DG ENER
FRAMEWORK SERVICE CONTRACT
SRD MOVE/ENER/SRD.1/2012-409-LOT 3-COWI
COWI CONSORTIUM
COWI BELGIUM
AV. DE TERVUEREN 13-B
B-1040 BRUSSELS
BELGIUM
TEL +32 2 511 2383
FAX +32 2 511 3881
WWW.COWI.COM



EUROPEAN COMMISSION
DG ENER

STUDY ON ACTUAL GHG DATA FOR DIESEL, PETROL, KEROSENE AND NATURAL GAS

FINAL REPORT

WORK ORDER: ENER/C2/2013-643

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ABBREVIATIONS

ACG	Azeri–Chirag–Gunashli
AFRA	Average Freight Rate Assessment
AGR	Acid Gas Removal
AIS	Automatic Identification System
APEX	Analysis of Petroleum Exports
APG	Associated Petroleum Gas
API	American Petroleum Institute
BAT	Best Available Techniques
bbl/d	Barrels per day
BCF	Billion Cubic Feet
BCM	Billion Cubic Meters
BPS	Baltic Pipeline System
BTC	Baku-Tbilisi-Ceyhan
CARB	California Air Resources Board
CDU TEK	Central Dispatching Department of Fuel Energy Complex
CDP	Carbon Disclosure Project
CHP	Combined Heat and Power
CAPP	Canadian Association of Petroleum Producers
CI	Carbon Intensity
CIF	Cargo Insurance Freight
CNG	Compressed Natural Gas
CNPC	China National Petroleum Corporation
CPC	Caspian Pipeline Consortium
DEA	Danish Energy Agency
DECC	Department of Energy and Climate Change
DEFRA	Department of Environment, Food and Rural Affairs
DG ENER	Directorate General for Energy
DUC	Danish Underground Consortium
DWT	Dead Weight Tonnage
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EEA	European Environment Agency
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery
ETS	European Trading Scheme
EU	European Union
EW	Environmental Web
FCC	Fuel Catalytic Cracking
FOB	Free on Board

FOR	Flaring to Oil Ratio
FQD	Fuel Quality Directive
FSU	Former Soviet Union
GATT	General Agreement on Tariffs and Trade
GGFR	Global Gas Flaring Reduction
GHG	Greenhouse Gas
GOR	Gas-to-oil ratio
GWP	Global Warming Potential
HCICO	High Carbon Intensity Crude Oil
ICCT	International Council on Clean Transportation
ICE	Inter-Continental Exchange
IEA	International Energy Agency
IFP	Institut Français du Pétrole
ILUC	Indirect Land Use Change
IPCC	Intergovernmental Panel on Climate Change
IPIECA	International Petroleum Industry Environmental Conservation Association
ISO	International Organization for Standardization
JEC	JRC - EUCar and CONCAWE
JRC	Joint Research Centre
LCA	Lifecycle Assessment
LCFS	Low Carbon Fuel Standard
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
MCON	Marketable Crude Oil Name
MENA	Middle East and North Africa
MFN	Most Favoured Nation
mmcm	million cubic meters
MS	Member State
MTA	Million Ton per Annum
NCS	Norwegian Continental Shelf
NETL	National Energy Technology Laboratory
NG	Natural Gas
NNPC	National Nigeria Petroleum Company
NOAA	National Oceanic and Atmospheric Administration
NPD	Norwegian Petroleum Directorate
NWE	Northwest Europe
OGJ	Oil and Gas Journal
OGP	International Association of Oil & Gas Producers
OPGEE	Oil Production Greenhouse gas Emissions Estimator
OSPAR	Oslo and Paris Convention
PDVSA	Petroleos de Venezuela
RED	Renewable Energy Directive
SCO	Synthetic Crude Oil
SOC	(Iraq's state-owned) South Oil Company
SOR	Steam-to-Oil Ratio

TBT	Technical Barriers to Trade
TEOR	Thermally Enhanced Oil Recovery
toe	ton of oil equivalent
ToR	Terms of Reference
TSP	Technical Service Provider
UAE	United Arab Emirates
UGTS	United Gas Transmission System
ULCC	Ultra Large Crude Carrier
ULSD	Ultra Low Sulphur Diesel
UNFCCC	United Nations Framework Convention on Climate Change
VFF	Venting, Flaring and Fugitive
VLCC	Very Large Crude Carrier
VOR	Venting to Oil Ratio
WOR	Water to Oil Ratio
WSPA	Western State Petroleum Association
WTI	West Texas Intermediate
WTO	World Trade Organization
WTT	Well-to-Tank
WTW	Well-to-Wheel
WWF	World Wildlife Fund

SUMMARY

This project, "Study on actual GHG data for diesel, petrol, kerosene and natural gas", is implemented by EXERGIA S.A. (Leader), in collaboration with E3M-Lab (Economics Energy Environment Modelling Laboratory) of the National Technical University of Athens and COWI A/S. The total project duration is 15 months and this Report is submitted in July 2015.

The project implementation was organized in six discrete Tasks (a to f) with the addition of the project management Task 0. Two of the Tasks, namely **Task a: Literature survey** and **Task b: Data acquisition,** were completed at the time of submission of the Interim Report and the rest of the Tasks, namely **Task c: Models to estimate max and min GHG emissions, Task d: Emissions due to accidents and other operational failures, Task e: Other issues related to sustainability** and **Task f: Emissions projections up to 2030** were completed recently.

The major effort of the Consultant has been addressed to the activities of data acquisition and especially in collecting lifecycle actual GHG emissions data**,** both for oil and natural gas, in accordance to the main objective of the project mandate. Thus, all open sources of relevant information have been investigated, mainly availed by national, international organizations and oil and gas associations. Furthermore, all major oil and natural gas companies, related to oil and gas streams supplied to the EU, have been contacted and requested specific and disaggregated data per process. The results were satisfactory in countries where organized GHG emissions are registered and relevant reporting procedures are in place (e.g. Norway, UK, Netherlands, Denmark, etc.). On the other hand, aggregated actual data were also identified in the UNFCCC reports of Annex I countries and in specific reports of companies operating the oil and gas fields. The response of the oil and gas companies contacted for provision of GHG disaggregated data was very poor eventually. For the cases where actual Carbon Intensity (CI) data could not be found, we assessed GHG emissions by using three models, namely OPGEE and PRIMES-Refinery for oil and GHGenius for natural gas. The necessary input data for these models were in principle actual data mostly gathered for the needs of this project. Especially, regarding the estimation of the downstream oil sector GHG emissions we updated the PRIMES-Refinery model with recent information about the EU refining capacity and developments.

Reasonable assumptions were made in order to structure the estimations of GHG emissions in comprehensive and realistic pathways for the EU. The Marketable Crude Oil Name (MCON) system was used as the basis for oil sector pathways definition and the Gas Stream concept for natural gas sector respectively. In addition, focus was placed on the most significant flows of oil and gas imported in the EU, leaving aside the small and insignificant fuel flows. Therefore, 115 pathways of oil products (petrol, diesel, kerosene) GHG emissions estimations were considered and respectively 46 pathways for natural gas products (CNG,

LNG) supplying transportation. For all these pathways the lifecycle GHG estimations have been carried out either as an elaboration of actual data, or as a model output based on actual data input, or as a combination of both approaches.

Indirect GHG emissions of fossil fuel streams were taken into account by the project, in addition to the direct Carbon Intensity (CI) described above. Two categories are distinguished: attributional emissions, which are associated with the full estimation of the actual lifecycle emissions, and consequential emissions, which are associated with the projections on future GHG emissions. The project concentrated on CI due to induced land development, relevant in areas where there is a potential for deforestation, military involvement, relevant in areas with politically unstable conditions such as in the Middle East, and accidents, which may occur throughout the pathways followed by the fossil fuels. The analysis defined the cases of oil and gas supply to EU that are subject to these three indirect CI cases. The results concluded to unitary indirect GHG emissions, which should be considered in the calculation of the total CI of oil and gas streams.

The sustainability implications, which are related to the findings of this assignment on actual data of GHG emissions for transport fuels, have been considered. The wide spread of the emission levels found for various oil and gas streams might affect the CI reduction policies of the EU and the international trade obligations due to the WTO. In this context a survey addressed to all competent stakeholders took place throughout a questionnaire. We received 114 responses from the six categories of stakeholders, namely: biofuels industry, consumers' associations, NGOs, oil and gas industry, public authorities and research/technology/consultancies. For most of the questions there were contradictory positions between the two most interested stakeholders, i.e. oil and gas and biofuels industries. With the exemption of oil and gas industry, there was a significant support to the ideas of use of actual CI data in all disaggregated individual fuel streams under a consistent verification system. On the other hand issues of regulatory stability and economic competitiveness were stressed out.

The study assessed also the GHG emissions associated with fuels projected to be consumed in the EU up to 2030, with particular emphasis on the period up to year 2020. The projections on future demand for petroleum refined products are based on projections drawn from the PRIMES model. Two scenarios already quantified using PRIMES are used: the Reference scenario 2013 and the GHG40 scenario used for the Impact Assessment by the European Commission for the policy framework for climate and energy in the period from 2010 up to 2030. The market restructuring and especially the expected changes in the global crude oil supply and the tendencies of refining products adapted to market demand needs have been incorporated in the analysis. The results of average refinery emissions (expressed per unit of energy equivalent of crude) are projected to be reduced by 4% in 2020 and by 6% and 9% up to 2030 under the reference and decarbonisation scenarios, respectively. On the contrary, the estimates on upstream and midstream GHG emissions of gas supplied to the EU show an overall increase in CI values in 2020 and 2030.

1 REVIEW OF STUDY TASKS

1.1 Introduction

In order to reach the targets set by the Renewable Energy and Fuel Quality Directives, a certain percentage of fuels used in the transport sector nowadays have to be replaced by biofuels. Sustainability issues arising from the enhanced use of biofuels and the Greenhouse Gas (GHG) emissions from their whole lifecycle have been discussed extensively; however, there is no detailed information about the **actual lifecycle GHG emissions** of fossil fuels consumed in the transport sector.

In many cases, lifecycle GHG emissions of biofuels are compared to the respective average emissions of oil products used as fuels in transport. In order to provide a fair and clear picture of fossil fuel GHG emissions directed to transport, more detailed data, especially throughout Europe, are needed. Therefore, the overall aim of this project is to provide information about lifecycle GHG emissions based on collection of actual data as possible. The considerable information uncertainty endorsed to collection and elaboration of these data, as well as to the required regional/geographical specification of data might be tackled with estimations on the range of the GHG emission quantities in the form of minimum and maximum values.

Therefore, the lifecycle Carbon Intensity (CI) of petrol, diesel, kerosene and natural gas have been assessed in a "well-to-tank" (WTT) approach. In general, WTT emissions refer to those ones associated with fuel pathways from extraction up to fueling the tanks of land, sea and air transportation means. A chain of significant production stages of oil and gas, like exploration, exploitation, upgrading, transportation, transmission, refining, distribution, dispersing etc. are considered; thus excluding the final stage of combustion in the transportation means' engines.

The study results are based on data acquisition from reliable and official sources and on output from consistent and widely acceptable GHG emissions and energy models.

The project has been assigned through the REQUEST NO: ENER/C2/2013-643 and has been implemented by **EXERGIA S.A.** (leader), in collaboration with **E3M-Lab** (Economics Energy Environment Modelling Laboratory) of the National Technical University of Athens and **COWI A/S**. These three organizations are core members of the consortium led by COWI Belgium, which participates in the Framework Service Contract SRD MOVE/ENER/SRD.1/2012-409-LOT3-COWI. The group of organizations accumulates important experience in energy and GHG modelling relative to energy policy decision making, collection and elaboration of data and analyzing sustainability issues.

Lastly, readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the European Commission.

1.2 Legal Context

The EU policy on GHG emissions of oil products is implemented under the context of two Directives:

- **(RED) Renewable Energy Directive** (2009/28/EC) and
- **(FQD) Fuel Quality Directive** (2009/30/EC)

In the framework of mandatory national overall targets and measures for the use of energy from renewable sources provided by the RED, the overall target set for the EU is at least a 20 % share of energy from renewable sources in the Community's gross final consumption of energy in 2020. According to Article 3/4 of the RED, each Member State shall ensure that the share of energy from renewable sources in all **forms of transport in 2020 is at least 10 % of the final consumption** of energy in transport in that Member State. The blending of biofuels is one of the methods available for Member States to meet this target, and is expected to be the main contributor. Also in Article 17/2 it is provided that under sustainability criteria biofuels under consideration should reduce GHG emissions by at least 35% compared to substituted petrol or diesel. Thus volumetric targets are set, but also some sort of mandatory CI performance is imposed, which is implemented in the broader area of conventional fuel substitution. The latter GHG emissions percentage increases to 50%-60% by January 1, 2017 according to set provisions.

On the other hand, the FQD, Article 7a mandates that Member States shall require suppliers to reduce as gradually as possible lifecycle greenhouse gas emissions per unit of energy from fuel and energy supplied by **actually up to 6** % by 31 December 2020; thus setting this way a Low Carbon Fuel Standard (LCFS). As in the RED, the GHG emission saving from the use of biofuels taken into account shall be at least 35 %. Furthermore, with effect from 1 January 2011, suppliers shall report annually, to the authority designated by the Member State, on the greenhouse gas intensity of fuel and energy supplied within each Member State by providing, as a minimum, the following information:

- the total volume of each type of fuel or energy supplied, indicating where purchased and its origin; and
- lifecycle greenhouse gas emissions per unit of energy.

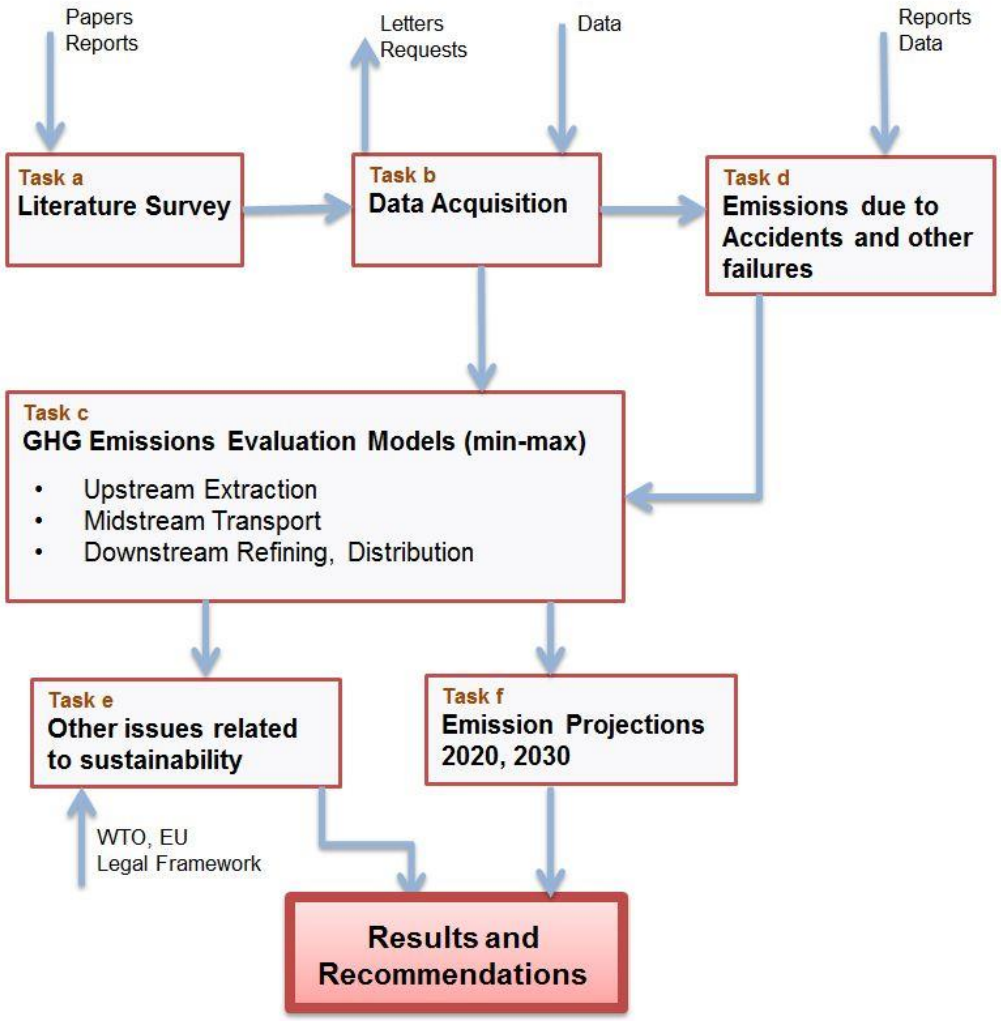
An accurate accounting of the lifecycle GHG emissions of fossil fuel extraction based on actual data is important for the implementation of both Directives, due to the required fulfilment of the volumetric target. Especially in the case of the FQD the accounting is requested also as a necessary tool to assess and verify GHG emissions. A differentiated accounting of GHG emissions of various oil and gas streams contributes in demonstrating cases of low and high carbon fuels, but also in considering measures for reductions in the carbon intensity at the stages of extraction, transportation and refining, in principle. The

comparison with alternative or renewables based fuels (biofuels, electricity, CNG, LNG, etc.), mentioned in both Directives, becomes substantial and realistic in the case of differentiated accounting. Therefore a combination of policies could be undertaken towards fulfilling the set targets for the transportation fuels.

1.3 Overview of Study Tasks

Figure 1-1 depicts the main Tasks of the project and the main data flows and information linked with the project tasks. In the following Sections a brief description of these Tasks is presented.

Figure 1-1 Diagram with project Tasks and flows of information inputs



1.3.1 Task a: Literature survey

The starting point of the literature survey is the in-depth analysis of EU legislation related to GHG emissions of transport fuels and its targets, as well as the Member States' laws that comply with these targets. More specifically, the Directives that are being used as reference, i.e. the Renewable Energy Directive (RED), along with the National Renewable Energy Action Plans submitted by the Member States and the Fuel Quality Directive (FQD) are analyzed thoroughly, in order to understand the requirements of EU policies and their implementation within the legislation of each Member State. Moreover, all relevant EC Communications and Initiatives have been reviewed, in order to further comprehend the principles and recommendations of EU GHG emissions policy.

The literature survey covers also a broad range of subjects related to GHG emissions of lifecycle of diesel, petrol, kerosene and natural gas and will break these down by type. The subjects that are covered include e.g. GHG emissions calculation methods, fuel extraction, fuel transport, fuel refinement, etc. Additionally, the literature survey includes a broad range of information resources that are also broken down by type, e.g. private companies reports, international organizations reviews, scientific papers, etc.

The literature survey focuses on the **most up-to-date data and knowledge on the subject of GHG emissions** and is based on two methods: extensive online literature search, as well as identifying valuable items based on discussion and communication with stakeholders. The consultant sets the criteria, in communication with the Contracting Authority, that allow sorting out the various reading materials, in order to create a literature database.

The main output of this Task is a comprehensive categorized literature database based on the assessment of available documentation.

1.3.2 Task b: Data acquisition

It is stressed that the outcome of the assignment is largely dependent on the development of a detailed and robust database. In principle, **the Consultant bases the analysis on actual data** provided mainly by public organizations, oil companies and oil companies' associations. However, acknowledging the fact that oil companies have been reluctant to disclose data in the past, information from other sources are used for the development of the database that forms the basis for the assessment of the GHG emissions (Tasks c and f).

This project mandate suggests a two-step approach regarding data collection that involves data acquisition from private companies and data acquisition from other open access sources, including international organizations. Necessary information refers to all sectors of the oil and gas fuels value chain (upstream, midstream, downstream), i.e. data pertaining to the crude oil extraction, tanker transportation, gas production and transmission, LNG and CNG transformation, energy consumption in refineries, venting/flaring emissions, data regarding unconventional oil and gas production and transportation, etc.

The main output of this Task is the database on direct GHG emissions from the lifecycle of diesel, petrol, kerosene and natural gas concentrating on the year 2012 that will be the main

input to the following modelling Tasks.

1.3.3 Task c: Models to estimate max and min GHG emissions

The focus of this study is the assessment of the well-to-tank (WTT) GHG emissions of petroleum fuels and natural gas. **Actual data of GHG emissions are considered in priority, however in cases of lack of proper data the use of specialized models**, namely OPGEE for oil and GHGenius for gas, are used to estimate the necessary GHG emissions. These models are modified to adapt to the EU reality in terms of gas and oil imports and transmission, processing up to distribution to tanks of final consumers. Differentiated oil pathways based on Marketable Crude Oil Names (MCONs) are used for oil types reaching the EU refineries. Respectively the main gas streams are used to represent the pathways from the main gas producing fields up to their entry to the transmission systems of the EU countries and their transfer to distribution to final consumers in the form of CNG or LNG.

The GHG emissions associated with petroleum fuels and natural gas are estimated based on the data collected during the course of Task b; in principal this study intends to make use of actual data obtained from private companies and other sources, as specified by the requirements of Task b. In case disclosure of actual data by companies is not feasible, other sources are used; the latter have been determined during the development of the database that is undertaken in Task b. The already existing OPGEE and GHGenius databases serve as guidance to determine information requirements and as checks to verify the quality and accuracy of the new data to be collected.

The present study additionally takes into account oil from unconventional sources. Emissions due to bituminous sand, shale oil and gas extraction and upgrading are estimated separately. The estimation takes into account emissions due to energy consumption and venting/flaring emissions within the unconventional oil and gas extraction and upgrading stages.

The midstream GHG emissions pertain to emissions resulting from the feedstock transportation from the extraction source to the refinery gate. Emissions mainly occur due to the energy consumption during the transport of petroleum and its products and gas. In addition to seaborne transportation, land transportation (most commonly via pipelines) is included. For natural gas transportation the present study used also the currently available GHGenius gas model database, as well as information from other sources, mainly European, which are detailed enough, including all current and future gas pipelines (Eurasian and North Africa coverage) as well as details on the global trade, liquefaction and gasification of LNG.

The present study estimates GHG emissions of petroleum fuels during the upstream and midstream sectors at world level, i.e. feedstock originating from all continents will be taken into account. However, only the EU refinery system will be taken into consideration with regard to the processing of the fossil fuels at downstream operations. In order to associate emission factors to the concrete refinery output products (diesel, petrol, kerosene) in a more adequate manner, the study uses a methodology, which allows for calculation of both

average emission and marginal emission factors. This method includes allocation of emissions to individual products based on marginal emission content.

The output of Task c concentrates on the identification of GHG emission factors associated with the WTT supply chain of diesel, petrol, kerosene and natural gas for the year 2012.

1.3.4 Task d: Emissions due to accidents and other operational failures

The objective of this Task is to evaluate the importance of the various sources of indirect GHG emissions identified within the existing literature and data resources. The indirect emission sources have to be considered in addition to the direct emissions related to upstream, midstream and downstream processes. The most significant sources of indirect GHG emissions of fossil fuels include (among others):

- Emissions from **accidents outside of normal operation conditions:** These include the emissions from the accident itself, the emergency response and clean-up or remediation efforts.
- Emissions from **induced land development and land use:** The Induced Land Development is the land use change that is caused by fossil fuel extraction in an indirect way, i.e. the construction of access roads for oil and gas extraction etc. The Land Use effect includes GHG emissions from using the land after the rainforest was cleared. This type of indirect emissions is in correspondence with GHG emissions produced by the Indirect Land Use Change (ILUC), which is an important emissions source for biofuels.
- Emissions caused by **military involvement:** These include the military activities and reconstruction efforts to protect and stabilise the supply of oil to global markets, i.e. from military vehicles, military infrastructure etc.

The main output of this Task is the identification of indirect GHG emissions from the lifecycle of diesel, petrol, kerosene and natural gas that have been considered in addition to the direct emissions for the completion of the picture of 2012.

1.3.5 Task e: Other issues related to sustainability

Depending on the emission levels found for various fossil fuels, the EU is likely to be faced with a variety of policy options. Indeed, the EU could decide to impose a disaggregated policy on measuring the emissions of fossil fuels, which could in turn result in certain trade restrictions that may be incompatible with international trade law. Furthermore, depending on the significant variety of CI values found, the EU could decide to revise the GHG emission saving values, targets and other conditions, which are set in the Renewable Energy Directive (2009/28/EC) and the Fuel Quality Directive (2009/30/EC). Therefore the objective of Task e is to study the above two significant effects. In light of the above, a Task exploring the various policy options as well as potential trade law concerns appears pertinent. Therefore, Task e includes a **legal and policy exercise** addressing these issues.

In this context a survey, addressed to all competent stakeholders, took place through a questionnaire. We received 114 responses from the six categories of stakeholders, namely:

biofuels industry, consumers, NGOs, oil and gas industry, public authorities and research-technology-consultancies. The elaboration of the questionnaires' information revealed the different interests and approaches of the main categories of stakeholders.

The analysis and results of Task e provides the EU with the necessary background allowing it to continue framing a robust and sustainable policy, while avoiding exposure to international trade litigation.

1.3.6 Task f: Emissions projections up to 2030

The study addressed the objective of Task f using the **official projections provided by E3M-Lab to the European Commission in 2013 using the PRIMES** large scale energy model. Projections of demand and supply of oil fuels and natural gas were used for a Reference and a Decarbonisation scenario as quantified using the PRIMES energy system model for the European Commission in 2013. Refineries inputs and outputs are also explicitly projected by the PRIMES model. PRIMES also provides projections regarding net imports of refinery feedstock, ready-to-use refinery products and natural gas. The coverage is by EU Member States.

The projected net imports of refinery feedstock and ready-to-use petroleum products by PRIMES were analyzed based on country of origin and type, in order to obtain detailed commercial flows. The analysis for projection years are based on assumptions relevant to current trends and to future production/import projections. These assumptions are harmonized to latest IEA World Outlook projection of global oil/gas trade flows and regional production. For all projection years, average/marginal emissions of the fuel supply chain are calculated. Emissions were allocated to each fuel based on the marginal emission content of fuels.

The output of Task f is the estimation of GHG emissions for projection years until 2030 (with emphasis up to 2020). The results are presented in a tabular format for each fuel and EU country.

1.4 Contribution of the Present Study to Oil and Gas GHG Emissions Assessment

This project contributes to the scientific area of lifecycle GHG emissions assessment of oil and gas directed to transport sector by combining methods and approaches, which build on the existing experience and the available information by public institutions and private companies. Certainly there are a number of important studies carried out in both sides of the Atlantic, which provide key background information for the current study as they provide recent data and/or approaches. A brief presentation of these studies in the following Sections provide an overview of their scope and main characteristics and indicates the differences compared to our project analysis and scope.

The main characteristics of this study could be considered as follows:

- **Emphasis and priority is placed on the collection and use of actual data.** This approach is interpreted in two ways: either effort to use directly available GHG data coming from reliable sources or in case the analysis of the collected data is not sufficient for direct use, utilization of actual data as inputs in the used models (OPGEE, GHGenius, PRIMES-Refinery) or relevant analyses and calculations.
- **The WTT approach includes full and thorough analyses of upstream, midstream and downstream stages for the EU case.** Therefore our approach is absolutely related to the most significant pathways or streams of oil and gas fuels addressed to the EU transportation sector, thus covering mostly the presentation of the current situation (2012), but also carrying out the necessary extrapolation up to 2030 by using the most well-known model (PRIMES) for the EU energy economic policy assessments.
- **Linkage of upstream and midstream stages through the MCON concept.** The utilization of the concept of MCON aims at correlating the physical properties characterizing crude oil as it is extracted from the oil field and those of the crude oil blended during or before the refining process. Furthermore, the concept of MCON practically facilitates the connection of the refinery input (which has a marketable name) with the primary source of crude oil (at the oil field).
- **Use of min/max methodology.** The study aims at developing an integrated, consistent and detailed methodology to evaluate the actual range of emissions in the form of minimum, weighted average and maximum values that relate to the whole lifecycle of diesel, petrol, kerosene and natural gas. The presentation of final GHG emissions per MCON or final fuel in a range incorporates the inherent uncertainties around GHG emission estimation and allows policymakers to better evaluate the emissions of each primary source or final fuel as these are illustrated in a more objective manner.
- **Incorporates indirect emissions and unconventional crude oil and natural gas cases.** We do not ignore the contribution of indirect GHG emissions, although they are considered of small scale in comparison to the direct emissions for fossil fuels. Furthermore, we consider potential and characteristic pathways of unconventional oil and gas that might play significant role in the supply of EU in the forthcoming years.
- **Place particular emphasis on significant oil and gas streams for EU supply.** Especially, we consider that the size and the significance of the Russian oil and gas directed to the EU requires proportional effort for the analysis, given that the provision of information is poor at institutional and energy company level. For example we try to cope with difficulties on the disaggregation to specific types of crude oil, where several types of MCONs might be depending on the mode of transport, port and transport costs. In general although we pace a step forward on this analysis the lack of proper data remains a restrictive factor.
- **Detailed assessment of crude oil emissions using the OPGEE model.** In the absence of direct and detailed GHG emissions data by oil companies, the Consultant has used the OPGEE model for the assessment of GHG emissions for the upstream and midstream lifecycle stages. OPGEE is a complex engineering model that requires a large amount of data as inputs. The collection of such data has been a rather time consuming Task, since it requires research within a large amount of sources. The

effort and the resources that have been committed by the Consultant for the collection of actual data for OPGEE inputs are significant. For the few missing inputs smart default values are used by the model. Our effort is to minimize the use of the default values and thus to optimize the accuracy of the estimated GHG emissions.

- **Assessment of emissions of oil refined products imported in EU.** Besides crude oil imports, the EU is increasingly importing refined oil products primarily from Russia and United States of America. This fact is usually being overlooked in relevant studies. In the context of this study the emissions of refined products imported from the United States and Russia have been assessed as these constitute significant part of EU final fuel supply.

1.4.1 JEC Report: Well-To-Tank (WTT) emissions

The present version of this report (version 4) has been published by the JEC Consortium in July 2013 (JRC - EU Commission's Joint Research Centre, EUCAR - the European Council for Automotive R&D and CONCAWE - the oil companies' European association for environment, health and safety in refining and distribution) and replaces the previous version (version 3c).

The current version of the study addresses the processes of producing, transporting, manufacturing and distributing a number of fuels suitable for **road transport powertrains**. Oil products and gas in the form of CNG are included as well. It covers all steps from extracting, capturing or growing the primary energy carrier to refueling the vehicles with the final fuel.

In this study, all fuels and primary energy sources (crude oil, coal, natural gas, shale gas, LPG, biomass, nuclear energy, wind energy and electricity) that appear relevant within the analysed timeframe, which broadly speaking is the next decade, i.e. around 2020-2025, have been considered and it has been attempted to answer the following questions:

- What are the alternative uses for a given resource and how can it best be used?
- What are the alternative pathways to produce a certain fuel and which of these hold the best prospects?

The primary target of the study has been to establish the energy and greenhouse gas (GHG) balance for the different routes. The methodology used is based on the description of individual processes, which are discreet steps in a total pathway, and thereby easily allows the inclusion of additional combinations, that will be regarded as relevant in the future. The study is forward-looking and considers state-of-the-art technology to assess and project future choices.

The average WTT GHG emissions for crude oil based fuels for Europe has been estimated at slightly above 15 grCO_2eq/MJ of final fuel. The processes that have been analyzed are production and conditioning at extraction source, transportation to the market, conditioning and distribution and transformation near the market for all types of fuels. The study concludes that crude oil refining is the most energy-consuming step followed by crude production.

For Compressed Natural Gas (CNG) the GHG balance is estimated at approximately 13 g CO_2/MJ of final fuel for EU mix supply. CNG from imported natural gas on an average distance of 7,000 km (typically Russia) is estimated at above 22 grCO_2eq/MJ final fuel, while CNG from imported NG from an average distance of 4,000 km (typically Middle East, Caspian Sea) is estimated at approximately 16 grCO_2eq/MJ. Emissions for CNG coming from LNG stations vary from approximately 17 grCO_2eq/MJ to 22 grCO_2eq/MJ (depending mainly on the vaporization and liquefaction process).

Version 4.0 of the JEC WTT report is a comprehensive analysis of primary fuels pathways and GHG balances. Even though, the high level methodology is analyzed sufficiently, the GHG emissions results are mostly aggregated and only in some cases uncertainty is estimated (gas). Furthermore, emphasis is placed on detailed analysis of alternative or unconventional fuels, whereas gas and oil products for transport are rather treated in a way not relevant to their significance for the EU energy balance.

1.4.2 NETL Report: An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Lifecycle Greenhouse Gas Emissions

The National Energy Technology Laboratory (NETL) has analyzed the full lifecycle GHG emissions of transportation fuels derived from **US crude oil and crude oil imported to the US** from the most significant exporting countries. The study analyses the impact of crude oil from a WTT perspective for the following lifecycle stages:

- Raw Material Acquisition (Associated Natural Gas Flaring and Venting, Bitumen Extraction and Upgrading);
- Emissions by Feedstock Source;
- Raw Material Transport;
- Liquid Fuels Production (refining of crude oils of different quality).

This analysis reveals that producing diesel fuel from imported crude oil results in WTT GHG emissions that are, on average, 59% higher than diesel from domestic crude oil (22.6 versus 14.2 grCO_2eq/MJ). The study concludes that imported crude oils are on average heavier and contain higher levels of sulphur, and the controls on venting and flaring during crude oil production are not as good as in US operations. The study also shows that Venezuela bitumen, Canada oil sands, and Nigerian crudes stand out as having high GHG emissions compared to other sources.

The NETL clearly outlines the scope of the analysis and the system boundary for the LCA. It takes into consideration the most important emission sources and excludes from the analysis construction-related emissions and any emissions from land use change. The analysis conforms to the International Standards Organization (ISO) 14040 and 14044 lifecycle assessment standards. Lastly, the analysis has been conducted on a country basis, rather than crude oil type or oil field basis, which provides a more generic assessment of crude oil type's carbon intensity.

1.4.3 ICCT Study: Upstream Emissions of Fossil Fuel Feedstocks for Transport Fuels Consumed in the European Union

The main goal of this study prepared by the International Council for Clean Transportation (ICCT) in collaboration with Energy Redefined (ER), Stanford University and Defense Terre, is to define the **Carbon Intensity (CI) for crude oils entering the European Union** up to the refinery gate. The analysis is based on the list of crude oil imports published by DG ENER for 2010. Emphasis is given on the use of publicly available data and publicly available LCA GHG assessment models.

The report begins with a thorough analysis of existing legislation and a presentation of the sources of European crude oils. Then, it presents and compares productively the results of several desk studies on the EU fossil fuel feedstock market and associated empirical and modeled data on GHG emissions. Onwards, it provides information on OPGEE, a spreadsheet model for lifecycle analysis of crude oil extraction and transportation, developed by Stanford University and provides an estimate using that model of the carbon intensity of crude oil supplied to the European Union. The objective is to calculate the carbon intensity (CI) for the most important types of crude oil entering the EU.

The analysis has been done on an oil-field basis by collecting key data for each one of these. Each aggregated type of crude, as given in the DG ENER list, was further correlated to oil fields contributing to each given type of crude oil entering the EU. In total, 265 oil fields worldwide covering 93% of European oil consumption were considered. Available data to be used as inputs in OPGEE were thoroughly analyzed and commented within the report.

The study concludes that the biggest challenge in calculating the CI of crude oil pathways is the collection of robust data. Given the available data, the volume weighted average upstream emissions of crude oil arriving to European refineries were estimated using OPGEE at 10 $grCO_2eq/MJ$, which is lower than the CI of crude oil consumed in California, but slightly higher than the estimations of previous studies.

This study includes one of the most comprehensive estimations for carbon intensity of crude oil entering Europe and one of the few conducting a detailed analysis on an oil field basis. However, it does not provide the percentage in which the oil fields participate into the aggregated types of crude, thus being unclear on the method used for the final calculation of carbon intensities of the aggregates.

1.4.4 ICF Study: Independent Assessment of the European Commission's Fuel Quality Directive's "Conventional" Default Value

This report has been prepared by ICF International in 2013 and analyzes the lifecycle GHG emissions for diesel and petrol with a two-fold objective: (a) to analyze the methodology that has been used in the last JEC reports (version v3c and version 4.0) to determine the default conventional crude oil, petrol and diesel carbon intensity values; and (b) building on

that knowledge, to develop a more accurate carbon intensity range for petrol and diesel from conventional crude oils, using the OPGEE model.

The study elaborates a lifecycle analysis from "well-to-tank" (WTT) perspective taking into consideration the most important emissions sources during crude oil extraction and production, venting, flaring, and fugitives, crude oil transport and refining. It gives specific emphasis on data quality and availability since these are two of the most important factors in LCA estimations. The study also points out the lack of reliable reported data for crude oils outside Canada and the USA. In order to mitigate this, ICF uses literature data that by definition introduce some bias in the analyses.

The study estimated as the most likely range of crude oil GHG intensity from production processes using the OPGEE model at 2.0–5.9 $grCO_2eq/MJ$ and from VFF (Venting, Flaring, Fugitive) releases at 3.8–11.0 $grCO_2eq/MJ$.

The ICF study builds on existing LCA methodologies and conducts a comprehensive literature review of existing studies. Unlike other studies which mainly analyze GHG emissions on a regional or country basis, ICF uses the concept of MCON introduced by California Air Resources Board (CARB), while the analysis of GHG emission intensity per MCON is done via representative oil fields. Nonetheless, the coverage of specific crude oils imported in Europe is limited. Furthermore, the number of representative oil fields analyzed in order to assess carbon intensity of specific crude oil types remains limited. Furthermore, there is no analysis for specific MCONs that constitute significant part of European crude oil imports, such as Urals crude oil. Lastly, the rationale and methodology for the choice of the specific dataset of MCONs and oil fields remains unclear.

1.4.5 Jacobs Consultancy Report: EU Pathway Study: Lifecycle Assessment of Crude Oils in a European Context

Jacobs Consultancy in collaboration with Lifecycle Associates was assigned in 2011-2012 by the Alberta Petroleum Marketing Commission, to carry out a study concerning the lifecycle GHG emissions for crude oil pathways to Europe.

The goal of this Study was twofold: (i) to evaluate the lifecycle GHG emissions for potential crude oil pathways to Europe for producing petrol and diesel from representative heavy crude oils from Alberta, Canada and (ii) to evaluate the lifecycle GHG emissions of representative crude oils refined in representative refineries. This approach should help achieve a better understanding of the variability in GHG emissions for different pathways for producing petrol and diesel for the EU market.

The intent of this work was to better understand the carbon intensity of pathways for petrol and diesel from particular individual crude oils. The approach of representative pathways went beyond calculating **carbon intensities from average crude oils in an average European refinery**, as such an approach would entail the risk of losing the information that defines the range of carbon intensities for petrol and diesel from different crude oils produced in different regions and refined in different refineries.

Thus, the authors chose to rather select representative crude oils ranging from light to heavy from the major supply regions for the purpose of their study. Therefore their study does not cover all crude oils imported in Europe, but only the ones treated in three representative refineries, namely:

- FCC-Coking refinery – situated in Germany;
- FCC-Visbreaking refinery – situated in France;
- Hydrocracking-Visbreaking refinery – situated in Italy.

The results were compared to the GHG emissions from a US and a Russian refinery exporting refined products to Europe, in order to point out that the location of the refinery affects the lifecycle emissions.

The study concludes that Well to Tank (WTT) carbon intensities vary widely, depending on how the crude is produced, the amount of gas flaring, the amount of fugitive emissions released during production, and the emissions from oil refining, Also, the limited availability of robust data is discussed, as well as the uncertainty in the calculation due to this unavailability, especially in the production processes. The study provides also a valuable assessment of the emissions of the refining sector depending on the physical properties (API and sulphur content) of crude oil, the refinery configuration the exact input blend of the refinery and the refinery final product (diesel kerosene, petrol, etc.).

The average carbon intensity of diesel fuel produced from representative crude oils refined in representative European refineries has been found to be in the order of 15 $grCO_2eq/MJ$ and around 18 $grCO_2eq/MJ$ respectively for the produced petrol.

1.4.6 ICF Study: Desk Study on Indirect GHG Emissions from Fossil Fuels

The study was assigned by DG CLIMA to ICF international and was carried out in 2013. The overall objective is to provide an overview that enables the European Commission to evaluate the indirect GHG emissions from fossil transport fuel pathways.

Direct emissions are defined as the ones emitted from the processes of production, transport and combustion of the fuel along its lifecycle, whereas the indirect emissions are those that are influenced or induced by economic, geopolitical or behavioral factors, but which are not directly related to extraction, processing, distribution or final combustion of the fuels.

The study identifies and evaluates six possible sources of indirect GHG emissions from fossil fuels:

- Induced land development;
- Military involvement;
- Accidents;
- Marginal effect;

- Price effects;
- Export of co-products.

The study has been based on a thorough literature review in the field of indirect emissions. Where possible, estimates on the emissions are provided. The report concludes that there is no common characterization of direct and indirect sources of GHG emissions between relevant stakeholders and those comprehensive methodologies to calculate indirect emissions are still to be developed. Among the above listed sources of emissions, only the emissions due to accidents are considered as negligible, whereas the market mediated effects (i.e. prices effects and export of co-products to other markets) appear to be the most important source, representing 2.2% – 4.5% of the whole WTW GHG emissions.

The study is an important source for analyzing and estimating indirect emissions and also provides the basis for defining the boundaries between direct and indirect GHG emissions sources in the current project.

1.4.7 NETL: Lifecycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

The main objective of the study is to present the methodology used by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy to analyze and create an inventory of GHG emissions related to natural gas lifecycle, including extraction, transport and use of gas in the U.S. The inventory focuses on the "cradle-to-gate" value chain, i.e. the lifecycle up to the power station gate, therefore it is considered as an upstream inventory in principle. The study utilizes data from 2009.

The report analyzes the upstream emissions of natural gas compared to those of coal and concludes that despite the fact that natural gas combustion emits less greenhouse gases than coal combustion, nevertheless the GHG emissions related to its production and transport to the U.S. power plants are higher than those of coal. This conclusion is probably related to the sources of NG consumed within the U.S. which are, at their majority unconventional (56% unconventional sources of natural gas according to the present report).

The overall emissions of the U.S. natural gas lifecycle including combustion are lower than those of coal. However, the extraction and delivery of the gas has a large climate impact 32 % of U.S. methane emissions and 3 percent of U.S. greenhouse gases. The vast majority of the GHG emissions in extracted natural gas - 70 % of the total cradle-to-gate emissions can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations.

1.4.8 OGP Report: Environmental Performance Indicators - 2012 Data

The International Association of Oil & Gas Producers (OGP) has been collecting environmental data from its member companies for the last 14 years on an annual basis. These data are divided into the following categories, which follow the guidelines provided

within the "Oil and gas industry guidance on voluntary sustainability reporting" by IPIECA/API/OGP:

- Gaseous emissions;
- Energy consumption;
- Flaring;
- Aqueous discharges;
- Non-aqueous drilling fluids retained on cuttings discharged to sea;
- Spills of oil and chemicals.

This report summarizes the above listed environmental information on activities related to exploration and production (upstream) carried out by OGP member companies in 2012. Data coverage is relatively low - 32% of 2012 world production - while regional coverage varies from 96% in Europe to 8% in Former Soviet Union. Overall, data from 43 OGP member companies, representing upstream activities in 78 countries, are presented in the report.

The results provided within this report are aggregated following confidential information provided by member companies to OGP and no specific data by company or by field are given.

1.4.9 Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries

The study was carried out in 2010-2011 by Adam R. Brandt from Stanford University. The issues the report focused on were the following:

a) to provide an overview and description of oil sands extraction, upgrading, Synthetic Crude Oil (SCO) and bitumen, non-combustion process emissions and land use change associated emissions;

b) to compare a variety of recent estimates of GHG emissions from oil sands and to outline the reasons for variations between the estimates in surface mining, in situ production, upgrading, refining and VFF;

c) to outline low, high and "most likely" estimates of GHG emissions from oil sands, given results from previously produced estimates, and compare these emissions to those of conventional EU refinery feedstock.

