HAWAIʻI STATE ENERGY OFFICE

Lifecycle Greenhouse Gas Emissions – Technical Documentation

Alternative Fuel, Repowering, and Energy Transition Study

Contents

Background

The State of Hawaiʻi is one of only seven states to set a statutory target to fully decarbonize, and one of only two to commit to it by 2045. Achieving economy-wide carbon reductions will require ambitious GHG reductions in the electric sector.

In 2023, the Hawaiʻi Supreme Court ruled on the critical importance of lifecycle emission accounting in its decision regarding the *Application of Hawaiʻi Electric Light Company For Approval of a Power Purchase Agreement for Renewable Dispatchable Firm Energy and Capacity.*[1] In its decision, the court affirmed the Public Utilities Commission's (PUC's) authority to carry out its public interest mission by addressing the court's remand instructions to consider the reasonableness of the proposed project in light of its greenhouse gas emissions and project costs.[2] At the core of this decision was a biomass project's lifecycle analysis presented to the PUC, which showed that the project's associated lifecycle emissions were substantial and could not be appropriately mitigated through the prescribed offsets.[3]

The State Legislature further upheld the precedent set forth by the Hawaiʻi Supreme Court and added additional language to Hawaiʻi Revised Statutes (HRS) to ensure lifecycle accounting is incorporated into PUC decision-making by passing Act 54, Session Laws of Hawaii 2024. Act 54 set forth an explicit requirement to analyze lifecycle emissions for combustion projects.[4] HRS §269-1, as amended, defines lifecycle greenhouse gas emissions assessment as "*the evaluation of potential greenhouse gas emissions over the course of a product, program, or project's lifetime or stages of production, construction, operations, and decommissioning, which includes but is not limited to, as applicable, upstream stages such as extraction and processing of materials, and transportation; operations stages such as the use of any fuels or feedstocks and the production of any materials; and downstream stages such as transportation, decommissioning, recycling, and the final disposal*." This discussion focuses on the extraction and production of fuels as well as the operations of power plants; construction activities and decommissioning were not included in this analysis.

As of 2023, 65% of Hawaiʻi's grids are powered with low-sulfur fuel oil (LSFO) or diesel, making Hawaiʻi the last state in the country to provide the bulk of its electricity in this manner. On Oʻahu, just 33% of the total generation on the island was from renewables—the remaining 67% is powered by *bottom-of-the-barrel* LSFO, a type of residual fuel oil (RFO). On outer islands, the fossil fuel used is diesel, categorized as distillate fuel oil (DFO).[5] The term, *bottom-of-the-barrel* is

[1] Supreme Court of Hawaiʻi. (2023). *In re: the Application of Hawaiʻi Electric Light Company, Inc. for approval of a power purchase agreement for renewable dispatchable firm energy and capacity* (SCOT-22-0000418). Decided March 13, 2023.
[2] *Id*.
[3] Before the Public Utilities Commission in the Matter of the Application of Hawaiʻi Electric Light Company Inc. Docket No. 2017-0122. For Approval of a Power Purchase Agreement for Renewable Dispatchable Firm Energy and Capacity. Decision and Order No. 38395
[4] Act 54, Session Laws of Hawaiʻi 2024, Relating to Renewable Energy.
[5] Data Compiled by the Hawai'i State Energy Office, Source PUC Docket 2007-0008, Hawai'i Renewable Portfolio Standard Status Reports

used to describe these fuels because RFO is the heavier, leftover residue of crude oil after lighter hydrocarbons and distillates are removed during the refining process, these lighter distillates are most used in ground transportation and aviation. Outer islands primarily use diesel, a heavier distillate oil.

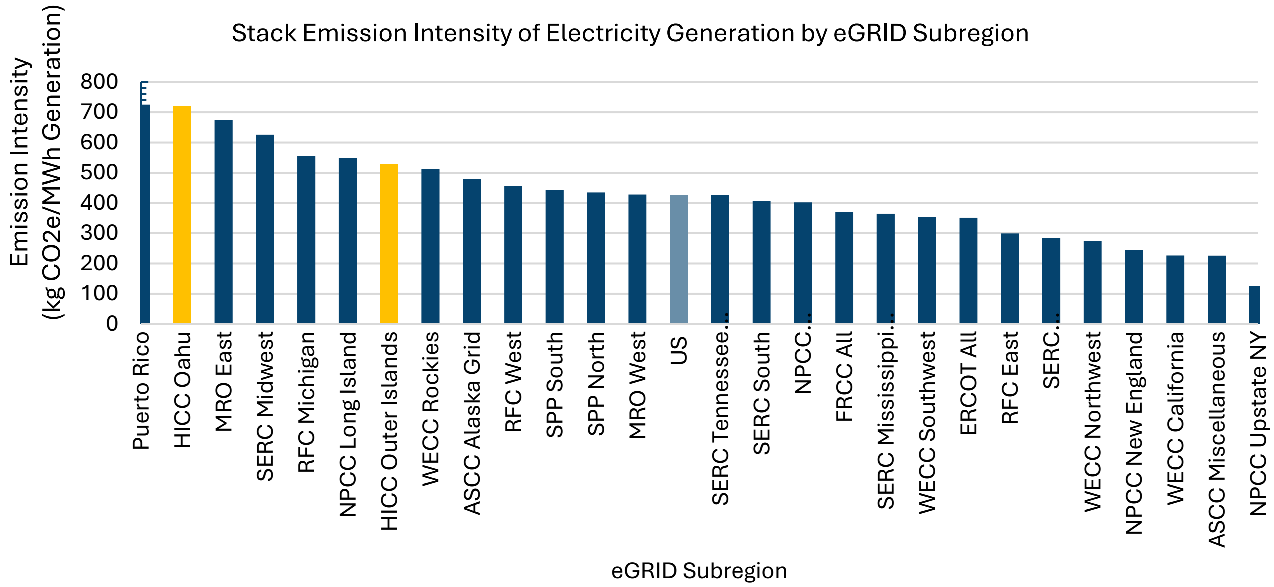


Figure 1 Stack emission intensities for US eGRID Subregions. Source EPA eGRID 2022 Data.

The consequences of burning LSFO for the majority of Hawai'i's generation has resulted in the island of O'ahu having the highest emission intensity in the country, or the highest carbon emissions, per unit of electricity produced when compared to other electric grid subregions (Figure 1), with only Puerto Rico having a higher emission intensity, also known as carbon intensity (CI). While these statistics represent emissions at the stack, or emissions released during combustion; when accounting for the full lifecycle emissions for electrical generation from "well-to-outlet" oil-fired generation comparatively has the highest carbon emissions intensity, on average, compared to other cost-competitive conventional options, with only coal exceeding oil emissions on a lifecycle accounting basis.[6]

[6] National Renewable Energy Laboratory (2021), *Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update.* Office of Energy Efficiency and Renewable Energy Operated by the Alliance for Sustainable Energy, LLC https://www.nrel.gov/docs/fy21osti/80580.pdf

* Top-down approaches derive emissions estimates from direct measurements such as those obtained from remote sensing (satellite or flyover) and imaging spectroscopy. Bottom-up estimation approaches derive emission estimates from known emission factors and system component leakage estimates. This analysis uses a hybrid approach.

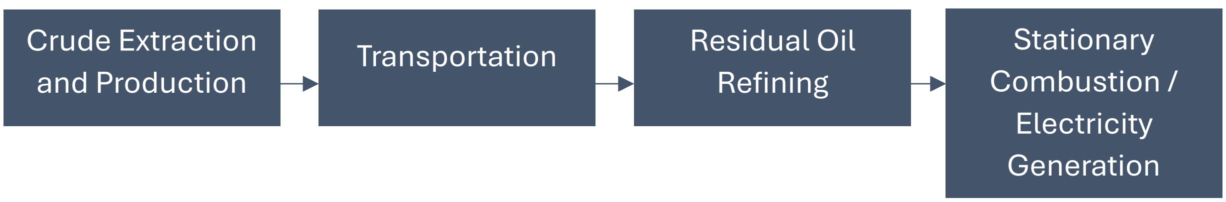
Applicability for the Various Fuel Types Evaluated in the Alternative Fuels Study

For this study, all alternative fuel options were considered, and emissions were compared on a lifecycle carbon intensity (CI) basis.[7] The fuel lifecycle varies by fuel type. Emissions estimates can also differ based on assumptions, methodology—e.g. top-down or bottom-up approaches*, emission factors assumed, system boundaries, and applied global warming potentials (GWP).[8] For this reason, this analysis and comparative literature review strived to use various data sources and emission factors.

Lifecycle Stages by Fuel Type

The key lifecycle stages for differing fuel types are unique. Stages of differing fuel types are summarized below.

Lifecycle of Oil for Electricity Generation



1. **Extraction and production (Upstream)**

Emissions from extraction and production occur during the different processes required to extract oil from source wells. These emissions may result from gas flaring and venting practices (which can vary widely depending on the source country or basin) and from fugitive methane leakage, which occurs in both natural gas and oil extraction.

In addition, greenhouse gases are emitted from the energy used to operate drilling rigs, pumps, and other processing equipment, also accounted for at this stage.

2. **Crude and Final Product Transport (Transportation)**

Emissions at this stage are from the transport of crude oil products to where they will be refined, typically via ship or pipeline. In Hawai‘i's case, crude oil is transported via ship most frequently from Northern and Western Africa as well as South America. These distances were incorporated into the weighted GHG analysis presented.

[7] Carbon intensity (CI) refers to the amount of carbon dioxide equivalent (CO_2e) emissions produced per unit of output or activity. In this analysis, CI units are CO2e per MMBtu.

[8] Global Warming Potential (GWP) is a measure of the relative radiative effect of a greenhouse gas compared to carbon dioxide over a chosen time horizon. GWPs used herein are from the IPCC Sixth Assessment Report (AR6). See Section A-4.

Emissions from the transport of fuel, mostly through pipelines, after refining takes place are also incorporated into this stage.

3. Refining (Midstream)

Emissions from refining are typically released from stationary fuel combustion units but may also be released from cracking and coking units, blowdown systems, storage tanks, and general equipment leaks.

Note, the refining of some fuels may occur before transport to Hawai‘i. If refined out of state, refining emissions are still incorporated into the lifecycle estimates. Since Par Hawai‘i is the current supplier of most of Hawaiian Electric’s fuels, the refining stage is placed after crude transport in this analysis.

4. Stationary Combustion / Electricity production (Downstream)

Emissions from stationary combustion are produced at power plants during the combustion of fuel to generate electricity. These emissions can be categorized as input emissions and output emissions. Input emission intensities are determined by dividing total emissions by the total heat input from combustion. Output emission intensities, on the other hand, are calculated as the total emissions released per unit of electricity generated. For this stage, output emission intensities should be utilized to accurately reflect electricity generation, with the energy conversion efficiency of the plant considered throughout the entire lifecycle to account for heat loss.

