INSTITUT FÜR ENERGIE- UND UMWELTFORSCHUNG HEIDELBERG

Analysis of the greenhouse gas intensities of LNG imports to Germany.

On behalf of the Wissenschaftsplattform Klimaschutz
Final report

Daniel Münter and Axel Liebich

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ifeu Wilckensstraße 3 69120 Heidelberg Phone +49 (0)6 221. 47 67 - 0 E-mail ifeu@ifeu.de www.ifeu.de

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1 Summary

The aim of this study is to estimate the greenhouse gas emissions resulting from the import of LNG to Germany and to calculate the resulting climate impact. For the most important prospective supplier countries, technological key figures, existing emission inventories and the results of more recent measurement campaigns were collected and evaluated. This includes data on all process steps from natural gas production, processing, liquefaction, and transport to landing and regasification in Germany.

Particular attention was paid to the current findings on increased methane emissions from oil and gas production. As described in the latest IPCC report and methane reports of the United Nations Environment Programme (UNEP and CCAC 2022) among others, oil and gas extraction is very likely responsible for more than 20% of anthropogenic methane emissions. In recent years, this has meant a release of more than 80 million tons of natural gas annually. This total amount has been scientifically established by so-called top-down measurements (satellite remote sensing, aircraft measurements and isotope analyses in global atmospheric measurement networks). It is significantly larger than the sum of emissions reported by industry and government agencies.

However, attribution to individual steps in the supply chains of natural gas and oil was not possible for a long time and has therefore been the subject of intensive research in the recent past. Further obstacles to the inclusion of increased methane emissions in LCA databases and LCA studies have so far been the allocation to the jointly produced products oil and gas, the differentiation between conventional and unconventional production (fracking), and onshore and offshore production. However, there is now a pragmatic solution with the approach first presented by the International Energy Agency as part of the "World Energy Outlook 2017" and subsequently published as the online tool "IEA Methane Tracker". In the current version, methane emission profiles of the oil and gas industry are given for more than 70 countries. By comparison with numerous research studies in the USA, we conclude in this study that the IEA values can be plausibly used for the United States. We subsequently use them for all other countries studied, too, even though there are less field studies then in the US.

Figure 1 shows the central results of this study: the global warming potentials over a period of 100 years (GWP100) differentiated by sections of the process chain and supplier countries. Extraction and processing as well as liquefaction represent the process sections with the largest climate impact. The differences between the countries of origin result both from different energy intensities in production and from country-specific methane emissions.

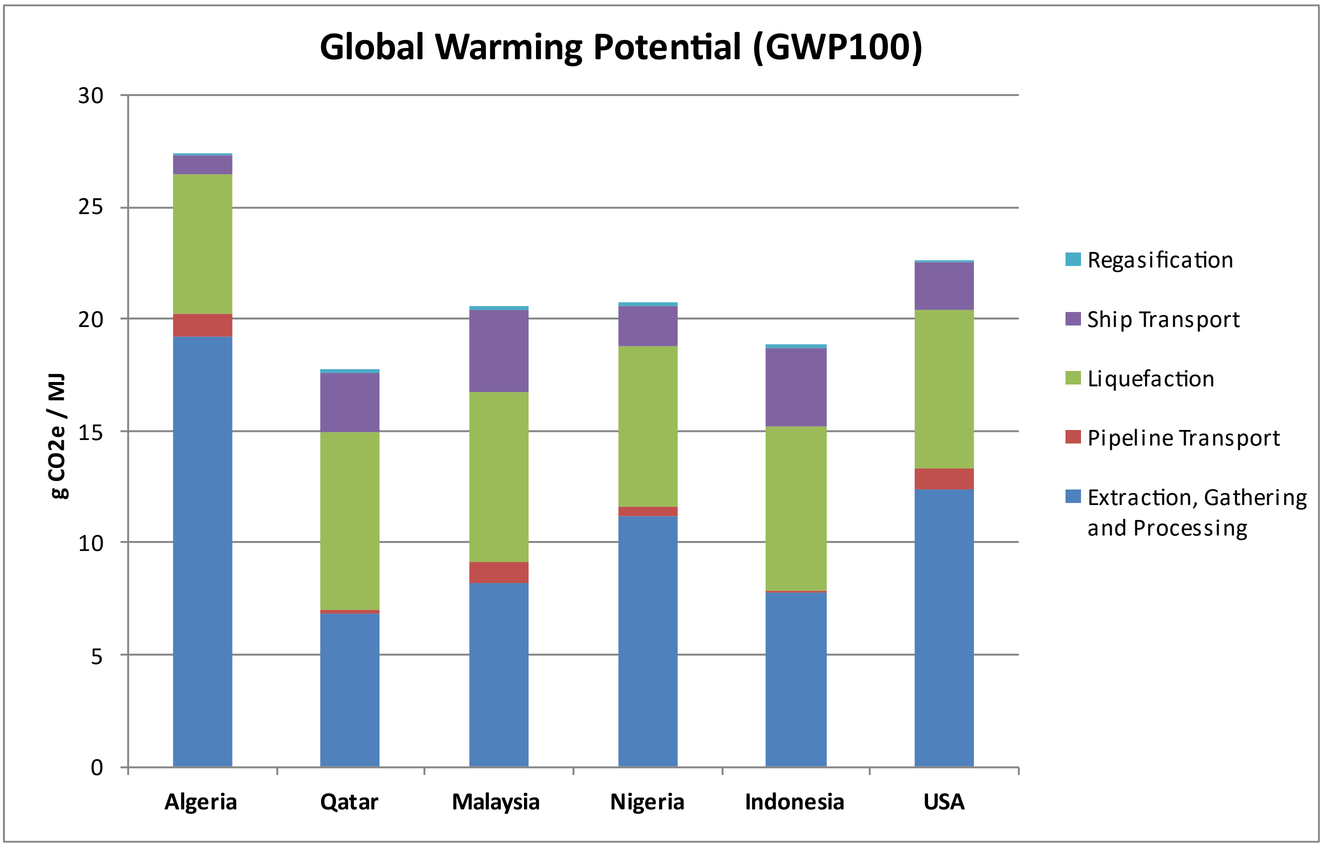

Figure 1: Global warming potential over a period of 100 years (GWP 100 according to AR5 IPCC 2013) for the provision of LNG including unloading and regasification in Germany from the countries of origin investigated, differentiated by life cycle stages in terms of lower heating value (source: ifeu, own calculation).

In addition to these upstream emissions, there are further emissions during distribution, storage and use. For example, complete combustion of natural gas, such as in a gas-fired power plant, releases another 56.1 gCO_2/MJ.

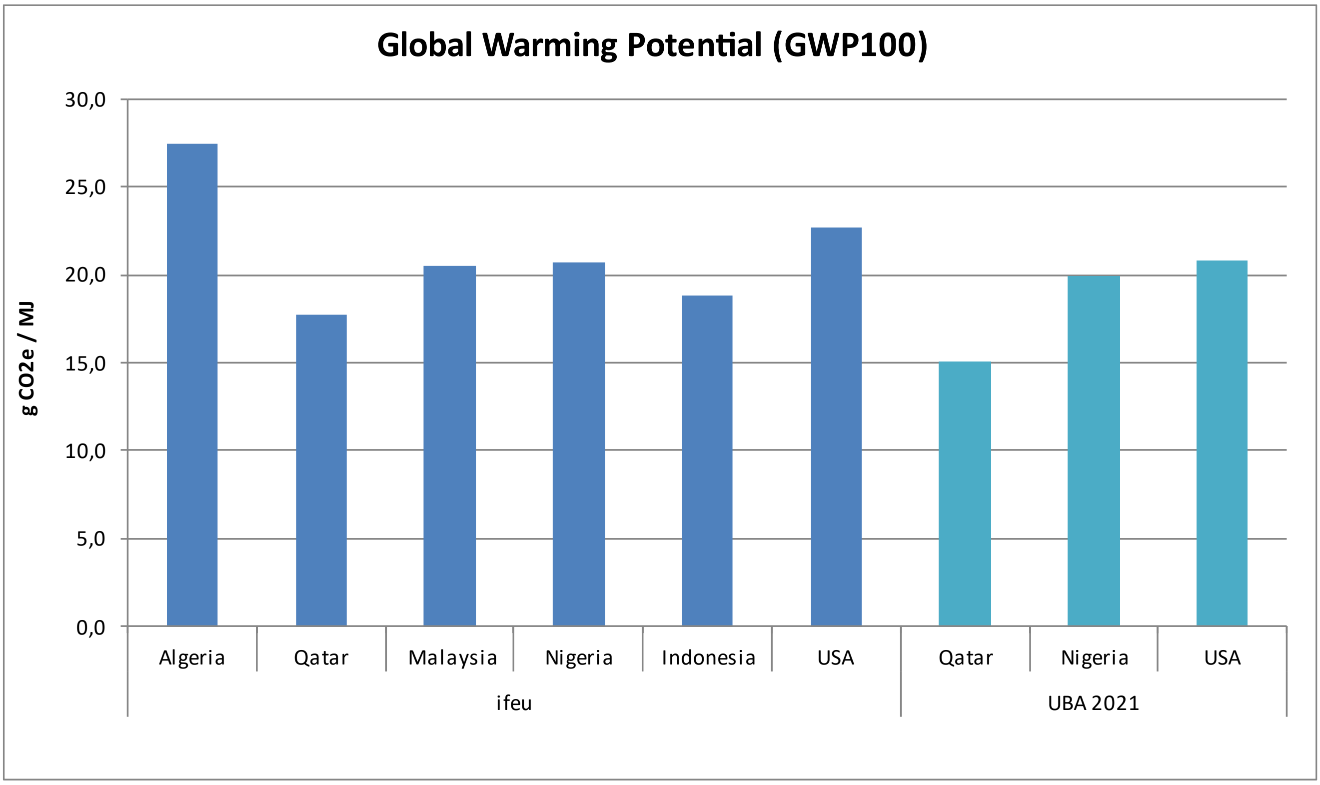

Figure 2: Global warming potential over a 100-year period (GWP100 according to AR5 IPCC 2013) for the provision of LNG including unloading and regasification in Germany in this study and for pipeline gas in two comparative studies (sources: ifeu, (Baumann and Schuller 2021) commissioned by UBA and (Ecoinvent 2022))

Figure 2 shows the results of this study in comparison with those for pipeline-bound gas from the life cycle assessment database Ecoinvent v3.9.1 (Ecoinvent 2022) and the UBA study (Baumann and Schuller 2021). While Ecoinvent already considers increased methane emissions, these are significantly lower in the UBA study. Pipeline gas from Norway has a short transport route and a transparently documented and implemented strategy to avoid methane emissions. The emissions allocated according to the IEA methane tracker are correspondingly low. Compared to pipeline-bound natural gas from Norway in both comparative studies, LNG imports have six to eight times the climate impact in the supply chain. For pipeline gas from Russia, the long transport distance and the methane emissions according to IEA lead to more than twice as high values in Ecoinvent. Therefore, pipeline gas from Russia has a higher global warming potential per unit of energy than LNG from all producing countries studied except Algeria.

To estimate the ratio of the upstream emissions determined in this study to those of the downstream emissions, they are compared to the standard emission factor for stationary energy conversion according to (IPCC 2006) . This is 56.1 gCO_2 e/MJ and represents only the CO_2 produced by complete combustion. The effects of other emissions (e.g. methane slip) and the burdens of distribution and storage are not taken into account.