The author used EU-specific emission factors for transport and refining of fuels. The study concludes that, while oil sands based crude oil is endorsed with higher emissions than conventional crude oil, the production-weighted emission profiles are significantly different and therefore, the regulatory frameworks should address this discrepancy with pathway-specific emissions factors that distinguish between oil sands and conventional oil processes.

Closing, the author suggests the need for additional research of the uncertainties in modelling GHG emissions from the Canadian oil sands. The most important uncertainties mentioned are treatment of cogenerated electric power, treatment of refining and the interaction of markets with LCA results.

2 TASK A: LITERATURE SURVEY

The literature survey was the initiating Task of the project and focused on identifying and reviewing up-to-date documents publicized worldwide regarding lifecycle GHG gas emissions of transport fuels.

The literature survey considered a number of subjects, including:

- Important legal documents in the framework of the present project regarding the Renewable Energy Directive (RED), which sets a target of 10% renewables in the transport sector, the Fuel Quality Directive (FQD), which sets a target of 6% reduction of GHG emissions from road transport, as well as relevant EC Communications and initiatives which set the basis of the EU GHG emissions policy.
- A broad range of subjects related to lifecycle GHG emissions of diesel oil, petrol, kerosene and natural gas. The subjects included regard GHG emissions calculation methods, fuel extraction, fuel transport, fuel refinement, etc.
- Broad range of information resources broken down by type, including private companies reports, international organisations reviews, scientific papers, etc.

The literature survey focused on the most up-to-date data and knowledge on the subject of lifecycle GHG emissions and was based on two methods: extensive on-line literature search, as well as the identification of important relevant information sources through communication with stakeholders i.e. oil and natural gas companies and international organizations. The Consultant set the criteria which allowed the classification of the various documents and the establishment of a tailor made literature electronic database.

2.1 Survey Approach

A large number of documents could be in principle considered in the literature survey related to oil and gas and the respective transportation fuels. It was considered however that a more efficient and targeted approach would be required focusing on documentation whose content is closely related to the subjects addressed by the current study and considering as well their reliability and their significance on the project topics for the potential future reader or researcher. The survey work focused on collection of literature selected in accordance with criteria relating to the content and the type of these documents.

Documents focusing on the following content topics were surveyed:

- **GHG emissions (direct/indirect) for oil and natural gas**: The exact distinction between direct and indirect emissions is related to the choice of the system boundaries. In general, direct emissions are related to the processes of production, transport and combustion of the fuel along its lifecycle, while indirect emissions are related to economic, geopolitical or behavioural factors not directly related to the aforementioned processes.
- **Policies related to transportation fuels and GHG emissions**: Documents referring to policy and strategy aspects of GHG emissions and emission reduction options.
- **Modelling and methodological aspects of Lifecycle Analysis (LCA) of GHG emissions**: Such documents include information regarding models used widely for the estimation of GHG emissions such as OPGEE, GHGenius and GREET or other aspects related to modelling specific aspects of the fuel lifecycle.
- **Conventional and unconventional oil and natural gas pathways, processes and technologies**: These type of documents describe engineering and technological aspects of oil and natural gas production and extraction that will help the reader understand sources of various types of emissions.

Furthermore, literature of the following types was surveyed:

- **Reports and studies**: This is the main type of literature source utilized for the elaboration of the project Tasks. It includes studies from international organizations, national authorities, research institutes, consulting firms and oil and gas companies, which provide comprehensive and up-to-date analyses of lifecycle GHG emissions of transportation fuels.
- **Books**: Textbooks as literature sources providing fundamental technical background for oil and gas exploration, production and transportation.
- **Research papers**: Refers to papers published by universities and research institutes and provide a valuable input for the project, particularly when related to fundamental concepts for the assessment of carbon intensity of fossil fuels.
- **User manuals**: Refers to the supporting documentation for the use of lifecycle emission's assessment and macroeconomic models (OPGEE, GHGenius, GREET, PRIMES etc.) and are particularly useful for introducing these models to the reader and for analysing methodological aspects of GHG emission's assessment.
- **Datasheets**: Refers to data sets published by international organizations or private entities (such as oil and gas companies) that provide input regarding crude oil specifications, crude oil and natural gas production, transport and refining data, overall emissions from their activities.
- **Presentations**: Refers to presentations given by individual experts or organizations which are a useful literature source, despite the fact that they may not provide an in-depth analysis on specific issues. However, they can provide a comprehensive overview of extensive studies and a compact summary of key issues and results.
- **Legislation**: It refers to documents such as relevant European Directives, Regulations and Communications.

The literature survey was carried out during the first months of the project period resulting in the selection of a large number of documents on the basis of content as mentioned above. However, the list of documents consulted has been growing until the end of the assignment, as the project team was collecting and registering additional documents in the course of carrying out the other project Tasks.

In order to store the identified literature and to provide access to all project partners and EC officials, an online literature database was created. The database remained active and was updated throughout the duration of the project so as to include all the necessary documentation that was utilized for the needs of the Tasks of the study. Up tp the end of the project, the literature database included references to more than 80 documents.

A list of the literature stored in the database, including all information attached to each document is presented in Annex C.

2.2 Presentation of Literature Database

The literature database is a tool developed for the needs of the project in order to store and classify the documentation surveyed and provide a common document repository accessible by all project partners and EC officials. It is a user-friendly web-based platform designed specifically for use in the course of this project, providing reference and information on the collected documents.

The database is available on-line at the web address http://ghg-oilgas-literature.eu.

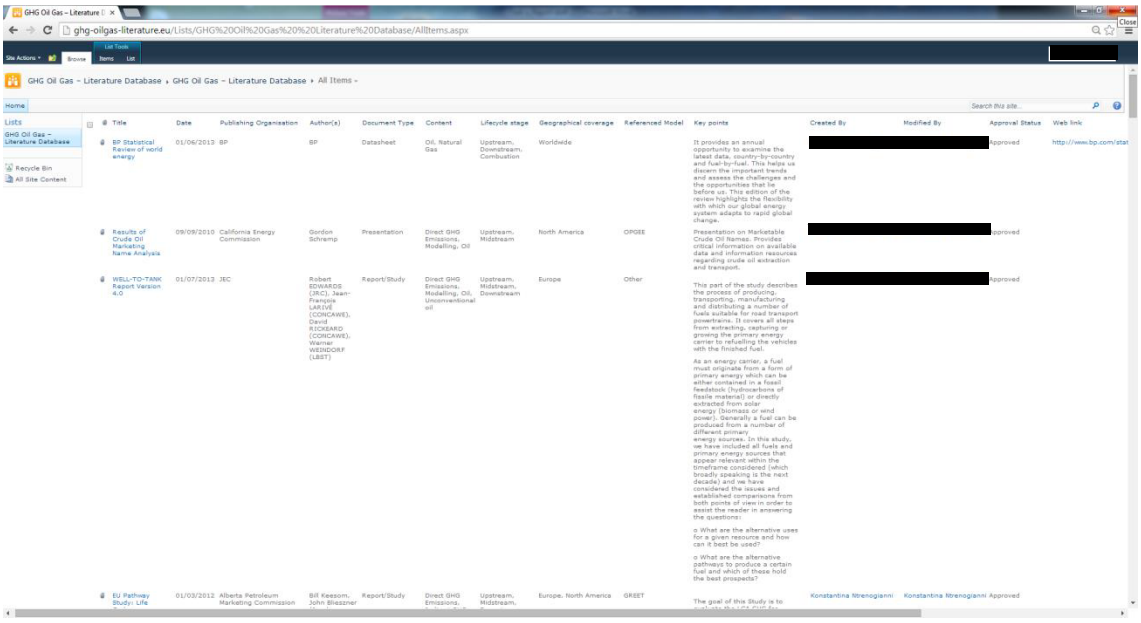
Documents are added to the database along with certain "data fields" providing specific additional information on each document. These fields can be used for sorting and classifying the database documents according to a predefined order depending on the content, thus facilitating the user in selecting specific document references for review.

For each document in the database, the following information is provided

- **Literature fields** i.e. Publisher, Author(s), date of publication;
- **Document type** i.e.Report, Research paper, Legislation, Datasheet, etc.;
- **Content** i.e. Policy, Modelling, etc.;
- **Lifecycle stage** i.e. the specific stage of the lifecycle of transport fuels the document refers to - if applicable;
- **Geographical coverage** i.e. the geographic areas the document provides information on;
- **Referenced model** i.e. the GHG emissions model the document refers to (if applicable);
- **Key points** i.e. a short review of the information provided within the document and its relevance for the study;
- **Web link** i.e. the internet location where the document can be found (if applicable).

A snapshot of the literature database in presented in the following Figure 2-1 while Annex C presents the complete list of documents and related information which is currently stored in the literature database and the generic database.

Figure 2-1 Snapshot of the literature database



The Consultant has added a section under the name "generic literature database" which includes documents of general interest i.e. handbooks, glossaries, general environmental reports for GHG emissions and other relevant studies. These literature sources are not vital for the elaboration of the study but include useful background information for the potential reader.

3 TASK B: DATA ACQUISITION

3.1 EU Oil and Gas Supply

3.1.1 EU crude oil supply

Europe is largely dependent on Former Soviet Union for its primary energy supply in crude oil - approximately 40% - as it can be obtained by Figure 3-1. Europe produces approximately 20% of its domestic consumption, while another 20% is approximately being supplied from countries of the Middle East.

Figure 3-1 EU crude oil supply 2010 - 2013 (source: DG ENER)

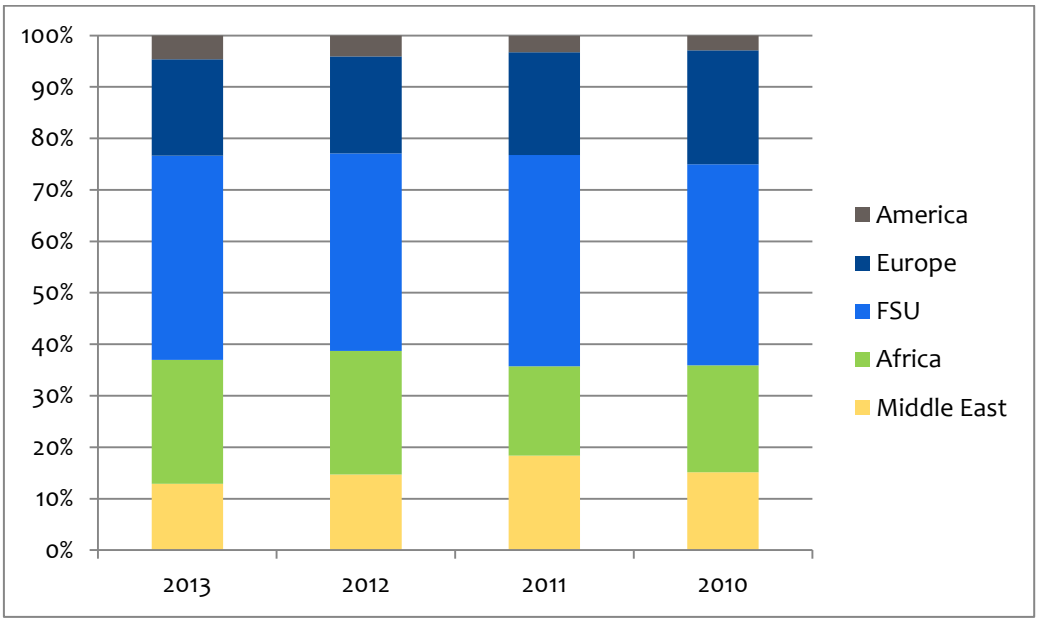
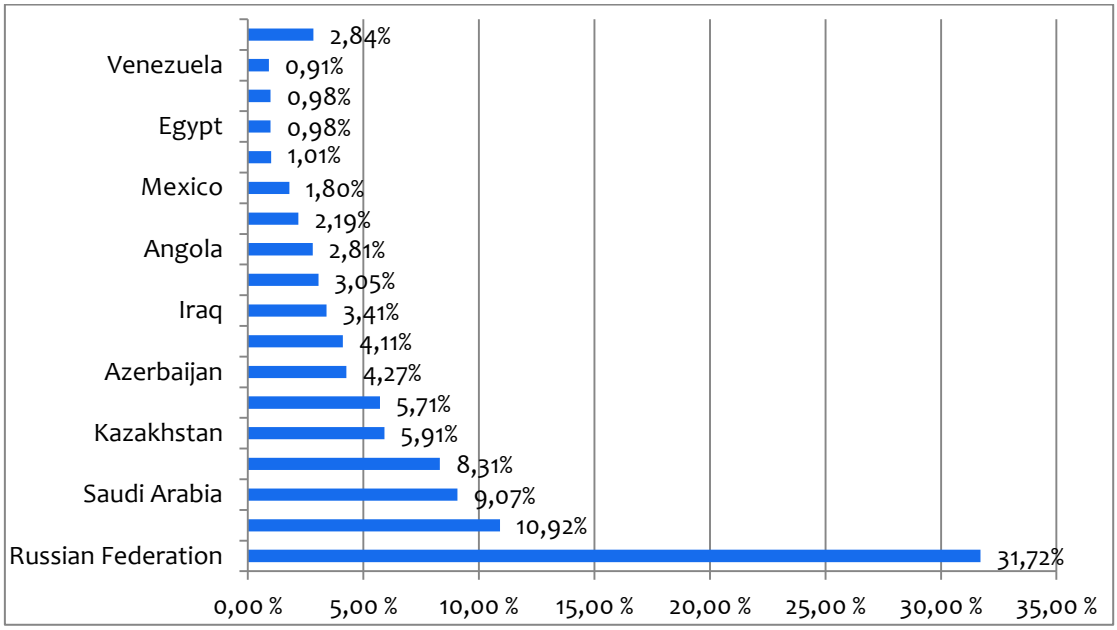


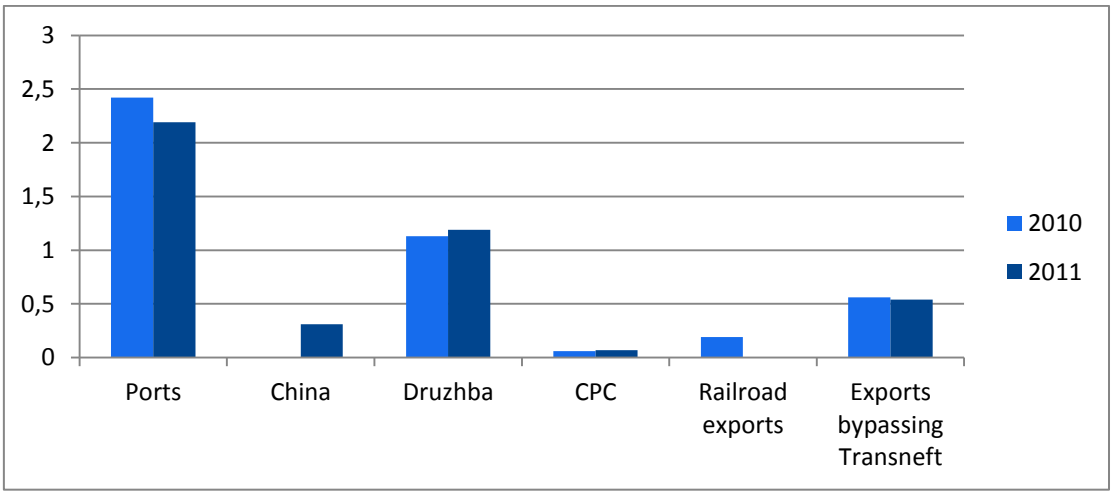
Figure 3-2 illustrates the EU 28 crude oil supply by country of origin for 2012. Currently, Russia is steadily the largest exporter of oil to Europe, exporting crude oil to Europe from the areas of Urals-Volga, Western Siberia and Timan-Pechora under several marketable names (Urals, Western Siberia and Russian Export Blend, also known as REBCO). The second largest supplier of crude oil to Europe is Norway with approximately 11% of total imports. Europe is also supplied significant quantities of Arabian light and heavy crudes, as well as light and medium crude oils from Nigeria. Apart from the Russian crude oil, Europe is supplied large quantities of crude oil from other FSU countries, primarily Azerbaijan (Azeri light and Azeri BTC) and Kazakhstan (Tengiz and CPC blend).

Figure 3-2 EU crude oil by country in 2012 (source: DG ENER)



The largest part of Russian oil towards Europe is exported through the Transneft pipeline system. The Transneft pipeline system spans over 31,000 miles in total and reaches to the ports of Novorossiysk and Primorsk from which major crude oil exports take place.. The Druzhba pipeline system transports the largest part of Russian oil to Europe. Figure 3-3 provides the Russian crude oil exports of the years 2010 and 2011 via various modes of transport.

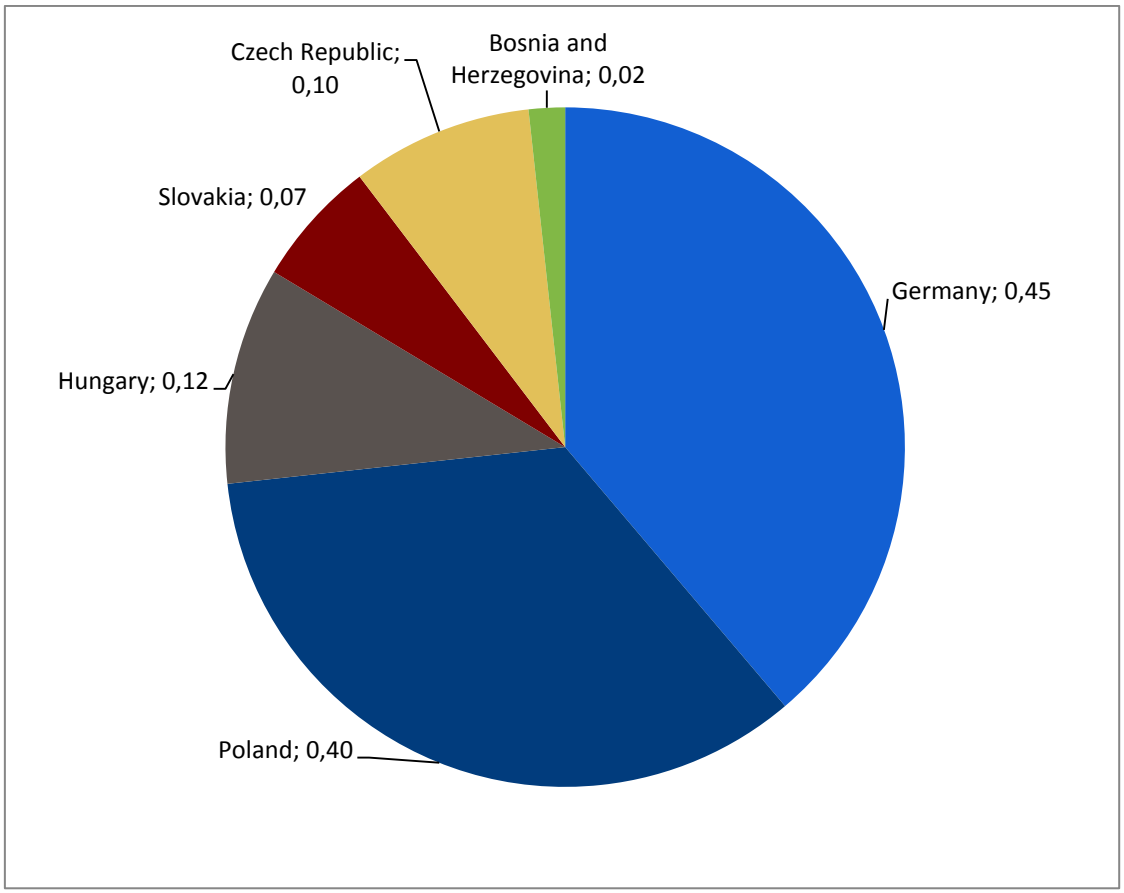
Figure 3-3 Russian crude oil exports in million bbl/dbbl/d (source: CDU-TEK)



From the crude oil transported via the Druzhba pipeline Germany imports the largest fragment with 0.45 million bbl/dbbl/d and Poland comes next with 0.4 million bbl/dbbl/d in the first quarter of 2011, as it is shown in Figure 3-4. Hungary, Slovakia, Czech Republic

receive a smaller fragment of crude via the pipeline at the order of magnitude of 0.1 million bbl/dbbl/d.

Figure 3-4 Transneft's Druzhba deliveries plan for 1st Quarter of 2011 in million bbl/dbbl/d excluding transit (source: Transneft)



3.1.2 Supply of refined products from third countries

Besides crude oil imports, Europe is increasingly importing refined oil products primarily from Russia and United States of America, as it can be seen in Table 3-1.

The increase of refining output and quality of refined products in Russia over the last years has been the result of recent regulatory reforms. Russia has adopted the European fuel quality standards, both for imported and domestically manufactured ones, for road transport vehicles. As of January 2013, Russia switched to Euro-3 standards, which caps sulphur content at 350 ppm (diesel oil) and 150 ppm (petrol) sulphur required. Euro-4 fuel standard will be implemented beginning 1 January 2015 (with max 50 ppm sulphur required), while Euro 5 fuel (with max 10 ppm sulphur required beginning) as of 1 January 2016. These regulations have led Russian oil companies to make investments in order to upgrade their refineries so as to produce cleaner products, primarily Ultra Low Sulphur

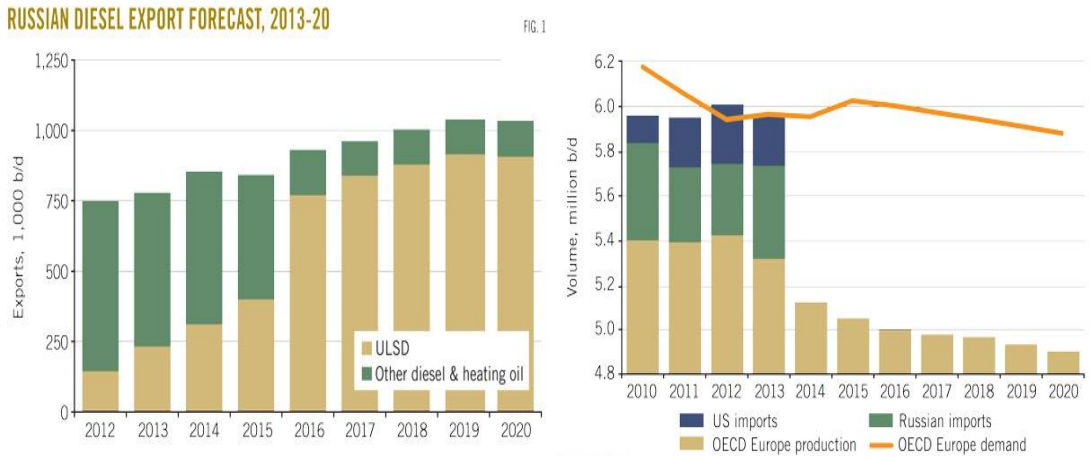
Diesel (ULSD). This has resulted into an increased share of Russian refiners in the EU market at the expense of their European competitors.

Table 3-1 Imports of refined products by FSU and USA (source: Bloomberg)

Source and Year	Daily imports (1.000 barrels)	Annual imports (1.000 barrels)
Imports from FSU 2013	559	204,035
Imports from FSU 2014 (until May 22)	629	229,585
Imports from US 2013	321	117,165
Imports from US 2014 (until May 22)	304	110,960
Total FSU+US imports 2013	880	321,200
Total FSU+US imports 2014 (projection)	933	340,545

Figure 3-5 illustrates that the ULSD is the major refined oil export product to OECD EU and that the OGJ forecast anticipates increase for OECD EU diesel imports; thus it can be considered that domestic EU diesel production is anticipated to decline until 2020, with this gap between production and demand to be covered by diesel imports from USA and FSU.

Figure 3-5 Russian diesel export forecast 2014 – 2020 and OECD Europe diesel supply forecast 2014-2020 (source: OGJ, based on ESAI Energy study)



The increased diesel production to Europe will be supported by expansions of the Sever pipeline. More specifically, the operator of the pipeline, Transneft, has planned two expansion projects of the pipeline. With a nominal capacity of 170,000 bbl/dbbl/d to facilitate ULSD exports from the Baltic Sea, the pipeline already operates above the nominal capacity. In late 2013, the average diesel exports were 200,000 bbl/dbbl/d, which rose to a record of 235,000 bbl/dbbl/d in January 2014. This implies that approximately half

of the refined products imported from Russia are transported to Europe via the Sever pipeline.

United States exported 13.37 million tons (about 273,000 bbl/dbbl/d) to Europe, or 42% of the 32.2 million tons (about 658,000 bbl/dbbl/d) that was imported into the region in 2013 (Eurostat). The Netherlands with 576,000 tons of all ULSD imported into Europe is the major importer, followed by France with 310,000 tons, the country with Europe's biggest diesel deficit.

3.1.3 Unconventional crude oil

Unconventional oils are typically much heavier and sourer even compared to the lowest-quality conventional crude oil. Furthermore, these extra heavy oils require very large energy inputs to be upgraded and pre-processed into synthetic crude oil that is further processed by a refinery. As some of these oils are practically solid they need to be extracted from ground through mining or heating (in-situ methods). The major types of unconventional crude oils are oil sands and shale oil which are briefly discussed below.

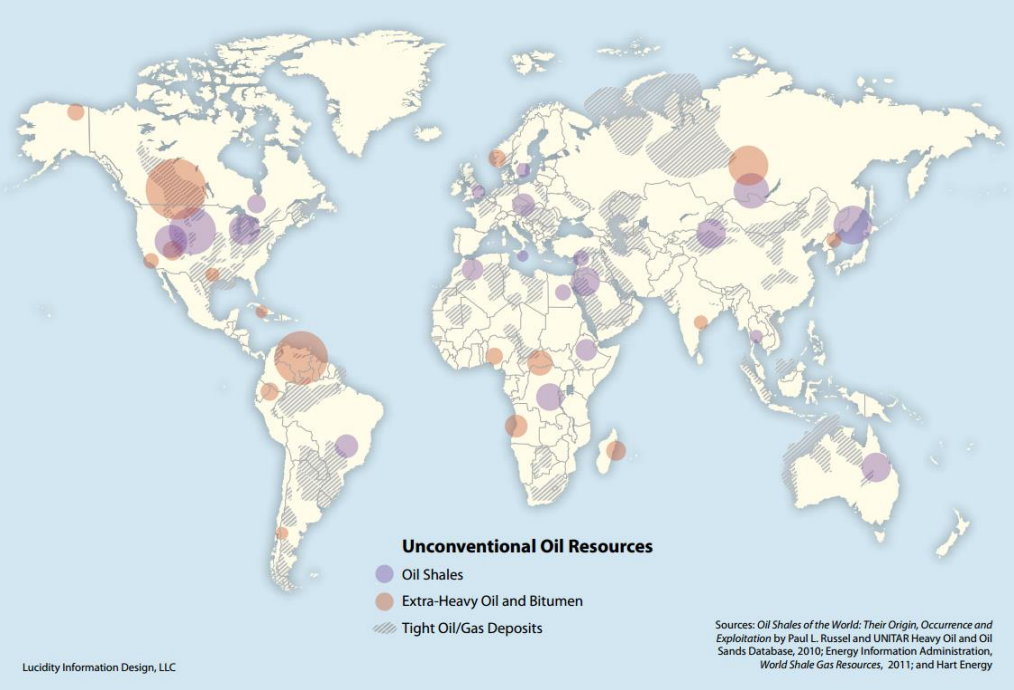
Oil sands are a combination of quartz, sand, clay, water, trace minerals, and a small (10-18% percent) share of bitumen, while their sulfur content can exceed 7%. This extremely complex hydrocarbon mixture can be synthetically processed into oil. Nonetheless, due to their high viscosity they cannot be transported via pipelines without the addition of diluents - typically oil condensates. Therefore, bitumen's are upgraded to synthetic crude oil and other products before they are sent to refineries.

Oil shale is has not stayed underground long enough to be transformed into oil. It is composed of clay, silt, and salts, with a small share of insoluble organic matter (kerogen) and even smaller share of soluble bitumen. The organic kerogen, once extracted and separated from the oil shale, can be processed into oil and gas. Like oil sands, oil shale has similarly high sulfur content up to 7%.

Oil sands are the most promising extra-heavy oils in terms of market interest. The largest deposits are located in Canada, mainly in Alberta: the Athabasca area, Cold Lake and Peace River. Besides Canada various other countries have bitumen resources, including United Sates (various states), Kazakhstan (in the North Caspian Basin), Russia (in the Timan-Pechora and Volga-Ural basins), Venezuela (Orinoco Belt), Republic of Congo, Madagascar, and Nigeria. Nonetheless, Canadian reserves are by far the largest and more easily recoverable.

The largest extra heavy oil bitumen and deposits worldwide are illustrated in Figure 3-6.

Figure 3-6 World shale oil, extra heavy oil and bitumen deposits



The lifecycle analysis of the GHG emissions of unconventional crude oils is different compared to conventional crudes oil, due to different extraction techniques and processing prior to refining. Most LCAs do not include an assessment of raw bitumen, because it is near solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. Thus, bitumen is often diluted with liquid hydrocarbons or converted into a synthetic light crude oil. Several kinds of crude-like products can be generated from bitumen, and their properties differ in some respects from conventional light crude. They include the following:

- **Upgraded Bitumen, or Synthetic Crude Oil (SCO).** SCO is produced from bitumen through an upgrading process that turns the very heavy hydrocarbons into lighter fractions. The upgrading process takes place at the production facility, and therefore the upstream GHG emissions are higher compared to other crude types.
- **Diluted Bitumen (Dilbit).** As the name implies, Dilbit is bitumen mixed with diluents - typically natural gas liquids such as condensate - to create a lighter, less viscous and more easily transportable product. Mixing bitumen with less carbon-intensive diluents lessens the GHG emissions impact per barrel of Dilbit in relation to bitumen or SCO. Some refineries need modifications to process large quantities of dilbit feedstock, since it requires more heavy oil conversion capacity than conventional crudes. Increased processing in refineries transfers part of GHG emissions at the downstream side, potentially intensifying the downstream GHG emission impact of dilbit in relation to SCO or other crudes (e.g., if Dilbit is transported from Canada to the United States via a pipeline, the need for increased refining downstream would shift the potential for emissions to the United States).

- **Synthetic Bitumen (Synbit).** Synbit is a combination of bitumen and SCO. Due to the differences in the mixtures, the properties of each kind of Synbit blend vary significantly, but blending the lighter SCO with the heavier bitumen results in a product that more closely resembles conventional crude oil.

Extraction Process

In general, two types of methods for extracting bitumen from the reservoir are currently used for oil sands. They include the following:

- **Mining.** Oil sands deposits that are less than approximately 75 meters below the surface can be removed using conventional strip-mining methods. Approximately 20% of currently recoverable reserves can be mined. The strip-mining process includes removal of the overburden, excavation of the bitumen, and transportation to a processing facility. Strip-mining techniques entail increased land use changes resulting in higher intensities of GHG emissions.
- **In-situ.** Oil sands deposits that are deeper than approximately 75 meters are recovered using in-situ methods. Most in-situ recovery methods involve injection of steam into an oil sands reservoir to heat - and thus decrease the viscosity of - the bitumen, allowing it to flow out from the reservoir to collection wells. Steam is injected using Cyclic Steam Stimulation (CSS), where the same well cycles both the steam and the bitumen, or by Steam-Assisted Gravity Drainage (SAGD), where a top well is used for steam injection and the bottom well is used for bitumen recovery. In general, in-situ methods are generally more GHG intensive compared to conventional mining – leaving aside land use impacts – due to the fact that significant amounts of energy are required to create steam.

Alberta bitumen

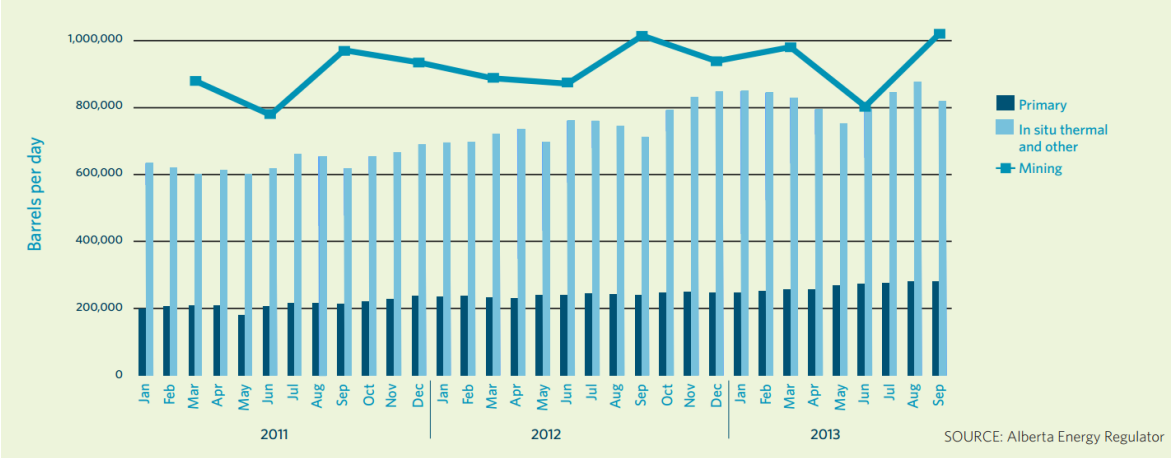
Alberta has the largest oil sand deposits globally. The three major oil sands locations are: Athabasca, Cold Lake, and Peace River. Each area is covered by a layer of overburden consisting of muskeg, glacial tills, sandstone and shale. Figure 3-7 illustrates the location of major oil deposits in Alberta.

As discussed, bitumen is extracted by two means - mining and in situ. The largest part of unconventional deposits until very recently was extracted via conventional mining techniques. In 2011, according to Alberta oil and gas industry, approximately 51% of oil sands production came through mining extraction. Currently, approximately 2/3 of oil sands are extracted via in-situ methods and approximately 1/3 via mining as it can be obtained from Figure 3-8. Alberta in the future will rely to a greater extent on in-situ production, as 80% of the province's proven bitumen reserves are too deep to recover using conventional mining techniques.

Figure 3-7 Map of Alberta's oil sands deposits



Figure 3-8 Alberta oil sands production by extraction method (source: Alberta Energy Regulator)



Due to the recent technological evolution in extraction and upgrading techniques the annual production of Alberta crude oil has increased significantly over the last years and was slightly above 1 million barrels per day in 2012. The excess oil is transferred to the Eastern Canadian and US coast, and will be transferred to Europe in the near future. Currently, oil trains are transporting some of the excess. More specifically, in an annual forecast, the Canadian Association of Petroleum Producers (CAPP) predicted that oil

transported by rail would increase from about 200,000 barrels a day in late 2013 to 700,000 a day by 2016.

Alternatively, the large quantities of crude oil produced are going to be transferred in the future from Alberta to the East Coast via two proposed pipelines, as illustrated in Figure 3-9 One of these two projects the Keystone XL pipeline, which was proposed by TransCanada in 2008, has raised significant debate due to environmental considerations and is blocked till present. An alternative route of Keystone XL - partially to bypass the blockage of Keystone XL - has been the Energy East pipeline proposed by the same company. The pipeline will have a length of 2,858 and a capacity of 1.1 million barrels a day and will be developed by converting a 1,864-mile section of existing natural gas pipeline that runs from just east of Alberta to the western edge of Quebec. The new sections will be added at either end of the pipeline and two marine terminals will be built build on the East Coast. From those terminals the oil could be shipped to refineries along the U.S. East and Gulf Coasts, and it would also find ready markets in Europe and Asia, according to CAPP.

Figure 3-9 The proposed Keystone XL and Energy East pipelines (source: National Geographic)



Crude oil from Alberta is marketed under various names based on the production and upgrading techniques, the most important of which are presented in Table 3-2.

Table 3-2 Overview of Alberta's most important unconventional crudes (source: CARB)

MCON	Remarks
Albian Heavy Synthetic	Albian Heavy Synthetic (AHS) is a partially upgraded crude produced at Shell Canada Scotford Upgrader. AHS is a heavy crude, but due to the partial upgrading, contains lower sulphur than unprocessed Dilbits and Synbits. The API of AHS heavy oil produced through mining is estimated at 8 while the API of Albian heavy through TEOR is estimated at 10.
Borealis Heavy Blend	Borealis Heavy Blend (BHB) is a Suncor Energy Canada diluted bitumen (dilbit) comprised of SAGD produced bitumen and hydrotreated naphtha/conventional diluent with API around 11. It is shipped from Fort Mc Murray to Edmonton and Hardisty, then to further markets across North America.
Cold Lake	The main players in the Cold Lake oil sands deposit are Imperial Oil Resources, Cenovus Energy, Canadian Natural Resources Limited and Shell Energy. Its API is estimated to be around 10. Cold Lake production is bitumen based and requires the use of steam to release the bitumen from the underground reservoirs, and the use of diluents to meet pipeline viscosity and density specifications.
Long Lake Heavy	Long Lake Heavy is a heavy sour Synbit composed of SAGD produced bitumen and synthetic crude upgraded from the same bitumen production.
Hardisty Synthetic Crude	Hardisty Synthetic Crude is a combination of light sweet synthetic crudes consisting of Long Lake Light Synthetic and Husky Synthetic Blend.
Husky Synthetic Blend	Husky Synthetic Blend is an upgraded, bottomless sweet synthetic crude.
MacKay Heavy Blend (MKH)	MacKay Heavy Blend (MKH) is a Suncor Energy Canada diluted bitumen (Synbit) comprised of SAGD produced bitumen and sweet synthetic crude oil (SCO). The API of Mackay Heavy Blend produced through mining SCO is estimated at 8, while through SAGD at 11. It is shipped from Fort McMurray to Edmonton and Hardisty, then to further markets across North America.
Peace River Heavy	Peace River Heavy is produced at Shell Energy Canada's Cadotte Lake thermal production complex near Peace River with an API of approximately 11. It uses enhanced oil recovery techniques to recover bitumen from underground reservoirs. Peace Heavy is a heavy bitumen blended with diluent (a dilbit) to meet pipeline specifications for density and viscosity. Peace Heavy is delivered to Edmonton on the Rainbow Pipeline system.
Suncor	Suncor is a light sweet synthetic crude produced from the Suncor Canada Project located north of Fort McMurray, Alberta. The Suncor facilities includes a mine, SAGD and upgrader operations. OSA is a classic bottomless blend of hydrotreated naphtha, distillate, and gasoil fractions produced from a coker based upgrader facility. The Suncor project came on stream in 1967 and became the world's first oil sands operation.
Shell Synthetic Light	Shell Synthetic Light is a light sweet synthetic crude produced from the Scotford Upgrader located immediately adjacent to Edmonton, Alberta. The Scotford Upgrader - which is part of the joint venture project between Shell Canada, Chevron Canada (a wholly owned subsidiary of Chevron Corporation) and Marathon Oil Sands L.P. - is operated by Shell Canada. The bitumen feedstock is mined north of Fort McMurray and transported to the upgrader near Edmonton.
Surmont Heavy Blend	Surmont Heavy Blend is a heavy sour Synbit composed of SAGD production and domestic synthetic crude. SHB is produced only at the Surmont Project, operated by Conoco Phillips Canada. Total E&P Canada has an equal 50% ownership stake in the Surmont Project.
Synbit blend	Synbit Blend combines Statoil Cheecham Synbit, Surmont Heavy Blend, Christina Synbit Blend, Mackay River Heavy, and Long Lake Heavy in tankage at Superior.
Syncrude	Syncrude Synthetic is a light sweet synthetic crude produced from the Syncrude

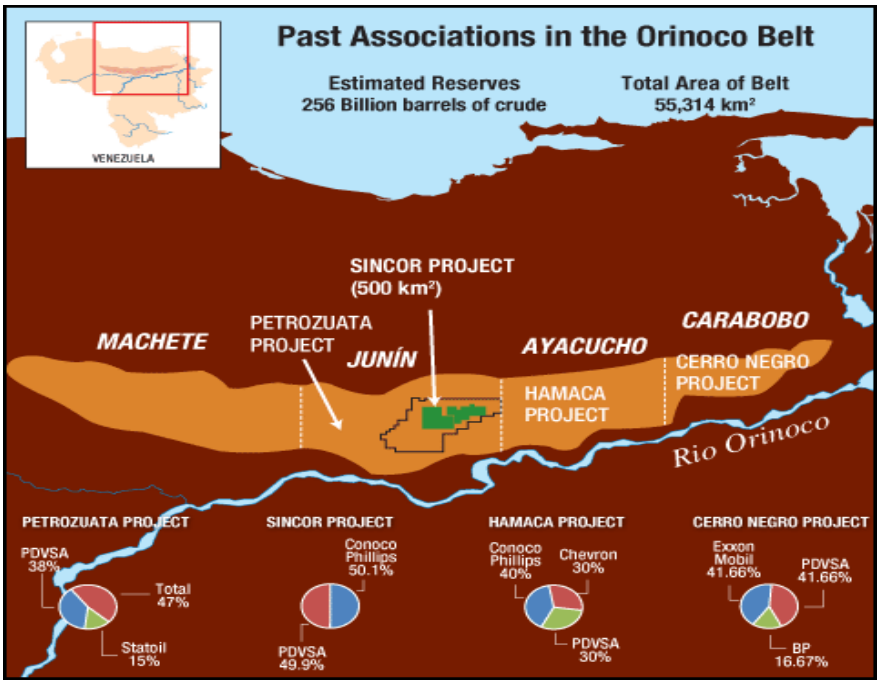
MCON	Remarks
Synthetic	Canada Project located north of Fort McMurray, Alberta. The Syncrude Project includes a mine and upgrader operations. It is a classic bottomless blend of hydrotreated naphtha, distillate, and gasoil fractions produced from a coker and hydrocracker based upgrader facility.
Western Canadian Select	Western Canadian Select is a Hardisty based blend of conventional and oilsands production managed by Canadian Natural Resources, Cenovus Energy, Suncor Energy, and Talisman Energy.

Venezuela heavy oil

Venezuela's recoverable heavy oil deposits found in the Orinoco Belt, are estimated according to a study released by the U.S. Geological Survey[1], at 513 billion barrels of crude oil. The nationalized oil & gas company Petroleos de Venezuela S.A (PDVSA) began the Magna Reserva project in 2005, which involved dividing the Orinoco region into four major areas: Ayacucho, Boyacá, Junín and Carabobo that are further divided into 28 blocks. The four areas are illustrated in Figure 1-1. This initiative resulted in the upgrading of Venezuelan proven reserve estimates by more than 100 billion barrels.

The Magna Reserva projects involve converting the extra heavy crude and bitumen to lighter, sweeter crude, known as Syncrude. While the country's four upgraders have an installed production capacity of about 600,000 bbl/d of Syncrude, industry estimates place production levels for these facilities at less than 500,000 bbl/d as a result of maintenance and safety issues.

Figure 3-10 The four oil producing areas in the Orinoco Belt of Venezuela



[1] http://www.eia.gov/beta/international/analysis.cfm?iso=VEN

The Petrozuata project is a massive programme designed to fully exploit the oil deposits found in the Orinoco belt of Venezuela. The operators of Petrozuata are PDVSA and the American oil company Conoco. The production process has been supported by multiphase pumps since 1997, and the normal practice is to install 2 - 4 pumps in parallel. The clusters have approximately 10 to 12 wells and the viscosity of the oil is around 8 to 12 °API. The oil is transported via a 130 mile pipeline from the oil fields to the upgrading facility in Jose. The upgrader plant uses Conoco's specialized delayed coking technology. The production capacity is 104,000 barrels/day of Syncrude. This is transformed from an original 120,000 barrels/day of crude oil delivery.

3.1.4 EU natural gas supply

Unlike oil supply in the EU, which is almost exclusively dependent on imports from third countries, natural gas supply is ensured by domestic production combined with imports by non EU countries. In 2012, 66% of total natural gas demand in the EU was met by imported gas, up from 45% in 1990. This growing dependence is caused to a large extent by two factors: increasing demand for natural gas, as the cleanest and most versatile fossil fuel, and decreasing domestic production for domestic use within the EU. The large gas fields, which produce at relatively low cost, are becoming depleted, while smaller and offshore gas fields are more expensive to exploit.