See *Hawai‘i Power Plant Combustion Input and Output Emissions and Calculated Conversion Efficiencies* for the input and output emissions rates of existing power plants in Hawai‘i as well as the calculated energy conversion efficiencies. Energy conversion efficiencies, also known as heat rates (more commonly presented in units of btu/kWh), are calculated using the following equation:

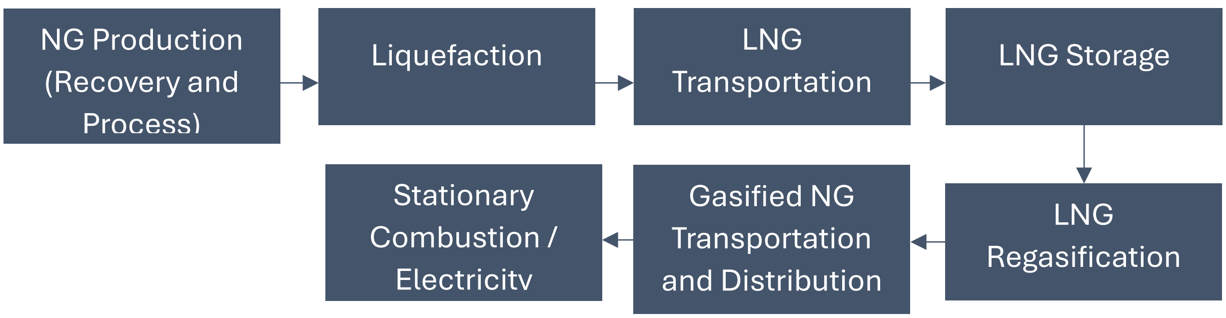
$$\frac{\left(\frac{kgCO2e}{mmbtu\ electricity\ generated}\right)}{\left(\frac{kgCO2e}{mmbtu\ fuel\ combusted}\right)} = energy\ conversion\ efficiency\ \left(\frac{mmbtu\ fuel\ combusted}{mmbtu\ electricity\ generated}\right)$$

The powerplant efficiency ultimately determines how much energy is consumed in the combustion process per unit of energy generated. When deriving carbon intensities, the energy conversion efficiency of the power plant is applied to all points in the lifecycle, because the power plant efficiency ultimately dictates the amount of fuel required to generate electricity. While the heat rates fluctuate based on a variety of factors including load variations and plant cycling, fuel quality, and plant age, it is important to include some metric of heat loss across all lifecycle stages because power plants convert only a portion of the energy in the fuel into electricity, with the rest lost as heat.

The efficiency multiplier captures this conversion loss. This is a standard practice in the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model.

Lifecycle of Liquefied Natural Gas for Electricity Generation

There are many parallels between the lifecycle of natural gas and the lifecycle of oil and liquid petroleum fuels. Often, natural gas is extracted at the same location as oil, with many production wells producing both.[9] There are more steps in the natural gas fuel lifecycle than in oil systems due, in part, to the liquefaction and regasification needs, only applicable to locations that require import. Because methane (CH_4) is a gas at normal temperatures and pressures, it must be cooled and stored at high pressures to be transported long distances efficiently without occupying substantial space. These additional lifecycle stages add risk for additional operational and fugitive releases and should be carefully accounted for in the lifecycle analysis.



1. Production – Recovery/Extraction and Processing

Emissions from the extraction of natural gas are very similar to that of crude oil and result from fugitive methane leakage and gas flaring and venting practices, which can vary widely depending on the source country as well as the geological hydrocarbon basin (e.g. the Permian Basin vs. the Marcellus Basin), where the gas is extracted.

In addition, emissions arise in this stage from the energy used to operate drilling rigs, pumps, and other processing equipment. Additionally, natural gas undergoes processing to separate natural gas liquids and remove impurities such as carbon dioxide, hydrogen sulfide, or sulfur dioxide.

2. Liquefaction

Most of the emissions are carbon dioxide from either fuel combustion for refrigeration compressors or generator turbines. Carbon dioxide emissions occur during flare combustion which is used to destroy high global warming potential waste gases, mostly methane, which may need to be released for maintenance or for a short duration during emergencies. Methane (CH_4)

[9] https://www.eia.gov/petroleum/wells/

emissions from incomplete flaring and leaks may also occur; however, these emissions are much smaller in amount when compared to the production/extraction stage.[10]

3. LNG Transportation and Distribution

Emissions from the LNG transportation and distribution stage occur during the transportation of the LNG. For Hawai‘i, transport emissions include fuel used for shipping, as well as energy used for LNG handling (primarily cooling). Emissions from transport may include methane fugitives (unintentional leaks, typically from seals or equipment connections) and venting emissions (intentional emissions via dedicated outlets to the atmosphere, primarily for safety) from the onboard LNG and vapor handling plant.[11] The LNG tanker type impacts the emission rates.

4. LNG Storage

Emissions from LNG storage primarily arise from boil-off and leaks.

Boil-off refers to the small amount of liquefied natural gas (LNG) that naturally evaporates during storage, loading, transport, and unloading due to heat ingress. LNG is stored at cryogenic temperatures in insulated tanks, but some heat transfer is inevitable, causing vaporization and necessitating pressure management. Strategies to mitigate evaporation during LNG storage and transportation include utilizing the evaporated gas efficiently, heat ingress may be reduced with more advanced tank design.

Leaks are unintended releases of LNG or vapor, sources of leaks include compromised tank, valve, or seal integrity and leaks during transfer operations. Regular inspections, maintenance, adherence to safety guidelines, and installation of vapor recovery systems can reduce leaks and fugitive emissions from LNG storage.

5. LNG Regasification

The main sources of methane emissions from LNG export/import terminals include fugitive leaks from equipment, incomplete combustion of fuel from power-generating equipment, and incomplete combustion from flare and boil-off systems. Carbon dioxide emissions arise from flaring systems as well as general energy use.

6. Stationary Combustion for Electricity Generation

After regasification, natural gas is combusted in stationary sources such as gas turbines or boilers to produce electricity or heat. Emissions from this stage are the result of burning or combusting the fuel to generate electricity in stationary sources such as gas turbines or boilers to produce electricity or heat. The combustion process primarily releases CO_2, but emissions can contain small amounts of CH_4 and N_2O. Ultimately, the efficiency of the combustion technology (i.e.

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[10] Zheng et al., 2023. Measuring carbon dioxide emissions from liquefied natural gas (LNG) terminals with Imagin spectroscopy https://agupubs.onlinelibrary.wiley.com/doi/pdf/10.1029/2023GL105755

[11] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC9261184/

powerplant heat rate) and the combustion conditions determine the quantity and chemical makeup of emissions.

The **energy conversion efficiency of the power plant is considered at all points in the lifecycle.** This is because power plant efficiency ultimately dictates the amount of fuel required to generate electricity, which is critical if an intensity value is derived.

Efficiency for typical natural gas power plants ranges from 43% to as high as 58%, for combined cycle power plants. The energy conversion efficiency is essentially the inverse of a plant's heat rate. Choosing an average 51% efficiency conversion factor equates to a multiplier of 1.9 MMBtu of fuel per 1 MMBtu of electricity produced.[12] This multiplier must be applied to all points in the lifecycle to account for energy loss. However, 58% efficiency may not be attainable if there is frequent plant cycling.

For the natural gas and oil comparison, this efficiency factor is a large driver of emissions reduction, as shown in the *Comparative Analysis Section*.

Accounting Methods and Challenges in Oil and Natural Gas

Estimating emissions from the oil and gas industry is done using two primary methods: top-down and bottom-up. Top-down calculations are typically derived from site or field measurements, which may include emissions recorded during flyovers, measuring stations, drive-by detection, or satellites. Bottom-up emission estimates are derived from equipment specifications and component-specific leak factors.[13]

Recent studies have demonstrated that national emission inventories, which use bottom-up accounting, underestimate methane emissions compared to top-down measurements.[14] However, new bottom-up methods are being developed to better incorporate top-down measurement-informed data.[15]

Given the variability of emission estimates across differing methods, HSEO developed a scenario approach to evaluate emission estimates from different sources, inclusive of bottom-up and, at the stages available, top-down estimates. A hybrid approach was used when certain stages in the supply chain were not part of a published dataset. For example, Rocky Mountain Institute's (RMI) Oil Climate Index plus Gas (OCI+) model, a hybrid top-down and bottom-up emissions dataset, did not include emission estimates from liquefaction, therefore RMI estimates were used for upstream estimates and added the ANL (Argonne National Laboratory) GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) tool for midstream and downstream estimates.

12 GREET, 2023.
13 Oil Climate Index plus Gas (rmi.org)
14 Zhu, Y., Allen, D., & Ravikumar, A. (2024). Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains. DOI: 10.26434/chemrxiv-2024-9v8dw
15 Oil Climate Index plus Gas (rmi.org)

For the LNG supply chain in particular, the main determinants of methane emissions are facility design, age, and operational and management procedures. Facilities designed with an emphasis on emissions can achieve very low emissions during normal operations and can strive to reduce emissions during maintenance. These facility designs, practices, and procedures are often impacted by the environmental regulations in place for source countries, thus resulting in geographic differences in upstream emissions. The underlying geology and shale composition can also impact emissions estimates, resulting in basin-specific and geographic differences.[16]

Further discussion on the analysis conducted is presented in the *Comparative Analysis*.

Lifecycle of Biofuels for Electricity Production

Lifecycle analysis for biofuels can generally be broken into the following stages: 1) feedstock production and collection, which includes emissions from land use change, farming inputs, and energy inputs; 2) farm-input manufacturing; 3) the production of the fuel itself (i.e. feedstock processing and refining); and 4) the combustion of the fuel and, as applicable, electricity production.

Empirical limitations are significant for bioenergy and are discussed by lifecycle stage below.

1. Land Use Change and Soil Carbon Flux

Land use change (LUC) is defined as the shift in land use and land cover that accompanies feedstock or fuel crop production. Emissions estimates from various biofuel lifecycle analysis documentation stem from both economic modeling of market-mediated effects as well as biophysical modeling of soil carbon and other biological systems and processes.[17] The LUC stage in lifecycle analysis incorporates estimates of emissions from activities such as cultivating new land for feedstocks including deforestation (applicable for fuels such as palm oil, and indirectly applicable for tallow feedstocks), soil carbon flux from soil disturbances, and other elements such as temporality; however, these stages are highly variable and region- or farm-specific, thus can be challenging to summarize in “average”, or general terms.

LUC often results in nonlinear feedback effects, which are challenging to account for empirically. When ecosystems change—such as deforestation, reforestation, or shifts to agricultural use—these alterations can trigger complex interactions among carbon, water, and nutrient cycles within both the aboveground biomass and within the soil. Such nonlinear responses are influenced by a variety of factors, including soil health, biodiversity, and climate, and their impact on GHG emissions may not be immediately observable. Variability arises from a multitude of interacting factors that influence the carbon absorption and storage capacities of ecosystems.

[16] Zhu, Y., Allen, D., & Ravikumar, A. (2024). Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains.

[17] Wang, M., Elgowainy, A., Lee, D., & Bafana, A. (2021). *Cradle-to-Grave Lifecycle Analysis of U.S. Light Duty Vehicle-Fuel Pathways: A Greenhouse Gas Emissions and Economic Assessment of Current and Future Technologies* (No. ANL/ESD-21/30). Argonne National Laboratory. https://publications.anl.gov/anlpubs/2021/10/171711.pdf

For example, water availability, which can be affected by local climate and seasonal drought conditions, directly impacts plant growth rates and, consequently, the carbon sequestration potential of a given area. Similarly, temperature fluctuations can either stimulate or suppress plant growth, depending on the species and ecosystem, thereby affecting carbon dynamics. Soil conditions, including soil organic matter, nutrient availability, and structure, also play a critical role in supporting plant growth and carbon retention. Soils with high organic content and rich nutrient levels can enhance plant productivity and carbon sequestration. Conversely, degraded soils may inhibit these processes, limiting the ecosystem's ability to offset GHG emissions.

Carbon accounting for biogenic, or biologically derived energy sources, is particularly challenging because it must consider the timing of both carbon release and sequestration in biological systems, also known as temporality. Like fossil fuels, which release carbon immediately at each stage of their lifecycle, biogenic emissions from biofuels are also released immediately during combustion but are not necessarily accounted for in the same way because the carbon balance of biogenic emissions is often evaluated differently. This is due to assumptions about carbon neutrality, which considers the potential for biogenic carbon to be reabsorbed by the ecosystem through natural processes like photosynthesis, thereby offsetting the emissions over time. However, the overall *neutrality* of biofuels depends on the payback period, which is influenced by the variable processes of plant growth and decomposition. These processes occur over months, years, or even decades, creating a time lag between carbon uptake during plant growth and carbon release upon biomass combustion, conversion, or decay. This temporal aspect introduces significant challenges for accurate accounting, as the carbon balance for biogenic energy sources is dynamic and fluctuates based on factors like seasonal growth rates, harvest cycles, and land management practices. This feedback adds layers of complexity to carbon accounting model which must be considered both in this lifecycle stage, as well as in the final combustion stage.

