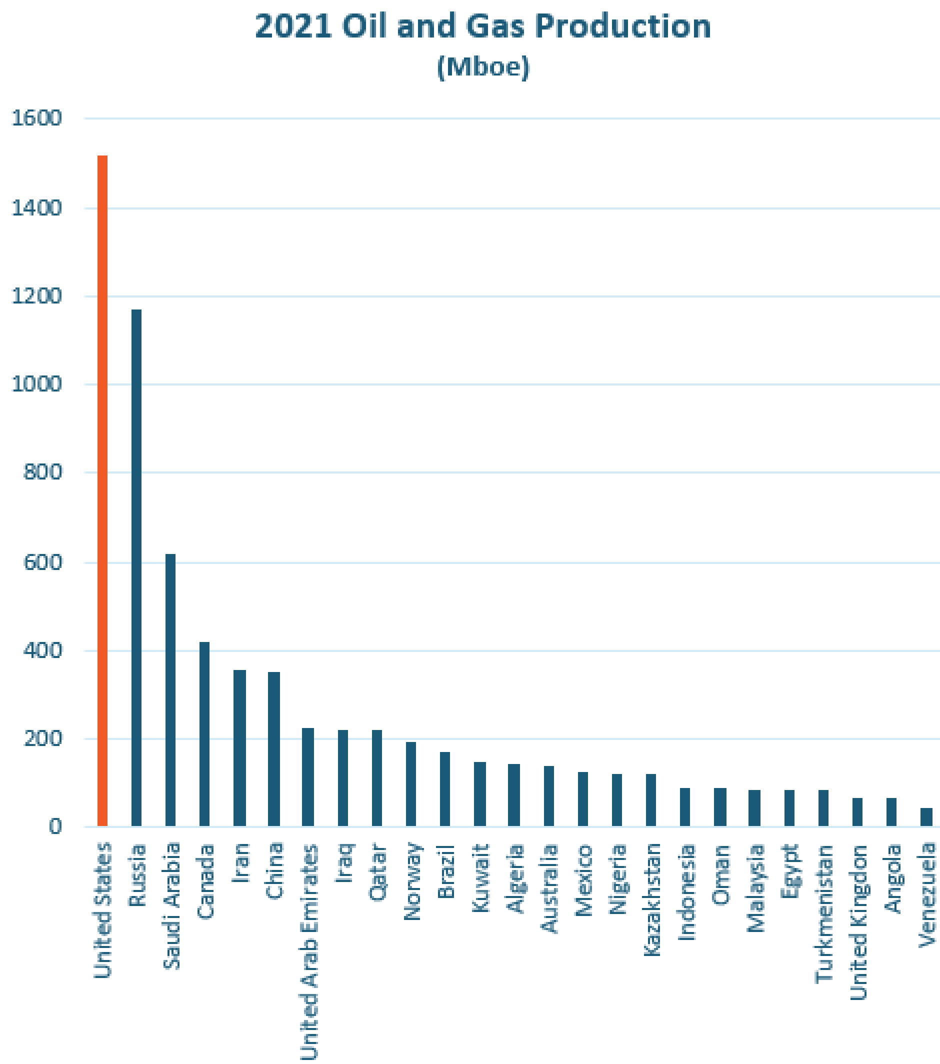
[1] https://www.eia.gov/todayinenergy/detail.php?id=53719#
[2] U.S. Energy Information Administration, *Annual Energy Outlook 2023 (AEO 2023)*, https://www.eia.gov/outlooks/aeo/
[3] IEA (2022), Methane Emissions from Oil and Gas Operations, IEA, Paris https://www.iea.org/reports/methane-emissions-from-oil-and-gas-operations, License: CC BY 4.0
[4] https://www.energy.gov/eere/iedo/low-carbon-fuels-feedstocks-and-energy-sources
[5] https://www.eia.gov/environment/emissions/co2_vol_mass.php
[6] IPCC, 2023: Climate Change 2023: Synthesis Report. A Report of the Intergovernmental Panel on Climate Change. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland, (in press)
[7] https://www.nasdaq.com/articles/what-countries-are-the-top-producers-of-oil

American natural gas presents an opportunity to provide the world with lower-emission energy on a very large scale.

Figure 1: The IEA develops Methane Emission Scaling Factors based on a country's age of infrastructure, types of operators within each country (international oil companies, independent companies, or national oil companies) and average flaring intensity. The United States has one of the lowest methane emission intensities of all producing countries. Only 7 other countries have a lower methane scaling factor, and the US produces almost as much as all 7 of those countries combined.





Source | Global Methane Tracker, IEA; Production Data from EIA;

Illustrating this point, in 2022 U.S. producers supplied nearly half of Europe's LNG[8] alleviating Europe's reliance on Russian natural gas and meeting a 65% increase in European demand compared to 2021. As our allies in Europe and around the world want to reduce their reliance on Russia or transition away from coal, demand for U.S. natural gas will continue to grow. Indeed, Europe expanded its LNG import capacity in 2022, with 33% of additional growth expected by the end of 2024 as countries add new LNG import facilities (regasification and expanded import terminals).[9]

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[8] https://www.eia.gov/todayinenergy/detail.php?id=55920
[9] https://www.eia.gov/todayinenergy/detail.php?id=54780

About American Exploration and Production Council

AXPC is a national trade association representing 34 leading independent oil and natural gas exploration and production companies in the United States. These companies alone are responsible for producing over 40% of all of US natural gas production. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of ensuring positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. The United States is a world leader in oil and natural gas production, achieving that status while substantially reducing emissions. The historic reductions in U.S. greenhouse gas (GHG) emissions over the last decade have been driven by the emergence of U.S. natural gas production as a low-cost source of reliable energy. It is important that regulatory policy enables us to build on that success. AXPC members support continued progress on both fronts through innovation and collaboration.

Consistent with the AXPC organizational mission and membership composition, the input will focus on Topic 1 (Environmental Profile of Upstream Supplies).

Topic 1: Environmental Profile of Upstream Supplies

1.1. What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

AXPC members have employed many different technologies and strategies to mitigate greenhouse gas emissions and other environmental impacts caused during the exploration and production of natural gas that is ultimately delivered to a liquefaction facility. While there is no "one size fits all" solution to emissions mitigation for this industry, there are various technologies and work practices that are available, maturing, or in development, which are described in this response.

Generally, emissions reduction opportunities constitute a portfolio of source specific work practices, engineering design, and technologies. A generalized approach to creating an emissions reduction strategy for an asset and/or region includes:

1) development of an emissions inventory,
2) identification of the largest sources of emissions (e.g., opportunities for reduction), and
3) identification, and deployment of, the most cost-effective options to reduce emissions for those largest sources.

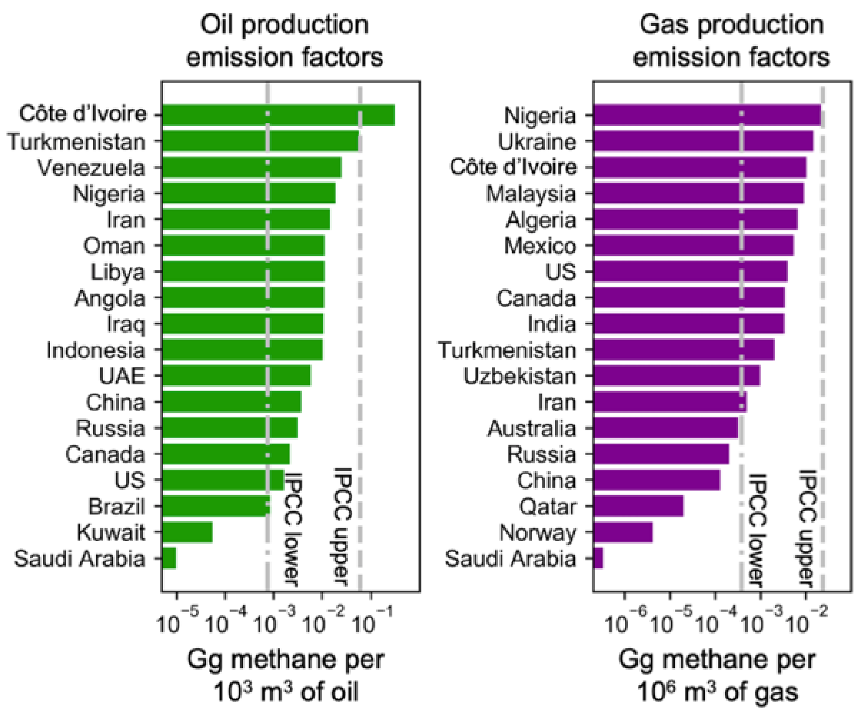
Sometimes this process is formalized through the development of a Marginal Abatement Cost Curve (MACC), which charts the opportunities with relative cost and abatement potential.[10]

[10] https://www.chevron.com/sustainability/environment/lowering-carbon-intensity

Emissions Inventories

The magnitude and relative contributions of sources of emissions are regional and even asset and production type specific as shown in Figure 2. This is why it is imperative to begin any emission reduction initiative with the development and/or refinement of an emissions inventory.