Dependence on natural gas imports varies widely among individual EU Member States. Imports to the United Kingdom and Romania are relatively low, while Denmark and the Netherlands are net exporters. On the other hand, six countries (Finland, Latvia, Lithuania, Estonia, Slovakia and Bulgaria) are fully dependent on imports from Russia.

The most important suppliers of the EU natural gas market are Russia (23.24% of total EU supply), Norway (21.45% of total EU supply - pipeline and LNG combined), the Netherlands (17.55% of total EU supply), the UK (8.46% of total EU supply) and Algeria (9.14% of total EU supply – pipeline and LNG combined). These five countries provided almost 80% of the EU gas supply in 2012.

As shown in the graph in Figure 3-11 the most important producers of natural gas in the EU are the Netherlands, the UK and Germany. Italy, Romania, Poland and Hungary consume almost the entire quantities of natural gas produced within their territory. The Netherlands, on the other hand, is a major exporter of natural gas, not only to the EU, but also to third countries.

Figure 3-12 illustrates the countries supplying natural gas to EU and the corresponding share for 2012.

Figure 3-11 EU Natural Gas Imports, Production and Consumption in million cubic meters for 2012

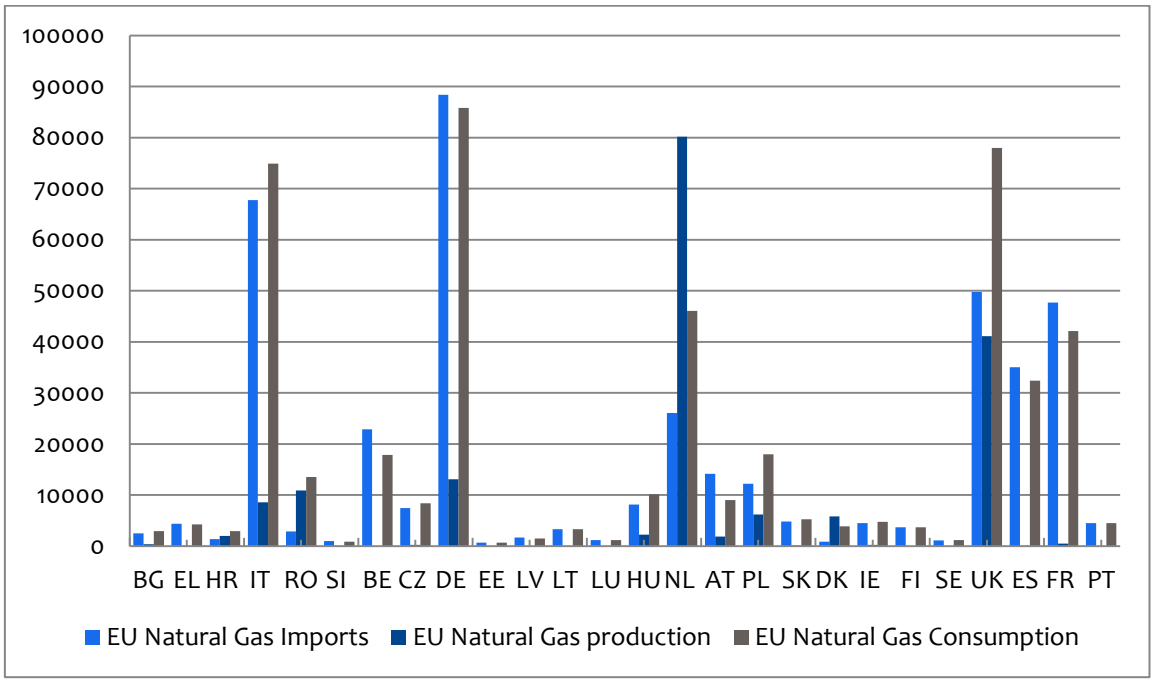
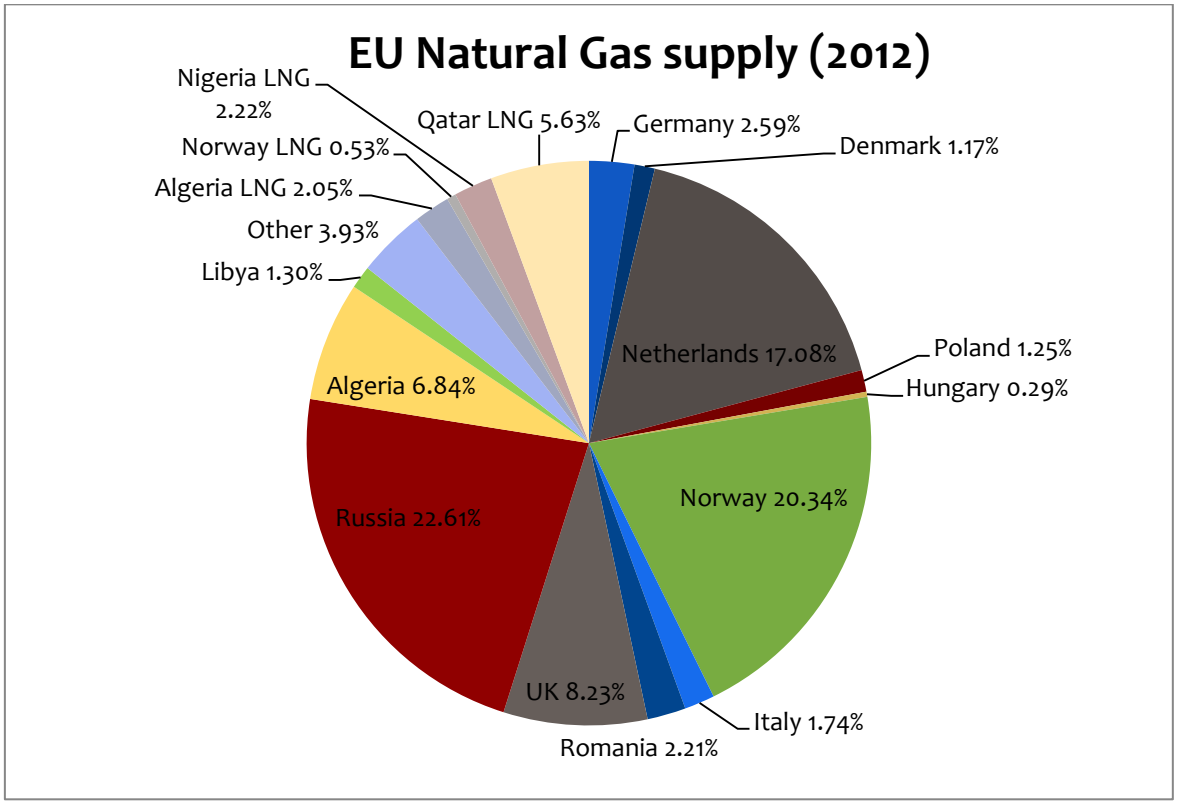


Figure 3-12 EU natural gas supply by country of origin, 2012 (source: IEA)



Gas is imported into Europe by two ways: through pipeline in gaseous form or alternatively by LNG supply chain, where it is liquefied in the country of origin, transported in marine vessels and finally regassified at the entry points in Europe.

There are two major LNG suppliers to Europe, although smaller quantities may arrive from other countries i.e. Algeria and Qatar. Algeria is also connected to the European gas transmission system by pipeline through Spain and Italy. The EU countries receiving the largest quantities of LNG are Spain, France, Italy and Germany. Overall, the share of LNG in the European gas market is presented in Table 3-3.

Table 3-3 EU natural gas supply share by mode of transport

EU NG supply mode	Quantity (million cubic meters - mmcm)	Percentage
Pipeline	**430,682**	**89.3%**
LNG	**516,49**	**10.7%**

The physical flows of natural gas within the EU (blue lines) and the major importing pipelines transporting gas to EU (red lines) are illustrated in the IEA map of Figure 3-13.

Figure 3-13 Gas trade flows in Europe (source: IEA)



3.2 General Methodological Considerations for GHG Lifecycle Emissions Assessment

3.2.1 Fuels examined

The overall aim of the assignment is to provide the actual, as possible, GHG emissions of petrol, diesel, kerosene and natural gas through a lifecycle "well-to-tank" approach. In this context, the Consultant assesses the upstream, midstream and downstream emissions for existing pathways of crude oil and natural gas. Furthermore, the Consultant develops a specific methodology for the assessment of LCA emissions for a basket of the most significant grades of unconventional crude oil and natural gas that will be imported and/or produced in Europe in the forthcoming years.

3.2.2 Categorization of data collection

Generally a GHG emissions inventory of actual data is comprised of calculated and estimated emissions from individual emission sources that are aggregated to produce the inventory. Emissions information is typically obtained either through direct on-site measurement of emissions, or the combination of an emission factor and some measure of the activity that results in the emission which is referred to as the activity factor. Emission factors describe the emission rate associated with a given emission source, which may be either based on site-specific measurements or published data. Activity factors are generally a measured quantity, such as a count of equipment or amount of fuel consumed.

According to ISO14041, data quality requirements should be specified. The requirements should concern time, geographical and technical coverage of the data. To meet those requirements, one may collect adequate data in several ways. Especially in this project the collected data have been classified according to the source of origin that implies also the level of reliability. A three stage hierarchy of data collection with highest priority of course placed on the Actual Data has been considered, as it is the mandate of this project:

- **Actual CI Data** gathered from existing data bases of renown national and international organizations as well from certified data availed by oil and gas companies. These data are in principle based on direct measurements, mass balances, validated emission factors and relevant engineering calculations which have been verified.
- **Actual Data for Models**, collected as above and used as input in this project models, namely OPGEE, GHGenius and PRIMES-Refinery. The outputs of these models cover the cases where actual CI data are not available or there is lack of them. In order to run these models a large number of input data are required and thus have been collected. These latter data are in principle actual data.
- **Literature data**, coming from other studies in GHG emissions for which the Consultant has no access on the detailed way these estimations have been carried

out. This latter stage will be used only in cases where the previous two stages fail to provide reliable results and hopefully its contribution in the project GHG emission calculations is negligible.

Therefore the Consultant has collected actual emissions data both for oil and natural gas in priority i.e. data verified through measurements and calculations as those are provided by energy companies or authorities related to GHG emissions. In order to do so, the Consultant has investigated all open sources of relevant information, mainly availed by national, international organizations and oil and gas associations. Furthermore, all major oil and natural gas companies related to oil and gas streams directed to the EU have been contacted and requested specific and disaggregated data per process. Another source of actual data have been reports published by oil and natural gas companies, which typically include aggregated data, with limited usefulness for our analyses and comparative purposes.

The procedure and the priorities in GHG data collection that has been explained above is presented in Figure **3-14**.

3.2.3 Geographical coverage

The study examines the GHG emissions of petrol, diesel oil, kerosene and natural gas in the form of CNG or small scale LNG used in the transportation sector of EU 28 countries. It must be noted that at the time the ToR was written Croatia was not a full MS. Thus, the country coverage has been extended to include Croatia also.

3.2.4 Choice of baseline year

The baseline year for the assessment of carbon intensity has been chosen to be 2012, primarily because there is a large availability of data for this year regarding all lifecycle stages of the oil value chain, namely upstream, midstream and downstream.

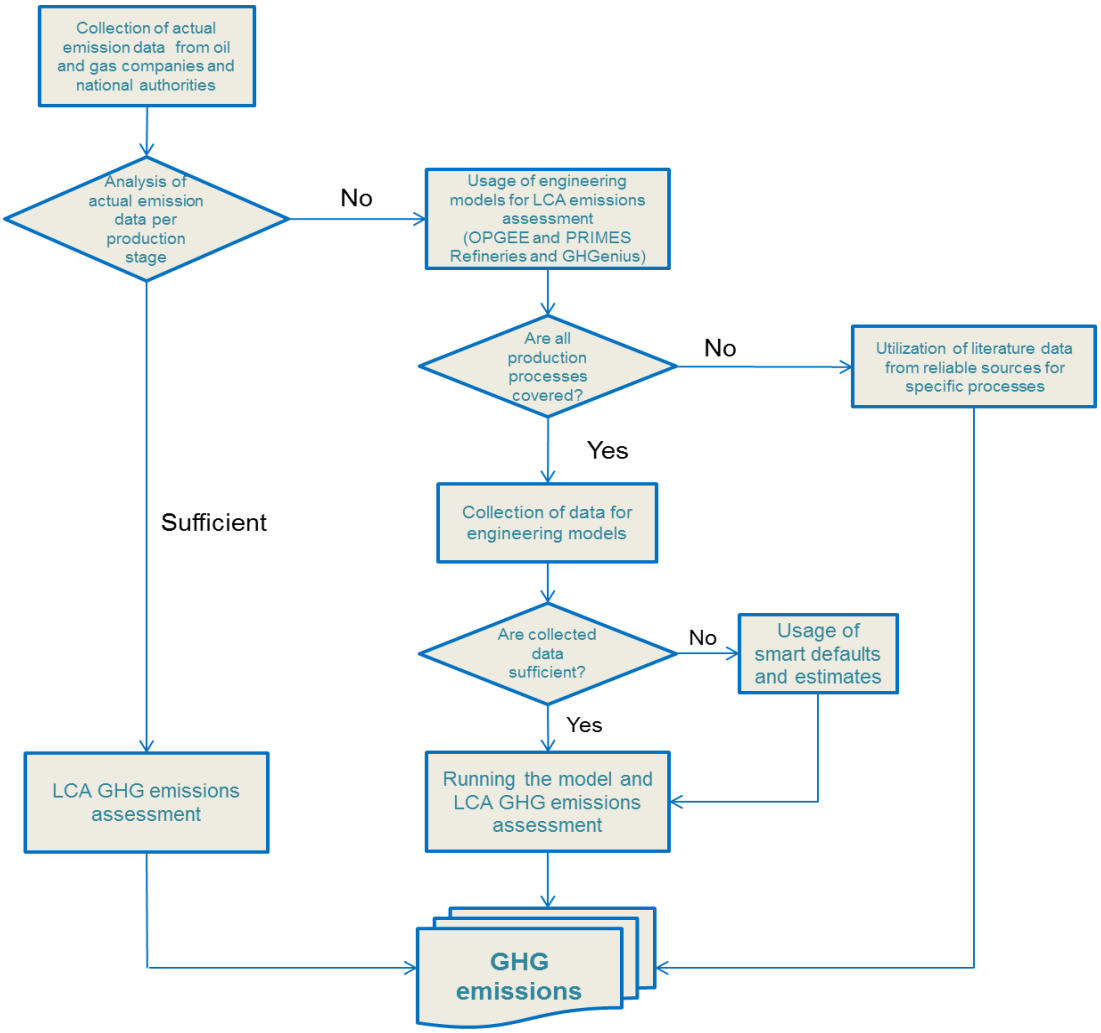
3.2.5 System boundaries

In general, "well-to-tank" emissions refer to those associated with exploration, production, fuel recovery, upgrading, pipeline and maritime transportation, refining, LNG transformation, gas transmission and storage, CNG compression and distribution to final consumers, thus excluding the emissions resulting from the final combustion in the transportation means' engines.

3.2.6 Global Warming Potential (GWP) used

The latest versions of OPGEE (1.1c) and GHGenius (4.03a) use the GWP of 2007, as most of the recent LCA studies. Therefore, it has been considered as preferable option to utilize the GWP 2007 instead of the 2013 GWP in order to ensure consistency of figures and allow comparisons between various studies.

Figure 3-14 Overview of the strategy for the assessment of GHG emissions for crude oil and natural gas



3.2.7 Utilization of Minimum/Maximum approach

The study aims to develop an integrated, consistent and detailed methodology to evaluate the actual range of emissions in the form of minimum, weighted average and maximum values that relate to the whole lifecycle of diesel oil, petrol, kerosene and natural gas. Unlike other relevant studies, which provide one single value regarding GHG emissions per field or fuel type, the present study through the utilization of a minimum/maximum approach allows for various uncertainties to be better expressed and consequently policymakers to better understand the range of GHG emissions of each oil and gas stream and final fuel, as these are evaluated in a more realistic and objective manner.

The potential range in the value of GHG emissions of each oil and gas pathway can be influenced by the following parameters, as also by other ones:

A. Upstream

- Different fields constituting the source of each pathway (MCON or Gas stream).
- Variable quantities of oil or gas production for a specific field.
- Differences in oil field characteristics (particularly API gravity and depth), as also in the natural gas characteristics contributing to a pathway of oil or gas.

B. Midstream

- Mode of transport for a specific oil or gas pathway (marine/pipeline).
- Different final destinations of crude oil or gas per mode of transport.
- Uncertainties related to the exact properties of a crude pipeline blend.

C. Downstream

- Exact constitution of a crude oil blend for the refining process.
- Estimations of emissions for the oil and gas distribution systems within a country.
- Estimations of crude yields on specific products during the refining process.

3.3 Methodological Approach for Oil

3.3.1 Introduction

The methodology for the assessment of GHG emissions of crude oil has been adapted to the three main stages of oil handling chain: upstream, midstream and downstream. Figure 3-15 illustrates the main stages of crude oil handling chain and indicates at high level the general pathways followed in the assessment of each oil grade. In the following sections more detailed presentations of these pathways will be explained. It is worth considering that 35 crude oil pathways in the upstream and midstream stages will be considered covering approximately 88% of the crude oil imports in the EU in 2012. Finally 105 streams (35 for each one of diesel oil, petrol, kerosene) of oil products are considered in the downstream stage up to the tank of transport means.

The nine methodological steps for the calculation of the Carbon Intensities (CI) or GHG emissions in the three stages for each oil pathway are illustrated in Figure 3-16. Essentially four components of CI are distinguished in each oil pathway and the relevant calculation or data collection effort will be directed accordingly. In the following Sections of this Chapter each stage and the relevant approach of the Consultant is thoroughly analyzed.

Figure 3-15 Physical flow of crude oil illustrating the basic stages that are examined by the study

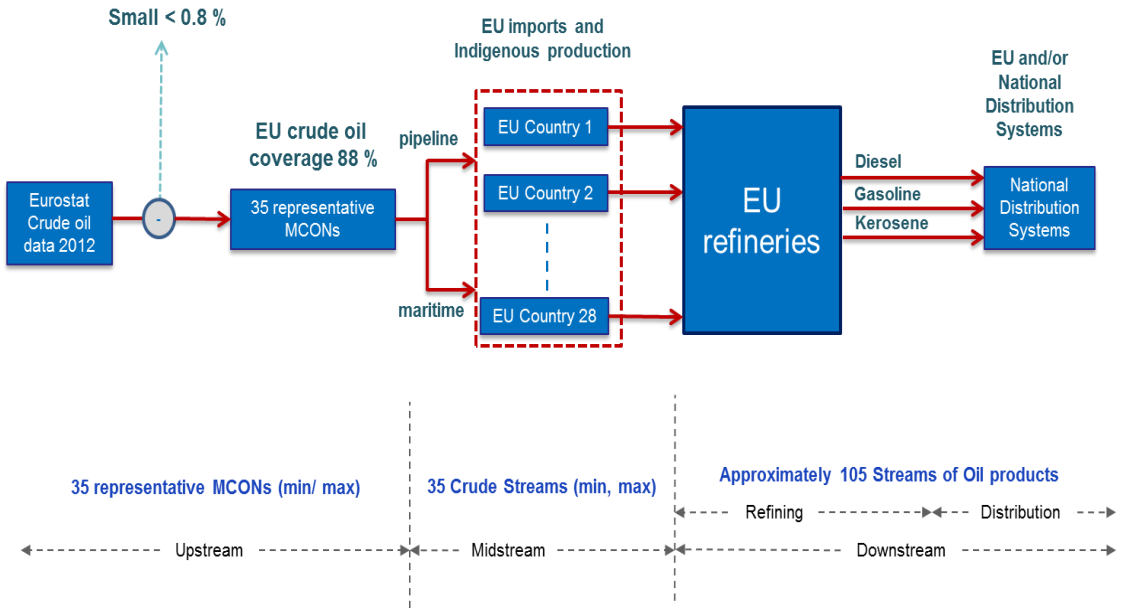
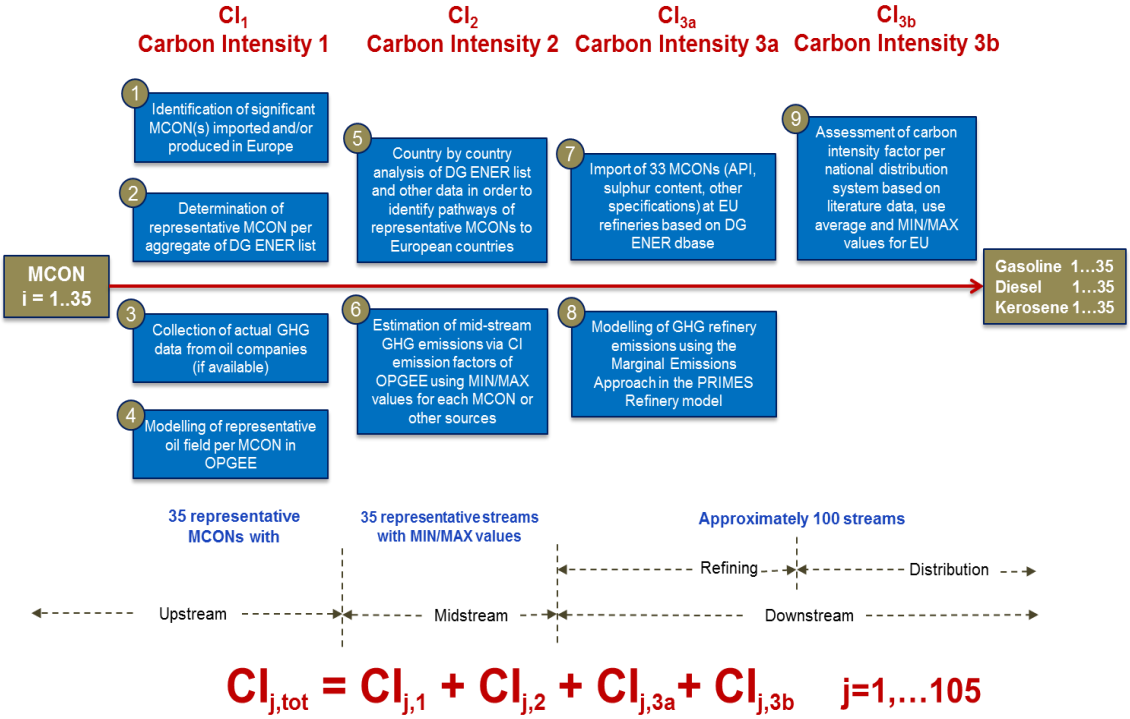


Figure 3-16 Main steps for the assessment of GHG emissions of petrol, diesel and kerosene



Oil trading fundamentals

Oil is a very particular commodity since it is simultaneously a financial asset, but also has a physical dimension. Therefore, the pricing of crude oil in the financial markets is inevitably related to its physical characteristics, production techniques, transportation and storage patterns. The complexity in the pricing of crude oil is related to the various types of internationally traded crude oil with different qualities and characteristics which have a bearing on refining yields. Therefore, different crude oils have different prices.

The adoption of the market-related pricing system by many oil exporters in 1986-1988 constituted a shift from a system in which prices were first administered by the large multinational oil companies in the 1950s and 1960s and then by OPEC for the period 1973-1988 to a market base system. In the current system, the prices of these crudes are usually set at a discount or a premium to a benchmark price of a crude oil according to their quality and their relative supply and demand balance. The main benchmarks currently used are: **Brent, West Texas Intermediate (WTI) and Dubai-Oman**.

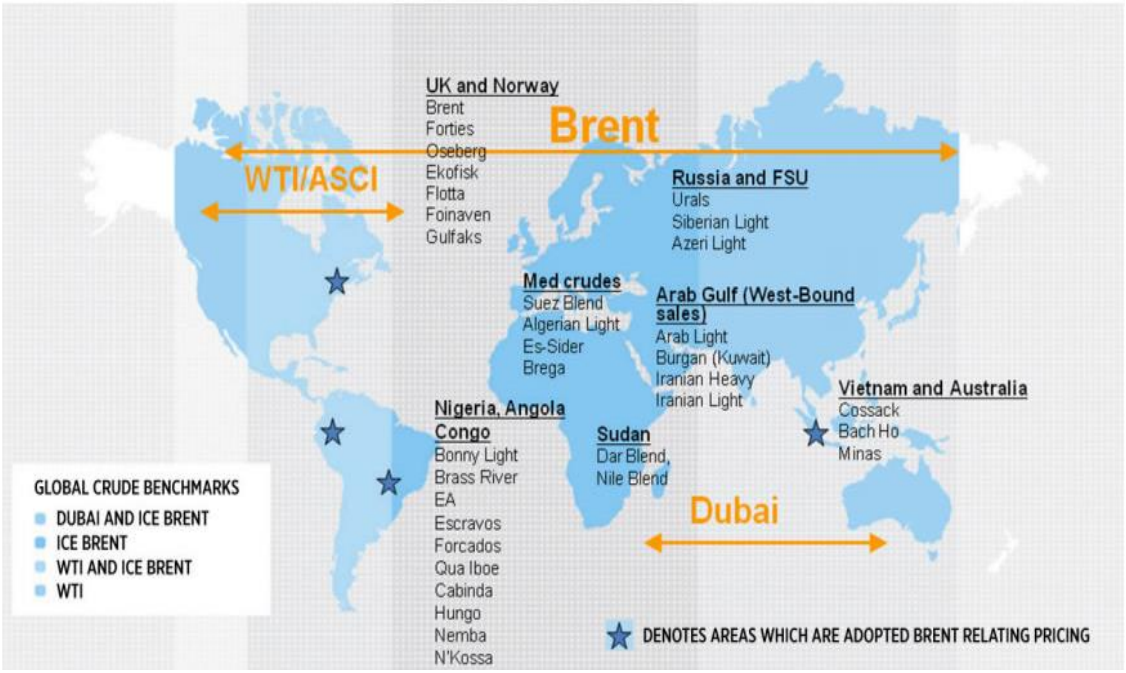
Other reference benchmark is the OPEC reference basket, which is the weighted average of the following blends of oil:

- Saharan Blend (Algeria)
- Ecuador
- Iran Heavy (Islamic Republic of Iran)
- Basra Light (Iraq)
- Kuwait Export (Kuwait)
- Es Sider (Libya)
- Bonny Light (Nigeria)
- Qatar Marine (Qatar)
- Arab Light (Saudi Arabia)
- Murban (UAE)
- BCF 17 (Venezuela)
- Girassol (Angola)

Other significant reference crude oils include Tapis crude oil, which is traded in Singapore, Urals oil used in Russia and Mexico's Isthmus. Figure 3-17 presents the extent of oil benchmarks used worldwide.

The names of the above mentioned crude oils indicate their origin but also and most particularly their commercial recognition in the oil markets. These names are used in the marketing of crude oils and are generally understood as Marketable Crude Oil Names (MCONs).

Figure 3-17 Crude oil benchmarks used worldwide (source: ICE)



Marketable Crude Oil Name (MCON)

One of the novelties of the study is the utilization of the concept of Marketable Crude Oil Name (MCON) in order to correlate the physical properties characterizing crude oil as it is extracted from the oil field and those of the crude oil blended during or before the refining process. Furthermore, the concept of MCON facilitates practically the connection of the refinery input (which has a marketable name) with the primary source of crude oil (at the oil field).

More specifically, the concept of MCON has been introduced by the California Air Resources Board (CARB) in order to match the marketable crude oil names to their respective field sources. The ultimate purpose of this classification is to systematize the various types of crude oils in order to identify High-Carbon Intensity Crude Oils (HCICOs) at a second stage and implement regulatory barriers on polluting crudes imported in the State of California. The initial crude oils of the list have been provided to the Air Resources Board by the Western State Petroleum Association (WSPA) and augmented with other proprietary information resources:

- International Crude Oil Handbook (ICOM)
- Energy Information Administration list of crude oil names (EIA-856)
- Journal of Commerce – Petroleum Import Exports Reporting System
- Crude Information Management System from PetroTech Intel

For the crude oils selected in the CARB list a sequential procedure to assign "pass" or "fail" according to LCA GHG emissions is implemented based on:

- Flaring intensity
- Thermally enhanced oil recovery (TEOR)
- Mining extraction of bitumen
- Use of upgrading facilities to produce synthetic crude oils

Currently, CARB has identified over 250 MCONs globally, while the list is often reviewed. MCON characteristics are constantly changing due to large number of oil fields, oil fields relative contribution in the MCON, depletion of oil fields, and emergence of new exploration and development effort. below illustrates the most important crudes.

In the Council Directive 2015/652 on "laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC", a number of 618 **Feedstock Trade Names** are specified and included in the proposed methodology for calculating the greenhouse gas intensity of conventional fuels directed to transport sector. Nevertheless the need for using Feedstock Trade Names for crude oils is the same as in CARB with MCONs, i.e. to adopt a more precise crude oil naming that is widely recognized in the market and easier to link to GHG emissions.

Figure 3-18 presents some of the most significant MCONs with respect to their API degree, sulphur content and produced quantities.

3.3.2 Upstream

Step 1: Identification of key MCONs for Europe

The starting point of this study step is the list published by DG ENER regarding imports and deliveries of crude oil for 2012, which is illustrated in Table 3-4 as this has been considered the most reliable source of the crude oils imported in Europe.

Figure 3-18 Quantities produced globally and properties of main crudes (source: ENI 2012)

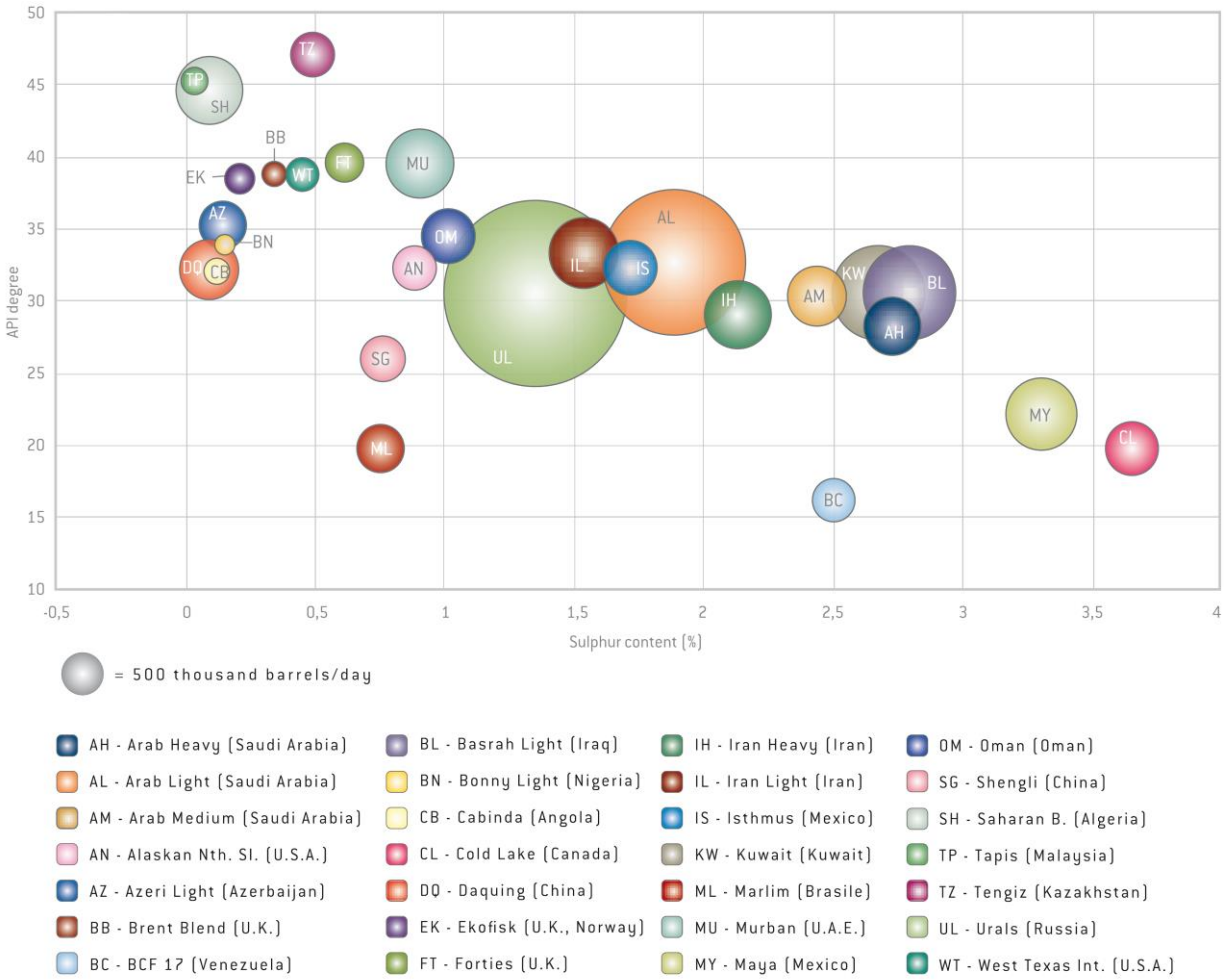


Table 3-4 European imports and deliveries of crude oil for 2012 (source: European Commission, DG ENER)

Region	Country of Origin	Type of crude oil	Volume (1000 bbl)	Total Value ($ 1000)	CIF price (2) ($/bbl)	% of Total Imports
Middle East	Abu Dhabi	Upper Zakum	617	71,007	115,08	0.02 %
	Iran	Other Iran Crude	3,429	382,270	111,50	0.09 %
		Iranian Heavy	33,221	3,746,230	112,77	0.82 %
		Iranian Light	13,665	1,508,091	110,36	0.34 %
	Iraq	Basrah Light	79,604	8,401,086	105,54	1.98 %
		Kirkuk	61,288	6,717,371	109,60	1.52 %
		Other Iraq Crude	10,909	1,121,944	102,84	0.27 %
	Kuwait	Kuwait Blend	33,600	3,636,667	108,23	0.83 %
	Oman	Oman	621	69,620	112,14	0.02 %
	Other Middle East	Other Middle East Crude	433	55,264	127,58	0.01 %

Region	Country of Origin	Type of crude oil	Volume (1000 bbl)	Total Value ($ 1000)	CIF price (2) ($/bbl)	% of Total Imports
	Countries					
	Saudi Arabia	Arab Light	282,801	31,412,348	111,08	7.02 %
		Arab Medium	17,468	1,917,619	109,78	0.43 %
		Arab Heavy	38,376	4,092,054	106,63	0.95 %
		Berri (Extra Light)	15,672	1,728,847	110,31	0.39 %
Middle East			**591,703**	**64,860,417**	**109,62**	**14.68 %**
Africa	Algeria	Saharan Blend	106,964	11,814,595	110,45	2.65 %
		Other Algeria Crude	8,301	934,748	112,61	0.21 %
	Angola	Cabinda	1,992	240,228	120,60	0.05 %
		Other Angola Crude	65,971	7,407,561	112,28	1.64 %
	Cameroon	Cameroon Crude	12,561	1,405,290	111,88	0.31 %
	Congo	Congo Crude	16,594	1,858,782	112,02	0.41 %
	Congo (DR)	Congo (DR) Crude	5,811	637,775	109,75	0.14 %
	Egypt	Heavy	8,832	946,578	107,17	0.22 %
		Medium/Light (30-400)	18,595	2,075,434	111,61	0.46 %
	Gabon	Other Gabon Crude	6,612	728,845	110,23	0.16 %
	Libyan Arab Jamahiriya	Medium (30-400)	175,327	19,828,547	113,09	4.35 %
		Heavy	16,405	1,819,254	110,90	0.41 %
		Light (>400)	124,749	13,936,209	111,71	3.10 %
	Nigeria	Medium	91,210	10,524,436	115,39	2.26 %
		Light (33-450)	206,569	23,681,373	114,64	5.13 %
		Condensate (>450)	14,383	1,599,594	111,21	0.36 %
	Other African Countries	Other Africa Crude	77,954	8,858,861	113,64	1.93 %
	Tunisia	Tunisia Crude	9,571	1,064,795	111,25	0.24 %
Africa			**968,402**	**109,362,907**	**112,93**	**24.03 %**
Australia	Papua New Guinea	Papua New Guinea Crude	1,622	177,421	109,38	0.04 %
Australia			**1,622**	**177,421**	**109,38**	**0.04 %**
FSU	Azerbaijan	Azerbaijan Crude	132,683	15,433,873	116,32	3.29 %
	Kazakhstan	Kazakhstan Crude	204,049	22,932,053	112,39	5.06 %
	Other FSU countries	Other FSU Crude	22,030	2,618,938	118,88	0.55 %
	Russian Federation	Other Russian Fed. Crude	540,118	59,653,602	110,45	13.40 %

Region	Country of Origin	Type of crude oil	Volume (1000 bbl)	Total Value ($ 1000)	CIF price (2) ($/bbl)	% of Total Imports
		Urals	647,728	71,665,578	110,64	16.07 %
FSU			**1,546,607**	**172,304,045**	**111,41**	**38.38 %**
Europe	Denmark	Denmark Crude	42,716	4,871,698	114,05	1.06 %
	Norway	Statfjord	42,622	4,837,953	113,51	1.06 %
		Ekofisk	69,118	7,759,280	112,26	1.71 %
		Other Norway Crude	225,439	25,590,415	113,51	5.59 %
		Oseberg	39,138	4,493,530	114,81	0.97 %
		Gullfaks	34,095	3,906,708	114,58	0.85 %
	Other European countries	Other Europe Crude	104,909	11,463,813	109,27	2.60 %
	United Kingdom	Flotta	14,075	1,620,525	115,13	0.35 %
		Forties	38,083	4,274,373	112,24	0.94 %
		Brent Blend	56,028	6,359,949	113,51	1.39 %
		Other UK Crude	93,937	10,659,678	113,48	2.33 %
Europe			**760,159**	**85,837,922**	**112,92**	**18.86 %**
America	Brazil	Brazil Crude	26,412	2,920,991	110,60	0.66 %
	Canada	Light Sweet (>300 API)	3,634	407,144	112,03	0.09 %
	Colombia	Other Colombia Crude	30,410	3,152,847	103,68	0.75 %
	Mexico	Olmeca	331	36,790	111,15	0.01 %
		Isthmus	12,393	1,374,428	110,90	0.31 %
		Maya	50,426	5,193,475	102,99	1.25 %
	Other L. America countries	Other Latin America Crude	1,485	167,421	112,74	0.04 %
	United States	Other US Crude	60	4,851	80,75	0.00 %
	Venezuela	Medium (22-300)	2,785	298,050	107,01	0.07 %
		Heavy (17-220)	3,716	410,023	110,34	0.09 %
		Light (>300)	4,933	540,946	109,67	0.12 %
		Extra Heavy	25,055	2,556,660	102,04	0.62 %
America			**161,640**	**17,063,627**	**105,57**	**4.01 %**
	World	Other crudes	75	8,456	112,17	0.00 %
World			**4,030,208**	**449,614,795**	**111,56**	**100. %**

Step 2: Representative MCONs and oil fields

One significant methodological pitfall of the DG ENER list – relevant to the study - is that the used term "type of crude" oil does not necessarily correspond to specific MCONs as expected. Instead, crudes are presented in an aggregated form that does not allow for the precise identification of MCONs imported in Europe. For example, the "Nigerian Light"

crude oil corresponds to several MCONs. Furthermore, the list uses also aggregate figures such as "Other Norwegian Crude" which again corresponds to several marketable names (MCONs). Therefore, the Consultant has determined to use the concept of **representative MCON** so that one or two representative MCONs are used for each "type of crude oil". The choice of representative MCONs has been based on the following principles:

- **Largest quantities of related MCONs imported and/or produced in Europe.** Representative MCONs have been chosen on the basis of quantities of crude oil imported and/or produced in Europe in order to maximize the coverage of the DG ENER aggregates. Thus, MCONs with the higher quantities of imports or production (for European crudes) have been chosen as representative. However, in the case of certain countries (i.e. Nigeria, Angola, Libya) it has been difficult to exactly identify the quantities imported in Europe from all MCONs and therefore determined the one with the largest imports. In these cases, it has been assumed that the MCON that corresponds to the fields with the largest production is representative of the DG ENER aggregate.
- **Maximum geographical coverage of the exporting country.** Another significant consideration for the choice of representative MCONs has been the maximization of the geographic coverage of the exporting country. This is necessary because our background analysis using the OPGEE and work previously done has shown that crudes extracted within a specific vicinity exhibit similar upstream emissions. This has been anticipated because the reservoirs of fields that are located closely most likely have the same geological characteristics.
- **Significance of MCON in EU crude oil supply over the years.** The supply of Europe and Member States in specific MCONs does not exhibit significant variations over time. However, the choice of a specific baseline year for the study might not capture significant crude oil sources. For instance, Iranian crude is significant for EU crude oil supply (4.00 % of EU imports in 2011 and 2.47% in 2012 %,), but no quantities were imported in 2013 for political reasons. However, it is anticipated that in the close future Europe will start importing again Iranian. Similarly the Venezuelan extra heavy crude oil (Boscan), in 2012 constituted 0.62% of EU supply and is anticipated according to our market prospects that it play a constantly increasing role in Europe's crude oil supply. Therefore, it has been determined to include of the scope the analysis these two crudes.

In order to take into account only MCONs that constitute a significant fragment of EU supply, the Consultant has removed aggregates comprising less than 0.8% of EU imports with the exception of Venezuela bitumen. Additionally, the aggregates "other Europe crude" and "other UK crude" have been removed. With the removal of these aggregates the EU import coverage reaches the satisfactory level of 87.84%.

Following the choice of representative MCON, an intensive analysis of the oil fields comprising each MCON has followed. The extent to which an oil field is representative of an MCON (and by extension affects its physical characteristics) is highly volatile as this depends on the number of fields feeding an MCON and spans over time. For instance, the

Statfjord blend is fed by the oil fields of Statfjord, Snorre, Sygna, Satellites Statfjord North and East, which demands for manageable effort regarding data collection. However, for crude aggregates such as Brent there are over 70 fields feeding the MCON. Furthermore, the analysis of work previously done and primarily the analysis of upstream emissions conducted by ICCT using the OPGEE model has shown that oil fields with small geographical proximity have similar upstream emissions. Thus, it has been considered that the choice of the fields with the highest production is representative for each MCON. The revised DG ENER list with representative fields and MCONs is illustrated in Table 3-5. This list is considered for the analyses carried out onwards in this study.

One significant methodological difficulty for the disaggregation is that for a specific type of crude oil, there might be several types of MCONs or grades depending on the mode of transport (e.g. pipeline or maritime), exporting port, etc. This difficulty is mostly related to Russian crudes and the case of Urals crude oil is illustrated in Table 3-6. The presented grades of Urals are mostly imported in Europe via several ports and the Druzhba pipeline.