To improve the accuracy of emissions estimation for biofuels, the Argonne National Laboratory's GREET model incorporates the Carbon Calculator for Land Use and Land Management Change from Biofuels Production (CCLUB). CCLUB attempts to estimate emissions from land use changes (LUC) related to biofuel production, factoring in land management practices and temporal aspects. Specifically, CCLUB aims to provide a better approximation of carbon fluxes by incorporating delayed sequestration and emissions tied to land use. Within the Renewable Fuel Standard (RFS) program, CCLUB is utilized to help address these temporal accounting complexities in the LUC stage, thereby enhancing the accuracy of lifecycle GHG assessments for biofuels.

A notable critique of the RFS program is its inability to fully capture the timeframe required to offset emissions initially released by biofuels.[18] When biofuels are produced and burned, the

[18] Lark, T. J., Hendricks, N. P., Smith, A., Gibbs, H. K., & Marshall, E. (2022). Environmental outcomes of the US Renewable Fuel Standard. *Proceedings of the National Academy of Sciences, 119*(9), e2101084119. https://doi.org/10.1073/pnas.2101084119

immediate release of carbon dioxide (CO_2) may not be effectively balanced by carbon sequestration through new plant growth or reforestation within a relevant policy timeframe. Consequently, there is a time gap before the displaced fossil fuel emissions, intended as an environmental benefit of biofuels, are counterbalanced by the carbon uptake of regrowing biomass. This time lag has raised concerns among researchers and policymakers who argue that without accounting for these temporal dynamics in carbon sequestration, biofuel emissions reductions may be overstated in the short term.

Further, LUC emissions exhibit significant variability across regions and feedstocks, making it difficult to establish a one-size-fits-all approach to carbon accounting in the global fuel market.

2. Feedstock Production and Collection

This stage includes growing, harvesting, or collecting the raw materials needed for renewable fuel production. Emissions associated with feedstock production can be further broken down into a) agricultural inputs and b) agricultural energy inputs.

a. Agricultural Inputs

This stage includes emissions associated with key inputs for crop or feedstock production. Dominant emitting inputs include fertilizers, pesticides, and herbicides, but emissions from water extraction processes used for irrigation may also play a significant role. The definition of system boundaries at this step is critical. For example, if a lifecycle analysis (LCA) includes only emissions from fertilizer application (e.g., N2O, Nox, and SOx) and excludes emissions from fertilizer production (CO2, CH4, N2O), this may lead to underestimating total upstream emissions.

Thus, a major question is: how far upstream in the supply chain should emissions be accounted for?

For feedstocks derived from animal byproducts (e.g., beef tallow), the question arises of whether and how to account for indirect emissions associated with the primary production of the animal product. Should the emissions from raising livestock, including methane from enteric fermentation and manure management, be allocated to the feedstock? Such decisions are pivotal in determining the overall CI of renewable fuel.

b. Agricultural energy inputs

Agricultural energy inputs include emissions associated with the energy required for field operations (e.g., planting, harvesting, and tilling), transportation of raw materials, and the use of machinery and equipment. This category also encompasses energy used for post-harvest processes, such as drying or initial processing of feedstocks, which may vary significantly depending on the type of crop or byproduct. The energy source for these operations also influences the carbon intensity of agricultural energy inputs.

For the land use change and soil carbon flux emissions estimates, each of these factors results in a highly localized nature of LUC and feedstock production emissions, underscoring the importance of understanding the specific climate and ecological context of the feedstock source for accurate carbon flux accounting. However, in the global fuel market, such granular accounting is arguably impractical. This challenge is especially relevant in Hawaiʻi, where local feedstock production faces constraints due to limited land availability and the prohibitive costs of shipping domestic products imposed by the Jones Act.

3. Feedstock & Co Product Transport

Emissions in this stage are from transporting feedstocks and other inputs to the sites where they will be processed. For example, if renewable fuels are refined in Hawaiʻi utilizing imported feedstocks (e.g. imported tallow), the emissions from shipping the input feedstocks to Hawaiʻi refineries would be accounted for in this stage. Emissions from shipping are highly impacted by ship/barge fuel efficiency. For imported as well as locally produced feedstock, this stage would also account for any trucking emissions associated with moving feedstock to refineries (e.g. transporting used oil from various restaurants in heavy-duty vehicles).

4. Fuel Production

Per the EPA's RFS program and the GREET model, the fuel production stage includes "GHG emissions associated with a specific type of fuel production technology, including all the energy and material inputs used in the fuel production process and the impacts of any co-products. This includes energy and material input used for handling, processing, and storing the feedstocks, co-products, intermediate products, and resulting fuel. The GHG emissions are calculated using emissions factors for all the process energy (e.g., natural gas, coal) and electricity used for fuel production operations. These factors include the upstream emissions associated with extraction, transport, and distribution of the energy, and are generally determined on an average basis (e.g., grid average electricity in the United States). The upstream emissions associated with significant material inputs used to produce the renewable fuel, such as methanol for biodiesel production, are also included."[19]

5. Fuel Distribution

Emissions in this stage are from transporting refined fuel from the source location. For example, if fuels are imported as refined products to Hawaiʻi, emissions from shipping would be accounted for in this stage. Distribution of fuels is typically more significant in the transportation sector due to the need to transport/truck refined fuels to fueling locations. For electricity generation, most on-island distribution of refined products would likely occur via pipeline, reducing emissions from trucking.

[19] https://www.epa.gov/renewable-fuel-standard-program/lifecycle-analysis-greenhouse-gas-emissions-under-renewable-fuel

6. Stationary Combustion for Electricity Generation

Emissions in this stage are the same as those described in the oil and natural gas final stationary combustion stage. However, because emissions are considered "biogenic" many accounting standards consider these emissions to be carbon neutral because, in theory, the carbon had once been captured from the atmosphere through photosynthesis. However, as discussed in Chapter 5 of the Hawaiʻi Pathways to Decarbonization Report, scientific consensus generally recognizes this assumption as flawed.[20]

The final use stage of the GHG analysis must be customized to account for the energy conversion efficiencies unique to each power plant(s) burning the biofuel, and the electricity conversion efficiency must be applied to all upstream stages when calculating intensity.

Challenges with Lifecycle Accounting for Biofuels

Land use change involves emissions from activities such as deforestation, reforestation, or soil disturbances that are influenced by site-specific factors like biodiversity, soil composition, and climate. These elements often interact in nonlinear and regionally distinct ways, making it challenging to generalize emissions estimates. The temporal lag between ecosystem alterations and observable effects on greenhouse gas (GHG) fluxes further complicates accurate accounting.

Further, the production and collection of feedstocks involve numerous inputs like fertilizers, pesticides, and water, as well as the energy needed for field operations. Defining system boundaries is critical; for example, whether emissions from fertilizer manufacturing should be included affects lifecycle estimates, and is a critical item to measure, but the inputs to account for these emissions estimates are not always disclosed. Additionally, indirect emissions for animal-based feedstocks, such as those arising from livestock production, highlight the complexity of allocating responsibility in upstream processes.

Given these challenges, developing a holistic and adaptable framework for regulatory decisions in Hawaiʻi is important, but will require adequate regulatory resources. Given Hawaiʻi's reliance on international sources for fuel and feedstock imports, accountability for upstream emissions is complex given the diverse environmental policies, economic drivers, and agricultural practices in different countries. Developing a comprehensive, adaptable regulatory framework is essential to address these complexities. This framework should account for regional variations in LUC emissions, consider the temporality of the feedstock, emphasize supply chain transparency, and include international monitoring and verification mechanisms, as appropriate.

Local sourcing dramatically reduces uncertainties tied to international land use changes and their variable impacts. Monitoring local soil carbon flux, biodiversity, and ecosystem shifts becomes more feasible, allowing for region-specific data collection that improves the accuracy of

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[20] Liu, W., Zhang, Z., Xie, X., Yu, Z., Von Gadow, K., Xu, J., ... & Yang, Y. (2017). Analysis of the global warming potential of biogenic CO2 emission in life cycle assessments. *Scientific Reports*, *7*(1), 39857. Doi: 10.1038/srep39857

emissions estimates. Local context also helps address temporal and nonlinear feedback; however, regulatory and land management agencies will need to enforce land management practices to mitigate emissions from soil disturbances, fertilizer application, and land conversions.

Comparative Analysis

The various data sources for this comparative analysis used to determine the lifecycle emissions of fuels are listed and cited below. A full copy of the weighted analysis is available for download at: https://energy.hawaii.gov/alternative-fuels-repowering-and-energy-transition-study/

- Argonne National Laboratory. (2023). *GREET model: The greenhouse gases, regulated emissions, and energy use in technologies model*. Argonne National Laboratory. https://greet.anl.gov/; DOI: 10.11578/GREET-Excel-2023/dc.20230907.1

  General/default and customizable spreadsheets were used to conduct the analysis. The R&D GREET spreadsheet served as the primary harmonization tool for incorporating emission intensities at different lifecycle stages from other sources.

- RMI/OCI+ (2024) https://ociplus.rmi.org/

  The RMI/OCI+ dataset includes a hybrid approach to emission accounting incorporating both top-down emissions estimates and bottom-up emissions estimates.

- National Ocean Industries Association (NOIA). (2020). *GHG emission intensity of crude oil and condensate production*. https://www.noia.org/noia-report-ghg-emission-intensity-of-crude-oil-and-condensate-production/

- U.S. Environmental Protection Agency. (2023). Inventory of U.S. greenhouse gas emissions and sinks. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

To allow for comparative analysis, the functional unit for carbon intensity, or greenhouse gas emissions intensity, is kg CO_2e / mmBtu. For all analyses, 20-year and 100-year global warming potentials (GWP) were applied. GWPs from the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) were used.[21]

Current Generation Mix

Hawaiʻi's current generation mix consists of 65% fossil generation – with fossil fuels comprised of *bottom-of-the-barrel* LSFO primarily on Oʻahu (making up 67% of generation) and diesel primarily

[21] Intergovernmental Panel on Climate Change (IPCC). (2021). *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (V. Masson-Delmotte et al., Eds.). Cambridge University Press. https://doi.org/10.1017/9781009157896

serving units on the Maui, Hawaiʻi Island, Kaua'i, Molokaʻi, and Lānaʻi. For this analysis, fossil fuel generation was the focus of comparison.

Natural Gas v. Oil

Natural gas upstream—recovery and extraction—emissions vary dramatically by source country. The first part of the analysis involved an evaluation of likely source countries for natural gas, see *C-3: Oil-LNG Comparative Breakdowns for Selected Locations Using the RMI/OCI+ Index*. HSEO identified likely source countries for LNG were British Columbia, Canada, and Australia. The next step was to use a scenario approach to estimate lifecycle emissions using various data sources. Scenarios are defined below.

Fuel	Scenario	Description
Oil	ANL GREET Default	CIs are directly from GREET default, with HICC as local grid generation mix.
	RMI/OCI+	All CIs are directly from RMI/OCI+.
	RMI/OCI+ and GREET Hybrid	Upstream CIs are from the RMI/OCI+ database (2022), while CIs of crude transport, refinery, and combustion are from ANL GREET Default.
	NOIA Report and GREET Hybrid	Upstream CIs are from the NOIA report, while CIs of crude transport, refinery, and combustion are from ANL GREET Default.
LNG	ANL GREET Default	CIs are directly from GREET default.
	RMI/OCI+ (AUS) and GREET Hybrid	Upstream and midstream CIs are from RMI/OCI+ estimates from Australia and all the other stages are from ANL GREET Default.
	RMI/OCI+ (CAN - Montney BC) and GREET Hybrid	Upstream and midstream CIs are from RMI/OCI+ estimates from British Columbia, Canada, and all the other stages are from ANL GREET Default.
	EPA Report and Customized GREET	ANL GREET inputs are customized based on EPA GHGI.

See *Multiple Source Analysis Results* for emissions estimates for each scenario, because the scenario analysis did not reveal any significant outliers, averages across scenarios were used to estimate LNG and LSFO lifecycle CI. Average CIs are presented in Table 1, where the fuel input CI and total output electricity carbon intensities are shown for liquified natural gas and oil.