Figure 2: Methane emission factors for oil-gas production activities in 2019.



Source | Scarpelli *et. al.*, *Atmos. Chem. Phys.* **2022**.[11]

AXPC member companies report greenhouse gas emissions to EPA through the Greenhouse Gas Reporting Program (GHGRP) for facilities exceeding the reporting threshold of 25,000 metric tons CO2e per year. EPA then uses reported emissions from the GHGRP to help develop the US Greenhouse Gas Inventory (GHGI).

EPA is currently in the process of making specific updates to the GHGRP, including for 40 Code of Federal Regulations (CFR) subpart W ("Subpart W"), which includes reporting requirements for petroleum and natural gas systems.

[11] Tia Scarpelli, Daniel J. Jacob, Shayna Grossman, Xiao Lu, Zhen Qu, Melissa P. Sulprizio, Yuzhong Zhang, Frances Reuland, Deborah Gordon, and John R. Worden. *Atmos. Chem. Phys.*, 22, 3235–3249, **2022** https://doi.org/10.5194/acp-22-3235-2022

To facilitate the development of a more accurate emissions understanding, which ensures effective emissions reductions, AXPC member companies have voluntarily utilized direct emissions measurements and other data management techniques to apply more refined emissions estimation to the development of facility-level emissions inventories.

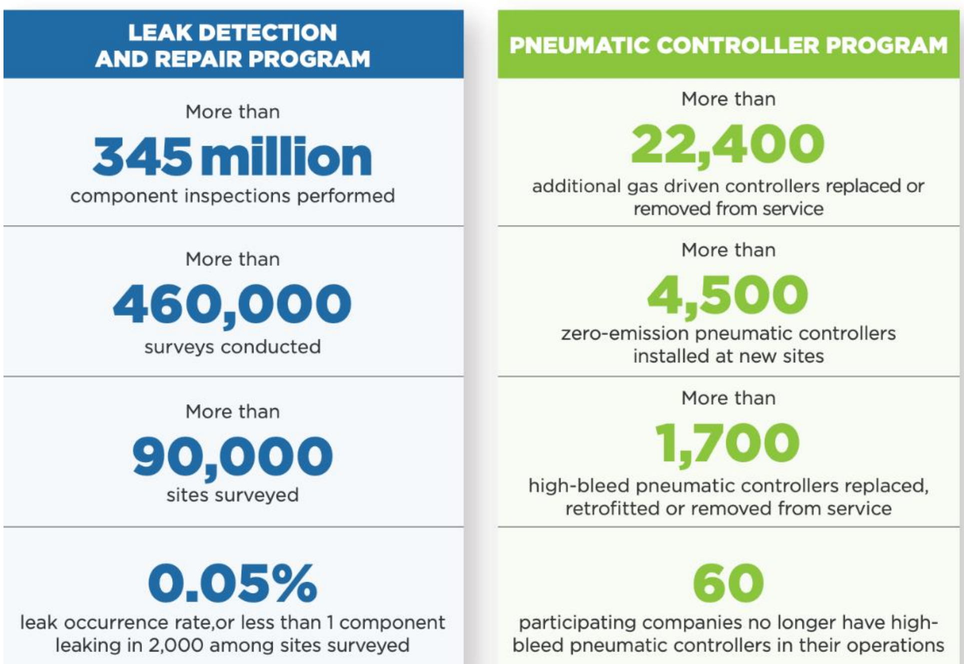
Largest Emissions Source Opportunities

Once an emissions inventory is developed, companies will work to identify the largest emissions source(s) and opportunities to address those emissions.

Case Study: Emissions from Pneumatic Devices and The Environmental Partnership (TEP)

Led by the American Petroleum Institute, The Environmental Partnership is comprised of companies in the U.S. oil and natural gas industry committed to continuously improve the industry's environmental performance. Accordingly, through its collective membership representing greater than 100 US companies covering more than 70% of U.S. onshore oil and natural gas production, significant voluntary progress has already been made to abate emissions from the top categories of emissions sources as shown in Figure 3.

Figure 3: Performance highlights from The Environmental Partnership's 2022 Annual Report on pneumatic controller and equipment leak emissions abatement initiatives in 2021.

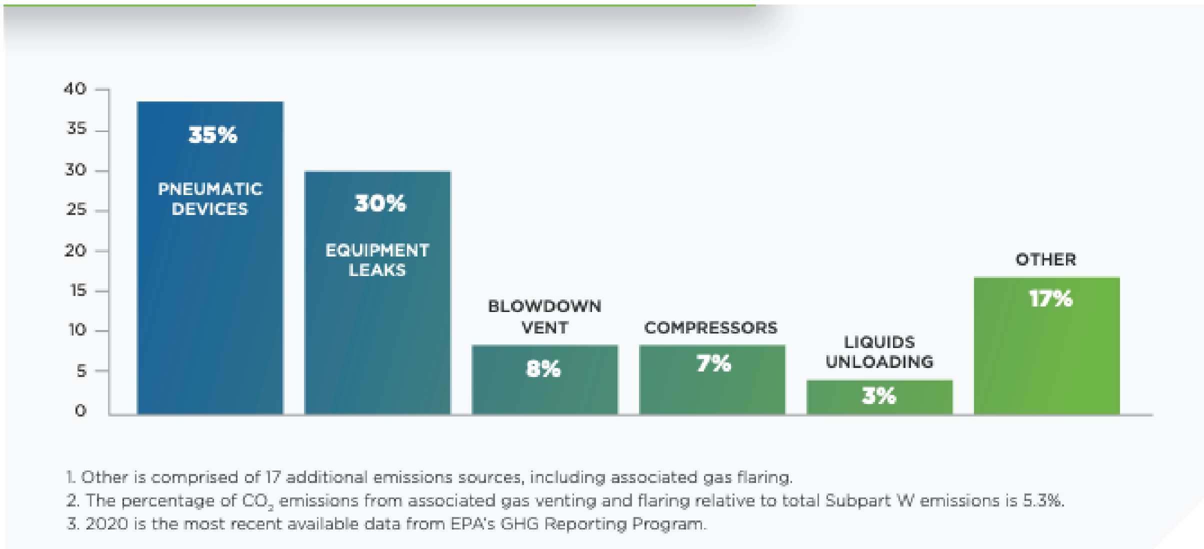


Source | Annual Report 2022 of The Environmental Partnership[12]

[12] https://theenvironmentalpartnership.org/wp-content/uploads/2022/09/API-TEP-Annual-Report-2022.pdf

On an annual, national average basis, pneumatic controllers contributed the largest share of CO_2e from the production segment in 2020 (Figure 4) at 35% of all production segment emissions.[13]

Figure 4: EPA's GHGRP 2020 Emissions



Source | Annual Report 2022 of The Environmental Partnership[14]

Collectively the industry, led by TEP, initiated a pneumatic controller replacement program. As of the end of 2021, a total of 51,000 gas driven pneumatic controllers were replaced with lower emissions sources. More than 10,000 zero-emissions pneumatic controllers have been installed. This resulted in a reduction of methane emissions from pneumatic controllers of about 10.2% from 2020 to 2021.[15]

Additionally, EPA's forthcoming regulations are expected to drive additional significant reductions across the segment. Specifically, if EPA promulgates zero-emissions standards or the elimination of venting directly to the atmosphere from certain emissions sources, then sources like pneumatic controllers may be reduced even further to a relatively minor source.

Reduction Opportunities

Reduction opportunities can be categorized into two main types:

1) Changes in facility design, where these reductions tend to be capital intensive for existing facilities. New facilities, however, generally incorporate the specific equipment and engineering designs that result in reduced emissions, thus making new facilities much cleaner to operate with a lower overall environmental impact.

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[13] https://www.epa.gov/natural-gas-star-program/estimates-methane-emissions-segment-united-states#Production

[14] https://theenvironmentalpartnership.org/wp-content/uploads/2022/09/API-TEP-Annual-Report-2022.pdf

[15] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021; Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021 – Main Report (epa.gov)

2) Changes to or addition of work practices, which are often easier to implement for existing facilities, tend to be labor and resource intensive.