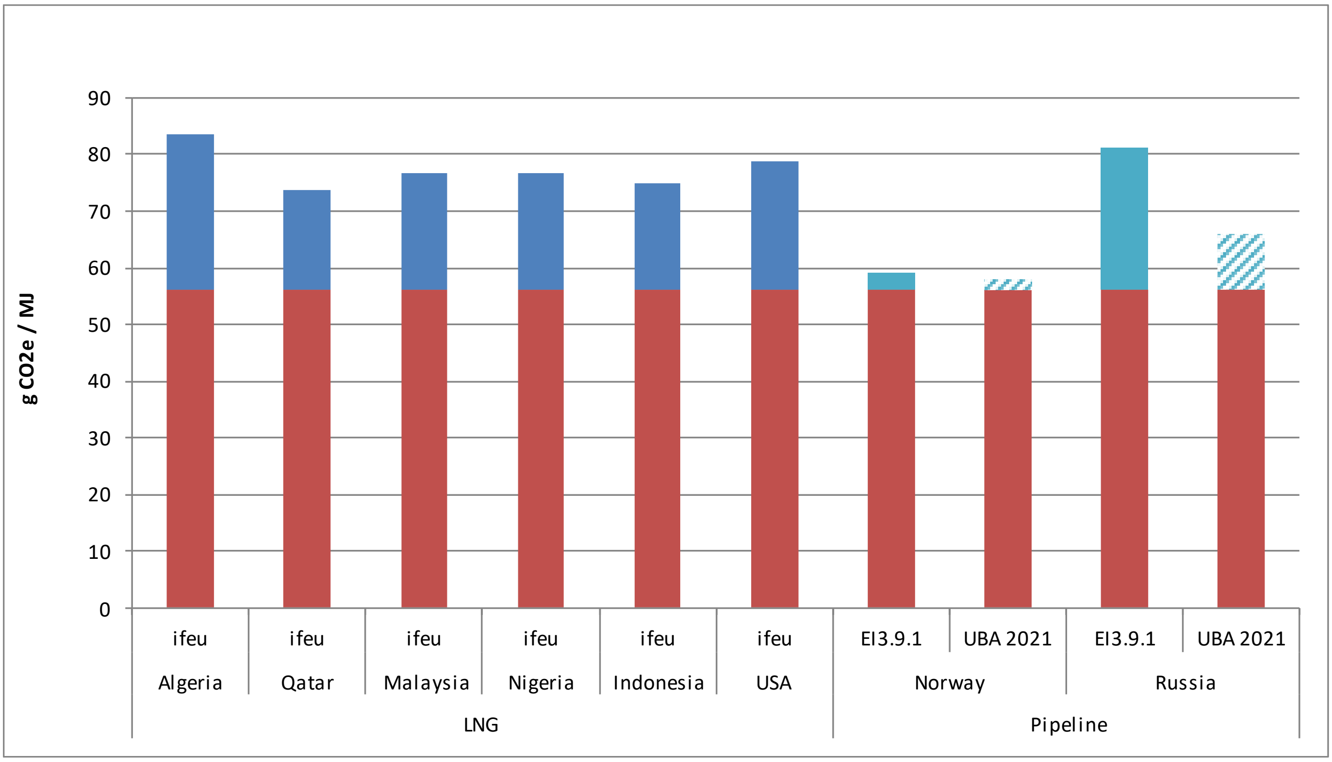

Figure 3: Global warming potential over a 100-year period (GWP100 according to AR5 IPCC 2013) of provision (blue) and combustion (red) of LNG in this study and pipeline natural gas in two comparative studies (Sources: ifeu, (Ecoinvent 2022), (Baumann and Schuller 2021) commissioned by UBA, (IPCC 2006))

Figure 3 shows the global warming potential over a 100-year period (GWP100 according to AR5 IPCC 2013) of provision and combustion of LNG in this study and pipeline natural gas in two comparative studies. The upstream emissions for LNG range from 24% (Qatar) to 33% (Algeria) of the simplified total emissions. Using the values from the study for the German Federal Environment Agency (UBA), in which the global warming potential for pipeline-bound gas was determined without the increased methane emissions, the upstream chain shares range from 3% (Norway) to 15% (Russia).

2 Introduction

The Russian war on Ukraine has caused severe turbulence in the natural gas supply of Germany and Europe. Current political decisions are guided by the need to avert an acute energy and gas supply crisis. However, as significant investments are flowing into the production, processing and transport infrastructure of liquefied natural gas (LNG) - both in the producing countries and in Germany - it is to be expected that LNG will play a greater role for German energy supply in the long term.

What environmental impacts - especially on the climate - are associated with the switch to LNG? Future LNG supplies will very likely come from regions of origin from which Germany has so far imported little or no natural gas. However, the greenhouse gas emissions associated with extraction and processing vary from region to region. The environmental impacts associated with transporting liquefied natural gas are also different from those of importing it by pipeline. Therefore, the environmental impact of the German consumption mix will also change with the shift to LNG. In addition, there is a growing international recognition that methane emissions from oil and gas production have been systematically underestimated to date. Here, too, research indicates that there are strong regional differences.

The aim of this study is to estimate the greenhouse gas emissions resulting from the import of LNG to Germany and to calculate the resulting climate impact. For the most important prospective supplier countries, technological key figures, existing emission inventories and the results of recent measurement campaigns were collected and evaluated (chapter 5). This includes all process steps from natural gas production, processing, liquefaction and transport to unloading and regasification in Germany. Bandwidths are given or discussed for the particularly significant contributions. The process chain emissions were then aggregated into an upstream burden of LNG imports. The emission volumes from the relevant process steps listed above were aggregated, evaluated, and presented in a comparative manner (Chapter 6 and 7). Finally, the uncertainties in data quality and possible regional and international trends in emissions associated with natural gas production are described (chapters 8 and 9).

3 The LNG process chain

3.1 Properties of LNG

Natural gas becomes liquid at a temperature of approximately -163 °C. The volume of liquefied natural gas (LNG) is less than 0.2% of the gas volume, so it can be stored and transported efficiently and with a high energy density. Before liquefaction, impurities such as heavier hydrocarbons, carbon dioxide, hydrogen sulfide (H_2S), nitrogen and helium are largely removed, and the gas is dried. LNG is non-toxic and non-corrosive, but requires a higher energy, economic and material cost than gaseous natural gas and needs to be stored in insulated tanks.

3.2 Process stages

The LNG process chain can be divided into the following six main process stages, each of which is associated with different GHG emissions. (Wachsmuth et al. 2019)

Gas production: Gas deposits can be conventional or unconventional, for which corresponding production methods are used (chapter 3.4). Once gas deposits have been identified and test wells have been successfully drilled, production wells are drilled, and natural gas is produced.

Gas processing: The raw natural gas at the well usually differs significantly in composition from natural gas that is later delivered to end users. The latter consists essentially of methane. In addition to 50 and 90 % methane, raw gas usually contains other hydrocarbons, mainly ethane, propane, butane and pentane. It may also contain water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen and other compounds. The concentrations of the constituents vary with the reservoirs. This raw gas is often referred to as *wet gas*. Natural gas processing consists of the (partial) separation of long-chain hydrocarbons, as well as liquids, impurities, and undesirable compounds from the raw gas, with the effort again varying greatly depending on the reservoir. Processing often takes place in two steps: In the first, acidic components (sulfur compounds and CO_2) and water are greatly reduced (boosting), usually in the vicinity of the production site. In a second step, the long-chain gaseous hydrocarbons (natural gas liquids, ethane to pentane) are separated (processing) and marketed separately.

Gas transport in pipelines to the liquefaction plant. Depending on the type of production area and its distance, the processed natural gas (*dry gas*) is transported under pressure over longer distances in pipelines to the liquefaction plant. The pressure is maintained at regular intervals by natural gas-driven compressors.

Liquefaction: Natural gas sometimes reaches a liquefaction plant as raw natural gas from gas fields closer by. In this case, the entire processing takes place in the liquefaction plant. If natural gas that has already been processed arrives, only a minor final purification is required. After almost all impurities and unwanted compounds have been removed from the natural gas, it is liquefied by lowering its temperature to around -163 °C. This process is called liquefaction. A whole range of different liquefaction technologies are in use around the world, with which the target temperature is reached in several stages.

LNG transport: On long routes, transport is usually facilitated by special LNG ships, which keep the natural gas cooled and collect evaporating gas, use it as marine fuel or reliquefy it on board.

Unloading and regasification: At the unloading terminal, the LNG is pumped into terminal storage tanks. If no direct use of the liquefied gas is planned, e.g., as marine fuel, the liquefied natural gas is vaporized, and the pressure is adjusted to around 80 bar. During regasification, the necessary heat for vaporization must be supplied to the gas. Heat exchangers fed with seawater are often used, i.e. ambient heat. After regasification, the gas is fed into the gas grid and transported by pipeline to the end users.

3.3 Emission sources

GHG emissions from gas extraction and processing are due to the following (Wachsmuth et al. 2019).

Emissions during exploration and expansion drilling: These emissions are emissions that occur during exploration drilling and preparation for production. The expenditure for subsequent expansion drilling also falls into this category. Emissions are generated by the generators for drills and pumps. Emissions also arise from fluids discharged to the surface, such as fracking fluids, drilling wastewater, the drilling debris from the wells, and via the wellbore that has not yet been sealed, e.g., during the drilling process and during the run-in phase in the first few weeks.

Drilling and preparation of the production well: A lot of energy is needed to operate the equipment for drilling and preparation of the main well, which is mostly provided by burning diesel. This contributes to greenhouse gases in the production process. For unconventional shale gas production, additional energy is needed to run the pumps that pump large amounts of water, sand, glass, and chemicals into the wells at high pressure to hydraulically fracture the shale to release natural gas. A significant amount of water comes to the surface in the first few days to weeks after injection along with hydrocarbon liquids, sand/glass, or other materials as backflow (back flows) and is accompanied by large amounts of methane. By default, the gas from the back flows is blown off or flared and the sand, water, and other fluids are discharged to ponds or tanks. The emissions generated in this context are very individual depending on the gas well and the production drilling technique on site. After some time, the mixture coming to the surface is largely free of water and sand, so the production well is connected to the permanent gas collection system at the production site.

Liquids Unloadings: "Liquids unloadings" are intermittent emissions. After several years of natural gas production from wells, it is common for well operators to have to remove water and condensate accumulations because they impede the flow of gas during production. One possible approach to this is to first shut off the well to allow the pressure to rise and then vent the well to the atmosphere (well blowdown). These operations are not part of daily, steady-state production operations, but represent significant emissions from the occasional maintenance of a well.

Fugitive emissions in gas extraction, processing, and transportation: The fourth major category of emissions is due to fugitive emissions in gas extraction and processing. They are generated either intentionally by the design of plant components (e.g., pneumatic equipment) or by inefficient or malfunctioning production equipment and directly downstream plant components (e.g. . gas dryers, compressors, separators, and tanks). Leaks in piping and seals are also included. A significant portion of the emissions from gas production arises from these fugitive emissions.

Energy consumption at the extraction site: Another source of emissions is the use of energy in extraction and in natural gas processing plants. Natural gas is very often used here. In the data used for this study, it is not always possible to separate fuel consumption from combustion for disposal (flaring).

Combustion-related emissions during the liquefaction and transport of gas: These emissions result from the combustion of fuels in stationary or mobile plants. Within the "LNG supply" process chain, combustion-related emissions occur during the liquefaction and transport of gas by burning gas in turbines or to generate electricity to operate compressors.

3.4 Regional differences in natural gas production

Depending on the country and production area, the deposits and thus also the production conditions can differ considerably. A first distinguishing feature is the division into conventional and unconventional natural gas production.

Conventional reservoirs are geological traps for natural gas created by the gas having migrated through the pores in permeable rock until it reached an impermeable rock cover and became trapped. When such a reservoir is drilled, the gas flows upward through the wellbore due to the higher pressure below the surface.

Unconventional resources are oil- or gas-bearing strata where permeability and porosity are so low that the resource cannot be economically produced by vertical drilling alone. Instead, additional horizontal drilling followed by multi-stage hydraulic fracturing ("fracking") is required. Hydraulic fracturing uses fluids injected at high pressure to create fractures in the rock formation that stimulate the flow of natural gas or oil, increasing recoverable volumes. Wells can extend vertically hundreds of meters below the earth's surface and include horizontal sections that extend for several kilometers. Fracking fluid typically consists of water, proppants, and chemical additives that open and enlarge fractures in the rock formation. The proppants - sand, ceramic beads, or other small, non-compressible particles - keep the newly formed cracks open.

Unconventional gas reservoirs are divided into three categories:

- Tight gas or tight sands gas is trapped in sandstone and carbonate rocks that have very low permeability.
- Shale gas forms in low-permeability shale rock and is trapped in clay particles or in small pores and microfractures in the rock.
- Coal bed methane is absorbed by the solid coal particles in coal and is recovered from coal mines usually by removing water from the reservoir.

In the U.S., unconventional natural gas now accounts for 79% of marketed gas. (EIA 2022)

Regardless of whether natural gas is extracted from conventional or unconventional reservoirs, it often occurs in varying quantities together with crude oil. Whether a well is called an oil well or a gas well is defined by the gas-to-oil ratio (GOR). The U.S. Energy Statistics Administration (EIA) defines a GOR of 6,000 cubic feet of natural gas to 1 barrel of oil as the threshold. At a lower gas ratio, the natural gas produced is also referred to as associated gas (of oil production). In the U.S., associated gas currently accounts for about 16% of total production. (EIA 2022).