Table 1 Weighted average carbon intensity estimates for Low Sulfur Fuel Oil and LNG using 20-year and 100-year GWPs for fuel inputs (right) and electricity output (left). Electricity output calculation assumed the current HICC powerplant efficiency of 32% (Source eGRID 2022), and LNG used a modeled powerplant efficiency of 46%. Transmission and distribution loss was assumed at 5.4%.

Fuel and Lifecycle Stage	Weighted Carbon Intensity (kg Co2e/MMBtu fuel input) 20-year GWP	100-year GWP	Weighted Carbon Intensity (kg CO2e/MMBtu electricity output) 20-year GWP	100-year GWP
LSFO				
Upstream - Production	18.6	11.4	60.9	37.3
Transport - Crude	2.1	2.0	6.9	6.6
Refinery - Residual Oil	6.2	5.8	20.1	18.9
LSFO - Combustion	82.8	82.6	270.9	270.4
TOTAL	109.7	101.8	358.8	333.2
LNG				
Upstream+ Midstream - NG Production	17.6	9.3	40.3	21.4
Liquefaction	9.6	7.6	22.0	17.5
LNG T&D	4.5	2.2	10.3	5.1
LNG Storage	1.8	0.7	4.1	1.5
LNG Regasification	2.4	1.2	5.5	2.8
Gasified NG T&D to Power Plant	0.7	0.4	1.6	0.8
NG - Combustion	59.6	59.5	136.9	136.7
TOTAL	96.1	80.9	220.8	185.8

Natural gas power plants are generally more efficient at cycling than oil-fired generation due to the faster response times and better load-following capabilities of natural gas turbines. Natural gas plants can ramp up or down quickly, adjusting their output in response to fluctuations in renewable energy generation or grid demand. In contrast, oil-fired plants are typically slower to adjust and less flexible, which makes them less efficient when frequently cycling. This efficiency advantage allows natural gas plants to better accommodate grid fluctuations, providing more reliable backup power with less fuel consumption compared to oil-fired plants.

The comparison between Natural Gas and Oil-Fired Generation shows a weighted average 38-44% savings over 20-year and 100-year GWPs respectively, when accounting for improved power plant efficiencies. Current powerplant efficiencies: Crude oil current powerplant efficiency of 32%, Natural gas combined cycle and simple cycle weighted powerplant efficiency were estimated from capacity expansion modeling averages from 2030-2045 of 46%.

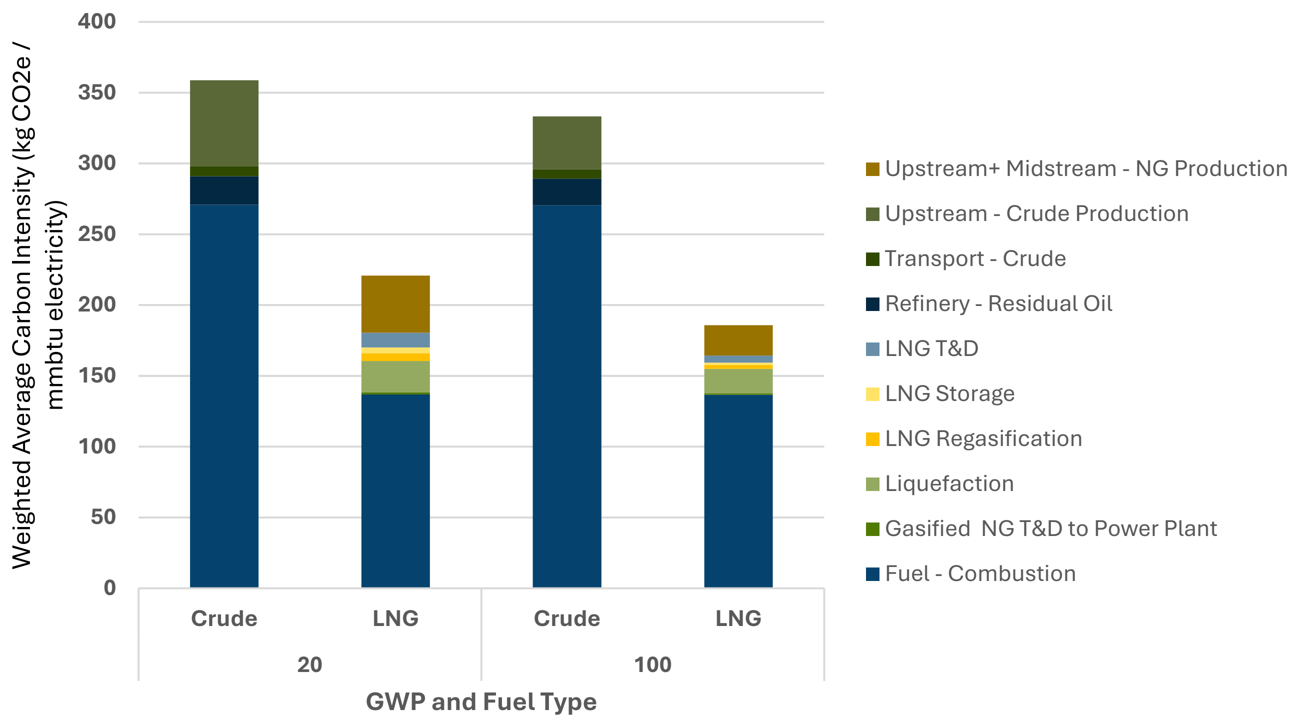


Figure 2 Comparative analysis of natural gas lifecycle emissions vs. current petroleum generation.

Table 2 Total lifecycle emissions estimates for low sulfur fuel oil and LNG

	Weighted Total Lifecycle Carbon Intensity Estimate (kg CO2e/MMBtu Elec)		
GWP	**Low Sulfur Fuel Oil**	**LNG**	**Percentage Change**
20	358.8	220.8	38%
100	333.2	185.8	44%

Lifecycle of Biofuels

The lifecycle carbon intensity of biofuels one of the most difficult fuels to quantify. Emissions from biofuels, including biodiesel, renewable diesel, cellulosic diesel, ethanol (typically blended with other fuels), and renewable naphtha (more commonly used in industrial and transportation sectors but can be used for electrical generation) have substantial variation.

The US Renewable Fuel Standard (RFS) is the world's largest existing biofuel program. The program requires empirical lifecycle assessment of greenhouse gas emissions to determine if fuel pathways can qualify, there are many frameworks available to account for lifecycle emissions from bio-based sources.

The RFS is referenced in this comparison due to the availability of data from EPA-evaluated fuel pathways and published numerical GHG results.[22] With the continental U.S. producing nearly 47% of the global output of renewable liquid fuels over the last decade, the RFS has been a driving policy incentivizing biofuel production. The RFS program is designed to compare renewable fuels against common transportation fuels (gasoline and diesel). The upstream and midstream estimates can be applied to inform lifecycle emissions from stationary combustion for electricity generation and adjusted appropriately based on powerplant efficiencies.[23] The EPA's RFS program has approved certain pathways for various feedstocks and fuel types. Figure 3 and Figure 4 show estimated emissions from proposed fuel pathways. While the RFS program applies to U.S. production, the program includes feedstocks grown outside the US, and therefore is also applicable to Hawaiʻi imports. The EPA has not approved pathways with palm oil feedstocks.

The biofuel lifecycle CI presented in Figure 3 and Figure 4 are unadjusted values submitted to and reviewed by the EPA for the RFS program.

- U.S. Environmental Protection Agency. (2023). *Lifecycle greenhouse gas results*. Renewable Fuel Standards (RFS) Program summary data. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

Figure 3 shows the variability across lifecycle stages of different feedstock types using the average CI for each lifecycle stage. The figure demonstrates the variability of CI for different biofuels, using average CIs reported to the RFS program. Figure 4 shows the variability by feedstock type.

The values presented are "fuel inputs" and do not account for the conversion of fuel to electricity, which is dependent on the power plant configuration. For locally produced feedstocks land use change estimates would also need to be adjusted; however, there is limited data availability for this to be incorporated.

[22] U.S. Environmental Protection Agency. (May 2023). *Lifecycle greenhouse gas results*. U.S. Environmental Protection Agency Fuels Registration, Reporting, and Compliance. Retrieved from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

[23] "Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis" (EPA-420-R-10-006).

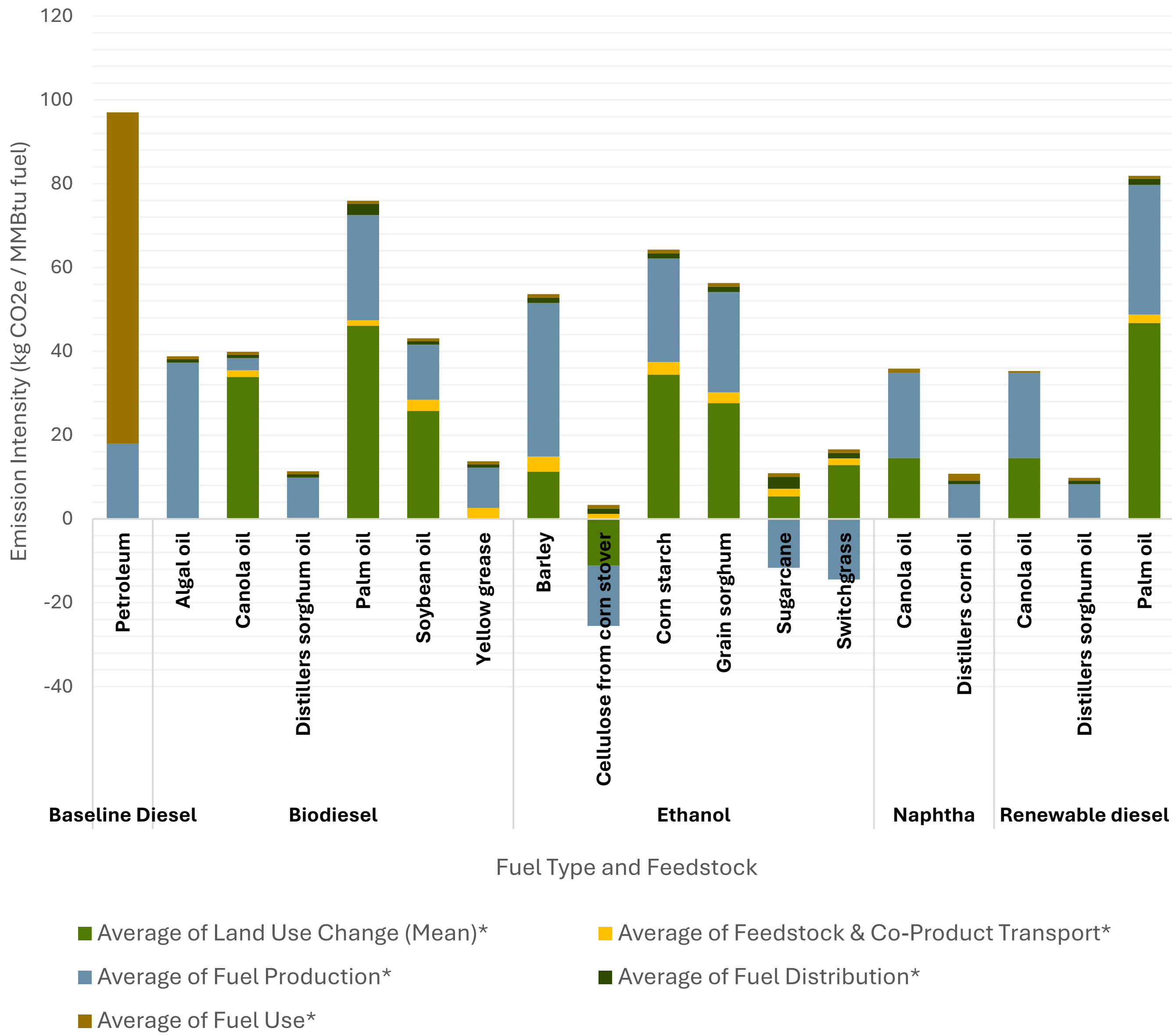


Figure 3 Unadjusted average lifecycle CI fuel input by feedstock and fuel type from submitted fuel pathways with full LCAs submitted. Colors demonstrate various lifecycles

Figure 4 shows the wide ranging variability of total lifecycle net emissions from various feedstocks and fuels.