Table 3-5 List of representative MCONs and oil fields

Region	Country of Origin	Type of crude oil	Share	Representative MCON	Representative Oil field Name
Middle East	Iran	Iranian Heavy	0.82 %	Iranian Heavy	Gachsaran
	Iraq	Basrah Light	1.98 %	Basrah Light	Rumaila (South)
					West Qurna
		Kirkuk	1.52 %	Kirkuk	Kirkuk
	Kuwait	Kuwait Blend	0.83 %	Kuwait Blend	Burgan
	Saudi Arabia	Arab Light	7.02 %	Arab Light	Gwahar
					Kurais
		Arab Heavy	0.95 %	Arab Heavy	Manifa
Africa	Algeria	Saharan Blend	2.65%	Saharan Blend	Hassi Messaoud
	Angola	Other Angola Crude	1.64%	Dalia	Block 17/Dalia
				Girassol	Girassol
				Greater Plutonio	Greater Plutonio
	Libyan Arab Jamahiriya	Medium (30-40o)	4.35%	Es Sider	Es Sider
		Light (>40o)	3.10%	El Sharara	El Sharara
	Nigeria	Medium	2.26%	Bonga	Bonga
				Forcados	Forcados Yokri
		Light	5.13%	Bonny light	Agbada
					Caw Thorne Channel
				Escravos	Escravos Beach
FSU	Azerbaijan	Azerbaijan Crude	3.29 %	Azeri light	Azeri-Chirag-Gunashli (ACG)
				Azeri BTC	Azeri-Chirag-Gunashli (ACG)
	Kazakhstan	Kazakhstan	5.06 %	CPC Blend	Tengiz

Region	Country of Origin	Type of crude oil	Share	Representative MCON	Representative Oil field Name
		Crude		Tengiz	Tengiz
	Russian Federation	Other Russian Fed. Crude	13.40 %	Western Siberia Light	Tevlinsko-Russkinskoye
					Uryevskoye
					Samotlor
					Vat-Yeganskoye
					Povkhovskoye
				Druzhba	
		Urals	16.07 %	Urals	Romashkino
					Unvinskoye
					Pamyatno-Sasovskoye
Europe	Denmark	Denmark Crude	1.06 %	DUC	Halfdan
	Norway	Statfjord	1.06 %	Statfjord	Statfjord
		Ekofisk	1.71 %	Ekofisk	Ekofisk
		Other Norway Crude	5.59%	Troll	Troll B/C
				Asgard Blend	Tyrihans
		Oseberg	0.97%	Oseberg	Oseberg
		Gullfaks	0.85 %	Gullfaks blend	Gullfaks
	UK	Forties	0.94 %	Forties	Buzzard
		Brent Blend	1.39 %	Brent Blend	Ninian
		Other UK Crude	2.33 %	Captain	Captain
America	Mexico	Maya	1.25 %	Maya	Cantarell
	Venezuela	Extra Heavy	0.62 %	Boscan	Boscan
Total EU import coverage:			87. 84%		

Table 3-6 Different grades for Urals crude oil (source: Argus Media)

Grade	Typical °API gravity	Typical Sulphur (%)	Conversion factor (t/bl)	Basis/ Location	Timing	Cargo size (tons)
Urals NWE	30.83	1.44	7.2161	CIF Northwest Europe	Loading 10-25 days ahead	
Urals Med 80,000t	30.84	1.29	7.2165	CIF Augusta, Italy	Loading 10-25 days ahead	80,000
Urals Med 140,000t	30.84	1.29	7.2165	CIF Augusta, Italy	Loading 10-25 days ahead	140,000
Urals fob Primorsk	30.83	1.44	7.2161	FOB Primorsk, Baltic	-	100,000
Urals fob Ust-Luga			7.2156	FOB Ust-Luga, Baltic	-	
Urals fob Novorossiys	30.84	1.29	7.2165	FOB Novorossiysk,	-	80,000

Grade	Typical °API gravity	Typical Sulphur (%)	Conversion factor (t/bl)	Basis/ Location	Timing	Cargo size (tons)
k 80,000t				Black Sea		
Urals fob Novorossiysk 140,000t	30.84	1.29	7.2165	FOB Novorossiysk, Black Sea	-	140,000
Urals cif Black Sea 80,000t	30.84	1.29	7.2165	CIF Black Sea	-	80,000

Similarly, there are several grades (usually referred to as price assessments in crude oil pricing) for deliveries of Russian Urals crude to refineries in eastern inland Europe via the Druzhba (Friendship) pipeline, which have the same physical properties of oil and thus the same emissions related to upstream activities, but different emissions related to crude oil transport. Table 3-7 presents the reality with the Druzhba pipeline delivering the same MCON to different destinations in EU.

Table 3-7 Price assessments for crude oil transported via the Druzhba pipeline (source: Argus Media)

Grade	Typical °API gravity	Typical Sulphur (%)	Conversion factor (t/bl)	Basis/ Location	Timing	Cargo size (tons)
Druzhba Czech Republic	30.82	1.60	7.2156	fit Budkovce, Slovakia (for Czech delivery)	Delivered during the previous month	10,000t tranche
Druzhba Slovakia	30.82	1.60	7.2156	fit Budkovce, Slovakia (for Slovak delivery)	Delivered during the previous month	10,000t tranche
Druzhba Hungary	30.82	1.60	7.2156	fit Fenyeslitke, Hungary (for Hungarian delivery)	Delivered during the previous month	10,000t tranche
Druzhba Poland	30.82	1.60	7.2156	fit Adamowo, Poland (for Polish delivery)	Delivered during the previous month	10,000t tranche
Druzhba Germany	30.82	1.60	7.2156	fit Adamowo, Poland (for German delivery)	Delivered during the previous month	10,000t tranche
Druzhba Czech Republic	30.82	1.60	7.2156	fit Budkovce, Slovakia (for Czech delivery)	Delivered during the previous month	10,000t tranche

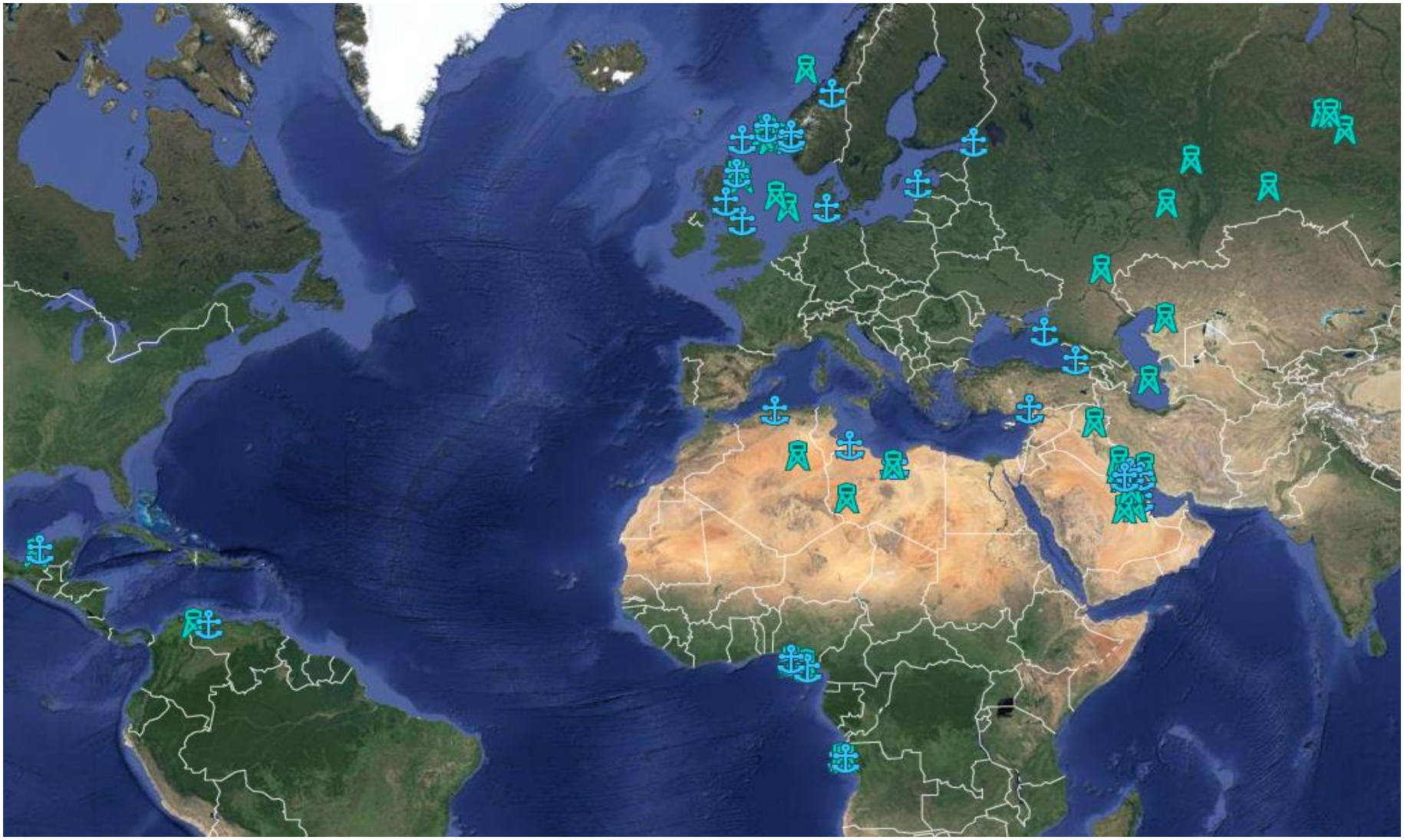
Reliability of the choice of representative MCONs and oil fields

It must be noted that for few specific cases there is a small possibility that a chosen representative MCON or oil field might not arrive at Europe, particularly for MCONs presented in an aggregated way (e.g. Nigerian crudes). However, this is strongly mitigated by the fact that the likelihood that the specific MCONs (e.g. Bonny light) arriving at Europe is increased as these are the most important crudes in terms of quantities for the specific category (e.g. Nigerian Light). Furthermore, a background consistency check has been made with several sources (Platts, Argus, Lloyd's, Bloomberg) so as to ensure that the specific MCON actually arrives at Europe.

Similarly, the rationale for the choice of a representative oil field based on production volumes entails a small risk that oil from the specific fields might not arrive at Europe. For Russian and FSU crudes, this risk is very limited as most of these crudes (and respectively oil fields) enter the same pipeline system that supplies Europe directly or via maritime. The possibility that an oil field is not fully representative is increased in the case where a large number of oil fields comprise an MCON (e.g. Brent, Forties, Bonny light). In this case, even though the field might not supply crude oil to Europe the reliable assumption that the field has similar characteristics to its neighboring fields and therefore emissions has been made. This assumption has been validated by background analysis of neighboring fields in OPGEE which produce results in the same range of values.

The sites of all fields and the exporting ports of the MCONs considered in this study are presented in Figure 3-19.

Figure 3-19 Map of representative oil fields and their terminals



Step 3: Collection of actual data from oil companies and national authorities

Following the finalization of representative MCONs and oil fields, the Consultant started the procedure for collecting actual data of MCONs and their representative oil fields. The main sources of these data are either the oil companies that are operators of the specific oil fields or the national authorities responsible for oil activities in each country. The list of the targeted field and MCON operators for the representative MCONs considered in this study as well as the other involved companies are presented in Table 3-8.

Table 3-8 Representative MCONs and their operators

Representative MCON	Operator	Other companies
Iranian Heavy	National Iranian Oil Company	-
Basrah Light	BP	China National Petroleum Corporation (CNPC) Iraq's state-owned South Oil Company (SOC)
	Iraq National Oil Company	Exxon Mobil, Royal Dutch Shell, Lukoil, Statoil
Kirkuk	North Oil Company	London-based BP, Iraq Petroleum Company, Iraq's National Oil Company
Kuwait Blend	Kuwait Oil Company	-
Arab Light	Saudi Aramco	-
Arab Heavy	Saudi Aramco	-
Saharan Blend	Sonatrach	-
Dalia	Total	Total is operator with 40% interest. Esso Exploration Angola holds 20%, BP holds 16.67%, Statoil holds 23.33%.
Girassol	Total	Esso Exploration Angola (20% interest), BP (16.7%), Statoil (13.3%) and Norsk Hydro (10%).
Greater Plutonio	BP	Sonangol Sinopec International, a joint venture between the Chinese and the Angolan state oil companies,
Es Sider	NOC / ConocoPhillips / Marathon / Hess	-
El Sharara	Repsol, Akakus	Total / OMV / Statoil
Bonga	Shell Nigeria	Royal Dutch Shell, ExxonMobil, Total S.A., Eni
Forcados	Shell Nigeria	-
Bonny light	Chevron	Shell
Escravos	Chevron ELF	-
Azeri light	BP	Chevron with 11.3%; SOCAR with 11.6%; INPEX with 11%; Statoil with 8.6%; ExxonMobil with 8%; TPAO with 6.8%; Itochu with 4.3%; and Hess with 2.7%
Azeri BTC	AIOC	Shareholders of the Azeri-Chirag-Gunashli offshore field

Representative MCON	Operator	Other companies
	BP	include BP with 34.1367% of stakes, ChevronTexaco - 10.2814%,SOCAR - 10%, INPEX - 10%, Statoil - 8.5633%, ExxonMobil - 8.006%, TPAO - 6.75%, Devon Energy - 5.6262%, Itochu - 3.9205% and Hess - 2.7213%. Russia's Lukoil oil company pulled out of the project in 2003 selling all of its interest to INPEX.
Tengiz	Tengizchevroil	Chevron Corporation (50%), ExxonMobil (25%), KazMunayGas (20%)
CPC blend	Tengizchevroil	Chevron Corporation (50%), ExxonMobil (25%), KazMunayGas (20%)
Druzhba	Lukoil	-
	Lukoil	-
Siberia Light	Lukoil	-
	Lukoil	-
Urals	Lukoil	-
	Lukoil	
DUC	Maersk Oil	Gas A/S, Royal Dutch Shell, Chevron Corporation
Statfjord	Statoil	
Ekofisk	ConocoPhillips Skandinavia AS	Petoro, Statoil, Eni, ConocoPhillips, Total S.A.
Troll	Statoil	Petoro (56%), Royal Dutch Shell (8.1%), ConocoPhillips (1.62%) and Total S.A. (3.69%)
Asgard Blend	Statoil	Petoro (35.69%), Eni Norge (14.82%), Total E&P Norge (7.68%) and ExxonMobil (7.24%)
Oseberg	Statoil	ConocoPhillips Skandinavia AS 6.17 %, ExxonMobil Exploration & Production Norway AS 28.22 %, Petoro AS 28.94 %, Statoil Petroleum AS 36.66 %
Gullfaks blend	Statoil	Norsk Hydro the former Saga Petroleum
Forties	NEXEN PETROLEUM U.K. LIMITED	Suncor Energy - 30%, BG Group - 22%, Edinburgh Oil & Gas - 5%
Brent Blend	Canadian Natural Resources Limited (UK)	Eni 13%
Captain	Chevron	Texaco North Sea UK Company (85%) and the Korea Captain Company Limited (15%)
Maya	Pemex	-
Boscan	Empresa Mixta Petroboscan	Petroleos de Venezuela (PDVSA) and Chevron

Step 4: Modelling of upstream emissions in OPGEE model

The literature review and the direct contacts with oil companies till present have made explicit that oil companies are cautious regarding the emission figures they publish, which are presented in generic and aggregated manner. Furthermore, data collected by national authorities or environmental organizations are typically on a country level which is insufficient for the analyses and comparisons of this study.

In order to mitigate the difficulty to obtain actual GHG emissions data on a field or MCON level the OPGEE model might be used for the estimation of GHG emissions of several MCONs. Therefore, the effort of the project team focused in gathering necessary data which are input for OPGEE. The main sources of these were official reports and publications from international organizations and oil companies involved in oil exploitation.

The rationale and the structure of the OPGEE model concentrates on simulating the upstream and midstream processes per oil field; details about the model are presented in the next Sections of this report.

3.3.3 Midstream

Step 5: Assessment of crude oil pathways to Europe

The purpose of this step is to estimate the GHG emissions related to the transport of crude oil to Europe. The Consultant has initially located the loading terminals for each MCON as they are presented in Table 3-9. These terminals are used for the calculation of distances towards the main EU unloading ports. The relevant estimation of distances and GHG emissions will be presented in the next Sections.

Table 3-9 Most significant oil terminals supplying crude oil to Europe

Type of crude oil	Representative MCON	Representative Oil field Name	Terminal Name
Iranian Heavy	Iranian Heavy	Gachsaran	Kharg Island
Basrah Light	Basrah Light	Rumaila (South)	Al Basrah Oil Terminal
		West Qurna	Al Basrah Oil Terminal
Kirkuk	Kirkuk	Kirkuk	Ceyhan
Kuwait Blend	Kuwait Blend	Burgan	Mina al Ahmadi
Arab Light	Arab Light	Gwahar	Ras Tanura
		Kurais	Ras Tanura
Arab Heavy	Arab Heavy	Manifa	Ras Tanura
Saharan Blend	Saharan Blend	Hassi Messaoud	Arzew
Other Angola Crude	Dalia	Block 17/Dalia	Dalia FPSO
	Girassol	Girassol	Girassol FPSO
	Greater Plutonio	Greater Plutonio	Greater Plutonio FPSO

Type of crude oil	Representative MCON	Representative Oil field Name	Terminal Name
Medium (30-400)	Es Sider	Es Sider	Es Sider
Light (>400)	El Sharara	El Sharara	Zawiya
Medium	Bonga	Bonga	Bonga FPSO
	Forcados	Forcados Yokri	Forcados Terminal
Light	Bonny light	Agbada	Bonny Terminal
		Caw Thorne Channel	Bonny Terminal
	Escravos	Escravos Beach	Escravos Terminal
Azerbaijan Crude	Azeri light	Azeri-Chirag-Gunashli (ACG)	Supsa
	Azeri BTC	Azeri-Chirag-Gunashli (ACG)	Ceyhan
Kazakhstan Crude	CPC Blend	Tengiz	Ceyhan
	Tengiz	Tengiz	Novorossiysk
Other Russian Fed. Crude	Western Siberia (light)	Tevlinsko-Russkinskoye	Novorossiysk, Primorsk
		Uryevskoye	Novorossiysk, Primorsk
		Samotlor	Novorossiysk, Primorsk
		Vat-Yeganskoye	Novorossiysk, Primorsk
		Povkhovskoye	Novorossiysk, Primorsk
Urals	Urals	Romashkino	Novorossiysk, Primorsk
		Unvinskoye	Novorossiysk, Primorsk
		Pamyatno-Sasovskoye	Novorossiysk, Primorsk
Denmark Crude	DUC	Halfdan	Fredericia
Statfjord	Statfjord	Statfjord	Statfjord
Ekofisk	Ekofisk	Ekofisk	Teesside
Other Norway Crude	Troll	Troll B/C	Mongstad
	Asgard Blend	Tyrihans	Asgard FPSO
Oseberg	Oseberg	Oseberg	Sture
Gullfaks	Gullfaks blend	Gullfaks	Mongstad
Forties	Forties	Buzzard	Hound Point
Brent Blend	Brent Blend	Ninian	Sullom Voe
Other UK Crude	Captain	Captain	Captain FPSO
Maya	Maya	Cantarell	Caya Arcas
Extra Heavy	Boscan	Boscan	Bajo Grande

Maritime transport

Europe is supplied with crude oil either via maritime transport from major ports that are interconnected with oil pipelines or directly from oil terminals. More specifically, significant part of Russian oil arrives in Europe via Primorsk which is Russia's largest oil terminal, with a loading capacity of 1.5 million bbl/dbbl/d. It is located near St. Petersburg and is a two-berth harbor that can accommodate ships with maximum length of 307 meters. Novorossiysk is Russia's main oil terminal at the Black Sea coast. Its load capacity is 950,000 bbl/dbbl/d, and it can load tankers up to 150,000 deadweight tons (dwt). Tuapse is located on the northeastern shore of the Black Sea, southeast of Novorossiysk. Two of the six berths load crude oil. The port mainly exports Siberian Light. Its loading capacity is about 350,000 bbl/dbbl/d. In addition, the terminal has more than 580.000 barrels of oil and oil products storage capacity. The port can accommodate tankers with up to 80,000 dwt. Yuzhny terminal is located in Ukraine, near Odessa, although it mainly exports Russian and Kazakh crude oil via the Black Sea. This port's load capacity is 315,000 bbl/dbbl/d, and it can accommodate vessels up to 70,000 dwt. Additionally, other significant Russian oil ports are at Ventspills, Ust Luga and Gdansk in Poland; all of them are exporting Urals oil.

In terms of quantities imported, the largest Russian oil terminal is Primorsk which in 2011 exported over 1.3 million bbl/dbbl/d. Novorossiysk is the largest Russian oil terminal in the Black sea, through which Russia exported approximately 0.9 million bbl/dbbl/d in 2011, as it can be obtained from Figure 3-20.

From these ports crude oil arrives at Europe via various categories of tankers the categories of which are illustrated in Table 3-10 and will be used in the calculation of GHG emissions of oil maritime transport.

Figure 3-20 Exports in million bbl/dbbl/d including transit through Russian ports Quarter 1 of 2010 to Quarter 1 of 2011 (source: CDU)

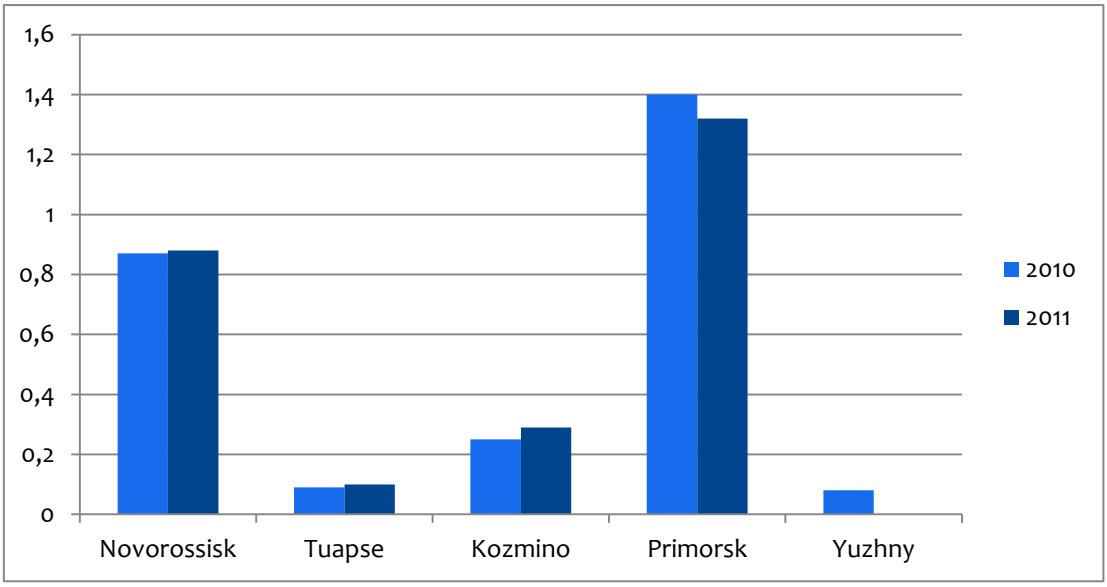
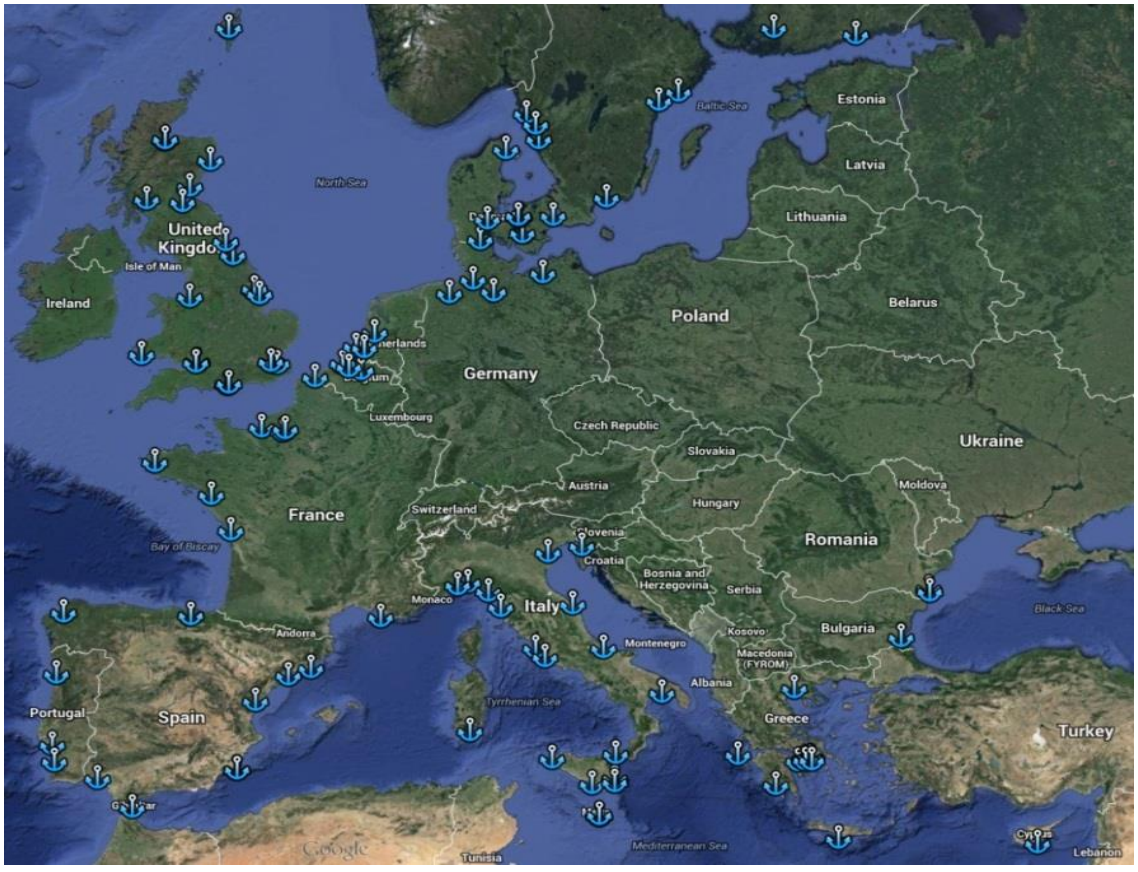


Table 3-10 Crude oil tanker categories (source: Lloyds)

Name	DWT Range (tons)	Description
Aframax	80,000 - 119,000	This is the largest crude oil tanker size in the AFRA (Average Freight Rate Assessment) tanker rate system.
Suezmax	120,000 - 150,000	This is the maximum size crude oil ship that can pass through the Suez Canal in Egypt.
VLCC	150,000 - 319,999	These are very large crude oil carriers that transport crude oil from the Gulf, West Africa, the North Sea and Prudhoe Bay to destinations in the United States, Mediterranean Europe and Asia. Although VLCCs are otherwise too large, it is possible to ballast these vessels through the Suez Canal.
ULCC	320,000 - 999,999	These are the largest man-made vessels that move. Currently, the largest ULCC is 564,939 dwt. These ships sail the longest routes, typically from the Gulf to Europe, the United States and Asia. They are so large that they require custom-built terminals for loading and unloading.

Figure 3-21 illustrates the major ports that have facilities for unloading of crude oil in Europe. These ports are the recipients of crude oil transported from the exporting ports of the representative MCONs which have been presented above.

Figure 3-21 Map of major ports importing crude oil in Europe



Pipeline transport

The largest part of the Russian oil is supplied to Europe via the **Druzhba pipeline** system, which remains the largest oil pipeline in the world. The vast majority of the oil refined in Poland, Slovakia, Hungary, Eastern part of Germany and Czech Republic is supplied via the Druzhba pipeline. Table 3-11 presents the main destinations of the Druzhba pipeline and the capacity of refineries which are supplied by the pipeline.

The Baltic Pipeline System (BPS) is a Russian oil transport system operated by the oil pipeline company Transneft. The BPS transports oil from the Timan Pechora region, Western Siberia and Urals-Volga regions to Primorsk oil terminal. Main sections of the BPS I are the Yaroslavl Kirishi pipeline and Kirishi-Primorsk pipeline. The capacity of the BPS I is 76.5 million tons of oil per year. The Baltic Pipeline System II is the second route of the Baltic Pipeline System. The BPS-II was completed in 2011 and became operational in 2012. The pipeline runs from Unecha to the port of Ust Luga (west of St. Petersburg and passes through Smolensk. It has a total length of 1,170 km and a capacity of 50 million tons per year. The main routes are presented in Figure 3-22.

Table 3-11 EU refining locations and capacities linked to Druzhba pipeline

Country	Location	Capacity (MTA)
Lithuania	Mazeikiai	9.4
Poland	Gdansk	10.5
	Plock	17.8
Germany	Leuna	11.2
	Schwedt	12.0
Czech Republic	Litvinov	5.1
	Kralupy	3.1
	Padubice	1.0
Slovakia	Bratislava	5.7
Hungary	Szazhalombatta	7.9
TOTAL		**83.7**

Figure 3-22 The Baltic Pipeline System, gas pipelines shown in red color, oil pipelines in green and the dashed line shows the planned pipelines (source: EIA)



The **Caspian Pipeline Consortium (CPC)** oil pipeline, was commissioned in 2001 and runs from Kazakhstan's Tengiz oil field to the Russian port of Novorossiysk at the Black Sea. The consortium transported an average of 684,000 bbl/dbbl/d of crude oil in 2011, including 608,000 bbl/dbbl/d from Kazakhstan and 76,000 bbl/dbbl/d from Russia. In addition, approximately 53,000 bbl/dbbl/d of Tengiz crude was discharged at Atyrau, Kazakhstan, for loading onto rail cars. In 2011, CPC partners began the expansion of the pipeline capacity to 1.4 million bbl/dbbl/d. The project will be implemented in three phases, with capacity increasing until 2016. The expansion is expected to provide additional transportation capacity to accommodate increased production from Tengizchevroil.

The **Baku-Novorossiysk pipeline** is 830 miles long and has a capacity of 100,000 bbl/d. The pipeline runs from the Sangachal Terminal to Novorossiysk, Russia on the Black Sea. SOCAR operates the Azeri section, and Transneft operates the Russian section. An ongoing dispute between SOCAR and Transneft concerning transportation tariffs occasionally complicates the pipeline's operation. There are proposals to increase the pipeline capacity to between 180,000 and 300,000 bbl/d, a key transportation addition as production grows in the ACG oil field and throughput from Kazakhstan increases in the future. In 2010, Baku-Novorossiysk transported approximately 45,500 bbl/dbbl/d.

Since the collapse of the Soviet Union, European countries have begun investing in alternative export routes. The **Baku-Tbilisi-Ceyhan** (BTC) pipeline is a 1-million bbl/dbbl/d line in Azerbaijan, which came online in 2006. Kazakhstan has a contract with Azerbaijan and the BTC Pipeline Company to ship up to 500,000 bbl/dbbl/d of oil via the BTC pipeline. Kazakh oil supplies were loaded into the BTC for re-export for the first time in October 2008. Oil supplies are delivered by tanker across the Caspian to Baku. The BTC pipeline system runs 1,110 miles from the ACG field in the Caspian Sea, via Georgia, to the

Mediterranean port of Ceyhan, Turkey. From there the oil is shipped by tanker mainly to European markets.

Kazakhstan's other major oil export pipeline, **Uzen-Atyrau-Samara**, is a northbound link to Russia's Transneft distribution system, which provides Kazakhstan with a connection to world markets via the Black Sea. The line was upgraded in 2009 by the addition of pumping and heating stations and currently has a capacity of approximately 600,000 bbl/dbbl/d. Before the completion of the CPC pipeline, Kazakhstan exported almost all of its oil through this system.

Table 3-12 presents the main oil pipelines supplying crude oil to Europe as well the capacities of the pipelines and the estimated distances to the main destinations. Also Figure 3-23 presents in a regional map the main routes of Russian oil pipelines supplying oil to Europe.

Due to the above presentation of the Russian oil pathways it is evident that there is high complexity in defining the MCONs and their precise oil field components. Figure 3-23 presents the approach of the Consultant in representing the midstream pathways and the relevant Russian MCONs, especially those directed to EU destinations. Therefore oil transported by Druzhba constitutes one MCON which differentiates in the GHG emissions according to the country of delivery due to different distances and a min-max calculation will be used. On the other hand we consider two Urals MCONs due to the two pathways used to export it by maritime (Primorsk, Novorossiysk) and one Siberian Light MCON export through Novorossiysk.

Figure 3-23 Russian crude oil analysis from oil field to MCON

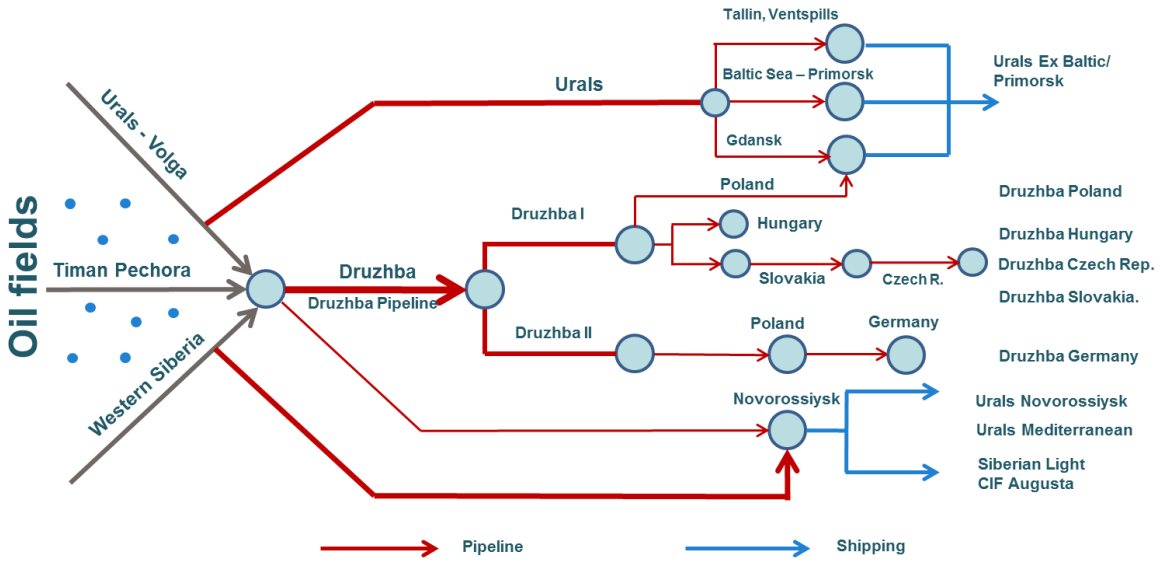


Table 3-12 Russian and Caspian pipeline supplying Europe (source: EIA)

Pipeline	Route	Length (miles)	Capacity (million bbl/d)	Details
Druzhba	Northern Route: Belarus, Poland Germany; Southern Route: Belarus, Ukraine, Slovakia, Czech Republic, Hungary	2,400	2	
Baltic Pipeline System I	Timan Pechora to Primorsk Terminal	730	1.5	
Baltic Pipeline System 2	Unecha to Ust-Luga Terminal	620	1	
North-West Pipeline System	Polotsk to Butinge and Ventspills	500	0.3	Branches off of Druzhba near Russia-Belarus border and transports Russian oil via Belarus to Latvia and Lithuania
Caspian Pipeline Consortium (CPC)	Tengiz (Kazakhstan) to Russian Black Sea port of Novorossiysk	940	0,7	Planned expansion to 1.4 million bbl/dbbl/d by 2016
Baku-Tbilisi-Ceyhan (BTC)	Connects ACG, Shah Deniz, Tengiz		1,000,000 bbl/d	Kazakhstan-Azerbaijan-Georgia-Turkey
Baku-Novorossiysk Pipeline	Sangachal Terminal (Azerbaijan) to Russian Black Sea port of Novorossiysk	830	0.1	Planned expansion to 0.3 million bbl/dbbl/d
Source: Transneft, IHS, PFC Energy, Petroleum Economist				

Rail export routes

Rail exports comprise a very small portion of Russian oil exports. Rail transport generally used as an alternative to Transneft's pipeline network, although rail transport is generally more expensive than pipeline transportation. It is referred that Russia exports crude oil and petroleum products by rail to Estonia and Latvia. These quantities are small and will be ignored in this study.

Figure 3-24 Map with main routes of Russian pipelines supplying crude oil to Europe



http://pipelinesinternational.com/news/druzhba_pipeline/008045/

Step 6: Estimation of midstream GHG emissions

The Consultant has approached the transportation of crudes (MCONs) by ships at the refinery gate by correlating discharges of crude oil cargoes at ports (which is an information relatively available) with neighboring refineries. It has been taken into account that most EU refineries either own an oil terminal or are built close to ports. Similarly, most refineries in Central Europe are built alongside major crude oil pipelines. The precise blend input of refineries - either via marine transport or pipeline - is unfortunately not available as it is of high commercial value for refineries and has therefore been impossible to find this information in a consistent and reliable manner. One possible source of this information could be maritime databases using vessel tracking via the automatic Identification System (AIS) that most ships have installed over the last decade.

Maritime transport

A database that contains such information and reviewed by the Consultant is APEX (Analysis of Petroleum Exports) providing details of laden tanker movements for vessels greater than 10,000 DWT engaged in world-wide crude oil trades and laden tanker movements for vessels greater than 60,000 DWT in world-wide oil product trades as well as current tanker activities for specific size ranges.

The APEX database is a product of Lloyd's List Intelligence that draws on the extensive movements' database of its parent company Informa Group. The database is compiled from

movements observed by over 1,500 Lloyd's Agents worldwide, supplemented with data from the network of AIS stations; the world's largest, and satellite AIS data. From this database Lloyd's List Intelligence extracts movements' details for all tankers and combination carriers in excess of 10,000 DWT. These data is then analyzed by a team of analysts who identify the laden voyages which are then inputted into the APEX database.

Even though the APEX database is probably one of the most comprehensive commercial information tools for the analysis of maritime crude oil shipments it has been considered as insufficient for the purpose of this study, as in several cases the precise type of the shipment is not explicitly mentioned or stated as "multiple cargo" which does not allow for further analysis. Furthermore, despite its depth of information regarding maritime transport, the database does not contain information regarding pipeline oil transport. However, it must be stated that the database contains a wealth of information relevant to:

- Vessel name
- Cargo type and tons
- Crude type
- API of crude transported
- Loading port and date
- Discharge port and date
- Refinery capacity at place
- Refinery location, capacity and owner
- Distance
- Dead Weight Tonnage

Other useful programs for identifying ships vessel movements carrying crude oil is the Sea Web tool by IHS, combining comprehensive data regarding ships, ports, real-time positions and historic vessel movements. A similar tool including ship vessel movements is FleetMon.

However, it has still been impossible to fully contemplate the EU refineries input blend by the shipments arriving in relevant ports as most of the times several crudes are loaded from the loading port making it impossible to fully analyze the exact type of crude a vessel is carrying. Furthermore, there is also the probability of double counting of vessels particularly for voyages off Rotterdam.

In order to mitigate this uncertainty, the Consultant has finally used the information filled in by Member States to DG ENER and elaborated it to identify which MCONs are imported by each Member State **on a country basis**. Furthermore, the ports which have crude oil terminals have been linked to the nearby refineries; therefore we may approximate minimum and maximum distances of MCONs transportation from loading port to the gates of EU refineries.

Pipeline transport

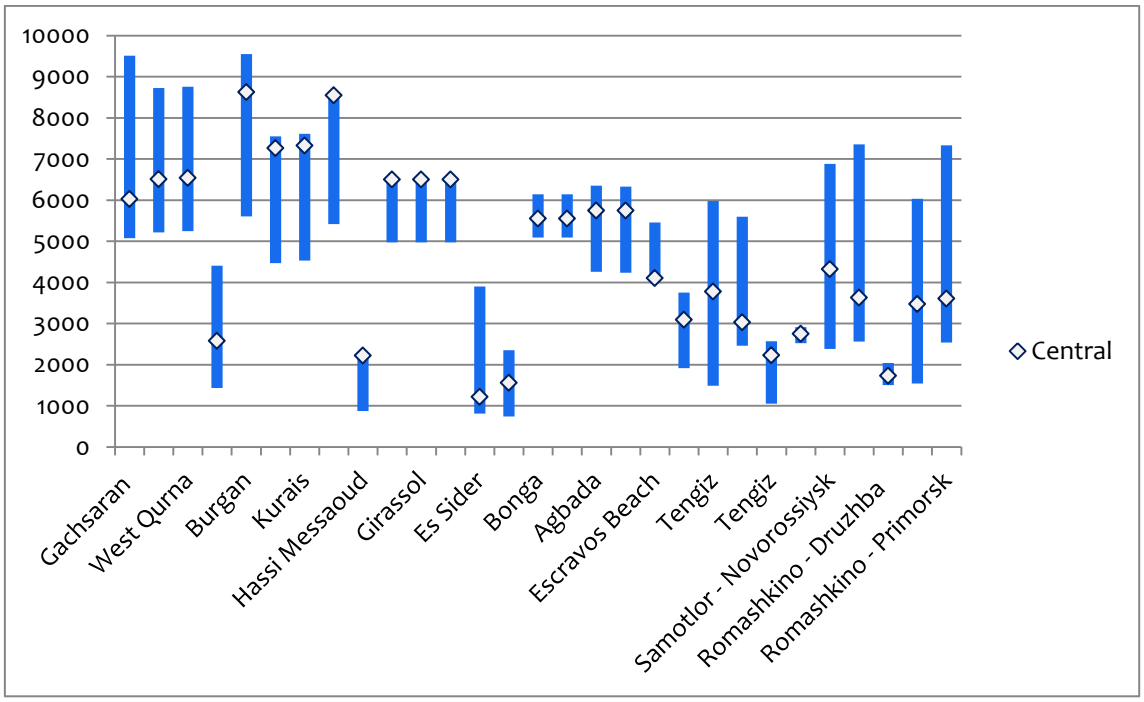
As discussed during Step 5, Europe is supplied crude oil via a complex pipeline system of thousand kilometers starting from Western Siberia and supplying Central Europe. The exact type of crude of the Druzhba pipeline cannot be defined with precision as crude oil from

various fields enters the pipeline and oil is unloaded in various refineries on its length. Our analysis based on information from Argus and Platts has concluded that the crude oil, with the same physical properties, transported via the Druzhba pipeline is transported to 5 EU destinations. Background analysis of the upstream Russian oil sector has indicated that the Druzhba pipeline carries on average 2/3 of oil from the Urals area and 1/3 from the Western Siberia in general.

Modelling of midstream emissions in OPGEE

Following the identification of major pathways of imported oil in Europe, the GHG emissions due to crude oil transport have been calculated using the OPGEE model. Taking into consideration that each MCON, either via marine transport or pipeline, is exported to several EU countries, the Consultant identifies the minimum, central and maximum distance of the followed route. The range of midstream distances for all the examined (conventional) MCONs is illustrated in Figure 3-25. The detailed results of the midstream distances including the specific pathways and per mode of transport are presented in Annex D.

Figure 3-25 Midstream distances for all the examined conventional MCONs (source: own elaboration)



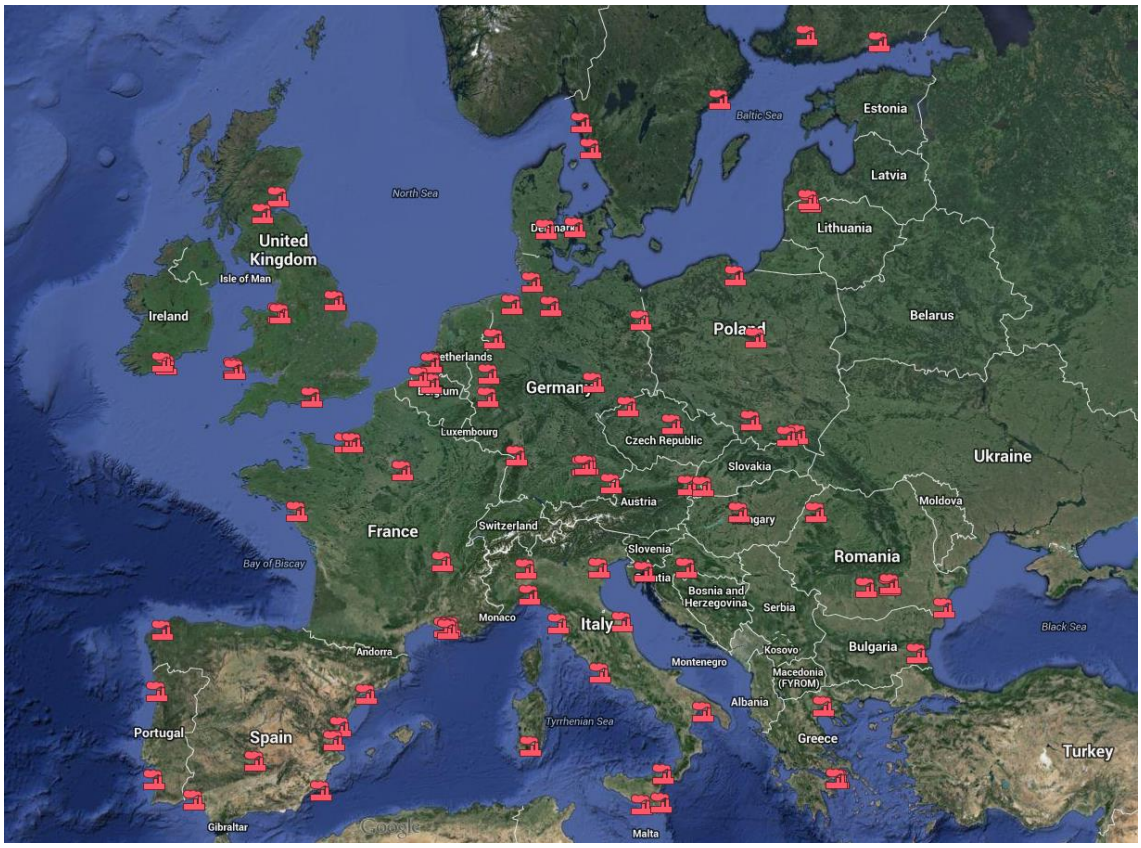
3.3.4 Downstream

Step 7: Estimation of GHG emissions during the refining process

This step refers to the calculation of the GHG emissions that are related to the refining of crude oil. Figure 3-26 illustrates the location of the major refineries in EU. It can be seen from the map that refineries are typically built close to ports or have their own port terminals to ensure crude oil supply. Refineries located in Central Europe are supplied crude

oil primarily via the Druzhba pipeline or via small pipelines that are connected to port terminals.