Industry collaborations have rallied around the development of best practices to minimize emissions and produced various toolkits, best practices, and knowledge exchange forums. Two of the most notable include Methane Guiding Principles (MGP)[16] and The Environmental Partnership (TEP).[17] MGP developed a series of ten Best Practice Guides covering mitigations, costs, and available technologies covering sources (flaring, equipment leaks, venting, pneumatic devices) as well as other relevant topics (e.g., continual improvement, measurement and quantification). TEP developed six Environmental Performance Programs focused on cost-effective technology deployment for emissions reduction. A non-exhaustive list of emissions reduction approaches deployed across AXPC membership are listed in Table 1.

Table 1: Approaches deployed among AXPC members:

Emissions Reduction Approach	**Examples**
Facility design (equipment)	
Low emissions power	Using low-emission diesel or clean-burning natural gas to power equipment and facilities
Gas/vapor recovery	Install vapor recovery units to capture gas that would otherwise be vented or routed to flare, such as from tanks, and return to process or sales
Infrastructure improvements	Adding infrastructure to transport oil to reduce truck traffic and emissions associated with loading/unloading; ensure adequate takeaway capacity for associated gas (gas produced as a co-product in oily production regions)
Gas driven pneumatic device changes/elimination	Retrofits to lower emission equipment (high bleed pneumatic controllers to low bleed) and/or conversion to compressed air or electric
Updates to component types prone to leaks or other emissions events	Equipment replacement or repair for frequently emitting tank components such as pressure relieve devices or hatches (i.e., tank seals) that provide tank access
Emissions controls on material transfer processes	Work practice changes to truck loading (submerged fill, vapor control), installation of Lease Automatic Custody Transfer (LACT) units, use of vapor control during transfers such as vacuum systems or carbon canisters
Facility electrification	Whole site electrification, transition of gas lift compressors to electric compressors
Carbon capture, utilization, and storage	Use of Carbon Capture Sequestration to remove CO2 from gas delivered to LNG terminals, resulting in elimination of CO2 fugitive emissions from pipelines and facilities downstream of

[16] https://methaneguidingprinciples.org/
[17] https://apitep02.wpengine.com/what-were-doing/taking-action/

	the CCS project. CCS can be stored underground permanently, for enhanced oil recovery, or delivered to CO2 suppliers for use in food grade products
Flaring	Route gas to flare instead of venting
Green completions	Using zero- or low- emissions equipment for well flowback and separation processes
Work Practices	
Leak detection and repair	Periodic inspections using various technique: AVO (audio, visual, olfactory), gas sniffers, optical gas imaging cameras, emergent technology (e.g., drones, flyovers, aircraft) and repairing observed emissions sources
Continuous emissions monitoring	Use of point sensors, fixed optical gas imaging cameras, and other continuous monitoring devices to rapidly identify and enable swift mitigation of conditions (malfunctions, process excursions, control device outage, etc.) resulting in increased emissions
Minimizing magnitude/duration of venting activities	Minimizing duration of manual gas well liquids unloadings,[18] reducing equipment and/or pipeline pressure to the extent possible before blowdown, utilizing hot tapping, routing blowdowns to flare
Optimized maintenance procedures	Proactively maintaining equipment to prevent leaks such as with pressure relief devices, compressor seals, etc.

Source | AXPC membership

1.2. To what extent do exporters request or have access to information about the source (e.g., production basin, transportation pipeline, custody transfers) of the natural gas they are liquefying for export? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means? Do the answers vary by the extent to which the gas is supplied by natural gas marketers or through bilateral contracts?

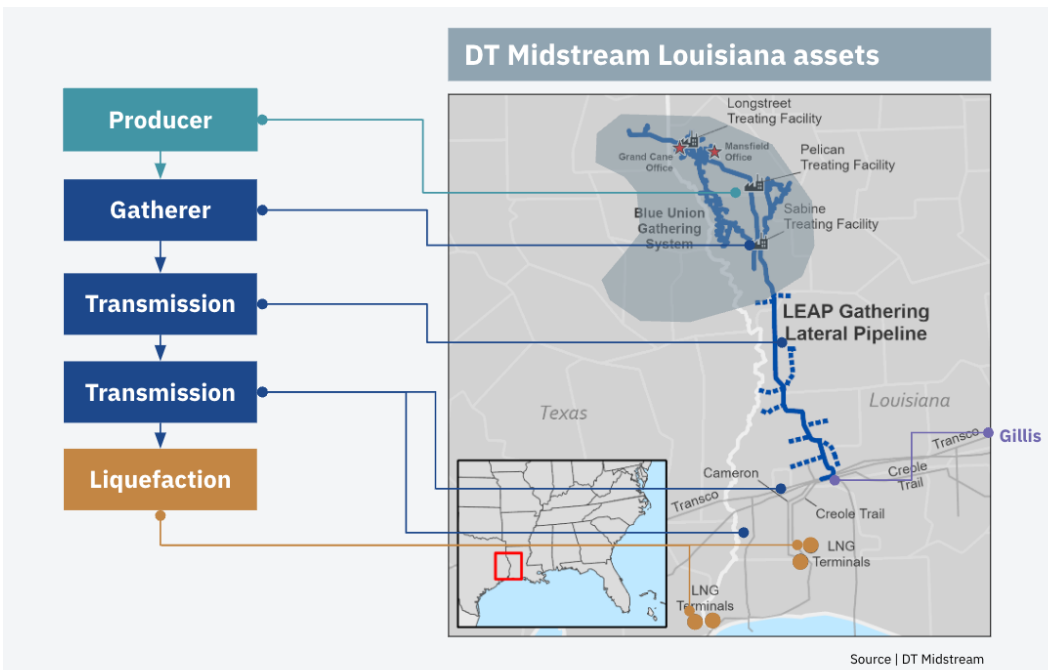
Exporters sometimes request emissions data from the gas suppliers they are purchasing from. For exploration and production sources, emissions data is readily available, but is dependent on emissions quantification technique, as discussed above, related to the development of emissions inventories. Continued improvements in emissions quantification should make this information more useful in terms of any form of comparison to other operators. However, AXPC believes that the stringency of regulations for US producers would make comparison a moot task because once anticipated U.S. regulations are fully implemented, the U.S. will have

[18] https://apitep02.wpengine.com/what-were-doing/taking-action/#:~:text=Liquids%0AUnloading%20Program-,VIEW%20MORE,-Leak%20Detection/

the most rigorous source control and inspection regulations in the world, resulting in some of the cleanest natural gas globally.

While producers, and LNG operators typically have their own emissions data, midstream assets that move/handle gas between the seller and the buyer generally do not take title of the gas thus making access to information on emissions/mitigation more difficult to obtain. Figure 5 illustrates a relatively simple example of this, where a producer from the Haynesville sells gas to an LNG operator and the gas flows on the DT Midstream assets to Gillis. In this case, though the producer may have emissions data for its production operations and the LNG operator may have emissions data pertaining to liquefaction and shipping activities, neither the seller (the producer), nor the buyer (LNG operator), nor a combination of the two, have visibility on the emissions from development through liquefaction.

Figure 5: Illustration of a simple value chain from gas production through liquefaction



Source | Validere

Building the supply chain emissions perspective is challenging. A number of initiatives have focused on creating a robust and consistent framework of data integration to represent the supply chain, addressing this issue. To date, no approach has been widely adopted. These frameworks may integrate U.S. EPA GHGRP data to describe the emissions along the supply chain.

- The International Group of Liquified Natural Gas Importers (GIIGNL) produced an MRV and GHG Neutral Framework[19] as a voluntary LNG cargo reporting

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[19] https://giignl.org/framework/

framework. The Framework is intended to provide a common set of principles for emissions MRV and common terminology used for carbon neutral LNG to enable distinction between cargoes on an emissions basis and incentivize GHG emissions reductions.

- The Energy Emissions Modeling and Data Lab (EEMDL)[20] at the University of Texas is developing models and datasets for accurate greenhouse gas emissions accounting across global oil and gas supply chains.
- MiQ launched a comprehensive GHG certification and registry focused on LNG,[21] where the new framework aims to track all methane, carbon dioxide, and nitrous oxide emissions from every segment of the LNG supply chain from production through regassification.

1.3. To what extent do exporters request or have access to information about the greenhouse gas emissions and/or practices to limit greenhouse gas emissions of the natural gas they are liquefying for export prior to delivery at the liquefaction facility? For those exporters that do not request or have access to such information, to what extent could they obtain access upon request or by other means?

It is relatively straightforward to access emissions data at the basin/company level from the U.S. GHGRP to understand the average emissions from for a company's operations in a region. In addition, individual companies are enhancing the transparency of emissions through various gas certification programs and alternative emissions inventory evaluations such as ONE Future[22] and OGMP 2.0.