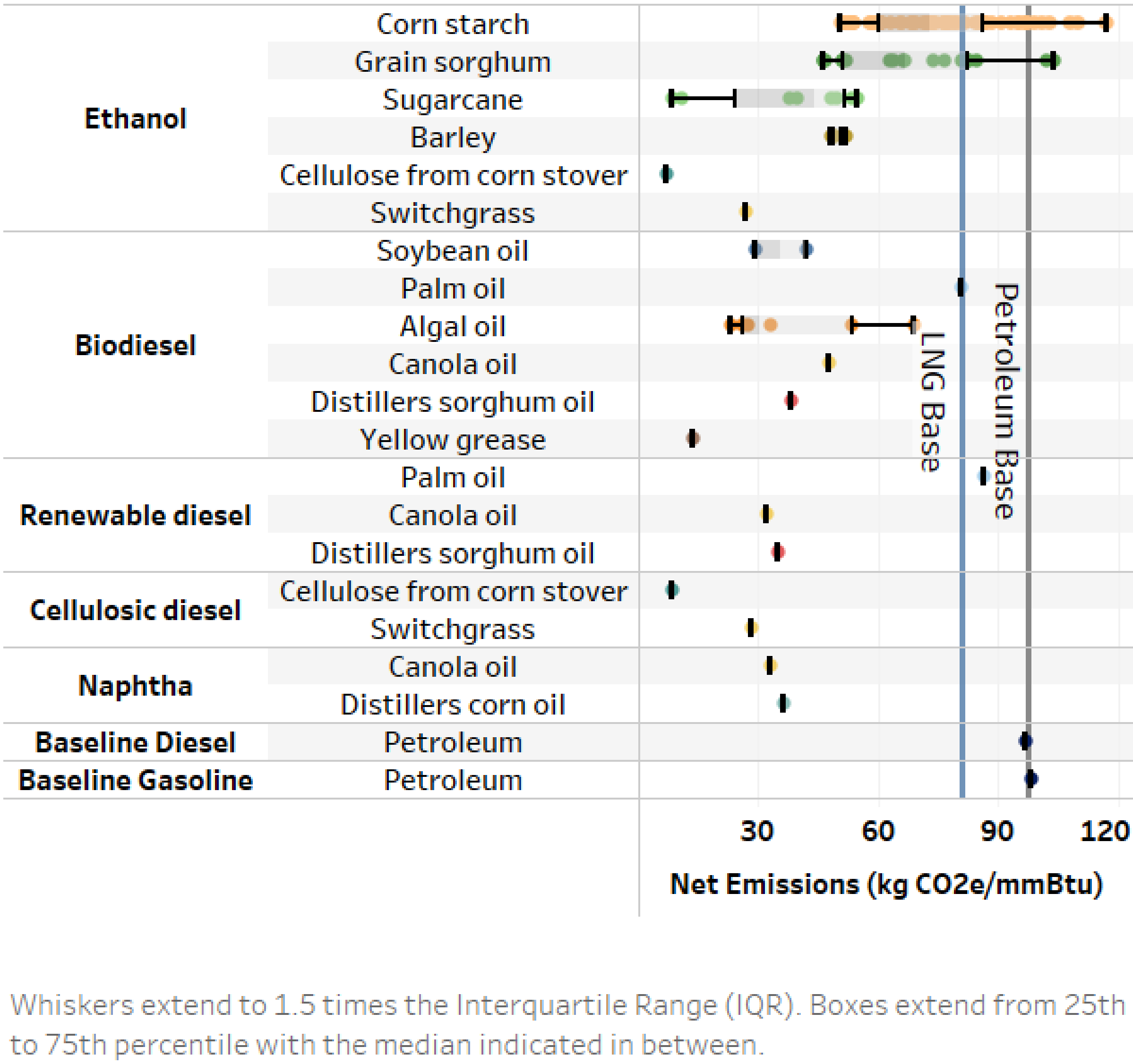


Figure 4 EPA Renewable Fuels Program, unadjusted average emission intensities for various fuel types and feedstocks. Values do not incorporate powerplant efficiencies and should be considered "fuel inputs". Source: EPA Completed Pathways Assessments Lifecycle Analysis. https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel. LNG Base is the "fuel input CI" from the weighted hybrid comparative analysis.

Not shown or included in the data set, includes lifecycle emissions from fuels produced with livestock tallow. For beef tallow-based fuels, GHG emission estimates are also dependent on whether the emissions from meat production are incorporated, or if the tallow is treated as a byproduct or waste product. The United States Department of Agriculture (USDA) Economic Research Service and the DOE report that animal fats, waste oils, and greases accounted for 37% of feedstocks used in U.S. biomass-based diesel production in 2023, up from 17% in 2020. This shift has reduced the reliance on vegetable oils like soybean, canola, and corn. Increased use of these alternative feedstocks, particularly used cooking oil, has driven U.S. import demand, with used cooking oil imports rising from 0.9 billion pounds in 2022 to over 3 billion pounds in 2023.[24]

Studies have demonstrated that the RFS program has inadvertently caused unintended consequences like increased fertilizer use, reduced conservation land, and expanded cropland. These factors elevated GHG emissions and undermined the RFS program's intended climate benefits. Empirical evidence indicates biofuels *may* have a higher overall impact than natural gas, particularly when land use change (LUC) and other upstream emissions are included, particularly when considering the bulk of fuels on the market are first-generation fuels, derived from corn, soy, and palm feedstocks.[25] To date, approximately 87% of the RFS mandate has been met using conventional renewable fuels, primarily corn ethanol.[26] This heavy reliance on corn ethanol has limited the realization of the anticipated benefits associated with the program's more advanced fuel requirements, such as those for cellulosic biofuels and biomass-based diesel; for certain corn-based ethanol lifecycle CI can be 24% higher than that of gasoline.

Comparison with Regulatory Filings

A copy of the spreadsheet used to compare HSEO estimates with past reports and filings is available at: https://energy.hawaii.gov/alternative-fuels-repowering-and-energy-transition-study/

Fuel Contract LCA for Hawaiian Electric

A lifecycle assessment was completed for the existing fuels contract with Par Hawaiʻi, Pacific Biodiesel, and Vitol and submitted to the Hawaii Public Utilities Commission by Hawaiian Electric for Approval of Fuels Supply Contact in Docket 2022-0014, as a part of the application, a lifecycle analysis was completed and submitted.[27] The resulting emissions from these contracts are summarized below. To allow for comparison HSEO converted all units to "kg CO2e per mmBtu" using the conversions listed in Section C-4.

Par Hawaiʻi – Liquid fuels derived from imported crude

HSEO's weighted carbon intensity estimates are consistent with the emission estimates submitted by Hawaiian Electric if the system boundaries are appropriately adjusted to account for power plant energy conversion efficiency.

[24] U.S. Department of Agriculture, Economic Research Service. (n.d.). *Chart detail: Major feedstocks for biomass-based diesel*. Retrieved from https://ers.usda.gov/data-products/chart-gallery/gallery/chart-detail/?chartId=109680

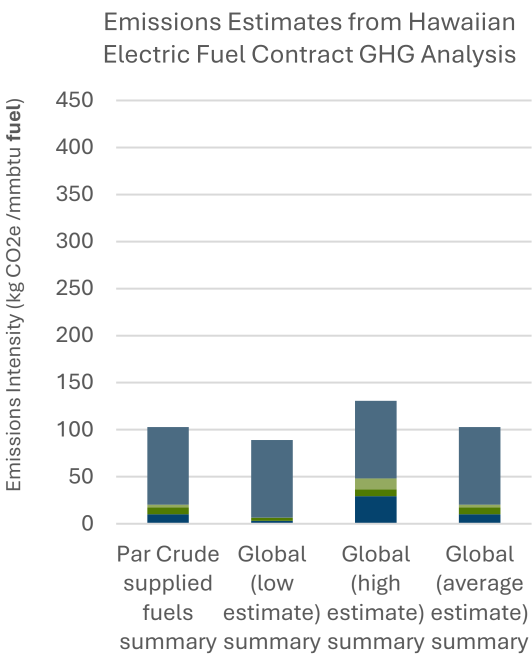
[25] Lark, T. J., Hendricks, N. P., Smith, A., Gibbs, H. K., & Marshall, E. (2022). Environmental outcomes of the US Renewable Fuel Standard. *Proceedings of the National Academy of Sciences, 119*(9), e2101084119. https://doi.org/10.1073/pnas.2101084119

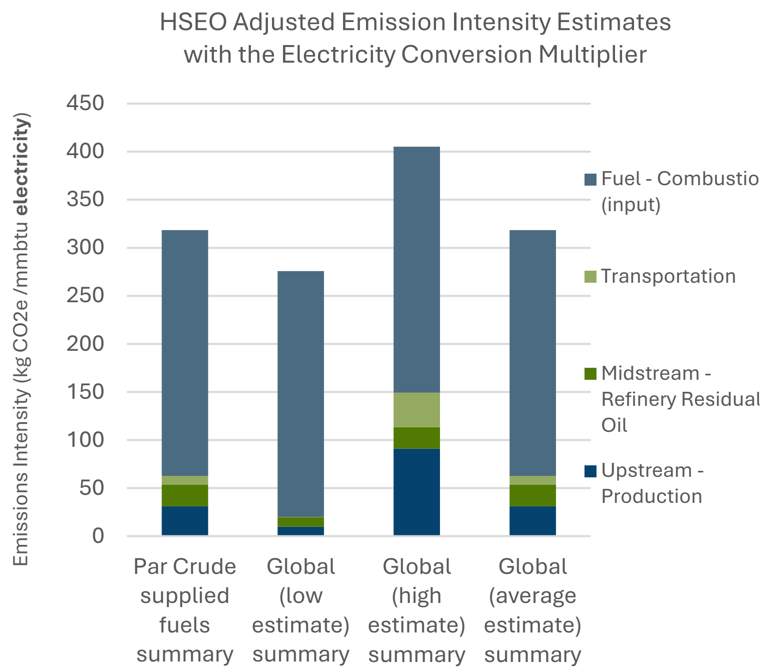
[26] Id

[27] Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., & Maui Electric Company, Limited. (2022). *Application for approval of fuels supply contract with Par Hawaii Refining, LLC, the Biodiesel Supply Contract with Pacific Biodiesel Technologies, LLC, and the Backup Fuels Supply Contract with Vitol, Inc. (Docket No.2022-0014).* Submitted to the Public Utilities Commission of the State of Hawai'i.

The lifecycle assessment for Par Hawai‘i presented in docket 2022-0014 as a part of the Hawaiian Electric fuel contract did not account for the conversion of fuel to electricity when determining lifecycle intensity values. Assuming power plant energy conversion efficiency of 32.3%[28] it takes approximately 3.1 MMBtu of fuel to produce 1 MMBtu of electrical energy.[29] This conversion factor is also known as power plant heat rate, more commonly expressed in Btu/kWh. This conversion factor must be applied upstream to account for energy loss across the entire fuel lifecycle. Consequently, the Hawaiian Electric analysis accounted for all input emissions, but did not account for energy loss during electrical generation; therefore, it underestimated lifecycle emission intensity from oil combustion by a factor of ~3.1 for all stages in the fuel's lifecycle. In other words, the analysis instead incorporates lifecycle emissions from well-to-powerplant, rather than well-to-outlet.

HSEO’s fuel analysis is consistent with the analysis completed for Par Hawai‘i if carbon intensity values are compared based on input fuel combustion, rather than electricity production. See *Oil-LNG Comparative Breakdowns for Selected Locations Using the RMI/OCI+ Index* for the energy conversion efficiencies of various power plants.