Figure 3-26 Location of major refineries in Europe



Actual emissions data for the refining stage are available by each EU country from the Environmental Energy Agency (EEA) and refer to the total emissions due to energy branch consumption of fossil fuels by refineries. However, these emissions are not assigned to each refinery output as it is required to calculate emissions over the lifecycle of mineral oil fuels. In addition, the refineries consume electricity and steam which are partly self-produced and so involve GHG emissions directly as part of the statistics on energy branch consumption of refineries and partly due to energy purchased from the market; in this case the related GHG emissions are indirect. Also refineries may also sell electricity and steam to third parties, as their own production facilities may be larger than refining needs require. Therefore, two more calculation issues arise:

- firstly to calculate total GHG emissions that directly and indirectly are associated to refining needs in total;
- secondly to allocate reasonably GHG emissions to each fuel output.

Allocation of direct and indirect emissions of a refinery

The first calculation requires data which are not directly available by Eurostat as the statistics do not show separately sales of electricity and steam by the refineries but only purchases of distributed steam and electricity. The fuels used for on-site generation of steam in refineries are provided in statistics; however they are not distinguished from similar fuels consumed by refineries for other purposes (e.g. in boilers). Therefore, total steam generated by refineries is not known in the statistics. So the methodology can rely only on Eurostat statistics for the assessment of the total GHG emissions in the refining system of each European country. To fill this gap the PRIMES model database has performed enrichment of the data on steam using the CHP surveys by country available by Eurostat and other information sources (plant inventory from Platts and other sources including a survey over concrete refinery companies). Based on these extended statistics and using modelling of the entire steam and electricity sector the PRIMES REFINERIES model calibration routine has performed reconstitution of statistical data for past years (latest calibration year is 2010) in which the calibration routine estimates in detail how steam is produced in refineries and which are the amounts of input and output of electricity as well as the sales and purchases of these energy forms at the level of the entire refinery sector in each European country. Based on these calibrated data for 2010 it is thus possible to calculate total direct and indirect GHG emissions for the refinery sector in each European country.

Allocation of GHG emissions to each product output

The second calculation stage is to allocate the total GHG emissions (direct and indirect) to each product output from the refineries in each European country. This requires a methodological approach because the allocation cannot be straightforward as refining is a process using energy and feedstock to produce multiple product outputs. The methodologies proposed in the literature range from simple approaches based on average emission factors leading to an allocation on total emissions in proportion to energy equivalent amounts of product outputs up to complex approaches based on marginal emission factors derived from a modelling of the refinery process. The second approach is generally superior from a methodological perspective but requires more complex modelling and detailed information.

The intention of the Consultant is to apply the second approach and to exploit the existing refining modelling framework of the PRIMES-Refineries model. For this purpose the Consultant proceeded intensively in an extension of the model in order to accommodate multiple crude oil types as inputs to the refinery modelling and also to separate stylized refinery types and so capture more adequately the emission estimation and the allocation of emissions to output products. Therefore, to calculate the GHG emissions that occur during refining, the Consultant will use an extended modelling tool of the PRIMES-Refineries sub-model which has been developed and maintained by E3MLab. The main purpose of following a model based analysis is mainly to allocate to each refined petroleum product (for our analysis: diesel, petrol, kerosene) a specific carbon intensity factor based on the estimation of marginal emissions.

Refining of crude oils involves a range of different energy intensive processes that produce multiple petroleum products. A large difference can be observed in product yield, energy

use and emissions between different refinery types depending on the type of crude and the complexity of the refining technology. Model calibration techniques are used to estimate product yields and the associated energy consumption and emissions in stylized refinery types by country. The capacity data of refining processes have been from the OGJ database which has been acquired for use in this study.

The use of a single configuration for European refineries is not appropriate because of the diversity of refinery units, the crude feedstock and production yields. To account for the large diversity, the PRIMES-Refineries model simulates stylized representative refinery types to reflect the average flow scheme met in European refineries and to capture the diversity. The refinery configuration includes major process units related to separation, upgrading and conversion of crude oil. The modelling approach is based on the fact that different products go through different processes within the refinery, thus production flows are used to simulate the various streams leading to the products of interest (petrol, diesel and kerosene).

The GHG emissions resulting from the feedstock refining are relevant to the type of feedstock used by the refinery. The resulting GHG emissions from the petroleum refining are therefore influenced by the energy intensity and the energy use by process. In reality, a variety of crudes of different quality is fed in the refining industry. Refineries process blends of crudes and adjust their processing conditions for the optimization of products yields. In order to gain a better evaluation of the carbon intensity of crudes with different characteristics, E3MLab will extend the PRIMES-Refinery model to include different types of crude oils as an input to the stylized refinery types. In this context, three broad categories have been already identified based on the API gravity and sulphur content (Heavy, Medium, Light).

The reason for selecting API gravity and sulphur content as the key criteria for distinguishing the crude types is that they indicate the quality of the crude and influence the level and the conditions of processing. According to engineering data the API gravity and sulphur content are the main features which can explain the diversity of fossil fuel consumption, hence emissions, in the various types of refining processing.

Average emissions need to be partitioned to each individual petroleum fuel produced. Most common approaches involve the emission allocation to the individual refinery products based on the product proportion to the total quantity produced or based on the energy content of the commodities. In order to associate emission factors with the concrete refinery output products (diesel, petrol, kerosene) in a more adequate manner, a methodology developed by the Institut Français du Pétrole (IFP) will be used. This method includes allocation of emissions to individual products based on marginal emission content.

Step 8: Estimation of GHG emissions during transportation of refined products

This step presents the approach that is followed by the Consultant for calculating the GHG emissions that take place during the transportation of the refined petroleum products from the production point (i.e. the refinery) to the consumption point (i.e. filling station). The transportation of the refined petroleum products from the refineries to the filling stations in EU countries usually takes place via three modes: road freight, freight rail and inland

waterways, which are currently operating mainly on fossil fuels. The share of each transport mode participating in the transportation of the refined petroleum products differs by EU country; this implies that the carbon intensity during transportation is different by country. The Consultant has further considered the fugitive GHG emissions at the stage of the filling stations.

Data on the refined petroleum products transported by transport mode at a national level (in tons and ton-kilometers) have been retrieved from EUROSTAT. Data on the average carbon intensity per transport mode are drawn from the PRIMES-TREMOVE[2] transport model, developed and maintained by E3MLab. The values used have also been validated with the values reported in the TRACC3S database. Regarding the fugitive GHG emissions at the level of the filling stations, the Consultant has used typical emission factors from literature as illustrated in GHG emissions of refined products.

The assessment of GHG emissions of refined products imported in EU has usually been overlooked in relevant studies. In the context of this study, the emissions of refined products imported from the United States and Russia will be assessed, as these constitute significant part of EU final fuel supply as illustrated in Figure 3 27 below. It has to be mentioned also that some negligible quantities of refined products are imported in EU from other countries (MENA) - which are constantly decreasing over the years – so they are not taken into account in the analysis.

GHG emissions of refined products

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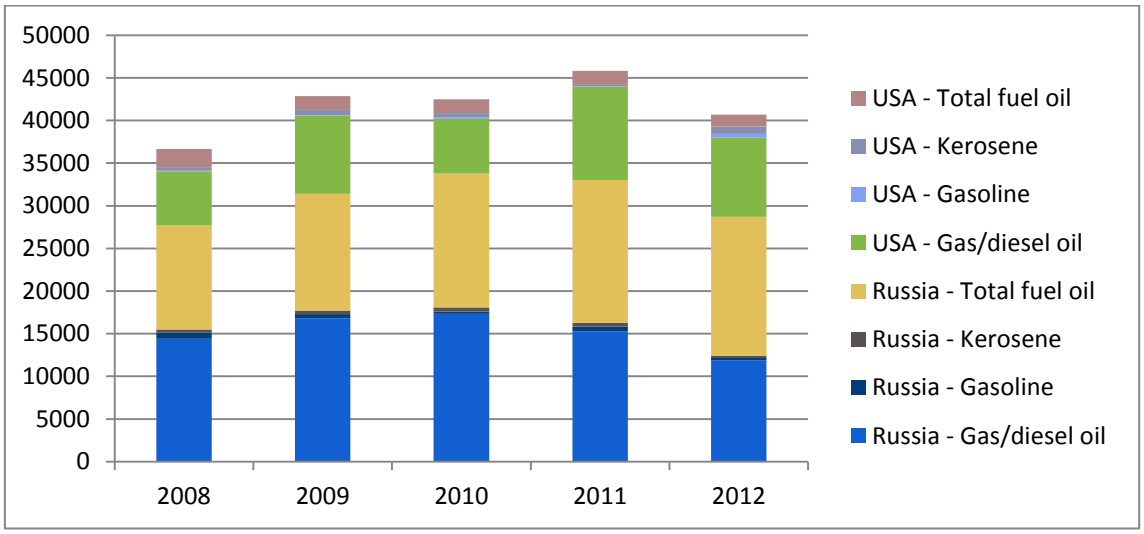
[2] http://www.e3mlab.ntua.gr/e3mlab/PRIMES%20Manual/PRIMES%20TREMOVE_v3.pdf

[3] http://traccs.emisia.com/

Table 3-13 Emission factors of petrol used for estimating fugitive emissions from filling stations in Denmark (Source: NERI, 2009)

Period	Reloading of tankers, kg NMVOC per ton petrol	Refueling of vehicles, kg NMVOC per ton petrol	Sum of reloading and refueling, kg NMVOC per ton petrol	Source
1985-1990	1.26	1.52	2.80	Fennmann &Kilde, 1994
1991	0.64	1.52	2.16	Fennmann &Kilde, 1994
1992-1995	0.08	1.52	1.60	GB EMF, Fennmann & Kilde, 1994
1996			1.38	Interpolation between 1995 and 2000
1997			1.17	Interpolation between 1995 and 2000
1998			0.96	Interpolation between 1995 and 2000
1999			0.75	Interpolation between 1995 and 2000
2000-2007	0.08	0.46	0.53	GB EMF

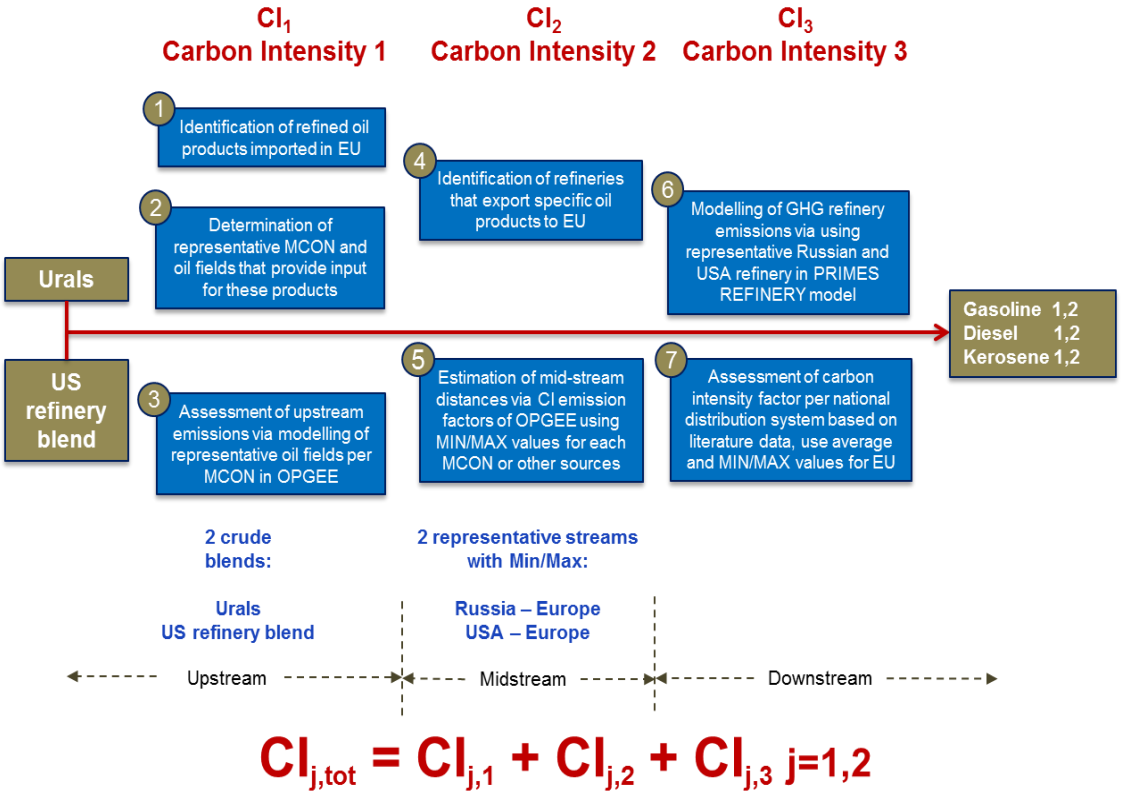
Figure 3-27 EU 28 imports of refined products (in barrels of oil per day) for specific refined products from Russia and USA (source: Eurostat)



The methodology for the assessment of emissions from refined products is shown in Figure 3-28. The approach for the assessment of GHG emissions of imported refined oil products is

identical to that of conventional crude oil for the upstream and midstream processes. The upstream emissions will be assessed through the collection of actual data and in the absence of these via the OPGEE model. Based on the analysis of the midstream sector and given the locations of the Russian refineries it has been considered that the MCON used for refining is exclusively Urals crude oil, while refineries in USA use a blend of several MCONs. Thus, there are two major streams of refined products to Europe: one from Russian and one from USA. In order to account for the GHG emissions of these imported fuels during the refining process in Russia and USA, the Consultant will use proxy values of emission factors based on calculation of emissions for refineries in European countries provided that they have similar refinery configuration to Russia and USA and other emission factor estimates based on literature for refineries in Russia and USA which are different from European refineries. Emissions due to the distribution of refined products will be assessed using the same approach for oil products refined in EU. In all cases, a minimum and maximum methodology will be used so as to represent a range of carbon intensity values where applicable.

Figure 3-28 Methodology for the assessment of emissions from refined products



Imported products from Russian refineries

Table 3-14 summarizes the most significant Russian refineries supplying refined products to Europe with their key characteristics such as capacity, crude type feedstock, crude oil supply mode and ULSD compliance. It is worth considering that all Russian refineries

presented in Table 3-14 export or will start exporting Euro V - ULSD compatible diesel to Europe.

Table 3-14 Russian refineries exporting ULSD to Europe (source: OGJ, company websites)

Refinery	Transport mode of final product	Owner	Capacity (bbl/dbbl/d)	Crude supply	Crude feedstock	ULSD compliance
Volgograd refinery	Petroleum products are shipped by rail, road and river transport	Lukoil	225,200	Crude oil is supplied to the Refinery via the Samara – Tikhoretsk pipeline	Refines a blend of light West-Siberian and Lower-Volga crudes	Euro 5 compatible
Kirishi refinery	Sever pipeline	Surgutneftegas	335,900			Euro 5 compatible
Perm refinery	Rail road and river transport and also via the Perm Andreyenka –Ufa pipeline	Lukoil	279,142	Crude oil is supplied to the Refinery via the Surgut–Polotsk pipeline &the Kholmogory –Klin pipeline	Refines a blend of crudes from the northern part of Perm Region and from Western Siberia	Output of Euro 5 ULSD fuel will increase by 325,000 tons per year
Yaroslavl	Sever pipeline	TNK-BP and Gazprom Neft,	8,700		The refinery processes West Siberian Crude	From January 2012, the Refinery, intends to stop producing motor fuels, which do not conform to the Euro 4/ Euro 5 standards
Nizhnekamsk Refinery		TAIF-NK	120,493		The refinery processes locally produced crude oil & gas condensate The crude is medium heavy & sour	Since May 2008, TAIF-NK completely shifted to the production of motor petrol, environmental standards EURO 4 Since June, 2012 TAIF-NK switched to 100% diesel fuel, quality standard EURO 5

Figure 3-29 below shows the location of Russian refineries on the map and links them to major crude oil pipelines. It can be obtained that all of them are supplied oil primarily from the Urals region and therefore the Urals MCON has been considered as their main feedstock. Moreover, the largest part of refined products is supplied to Europe via the Sever product pipeline which runs alongside the Baltic pipeline System. The conduit links several refineries in European Russia to the Baltic Sea, thereby giving them a means of exporting ULSD fuel. More specifically the pipeline runs from Kstovo to Primorsk via

Yaroslavl and Kirishi with a total length of 1056 km. From Primorsk the refined products are shipped to several European countries.

Imported products from USA refineries

In the context of the Study, the Consultant has focused particularly on the refined products arriving to Europe from Russia, because of the fact that less work has been conducted in the analysis of the Russian upstream and midstream sector and therefore more effort is required. On the contrary, for the United States there is a wealth of information regarding upstream, midstream and downstream sector, as well as their emissions. For refined products arriving from the United States the Consultant will assume that these are refined in a High Conversion refinery located on the US Gulf Coast and exporting diesel oil to Europe, with main discharge port being Rotterdam. A typical input blend of a US refinery based on the work conducted by Jacobs[4] is illustrated in Table 3-15.

Figure 3-29 Map of Russian Refineries supplying refined products to EU

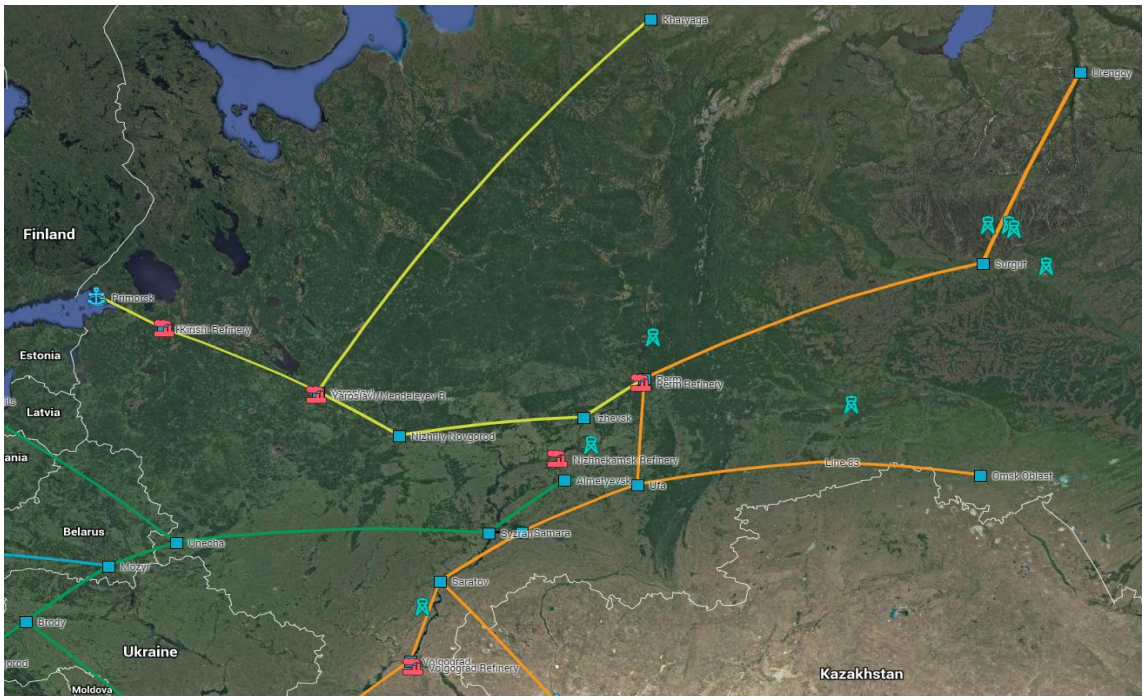


Table 3-15 Overview of feedstock input of representative US refinery (adopted by Jacobs, 2012)

MCON	High conversion US Gulf Coast
Forties	√
Arab Medium	√
Bonny Light	√
Tupi	√

[4] EU Pathway Study: Lifecycle Assessment of Crude Oils in a European Context, Jacobs Consultancy, 2012

MCON	High conversion US Gulf Coast
Bachaquero	√
Urals	√
SCO from Coking upgrader processing mined bitumen	√
Athabasca dilbit	√
Athabasca bitumen	√
Mariner	√

3.3.5 GHG emissions of unconventional crude oil and natural gas

At the end of the baseline year of the study (2012) unconventional fuels are not traced in the EU energy balance. However, it is anticipated that unconventional crude oil and will definitely be imported in Europe in significant quantities in the future. This will be also evident by the projections by the PRIMES model in the context of Task F.

A large amount of reliable information by public authorities and independent consultancies based on reporting of actual emissions and LCAs including use of engineering models is publicly available for unconventional crudes. Therefore, it is not intended to iterate or further analyze these LCAs. Instead, the Study focuses on the collection of actual emissions data and only in the absence of these LCA engineering models are going to be used.

The rationale for the assessment of the GHG emissions from unconventional crude oil is similar to that of crude oil. The Consultant based on current market trends, literature survey and its own assessments will determine the MCONs and the gas streams which constitute reasonable options for the EU relevant demand projected by the PRIMES model. Indicatively, key unconventional MCONs or gas streams that are representative will be analyzed could be the following:

- Syncrude as representative of Alberta Oil Sands
- Petrozuata as representative of Venezuela Bitumen
- Marcellus as representative of US Shale Gas

Actual emissions data for the assessment of upstream emissions of unconventional crude oil have been searched and collected for all the above mentioned characteristic cases. Due to the CARB analyses and the studies assigned by the US and Canadian authorities, expressing their interest to promote the unconventional oil and gas resources, there is availability of actual data and measurements carried out by reliable institutions. The OPGEE model will be also used for the modelling of upstream emissions of unconventional crudes for reasons of consistency, completeness and comparativeness, since it has already incorporated five production techniques specified by the type of extraction and the upgrading technology, namely:

- Bitumen mining with integrated upgrading;
- Bitumen mining with non-integrated upgrading;

- In situ production via non-thermal methods;
- In situ production via steam assisted gravity drainage;
- In situ production via cyclic steam stimulation.

The midstream GHG emissions occurring due to the transport of crude oil and gas (in principle through LNG) from the extraction point to the refineries or the transmission systems will be assessed utilizing the same approach as for conventional crude oil and natural gas. More specifically, in order to calculate the midstream emissions of unconventional crudes it has been assumed that crude will be transported via ships from the East Coast of Canada (Montreal) and Venezuela (Jose Port) to the port of Rotterdam in the future.

Lastly, distribution emissions will be calculated by using the approach and the emission factors as for conventional crude oil and natural gas.

3.4 Methodological Approach for Natural Gas GHG Assessment

3.4.1 Natural gas supply chain

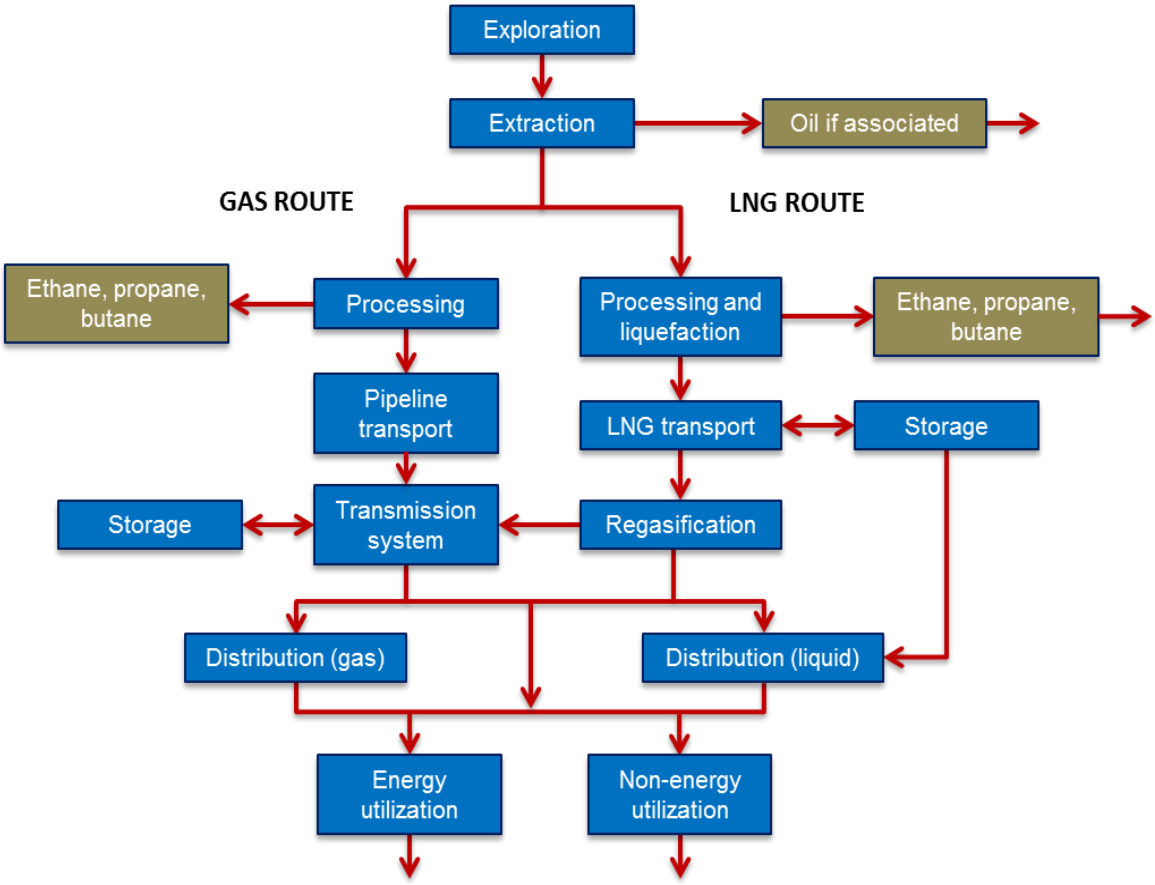
Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, and transmission and distribution pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user, which can generally be broken out into five sectors. Each sector is defined as follows:

- **Production**, focuses on taking raw natural gas from underground formations.
- **Processing**, focuses on stripping out impurities and other hydrocarbons and fluids to produce pipeline grade natural gas that meets specified tariffs (pipeline quality natural gas is 95-98 % methane).
- **Transport**, focuses on the movement of natural gas from the producing region to the consuming region. After processing, gas is often transported over very large distances. Most of this transport takes place through pipelines, although, there is a significant amount of gas that is liquefied at the producing region, transported via marine vessels as LNG (Liquefied Natural Gas) and finally regassified at the delivery point. Therefore, we distinguish two options for natural gas transport:
- Via Pipeline,
- Via LNG
- **Transmission and Storage**, focuses on delivery of natural gas from the interconnection point to city gate stations or industrial end users. Transmission occurs through a network of high-pressure pipelines. Natural gas storage also falls within this sector. Natural gas is typically stored in depleted underground reservoirs, aquifiers, and salt caverns.

- **Distribution**, focuses on the delivery of natural gas from the major pipelines to the end users (e.g., residential, commercial and industrial).

In the oil industry, some underground crude contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, **associated or solution natural gas** is produced. In case the exploration field produces in principle natural gas, then this gas might be called **non-associated gas**. Both associated and non-associated gas are considered conventional natural gas as part of this work. The basic pathways of the typical natural gas supply chain are presented in Figure 3-30.

Figure 3-30 Natural gas supply chain (Source: CE, Delft)



3.4.2 Methodology for assessing GHG emissions

The main stages of the natural gas value chain to be examined for the purpose of the present study are presented in Figure 3-31. As shown in this Figure, the lifecycle of natural gas is divided into 3 main stages: upstream, midstream and downstream.

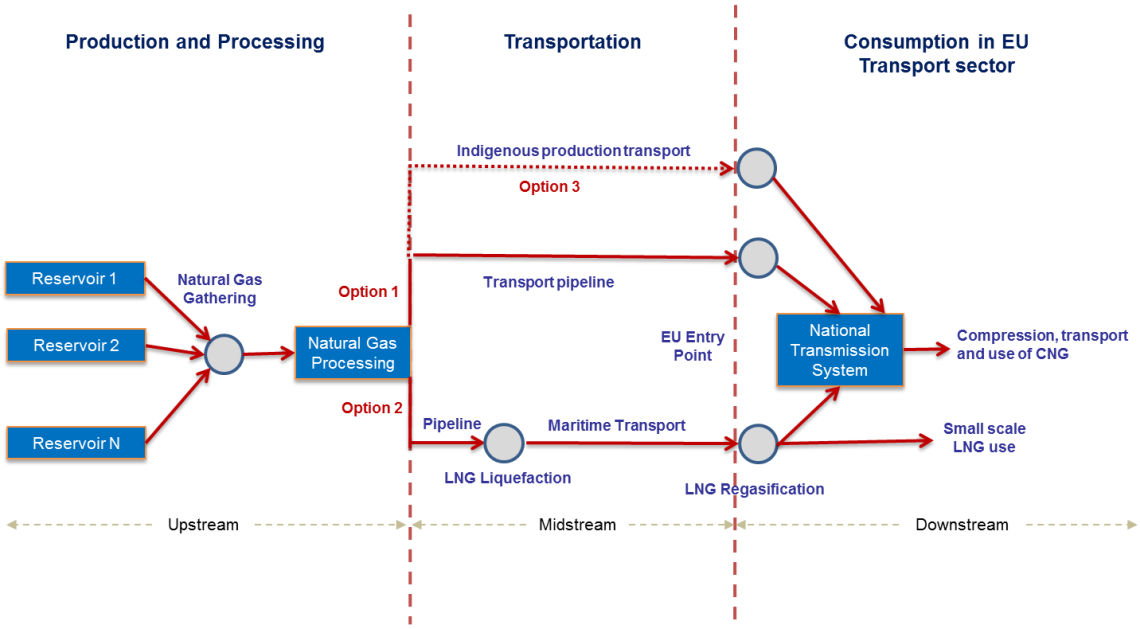
The upstream stage contains the natural gas production and processing sectors.

The midstream stage contains the transport of natural gas from the producing region to the consuming region for which there are three options:

- Option 1: The gas produced outside the EU is transported via pipeline to the corresponding EU regions;
- Option 2: The gas produced outside the EU is liquefied and transported by vessels to the corresponding EU LNG terminals, where it is re-gasified and fed to the transmission system;
- Option 3: The gas produced indigenously in the EU is either consumed within the producing country, or transported to other EU countries through the interconnected transmission systems.

Finally, the downstream stage contains the transmission and distribution of natural gas inside the EU regions.

Figure 3-31 Natural gas streams methodological approach



Following this approach, the EU natural gas supply has been distinguished into main **streams** according to their origin, mode of transport and delivery point within the EU that will be presented in the following Sections. The carbon intensity (CI) of the considered natural gas streams is estimated as the sum of the carbon intensities of each of the corresponding separate stages (upstream, midstream, downstream) that characterize each stream.

3.4.3 Natural Gas Streams

Step 1: Assumption for EU regions

The starting point for assessing the GHG emissions of natural gas supplied to the EU is to

define the main gas streams arriving to the consumption regions. We need to keep a rational number of gas streams that will allow obtaining a reasonable and representative picture of GHG emissions of the main gas streams supplying EU and on the other hand maintaining the necessary detail by distinguishing the CI performance and differentiation of various gas streams. To this end we need to make a number of assumptions, and under the most significant of them, EU has been divided into 4 consuming regions, namely South East EU, Central EU, North EU and South West EU. The four groups were selected in principle on the basis of common natural gas characteristics, e.g. common transportation pipelines or LNG suppliers. Thus in our analyses the gas streams under assessment are driven to 4 destinations instead of 26; with this aggregation we achieve relevant grouping of similar, more or less, CI cases in downstream and midstream, without losing in detail and differentiation of results.

In the context of the present study, Cyprus and Malta were not taken into account for the assessment of GHG emissions in the natural gas value chain, as they were not natural gas consuming countries in 2012.

Step 2: Natural gas producing countries

In order to determine the major natural gas suppliers of the EU, the Consultant has elaborated on the annual IEA data for 2012 regarding natural gas imports and indigenous production by country of origin. These imports and EU production are transported to the national transmission systems either through LNG or by transportation pipelines. Small quantities of gas imports or production (in general less than 500 million cubic meters per year) were considered negligible and will be not examined in detail in this study. Such small quantities are generally transacted in the spot market and thus are not representative of the EU natural gas supply. Following this analysis, the major natural gas suppliers to the EU are presented in Table 3-16.

Step 3: Finalization of the natural gas streams

After eliminating the negligible quantities of natural gas consumed within the EU, the Consultant has identified the main streams of natural gas arriving to each of the four EU regions. The final streams are illustrated in Figure 3-32 to Figure 3-35. Therefore 29 transport pipeline streams and 9 LNG streams are considered for GHG emissions assessment. Since there are 4 main pipeline systems supplying EU with Russian natural gas, this fact is taken into consideration and either distinguished streams by pipeline are considered or in case of small differences in CI the streams are aggregated and the min, max approach is used to cover small differences and uncertainties.

Table 3-16 Major natural gas suppliers of the EU

Mode of transport	Supplier	Share in the EU gas supply In 2012
Local production	Germany	2.59%
	Denmark	1.17%
	Netherlands	17.08%
	Poland	1.25%
	Hungary	0.29%
	Italy	1.74%
	Romania	2.21%
	UK	8.23%
Transport by pipeline	Russia	22.61%
	Norway	20.34%
	Algeria	6.84%
	Libya	1.30%
	Other	3.93%
LNG transported by marine vessels	Algeria LNG	2.05%
	Norway LNG	0.53%
	Nigeria LNG	2.22%
	Qatar LNG	5.63%

Figure 3-32 Natural gas streams arriving to the South East EU region

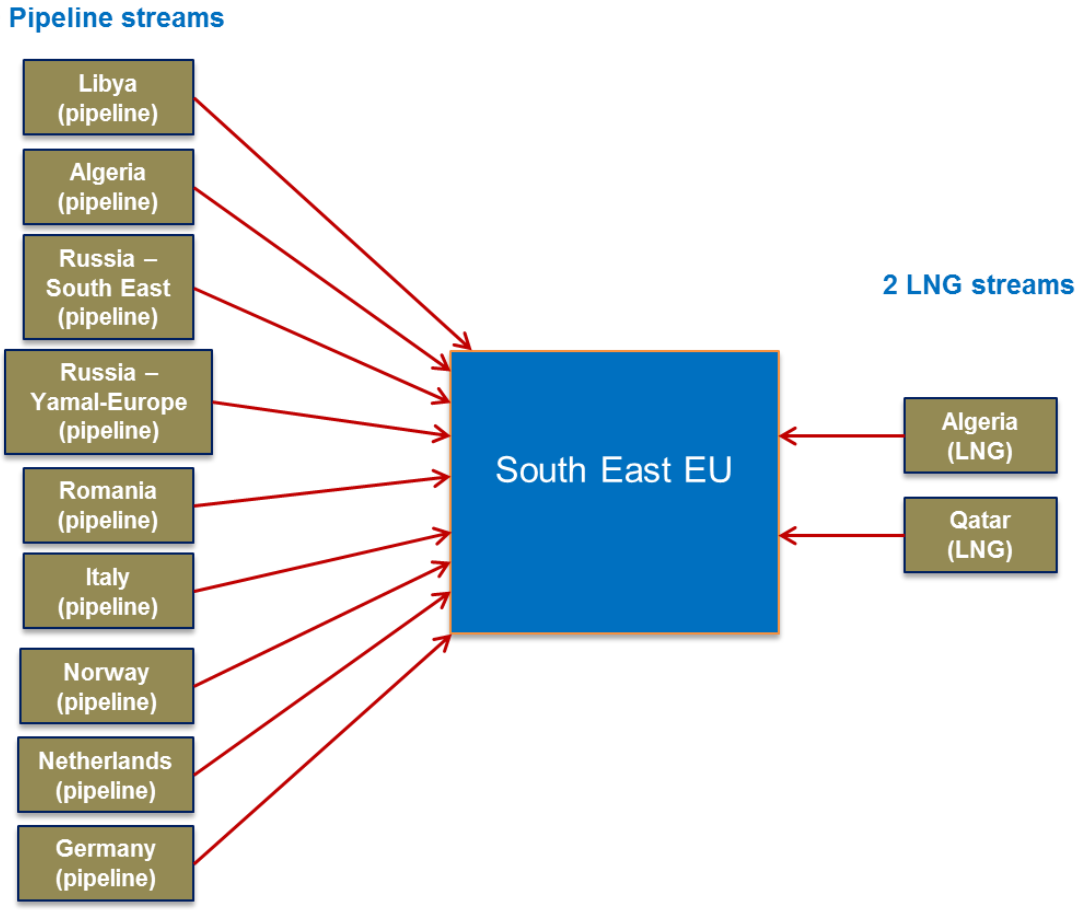


Figure 3-33 Natural gas streams arriving to the North EU region

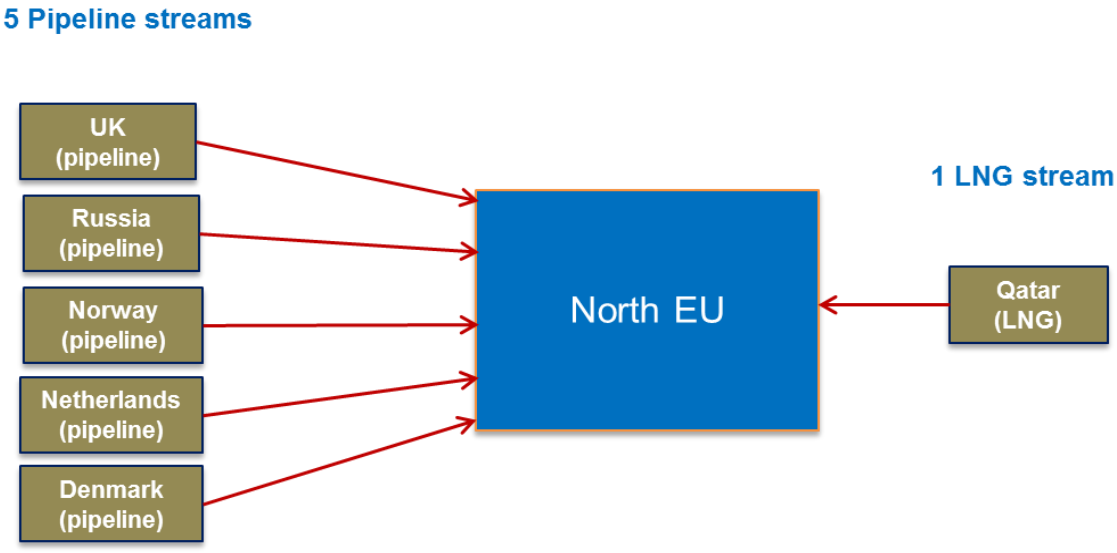


Figure 3-34 Natural gas streams arriving to the South West EU region

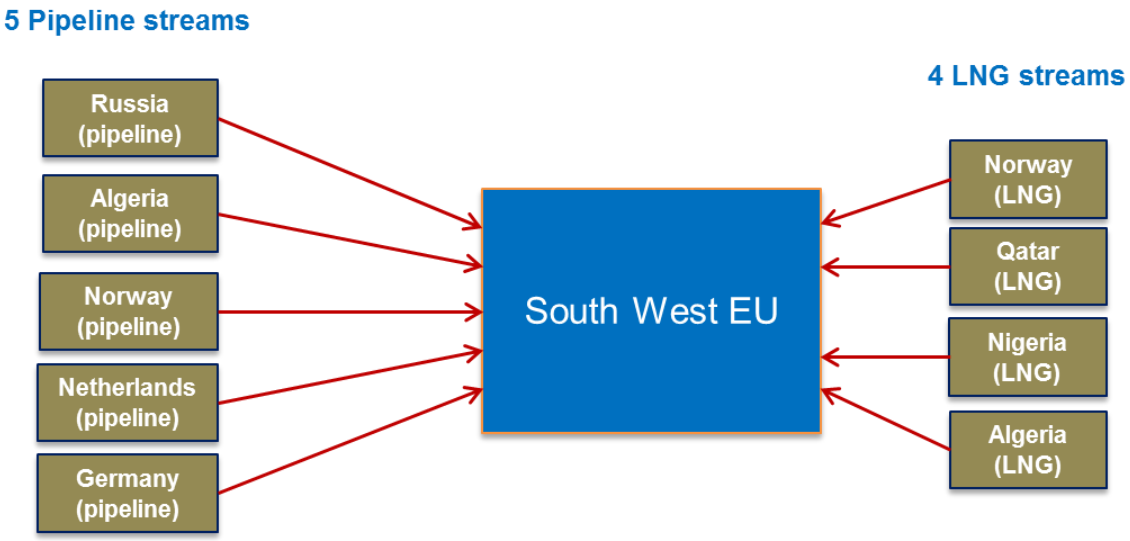
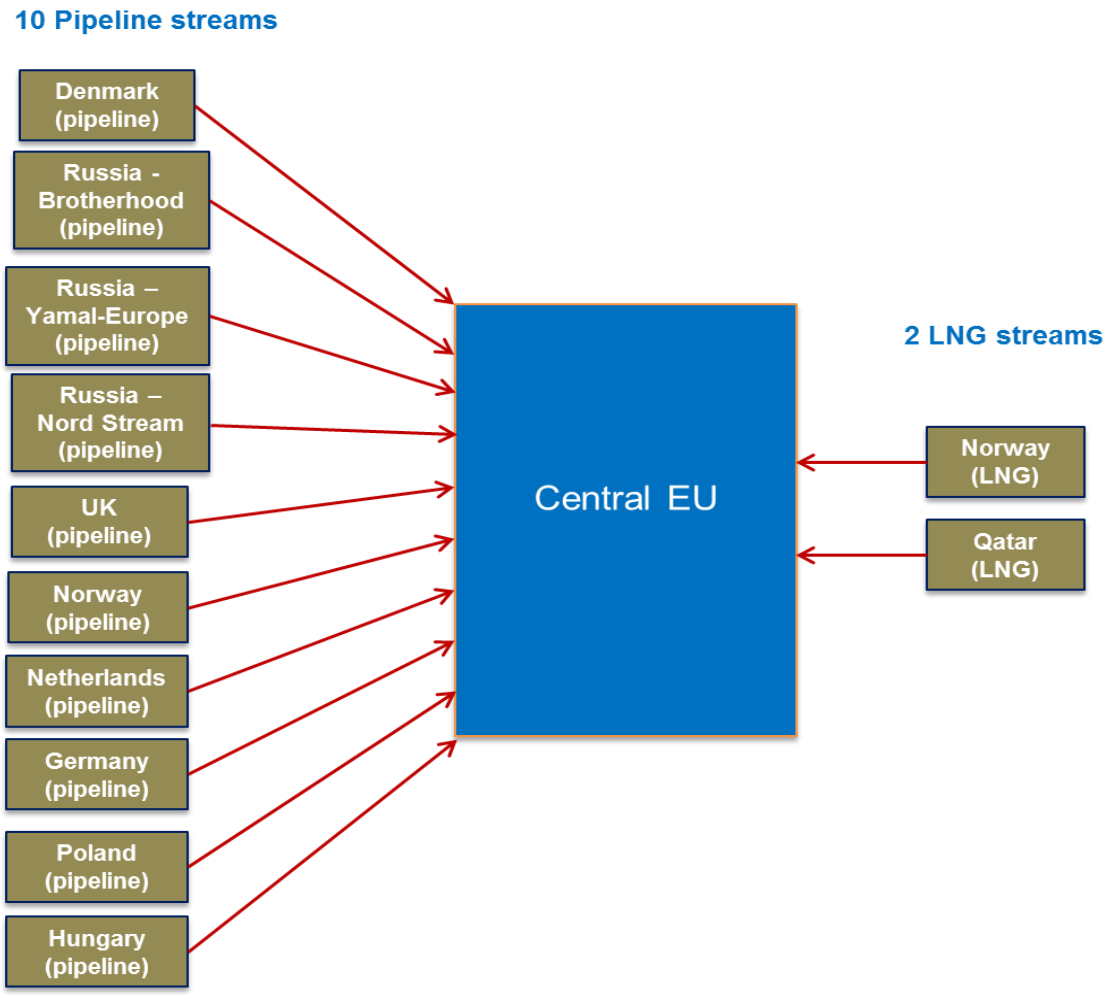


Figure 3-35 Natural gas streams arriving to the Central EU region



3.4.4 Upstream

The upstream stage includes exploration and drilling, extraction of natural gas and processing.