Conventional and unconventional production differ in the material and energy expenditures for exploration, drilling and production. For the joint production of crude oil and natural gas, an allocation of environmental burdens between the products is necessary as part of a life cycle assessment.

4 Methane emissions from oil and gas production

Methane (CH_4) is a potent greenhouse gas whose atmospheric concentration has more than doubled since pre-industrial times. It is the second most important greenhouse gas after carbon dioxide (CO_2) for climate change in the industrial era. Methane is a short-lived climate pollutant (SLCP) with an atmospheric lifetime of about a decade (the mean duration of effect of disturbances relevant to climate change is 12 years). Methane also contributes to the formation of tropospheric ozone (O_3), which like methane is a short-lived but potent greenhouse gas. (UNEP and CCAC 2022).

Natural gas is largely composed of methane, and significant amounts of gas can be released during production, processing, and transportation. How scientific knowledge on methane emissions has developed in recent years is presented in this chapter.

4.1 Global anthropogenic methane emissions and their fossil share

In 2021, the United Nations Environment Programme (UNEP) Global Methane Assessment compiled an overview of the state of the science on methane sources, complementing the IPCC report published the same year (IPCC 2021; UNEP CCAC 2021). UNEP reported that methane levels in the atmosphere had increased rapidly in the 2010s and by the end of the decade had reached average five-year growth rates not seen since the 1980s. In the latest "Global Methane Assessment: 2030 Baseline Report," UNEP indicates that atmospheric levels continued to rise in 2020 (UNEP and CCAC 2022). The World Meteorological Organization's (WMO) Global Atmosphere Watch Programme (GAW) in-situ observation network determined that globally averaged surface methane levels in 2020 reached 1889 ± 2 parts per billion (ppb) (WMO 2022). This value is 262 percent of the pre-industrial (pre-1750) level. The increase from 2019 to 2020, calculated as the difference between two annual averages (11 ppb), was higher than that observed from 2018 to 2019 and higher than the average annual growth rate over the past decade. Analysis of data from U.S. National Oceanic and Atmospheric Administration (NOAA) sites, which account for about 40% of the GAW network, showed the highest methane increase in the 38-year record for 2021 (https://gml.noaa.gov/ccgg/trends_ch4/).

The most important data on sources of methane in the atmosphere are regularly compiled, reviewed and documented by the Global Carbon Project (Kirschke et al. 2013; Saunois et al. 2016, 2020). Bottom-up inventories are one type of its data sources, which provide estimates based largely on activity data and emission factors. These include the CEDS inventory (Hoesly et al. 2018), the EDGAR inventory (Crippa et al. 2018), the US EPA's Global Non-CO_2 Projections (US EPA 2019), and the IIASA inventory (Höglund-Isaksson et al. 2020). In addition, top-down inventories are compiled from atmospheric measurements, using atmospheric models to derive the contribution of specific sources to the observations. However, these top-down inventories typically do not cover all regions of the world.

Anthropogenic sources include agriculture (ruminants, manure, and rice cultivation), waste management (landfills, waste and wastewater treatment), energy (fossil fuels, i.e., production and use of coal, oil, and natural gas; burning of biofuels), and open burning of biomass. Natural sources are primarily wetlands, but also inland freshwater systems (lakes, rivers, reservoirs, river deltas, etc.), geological wells, termites, and wildlife.

At the global scale, anthropogenic sources are reasonably well known, with both bottom-up and top-down estimates yielding emissions of about 360 Mt/yr for the period 2008-2017 (uncertainty range 340-380 Mt/yr). Isotopic measurements provide evidence for source attribution, but uncertainties remain regarding isotopic signatures and the extent of some natural sources.

Despite considerable differences between emission estimates and the limited availability of current data to better constrain these values, many characteristics of current methane emissions are clear. The magnitude of anthropogenic methane sources from the Global Methane Assessment: 2030 Baseline Report, which is also intended to be the basis of international methane reduction efforts in the coming years (chap. 9.2), is shown in Figure 4.

Sector	**Mean [Mt/a]**	**EPA 2020 [Mt/a]**	**IIASA 2020 [Mt/a]**	**CEDS 2019 [Mt/a]**	**EDGAR 2020 [Mt/a]**
Agriculture	**147**	**143**	**149**	**133**	**161**
Livestock	114	114	113	107	123
Rice cultivation	30	25	32	25	38
Waste	**73**	**60**	**65**	**83**	**84**
Solid waste	43	40	45	40	47
Wastewater	30	20	20	41	37
Energy	**134**	**128**	**140**	**146**	**121**
Natural gas	35	21	44	32	43
Crude oil	43	47	44	53	29
Coal	41	38	41	46	37
Total (incl. 16 Mt/a from biomass combustion)	**372**	**348**	**371**	**378**	**391**

Figure 4 : Estimates of current sources of anthropogenic methane emissions in megatons per year. According to (UNEP and CCAC 2022)

4.2 Methane emissions in life cycle assessments of gas supply

An approximate calculation using 2020 oil and natural gas production figures from BP's annual statistical report (BP 2022) and the values from

Figure 4 yield the following estimate: a global production of 138.4 EJ of gas and 35 Mt of methane emissions over the same period equals a methane intensity of 0.253 g CH_4/MJ, or 9.26 g CH_4/Nm^3 (for natural gas with a calorific value of 36.6 MJ/Nm^3). This corresponds to an average loss rate of 1.6% in natural gas production, processing and use.

This estimate is much too coarse for an LCA, because it does not take into account regional differences such as production techniques, gas compositions, age of plants, regulation by industry standards or governmental requirements. In addition, an allocation to different steps of natural gas supply (drilling, production, processing, transport) and use (storage, distribution, combustion, or material use) is necessary to evaluate specific product pathways (e.g., LNG supply).

The information provided by the largest industry association in the oil and gas sector, the International Association of Oil & Gas Producers (IOGP), is also of no help here. In its sustainability report for 2021, the IOGP puts methane emissions at around 0.5 kg of methane per ton of hydrocarbons produced (IOGP 2022). Again, there is no distinction between oil and gas production and a simple estimate with an assumed methane content of 650 g/Nm^3 and a density of 0.78 kg/Nm^3 leads to an average loss rate of 0.06% in natural gas production. Although this is only a rough estimate for the production stage of the supply chain, it is still a factor of 25 lower than the IPCC, UNEP and Global Carbon Project values for total emissions from natural gas production and use.

To resolve this contradiction, measurements are needed at production and processing plants, at pipelines, liquefaction and regasification plants, as well as on ships transporting liquefied natural gas and in distribution networks and at end users. Such measurements have been carried out very intensively over the past 15 years, especially in the USA.

Basically, three types of studies can be distinguished:

- Component studies in which gas emissions are measured at individual typical plant components, e.g. (Zimmerle et al. 2019)
- Facility-level (site-level) studies in which emissions from extraction or processing facilities are measured by measuring gas concentrations in the environment (downwind). Measurements are often made using mobile measurement vehicles, drones, and aircraft, but also stationary measurement equipment, e.g. (Chen et al. 2022; Robertson et al. 2020)
- Studies at the production area level that infer the distribution of gas sources through satellite and aircraft measurements and the application of atmospheric transport models, e.g. (Zhang et al. 2020)

However, many measurements, especially at the facility and production area level, have also long been at odds with the values of the official US EPA emissions inventory (Greenhouse Gas Inventory (GHGI)), which is based on a - very detailed - scaling of component measurements. (US EPA 2018). Brandt et al. (2014) estimate in a review paper that the EPA methane inventory underestimates emissions by 50%. In their view, the atmospheric measurements suggest that a small fraction of facilities, so-called "super-emitters" - sources with extremely high emissions far in excess of normal operations - are likely an important reason for these differences. In 2018, Alvarez et al. published another review study with updated data that combined a bottom-up analysis with a top-down analysis that covered 30% of U.S. gas production. Their facility-based estimate of natural gas and petroleum supply chain emissions for 2015 is 60% higher than the US EPA GHGI estimate.

Although it is so well documented, at least for the USA, that the official emission inventories significantly underestimate methane emissions from oil and gas production, this finding has not yet been reflected in many life cycle assessment studies and databases, e.g., the Argonne National Laboratory's GREET life cycle assessment model. Moreover, such detailed measurements are only available for the USA, and even there it was not possible for a long time to make a satisfactory allocation to the products oil and gas and to the individual steps in the process chains. Probably for this reason, even the most recent studies on the supply of Europe with both pipeline-bound and liquefied natural gas point to the methodological uncertainties and continue to use the significantly lower emission values of the state inventories and company data (Baumann and Schuller 2021; Sphera 2021).

Progress in regional and sectoral allocation

In the five years following the publication of the study of Alvarez et al. (2018) however, the level of knowledge and methodological approach has improved once again. New algorithms of data analysis have made it possible to detect very large methane sources ("ultra-emitters" with emission rates > 25 t/h) in data from environmental satellites (e.g., Sentinel-5P) (Irakulis-Loitxate et al. 2021; Lauvaux et al. 2022). These ultra-emitters were found in many of the major oil and gas producing areas, the U.S.; North Africa, the Middle East, and the former Soviet Union during the period of observation.

With the procedure first described by the International Energy Agency in the "World Energy Outlook 2017" (IEA 2017) and subsequently published as the online tool "IEA Methane Tracker", there is now a pragmatic solution for allocating emissions to the oil and gas process chains. This is based on the research evaluated situation in the USA, from which a distribution scheme is derived that distinguishes between oil and gas production, onshore and offshore, upstream and downstream processes. This scheme is then adjusted to other producing countries based on socio-economic factors (structure of producing companies, government regulation, age of infrastructure, length of transportation network, and many others). The current version calculates methane emission profiles for the oil and gas industry for over 70 countries (IEA 2022). However, the documentation for the IEA Methane Tracker is very limited and the model has not gone through an independent review process.

While the IEA Methane Tracker takes more of a top-down approach by allocating emissions to products and process steps, bottom-up studies in the U.S. succeed in bridging much of the gap between emissions inventories and facility-based measurements. In the study by Rutherford et al. (2021) the authors present a model based on a comprehensive database on the use and emissions of individual technical components. A statistical method is applied to this (bootstrap resampling) that can better capture the occurrence of rare, large emitters (super-emitters). Using the method of Rutherford et al. (2021) and its integration in the Stanford model OPGEE (Oil Production Greenhouse Gas Emissions Estimator) (Brandt et al. 2020) the results of Alvarez et al. (2018) can be convincingly reproduced. Furthermore, it allows a transparent allocation to the products oil and gas.

In the meantime, the data on the increased methane emissions have also found their way into relevant life cycle assessment studies and databases. For example, in the Ecoinvent database version 3.9, emissions were included for the first time using the distribution scheme of the IEA Methane Tracker (Ecoinvent 2022; Meili et al. 2022). In 2021, the U.S. LCA model GREET has adjusted its emission factors for natural gas based on the method of Rutherford et al. (2021).

In the coming years, further improvement of the data situation and an expansion of the bottom-up method to other countries beyond the U.S. can be expected (chap. 9.1).

5 Data sources and selection

5.1 Data sources

In order to model and evaluate consistent supply chains for all supplier countries, it is desirable to use a data foundation that is as uniform and transparent as possible. Two suitable main data sources emerged from our literature review. A group of consecutive studies forms the one main data source:

- " Kritische Überprüfung der Default-Werte der Treibhausgasvorkettenemissionen von Erdgas". (DBI 2016)
- "Greenhouse Gas Intensity of Natural Gas; Study for the Natural & Bio Gas Vehicle Association (NGVA) Europe " (thinkstep 2017)
- "Life cycle GHG emission study on the use of LNG as marine fuel." (Sphera 2019)
- "2nd Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel." (Sphera 2021)
- " Emissionsfaktoren der Stromerzeugung - Betrachtung der Vorkettenemissionen von Erdgas und Steinkohle". (Baumann and Schuller 2021)

A positive aspect of these studies is that some of the data were collected directly from the companies involved (oil and gas producers, long-distance network operators) and that individual process steps, such as the liquefaction of natural gas or ship transport, were examined at a high technological and geographical resolution.