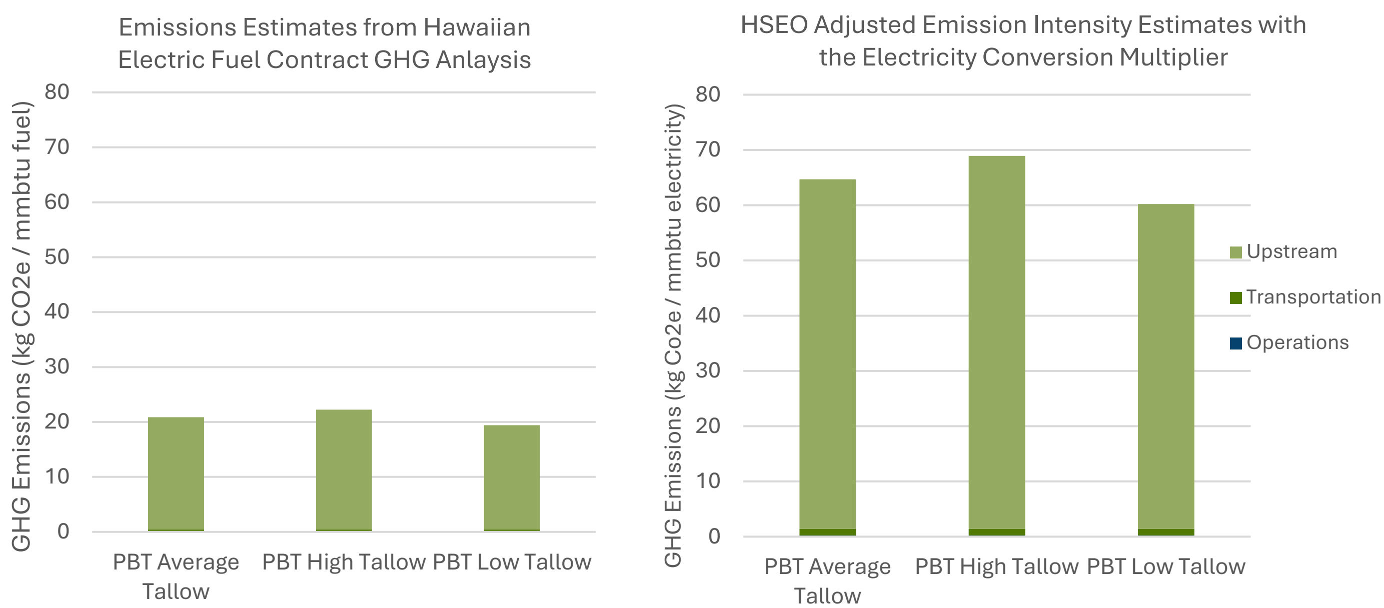
When accounting for the energy conversion factors (right), average emission intensity estimates for Par Hawai‘i-supplied liquid fuels are consistent with the estimates presented in the comparative analysis presented above, with total emission intensity for Par-supplied fuels:

[28] GREET and eGRID estimates for HICC mix (ANL GREET 2023 Workbook).
[29] GREET 2023

- Total emissions Par Hawaiʻi supplied fuels: 317 kg CO2e / MMBtu electricity (assuming 100-year GWP)
- Total emissions from average estimate HSEO weighted analysis: 333 kg CO2e / MMBtu electricity (assuming 100-year GWP) (Figure 2)

Pacific Biodiesel – Liquid biofuels derived from locally sourced used cooking oil and imported feedstock tallow

As a part of Hawaiian Electric's fuel contract with Pacific Biodiesel (PBT), Hawaiian Electric submitted a lifecycle GHG analysis in accordance with HRS 269-6(b).[30] According to the January 2022 submission to the PUC in Docket 2022-0014, PBT has historically sourced tallow from the continental US, shipping it in from California and Washington. Used cooking oil is collected from local restaurants in Hawaiʻi by truck. The tallow-oil mix varies based on availability and cost, with tallow typically representing 66-87% of the feedstock. The analysis assumed carbon neutrality for biogenic emissions.



It is unclear if the analysis incorporated power plants' energy conversion efficiencies (fuel to electricity) at all stages in the lifecycle analysis. **However, because the lifecycle analysis presented the GHG intensities in units of kgCO_2e/gal, HSEO believes conversion efficiencies were not incorporated into the analysis.** The total emissions estimates (as opposed to the intensity estimates) are accurate because PBT included annual consumption figures.

[30] Pacific Biodiesel Technologies (PBT) Biodiesel Contract GHG Analysis. January 2022. Hawaiian Electric submission to PUC Docket 2022-0014.

With a conservative emission factor applied (multiplier of ~3.1MMBtu of electricity/ MMBtu fuel), PBT-supplied fuels offer carbon savings under the applied system boundary assumptions, with high-tallow estimates providing approximately 79% lifecycle carbon savings. Carbon savings increase if biofuel is burned in more efficient power plants.

- Emission intensity fuel (high tallow): 22.23 kg CO2e / MMBtu fuel
- Emission intensity electricity generated: 68.93 kg CO2e / MMBtu electricity
- Petroleum fuel HSEO weighted analysis: 331 kgCO2e / MMBtu electricity

Notably, while it is standard practice to assume beef tallow as a byproduct or waste product in GHG accounting, it is worth acknowledging for this study tallow is assumed to be a waste product of meat production. GHG emissions associated with meat production were not included in the emission estimate, a common system boundary assumption. Rendering emissions were accounted for.

The submitted analysis for PBT is slightly higher than, but consistent with, the average CI for the EPA's RFS "Yellow Grease" average of 13.76 kg CO2e / MMBtu fuel.[31]

Comparison with Literature and Published Studies

The weighted analysis presented above is generally consistent with published scientific literature. Comparisons are presented in Table 3. Certain studies only evaluate specific stages in fuel lifecycles and may not account for energy conversion efficiencies, the "unit" column indicates whether a conversion efficiency was applied (i.e. units with *MMBtu electricity* indicate a conversion was applied, units of *MMBTU fuel* indicated no conversion efficiency was applied. Further research is needed to determine the underlying causes for differences; however, based on initial research, it is likely due to geographic distinctions and/or operational assumptions. Estimates shown in Table 3 compare HSEO estimates with other source estimates where supply-chain point divisions were distinct.

Table 3 Published emissions estimates compared to HSEO's weighted hybrid analysis averages. All intensities were converted to kg CO2e / MMBtu using conversion factors. All shaded cells indicate estimates where HSEO estimates are less than published estimates.

Sources	Unit	Supply Chain Point	Fuel Type	GWP	CI From Literature Cited	HSEO Average CI from Weighted Analysis for Comparison
NREL Harmonization (average)	kg CO2e/MMBtu electricity	Total	Oil	100	246.19	333
NREL Harmonization (average)	kg CO2e/MMBtu electricity	Total	LNG	100	142.44	185
NREL Harmonization (high)	kg CO2e/MMBtu electricity	Total	LNG	100	158.26	185

[31] U.S. Environmental Protection Agency. (2023) *Lifecycle greenhouse gas results*. Retrieved from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

Sources	Unit	Supply Chain Point	Fuel Type	GWP	CI From Literature Cited	HSEO Average CI from Weighted Analysis for Comparison
NREL Harmonization (low)	kg CO2e/MMBtu electricity	Total	LNG	100	123.09	185
NREL High EF	kg CO2e/MMBtu electricity	Total	Oil	100	342.91	333
NREL Low EF	kg CO2e/MMBtu electricity	Total	Oil	100	149.47	333
NREL Mid EF	kg CO2e/MMBtu electricity	Total	Oil	100	246.19	333
Abrahams et al. 2015	kg CO2e/MMBtu electricity	Total	LNG	100	192.0	185.8
Abrahams et al. 2015	kg CO2e/MMBtu electricity	Total	LNG	20	263.8	220.8
Howarth, 2024	kg CO2e/MMBtu electricity	Total	LNG	20	168.80	186
Howarth, 2024	kg CO2e/MMBtu electricity	Total	Coal	20	126.60	range 197-495 (100 year)
Howarth, 2024	kg CO2e/MMBtu electricity	Upstream + midstream	LNG	20	79.76	40.3
Howarth, 2024	kg CO2e/MMBtu electricity	Liquefaction	LNG	20	14.98	17.5
Howarth, 2024	kg CO2e/MMBtu electricity	"Combustion by final consumer"	Diesel	20	79.13	74.2
Howarth, 2024	kg CO2e/MMBtu electricity	"Combustion by final consumer"	LNG	20	58.03	59.6
Zhang et al, 2023	kg CO2e/MMBtu fuel	liquefaction	LNG	100	3.31	7.6
Zhang et al, 2023	kg CO2e/MMBtu fuel	liquefaction	LNG	100	7.65	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction (low estimate)	LNG	100	4.75	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction	LNG	100	4.96	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction	LNG	100	6.22	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	liquefaction (high estimate)	LNG	100	6.54	7.6
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	Upstream + midstream (Permian-UK)	LNG	100	20.47	9.3
Zhu, Allen, Ravikumar, 2025	kg CO2e/MMBtu fuel	Upstream + midstream (Permian-China)	LNG	100	21.42	9.3
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	Upstream + midstream (Marcellus-UK)	LNG	100	7.70	9.3
Zhu, Allen, Ravikumar, 2024	kg CO2e/MMBtu fuel	Upstream + midstream (Marcellus-UK)	LNG	100	8.02	9.3

National Renewable Energy Lab Harmonization Study

To compare the various intensities published across the literature, the National Renewable Energy Laboratory (NREL) completed a harmonization report titled *Life Cycle Greenhouse Gas Emissions from Electricity Generation*. This work is valuable for comparing fossil fuel sources to other electrical energy generation technologies and further illustrates why natural gas is a bridge fuel rather than a long-term solution, as intermittent technologies demonstrate substantially lower carbon intensities (CI). As shown in Figure 4, the weighted estimates presented here are generally consistent with and fall within the ranges provided in the harmonization report. One critical assumption to note: the biopower estimates below assume carbon neutrality for all biogenic emissions, skewing the results toward the lower end.

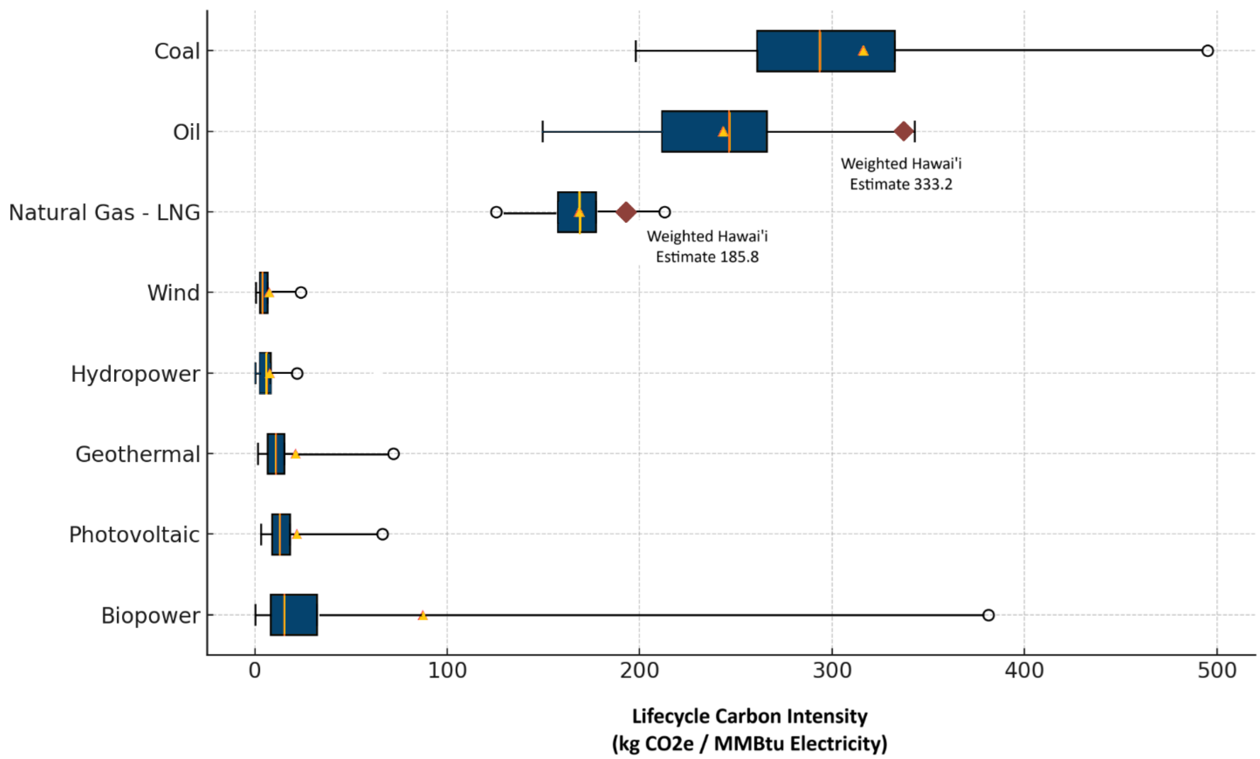


Figure 5 Lifecycle greenhouse gas emission intensities from NREL Harmonization Study for electricity generation technologies. Source: National Renewable Energy Laboratory, Life Cycle Greenhouse Gas Emissions from Electricity Generation Update. Data retrieved from https://www.nrel.gov/docs/fy21osti/80580.pdf Weighted estimates from HSEO analysis indicated by diamonds, both within the upper end of the published ranges of the NREL Harmonization work.