Exploration and drilling represent a small percentage of the total GHG emissions of the lifecycle of natural gas and in addition, emissions data for this stage are very hard to identify. Exploration cannot be directly linked to production. Some exploration will lead to production, some will not. This means that it is hard to include exploration in a lifecycle approach that tries to assess environmental impacts associated with a unit of natural gas. Therefore, exploration is the least significant stage in the lifecycle of natural gas, in terms of GHG emissions.

Extraction of non-associated natural gas requires little more energy than letting the gas flow from the reservoir. Extraction of non-associated natural gas gives a mixture of raw gas, condensed higher hydrocarbons, free water and carried along particles. The raw gas is isolated from solids and fluids by flashing, the so-called primary separation. The isolated raw gas will have an elevated temperature due to the higher temperatures in the reservoirs and a pressure of several bars to several hundreds of bars. It does not yet have sufficient quality to allow transportation to the consumer for application.

Further processing basically involves the separation of the methane fraction (CH_4) in the raw gas from co-products or pollutants such as:

- Water vapour
- Acid gases (CO_2, sulphurous compounds)
- Nitrogen (N_2)
- Condensable hydrocarbons (C5+)
- Ethane, propane, butane.

Which processes are applied depends on raw gas quality as well as required standard for the processed gas. Energy consumption and emissions at the processing stage depend on the quality of the raw natural gas. Gas from fields yielding low calorific gas may be mixed with high calorific gas to match required market standards. The hydrocarbons heavier than methane but lighter than pentane do not necessarily have to be separated, except for the production of some chemicals. They may be separated for economic reasons, as ethane and LPG (propane/butane) are excellent naphtha cracker feedstock and LPG (as well as C5+) may be sold as automotive fuels. Isolation of the so-called **Natural Gas Liquids (NGL)** can be economically viable in certain regions with a high demand and low (alternative) supply. The chemical composition of these hydrocarbons (NGL) is similar, yet their applications vary widely. Ethane occupies the largest share of NGL field production. It is used almost exclusively to produce ethylene, which is then turned into plastics. Much of the propane, by contrast, is burned for heating, although a substantial amount is used as petrochemical feedstock. A blend of propane and butane, sometimes referred to as LPG or autogas is a popular fuel in some parts of Europe, Turkey, and Australia; however LPG is not among the transport fuels considered in this study. Natural petrol (pentanes plus) representing 10-15%

of NGL can be blended into various kinds of fuel for combustion engines, and is useful in energy recovery from wells and oil sands. Natural Gas Liquids (NGL) representing partly a feedstock used in refineries or blended to produce petrol have not been considered as independent streams in this study, but are considered as contributing to the GHG emissions produced in the oil refining process.

In the case of **associated gas**, the natural gas may already be separate from the oil (free gas) or it may be dissolved in the oil (dissolved gas). Extra steps are involved in either case to separate the gas before processing takes place.

Most treatment processes require electricity for valves, pumps, etc. The electricity is often produced on site in case of off shore production and treatment or in case of fields located in remote areas. Otherwise electricity may be taken from the grid.[5]

Venting and flaring gas

One of the most important GHG emitting activities of the upstream stage is gas flaring and venting. Flaring is the controlled burning of natural gas in the course of routine oil and gas production operations. This burning occurs at the end of a flare stack or boom. Gas processing plants remove the water, H_2S, CO_2 and natural gas liquids from the raw natural gas to produce the market-ready natural gas. Flares are used to dispose of the unmarketable gases. All gas plants have flares to burn off gas safely during emergencies or "upset" conditions that interrupt the normal day-to-day operations. Many of the small plants are licensed to flare H_2S rich gas after it has been removed.

Venting is the controlled release of gases into the atmosphere in the course of oil and gas production operations. These gases might be natural gas or other hydrocarbon vapors, water vapor, and other gases, such as carbon dioxide, separated in the processing of oil or natural gas.

Flaring produces predominantly carbon dioxide emissions, while venting produces predominantly methane emissions. The two gases have different effects, however. The global warming potential of a kilogram of methane is estimated to be twenty five times that of a kilogram of carbon dioxide when the effects are considered over one hundred years (GWP 2007). When considered in this context, flaring will generally be preferred over venting the same amount of gas in the design of new facilities where sufficient amounts of gas will be produced to run a flare.[6]

Natural gas producers

The main natural gas producers for the EU 28, apart from indigenous production, are Russia, Norway, Algeria, Nigeria, Qatar and Libya. Intra-EU producers include the Netherlands, Germany, the UK, Denmark, Italy, Hungary, Poland and Romania. Figure 3-36 illustrates the main natural gas producing fields supplying the EU.

[5] The Natural Gas Chain - Toward a global lifecycle assessment, Delft, CE, 2006

[6] Flaring & venting in the oil & gas exploration & production industry, OGP Report No: 2.79/288 January 2000

Each producing country has its own characteristics regarding their upstream activities, which are summarized in Table 3-17.

Figure 3-36 Map of natural gas producing fields supplying the EU



Table 3-17 Key characteristics of natural gas producing countries supplying the EU 28

Producing country	Major natural gas fields	Characteristics
Russia	Yamburg – Urengoy Yamal Medvezh'ye	Russia's reserves account for about a quarter of the world's total proven reserves. The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezh'ye fields alone accounting for more than 40% of Russia's total reserves, while other significant deposits are located in northern Russia.
Norway	Troll	The majority of Norwegian gas fields are offshore platforms located in the North Sea. Despite maturing major natural gas fields in the North Sea, Norway has been able to sustain increases nearly every year in total natural gas production since 1993 by

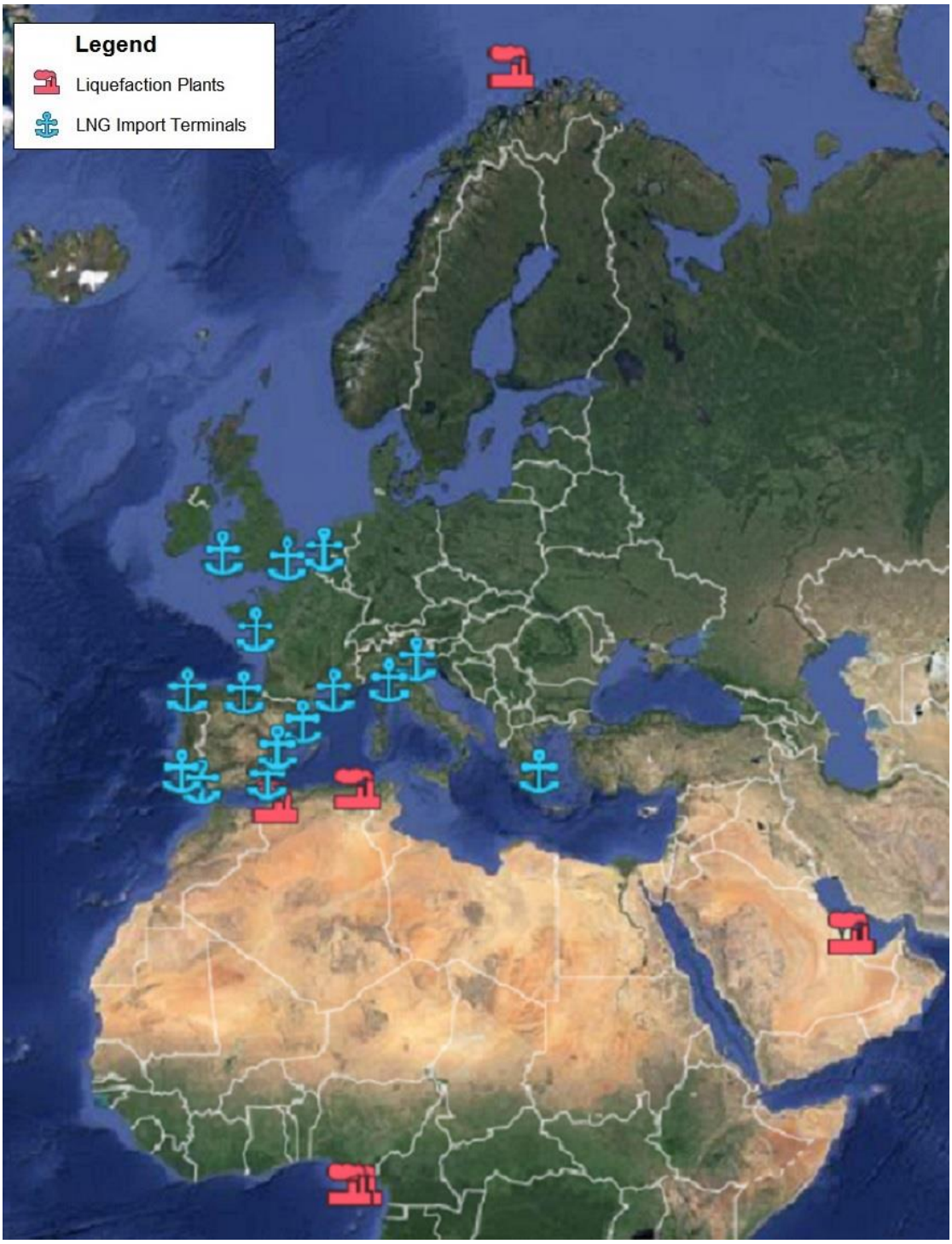
Producing country	Major natural gas fields	Characteristics
		continuing to develop new fields. Norway's largest producing natural gas field is Troll, which according to estimates from the NPD represented about 27% of Norway's total natural gas production in 2013. The three other largest producing fields in 2013 were Ormen, Lange Asgard and Kvitebjorn. These four fields accounted for just over 60% of Norway's total dry natural gas production in 2013.
Algeria	Hassi R'Mel	Algeria's largest natural gas field, Hassi R'Mel, was discovered in 1956. Located in the center of the country to the northwest of Hassi Messaoud, it holds more than half of Algeria's total proved natural gas reserves. According to the Arab Oil & Gas Journal, Hassi R'Mel accounted for three-fifths of Algeria's gross natural gas production in 2012. The remainder of Algeria's natural gas reserves is located in associated and non-associated fields in the southern and south eastern regions of the country. Hassi R'Mel also serves as a gathering point for natural gas from other gas fields located in the Algerian desert.
Nigeria	Escravos	Nigeria is the largest holder of natural gas proven reserves in Africa and the ninth largest holder in the world, while ranked as the world's 25th largest natural gas producer. Natural gas production is restricted by the lack of infrastructure to monetize natural gas that is currently being flared. The majority of the natural gas reserves are located in the Niger Delta.
Qatar	North field	Qatar was the world's fourth largest dry natural gas producer in 2012 (behind the United States, Russia, and Iran), and has been the world's leading liquefied natural gas (LNG) exporter since 2006. Qatar is also at the forefront of gas-to-liquids (GTL) production, and the country is home to the world's largest GTL facility. Nearly all of Qatar's natural gas production comes from the North Field, which is part of the largest non-associated natural gas field in the world. The Qatari North Field contains about 25 trillion cubic meters (Tcm), which accounts for 14% of worldwide natural gas reserves. The South Pars field, a geologic extension of the North field, contains an estimated 8 trillion cubic meters (Tcm) of natural gas. Thus, this single accumulation contains about 20% of the world's natural gas reserves. Based on current production capacity, the North field has reserve-production ratio of more than 400 years.
Libya	Wafa Bahr Es Salam	Libya is the fourth largest natural gas reserve holder in Africa. Libya's natural gas production and exports increased

Producing country	Major natural gas fields	Characteristics
		considerably after 2003 with the development of the Western Libya Gas Project and the opening of the Greenstream pipeline to Italy. Flows through the Greenstream pipeline were disrupted during most of the 2011 civil war.
Netherlands	Groningen	The Netherlands is the second-largest producer and exporter of natural gas in Europe, following Norway. Most of its natural gas fields are located offshore in the North Sea, although a number of them are located onshore, including Groningen, one of the ten largest natural gas fields in the world. The government has capped production at Groningen, which accounts for approximately 75% of the country's natural gas output as part of a policy to stem reserve declines and encourage production from smaller fields.
UK	Shearwater-Elgin area SAGE	The UK is the second largest producer of natural gas in EU. Most of the UK natural gas reserves occur in three distinct areas: 1) associated fields in the UKCS; 2) non-associated fields in the Southern Gas Basin, located adjacent to the Dutch sector of the North Sea; and 3) non-associated fields in the Irish Sea. The largest concentration of natural gas production in the UK is the Shearwater-Elgin area of the Southern Gas Basin. The area contains five gas fields: Elgin, Franklin, Halley, Scoter, and Shearwater. UK's largest share of natural gas production among all fields and gathering systems comes from the Scottish Area Gas Evacuation (SAGE) system, which produced a total of 6.9 billion cubic meters (bcm) in 2011. In addition to SAGE, the Shearwater-Elgin Area Line (SEAL) produced more than 5.6 bcm of natural gas during the year.
Germany, Denmark, Italy, Hungary, Poland and Romania	multiple	These EU countries have small domestic oil and natural gas production and rely heavily on imports. However, their indigenous production covers an important share of their internal natural gas demand while in some cases export to their neighboring countries.

Liquefaction of LNG

In the case of **LNG production**, the midstream stage includes also the transportation of natural gas to the liquefaction plant and the process of liquefaction. Liquid natural gas (LNG) is natural gas cooled to a low temperature (-162°C) so it becomes a liquid that hence occupies a much smaller volume. It can be transported over long distances without the need for a fixed infrastructure. The LNG process consists of several steps: liquefaction, transport, storage, and regasification.

Figure 3-37 Map of LNG supply of the EU including liquefaction plants and importing terminals



Liquefaction of LNG means cooling the natural gas to below its condensation temperature of –162°C. The heavier hydrocarbon components in the natural gas condense at higher temperatures and are therefore liquefied – and removed – during the process. LNG often consists of both methane and ethane, the latter re-added to fluid methane after methane

liquefaction (ethane liquefying before methane does). By-products of LNG production are LPG and petrol, the heavier fractions of the raw natural gas.

The LNG is stored in full containment tank normally consisting of a concrete outer tank and an inner tank of 9% nickel steel. The boil-off gas and pre-cooling and loading vapours are compressed and used as fuel gas for the liquefaction units or flared. Transportation to and from storage is driven by pumps. Storage may also take place at other stages in the LNG chain (after international transport or before regasification). Again, boil-off gas is mostly put to use, but may be vented in emergencies.

Error! Reference source not found. presents the geographical locations of liquefaction lants supplying the EU 28 with LNG, as well as the EU importing terminals.

3.4.5 Midstream

The midstream stage concerns the transport of natural gas from the producing region to the consumption region. There are two ways of transportation of natural gas to the EU entry points: long distance pipelines from third countries and LNG tankers, whereas indigenous production flows through the EU transmission systems. The latter will be considered in the downstream stage as it utilizes the interconnected transmission systems of EU countries to reach its destination, therefore the related GHG emissions are linked to the transmission network of each EU country.

In the case of **transport via pipeline**, the midstream stage includes the route carrying the natural gas from the processing plant to the EU entry point. The total pipeline "system" may consist of the pipeline, compression stations, import/export stations and metering. Normally, pipeline diameters range from 25 to 150 cm.

Before transport, gas is compressed to pressures of approximately 70 bar. In the case of subsea pipelines, the initial pressure may be higher (more than 200 bar) due to the impossibility of intermediate transfer compression. Pressure loss due to friction of gas along the pipeline wall is compensated by intermediate compressor stations along the pipeline. Compressors are almost always driven by natural gas, as this is obviously easily available.

Apart from energy consumption for the transport itself, maintenance and check-up activities – especially in remote areas – may require energy. Another source of gas 'consumption' during transport is leakage. Methane, the principal ingredient of natural gas, is a powerful greenhouse gas; therefore leaks may have a significant environmental effect.

For international gas pipelines, the major environmental impact comes from the gas combustion to run the compressor stations. The impact is larger with increased distance. Some of the critical points in the transmission process for gas consumption are turbine compressors that burn natural gas at compressor stations along the way, electric motors and gas engines, power generation, and leaks of methane gas – fugitive emissions – during transmission. Fugitive emissions are a major component of GHG emissions from natural gas systems, however they are often difficult to accurately identify.

Long-distance transport of LNG takes place primarily by cargo ships with an insulation system to keep the temperature at -162°C. The LNG is often carried in separate tanks. Boil-off gas provides a large fraction of the fuel need for the ship, also on the return journey when some LNG is left in the tanks to ensure that the gas concentration in the tanks is above the upper explosion limit (UEL).

Regasification consists of increasing the LNG temperature often by heat exchange with (sea) water at roughly ambient temperature or heated. The gas is then ready to be transported in the regular regional transmission and distribution network after quality control. The major functions of LNG receiving terminals are: (1) regasification of liquefied natural gas, (2) in some countries, calorific value adjustment by adding LPG, and (3) pressurization of the natural gas for supply to customers. These processes all use energy.

The above described two supply chains differ not only from the physical and economical point of view, but also from the environmental one. In order to transport the gas from the production fields to Europe, energy is required and its overall amount differs according to the way and the path the gas is imported. Furthermore other factors, like methane fugitives and nitrous oxide emissions, are affected not only by the physical characteristics of the chain, but also from the technology used and from obsolescence of installations.[7]

In the following paragraphs, the major natural gas supply routes to the EU are presented according to the corresponding producing country and mode of transport.

Russia

Transportation of Russian natural gas to Europe proceeds through several pipelines, connecting gas fields in the North of Russia through the United Gas transportation system to the European countries. Figure 3-38 presents the main natural gas export pipelines from Russia to Europe.

The "Brotherhood" pipeline (Urengoy-Pomary-Uzhgorod) is the largest gas transportation route. It can carry over 100 bcm gas per year, transiting Ukraine and running to Slovakia. In Slovakia, the pipeline is split and one branch goes to the Czech Republic. Russian gas transported through the Czech Republic flows in the direction of Waidhaus and Hora Svaté Kateřiny via Uzhgorod, as well as from the Yamal-Europe gas pipeline, with Olbernhau and Brandov as entry points. Its second branch goes to Austria. This country plays an important role in the delivery of Russian natural gas to Italy, Hungary, Slovenia and Croatia. Gas deliveries through this pipeline started in 1967.

The Yamal-Europe pipeline runs across Russia, Belarus and Poland reaching Germany. Its length is beyond 2,000 km, 14 compressor stations are operational along it. The pipeline construction began in 1994 close to the German and Polish borders, and first sections of the pipeline were brought online as early as in 1996. The Belarusian part where Gazprom has

[7] The Natural Gas Chain - Toward a global lifecycle assessment, Delft, CE, 2006

become the sole investor was commenced in 1997. Upon commissioning of the last compressor station in 2006, Yamal – Europe reached full capacity – 33 billion m^3 per annum.

Figure 3-38 Map of major Russian natural gas pipelines arriving to Europe (Source: Wikipedia)



The South East gas transportation route through Romania carries Russian gas to this country, transiting Ukraine and Moldova, and runs further to the Balkan countries and Turkey. The pipeline construction began in 1986, and the second line was added in 2002.

Furthermore, the consumers in Finland receive Russian gas through the gas transportation system in the Leningrad Region.The Nord Stream offshore pipeline laid on the bottom of

the Baltic Sea with capacity of 55 bcm per year allows direct gas transportation for clients in Western Europe, primarily in Germany, bypassing transit states.[8]

Norway

All gas pipelines on the Norwegian Continental Shelf with third party customers are owned by a single joint venture, Gassled, with regulated third party access. The Gassled system is operated by the independent system operator, Gassco AS, a company wholly owned by the Norwegian State. In 2010, the Gassled system transported 97.3 bcm of gas to Europe.

Figure 3-39 Map of the Norwegian Continental Shelf natural gas pipelines



Figure 15.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

[8] Gazprom website

Norway operates several important natural gas pipelines that connect directly with EU countries, specifically France, the United Kingdom, Belgium, and Germany. The most important pipelines are:

- Franpipe, with a capacity of 19.85 bcm/y, exports gas to Dunkirk, France.
- Zeepipe I, IIA, and IIB have a total capacity of 68.18 bcm/y and transport gas to Zeebrugge, Belgium.
- Europipe I and II, with a total capacity of 42.2 bcm/y, export to Dornum, Germany.
- Norpipe, with a total capacity of 11.54 bcm/y, runs to Emden, Germany.
- Vesterled, capacity 14.06 bcm/y, links to St. Fergus, Scotland.
- Langeled, capacity 25.98 bcm/y, links to Easington on the east coast of England.

In 2010, the Gassled system was again expanded through the merger with the Gjøa Gas Pipeline. When new gas infrastructure facilities are merged into Gassled, the ownership interests are adjusted in relation to the relative value of the assets and each owner's relative interest.[9] Figure 3-39 depicts the natural gas pipelines reaching the EU from the Norwegian Continental Shelf.

Algeria

Algeria was the first country in the world to export LNG in 1964. Algeria exports natural gas to Europe via pipelines and on tankers in the form of liquefied natural gas (LNG). It has three transcontinental export gas pipelines: two natural gas transport pipelines to Spain and one to Italy. Algeria's LNG plants are located in the coastal cities of Arzew and Skikda. Figure 3-40 presents the map with the main locations and pipelines of the Algerian gas system. In this map, the MEDGAZ pipeline appears as "under construction", although it has been operating since 2011.

- LNG production

In 2013, Algeria was the world's seventh-largest exporter of LNG, accounting for about 5% of the world's total exports. Algeria has liquefaction units located along the Mediterranean Sea at Arzew and Skikda, with a total design capacity to process almost 96 million cubic meters per day of natural gas. The considered LNG streams from Algeria arriving to Europe consist of a pipeline leading the natural gas from the producing fields to the liquefaction plants and secondly marine vessel transportation. The corresponding GHG emissions of these streams will be estimated as a combination of these two modes of transport.

Algeria's domestic natural gas pipeline system transports natural gas from the Hassi R'Mel fields and processing facilities, owned by Sonatrach, to export terminals and liquefaction plants along the Mediterranean Sea. There are two main domestic pipeline systems transporting natural gas to the liquefaction terminals: (i) the Hassi R'Mel to Arzew system which is a collection of pipelines that move natural gas from Hassi R'Mel to the export

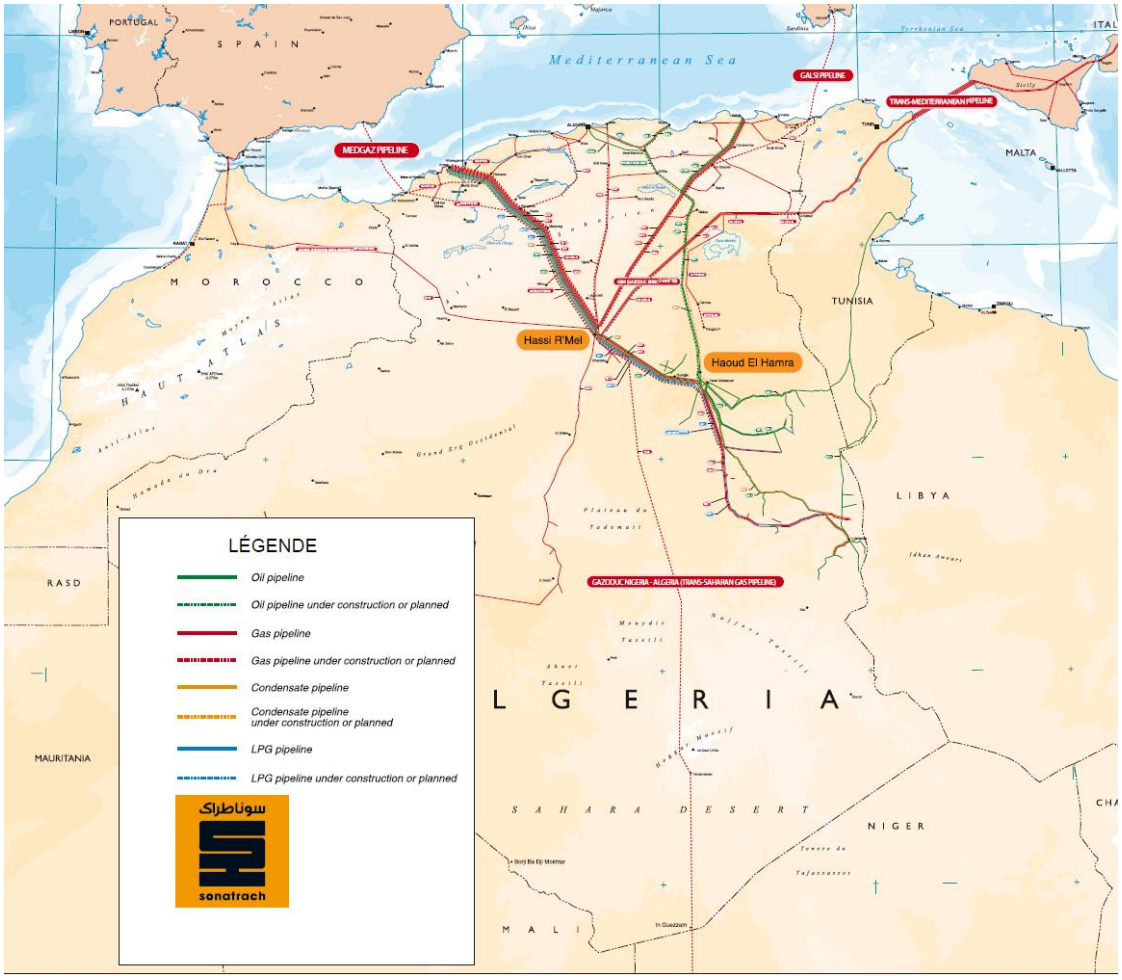
[9] Statoil website

terminal and the LNG plant at Arzew and the Hassi R'Mel to Skikda system which transports natural gas from the Hassi R'Mel fields to the Skikda LNG plant.

› Pipeline transport

Besides LNG, Algeria transports natural gas to Spain and Italy via three major pipelines. The largest pipeline, Pipeline Enrico Mattei (GEM), came online in 1983 and runs 1,650 km from Algeria to Italy via Tunisia. GEM's capacity is more than 36 bcm per year and it is jointly owned by Sonatrach, the Tunisian government, and Eni. The Pedro Duran Farell (GPDF) pipeline started in 1996 and travels 525 km to Spain via Morocco. GPDF's capacity is about 11 bcm per year. The newest pipeline, MEDGAZ, came online in 2011 and is owned by Sonatrach, Cepsa, Endesa, Iberdrola, and GDF Suez. It stretches 200 km onshore and offshore, from Algeria to Spain via the Mediterranean Sea.

Figure 3-40 Algerian natural gas transport pipelines map (Source: Sonatrach)



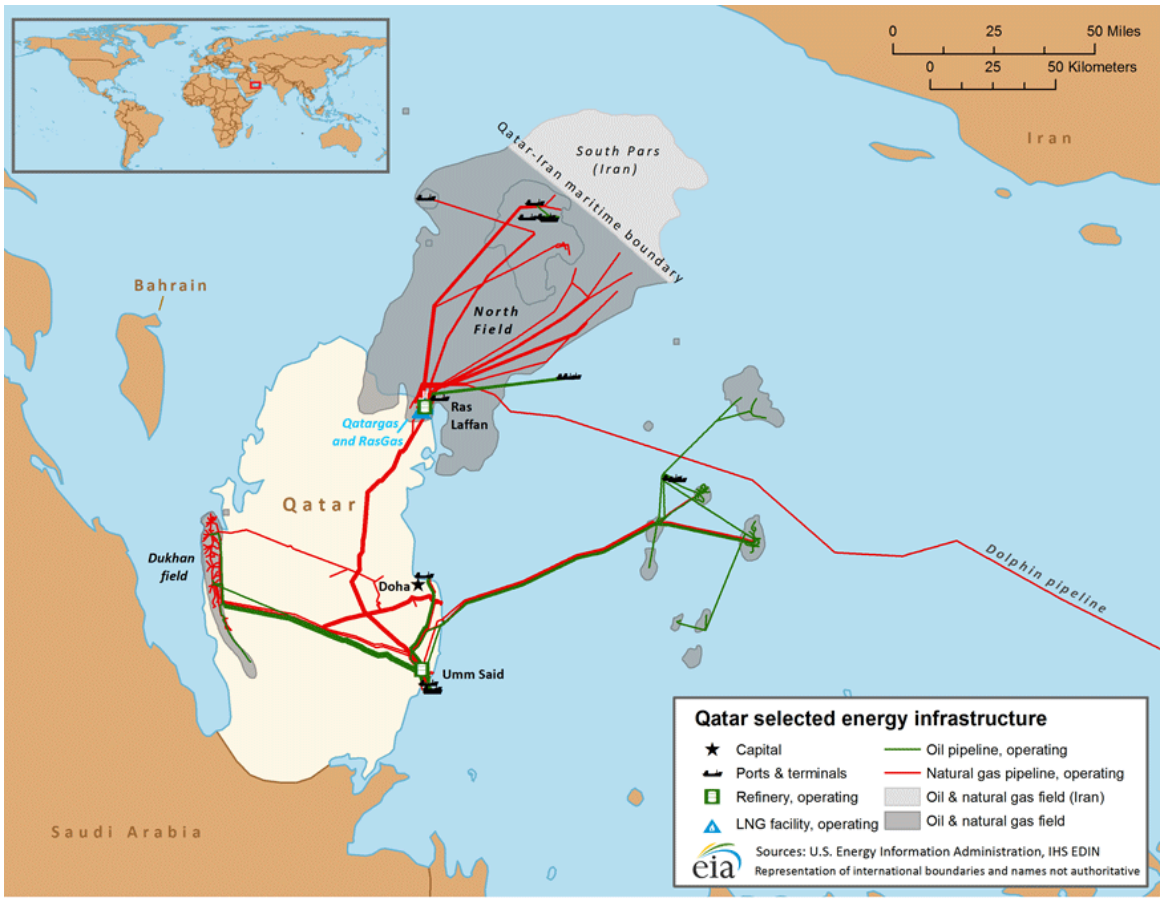
Qatar

Qatar is the world's largest producer of (LNG), accounting for about 15% of world liquefaction capacity. Nearly all of Qatar's natural gas production comes from the North

Field, which is part of the largest non-associated natural gas field in the world, although some smaller fields contribute production volumes as well.

Most of the field lies about 3,300 meters below the Arabian Gulf in water depths of about 65 meters, and is intersected by the Qatar-Iran border. The field spans 9,700 square kilometers. The Qatari North Field portion covers an area of over 6,000 square kilometers, almost half of the entire surface area of Qatar.

Figure 3-41 Qatar energy infrastructure map (Source: EIA)



With a limited demand for domestic consumption, Qatar Petroleum (QP), the state-owned company, and its international business partners have aggressively developed export markets. Most exports are in the form of liquefied natural gas (LNG).

Qatar's natural gas liquefaction facilities and related industries are located in Ras Laffan Industrial City, site of the world's largest LNG export facility. Ras Laffan is a self-contained city built by the government to support the processing and export of natural gas.

Figure 3-41 presents the major energy infrastructure in Qatar.

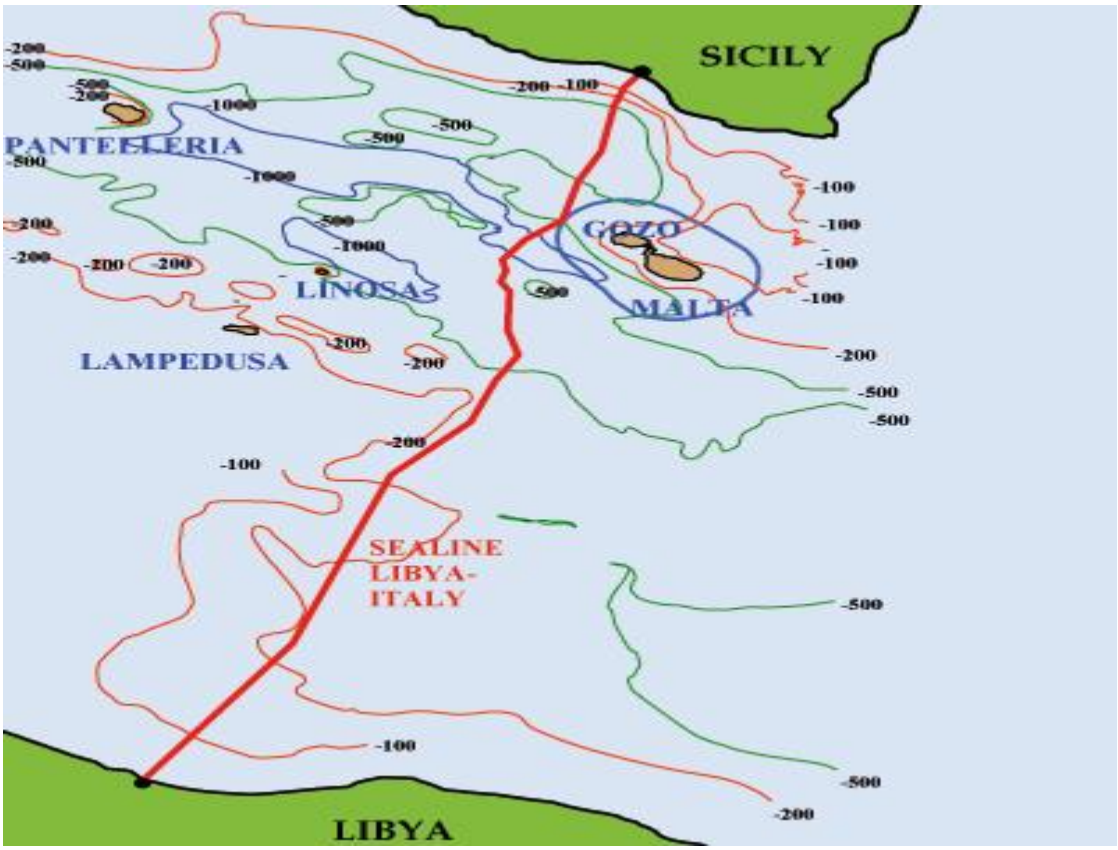
Libya

Libya's rank as a producer and reserve holder is less significant for natural gas than it is for oil. Most of its natural gas production is exported to Italy via pipeline. OGJ estimated that Libya's proved natural gas reserves were 1.5 trillion cubic meters, making it the fourth largest natural gas reserve holder in Africa.

Libya's capacity to export natural gas increased dramatically after October 2004, when the 595 km Greenstream pipeline came online. The pipeline starts in Mellitah, where natural gas piped from the onshore Wafa and offshore Bahr Es Salam fields is treated for export. It runs underwater to Gela, on the island of Sicily, and the natural gas flows onward to the Italian mainland (Figure 3-42). The Greenstream pipeline is operated by Eni in partnership with NOC. According to PFC Energy, total capacity is 11 billion cubic meters per year since the most recent capacity expansion.

Natural gas exports via Greenstream were completely suspended for nearly eight months from March 2011 to mid-October 2011 due to the civil war. Exports partially recovered to 228 Bcf in 2012, albeit lower than the 2010 level of 332 Bcf, according to the BP 2013 Statistical Review.

Figure 3-42 Map of the Greenstream pipeline

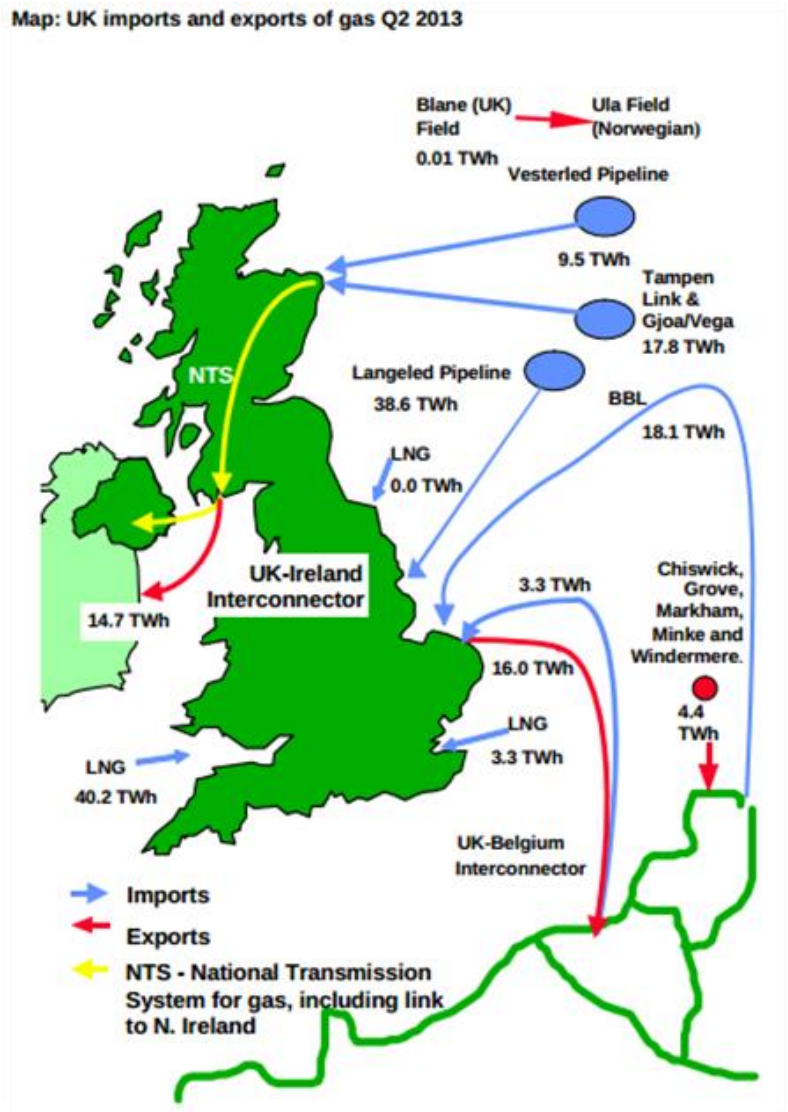


UK

The UK, in spite of being an EU 28 country, because of its geographical characteristics (not part of inland Europe), has several international pipelines, interconnecting it to the rest of the EU. The main pipeline exporting natural gas from the UK to the rest of the EU is the Interconnector pipeline which runs between Bacton, England and Zeebrugge, Belgium.

The Interconnector, inaugurated in 1998, is capable of bidirectional operation, meaning either it can export natural gas from the UK to continental Europe ("forward mode"), or it can import natural gas into the UK ("reverse mode"). Since it began operating, the Interconnector has mostly operated in forward mode, however during late fall and winter seasons, the pipeline has tended to operate in reverse mode. The pipeline has undergone three phases of expansion, with additional capacity and compression added between 2005 and 2007. The interconnector is currently capable of transporting 60 million cubic meters per day in forward mode and 75 million cubic meters per day in reverse mode. The international pipelines connecting the UK to other European countries are illustrated in Figure 3-43.

Figure 3-43 Map of the UK Natural gas international pipelines

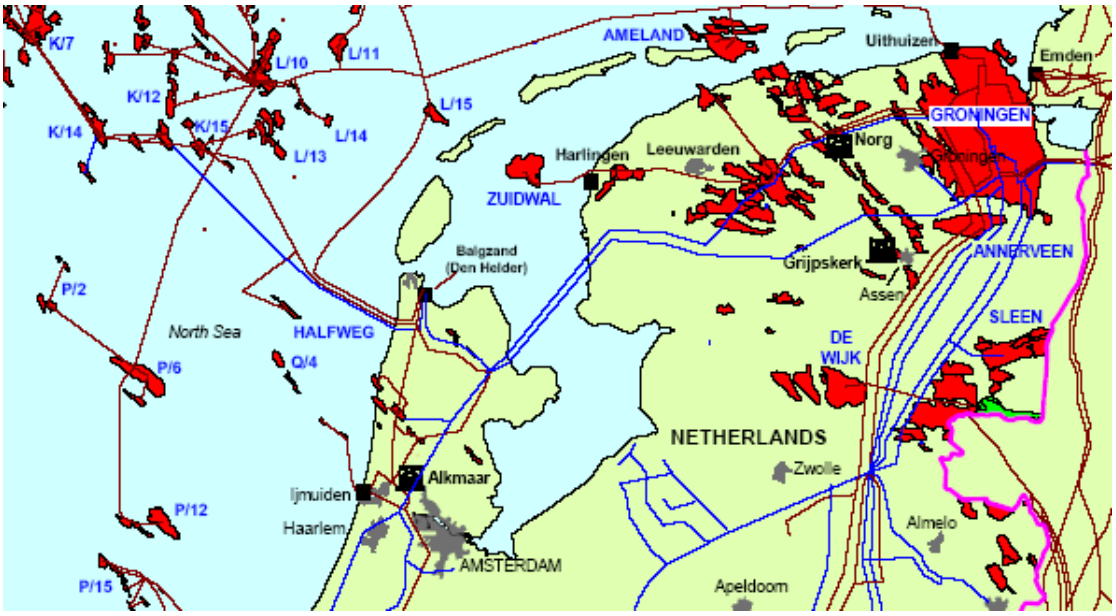


Netherlands

Most of the Dutch natural gas fields are located offshore in the North Sea, although a number of them are located onshore, including Groningen, one of the ten largest natural gas fields in the world.

Natural gas produced in the Netherlands is shipped via an extensive domestic and export pipeline system, which connects the country with United Kingdom, Germany, and Belgium. In addition to pipeline natural gas, the Netherlands now serves as a transport hub for liquefied natural gas (LNG). The Gas Access to Europe (GATE) LNG import terminal became operational in September 2011, with imported volumes purchased by Austrian, Danish, and German distribution and utility companies.

Figure 3-44 Netherlands gas transmission map



On December 1, 2006, the Balgzand-Bacton Line (BBL), the first pipeline to link the Netherlands and the United Kingdom, began operating and supplying the UK with natural gas from the Dutch mainland. The 236 km pipeline has a capacity of approximately 45 Bcm per day.

Figure 3-44 presents the main pipelines departing from Groningen, Netherlands transmitting natural gas.

3.4.6 Downstream

The downstream stage is the final step in the natural gas supply chain and includes transmission, storage and distribution of gas to the end-users.

Natural gas is introduced into a pipeline transmission system at various points such as liquefied natural gas (LNG) terminals, processing plants near indigenous gas production fields, and interconnections with other natural gas transmission pipelines and long

transportation pipelines. Gas storage sites are also connected to the transmission systems. The transmission and transportation pipelines are supported by gas fueled compressors.