Less advantageous is that thinkstep/Sphera only publish selected data of the modeled processes. The complete process data, as well as that of the background processes used (infrastructure, fuels, auxiliary materials) are taken from the proprietary life cycle inventory database GaBi (Sphera Datenbank 2021).

The second major data source used was the life cycle inventory database Ecoinvent version 3.9.1. The database is used worldwide for various types of sustainability assessments. It enables analyses of the environmental impact of products and services throughout their life cycle, from production to consumption to disposal. The database contains more than 18,000 life cycle inventory data from a wide range of economic sectors at both regional and global levels. (ecoinvent v3 2019).

For this study, it is particularly beneficial that Ecoinvent has completely revised the oil and gas supply data in the current version of the database (Ecoinvent 2022). The underlying assumptions and process data are comprehensibly documented and already take into account the increased methane emissions based on the IEA Methane Tracker (Bussa et al. 2022; Meili et al. 2022)..

Disadvantages of the oil and gas model in Ecoinvent are the, compared to Sphera, lower technological and geographical granularity.

Several other data sources are available for the U.S., some of which use industry data, high technological granularity, and most current research results to model the supply of oil and gas in North America:

- The National Energy Technology Laboratory (**NETL**) is a U.S. national research institute under the U.S. Department of Energy, Office of Fossil Energy. NETL researchers model and assess fossil fuel supply (NETL 2019; Rai et al. 2021).
- **GREET** (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) is a life cycle assessment model maintained by Argonne National Laboratory (U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy). It evaluates the energy and emissions impacts of fossil fuels, as well as advanced and new transportation fuels - the fuel cycle from source to wheel and the vehicle cycle to materials recovery and vehicle disposal. (GREET 2022)
- The Environmental Assessment and Optimization (EAO) group at Stanford University is developing models and tools to assess greenhouse gas emissions from fossil fuel energy systems. Their approach includes the development of engineering-based bottom-up models for life cycle analysis (LCA). The **OPGEE** (Oil Production Greenhouse gas Emissions Estimator) model, version 3, was extended in part through the work of Rutherford (2022) and Rutherford et al. (2021) to include the gas supply chain in great detail.

The following section lists and compares the process data taken from these data sources and presents the values selected for this study.

5.2 Process data

5.2.1 Production and processing of natural gas outside the USA

Available data on energy use in the production and processing of natural gas in producing countries outside the U.S. are shown in Table 1. While Ecoinvent (2022) based on Meili et al. (2022) uses data from IOGP (2020) which is differentiated according to seven world regions, Sphera (2021) collected data in part from companies (Nigeria) or sourced it from sustainability reports (Qatar). We give preference to the latter over the Ecoinvent data for these countries because of the better geographical reference. For other countries Sphera (2021) used Gabi, its own internal database (Sphera Datenbank 2021). Since that database is not transparent, we use the Ecoinvent data for these countries (Malaysia, Indonesia). For Algeria we also use Ecoinvent (2022), since the study used by Sphera (EXERGIA 2015) has methodological weaknesses.

Table 1: Energy use (calorific value, LHV) in natural gas production and processing, producing countries except USA , values used are highlighted green , sources: (Ecoinvent 2022; Sphera 2021)

Energy source	***Unit***	**Ecoin-vent 3.9.1 Qatar**	**Sphera 2021 Qatar**	**Ecoin-vent 3.9.1 Algeria**	**Sphera 2021 Algeria**	**Ecoin-vent 3.9.1 Nigeria**	**Sphera 2021 Nigeria**	**Ecoin-vent 3.9.1 Malaysia**	**Sphera 2021 Malaysia**
Power	***MJ/t***	60.3	0	15.9	402.0	15.9	0.3	104.4	1.2
Diesel	***MJ/t***	31.1	0	31.2	34.4	31.5	4.8	39.7	31.3
Natural gas*	***MJ/t***	710.1	1479.7	4341.2	1461.3	3774.3	2778.8	2953.5	875.6
Total	***MJ/t***	801.5	1479.7	4388.3	1897.7	3821.7	2783.9	3097.6	908.1
Data source		[1]	[2]	[1]	[3]	[1]	[4]	[1]	[5]

*Includes natural gas for energy use and flared gas.
[1] **(Meili et al. 2022)**, there regional (continental) values based on. **(IOGP 2020)**
[2] **(thinkstep 2017)**, there based on RarGas and Qatargas, Sustainability Reports 2015.
[3] **(thinkstep 2017)**, there based on **(EXERGIA 2015)**
[4] **(thinkstep 2017)**, there based on primary data from Nigeria Shell and ENI.
[5] **(Sphera Datenbank 2021)**

Table 1 (continued): Energy use (LHV) in the production and processing of natural gas, producing countries except USA, values used are highlighted green.

Energy source	*Unit*	Ecoinvent 3.9.1 Indonesia	Sphera 2021 Indonesia
Electricity	*MJ/t*	104.3	1.0
Diesel	*MJ/t*	39.7	32.8
*Natural gas**	*MJ/t*	2807.1	4392.8
Total	*MJ/t*	2951.1	4426.6
Data source		[1]	[5]

*Includes natural gas for energy use and flared gas.
[1] **(Meili et al. 2022)**, there regional (continental) values based on. **(IOGP 2020)**
[5] **(Sphera database 2021)**

Available data on gas and thus methane emissions from natural gas production and processing in producing countries outside the U.S. are shown in Table 2. Ecoinvent (2022) evaluates on the basis of Meili et al. (2022) country-specific data from the IEA methane tracker. (IEA 2022). In Sphera (2021) the same data sources are evaluated as for energy use. Since for the USA (chap. 5.2.2) I can be shown that the approach of Meili et al. (2022) is in good agreement with the transparent calculation from other publications, we use the data from Ecoinvent (2022) for all countries. In the future, it is desirable to improve the database for countries outside the US.

Table 2: Gas emissions from natural gas extraction and processing, producing countries except USA, values used are highlighted green, sources: (Ecoinvent 2022; Sphera 2021).

	Unit	Ecoinvent 3.9.1 Qatar	Sphera 2021 Qatar	Ecoinvent 3.9.1 Algeria	Sphera 2021 Algeria	Ecoinvent 3.9.1 Nigeria	Sphera 2021 Nigeria	Ecoinvent 3.9.1 Malaysia	Sphera 2021 Malaysia
NG Emissions	*Vol-% (m^3 NG/m^3 NG)*	0.68*	0.06	1.39*	2.00	1.22*	0.11	0.41*	0.75
Data source		[1]	[2]	[1]	[3]	[1]	[4]	[1]	[5]

*also includes direct methane emissions from energy use.
[1] **(Meili et al. 2022)**, there values based on **(IEA 2022)** and **(BP 2020)**
[2] **(thinkstep 2017)**, there based on RarGas and Qatargas, Sustainability Reports 2015.
[3] **(thinkstep 2017)**, there based on **(EXERGIA 2015)**
[4] **(thinkstep 2017)**, there based on primary data from Nigeria Shell and ENI.
[5] **(Sphera Datenbank 2021)**

Table 2 (continued): Natural gas emissions from natural gas extraction and processing, producing countries other than the U.S. (continued), values used are highlighted green, sources: (Ecoinvent 2022; Sphera 2021).

	Unit	Ecoinvent 3.9.1 Indonesia	Sphera 2021 Indonesia
NG Emissions	*Vol-% (m^3 NG/m^3 NG)*	1.10*	0.46
Data source		[1]	[5]

*also includes direct methane emissions from energy use.
[1] **(Meili et al. 2022)**, there values based on **(IEA 2022)** and **(BP 2020)**
[5] **(Sphera Datenbank 2021)**

5.2.2 Production and processing of natural gas in the USA

The available data on energy use in the extraction and processing of natural gas in the USA are shown in Table 3. While Ecoinvent (2022) based on Meili et al. (2022) uses an average value from IOGP (2020), Sphera (2021) sources data from its own internal database GaBi for conventional production and partly primary data from Exxon Mobil for unconventional production. The LCA model GREET 2022 uses values from Rai et al. (2021), some of which are based on industry data. For this study, we use data from GREET 2022 because we believe it best represents the situation in the United States. An average of 25% conventional and 75% unconventional production is assumed.

Table 3: Energy use (LHV) in natural gas production and processing in the US, values used are highlighted green, sources: (Ecoinvent 2022; GREET 2022; Sphera 2021).

Energy source	***Unit***	**Ecoinvent 3.9.1**	**Sphera 2021 USA conv.**	**Sphera 2021 USA unconv.**	**GREET 2022 USA conv.**	**GREET 2022 USA unconv.**	**GREET 2022 USA (25/75)****
Electricity	***MJ/t***	61.6	20.7	6.1	38.4	38.4	38.4
Diesel	***MJ/t***	59.0	40.3	367.1	22.9	15.9	17.7
Natural gas*	***MJ/t***	3349	1616	1040	2977	2792	2838
Total	***MJ/t***	3470	1677	1414	3038	2846	2894
Data source		[1]	[2]	[3]	[4]	[4]	[4]

*Includes natural gas for energy use and flared gas.
** Average of 25% conventional and 75% unconventional production.
[1] **(Meili et al. 2022)**, there regional (continental) values based on. **(IOGP 2020)**
[2] **(Sphera database 2021)**
[3] **(Sphera 2019)**, there partly Primary data from Exxon Mobil
[4] **(Rai et al. 2021)**, there partly company data

The available data on gas and thus methane emissions from natural gas production and processing in the U.S. are shown in Table 4. Ecoinvent (2022) also evaluates here on the basis of Meili et al. (2022) country-specific data from the IEA methane tracker (IEA 2022). In Sphera (2021) the same data sources are evaluated as for energy use. GREET 2022 calculates natural gas losses in one case based on US EPA (2018) and in another on the same basis and scaled following Rutherford et al. (2021). NETL (2021) calculates losses based on US EPA (2016, 2018). OPGEE 3.0 uses Rutherford (2022) and Rutherford et al. (2021). Because we consider the OPGEE 3.0 calculation to be the most transparent, elaborate, and technologically sophisticated, and the Ecoinvent value is very similar, we also use the Ecoinvent value for the United States for global consistency.

Table 4 : Natural gas emissions from natural gas extraction and processing in the U.S., values used green, sources: (Brandt et al. 2020; Ecoinvent 2022; GREET 2022; Rai et al. 2021; Rutherford 2022; Sphera 2021).

	Unit	**Ecoin-vent 3.9.1**	**Sphera 2021 USA conv.**	**Sphera 2021 USA un-conv.**	**NETL 2021**	**GREET 2022 with EPA 2022**	**GREET 2022 conv./un-conv.**	**OPGEE 3.0**
NG Emis-sions	*Vol-% (m^3 NG/ m^3 NG)*	1.23*	0.10	0.62	1.1	0.40	0.58	1.3
Data source		[1]	[2]	[3]	[4]			

*also includes direct methane emissions from energy use.
[1] **(Meili et al. 2022)**, there continental value based on **(IEA 2022)** and **(BP 2020)**
[2] **(Sphera Datenbank 2021)**
[3] **(Sphera 2019)**, there partly Primary data from Exxon Mobil
[4] **(Rai et al. 2021)**, there partly company data
[5] based on **(US EPA 2022a)**
[6] based on **(US EPA 2022a)** with **(Rutherford et al. 2021)**
[7] **(Brandt et al. 2020)** With **(Rutherford 2022; Rutherford et al. 2021).**

5.2.3 Pipeline transport in the producing country

The available data on energy expenditures and gas and thus methane emissions during pipeline transportation of natural gas in the producing countries under consideration are shown in Table 5 and Table 6. Ecoinvent (2022) sets a higher value for energy demand for producing countries outside Europe and North America than inside these regions. Sphera (2021) assumes the same energy demand worldwide. Since the energy values of Sphera are very close to those of GREET (2022) we use them for all countries. For pipeline natural gas losses, we follow Sphera's reasoning that offshore pipelines are closed systems with no leakage. For onshore pipelines outside the U.S., we use the value from Ecoinvent (2022) based on Bussa et al. (2022). For the US, we consider the GREET assumption to be the most appropriate. For the transport distances, we follow the assumptions of Sphera.