AXPC supports the allowance for empirical operations data in the calculation of methane emissions. However, emissions estimating methods should strike a pragmatic balance between emissions data quality and measurement.

Though the methane detection and measurement technology ecosystem surged over the last several years, methods to replace engineering-based, bottom-up estimates through independent, measured, annual site-level quantification are challenged. This is for several

[20] https://www.eemdl.utexas.edu/
[21] https://miq.org/miq-launches-worlds-first-comprehensive-greenhouse-gas-certification-and-registry-for-lng/
[22] https://onefuture.us/

reasons. Research has revealed significant spatial and temporal variability[23,24,25,26,27] in methane emissions. Many of the emergent technologies perform measurements over short timescales. Extrapolation of these measurements to longer duration emissions estimates from these short-term snapshot measurements is complicated by spatial and temporal variability and introduces significant uncertainty beyond the measurement uncertainty associated with individual measurements.[28] Technologies that sample for longer periods of time (generally fixed monitoring systems) rely heavily on models that also carry significant quantification uncertainties, but drive emissions down due to rapid detection of moderate to large emissions as they start. Use of these technologies both bolsters understanding of emissions sources and accelerates emissions reductions by supplementing emissions data and reducing the time between emissions source discovery and remediation, even if they do not provide a means by which to replace the need to create emissions inventories.

In particular, and in large part thanks to the DOE through innovation programs such as ARPA-E, the U.S. technology ecosystem is thriving. Resultantly operators are deploying the detection and measurement technologies fulsomely. While there remain some unmet needs in measurement quantification, the availability of technologies of different deployment modalities (fixed, drone, airplane, satellite, truck, handheld, etc.) have greatly enriched emissions understanding and mitigation.

Additionally, some of the source specific techniques, especially when combined with process knowledge, can result in improved emissions estimates. For example, the recent proposed amendments to Subpart W[29] would allow for flow meters, calibrated bags, and high-volume samplers for some sources such as dry seal vents and reciprocating compressor rod packing. These proposed revisions acknowledge that some measurements, for some sources, provide reasonably accurate results.

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[23] Lavoie, T. N.; Shepson, P. B.; Cambaliza, M. O. L. Spatiotemporal Variability of Methane Emissions at Oil and Natural Gas Operations in the Eagle Ford Basin. *Environ. Sci. Technol.* **2017**, *51*, 8001– 8009, DOI: 10.1021/acs.est.7b00814

[24] Vaughn, T. L.; Bell, C. S.; Pickering, C. K.Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region. *Proc. Natl. Acad. Sci. U.S.A.* **2018**, *115*, 11712– 11717, DOI: 10.1073/pnas.1805687115

[25] Allen, D. T.; Cardoso-Saldaña, F. J.; Kimura, Y. Variability in Spatially and Temporally Resolved Emissions and Hydrocarbon Source Fingerprints for Oil and Gas Sources in Shale Gas Production Regions. *Environ. Sci. Technol.* **2017**, *51*, 12016– 12026, DOI: 10.1021/acs.est.7b02202

[26] Daniel H. Cusworth, Riley M. Duren, Andrew K. Thorpe, Winston Olson-Duvall, Joseph Heckler, John W. Chapman, Michael L. Eastwood, Mark C. Helmlinger, Robert O. Green, Gregory P. Asner, Philip E. Dennison, and Charles E. Miller. *Env. Sci. & Technol. Lett.* **2021** 8 (7), 567-573. DOI: 10.1021/acs.estlett.1c00173

[27] Ravikumar, Arvind. "Temporal Variations in Methane Emissions from Midstream Natural Gas Infrastructure." AGU Fall Meeting 2021, held in New Orleans, LA, 13-17 December 2021, id. A22C-07.

[28] Colette Schissel and David T. Allen. *Environmental Science & Technology Letters* **2022** *9* (12), 1063-1067 DOI: 10.1021/acs.estlett.2c00731

[29] United States, Environmental Protection Agency, "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule." Vol. 87 No. 118 Fed. Reg. Page 36920 (June 21, 2022).

1.5. What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?

Third-party certification programs, in combination with the GHGRP provide a robust dataset that demonstrates how natural gas produced in the U.S. is produced following best practices to reduce environmental impact.

The certification programs all share a focus on greenhouse gas emissions mitigation and are the avenue for communicating the outcome of mitigation. These certification programs also play a critical role in providing third-party assurance on the reported emissions data. Data used in certification programs frequently exceeds data available in the EPA's GHGRP by inclusion of additional emissions sources beyond EPA's program. While differences do exist in the programs and methodologies, overall, these programs provide credibility to the data provided by industry, specifically for emissions reductions achieved. Certification programs are a mechanism for consumers who wish to buy a differentiated product, and we are supportive of a market that allows gas purchasers to make those differentiations.

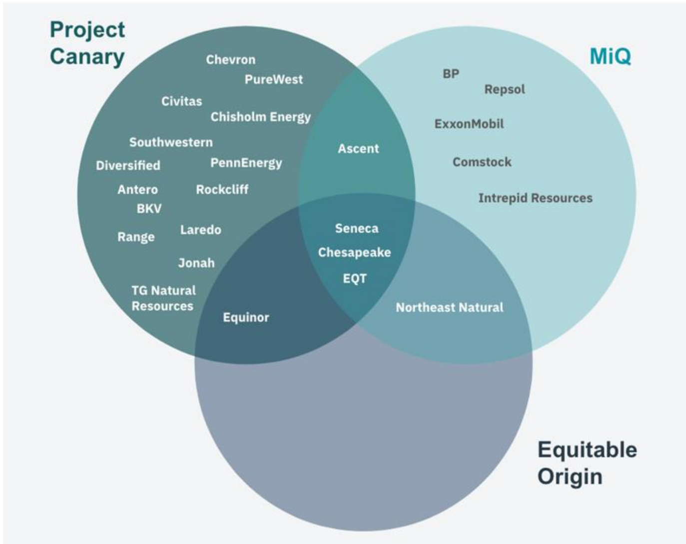
Today there are material differences between the various certificates including the asset boundaries for a certified unit, requirements for measurement and/or measurement-based emissions intensity estimates, audit requirements, and scope of elements of the certificates (methane only through portfolio of ESG issues).

1.6. What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?

No LNG companies are currently using these certifications to our knowledge. Largely, upstream producers have participated in these programs as shown in Figure 6,[30] with some early successes monetizing these efforts through domestic bilateral deals.

[30] However, standards across the value chain, and in particular LNG standards, such as from MiQ, have only recently become available and have potential for adoption.

Figure 6: Publicly known certifications across Project Canary, MiQ, and Equitable Origin as of 2023. Notably, many Project Canary engagements were pilot projects with their measurement technology.



Source | Validere

It is still unclear if or how the full LNG value chain will be certified under one of these programs.

1.7. What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

The intent of certification programs is to build trust, transparency, and transactability via independent audits and reporting. The hope is these programs may have the potential to provide enough rigor for buyers outside the U.S. to meet their emission goals (beyond the U.S. regulatory framework). Certification programs could have a role in helping create a global competitive advantage because of differences between basins, regardless of the specific regulatory requirements.

Notably, the U.S. is already a relatively low emissions intensity natural gas exporter, and gas that is certified with lower emissions may be more appealing to foreign markets, thus helping to create a global competitive advantage for American certified gas. While EPA, BLM, and PHMSA regulations will bring the nationwide methane intensity down, certification programs such as MiQ and Project Canary boast certifications achieving significantly lower methane intensity rates of less than 0.05%.[31]

[31] https://miq.org/

Respondent:

Differentiated Gas
|Coordinating Council

DIFFERENTIATED GAS COORDINATING COUNCIL

June 26, 2023

The Honorable Brad Crabtree
Assistant Secretary, Office of Fossil Energy and Carbon Management
U.S. Department of Energy
1000 Independence Ave. SW
Washington, DC 20585

RE: **Differentiated Gas Coordinating Council's response to the Department of Energy's Request for Information on Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas Exports. Submitted via the "ReduceGHGE_LNG_RFI@NETL.DOE.GOV" email address.**

Dear Assistant Secretary Crabtree:

As requested in the request for information (RFI) referenced above, please see the contact information below.

- Company name: COEFFICIENT, representing the Differentiated Gas Coordinating Council (DGCC)

The DGCC appreciates the opportunity to respond to the U.S. Department of Energy (DOE) Office of Fossil Energy and Carbon Management's RFI titled "Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. Liquefied Natural Gas (LNG) Exports."[1]

The DGCC is a coalition of stakeholders across the natural gas value chain dedicated to expanding the differentiated natural gas market, including participants in the global LNG export market. The DGCC's goal is to facilitate a pathway for regulators, utilities, and gas consumers to utilize differentiated gas as an important option to meet their climate goals. We believe adopting differentiated gas is the best way to rapidly reduce methane emissions in the oil and gas sector—a win for energy producers, energy consumers, and the climate.