The delivery of natural gas to the end user by a distribution system does not contain any compression as distribution involves moving smaller volumes of gas at much lower pressures over shorter distances to a great number of individual users. The medium pressure distribution network is normally operated at a pressure below 15 bar and the electric compressors of CNG production are usually connected at this pressure.

Transmission and distribution networks are equipped with a high number of valves (safety valves and operating valves). Meters and customer lines are also part of the distribution network.

Venting and fugitive emissions

Natural gas can be released to the atmosphere during operation of transmission systems. This is problematic not only in terms of product loss, but also due to the fact that the primary component of natural gas is methane, a powerful greenhouse gas 25 times more potent than carbon dioxide. Generally natural gas emissions are divided into intended releases (venting) and unintended emissions (fugitive). Intended releases highly depend on the technology involved in the process. For example, compressor seals try to minimize the flow of natural gas between the rotating shaft and the casing of the compressor. Emission levels depend on the technology used, the age of equipment and the availability of new technology. Often retrofitting is not possible due to space requirements or other local circumstances.

Pressure controllers and other such equipment periodically release a certain amount of gas, but this can be used for purposes such as preheating of gas before pressure reduction. Maintenance of equipment is necessary, but this often requires internal inspections of parts containing natural gas. This gas must be released first for worker safety. All extensions or repairs of the pipeline network, for example by welding, can only be executed if the natural gas is purged and replaced by air to avoid incidents. Those releases contribute a high percentage of the total emissions of gas companies.

The unintended releases can be the result of leakage from equipment in use or damage to pipelines. All flange connections between parts should in theory be tight, but in some cases there are gaps that allow gas to escape into the atmosphere. Also, valves are intended to seal completely to restrict the flow of gas, but this does not always happen. Finding these leaks is an important Task for worker safety but also helps both the environment and profitability.

Pipe damage can either be caused by material failures or corrosion, but the main cause is third-party damage, commonly during excavation. Companies take care to prevent such damage, e.g. through internal pigging or cathodic corrosion protection and through educating people doing excavation.[10]

[10] Reduction of Greenhouse gases - A Technology Guide, Produced by: International Gas Union, 2012

EU natural gas consumption in road transport

For the purpose of the present project, only natural gas that is consumed in the transport sector will be considered for 2012, which is the baseline year. It is considered that the use of natural gas by transport means could be either as Compressed Natural Gas (CNG) or as LNG through small-scale LNG systems. In 2012 CNG could be actually traced as transportation fuel, whereas LNG is expected to be consumed as fuel for big trucks and vessels in the forthcoming years.

As it is shown in Table 3-18, the majority of EU countries do not present any consumption of natural gas for road transport and even in the countries that do have vehicles powered by natural gas, the corresponding quantities of fuel consumed are rather small. The only countries where the consumption of natural gas for road transport represented a substantial percentage of the total natural gas consumption in 2012 are Sweden, Bulgaria and Italy. Actually quantities of gas fueled to other transport means are negligible.

Table 3-18 EU 28 Natural gas consumption for road transport in 2012 (source Eurostat)

Consuming country	Road consumption (million cubic meters)	Road consumption/ Total NG consumption %
BG - Bulgaria	79.03	2.66
EL - Greece	17.50	0.41
HR - Croatia	1.01	0.03
IT - Italy	924.04	1.23
RO - Romania	0.00	0.00
SI - Slovenia	0.84	0.10
BE - Belgium	10.37	0.06
CZ - Czech Republic	15.25	0.18
DE - Germany	259.03	0.30
EE - Estonia	0.00	0.00
LV - Latvia	0.00	0.00
LT - Lithuania	3.60	0.11
LU - Luxembourg	0.00	0.00
HU - Hungary	1.37	0.01
NL - Netherlands	24.21	0.05
AT - Austria	9.01	0.10
PL - Poland	0.00	0.00
SK - Slovakia	0.00	0.00
DK - Denmark	0.00	0.00
IE - Ireland	0.00	0.00
FI - Finland	6.72	0.18
SE - Sweden	59.48	5.05
UK - United Kingdom	0.00	0.00
ES - Spain	93.12	0.29

Consuming country	Road consumption (million cubic meters)	Road consumption/ Total NG consumption %
FR - France	98.60	0.23
PT - Portugal	13.76	0.31

The GHG emissions assessments, and therefore the gas streams, will not be restricted to the countries where there is gas consumption in transport in 2012 but will consider all natural gas streams supplied to EU 28 countries will be considered, as gas use in transport will be projected to 2030 (Task f of the study) and thus might be assessed in these projections.

3.5 Approach for Data Collection

3.5.1 Correspondence with oil and gas companies

As discussed in previous sections, a key target of this study is the collection of actual GHG emissions data. Thus, in line with the ToR requirements, the Consultant has come in direct communication with oil and natural gas production companies, national authorities as well as international organizations, in order to request actual data regarding field specific GHG emissions from the oil and gas upstream operations by each specific company. Specifically, GHG emissions data were requested on a field basis for the following activities both for oil and natural gas:

- Exploration, production and processing
- Venting, flaring and fugitive gas
- Transportation

The communication with the companies has been done both in a formal and informal manner. After establishing a contact with the relevant persons within each company, either by telephone or by e-mail, a formal letter was sent to them (a template of which is presented in Annex E). The purpose of this letter, which was signed by the Project Manager, was to request the provision of actual (emissions) data. The letter also mentioned the scope and the objectives of the project and stated the relevant support and interest of the European Commission. Onwards, follow-up communication by telephone and e-mail were made to the responsible persons within the oil and gas companies in order to establish a direct line of communication.

It should be mentioned as a general conclusion that oil and gas companies and their associations have been proven to be reluctant in providing actual emissions data till present and most of those who replied to the request for data, have guided us to look through their sustainability and environmental reports (if they exist). Unfortunately, these reports usually include aggregated and cumulative data covering the whole range of the company's activities, with few exceptions, and sometimes extending beyond oil activities.

Similarly, national authorities responsible for oil and gas activities or environmental authorities in key countries were contacted (e.g. Norwegian Petroleum Directorate, Association of Oil and Gas Producers, etc.) even though these institutions typically publish most of the data they have available from their members or participating oil and gas companies. Table 3-19 summarizes the correspondence with companies and institutions contacted, the departments contacted (if applicable), the way of communication and their response.

Generally the data collection output based on direct communication and request of existing actual data was very poor and it was disappointing that most of the contacted responsible officials tried to avoid replying or pass the request to other organizations, sometimes not so relevant to provide detailed information.

Table 3-19 Overview of the correspondence with oil and gas associations, agencies and companies

Oil Company	Position/Department	Letter sent by e-mail	Letter sent by post	Comments	Data provided
Oil					
Statoil	Senior Advisor Sustainability	yes	yes	Redirected to the Norwegian Petroleum Directorate	Not yet
Maersk	Group Sustainability, Head of Positioning & Strategic Risk Management, Lead, Climate Change	yes	yes	Redirected to the competent persons from Maersk oil, who did not reply	Not yet
Total	Director Sustainable Development and Environment	yes	yes	Letter sent to his assistant but no reaction	Not yet
ENI	Environment Manager	yes	yes	No reaction	Not yet
Shell	CO2 Policy Manager	yes	no	No reaction	Not yet
BP	Head of Energy & Carbon Policy and Strategy	yes	no	No reaction	Not yet
Lukoil	Contact in the Refining department	yes	no	Asked for a contact person in the Environmental Department but no reaction	Not yet
Chevron	Principal Advisor, Climate Change	yes	no	Redirected us to OGP	Not yet
Conoco Phillips	Various	no	no	Never managed to contact anyone within Conoco Phillips	
Nexen	HSE and Assurance manager	yes	yes	Redirected us to OGP	Not yet

Oil Company	Position/Department	Letter sent by e-mail	Letter sent by post	Comments	Data provided
Repsol	Deputy Director of Corporate Responsibility	no	no	Never managed to contact anyone within Repsol	
Saudi Aramco	Environmental Coordinator	yes	No	No reaction	Not yet
Natural gas					
Gazprom	Junior Environmental Researcher	yes	no	No reaction	Not yet
Qatargas	Head of Environment	yes	no	No reaction	Not yet
Sonatrach	Various	yes	no	No reaction	Not yet
Associations and organizations					
OGP	Environmental Director	yes	yes	No reaction. Only reaction when redirected by Chevron, but no further data provided	Not yet
CDP	Director, Global Operations	yes	yes	A long communication was established with the CDP, who were willing to help but did not have the authorization to provide us with data or contact details from the reporting companies	Not yet
National authorities					
NPD	Various	yes	no	Contacted them by telephone, but they informed us that all data they can provide are already public in their website	Not yet

3.5.2 Approach for actual emissions data collection

According to the data collection priority described in Section 3.2.2 the first step of the study was to collect actual data from oil companies and organizations regarding the carbon intensity of specific MCONs or crude oils extracted from specific fields. For the MCONs for which poor or unreliable emissions data were collected, the GHG emissions will be also assessed via the OPGEE model. Similarly, for natural gas sources and streams when actual data have been considered as insufficient GHG emissions have also been assessed via

GHGenius. In any case actual emission sources are extremely useful for comparisons with emissions calculated via models.

The progress of the correspondence with oil and gas companies has clearly indicated that the receipt of few actual data should be expected. Therefore, the Consultant has chosen to adapt its data collection strategy and search for actual data from published documents of national authorities, public organizations and company reports.

The literature sources where actual data were found till present are summarized in Table 3-20.

Table 3-20 Overview of actual data sources, type of data collected and data coverage

Country/ Region	Source	Actual data type	Coverage
EU wide or various countries			
Russia, Norway, UK, Netherlands	UNFCCC Annex I country reports for 2012	Emissions and co-efficient factors for the following activities regarding crude oil: › Production › Flaring and venting › Transport › Refining › Distribution	Country data
Worldwide	National Oceanic and Atmospheric Administration (NOAA)	› Flaring volumes for oil and natural gas	Country level and field level
EU wide	Environmental Energy Agency – European Trading Scheme	› Refining emissions	Country data
National reporting			
UK	National Atmospheric Emission Inventory	› Upstream oil activities › Upstream gas › Gas leakage › Venting › Flaring › Refining	Country data
	Department of Energy and Climate Change (DECC)	› Quantities of gas flared	Country data
Norway	Norwegian Oil and Gas association	Emissions for the following oil activities:	Country data

Country/ Region	Source	Actual data type	Coverage
		› Well testing › Flaring › Boilers › Engines › Turbines	
	Norwegian Environment Agency	Data regarding all Norwegian oil and gas fields and facilities: › Energy use › Production volumes › Emissions	Oil and gas field specific data
Denmark	Oil and gas production Annual Report 2013, DEA	› Fuel consumption (gas) per field › CO_2 emissions from production facilities in the North Sea › CO_2 emissions from consumption of fuel per m. toe › Gas flaring	Country level and field-specific level
Russia and the Caspian Region	Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan, EBRD (2012)	› Flaring emissions › Flared quantities of natural gas	Country data
	Associated Gas Utilization in Russia Annual Report 2011, KPMG	› Flaring emissions per region › Flaring emissions per company › APG utilization rates	Country data
Nigeria	Nigerian National Petroleum Corporation Annual Report 2013 (NNPC)	› Flaring quantities for a large number of fields	Field specific data
Company reporting			
Carbon Disclosure Project	Carbon Disclosure Project (CDP)	› Exploration, production & gas › processing › Storage, transportation & › distribution › Speciality operations › Refining	Data provided per company
BP	BP Sustainability report 2012 Azerbaijan	› Flaring emissions › Flaring volumes	Country specific data as well field specific data

Country/ Region	Source	Actual data type	Coverage
		› Production emissions	particularly for Azeri Chirag Gunashli
Nexen Petroleum	Nexen Petroleum U.K. Limited Environmental Statement 2012	› Flaring and production GHG emissions	For company oil fields (Buzzard, Ettrick, Scott)
CNR International	CNR International UK Operations Environmental programme Annual Report 2013	› Combustion › Flaring	Field specific data for Ninian System Oil fields
BP	BP Sustainability report 2012 Angola	› Actual direct emissions › Actual indirect emissions › Flaring volumes	Country data for (oil and gas) assets owned by the specific company

The Table is organized on the basis of the targeted country or region. This way of presentation of the collected actual data has been preferred due to the fact most of the times information is found on a country basis. Furthermore, the data source is mentioned as well as the data type (flaring, venting, fuel consumption, refining, etc.) and the scope they cover (country or field specific).

3.6 Actual Data for Crude Oil

A valuable data source including reliable information for oil and gas for various lifecycle stages have been the UNFCCC country reports. However, it has to be noted that the available data regard only Annex I countries and more specifically Russia, Norway, UK and the Netherlands (among the oil producing countries). The National Oceanic and Atmospheric Administration (NOAA) has conducted an extensive work on the elaboration of actual data for flaring both on a country and field level. However, it must be stated that data provided per field regard flaring both from oil and gas activities and a tailor made methodology has to be developed in order to disaggregate emissions for further analysis. Actual data for the European refining sector have been found per country by the European Environmental Agency, as those reported and verified for the European Trading Scheme.

The main sources of actual data for the UK oil and gas sector are included in the National Atmospheric Emission Inventory maintained by DEFRA. Norway has been the country for which the most actual data have been found for oil and gas both on country and field specific level. The main source of data for Norway has been the Norwegian Environment Agency and the Norwegian Petroleum Directorate (NPD), while Statoil published a wealth of data in line with national regulatory requirements. For Denmark, the Danish Energy

Agency (DEA) in its annual reports includes actual emissions data for oil and gas activities in its annual reports. Another significant source of actual data has been a study conducted by EBRD regarding the flaring emissions for Russia, Kazakhstan, Turkmenistan and Azerbaijan, which has collected statistics from national authorities from the aforementioned countries. This study is particularly important as in these countries there a remarkable difficulty for obtaining reliable data. Lastly, actual data regarding gas flaring volumes per oil field and company for Nigeria are included in the Annual Statistical Bulletin published by the National Nigerian Petroleum Company (NNPC).

Other sources of actual data include environmental and sustainability reports from oil and gas companies. More specifically, BP in its sustainability report for Azerbaijan provides actual emissions data per asset (field, pipeline) as well as cumulative figures, while for Angola it provides only cumulative figures for the entire company. NEXEN petroleum provides actual data for the oil fields it operates in UK and particularly for Buzzard which is a representative field.

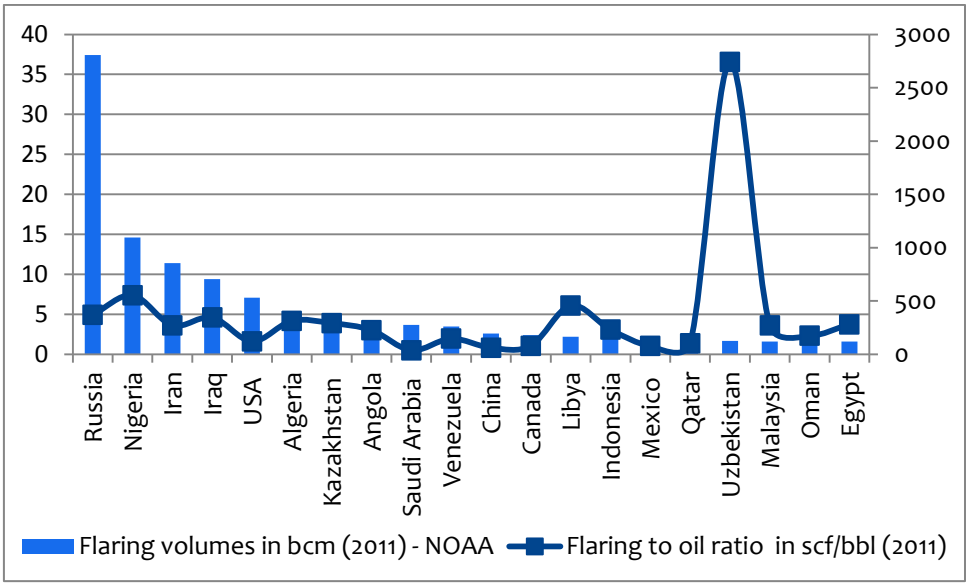
In the following Sections 3.6.1– 3.7.38the actual data that have been collected by various sources for oil and gas activities till present are presented exhaustively per region or country. In addition, in Section 3.6.8the emissions from oil and gas activities of various companies are presented per lifecycle process, as those have been reported to the Carbon Disclosure project. In Section 3.6.9the actual emissions of the European refining sector are presented per country. Finally, in Section 3.6.11an overview of the actual data that have been collected is being made in order to evaluate the needs for data collection for the OPGEE model.

3.6.1 Russia and FSU countries

Country data

In general, few actual GHG emissions data from upstream activities are available for Russia and FSU countries, with the exception of flaring emissions. The analysis of flaring emissions from Russian oil fields is of particular importance because these are extremely high - the largest among all oil producing countries as illustrated in Figure 3-45. Furthermore, as it can be obtained by the Figure 3-46, Russia has one of the largest flaring to oil ratio among countries studied by NOAA (i.e. associated gas flared volume per unit of oil extracted). The relevant ratio has been calculated by using gas flared volumes by NOAA/GGFR estimated and EIA oil production volumes per country and is also an important input for the modelling of GHG emissions in OPGEE.

Figure 3-45 Flaring emissions (in bcm) according to the NOAA/GGFR database and flaring to oil ratio (scf/bbl) for the calculated based on EIA production volumes for 2011



Besides the NOAA database, there are several studies dealing with flaring emissions both for Russia and FSU countries. Particularly a study conducted by Carbon Limits on behalf of EBRD provided a comprehensive overview of Russian and other FSU countries' flaring emissions (Figure 3-45) presenting official statistics from FSU countries. Another study dealing with Russia's flaring emissions has been elaborated by KPMG on behalf of WWF Russia, which has collected several actual GHG emissions data via request from oil companies.

Figure 3-46 summarizes the associated petroleum gas flaring volumes for Russia and other FSU countries. Data for Russia have been taken from the Central Dispatch Office of the Russian Fuel and Energy Industry (CDU TEK), for Kazakhstan from the Ministry of Oil and Gas, for Turkmenistan from NOAA/GGFR and Carbon Limits estimates based on IHS data sources. For Azerbaijan figures have been taken from BP's sustainability reports. As expected, Russia has by far the largest emissions among the examined countries. Furthermore, despite Russia's commitments for taking policy action regarding flaring reduction, emissions increase steadily since 2009.

A significant issue relevant to Russian and other FSU countries' flaring emissions is the inconsistency among published data by various sources, as there are large differences in flaring volumes published between national statistics, company figures and NOAA estimates. The discrepancy in flaring volumes between official statistics and NOAA assessments for Russia and Kazakhstan is clearly illustrated in Figure 3-47.

The gap between NOAA values and official statistics can be attributed to three factors (EBRD, 2013):

- Difficulties in converting luminosity to flaring volumes. This is related to several factors such as the possibility of overestimating or underestimating flaring volumes via appropriate conversion factors. Furthermore, NOAA satellite images capture only specific snapshots - and not measurements - and therefore do not take into account seasonal variations.
- Flaring volumes do not consider only flaring from associate petroleum gas but also other sources such as non-associated gas from gas processing plants or refineries.
- Underestimates of flaring from national statistics.

Figure 3-46 Flaring of associated gas in target countries in bcm according to national statistics for the years 2006 – 2012, in billion cubic meters (source: EBRD)

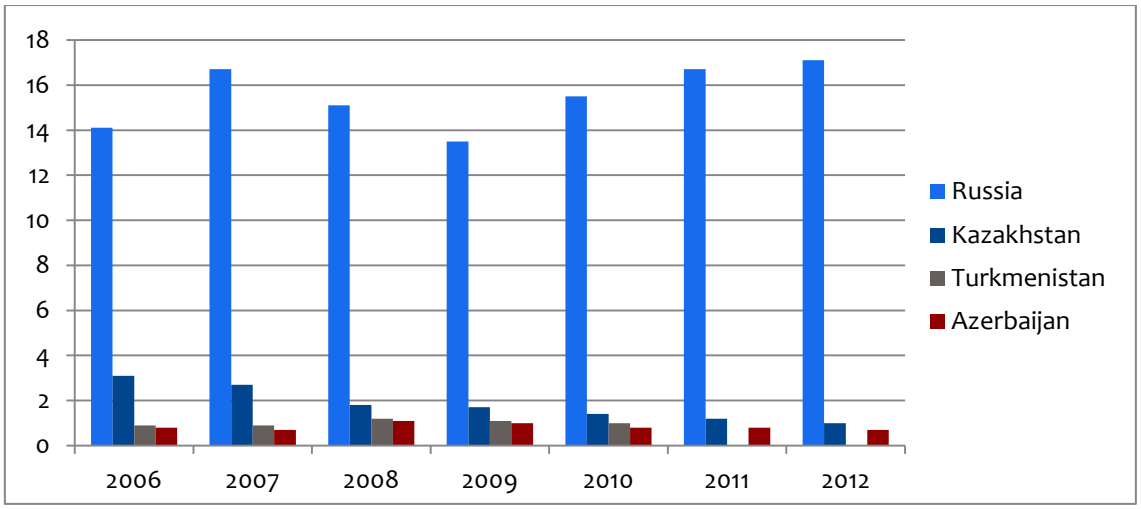
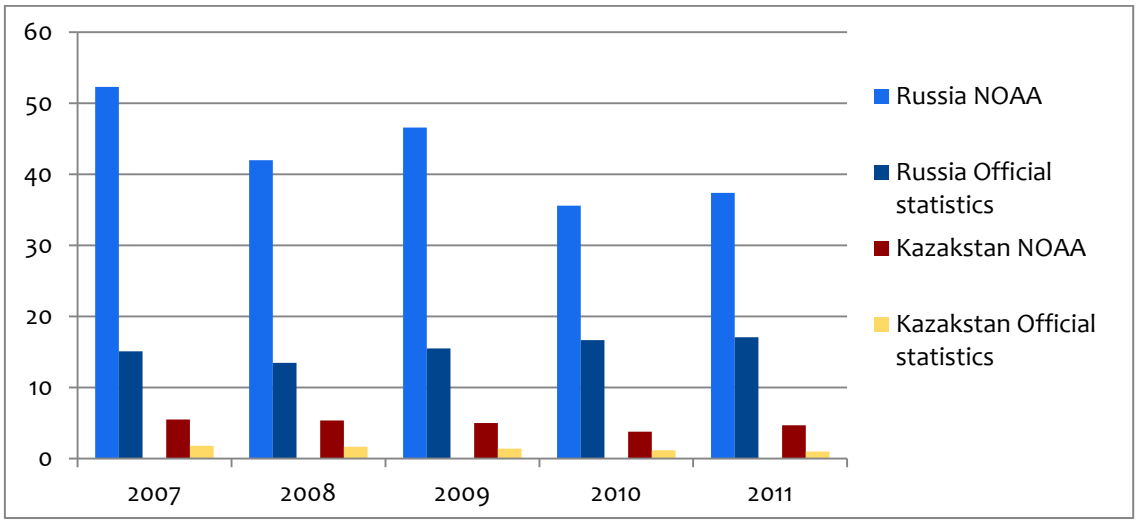


Figure 3-47 Comparison of associated flaring volumes in bcm between national statistics and NOAA estimates (source: EBRD)

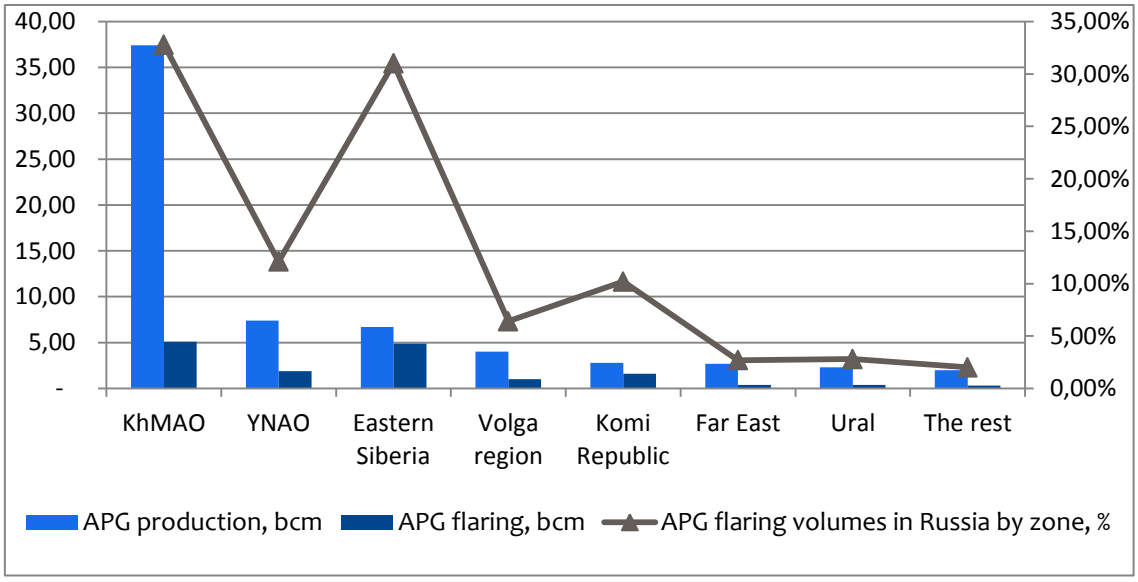


Regional dispersion of Russian flaring volumes

Figure 3-48 illustrates the Associated Petroleum Gas (APG) production volume per region and the APG flared volumes. It is evident that the largest fraction of APG production comes from Western Siberia with more than half of it being produced in Khanty-Mansi Autonomous Okrug. Large part of this APG is flared – approximately 5 bcm, with Eastern Siberia having the same flaring volumes. Together these two areas accounted for approximately 80% of Russian flaring emissions.

Further analysis of these data can be used for the assessment of flaring emissions for Urals and Siberia Light MCONs, even though it is doubtful whether these emissions can be reliably attributed to specific MCONs and oil fields.

Figure 3-48 APG production and flaring in Russia by zone in bcm, 2010 (source: KPMG)



UNFCCC emissions data for Russia

A significant source of reported GHG emissions data are the Annex I country reports submitted to UNFCCC. These include actual data both for oil and natural gas for key processes i.e. exploration, production, transport, refining, distribution, flaring and venting. The fact that figures are presented also in the form of emission factors (i.e. total emissions per well, emissions per ton of oil produced or refined, etc.) is particularly important, because they can be used directly in OPGEE and in GHGenius which calculates GHG emissions by use of proper emission factors. Table 3-21 summarizes the UNFCCC reported data for Russia and indicates the level of detail of analysis of these reports.

Table 3-21 Russian reported emissions per lifecycle stage for 2012 for oil and natural gas (source: UNFCCC)

GREENHOUSE GAS SOURCE AND SINK CATEGORIES	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
1. B. 2. a. Oil						204A58	908A40
I. Exploration	*number of producing and capable wells*	1000 numb.	181.70	220,845.96	74,454.96	40.13	13.53
ii. Production[4]	*oil produced*	Mt	497.43	314,758.69	1,690,370.7	156.57	840.83
iii. Transport	*(oil transported in pipelines)*	Mt	523.35	571.23	6,295.17	0.30	3.29
iv. Refining / Storage	*oil refined*	Mt	271.45	NE	36,871.12	NE	10.01
v. Distribution of Oil Products	*oil refined*	kt	271,453.00	NE	NE	NE	NE
vi. Other	*(NGL production)*	kt	21,322.00	355.79	1,910.72	7.59	40.74
1. B. 2. b. Natural Gas						84.34	13,525.23
i. Exploration	*number of producing and capable wells*	1000 numb.	9.79	172,553.69	72,163.80	1.69	0.71
ii. Production / Processing	*gas produced*	10^6 m^3	654,650.00	121.98	3,629.24	79.85	2,375.88
iii. Transmission	*(total gas transmission)*	kt	541,054.50	5.18	8,915.31	2.80	4,823.67
iv. Distribution	*gas consumed*	10^6 m^3	137,236.60	NE	20,908.30	NE	2,869.38
v. Other leakage	*gas consumed*	10^6 m^3	388,079.50	NE	8,904.32	NE	3,455.59
at industrial plants and power stations	*(gas consumed)*	10^6 m^3	343,301.70	NE	9,450.51	NE	3,244.38
in residential and commercial sectors	*(gas consumed)*	10^6 m^3	44,777.80	NE	4,716.82	NE	211.21
1. B. 2. c. Venting						8.78	839.62
i. Oil	*oil produced*	kt	497,425.00	13.99	1,609.93	6.96	800.82
ii. Gas	*length of pipelines*	km	175,100.00	8.50	IE	1.49	IE
iii. Combined	*(NGL production)*	kt	21,322.00	15.81	1,819.80	0.34	38.80
Flaring						36,594.35	219.95
i. Oil	*oil production*	kt	497,425.00	IE	IE	IE	IE
ii. Gas	*gas production*	10^6 m^3	654,650.00	3,725.88	22.94	2,439.15	15.01
iii. Combined	*(Associated gas flaring)*	10^6 m^3	17,077.60	2,000,000.0	12,000.00	34,155.20	204.93

NE (Not Estimated): For existing emissions and removals which have not been estimated
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category

3.6.2 Azerbaijan

Additional data for Azerbaijan have been found in the website of BP, which publishes detailed GHG emissions data in its Sustainability Report for 2012. Figure 3-49 illustrates BP's and its co-ventures' direct CO_2 emissions in Azerbaijan as well as its net GHG emissions. It is evident that both company emissions and cumulative emissions including co-ventures have remained relatively steady over the period examined (2008 - 2012).

Figure 3-49 BP's emissions in Azerbaijan for 2012 (emission in kilotons)

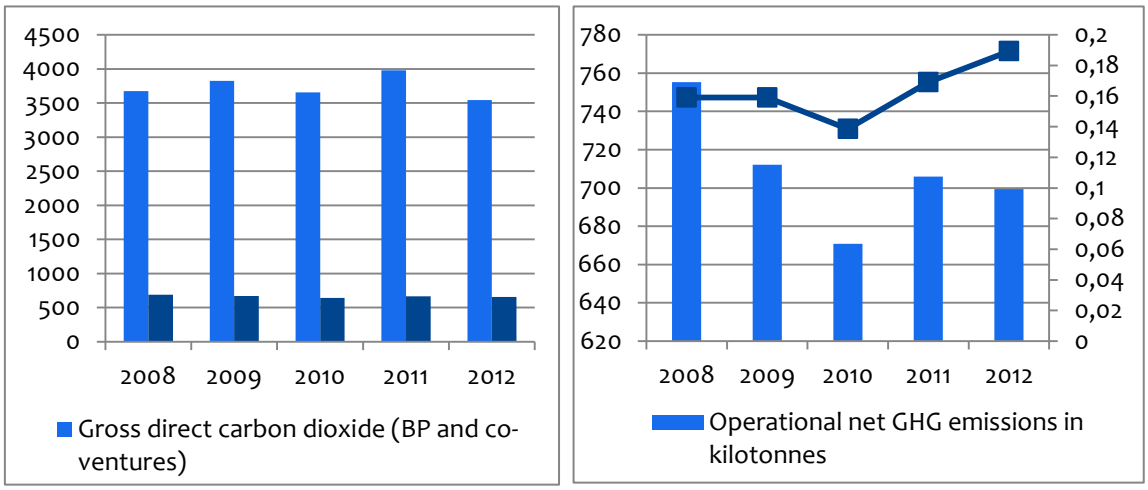


Table 3-22 summarizes BP's net GHG emissions per asset. It is worth mentioning that the Azeri oil field has the largest cumulative emissions, followed by the fields of Chirag and Gunashli (also known cumulatively as ACG field). There are extremely useful data as they can be compared with the emissions calculated for ACG field in OPGEE, which is a representative oil field for two MCONs.

Table 3-22 BP in Azerbaijan net GHG emissions per asset (in kilotons)

Asset / Facility	2011	2012
Central Azeri	130.0	117.2
West Azeri	52.6	44.0
East Azeri	44.6	46.0
Chirag	36.6	54.3
Deepwater Gunashli	88.8	70.6
Shah Deniz	1.9	2.1
Istiglal rig	3.4	3.8
Dada Gorgud rig	2.0	3.6
Sangachal terminal (Azeri-Chirag-Deepwater Gunashli)	247.8	252.5
Sangachal terminal (Shah Deniz)	41.8	44.8
Baku-Tblisi-Ceyhan pipeline in Azerbaijan	22.7	19.4
South-Caucasus Pipeline in Azerbaijan	0.2	0.2
Western Route Export Pipeline in Azerbaijan	4.0	4.3

In 2012, about 475.9 kilotons of hydrocarbons were flared from BP's operations in Azerbaijan. By implementing measures such as improving the reliability of the flash gas compressors at offshore installations, replacing existing engines on gas injection compressors and a gas export compressor at Central Azeri compression and water injection platform with more reliable and higher capacity engines, repairing flare valve at Chirag, post-turnaround flaring minimization at Deepwater Gunashli, BP claims that the overall level of flaring in 2012 compared to 2011 was reduced by 19%. Nevertheless, Figure 3-50 presents gross flaring by asset in kilotons, from where it can be obtained that Chirag had the highest flaring volumes in 2012.

3.6.3 Norway

The environmental performance of the Norwegian petroleum sector compared to other oil producing regions worldwide is illustrated in Figure 3-51, from where it can be obtained that it is one of the cleanest. This has been the result of a number of policy instruments and regulations deployed by the Norwegian government to regulate emissions from the oil and gas business. The most important of these are the carbon tax, Norway's participation in the EU emission trading market, flaring provisions in the Petroleum Activities Act, the requirement to assess power from shore when planning developments, emission permits and the Best Available Techniques (BAT) requirement. These instruments have prompted a number of measures by the petroleum sector that led to significant emissions reductions over the last years.

Figure 3-50 BP in Azerbaijan gross flaring volumes by asset in kilotons (source: BP)

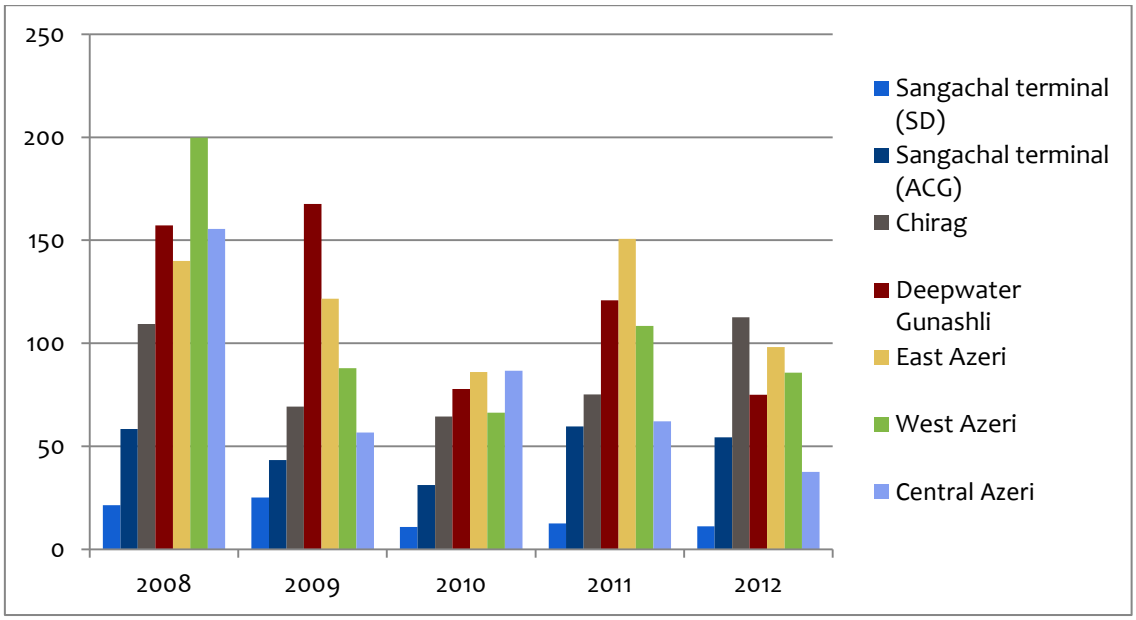
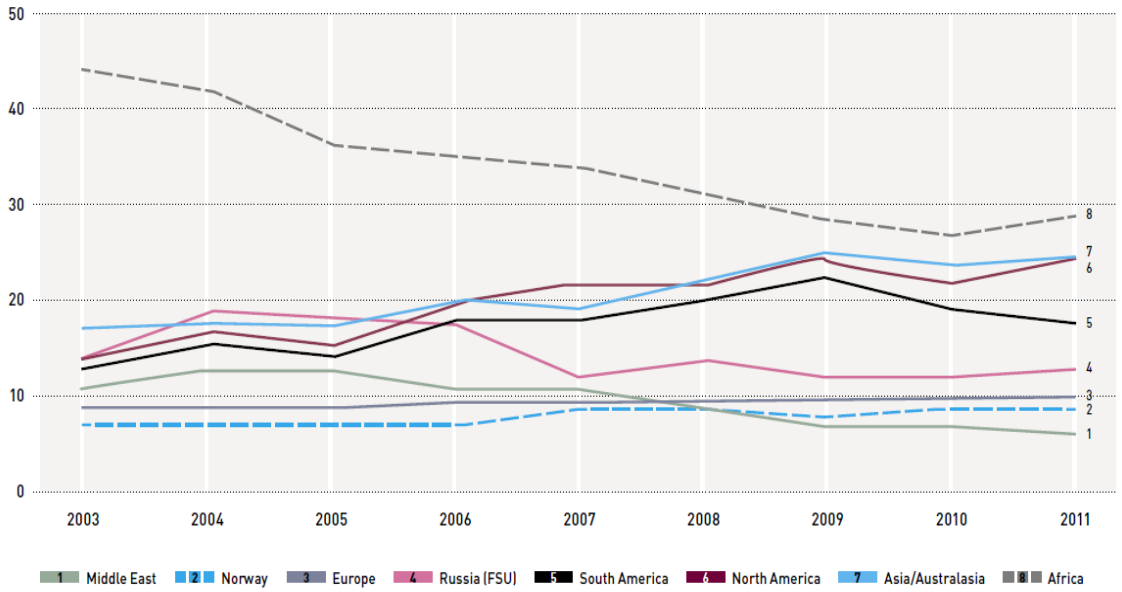


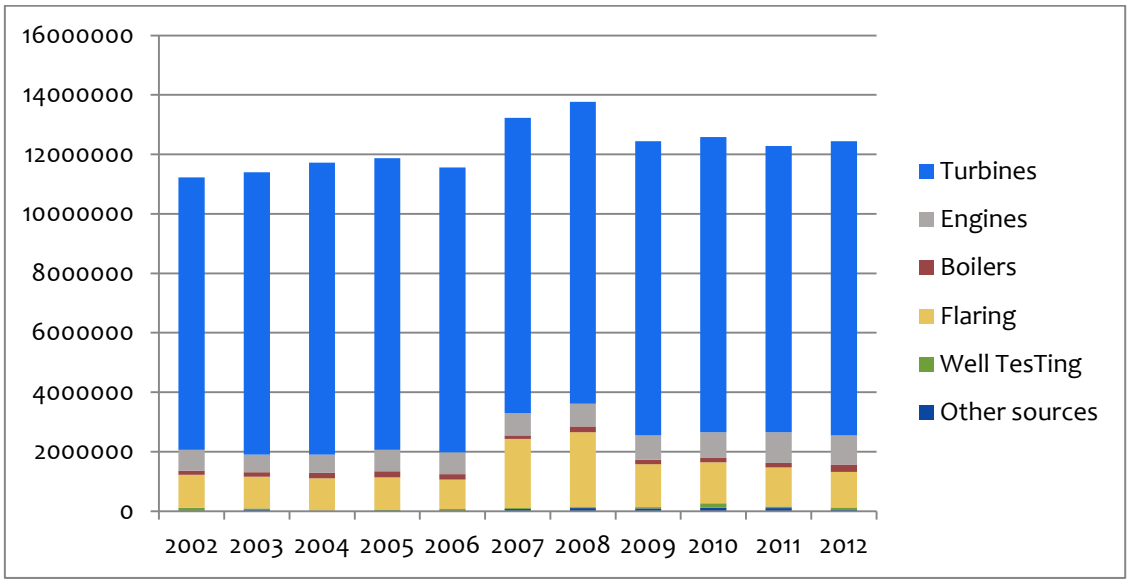
Figure 3-51 GHG emissions produced for petroleum from various origins in kg of carbon equivalent per barrel of oil produced (source: OGP, Environment Web)



The Climate and Pollution Agency, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database for reporting emissions to air and discharges to sea from the petroleum activities under the name «Environmental Web» (EW). In addition, all operators on the Norwegian continental shelf report GHG emissions and discharge data directly into the database. All these data are characterized by high consistency and transparency.

A major source of actual data for Norway has been the Annual Environmental Report published by the Norwegian Petroleum Directorate, which includes detailed emissions for all major pollutants (CO_2 NO_X, CH_4, VOC etc.). After a peak in 2008 GHG emissions have been steadily declining until 2012, as it can be seen in Figure 3-52. The main source of atmospheric emissions has been power generation using natural gas and diesel. The level of these emissions depends mainly on energy consumption by the facilities and the energy efficiency of power generation. The second largest source of this emission type is gas flaring. Flaring takes place to only a limited extent and is constantly decreasing pursuant to the provisions of the Petroleum Activities Act, but is permitted for safety reasons and in connection with certain operational problems.

Figure 3-52 Breakdown of GHG emissions by source in metric tons CO2 equivalent for Norway (source: NPD)



For Norway a detailed source of actual emissions data has been the Norwegian Environment Directorate, including total cumulative emissions and fuel consumption for all representative oil fields that are studied. Figure 3-53, illustrates the GHG emissions for these representative oil fields. As it can be observed in the Figure, the fields that exhibit the largest emissions are Oseberg followed by Gullfaks. Despite the adoption of stringent environmental regulations by Norway and the adoption of more energy efficient technologies by companies active in the Norwegian Continental Shelf, the GHG emissions from representative oil fields remained either stable, decreased or increased in absolute values by the time.

The increase of GHG emissions of representative oil fields can be better perceived by estimating the emissions per unit of output of oil from each oil field, which is illustrated in Figure 3-54. Given the fact that production in the specific fields steadily decreases over time, a general conclusion that can be drawn is that as fields become mature and depleted the energy intensiveness of oil extraction increases in order to maintain pressure at acceptable levels, which results in higher emissions per unit of output of oil over time. The GHG emissions per unit of oil produced are extremely useful for comparisons with the outputs of OPGEE, when these will be produced at a later stage of the project.