Table 5: Energy use (LHV) and gas losses pipeline transport, producing countries except USA, values used are highlighted green

	Unit	**Ecoinvent 3.9.1** **World except RER, RNA**	**Sphera 2021 Qatar**	**Sphera 2021 Algeria**	**Sphera 2021 Nigeria**	**Sphera 2021 Malaysia**	**Sphera 2021 Indonesia**
Ons-hore/offs-hore		Onshore =offs-hore	offshore	onshore	offshore	onshore	offshore
Natural gas for compres-sors	*MJ/(MJ*km)*	2.2E-05	3.0E-05	3.0E-05	3.0E-05	3.0E-05	3.0E-05
NG emissions	*%/1000km*	0.204	0	0.016	0	0.11	0
Distance	*km*		80	542	200	500	60

Table 6: Energy use (LHV) and gas losses pipeline transport in the USA, values used are highlighted green

	Unit	**Ecoinvent 3.9.1**	**Sphera 2021**	**NETL 2021**	**GREET 2022**	**Alvarez 2018**
Natural gas for compres-sors	*MJ/(MJ*km)*	9.0E-06	3.00E-05		2.8E-05	
NG emissi-ons	*%/1000km*	0.019	0.47	0.24	0.34	0.26
Distance	*km*	1020	500			

5.2.4 Liquefaction

The available data on energy expenditures and gas and thus methane emissions during the liquefaction of natural gas in the producing countries considered are shown in Table 7 and Table 8. Ecoinvent (2022) applies uniform values for all countries, while Sphera (2021) differentiates strongly by country-specific liquefaction technology and environmental temperatures. We choose these differentiated data for energy expenditures for this study.

The picture for direct methane emissions is more mixed. Although Sphera (2021) and Baumann and Schuller (2021) refer to the same sources, the values differ significantly. Sphera (2021) gives only the fraction of evaporating LNG (Boil Off Gas, BOG) that is emitted. The values of Baumann and Schuller (2021) (in Table 7 and Table 8 referred to as UBA 2021), on the other hand, also include methane emissions from the upstream chain (infrastructure, electricity). Since these cannot be comprehensibly separated from the direct emissions from liquefaction, we use for this study for all countries the value of (GREET 2022).

Table 7: Energy use (LHV) and gas losses liquefaction, producing countries except USA, values used are highlighted green, sources: (Baumann and Schuller 2021; Ecoinvent 2022; Sphera 2021).

	Unit	**Ecoinvent 3.9.1**	**Sphera 2021 Qatar**	**UBA 2021 Qatar**	**Sphera 2021 Algeria**	**Sphera 2021 Nigeria**	**UBA 2021 Nigeria**	**Sphera 2021 Malaysia**	**Sphera 2021 Indonesia**
Natural gas	***MJ/t***	4212	5220		7380	4847		4997	4996
Electricity	***MJ/t***	0	291		142	188		188	187
NG emissions	***Vol-% (m3NG/ m3NG)***	0.05	0.03 *	0.24**	0.03*	0.03 *	0.25**	0.03*	0.03*

*Only portion of evaporating LNG (Boil Off Gas, BOG) that is emitted.
**Including direct methane emissions from upstream (electricity, infrastructure, etc.)

Table 8: Energy use (LHV) and gas losses liquefaction in the US, values used are highlighted green, , sources: (Baumann and Schuller 2021; Ecoinvent 2022; GREET 2022; Sphera 2021).

	Unit	Ecoinvent 3.9.1	Sphera 2021	UBA 2021	GREET 2022
Natural gas	***kJ/t***	4212	5013		4279
Electricity	***MJ/t***	0	109		87
NG emissions	***Vol-% (m3NG/ m3NG)***	0.05	0.03*	0.24**	0.1

*Only portion of evaporating LNG (Boil Off Gas, BOG) that escapes.
**Including direct methane emissions from upstream (electricity, infrastructure, etc.)

5.2.5 Ship transport

The available data on fuel demand and on gas and thus methane emissions during ship transport of natural gas from the producing countries considered, as well as ship types used, are shown in Table 9 and Table 10. While Ecoinvent (2022) assumes a single type of ship powered by heavy fuel oil (SSD, slow speed diesel), and Bussa et al. (2022) a single type with dual-fuel propulsion (DFDE , Dual Fuel Diesel Electric), Sphera (2021) differentiates on the basis of IGU (2020) strongly by ship technologies and their use on different transport routes. We adopt Sphera's values with a simplified differentiation (three ship types instead of eight). The distances in Table 10 are determined with the online calculator sea-distances.org with the uniform destination port Wilhelmshaven.

Table 9: Fuel consumption (LHV), gas losses and methane slip (propulsion) in marine transport, values used are highlighted green, sources: (Bussa et al. 2022; Ecoinvent 2022; Sphera 2021).

	Unit	Ecoinvent 3.9.1 SSD	Bussa 2022 DFDE	Sphera 2021 SSD	Sphera 2021 Steam tur-bine	Sphera 2021 DFDE
HFO/VLSFO/MGO	***MJ/tkm***	0.110	0.068	0.084	0.015	0.005
BOG	***MJ/tkm***		0.154	0	0.133	0.099
Gas losses	***Nm3 LNG/tkm***			0	3.55E-06	2.65E-06
Methane slip	***g CH4/tkm***		0.129	0	0	0.055

Table 10 :Distances ship transport to Wilhelmshaven and simplified ship type mix according to (sea-distances.org 2023; Sphera 2021)

	Unit	**Qatar**	**Algeria**	**Nigeria**	**Austra-lia**	**Malay-sia**	**Indone-sia**	**Trinidad and To-bago**	**USA**
Distance	***km***	12000	3650	8500	18000	17000	16000	7900	9500
Ship type		80% SSD 20% DFDE	90% steam turbine 10% DFDE	45% steam turbine, 55% DFDE	45% steam turbine, 55% DFDE	45% steam turbine, 55% DFDE	45% steam turbine, 55% DFDE	45% steam turbine, 55% DFDE	45% steam turbine, 55% DFDE

5.2.6 Regasification

The available data on energy expenditures and on gas and thus methane emissions during the regasification of natural gas in Germany are shown in Table 11. Ecoinvent (2022) based on Bussa et al. (2022) assumes a technology mix of 60% open rack vaporizers (ORVs) and 40% submerged combustion vaporizers (SCVs). thinkstep (2017) uses values from the industry association GIE (Gas Infrastructure Europe). For this study, we use the data from the thinkstep study.

Table 11: Fuel consumption (LHV), gas losses and methane slip (propulsion) in marine transport, values used are highlighted green

	Unit	Ecoinvent 3.9.1	Thinkstep 2017
Natural gas	*MJ/MJ*	6.9E-03	8.5E-04
Electricity	*MJ/MJ*	0	4.8E-04
Diesel	*MJ/MJ*	0	2.0E-06
NG emissions	*Vol-% (m3NG/ m3NG)*	0.05 %	0.004 %

5.2.7 Background processes

All background processes (infrastructure, electricity, provision of fuels, auxiliary materials, etc.) are taken from the Ecoinvent life cycle inventory database, version 3.9.1.

6 LCA model and impact assessment

A parameterized model of the process chain for the provision of liquefied natural gas was built in Umberto 11 a material flow and life cycle assessment software.

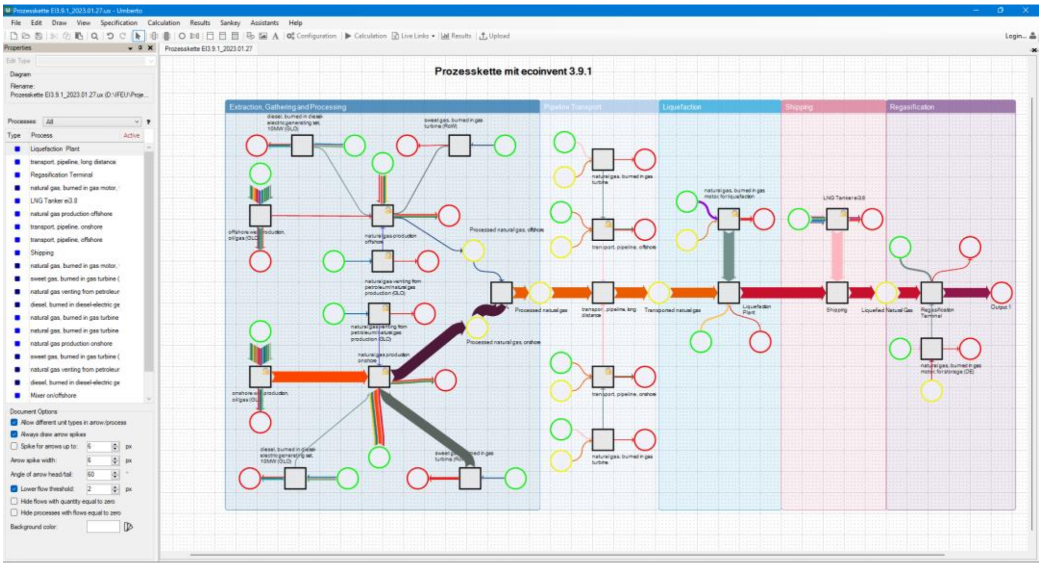

Figure 5: Screenshot of the LNG model in the LCA software Umberto 11.

For each supplier country, one set of parameters according to chapter 5 was compiled. The life cycle inventory (inputs and outputs from and to the environment) was calculated and evaluated according to the following methods:

Indicators used to assess the climate impact of direct and indirect emissions generated in the process chain were:

- Global Warming Potential over 100 years (GWP 100). This is the indicator most frequently used in studies in the impact category climate change.
- Global Warming Potential over 20 years (GWP20). This indicator more strongly reflects the effect of short-lived climate gases. This is particularly significant in connection with methane emissions from the gas provision.

The extent to which the emission of a greenhouse gas contributes to the respective indicator is determined by characterization factors. Since the manifold impact chains of greenhouse gases are the subject of ongoing research, the characterization factors for methane and nitrous oxide in particular have been repeatedly adjuted. The Intergovernmental Panel on Climate Change (IPCC) has established itself as the de facto normative body. Table 12 shows the characterization factors for CO_2, methane, and nitrous oxide in the IPCC reports 2007, 2013 and 2021. In the IPCC report 2013, characterization factors with and without carbon-climate feedback (CCFB)- are given for methane and nitrous oxide. CCFB accounts for the fact that a changing climate in turn changes CO_2 fluxes between the atmosphere, land, and oceans. Unfortunately, values using CCFB were not published for all gases in the 2013 IPCC report. For CO, NOx, SO_2, VOC, and fossil methane, only values without CCFB are available. For this study, the life cycle inventories were therefore calculated according to IPCC (2013) without CCFB and according to IPCC (2021). As described in chapters 7.1 and 7.2, these choices leads to only minor differences in the results, since the characterization factors for the most important greenhouse gases CO_2 and methane are only slightly changed.

Table 12 : Characterization factors for CO_2, methane, and nitrous oxide in the IPCC 2007, 2013, and 2021 reports. Sources: (IPCC 2007, 2013, 2021)

	GWP20 [kg CO_2 e/kg]			**GWP100 [kg CO_2 e/kg]**		
	CO_2	*$CH_{4,fossil}$*	*N_2O*	*CO_2*	*$CH_{4,fossil}$*	*N O_2*
IPCC 2007*	1	72	289	1	25	298
IPCC 2013*	1	84.6	264	1	29.7	265
IPCC 2021	1	82.5	273	1	29.8	273
*without Carbon-Climate Feedback (CCFB)-.						

7 Results

7.1 Climate change

Figure 6 shows the global warming potential over a period of 100 years (GWP100 according to IPCC 2013) of LNG from selected countries, differentiated by stages of the process chain. Production and processing as well as liquefaction represent the process sections with the largest climate impact. The differences between the countries of origin result both from different energy intensities in production and from country-specific methane emissions.