Differentiated gas, also known as certified gas, is natural gas that is marketed and sold based on its verifiable environmental properties, particularly the intensity of methane emissions throughout the value chain. In a world looking to reconcile climate change and the continued use of fossil fuels, energy products with smaller greenhouse gas

[1] *See* Opportunities to Reduce Greenhouse Gas Emissions and Other Air Pollutants Associated with U.S. LNG Exports.

(GHG) footprints will maintain a competitive advantage. The reliable verification of a cleaner product means that such a product can be sold at a premium, especially in the global LNG market.[2] To participate in this market, oil and gas companies track, quantify, and communicate their methane and carbon dioxide emissions to investors, customers, and regulators.

More than 70% of methane emissions in oil and gas operations are avoidable, and 45% are avoidable at no net cost.[3] Energy companies can detect and stop leaks as they occur, minimize routine flaring, and identify and replace problematic equipment. In 2019, oil and gas companies operating on U.S. public and tribal lands wasted $500 million worth of gas, and 163 billion cubic feet of methane—the equivalent of almost two million cars on the road a year.[4] Mitigating methane emissions through differentiated gas can quickly reduce emissions with little pain. Expanding America's differentiated gas market can enable the long-term viability of the LNG market and create a competitive advantage for U.S. LNG producers.

Differentiated gas is critical to credibly communicate the cleanliness of U.S. LNG to energy buyers abroad. By leveraging advanced technology and adhering to internationally accepted methodologies, it instills confidence in emissions data, underscoring the decarbonization advantages of natural gas over other energy types. For European buyers, who might encounter a Carbon Border Adjustment Mechanism for imported LNG, differentiated gas is crucial in mitigating financial risks linked to gas supply emissions.

These programs are increasingly becoming integral to long-term LNG supply agreements and may soon be a prerequisite for the most environmentally conscious international buyers. The DOE's initiative to create a best-practices framework for differentiated gas, utilizing a universally acknowledged methane quantification methodology, such as the Oil & Gas Methane Partnership 2.0 (OGMP 2.0), is vital for global recognition of the strategic benefits of American natural gas.

On the following pages, please find the DGCC's responses to certain questions posed by the DOE in its RFI.

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[2] *See* Bloomberg Law's "U.S. Can Ensure Climate Security With Differentiated Natural Gas."
[3] *See* International Energy Agency's "Slashing methane emissions is crucial for the climate."
[4] *See* Environmental Defense Fund's, "New Study Quantifies Natural Gas Wasted on U.S. Public and Tribal Lands," and Environmental Protection Agency's, "Greenhouse Gas Equivalencies Calculator."

Topic 1: Environmental Profile of Upstream Supplies

Question 1.1

What technologies or strategies are being used to mitigate the greenhouse gas emissions and other environmental impacts of the natural gas delivered to a liquefaction facility?

DGCC Response

Data plays a pivotal role in mitigating the GHG emissions and other environmental impacts of the natural gas delivered to a liquefaction facility. Advanced software and technology are essential for accurately measuring methane emissions and implementing cost-effective reduction strategies.

Leak detection is a key technology in this area. Optical gas imaging (OGI) cameras, continuous monitoring systems, sensing/detection technologies attached to satellites or aircraft, and other advanced technologies provide a visual representation or alert of specific methane leaks. Once these leaks are detected, they can be remedied using straightforward engineering solutions such as valve replacement or repair, contributing to the reduction of methane emissions in a timelier manner.

Current methods for collecting data on methane emissions, however, are often inaccurate and inefficient. The prevailing method, as required by regulation, relies on the use of emissions factors consisting of estimated gas-loss rates per unit of activity for specific items of equipment, with emissions calculated via formula and generic factors rather than direct observation. This approach is gradually being replaced by more robust methodologies like those prescribed by the OGMP 2.0, which calls for both equipment-specific direct measurement (i.e., "bottom-up") and engineered calculations (i.e., "top-down") across a facility as reconciled against technologies that use remote sensing to determine the concentration of methane in the atmosphere over a specific area. As this combined "bottom-up/top-down" approach, supplemented by emerging technologies, becomes more widespread, the differentiation of gas products will become more accurate and reliable.

While the technology needed to scale differentiated gas is developing rapidly, it is still in the early stages, with the primary benefit being leak detection rather than full-site quantification. Advanced detection technologies are lacking sufficient quantification capabilities for all sources of methane emissions, which requires the use of technologies such as a high-flow sampler to measure the flow rate of emissions to quantify them. Accordingly, it is crucial to encourage investment in methane detection and quantification technologies to ultimately improve performance, reduce workload by operations teams, reduce manual data collection, and drive automation, which will increase trust and transparency in the data used to determine source and site-level emissions. Additionally, continued investment will potentially make these technologies more cost-effective and accessible, further enhancing our ability to mitigate the environmental impacts of natural gas delivered to a liquefaction facility.[5]

Several different and emerging technologies and strategies are being used to detect, quantify, and monitor GHG emissions, primarily methane, from the production, transportation, and use of natural gas. From the ground up, these include handheld technologies, stationary technologies, continuous monitoring systems, mobile technologies, and sensors attached to drones, aircraft, and satellites.[6] Challenges in reconciling multiple sources of measurement will continue to evolve as the industry shares best practices to deal with minimum detection limits under varying environmental and operating conditions, as well as addressing the gap in varying time and space datasets available from aerial surveillance.

Handheld Technologies

Handheld technologies, primarily OGI cameras, can survey individual equipment and components for methane emissions and allow the identification of very small emissions sources. However, handheld technologies require close access to equipment and components and can be very time-consuming. A single component may require detection from multiple angles to classify with high accuracy. OGI cameras are approved as an alternative work practice for surveys required under the Environmental Protection Agency's (EPA) New Source Performance Standards OOOOa regulation and are the standard way that oil and gas operators conduct methane leak detection and repair (LDAR) programs.[7]

Stationary Technologies

Fixed sensors that continuously monitor methane emissions are another form of technology being used to potentially enhance and improve the detection and quantification of specific sources of methane. The number and placement of sensors necessary to optimize detection and quantification at a site are typically developed according to a proprietary model and vary by site, geography, and equipment types. A subset of stationary technologies is continuous monitoring systems, which are used to track emissions in real-time. These systems can alert operators to sudden increases in emissions, allowing them to respond quickly and remedy large-scale leaks. Sensors are also used for high-efficiency flare combustion and can significantly reduce methane emissions and steam usage.[8] Operators can verify their flare meters remotely, quickly identify issues, and intervene promptly by having access to real-time combustion efficiency data on the production floor. Advancements are still needed to improve the accuracy in more complex operations, such as those found in midstream operations, to determine the appropriate application of technology by equipment type and improve the accuracy of detection and quantification.

[5] *See* DGCC's "Measuring Our Way to Differentiation."
[6] *See* COEFFICIENT's "Methane Quantification: Toward Differentiated Gas," also provided as a separate document.
[7] *See* EPA's Implementation of Oil and Natural Gas Air Pollution Standards.
[8] *See* Baker Hughes' "Monitor, Reduce and Control Your Emissions with flare.IQ."

Mobile Technologies (Other/Cross-Cutting)
Many sensors can be used in a variety of mobile applications, including specific aerial applications described above, and with ground-based vehicles (e.g., cars, trucks, and vans). Ground-based mobile surveys are typically limited by available roads downwind from the site or sources of methane. Operators also highlight potential safety issues from driving vehicles around sites. Mobile technologies, as with any periodic detection techniques, have limitations, such as the limited overlap in intermittent emissions events, minimum detection thresholds, etc. Correlating operational data and maintenance activities during the collection of these datasets is imperative to understanding the results of these types of surveys.

Drone-Based Surveillance:
Unmanned aerial vehicles or drones equipped with sensors and cameras can be used to monitor facilities from the air. These technologies can typically measure methane in three dimensions, including methane concentrations in the vertical atmospheric column within a methane plume. In addition, some can calculate wind speed and direction, enabling more data for calculations. The use of drones can enable more frequent inspections and can help identify leaks or other issues that may not be visible from the ground.

Plane-Based Surveillance:
Manned aircraft, ranging from larger multi-engine research planes to small single-engine general aviation aircraft and helicopters can fly at different altitudes and a longer range. High-altitude flights can target large areas while low-altitude flights can detect and measure methane from a point source. Planes and helicopters can cover a larger area than drones, making them useful for monitoring multiple facilities or large-scale operations such as pipeline rights-of-way.