All analysis demonstrates the need to eventually phase out natural gas and only use it as a bridge fuel. While LNG offers a more immediate opportunity to reduce emissions while achieving cost savings in the near term, the prolonged use of LNG is not consistent with international, national, and state GHG targets.

Hawaiʻi Power Plant Combustion Input and Output Emissions and Calculated Conversion Efficiencies

Data Year	Plant name	Island	Plant primary fuel	Plant capacity factor	Plant nameplate capacity (MW)	Plant annual CO2 equivalent input emission rate (kg/MMBtu)	Plant annual CO2 equivalent total output emission rate (kg CO_2e/MMBtu electricity)	Conversion Efficiency / Heat Rate (MMBtu fuel/MMBtu electricity)	Efficiency
2022	Kahe Generating Station	Oʻahu	RFO	0.4692	609.7	74.256	233.309	3.142	32%
2022	Waiau Generating Station	Oʻahu	RFO	0.2176	474.6	74.261	253.067	3.408	29%
2022	Kalaeloa Cogen Plant	Oʻahu	RFO	0.4652	299.4	74.257	166.3	2.24	45%
2022	Māʻalaea	Maui	DFO	0.3336	229.8	74.324	202.743	2.728	37%
2022	Campbell Industrial Park	Oʻahu	DFO	0.1036	113	74.324	358.836	4.828	21%
2022	Port Allen	Kauaʻi	DFO	0.0534	89.5	74.324	215.414	2.898	35%
2022	Keāhole	Hawaiʻi	DFO	0.3656	89.1	74.324	221.23	2.977	34%
2022	Hāmākua Energy Plant,	Hawaiʻi	WO, OBL	0.3762	66	62.899	162.555	2.584	39%
2022	Schofield Generating Station	Oʻahu	OBL	0.0338	50.4	0.268	0.74	2.766	36%
2022	Kapaia Power Station	Kauaʻi	WO	0.4923	39.1	78.63	217.345	2.764	36%
2022	Puna	Hawaiʻi	DFO	0.1807	39.1	74.324	280.37	3.772	27%
2022	W H Hill	Hawaiʻi	RFO	0.5232	37.1	74.256	291.685	3.928	25%
2022	Kahului	Maui	RFO	0.5339	34	74.256	325.817	4.388	23%
2022	Kanoelehua	Hawaiʻi	DFO	0.016	21	74.324	570.574	7.677	13%
2022	Palaau Power Hybrid	Molokaʻi	DFO	0.2118	17.1	74.324	219.502	2.953	34%
2022	Miki Basin	Lānaʻi	DFO	0.3971	10.4	74.324	220.284	2.964	34%
2022	HNL Emergency Power Facility	Oʻahu	OBL	0.0154	10	0.268	0.741	2.769	36%
2022	Waimea	Hawaiʻi	DFO	0.0325	7.5	74.324	230.559	3.102	32%
2022	Hana Substation	Maui	DFO	0.0059	2	74.324	242.153	3.258	31%

Source: US EPA eGRID 2022. https://www.epa.gov/egrid

$$\frac{\left(\frac{kgCO2e}{mmbtu\ electricity\ generated}\right)}{\left(\frac{kgCO2e}{mmbtu\ fuel\ combusted}\right)} = energy\ conversion\ efficiency\ \left(\frac{mmbtu\ fuel}{mmbtu\ electricity}\right)$$

Multiple Source Analysis Results

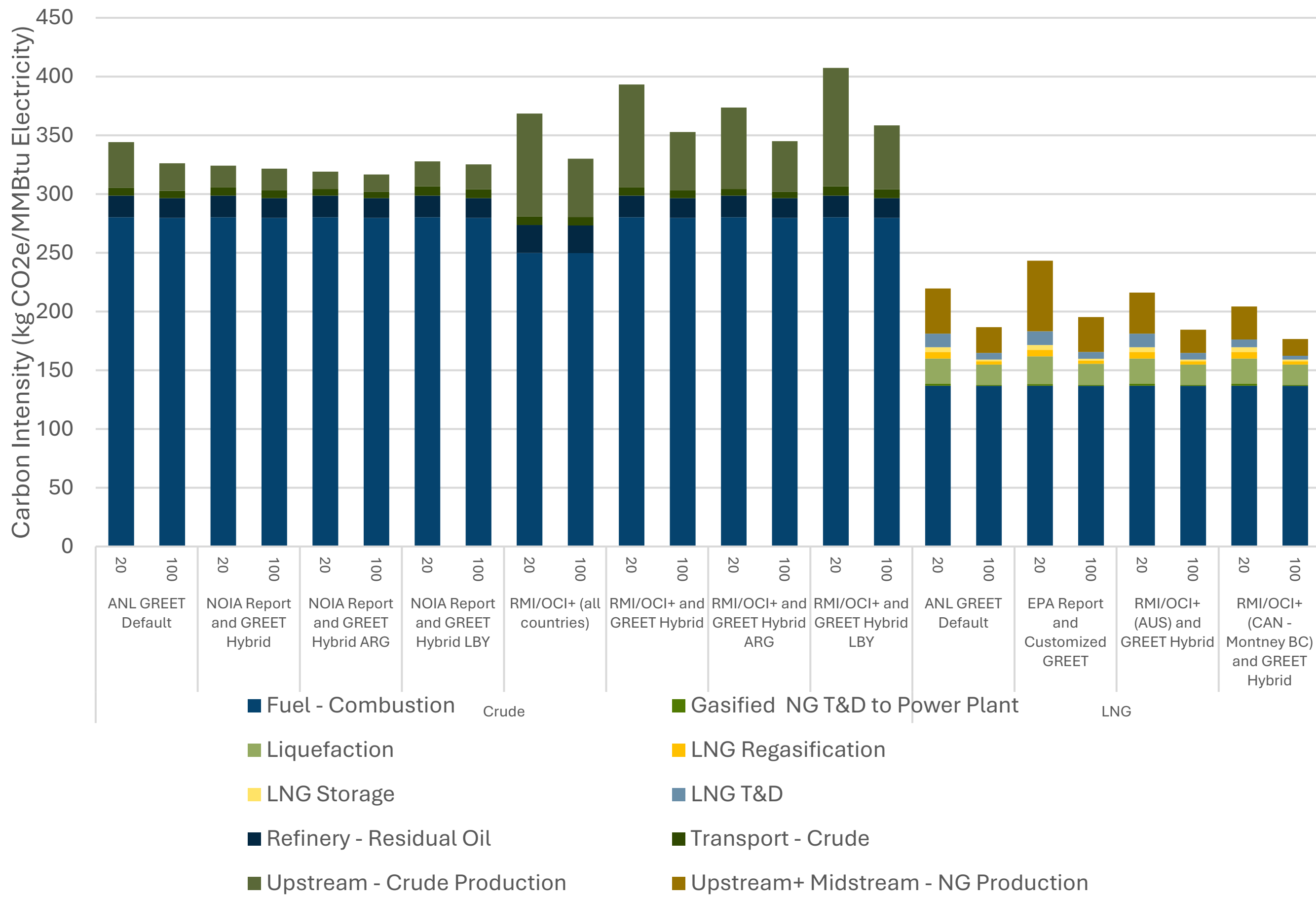


Figure 6 Lifecycle emissions intensities for natural gas and oil scenarios. Values presented are inclusive of powerplant energy conversion efficiency.

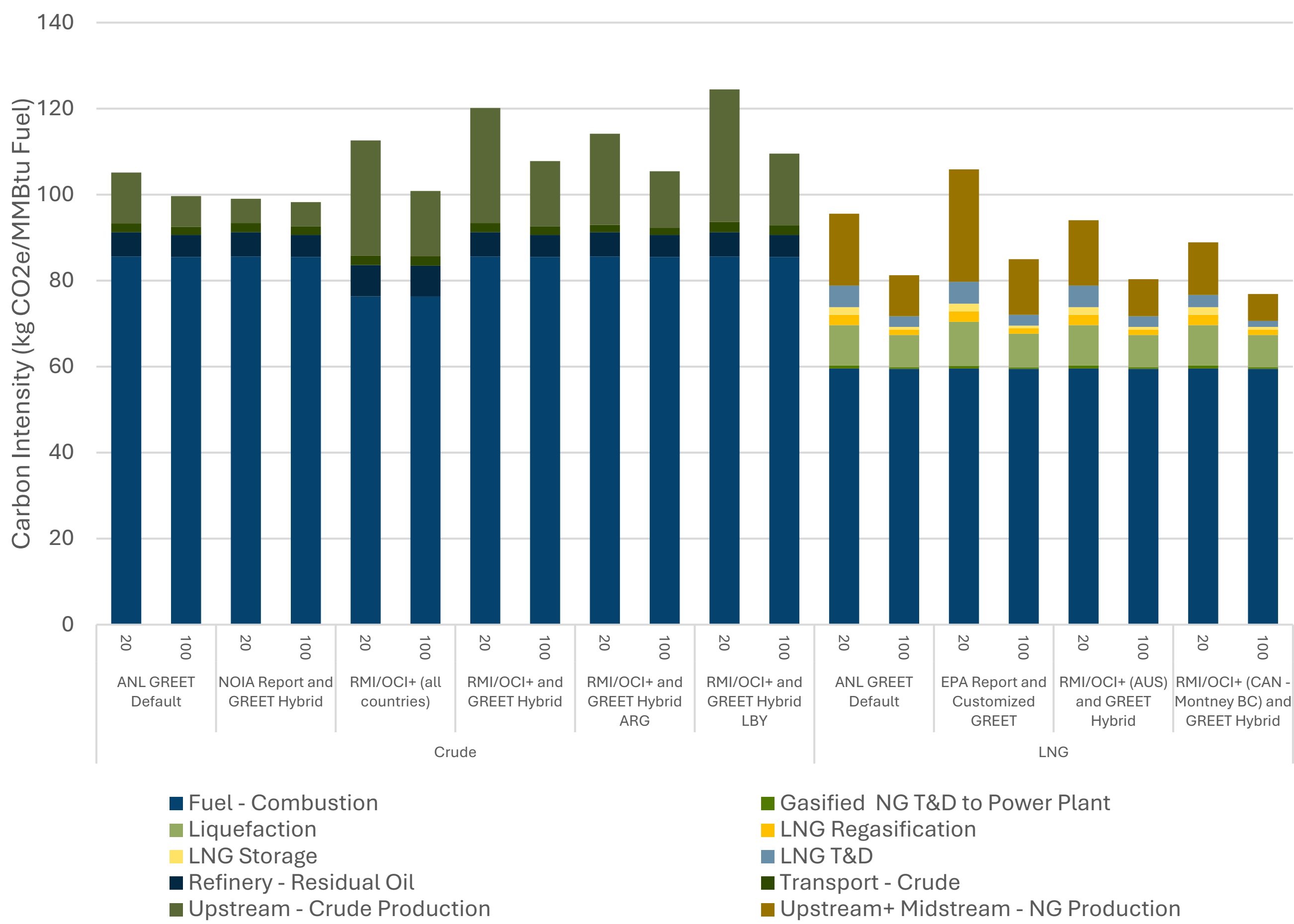
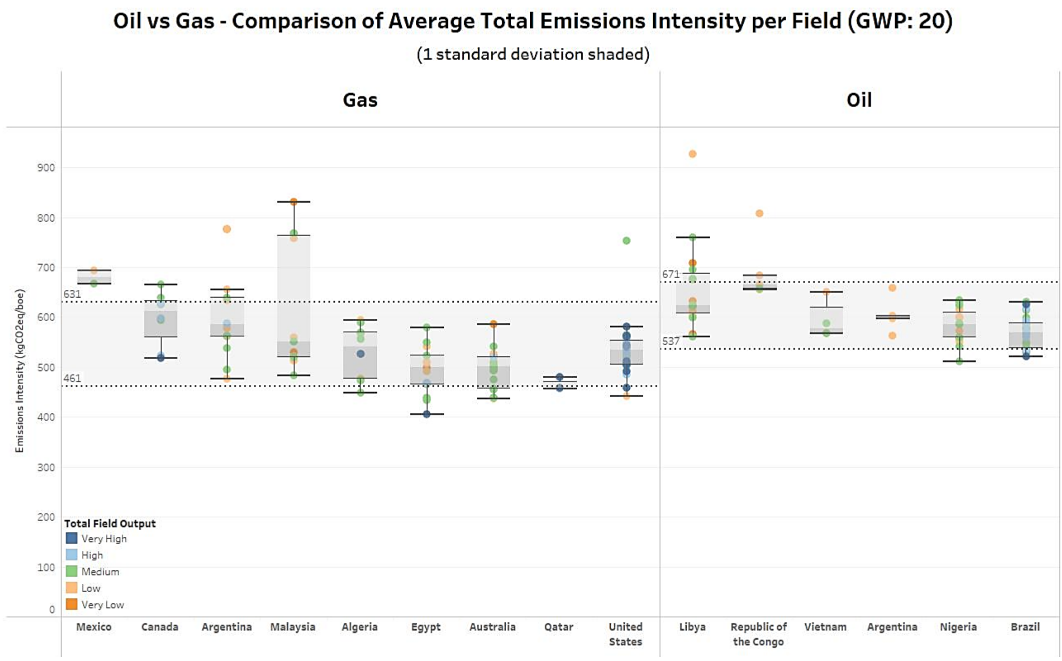