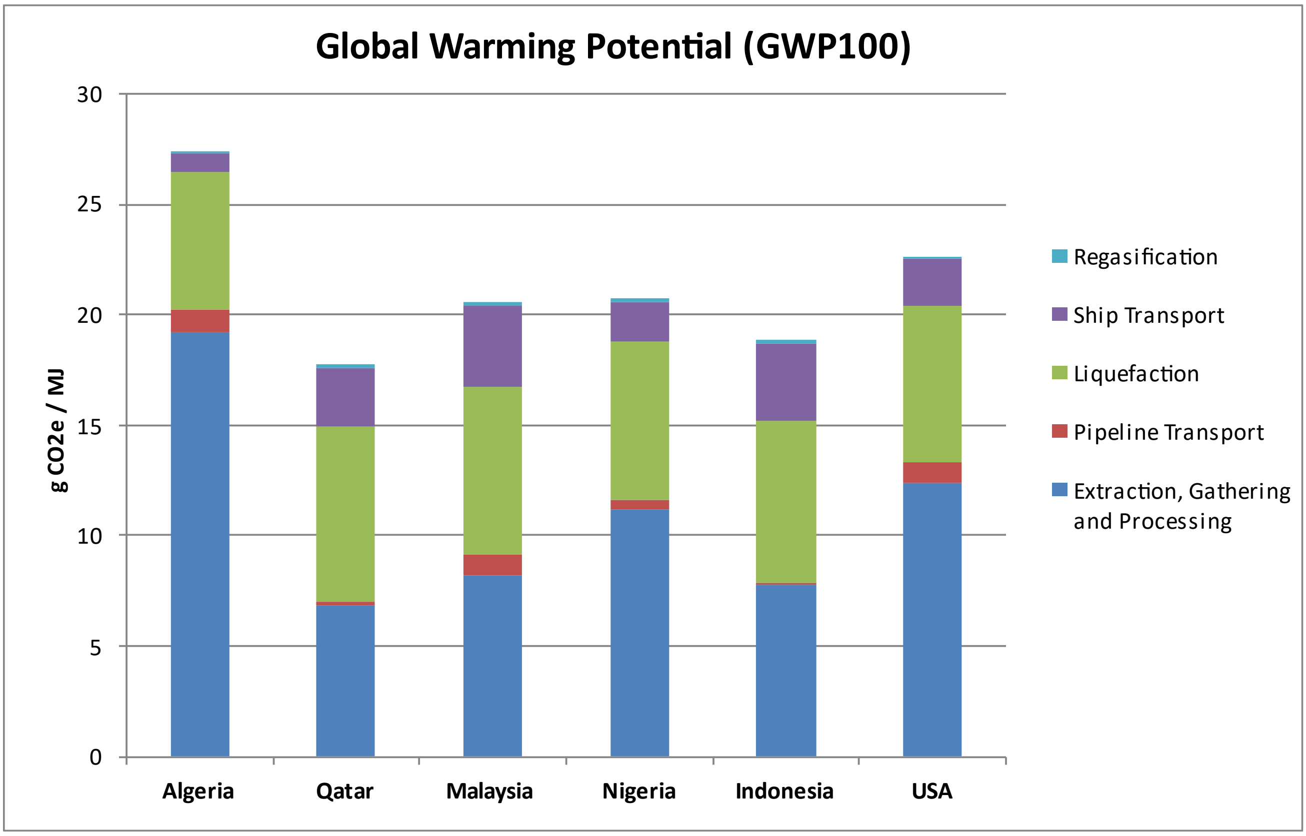

Figure 6: Global warming potential over a period of 100 years (GWP100 according to AR5 IPCC 2013) for the provision of LNG from selected countries up to regasification in Germany, differentiated by life cycle stages (source: ifeu, own calculation).

Table 13 shows the detailed results according to AR5 IPCC 2013 and the overall result according to AR6 IPCC 2021. The slightly changed characterization factors have almost no influence on the overall results.

Table 13 : Global warming potential over a period of 100 years (according to AR5 IPCC 2013) for the provision of LNG from selected countries up to regasification in Germany, differentiated by life cycle stages and as overall results according to AR6 IPCC 2021 (source: ifeu, own calculation).

	GWP 100 [gCO2e/MJ] according to IPCC 2013						**GWP 100 [gCO2e/MJ] according to IPCC 2021**
	Production and processing	Pipeline transport	Liquefaction	Ship transport	Regasification	Total	Total
Algeria	19.2	1.0	6.3	0.8	0.1	**27.5**	**27.3**
Qatar	6.9	0.2	8.0	2.6	0.1	**17.7**	**17.7**
Malaysia	8.2	0.9	7.6	3.7	0.1	**20.6**	**20.5**
Nigeria	11.2	0.4	7.2	1.9	0.1	**20.8**	**20.7**
Indonesia	7.7	0.1	7.3	3.5	0.1	**18.8**	**18.7**
USA	12.4	0.9	7.2	2.1	0.1	**22.7**	**22.6**

Due to the large contribution of methane emissions (details in the following chap. 7.2), the global warming potential over a period of 20 years is significantly higher. Figure 7 shows these results for LNG imported from the selected countries, differentiated by sections of the process chain. Since most of the methane emissions take place in the production and processing phase, their share in the overall greenhouse potential result (GWP 20) increases for all countries.

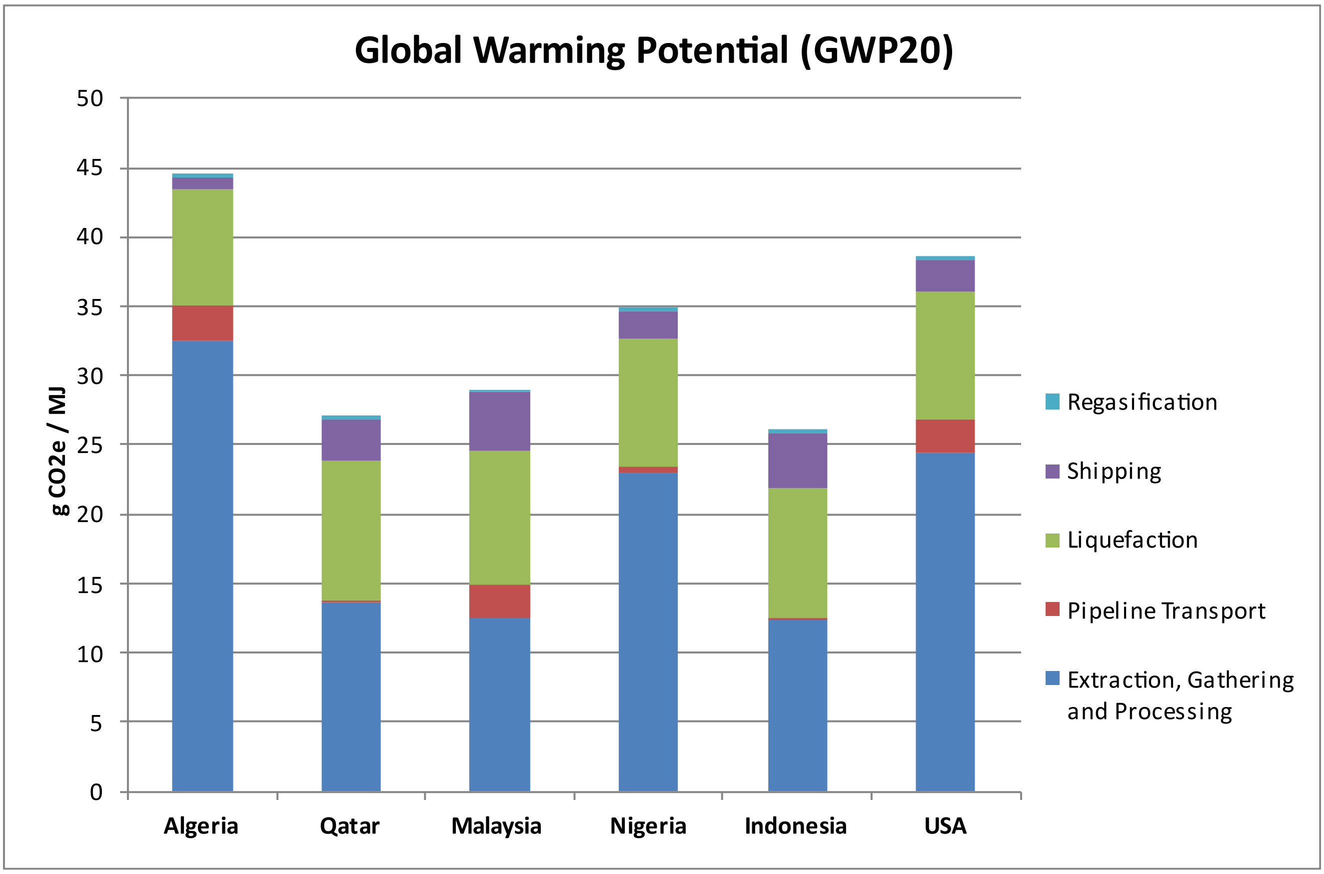

Figure 7: Global warming potential over a period of 20 years (GWP20 according to AR5 IPCC 2013) for the provision of LNG from selected countries up to regasification in Germany, differentiated by life cycle stages (source: ifeu, own calculation).

Table 14 shows the detailed results according to AR5 IPCC 2013 and the overall results according to AR6 IPCC 2021. The slightly changed characterization factors have only a minor influence on the overall results here as well.

Table 14 : Global warming potential over a period of 20 years (according to AR5 IPCC 2013) for the provision of LNG from selected countries up to gasification in Germany, differentiated by life cycle stages and as an overall result according to AR6 IPCC 2021 (source: ifeu, own calculation).

	GWP 20 [gCO2e/MJ] according to IPCC 2013						GWP 20 [gCO2e/MJ] according to IPCC 2021
	Production and processing	Pipeline transport	Liquefaction	Ship transport	Regasification	Total	Total
Algeria	32.6	2.5	8.3	0.9	0.2	**44.5**	**43.9**
Qatar	13.6	0.2	10.1	3.0	0.2	**27.1**	**26.7**
Malaysia	12.5	2.4	9.7	4.2	0.2	**29.0**	**28.7**
Nigeria	23.0	0.4	9.2	2.1	0.2	**34.9**	**34.4**
Indonesia	12.4	0.1	9.4	4.0	0.2	**26.1**	**25.8**
USA	24.4	2.4	9.2	2.4	0.2	**38.6**	**38.0**

7.2 Influence of individual climate gases

Figure 8 shows the global warming potential over a period of 100 years (according to IPCC 2013) of LNG from selected countries, differentiated by greenhouse gas. For Algeria, Nigeria and the USA, methane contributes about one third to the climate impact (GWP 100), for the other countries about 20%. Nitrous oxide and other greenhouse gases play virtually no role.

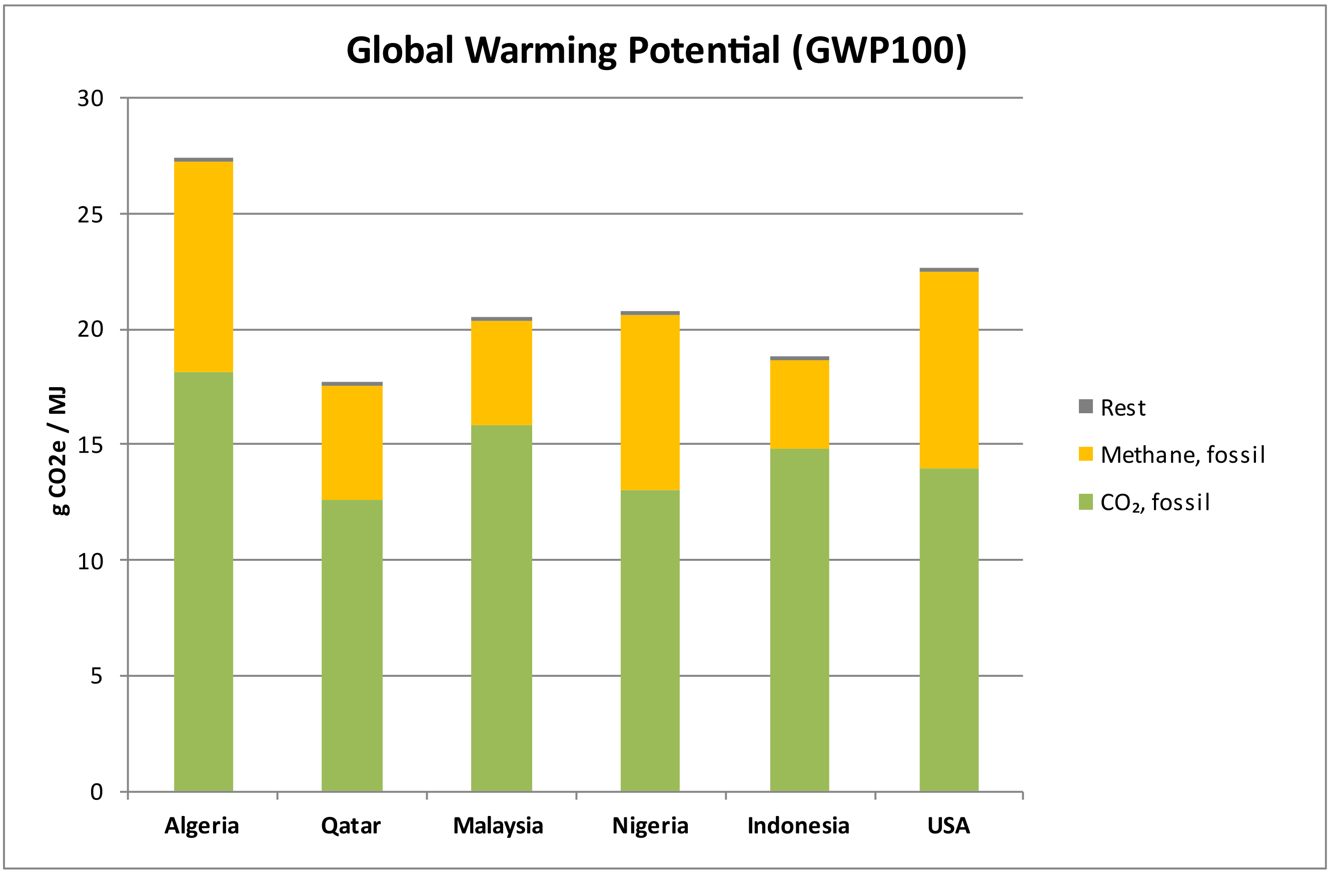

Figure 8: Global warming potential over a period of 100 years (GWP100 according to AR5 IPCC 2013) for the provision of LNG from selected countries up to gasification in Germany, differentiated by greenhouse gases (source: ifeu, own calculation).