Satellite-Based Surveillance:
Satellites can provide a global view of GHG emissions and are typically used for frequent, low-cost measurements over large areas. They are often used to identify super-emitters, monitor facilities over time, and verify other sources of methane estimates or measurements. Several satellites specifically focused on methane are already in operation or will be launched in the next few years. Sensors on satellites measure methane in the total atmospheric column; they are typically not able to identify a specific emissions source and are limited in detection abilities to include only larger, super-emitter types of events. This can help identify trends and hotspots and can also be used to provide insight into emissions data reported by individual facilities.

Question 1.5

What role do or could differentiated natural gas certification programs (also referred to as certified natural gas or responsibly sourced natural gas) play

> *in helping ensure the suppliers of natural gas sourced for export have taken measures to mitigate greenhouse gas emissions and other environmental impacts?*

DGCC Response

Differentiated natural gas certification programs, also known as certified natural gas or responsibly sourced natural gas, play a crucial role in ensuring that suppliers of natural gas for export take measures to mitigate GHG emissions and other environmental impacts depending on the protocols used to achieve the certification. These programs are becoming increasingly important as the world strives to meet the Intergovernmental Panel on Climate Change's 2050 limits on global temperature change, which will require significant reductions in human-caused methane emissions to obtain.

The oil and gas industry is uniquely positioned to substantially reduce its methane emissions over the next three decades, especially related to the LNG market. Major domestic and international buyers of natural gas are increasingly seeking proof of the low-emission attributes of natural gas across the entire supply chain, to the point where demonstrated low-methane-loss gas sells at a premium or provides an unofficial "license to operate" by climate-conscious buyers. However, the challenge lies in validating the emissions data attached to the various low-emission or certified gas programs. While it is true that what gets measured gets managed, it is also true that gas producers and buyers alike must "trust but verify." This is where certification programs come into play.

Certification programs are intended to provide independent ratings and/or verifications to differentiate certified natural gas from non-certified natural gas. They use both "bottom-up" assessments of data and "top-down" datasets (i.e., measurements of the concentration of methane at a site level) to drive greater trust in the reported emissions data.[9] This verification is beneficial to the development of a voluntary market for differentiated gas so buyers can trust the climate accounting data.

The main consideration in the certified gas market today is demonstrating the low-methane intensity of produced and transported natural gas based primarily on self-reported emissions estimates. However, some buyers are looking to move beyond this standard and demonstrate the low-emissions attributes of natural gas through actual measurement and across the full supply chain. They are also beginning to demand other operational and environmental attributes like advanced monitoring technologies and rigorous emissions quantification. These attributes are becoming increasingly important as sellers seek to further differentiate their products as certified, differentiated, or responsibly sourced gas on emission trading registries.

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[9] *See* the DGCC's response to question 1.1.

Certification, or proving the emissions intensity of natural gas, is becoming increasingly important to European buyers, as the European Union aims to finalize methane legislation by the end of 2023.[10] This legislation will likely require companies to submit source-level measurement, reporting, and verification (MRV) data and impose some LDAR requirements for energy imports. Thus, transparency of emissions data and certification or verification of the same is becoming increasingly valuable in a global energy marketplace.

Differentiated natural gas certification programs can play a vital role in ensuring the suppliers of natural gas for export take measures to mitigate GHG emissions and other environmental impacts. They provide independent verification of emissions data, encourage higher standards of methane abatement, and enable transactions in the market.

Question 1.6

> *What differentiated natural gas certification programs are LNG companies currently using? Are there any market gaps currently not filled by existing programs?*

DGCC Response

LNG companies are currently using several differentiated natural gas certification programs, including those offered by Project Canary, MiQ, and Context Labs.

Project Canary is a public benefit corporation that provides certification and emission MRV services.[11] It is known for its use of continuous monitoring technology, which continuously monitors methane emissions over long periods, detecting large emission events known as "super-emitter" events. Project Canary evaluates natural gas production with site-level operational and environmental assessments (TrustWell™) paired with the Low Methane Rating. In May 2022, U.S. LNG producer NextDecade announced a 15-year purchase agreement with European energy company Engie to sell 1.75 million tonnes of LNG per year using Project Canary-certified "responsibly sourced gas."[12]

MiQ assesses emissions across basins or regions rather than at individual facilities.[13] Operators can work with a wide range of technology partners to achieve MiQ Certification. MiQ requires companies seeking its certification to undergo periodic emissions monitoring and uses a proprietary algorithm to categorize that gas into one of its six grades of methane intensity. In March 2023, MiQ launched the world's first comprehensive GHG certification and registry for LNG. This new framework will track

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[10] *See* Politico Pro's "EU lawmakers back tougher rules on methane emissions."
[11] *See* ProjectCanary.com.
[12] *See* "NextDecade and ENGIE Execute 1.75 MTPA LNG Sale and Purchase Agreement," "NextDecade and Project Canary Form Pilot To Monitor Emissions From Rio Grande LNG Project," and "Energy ESG Market Leaders Turn to Next-Gen Certified Responsibly Sourced Gas."
[13] *See* MiQ.org.

all methane, carbon dioxide, and nitrous oxide emissions from every segment of the LNG supply chain—including production, gathering and boosting, processing, pipeline, liquefaction, shipping, and regasification.

Context Labs is another certifier whose mission is to improve the reliability of methane emissions detection, quantification, and reporting to enable better-informed business decisions and quantification of end-to-end emissions across the natural gas supply chain. They directly ingest and reconcile information from multiple sources in real-time, including continuous monitoring devices, aerial, satellite, and operational data directly from equipment.[14] With services provided by Context Labs, oil & gas operators can deploy capital more effectively to reduce GHG emissions and improve their operational efficiency. Although Context Labs is not yet publicly partnered with any LNG exporters, it is working with a number of leading upstream and midstream operators who are key suppliers to LNG facilities, to ensure that end-to-end full supply chain emissions are accurately measured and verified in accordance with OGMP 2.0 (Level 4/5) and Gas Technology Institute (GTI) Veritas standards, rather than estimated emissions.[15]

Some certifiers partner with blockchain carbon ledgers and digital registries. This allows for the environmental attributes of an LNG cargo to be transparently audited and communicated to buyers without fear of double counting. The goal of the LNG industry is to independently audit and certify each segment of the LNG value chain. MRV data related to each segment can be collected and then totaled through the value chain to bring a complete emissions profile to the end buyer of LNG.

While these certifiers offer different approaches for differentiated gas standards, they all represent the important principle of independent verification in the voluntary market space with the universal intent of encouraging companies to achieve higher standards of methane abatement and enabling transactions in the market.

The market for natural gas certification is continually evolving, but certain gaps are becoming evident. Differentiated gas producers' and sellers' needs and requirements are often unique; these differences are not currently addressed by these programs. For instance, there may be a need for more comprehensive certification programs that consider a broader range of environmental and social factors, or for programs that offer more flexibility in terms of the technologies and methodologies used for emissions monitoring and verification. Certifications also typically focus on natural gas production facilities and may fail to account for all emissions throughout the natural gas value chain. An end-to-end, full value chain approach is needed to provide trusted and transparent emissions data of gas delivered to LNG facilities. The best solution for filling these gaps is to adopt advanced monitoring technologies, improve data

[14] *See* ContextLabs.com.
[15] *See* Veritas.GTI.energy.

transparency, and ensure the DOE's best-practices framework for differentiated gas aligns with global standards.

Question 1.7

What role do or could differentiated natural gas certification programs play in helping to create a competitive advantage for U.S. natural gas in foreign markets as compared to other sources of natural gas? Do or could such programs facilitate long-term contracting by purchasers of U.S. natural gas?

DGCC Response

Differentiated natural gas certification programs could play a significant role in creating a competitive advantage for U.S. natural gas in foreign markets, particularly in Europe. Given Russia's invasion of Ukraine, Europe is actively seeking to reduce its dependence on Russian gas exports. The U.S., with its innovative technology and commitment to reducing GHG emissions, is well-positioned to fill this gap.

Differentiated natural gas is marketed with information about the GHG emissions resulting from its production and transport. In a world increasingly concerned about climate change, a fuel with a smaller GHG footprint should receive a competitive advantage. This is where differentiated natural gas certification programs come in.

Certifiers help provide trust, transparency, and transactability, enhancing the low-emissions credentials of U.S. natural gas suppliers across the supply chain and providing credibility regarding the environmental benefits of U.S. LNG. This is especially true in Asia as developing nations continue their coal-to-gas conversion. Differentiated natural gas allows buyers to select and target the cleanest supplies available, which generates a market mechanism that drives voluntary action of emission reductions to ensure market participation and a premium value. LNG buyers can avoid exposure to potential carbon border taxes, creating an additional value driver for differentiated gas products.