Figure 7 emissions intensities for natural gas and oil scenarios for input fuels. Values presented are not inclusive of powerplant energy conversion efficiency. Values demonstrate the importance of incorporating power plant efficiency into GHG analysis as the GHG savings are less substantial without this conversion applied.

Oil-LNG Comparative Breakdowns for Selected Locations Using the RMI/OCI+ Index.

Note: units are unadjusted and presented in kgCO2e / barrel of oil equivalent (boe).



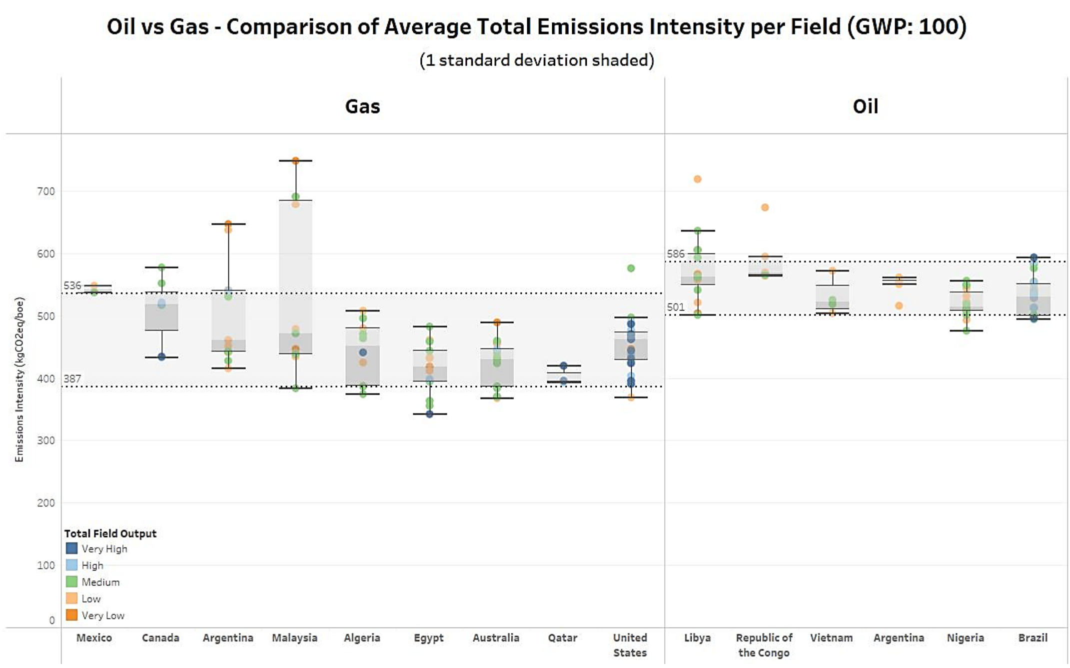


Figure 8 Oil and gas comparison of emission intensities from various possible source countries for gas and countries that have supplied Hawai'i's crude since 2015. Emissions estimates use RMI's OCI+. While Hawai'i has imported crude oil from Australia, no oil emission intensity values are reported in the OCI+ database. The top figure presents emissions derived using GWP 20, bottom uses GWP 100. ***Note emissions presented in this figure are unadjusted for powerplant efficiency.***

Each data point is an average of all reported annual emissions values for a given production field in RMI's OCI+ database from 2015-2022. Emissions do not account for liquefaction and LNG transport stages and should be considered averages used only as a comparison between different source countries. Based on these emissions, Mexico and Malaysia are not ideal source countries, and Hawai‘i should strive to ensure fuel suppliers do not source from these countries unless current environmental and operational venting and flaring practices are changed.

For Canadian natural gas, an ideal source country, upstream emissions are highly dependent on the oil field. Thus, the next step of the analysis was to narrow down upstream emissions from source countries by oil fields. Canadian natural gas from British Columbia, the likely source for Hawai‘i and the Pacific, exhibits lower emissions than emissions from eastern Canadian oil fields.

Figure 8 shows upstream emissions from likely source countries, compared to the dominant crude suppliers for Hawai‘i.

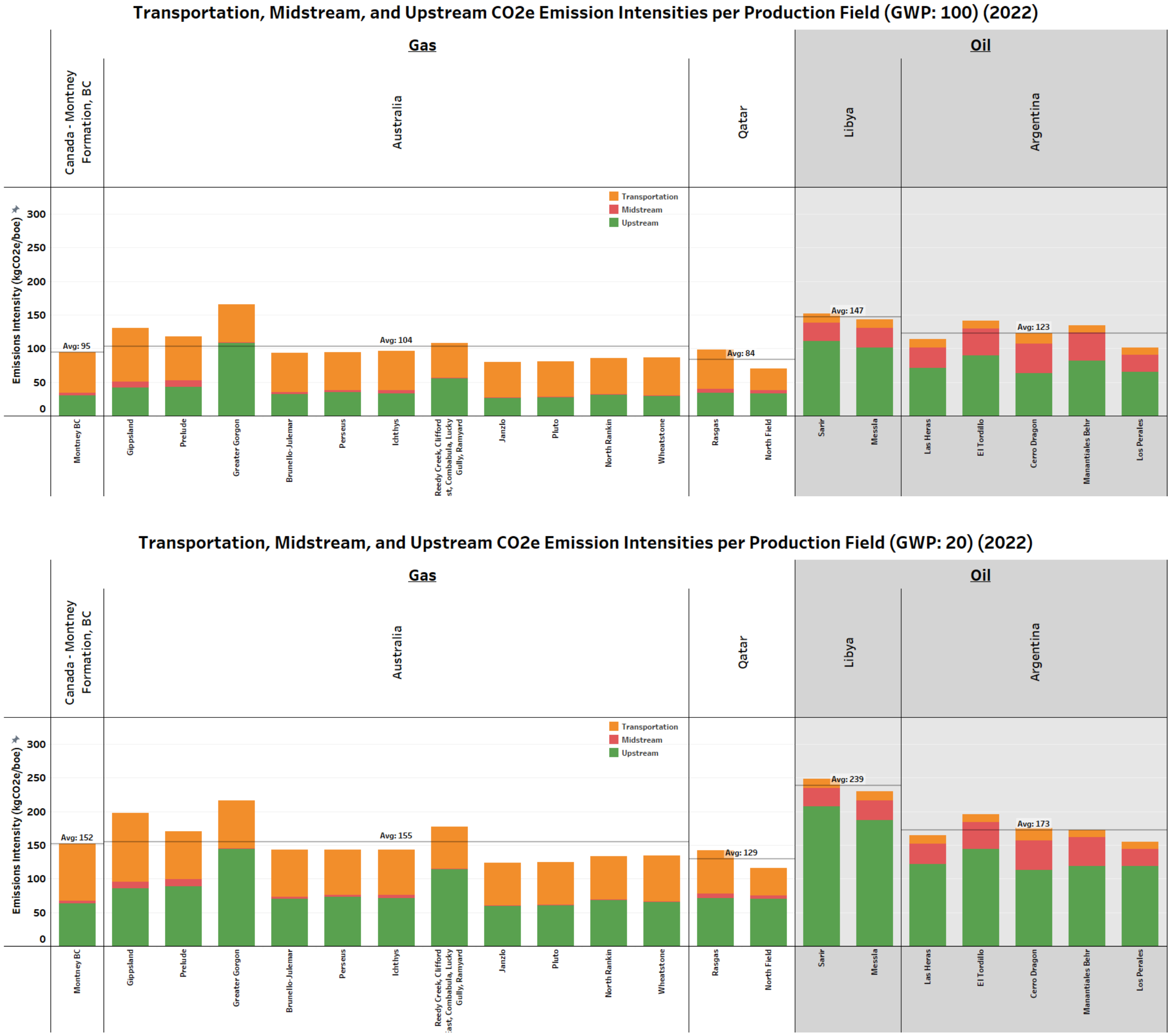


Figure 9 Upstream emissions from likely source countries by production field. Transportation emissions in the OCI index are not inclusive of liquefaction and LNG transport but do include average distance to end-use locations which may include liquefaction terminals. Estimates shown do not include powerplant efficiency gains.

Note: For RMI/OCI+ data, upstream refers to production (well to refinery gate), midstream refers to refining and petrochemical processing, and transportation refers to delivering the resource to refining and/or distribution locations other than end uses.

Downstream emissions are not shown in this figure.

Conversion Factors and GWPs

Conversion Factors

Value	Conversion
1,055	MJ per MMBtu
1,000	kg per MT
5,684,000	Btu per bbl.
5.68	MMBtu per bbl.
5,996.94	MJ per bbl.
0.0001706	MJ per boe
5.8	MMBtu per boe
3,412.14	kWh per Btu
0.003412	kWh per MMBtu
293.07	MMBtu per kWh
3.099	MMBtu fuel per MMBtu electricity for oil-fired generation (HICC mix)
1.938	MMBtu fuel per MMBtu electricity for natural gas-fired generation

Global Warming Potentials

AR Edition/Type Time Horizon (YR)	AR6/GWP 100-year	AR6/GWP 20-year
CO_2	1	1
CH_4	29.8	82.5
N_2O	273	273