Figure 9 shows the global warming potential over a 20-year period (according to IPCC 2013) of LNG from selected countries, differentiated by greenhouse gas. For Algeria, Nigeria, and the U.S., methane contributes about 60% to the climate impact (GWP 20), and between 40% and 50% for the other countries. Again, other greenhouse gases make virtually no contribution.

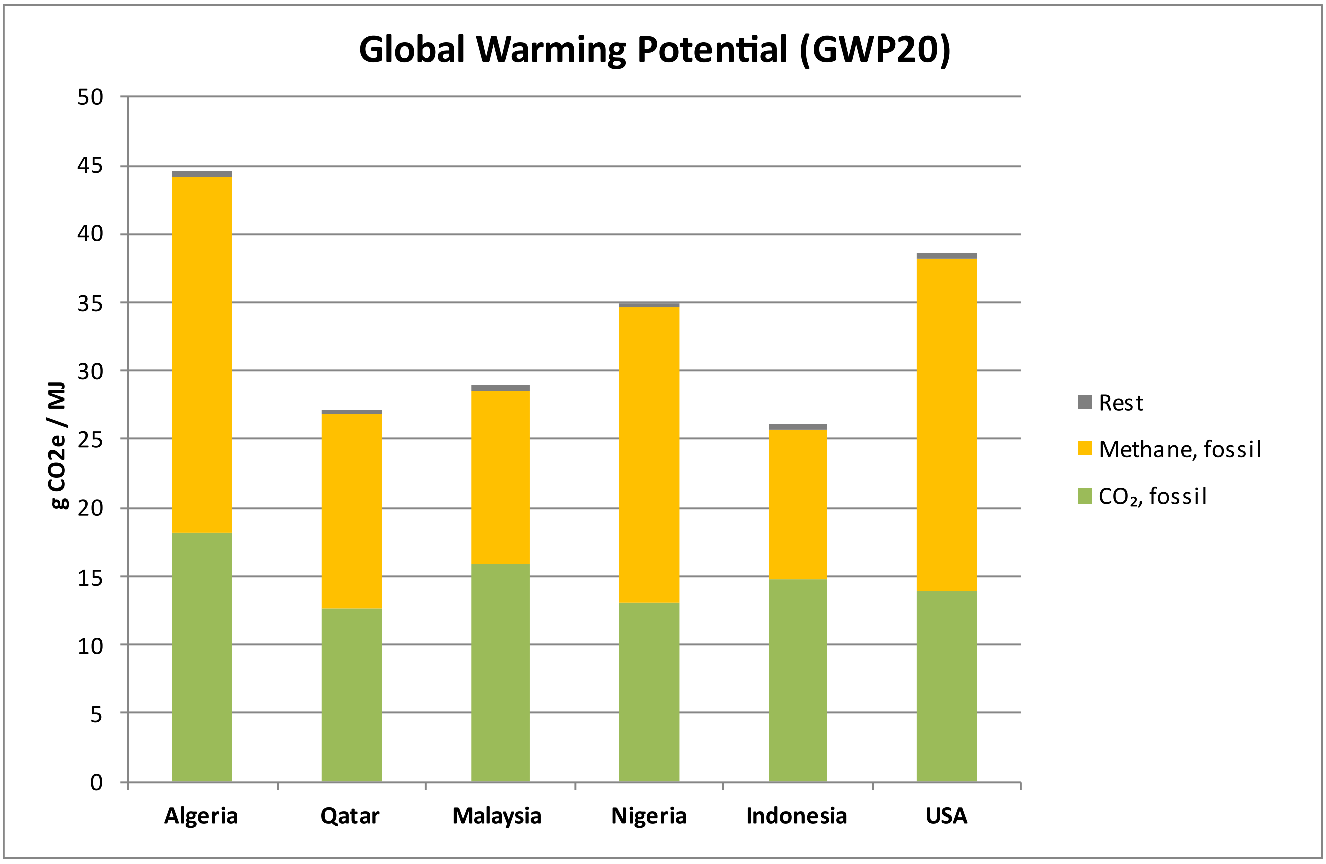

Figure 9: Global warming potential over a period of 20 years (GWP20 according to AR5 IPCC 2013) for the provision of LNG from selected countries up to regasification in Germany, differentiated by greenhouse gases (source: ifeu, own calculation).

8 Assessment and Evaluation

8.1 Comparison with pipeline natural gas and LNG in other studies.

Figure 10 shows the results of this study (GWP 100, IPCC 2013) compared with those for pipeline-bound gas from the life cycle inventory database Ecoinvent v3.9.1 (Ecoinvent 2022) and the study commissioned by the German Federal Environment Agency (Baumann and Schuller 2021). While Ecoinvent already takes into account increased methane emissions according to Meili et al. (2022) based on the IEA Methane Tracker, these are significantly lower in the other study. Pipeline gas from Norway has a short transport route and a transparently documented strategy to avoid methane emissions. The emissions allocated according to IEA Methane Tracker are correspondingly low. For pipeline gas from Russia, the long distance results in significant energy-related emissions, which were also reported in the study by Baumann and Schuller (2021). This leads to a GWP of about 10 gCO2e/MJ. The consideration of methane emissions according to IEA in Ecoinvent (2022) leads to values that are more than twice as high. In this case, pipeline gas from Russia has a higher GWP per unit of energy than LNG from all the producing countries studied here except Algeria.

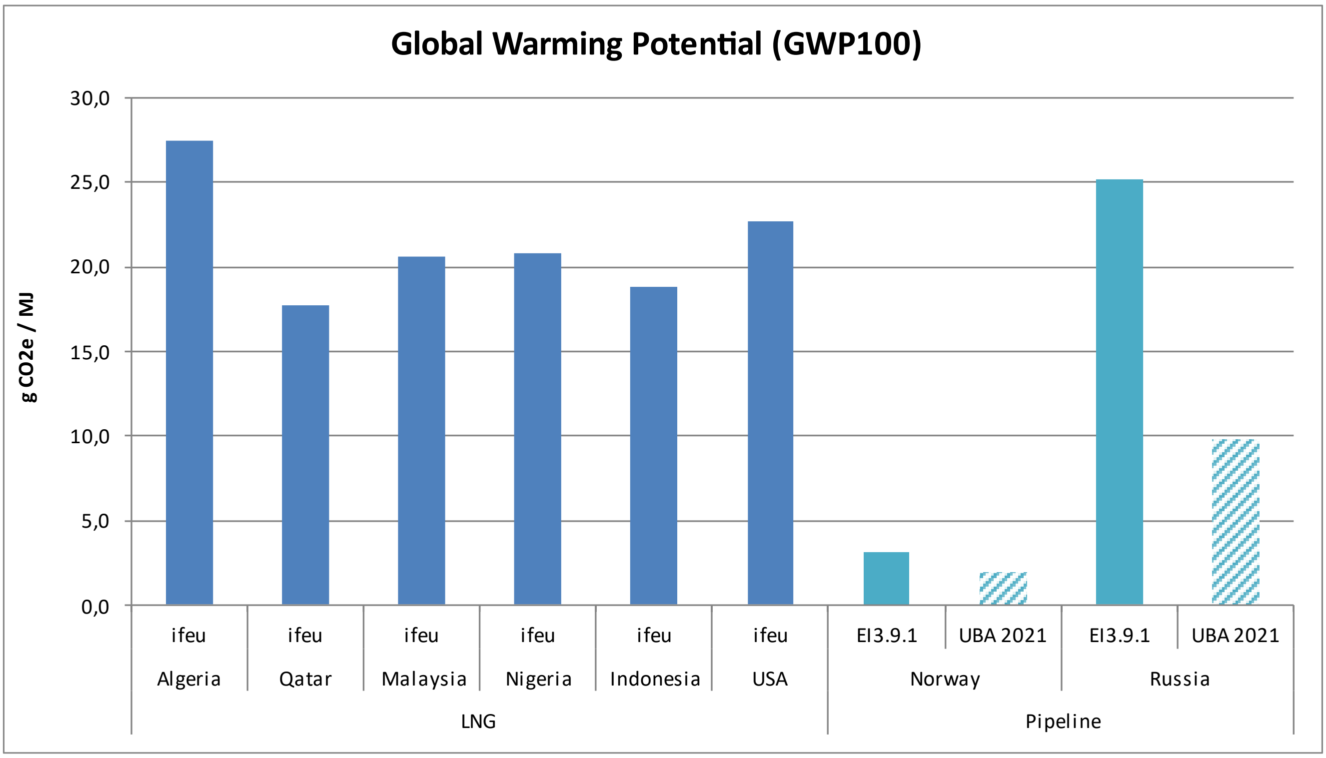

Figure 10 : Global warming potential over a 100-year period (GWP100 according to AR5 IPCC 2013) for the provision of LNG up to regasification in Germany in this study and pipeline natural gas in two comparative studies (Sources: ifeu, (Ecoinvent 2022) and (Baumann and Schuller 2021 on behalf of UBA))

Figure 11 shows the results of this study (GWP 100, IPCC 2013) in comparison with those for LNG from of the study commissioned by the German Federal Environment Agency (Baumann and Schuller 2021). The results are relatively close for the supply countries examined in both studies. Baumann and Schuller (2021) assume lower methane emissions in production and processing, but calculate a global warming potential for liquefaction that we cannot reproduce with the data sources given. With these emissions, the results in our study would increase by about another gram of CO2e per MJ for all countries.