Transparency is achieved using leading and emerging methane-detecting sensors and systems and blockchain-enabled carbon ledgers.[16] Trust is enhanced when these tools provide reliable data to regulators, investors, and other stakeholders making policy and investment decisions. Transactability is promoted by providing companies and governments with validated, actionable environmental performance data, which is particularly valuable for those with net-zero commitments.

These certification programs could also facilitate long-term contracting by purchasers of U.S. natural gas. By providing a clear and reliable measure of the environmental impact of natural gas, these programs can help buyers make informed decisions and commit to long-term contracts with confidence. Furthermore, the U.S. government can

[16] *See* the DGCC's response to Question 1.1.

facilitate the certification, standardization, and interoperability of high-quality data and verification needed to gain credibility in the eyes of non-governmental organizations, policymakers, and markets.

With best-in-class methane mitigation programs in place, the next step is to effectively communicate the validity of a product's low emissions data to end users. Blockchain platforms and digital registries, such as DGCC members EarnDLT and Xpansiv, are meeting this need by providing producers and certifiers the ability to securely register, trade, retire, and report emissions reductions.[17] These new functionalities are unlocking the ability to actively trade certified natural gas in a marketplace. These third parties collect and record natural gas production data, which is then complemented with certified emissions data. The use of blockchain technology eliminates double counting, improves data integrity, and enhances traceability and auditability, increasing the competitive advantage of U.S. LNG

Differentiated natural gas certification programs could play a crucial role in helping the U.S. gain a competitive advantage in foreign natural gas markets, facilitate long-term contracting by purchasers of U.S. natural gas, and promote continued decarbonization across the globe affordably and reliably. They present a unique opportunity to advance U.S. national security, domestic economic vitality, and leadership on climate issues.

Topic 4: Additional Information

Question 4.3

> *Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?*

DGCC Response

Earlier this year, the DOE announced its intent to establish a best-practices framework for differentiated gas, especially as it pertains to LNG exports.[18] If done correctly, this framework can play a significant role in ensuring buyer confidence in operator reporting, third-party certifications, and registries, particularly in the context of the LNG market. This can help preserve the voluntary market for differentiated natural gas.

First, the DOE needs to clarify its authority to undertake this initiative. This involves defining its jurisdiction and outlining the specific actions it can take to support the differentiated natural gas market, especially as it relates to the DOE's regulation of LNG exports.

Second, the DOE should ensure that U.S. standards align with or exceed international standards, such as the European Union's Methane Regulations.[19] This is crucial for

[17] *See* EarnDLT.com and Xpansiv.com.
[18] *See* DOE's "Natural Gas Roundtable Discussion at CERAWeek in Houston, TX."
[19] *See* European Parliament's "Fit for 55: MEPs boost methane emission reductions from the energy sector."

maintaining competitiveness in the global LNG market and ensuring that U.S. natural gas can meet the stringent environmental standards set by international bodies. Aligning the DOE's differentiated natural gas framework with monitoring frameworks that are already in development, such as the EPA's proposed supplemental methane rule is a good first step.[20] For example, the Supplemental Continuous Monitoring section of the proposed rule includes a definition for continuous monitoring that will, if the rule is adopted as proposed, be approved by the EPA. This definition, and other EPA-approved methodologies, could be a standard that consumers and governments point to as an approved methodology for monitoring.

Additionally, the DOE could consider drawing on existing frameworks such as OGMP 2.0. These principles provide a robust and widely accepted standard for emissions offset projects and could serve as a useful model for the differentiated natural gas market, including the LNG sector.

Voluntary initiatives, such as OGMP 2.0 and GTI Veritas, require measurement-informed inventories to replace inaccurate generic engineering estimates. The DGCC recommends replacing generic engineering estimates to calculate emissions inventories with measurements that are technologically agnostic, enabling innovation.

Finally, the DOE's best practices regarding accreditation processes should not hinder the speed at which the differentiated gas market develops or limit the ability of producers and certifiers to exceed existing regulatory or voluntary environmental standards. As with any emerging market, differentiated gas is growing rapidly in both size and environmental benefits. Any framework developed by the DOE should not impede that growth.

The DOE can play a pivotal role in ensuring buyer confidence in the differentiated natural gas market, particularly in the LNG sector, by clarifying its authority, aligning U.S. standards with international norms, drawing on existing frameworks and initiatives, and ensuring market growth.

Thank you for considering our thoughts as the DOE considers this proposed rule.

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[20] *See* EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.

About the Differentiated Gas Coordinating Council:
Established in 2022, the DGCC is an ad hoc coalition of stakeholders across the natural gas supply chain dedicated to expanding the market for low methane, "differentiated" natural gas. Its members include academics; downstream, midstream, and upstream energy producers; gas customers; and technology companies. The DGCC's goal is to facilitate a federal pathway for state regulators, utilities, and gas consumers to accept differentiated gas as an important option to meet their climate goals. We believe that the adoption of differentiated gas is the best way to rapidly reduce methane emissions in the oil and gas sector—a win for American energy producers, energy consumers, and the climate.

More information can be found at www.DGCCouncil.com.

Respondent:

American Bureau of Shipping

Request For Information DE-FOA-0003052
U.S. Department of Energy's (DOE) Office of Fossil Energy and Carbon Management (FECM).
Opportunities to Reduce Greenhouse Gas Emissions and Other Pollutants Associated with U.S. LNG Exports Department of Energy
National Energy Technology Laboratory

American Bureau of Shipping (ABS)

The DOE's Objective

Provide information on strategies and technologies that natural gas and liquefied natural gas (LNG) companies are deploying, or could deploy, to reduce greenhouse gas emissions and other air pollutants associated with natural gas delivered to a liquefaction facility, at liquefaction facilities, and during the loading, transport, and delivery of natural gas to a regasification facility.

Overview of ABS Maritime Operations and Decarbonization Qualifications

ABS is the NGO marine classification society recognized by the U.S. Government. Established in 1862, ABS provides specialized, third-party services to a variety of government agencies related to the agencies' maritime vessels and other assets. ABS is recognized by the U.S. Coast Guard's Director of Commercial Regulations and Standards as the society that advances commercial vessel safety and environmental performance. ABS also is expressly recognized by statute [46 U.S.C. § 3316(a)] as the sole provider of classification services for vessels owned by the U.S. Government and in all matters related to classification.

ABS holds or has held sole source support contracts with the U.S. Navy through NAVSEA, the Military Sealift Command (MSC), the U.S. Coast Guard (USCG), the Maritime Administration (MARAD), the National Oceanic and Atmospheric Administration (NOAA), and the U.S. Army through the Corps of Engineers (ACE) and Army Watercraft Division. We believe DOE EERE has the opportunity to contract directly with ABS to procure a wide range of services unique to our role as the marine classification, standards, and research organization for the U.S. through the use of sole source contracting procedures under FAR 6.302-5, FAR 6.302-1, and FAR 6.302-3.

ABS is a global leader in the maritime industry for providing guidance and tools to support more sustainable shipping and offshore operations through decarbonization and the reduction of emissions and other pollution. In fact, we have established global ABS Sustainability Centers of Excellence based in Houston, Copenhagen, Athens, and Singapore to support the industry with the best available guidance and technology in alignment with goals and requirements of various organizations. These include the International Maritime Organizations (IMO), nations states, and the UN Sustainable Development Goals (SDGs) framework, which is focused on achieving environmental, social, and governance (ESG) excellence.

With regard to industry guidance, ABS publications are defining the path forward in the industry for decarbonization, including the following:

- *Setting the Course to Low Carbon Shipping* – examining how the development of global trade will impact global emissions and identifying the three main fuel pathways on the course to meeting emissions reduction targets.
- *Low Carbon Shipping: View of the Value Chain* – providing a detailed value-chain analysis of the greenhouse gas (GHG) footprint of leading alternative fuels covering the entire life cycle from "well to wake"
- A series of Sustainability Whitepapers addressing the opportunities and challenges with alternative fuels for the shipping industry, including separate publications on hydrogen, ammonia, methanol, biofuels, LNG, and other gases such as LPG as marine fuels

With regard to marine classification services, we have developed the ABS *Guide for Sustainability Notations*. This Guide specifies requirements on sustainability-related topics and offers two optional notations from ABS, **SUSTAIN-1** and **SUSTAIN-2**, which demonstrate adherence to certain Sustainable Development Goals (SDGs) related to vessel design, outfitting, and layout that can be controlled, measured, and assessed. The Guide establishes a pathway for sustainability certification and reporting.

With regard to tools and technology, we have developed and are providing industry with powerful information technology tools to support sustainable shipping. For example, The ABS Environmental Monitor is the maritime industry's most comprehensive digital sustainability solution to help shipowners achieve their sustainability goals by leveraging multiple data sources, including vessel routing, waste stream, operations, and emissions data, to provide transparent reporting and management.

In addition to our own internal research, ABS also engages in critical consortia globally addressing this topic with the maritime industry. Two of great examples are the following:

- ABS is a founding member of the *Maersk McKinney Moller Center for Zero Carbon Shipping*. ABS and its partners are committed to creating a dynamic environment of innovation and creativity by bringing together industry and academia for the benefit of a sustainable future.
- ABS is a founding member of a new non-profit alliance, the *Blue Sky Maritime Coalition*, which brings together maritime stakeholders from across North America to collectively address the challenge of climate change.

ABS is working in every way to stay at the forefront of the decarbonization initiatives for the maritime industry, and ABS is positioned uniquely to assist on this topic.

Responses to Questions

ABS is responding to topics three, questions 3.1 – 3.4, and topic four published in this RFI.

Topic 3: Strategies to Measure and Reduce Emissions during Loading, Transport, and Delivery

3.1. What technologies or strategies are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG?

Shipyards and operators of LNG carriers are considering the use of **Carbon Capture technology** for use during the operation of the vessel.

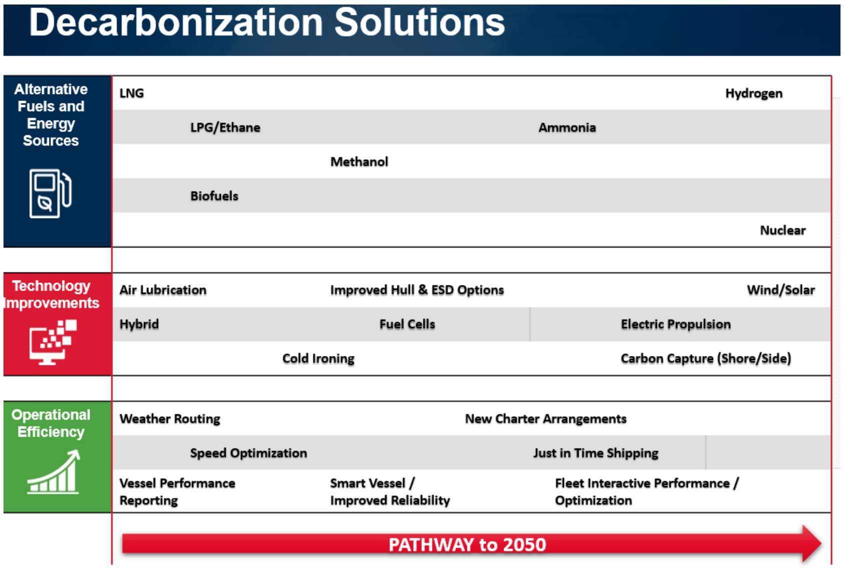
- The article in the link below addressed a Korean shipyard (DSME) installation of an onboard carbon capture system on an LNG carrier; ABS was involved in the verification of the design: https://www.offshore-energy.biz/dsme-verifies-its-onboard-carbon-capture-system-on-an-lng-carrier/

To support carbon capture, guidance and specific criteria have been developed on the topic:

- Whitepaper on Carbon Capture, Utilization and Storage https://absinfo.eagle.org/acton/media/16130/carbon-capture-whitepaper

- ABS Requirements for onboard Carbon Capture and Storage https://ww2.eagle.org/content/dam/eagle/rules-and-guides/current/other/333_req_onboard_carbon_capture_2022/carbon_capture_reqts_e-dec22.pdf

The following decarbonization solution technologies or strategies all, in part, are being deployed to reduce greenhouse gas emissions during the loading, transport, and delivery of LNG.



3.2. What approaches do LNG operators use to capture boil off gas (BOG) and limit loss of natural gas when storing, loading, transporting, and unloading LNG?

Per IGC Code Chapter 7.1.1:

With the exception of tanks designed to withstand the full gauge vapor pressure of the cargo under conditions of the upper ambient design temperatures, cargo tank's pressure and temperature shall be maintained at all times within their design range by either one, or a combination of, the following methods:

1.1.1 reliquefaction of cargo vapors;

1.1.2 thermal oxidation of vapors;

1.1.3 pressure accumulation; and

3.3.4 liquid cargo cooling.

3.3. What approaches do LNG operators use to minimize greenhouse emissions during tanker transport of LNG?

- See notes above regarding Carbon Capture, and above answer to 3.1 above.

For the Methane Mitigation Technologies program will be methane emissions (fugitive and otherwise), considering the GHG potential there and their remit. Some of this is covered by the code; ships tend to be designed to avoid CH4 leaks for safety reasons as well as environmental, but it seems environmental is their focus. Typical mitigations for CH4 release are the use of welded pipes and minimization of flanged connections, but equipment such as compressors, companders, relief valves, instrumentation access and other parts of the cargo containment and handling systems will all have leakage rates which while many are small, will be part of the accounting that will need to be carried out for these purposes.

With regard to the vessels themselves, there will be a GHG balance among how much boiloff is generated, how much is burned as fuel and how much needs to be reliquefied. The main use of boiloff (and hence P-T control) is normally propulsion fuel, so matching the engine efficiency to the boiloff rates for the normal speeds required is important and designers know this. Engine manufacturers have been increasing the efficiency of gas burning (dual fuel engines) incrementally and this has allowed containment system manufacturers to make attempts at improving the boiloff rates of their systems (to little boiloff and you have to force vaporization anyway). So we have seen a reduction from 0.15%V per day at the turn of the century to 0.08%V boiloff per day today, and new systems are being developed. This increase in efficiency/reduction in boiloff is likely a net gain for both fugitive CH_4 emissions (less handling) and CO_2 emissions (less fuel burned).

New containment systems are under development that could be better, but if your engines are not efficient enough, you would still need to force boiloff so the limiting factor for reducing boiloff tends to be engine efficiency. There are a handful of ships that burn conventional fuel and focus entirely on reliquefication to handle boiloff, and for such ships reduced boiloff can be the single guiding factor, but these ships have other problems with regard to emissions (i.e. they are diesels running on HFO). Use of HFO is not a trend in the industry today. SIGTTO (https://www.sigtto.org/publications/) have done recent work on fugitive methane emissions as well.

Also to note, engine efficiency is not the only means of reducing fuel consumption. Propulsive efficiency is another means and we have seen LNG carrier owners proceeding with technologies such as air lubrication, coating improvements and other technologies to do this, however again the containment efficiency needs to keep up with the fuel efficiency, or you just wind up incinerating the gas (CO_2) or reliquefying the excess boiloff (whatever emissions are associated with the energy of your reliq plant).

3.4. For contractual agreements that include the transport of LNG, what measures, if any, are taken to assure natural gas is not lost and greenhouse emissions are minimized during shipping?

Per IGC Code Chapter 7.1.1:

With the exception of tanks designed to withstand the full gauge vapor pressure of the cargo under conditions of the upper ambient design temperatures, cargo tank’s pressure and temperature shall be maintained at all times within their design range by either one, or a combination of, the following methods:

1.1.1 reliquefaction of cargo vapors;

1.1.2 thermal oxidation of vapors;

1.1.3 pressure accumulation; and

1.1.4 liquid cargo cooling.

Topic 4: Additional Information

4.1 What non-US requirements for greenhouse gas performance are LNG exporters being asked to respond to with emissions data? Are emission reduction requirements included in any contracts or other importing country requirements?

MARPOL Annex VI is arguably the most significant applicable international marine requirements which is implemented by LNG Carriers exporting US LNG. Others to consider:

- Poseidon Principles
- Sea Cargo Charter
- EU ETS & FuelEU

4.2 What changes or technology advances does industry think are needed to decarbonize the LNG supply chain from production through delivery? What are the economic benefits or challenges associated with the measures to decarbonize the LNG supply chain? Is there data or information available on the costs or savings associated with implementing these measures?

Increased qualification of new technology which emerges in the market. (ABS can provide this verification).

4.3 Is there any other information that would be relevant and necessary to assess emission reduction opportunities associated with LNG export?

- The transportation of carbon as a commodity is a developing market. Initial investigation is being completed on dual purpose vessels: used to transport LNG on an outbound voyage, used to transport CO2 on a return/other voyage.

- Starting in 2023 MARPOL ANNEX VI, EEXI/CII reporting schemes.