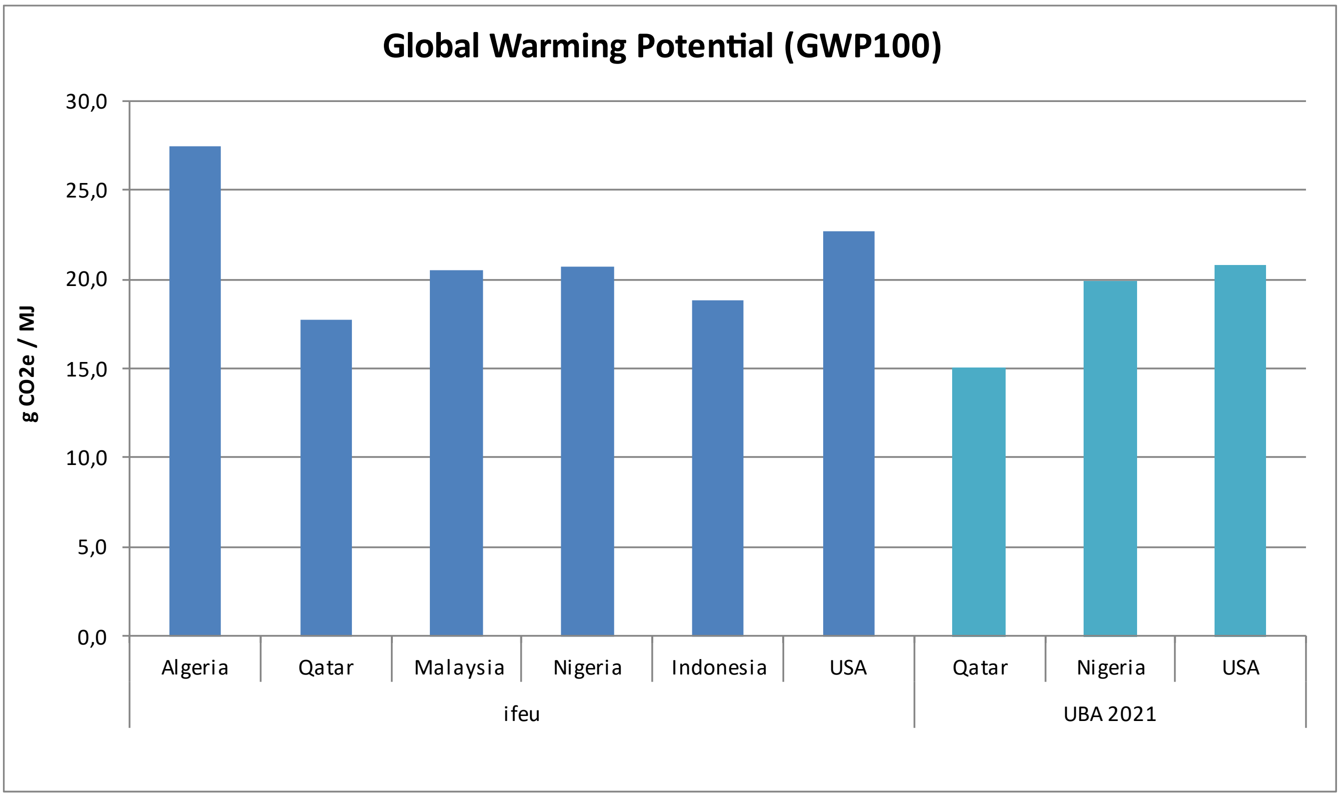

Figure 11 : Global warming potential over a period of 100 years (GWP100 according to AR5 IPCC 2013) for the provision of LNG up to regasification in Germany in this study and in a comparative study (sources: ifeu, (Baumann and Schuller 2021, commissioned by UBA)).

8.2 Influence on total life cycle emissions

Natural gas is used in Germany in various areas and for various purposes - in particular, electricity generation, heating, as well as process heat. In the chemical industry, natural gas is used as a feedstock to produce ammonia, methanol and other basic chemicals. The environmental impacts of these utilization paths differ considerably and depend on the technologies used, product utilization, recycling, and disposal.

To estimate the ratio of the upstream emissions determined in this study to those of the downstream life cycle stages, the standard factor for stationary energy conversion according to (IPCC 2006) is used. It is 56.1 gCO_2e/MJ and represents only the CO_2 produced by complete combustion. Effects of other emissions as well as of distribution and storage are not considered.

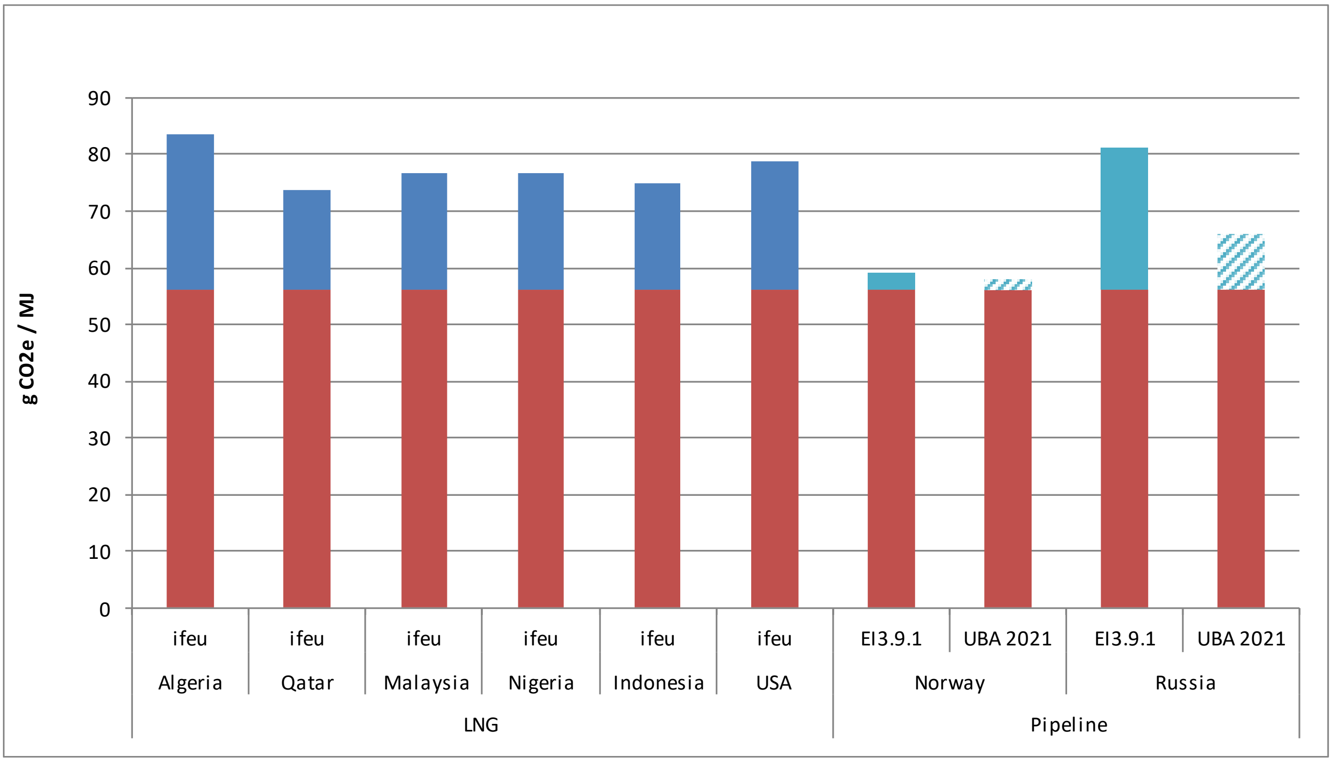

Figure 12 : Global warming potential over a 100-year period (GWP100 according to AR5 IPCC 2013) of supply and combustion for the provision of LNG up to regasification in Germany in this study and of pipeline natural gas in two comparative studies (Sources: ifeu, (Ecoinvent 2022), (Baumann and Schuller 2021, on behalf of UBA) and (IPCC 2006))

Figure 12 shows the global warming potential over a 100-year period (according to AR5 IPCC 2013) of supply and combustion of LNG in this study and pipeline gas in two comparative studies. The upstream emissions for LNG range from 24% (Qatar) to 33% (Algeria) of these simplified total emissions. Using the values from the study for the German Federal Environment Agency, in which the main GHG potential for pipeline-bound gas was determined without the increased methane emissions, the upstream shares range from 3% (Norway) to 15% (Russia).

8.3 Data quality and uncertainties

The assessment of data quality must differentiate by supply country and process step. The following regional differences can be identified:

- The data quality for the USA is satisfactory to good. On the one hand, there is a high spatial and technological resolution of the emission inventories, a large number of independent measurements and partly available industrial data. This provides a better basis than in all other (non-European) countries. On the other hand, the very large number of oil and gas production sites in the U.S. (600,000 - 1,000,000) makes it difficult to determine average values for production. In addition, there are hardly any studies so far that map the catchment area and thus the domestic U.S. production mix for LNG exports.
- Data for Qatar are of poorer quality compared to the U.S. and are mainly based on indirect company data. Direct satellite measurements of methane emissions are

difficult for offshore installations, and, unlike the U.S., there is not yet a bottom-up approach that validates the IEA methane tracker approach.

- The data quality is even worse for other countries in Asia and Africa, for which only continental parameters based on data from the industry association IOGP are presently available.

There are still significant uncertainties, particularly with regard to methane emissions. Some emission sources are still poorly recorded in all countries so far. Large, intermittent emissions ("super-emitters"), which are detectable in satellite studies, are hardly included in emission inventories and models so far. The study by Lauvaux et al. (2022) has shown that these super-emitters could account for up to 10% of methane emissions from the oil and gas industry. Other sources of gas, and therefore methane, that have been poorly accounted for include: unproductive gas wells at the end of their lives ("marginal wells"), and emissions from closed or abandoned production sites ("orphaned wells"). In addition, individual studies indicate that emissions from ships powered by LNG may be higher than those found in test-rig operations (Balcombe et al. 2022).

Overall, the data quality can be rated as sufficient at best. Accordingly, the uncertainties in the results are relatively high.

9 Outlook

9.1 Data availability and quality

Data availability and quality for the LNG supply is expected to improve in the coming years.

- A host of new methane satellites will increase the transparency of oil and gas production-from super-emitters to plant-scale measurements. (Jacob et al. 2022; Omara et al. 2023)
- Additional measurement campaigns in the U.S. will further improve attribution to individual emission sources. (Caulton et al. 2022; Hmiel et al. 2023)
- Data-driven bottom-up models such as OPGEE will be applied to the global production structure, reinforcing reliance on top-down approaches, or resolving contradictions. This is pursued by Brandt et al. (2020) at Stanford University as well as by other research groups, e.g., Climate Trace (https://climatetrace.org/) (Reuland et al. 2022).
- International initiatives (IMEO, GMP, OMGP; see next chapter) and regulations (e.g., CO_2 border adjustment systems, CBAM) will lead to greater transparency.

9.2 Political and regulatory initiatives

A series of international initiatives and frameworks, some of which build on each other, have set the goal of reducing anthropogenic methane emissions across all sectors but especially in oil and gas supply.

Global Methane Pledge. The Global Methane Pledge (GMP) was launched at COP26 in November 2021 to promote action to reduce methane emissions. Led by the United States and the European Union, more than 120 countries have joined the initiative as of August 2022. By joining, countries are committing to work together to reduce methane emissions by at least 30% below 2020 levels by 2030. Several countries have also announced additional measures to reduce methane emissions that build on and go beyond the GMP. In November 2021, the U.S. released its Methane Emissions Reduction Action Plan, which details the government's actions to achieve the Global Methane Commitment targets. In December 2021, the European Commission adopted a proposed regulation to reduce methane emissions in the energy sector as the first step of the EU Methane Strategy 2020.

The **International Methane Emissions Observatory (IMEO**) was launched at the G20 Summit on the eve of the UN Climate Change Conference COP26 in Glasgow. The Observatory will create a global public dataset of empirically verified methane emissions - starting with the fossil fuel sector - with increasing granularity and accuracy by integrating data primarily from four streams: Oil and Gas Methane Partnership 2.0 (OGMP 2.0) reports, oil and gas companies, direct measurement data from scientific studies, remote sensing data, and national inventories.

The **Oil & Gas Methane Partnership 2.0 (OGMP 2.0)** is a multi-stakeholder initiative launched by UNEP and the Climate and Clean Air Coalition. The OGMP 2.0 is a comprehensive, measurement-based reporting framework for the oil and gas industry designed to improve the accuracy and transparency of methane emissions measurement and reporting in the oil and gas sector. More than 80 companies with facilities on five continents, representing a significant portion of global oil and gas production, have joined the partnership. OGMP 2.0 members also include operators of natural gas transmission and distribution pipelines, gas storage facilities and LNG terminals.

In the U**.S.,** President Biden unveiled new proposals to regulate methane emissions from the oil and gas industry by the U.S. Environmental Protection Agency (EPA) at COP 27 in November 2022 (US EPA 2022b). EPA's proposal seeks to reduce routine flaring, such as associated gas in oil production. The proposal also targets emissions from high-emitting, lower-yielding production sites ("marginal wells") and requires regular monitoring at all sites with failure-prone equipment. The proposed regulations also include requirements for conversion to zero-emission pneumatic equipment components, a major source of methane emissions in the oil and gas industry. The new regulations are in the legislative process and are expected to be adopted later in 2023. However, some U.S. states, such as oil- and gas-rich Texas, have consistently opposed stronger regulations in the past.

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