Figure 3-53 GHG emissions of representative Norwegian oil fields in tons of CO2 equivalent (source: Norwegian Environmental Directorate)

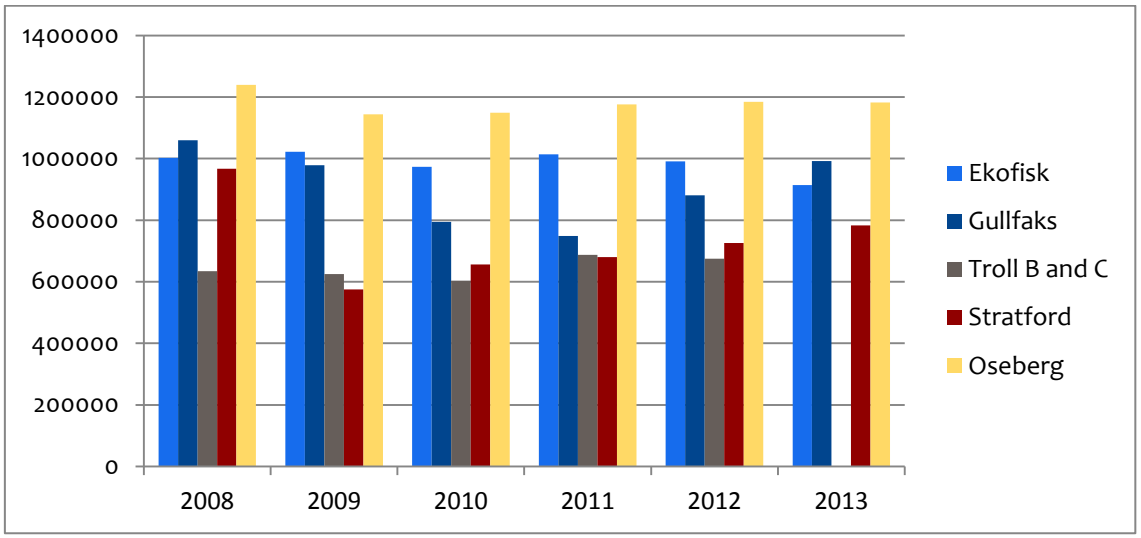
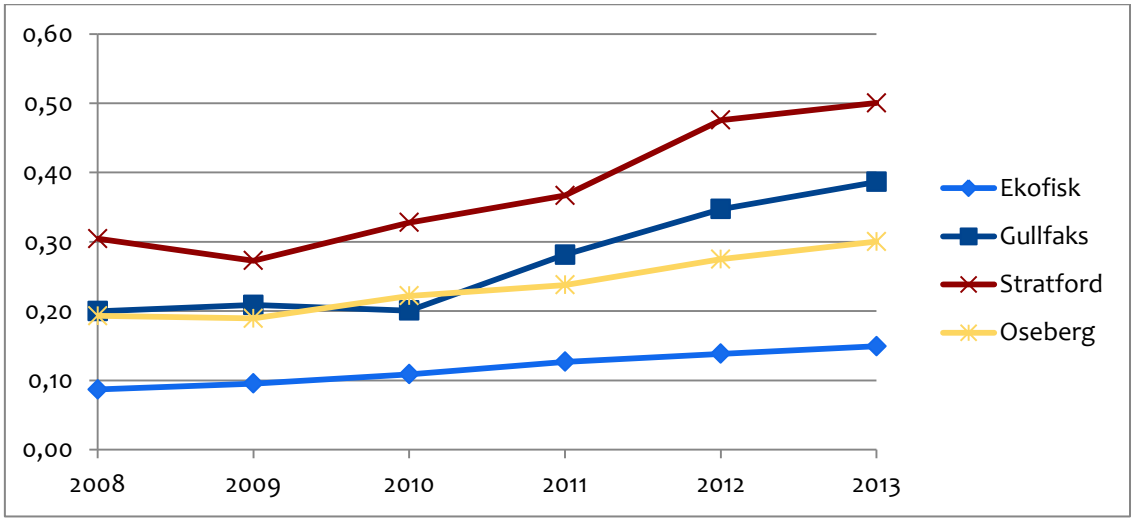


Figure 3-54 GHG emissions per unit of output of oil (in tons CO2 equivalent per m3 of oil) (source: NPD and own elaboration)



As discussed, reporting of GHG emissions in Norway is detailed, transparent and mandated by national legislation. In this context, all companies are obliged to report the emissions from their upstream activities. Detailed emission figures per asset have also been provided by Statoil (including oil and gasification terminals apart from oil and gas fields). Table 3-23 summarizes the GHG emissions of the 20 facilities owned by Statoil with the highest Scope 1 and Scope 2 GHG emissions (see paragraph 3.6.8 for explanations), according to CDP, which are equivalent to direct emissions according to the system boundaries defined in this study.

Table 3-23 Overview of Statoil's 20 facilities (terminals and platforms) with the highest GHG emissions (Scope 1 and Scope 2), as those reported to CDP

Facility	Scope 1 emissions (metric tons CO_2eq)	Scope 2 emissions (metric tons CO_2eq)	Total Emissions (metric tons CO_2eq)
Mongstad Drift PA	1,656,310		**1,656,310**
KÅRSTØ	1,049,019	4,766	**1,053,785**
MELKØYA	897,690		**897,690**
SLEIPNER	833,527		**833,527**
Mongstad - Kraftvarmeverket	606,209	210,897	**817,106**
Oseberg feltsenter	744,972		**744,972**
ÅSGARD B	716,617		**716,617**
KALUNDBORG	518,678	102,421	**621,099**
GULLFAKS A	471,987		**471,987**
HEIDRUN	394,343		**394,343**
ÅSGARD A	347,539		**347,539**
TJELDBERGODDEN	345,576	471	**346,047**
Troll C	336,883		**336,883**
NORNE	282,587		**282,587**
SNORRE A	279,780		**279,780**
Troll B	274,739		**274,739**
CPF	268,292		**268,292**
STATFJORD B	261,563		**261,563**
Peregrino FPSO	256,409		**256,409**
GULLFAKS C	236,620		**236,620**

Another source of data for the Norwegian oil sector is the Norwegian UNFCCC report. Data are provided both for oil and gas regarding all major lifecycle stages excluding the combustion stage. These data are presented at country level and have been developed based on the methodology of UNFCCC. Emissions reported to UNFCCC will be compared with national statistics in order to assess their consistency. Table 3-24 presents these data for the Norwegian oil and gas sectors.

Table 3-24 Emissions data for Norway for oil and natural gas

GREENHOUSE GAS SOURCE AND SINK CATEGORIES	ACTIVITY DATA			IMPLIED EMISSION FACTORS			EMISSIONS	
	Description	Unit	Value	CO_2	CH_4 N_2O		CO_2	CH_4
				(kg/unit)			(Gg)	
1. B. 2. a. Oil							1,252A136	8A893
i. Exploration	*number of wells drilled*	kg	NE	IE	IE	NO	IE	IE
ii. Production	*oil produced*	10^3m^3	111,523	IE	IE		IE	IE
iii. Transport	*oil loaded in tankers*	PJ	3,959.922	21,350.109	1,674.20		84.545	6.630
iv. Refining / Storage	*Oil refined*	PJ	551.619	2.093	4.104	N.	1,154.670	2.264
v. Distribution of Oil Products	*Petrol sold*	PJ	45.353	284,906.605	N.		12.921	N.
1. B. 2. b. Natural Gas							13.512	1.842
i. Exploration	*specify*		NE	IE	IE		IE	IE
ii. Production / Processing	*gas produced*	10^6 m^3	114,727.0	IE	IE		IE	IE
iii. Transmission	*gas consumed*		NE	IE	IE		IE	IE
iv. Distribution	*gas consumed*		NE	IE	NE		IE	0.030
v. Other Leakage	*(specify)*		NE	NE	NE		13.512	1.812
at industrial plants and power stations	*specify*		NE	NE	NE		13.512	1.812
in residential and commercial sectors	*specify*	km	N.	NO	NO		NO	NO
1. B. 2. c. Venting							119.833	14.676
i. Oil	*(e.g. PJ oil produced)*		IE	IE	IE		IE	IE
ii. Gas	*(e.g. PJ gas produced)*		IE	IE	IE		IE	IE
iii. Combined	*Oil and gas produced*	PJ	7,967.106	15,041.019	1,842.12		119.833	14.676
Flaring							1,359.733	0.726
i. Oil	*Oil flared*	PJ	0.461	75,650,118	9,456.26	709.22	34.853	0.004
ii. Gas	*Gas flared*	PJ	18.178	72,883,963	39,686.4	559.16	1,324.881	0.721

NE (Not Estimated): For existing emissions and removals which have not been estimated
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category
NO (Not Occurring): For emissions and removals of GHG that do not occur for a particular gas or source/sink category

3.6.4 United Kingdom

Country data

Actual emissions data on a national level for the oil and gas activities of the United Kingdom have been collected by the National Atmospheric Emission Inventory that has been developed by the Department of Environment, Food and Rural Affairs (DEFRA). Such data are presented in Figure 3-55. As it can be obtained from the Figure, the most significant emission source is flaring, which accounted for approximately 85% of total emissions of the UK oil sector in 2012, followed by venting which accounted for 7% of total emissions in 2012.

Another major source of actual emissions data for the UK has been the country's report under the UNFCCC, which is presented in Table 3-25. As discussed for Russia and Norway, UNFCCC is a useful source of information, since each country is obliged to submit data periodically in a consistent and reliable manner. However, the same limitations apply, including the difficulty to use data that are presented on an aggregated level. Generally the UNFCCC data are anticipated to be more useful for the assessment of natural gas GHG emissions via the GHGenius model and also for verification and comparison with other data sources at aggregated level.

The Department of Energy and Climate Change (DECC) also publishes flaring volumes per oil field. Table 3-26 illustrates the 20 oil fields with the largest flaring volumes in 2013. Flaring volumes are reported for Buzzard, Ninian and Captain, which are the three representative fields for UK crudes in the context of this study.

Apart from data presented on a national basis, actual emissions data for specific oil fields are also available by specific companies, which operate specific oil and gas fields, through their environmental reports. NEXEN petroleum in its Environmental Statement for 2012 publishes data for 3 key oil and gas fields that operates i.e. Buzzard, Ettrick and Scott, as it is presented in Figure 3-56. According to the company's report, the main combustion GHG emission from these sources is carbon dioxide (CO_2), along with smaller emissions of oxides of nitrogen, nitrous oxide, sulphur dioxide, carbon monoxide, methane and volatile organic compounds. The largest portion of carbon dioxide emissions offshore comes from combustion of fuels for energy production on-board the installations.

Figure 3-55 Breakdown of emissions of the UK oil sector by source (in million metric tons) (source: DEFRA)

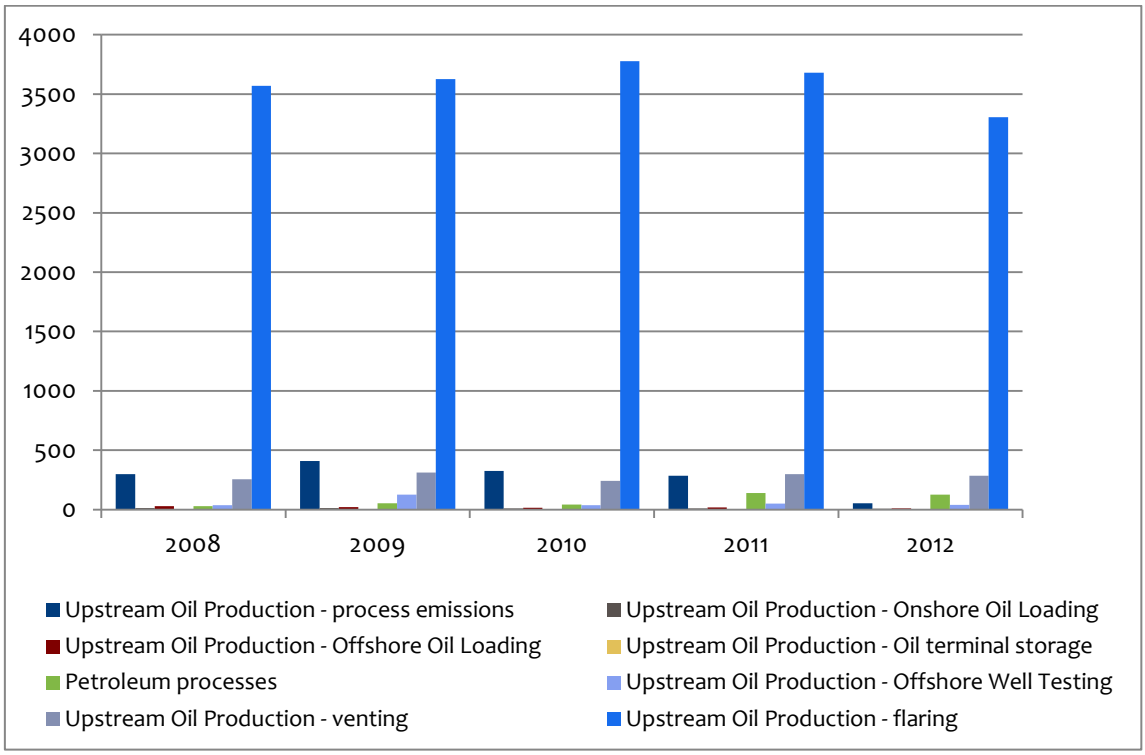


Figure 3-56 Total atmospheric CO_2 emissions and emissions due to consumption of fuel gas for energy production (in tons CO_2 equivalent) for three oil fields (source: NEXEN)

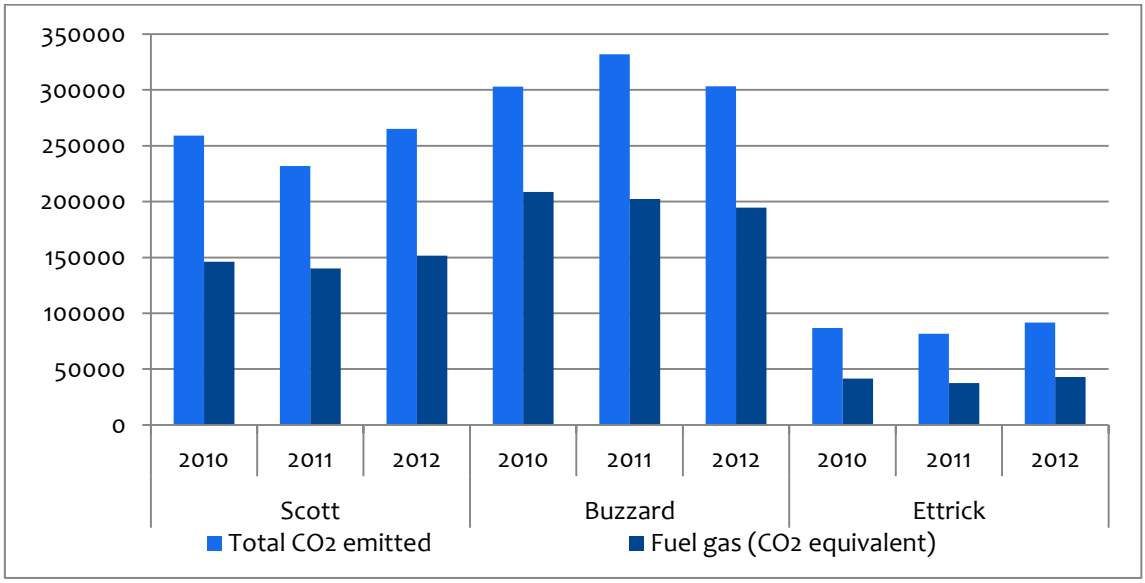


Table 3-25 UNFCCC Emissions data for United Kingdom for oil and natural gas

GREENHOUSE GAS SOURCE AND	ACTIVITY DATA			IMPLIED EMISSION FACTORS		EMISSIONS	
SINK CATEGORIES	Description	Unit	Value	CO_2	CH_4	CO_2	CH_4
				(kg/unit)		(Gg)	
1. B. 2. a. Oil						35.43	9.66
i. Exploration	*Well testing fuel use*	t	11,003.84	3,200.00	25.00	35.21	0.28
ii. Production	*Oil produced (net)*	PJ	1,941.49	110.84	1,320.70	0.22	2.56
iii. Transport	*Offshore loading of oil only*	t	7,704,447.21	NO	60.55	NO	0.47
iv. Refining / Storage	*Oil refinery throughput (net)*	PJ	2,989.07	NO	2,013.11	NO	6.02
v. Distribution of Oil Products	*(e.g. PJ oil refined)*		NA	NO	NO	NO	NO
vi. Other	*Onshore loading of oil*	PJ	2,034.99	NO	166.63	NO	0.34
1. B. 2. b. Natural Gas						248.55	189.47
i. Exploration	*Well testing fuel use*	t	36,670.50	2,800.00	45.00	102.68	1.65
ii. Production / Processing	*Natural gas production (net)*	PJ	1,464.78	95,344.39	2,201.52	139.66	3.22
iii. Transmission	*Final gas consumption*	GWh	553,368.15	0.12	3.47	0.23	6.92
iv. Distribution	*Final gas consumption*	GWh	553,368.15	2,960.79	87,953.71	5.90	175.21
v. Other Leakage	*Total gas use*	TJ	1,597,035.52	0.05	1.54	0.08	2.46
at industrial plants and power stations	*Not applicable*	PJ	NO	NO	NO	NO	NO
in residential and commercial sectors	*Total gas use*	PJ	1,597.04	0.05	1.54	0.08	2.46
1. B. 2. c. Venting						9.13	35.89
i. Oil	*None*		NA	NA	NA	8.54	13.15
ii. Gas	*None*		NA	NA	NA	0.58	22.73
iii. Combined	*None*		IE	IE	IE	IE	IE
Flaring						3,257.35	13.34
i. Oil	*Mass of gas flared*	t	1,155,734.92	2,604.16	10.63	3,009.72	12.28
ii. Gas	*Mass of gas flared*	t	107,241.69	2,309.02	9.86	247.62	1.06
iii. Combined	*Mass of gas flared*	Mg	IE	IE	IE	IE	IE

NE (Not Estimated): For existing emissions and removals which have not been estimated
IE (Included Elsewhere): For emissions or removals estimated but included elsewhere in the inventory instead of the expected category
NO (Not Occurring): For emissions and removals of GHG that do not occur for a particular gas or source/sink category
NA (Not Applicable): For activities in a given source/sink category that do not result in emissions or removals of a specific gas

Table 3-26 The twenty oil fields with the largest flaring volumes per day in UK for 2013 (source: DECC)

Producing Oil Fields	Average Flare million m^3 per day	Average Flare million ft^3 per day
CHESTNUT	0.12	4.32
BRENT	0.12	4.15
FOINAVEN	0.09	3.11
NINIAN	0.09	3.03
BRAE SOUTH	0.08	2.97
BUZZARD	0.08	2.72
THISTLE	0.07	2.58
ALBA	0.07	2.42
FORTIES	0.07	2.39
CAPTAIN	0.06	2.18
BLAKE	0.05	1.79
ORION	0.05	1.70
BERYL	0.05	1.62
CLAIR	0.04	1.55
BALLOCH	0.04	1.49
BRUCE	0.04	1.48
AFFLECK	0.04	1.45
STARLING	0.04	1.39
LENNOX	0.04	1.39
MURCHISON	0.04	1.37

3.6.5 Nigeria

In general, no actual data have been found for Nigeria apart from flaring which is one of the most significant emission sources of the Nigerian oil sector. According to the National Oceanic and Atmospheric Administration (NOAA), Nigeria flared slightly more than 515 Bcf of natural gas in 2011 - or more than 21% of gross natural gas production in 2011. Natural gas flared in Nigeria accounts for approximately 10% of the total amount flared globally. The amount of gas flared in Nigeria has decreased in recent years, from 575 Bcf in 2007 to 515 Bcf in 2011.

According to Shell, one of the largest gas producers in the country, the impediments to decreasing gas flaring has been the security situation in Niger Delta and the lack of partner funding that has slowed progress on projects to capture associated gas. The company recently reported that it was able to reduce the amount of gas it flared in 2012 because of improved security in some Niger Delta areas and stable co-funding from partners that allowed the installation of new gas-gathering facilities and repair of existing facilities damaged during the militant crisis of 2006 to 2009. Table 3-27 illustrates the 20 Nigerian fields with the largest flaring volumes, according to NNPC. It is obvious that the percentage

of gas flared varies significantly per field and company, making it difficult to draw uniform conclusions.

Table 3-27 Twenty Nigerian fields with the largest flaring volumes

Field	Company	Gas produced (in mscf)	Gas utilized (in mscf)	Gas flared (in mscf)	Percentage of gas flared (in mscf)
UTOROGU/UGHELI	NPDC	27,569,340	0	27,569,340	100%
UTOROGU/UGHELI	ND WESTERN	22,556,733	0	22,556,733	100%
IDU FIELDS	NAOC	36,747,486	25,197,140	11,550,346	31%
OFON	Total E&P	11,499,725,25	369,991	11,129,734	97%
KWALE FIELDS	NAOC	32,221,463	21,351,330	10,870,133	34%
OKONO/OKPOHO	NPDC	11,009,360	563,254	10,446,106	95%
AMENAM/KPONO	Total E&P	108,950,287,53	98,541,400	10,408,888	10%
AKRI FIELDS	NAOC	12,754,634	2,796,994	9,957,640	78%
ERHA	ESSO	112,226,569	102,889,639	9,336,930	8%
OBR/OBI FIELDS	NAOC	183,725,459	175,018,183	8,707,276	5%
USAN	TUPNI	14,874,000	6,539,000	8,335,000	56%
DELTA	Chevron	7,253,193	51,274	7,201,919	99%
MEREN	Chevron	15,115,125	8,093,216	7,021,909	46%
OSHI FIELDS	NAOC	18,830,177	11,903,725	6,926,452	37%
OBEN/SAPELE/AMUKPE	NPDC	6,819,131	0	6,819,131	100%
QIT	Mobil	8,638,294	1,980,359	6,657,935	77%
PARABE/EKO	Chevron	6,978,580	382,997	6,595,583	95%
OSO	Mobil	86,660,679	80,170,335	6,490,344	7%
AGBAMI	STARDEEP	93,068,067	86,700,089	6,367,978	7%
EDOP	Mobil	42,521,467	36,178,579	6,342,888	15%
EBOCHA FIELDS	NAOC	21,531,182	15,433,333	6,097,849	28%

3.6.6 Denmark

With regard to the climatic and environmental impact of the Danish oil and gas sector, the Danish Energy Agency (DEA) manages the atmospheric emissions of CO_2 from the combustion and flaring of natural gas and diesel oil, the effects of offshore oil and gas activities, the conditions in established international nature protection areas and the impact of oil and gas projects on the marine environment. Emissions, discharges and any marine spills are managed by the Ministry of the Environment, partly on the basis of regulations issued under the auspices of the international collaboration under the Oslo and Paris Convention (OSPAR). The Danish Subsoil Act regulates the volumes of gas flared, while CO_2 emissions (including flaring) are regulated by the Danish Act on CO_2 Allowances.

The evolution CO_2 emissions from the North Sea production facilities since 2003 are presented in Figure 3-57. It can be shown that CO_2 emissions totaled at about 1.695 million

tons in 2012, the lowest level in the past ten years, with both the quantity of fuel and gas flared being reduced. Gas used as a fuel accounted for approximately 90% of total gas consumption offshore in 2012, while the remaining 10% was flared. The development in the use of gas as fuel on Danish production installations is illustrated in Figure 3-58. The general increase until 2007 can be attributed to the rising oil and gas production and ageing fields. The main reason for the sharp drop from 2008 onwards is energy-efficiency measures taken by the operators, as reported by DEA.

Figure 3-57 CO2 emissions from production facilities in the North Sea (source: DEA)

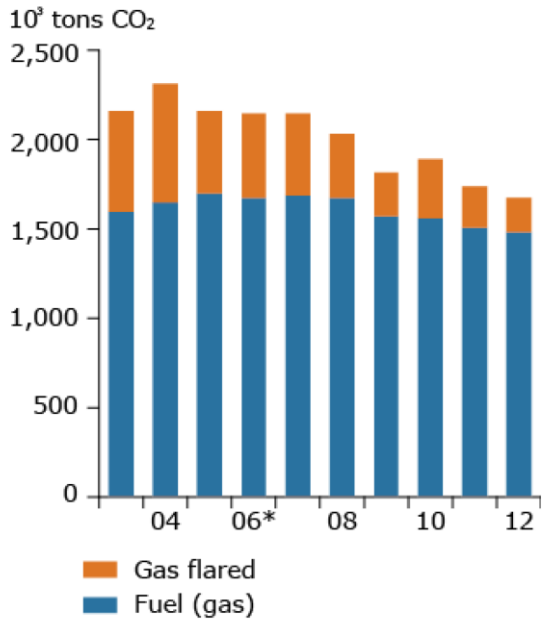
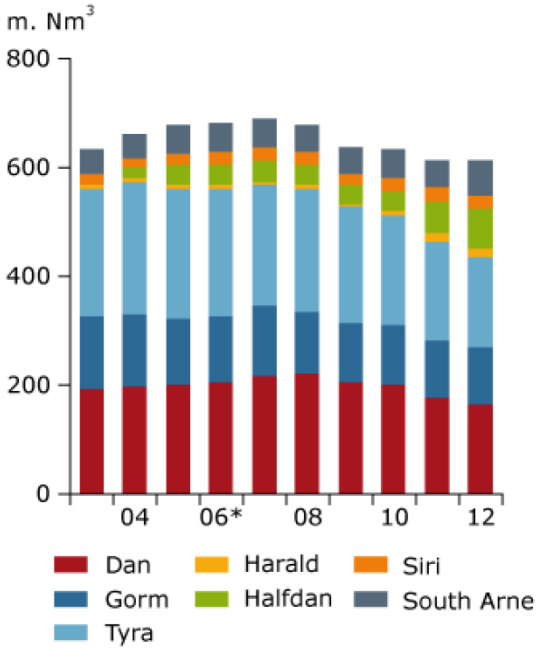


Figure 3-58 Fuel consumption (gas) for upstream activities (source: DEA)



CO_2 emissions due to fuel consumption have increased relative to the size of hydrocarbon production over the past decade, as illustrated in Figure 3-59.The reason for this increase is that oil and gas production has dropped more sharply than fuel consumption; this means that CO_2 emissions due to fuel consumption have increased relatively to the size of production.

The flaring of gas declined substantially from 2006 to 2012 in all fields with the exception of the Harald Field where flaring has remained unchanged. This development is attributable to more stable operating conditions on the installations, changes in operations and focus on energy efficiency. As appears from Figure 3-60, which shows the volumes of gas flared, flaring varies considerably from one year to another. The large fluctuation in 2004 is partially due to the tie-in of new fields and the commissioning of new facilities. In 2012, gas flaring totaled 71 million Nm^3.

Figure 3-59 CO2 emissions from consumption of fuel per mtoe (source: DEA)

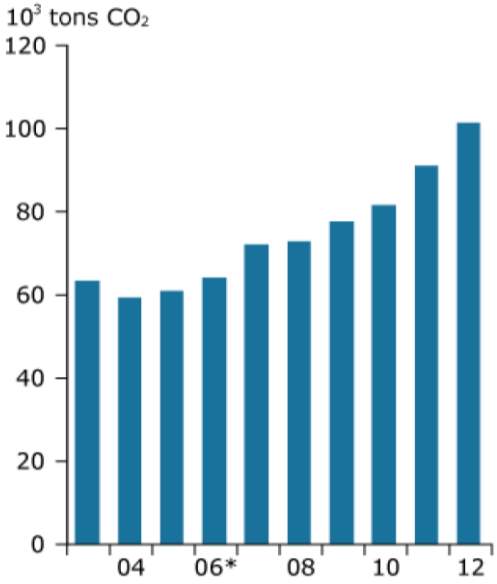
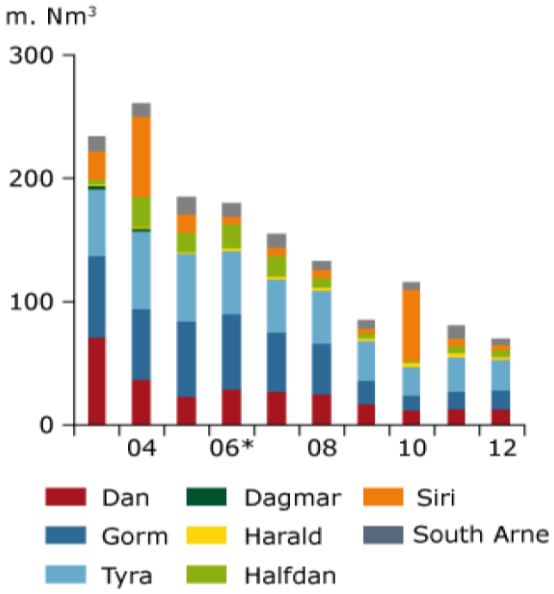


Figure 3-60 Gas flared (source: DEA)



3.6.7 Angola

BP in its 2012 Sustainability Report published actual data regarding the emissions from its activities of oil extraction activities in Angola. These data are illustrated in Table 3-28, where it is observed that the company's total emissions have decreased by approximately 10% in 2012 compared to 2011. Similarly, flared gas quantities have decreased slightly in 2012.

Table 3-28 Environmental data by BP's activities in Angola for the years 2006-2012 (source: BP)

Environment	2006	2007	2008	2009	2010	2011	2012
Total hydrocarbons produced (million barrels oil equivalent per day)	133	140	202	211	170	123	149
Equity share direct carbon CO_2 (tons)	484,666	940,541	1,208,764	1,162,490	1,055,204	1,006,583	898,618
Equity share indirect CO_2 (tons)	0	0	0	0	0	0	0
Equity share direct methane (CH_4) (tons)	1,643	4,160	2,644	2,502	2,444	2,079	3,220
Equity share direct GHG (tons CO_2 equivalent)	519,169	1,027,811	1,264,288	1,215,032	1,106,528	1,050,242	966,229
Total gas flared (tons)	1,987	148,882	200,221	138,093	227,851	323,693	308,095
Sulphur dioxide (SO_x) (tons)	108	232	206	259	98	298	559
Nitrogen oxides (NO_x) (tons)	1,587	5,800	2,923	1,849	928.4	1,060	3,828
Non-methane hydrocarbons (NMHC) (tons)	260	825	6,210	4,789	6,766	11,391	1,568

3.6.8 Carbon Disclosure Project (CDP) reports

CDP is an international, not-for-profit organization providing a global system for companies and cities to measure, disclose, manage and share vital environmental information. The CDP reported emissions are organized per company into 3 Scopes for the emissions for oil and natural. Scope 1 emissions include the total global direct emissions from sources owned or controlled by the reporting organization and more specifically:

- Stationary combustion: boilers, furnaces, engines, etc.;
- Mobile combustion: automobiles, planes, ships, trains, etc.;
- Process emissions: cement manufacturing, aluminium smelting, gas and oil production, refining, etc.;
- Fugitive emissions: equipment leaks, hydrofluorocarbon emissions from refrigeration, etc.

Scope 2 emissions include indirect GHG emissions that the company has caused through its consumption of energy in the form of electricity, heat, cooling or steam. Scope 3 emissions include indirect emissions that arise as a consequence of an organization's activities from sources that are owned or controlled by others.

It must be noted that the distinction between Scope 1, 2 and 3 emissions does not align with the definition of direct and indirect emissions set in the context of this study. Thus, Scope 1 and 2 emissions of CDP correspond to the direct emissions as those have been defined in this study. Table 3-29 provides the Scope 1 and Scope 2 emissions (sum) for four companies. It can be seen that EXXON and CHEVRON have the largest emissions. It can also be observed that large part of the companies' emissions comes from refining activities. However, the reporting methodology of companies to CDP has not been studied or evaluated.

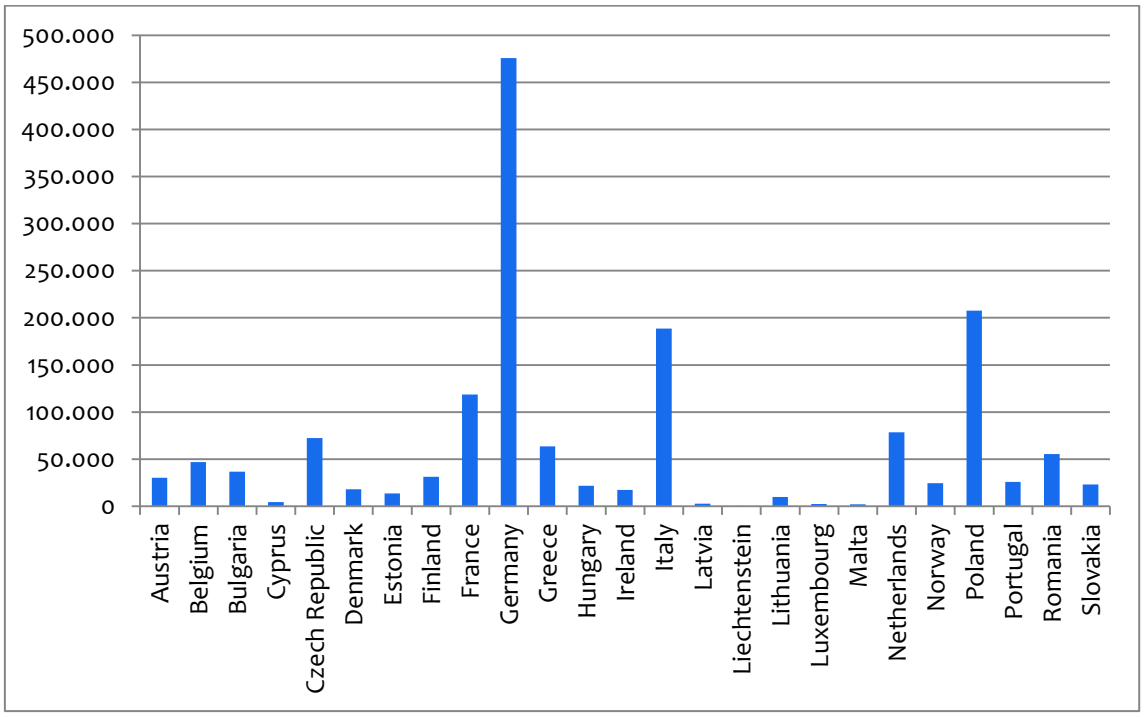
Table 3-29 Scope 1 and Scope 2 reported values for oil and gas emissions for specific companies (source: CDP)

Company	Segment	2008	2009	2010	2011	2012
CHEVRON	Exploration, production & gas processing	0	0	42,482,952	41,785,072	39,593,574
	Refining	0	0	22,978,452	23,328,912	21,553,218
	Speciality operations	0	0	1,158,459	789,899	1,261,745
	Total	**0**	**0**	**66,619,863**	**65,903,883**	**62,408,537**
EXXON	Exploration, production & gas processing	62,000,000	60,000,000	63,000,000	68,000,000	68,000,000
	Refining	59,000,000	58,000,000	60,000,000	59,000,000	55,000,000
	Total	**121,000,000**	**118,000,000**	**123,000,000**	**127,000,000**	**123,000,000**
REPSOL	Exploration, production & gas processing	0	0	23,566	21,288	27,522
	Storage, transportation & distribution	0	0	46,562	57,168	45,264
	Speciality operations	0	0	1,233,028	404,448	327,788
	Refining	0	0	505,224	558,076	1,115,982
	Retail & marketing	0	0	134,752	91,886	105,930
	Total	**0**	**0**	**1,943,132**	**1,132,866**	**1,622,486**
STATOIL	Exploration, production & gas processing	13,059,999	11,524,551	11,629,031	11,649,562	0
	Storage, transportation & distribution	118,924	106,470	75,661	89,178	0
	Refining	2,101,460	2,346,222	2,877,636	3,094,512	0
	Total	**15,280,383**	**13,977,243**	**14,582,328**	**14,833,252**	**0**

3.6.9 Refining

Actual data for the emissions of the European refining sector[11] for 2012 are illustrated in Figure 3-61 These data are verified emissions of the European Trading Scheme (ETS) and therefore fully reliable. It can be seen that the largest refining emissions take place in Germany, Poland and Italy. These figures can be used for comparisons with the outputs of PRIMES-Refineries, once these have been produced.

Figure 3-61 Emissions of the refinery sector per country for 2012 in kt CO2 equivalent as verified by the European Trading Scheme – ETS (source: EEA)



3.6.10 Unconventional crude oil

Two unconventional crudes have been considered as representative for the study of GHG emissions from unconventional crudes: Syncrude synthetic crude as representative of Alberta oil sands and Petrozuata as representative of Venezuela bitumen fields. The rationale for choosing the specific two crudes is the fact that these areas have the largest unconventional oil reserves globally.

Actual emissions data for all unconventional crude oil extraction facilities in Canada are maintained by the Canadian Greenhouse Gas Emissions Reporting Program (GHGRP)[12] which applies to the largest industrial GHG emitters in Canada. More specifically, all facilities that emit the equivalent of 50,000 tons (50 kilotons) or more of GHGs in carbon dioxide equivalent units (CO_2 eq.) per year are required to submit a report. Table 3-30 illustrates the

[11] http://www.eea.europa.eu/data-and-maps/data/data-viewers/emissions-trading-viewer
[12] http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8044859A-1

emissions of all unconventional oil extraction facilities in Alberta per facility for 2012. The methodology used for the assessment of emissions is based on a combination of monitoring or direct measurements, mass balances, emission factors or engineering estimates. Nonetheless, it should be noted that the reported figures cover solely the emissions of each facility. This implies that the system boundaries include only the processes that take place within the specific facility (e.g. upgrading).

Table 3-30 Total GHG emissions per unconventional extraction facility in Alberta for 2012 (source: Canadian Greenhouse Gas Emissions Reporting Program)

Facility Name	Reporting Company Legal Name	Total Emissions (tons CO_2eq.)
Mildred Lake and Aurora North Plant Sites	Syncrude Canada Ltd.	12,530,676
Cold Lake	Imperial Oil Resources	4,398,536
Long Lake Project	Nexen Inc.	3,614,080
Wolf Lake and Primrose Plant	Canadian Natural Resources Limited	3,527,252
Shell Albian Sands Jackpine Mine	Shell Canada Energy	1,044,304
Shell Albian Sands Muskeg River Mine	Shell Canada Energy	676,317
Jackfish 1 SAGD Plant	Devon Canada Corporation	653,803
Tucker Thermal	Husky Oil Operations Limited	584,081
Surmont SAGD Commercial Battery	ConocoPhillips Canada Resources Corp.	518,199
Jackfish 2 SAGD Plant	Devon Canada Corporation	491,597
Peace River Complex 5-21	Shell Canada Limited	269,246
Algar	Connacher Oil and Gas Limited	247,330
Pod One	Connacher Oil and Gas Limited	227,893
Orion Complex	Shell Canada Limited	150,967
MacKay River Commercial Project	MacKay Operating Corp	1,464

According to the data submitted to GHGRP, the upstream GHG emissions of Syncrude from Mildred Lake and Aurora North Plant Sites for 2012 based on emission factors and engineering estimates, have been estimated at **20.82 grCO_2eq/MJ.**

Apart from the GHGRP, most oil companies active in unconventional oil extraction publish GHG emissions data in their annual environmental/sustainability reports in response the escalating interest by public and environmental authorities, organizations and the scientific community. Shell Canada publishes annually a performance report specifically for oil sands.

GHG emissions from Shell's oil sands in Muskeg River, Jackpine mine, Scotford upgrader and in situ operations are presented in Table 3-31. According to Shell's data the average emissions for Muskeg River Mine and Scotford upgrader were 82.2 kg CO_2eq/bbl equivalent to 15.3 gr/MJ. This value is significantly lower compared to CARB's estimates for Albian Heavy Synthetic with a CI of 21.02 grCO_2eq/MJ, even though the system boundaries are not clearly described in the report.

Table 3-31 GHG emissions for Muskeg River and Jackpine Mine for the period 2008-2012 (source: Shell Canada)

GHG emissions (Oil Sands Operations - Muskeg River Mine, Jackpine Mine, Scotford Upgrader and In Situ)	2008	2009	2010	2011	2012
Total direct emissions (Mt CO2eq)	3.2	3.2	3.7	4.9	5.3
Total indirect emissions (Mt CO2eq)	1.6	1.5	1.3	1.9	1.7
Total emissions (M CO2eq)	4.8	4.7	5.0	6.7	7.0
Total CO2eq intensity (kg CO2eq/bbl)	84.0	82.8	88.5	86.2	82.2
Total CO2eq intensity (kg CO2eq/bbl) - Excluding Construction emissions				80.0	82.2
Total CO2eq intensity including offsets (kg/bbl)	82.1	74.5	45.2	53.5	56.4
Total CO2eq intensity including offsets (kg/bbl) - Excluding construction emissions				50.0	56.4
Total direct emissions (Mt CO2eq) - In Situ	1.1	1.0	0.9	0.6	0.6
Total Indirect emissions (Mt CO2eq) - In Situ	0.2	0.1	0.1	0.2	0.2
Total direct emissions (Mt CO2eq) - Scotford Upgrader	1.8	1.9	1.8	2.9	3.0
Total Indirect emissions (Mt CO2eq) - Scotford Upgrader	0.1	0.1	0.0	0.4	0.4
Total direct emissions (Mt CO2eq) - Jockpine and Muskeg River Mines	0.6	0.8	1.0	1.4	1.7
Total Indirect emissions (Mt CO2eq) - Jackpine and Muskeg River Mines	1.0	1.0	1.1	1.3	1.2

Another major company active in unconventional oil extraction, Suncor, that produces the crude oil with the same marketable name publishes in its sustainability report[13] its GHG intensity. Suncor's actual GHG emissions for the period 1990 – 2013 are presented in Table 3-32, while the company's GHG intensity for the same period is illustrated in Table 3-33.

[13] http://suncor360.nonfiction.ca/2014/ros-en/files/extfiles/downloadURL.PDF

Table 3-32 Suncor's actual GHG emissions for the period 1990 – 2013 (source: Suncor)

Actual and estimated tons CO2e/cubic metres of oil equivalent (m3 OE)	1990	2000	2008	2009	2010	2011	2012	2013
Oil Sands	1,196	0,817	0,667	0,569	0,587	0,510	0,561	**0,503**
Fort Hills	–	–	–	–	–	–	–	**–**
In Situ	–	–	0,474	0,458	0,455	0,502	0,535	**0,540**
Exploration & Production			0,137	0,163	0,174	0,170	0,157	**0,154**
Refining & Marketing	0,225	0,193	0,214	0,222	0,208	0,202	0,199	**0,200**
Renewable Energy	–	–	0,784	0,788	0,712	0,684	0,662	**0,668**

According to company data, the CI for its in-situ activities which largely reflects the emissions of Suncor is estimated at 0.54 tons of CO_2eq/m^3 of equivalent oil. This figure equals to 14.0 $grCO_2eq/MJ$ and regards direct and indirect emissions of upstream activities.

Table 3-33 Suncor's GHG intensity (source: Suncror)

Actual and estimated tons CO2e/cubic metres of oil equivalent (m3 OE)	1990	2000	2008	2009	2010	2011	2012	2013
Oil Sands	1,196	0,817	0,667	0,569	0,587	0,510	0,561	**0,503**
Fort Hills	–	–	–	–	–	–	–	**–**
In Situ	–	–	0,474	0,458	0,455	0,502	0,535	**0,540**
Exploration & Production			0,137	0,163	0,174	0,170	0,157	**0,154**
Refining & Marketing	0,225	0,193	0,214	0,222	0,208	0,202	0,199	**0,200**
Renewable Energy	–	–	0,784	0,788	0,712	0,684	0,662	**0,668**

Actual data based on reported and verified emissions for Petrozuata are not publicly available – contrary to Alberta's unconventional crudes as there are no obligatory regulatory provisions in Venezuela. Therefore, the GHG emissions of Petrozuata bitumen have been modelled using OPGEE as a conventional heavy crude oil adding the emissions due to the upgrading process in line with CARB's methodology.

3.6.11 Overview and evaluation of actual data collection progress for oil

As it has been evident till present, the Consultant has reviewed a large number of resources for the collection of actual emissions data. Ideally, information should have been found on an MCON or oil field basis. However, given the reluctance of oil and gas companies to provide actual data, often data have been found **on a country basis** with few exceptions. Unfortunately, cumulative emissions data found on a country basis cannot be directly used for the purpose of comparisons without further analysis (apart from cross-country comparisons) but given the scarcity of information, these country level data are extremely valuable. There are also cases where actual emissions data are found **per company** as published in sustainability and environmental reports, which usually refer to company's entire activities or the data are poorly broken down. This type of information can be used for comparisons of the carbon intensity of specific lifecycle stages (e.g. production of oil) between companies.

Following the identification of actual data sources, the Consultant has classified the information collected by **lifecycle stage both on a country and MCON level** i.e. production, venting flaring fugitive, transport, refining and distribution, as illustrated in Table 3-34. The purpose of this systematization is to identify the MCONs for which no actual data have been found and inevitably its GHG emissions will have to be assessed using the OPGEE model.

As a general conclusion, significant actual information on **a country level** has been found for Norway, Denmark and United Kingdom for most lifecycle stages. Partial information for flaring has been found for Russia and FSU countries. Lastly few data have been found for Nigeria regarding only flaring emissions and Angola.

The collection of **field specific data** has been a more difficult Task, because when oil companies have no legal obligation to report them officially they have no actual incentive. Actual GHG emissions data have been found for Norwegian representative fields. For representative fields located in the UK i.e. Buzzard, Captain and Forties, flaring emissions have been found, as well as total emissions for the Buzzard oil field. Surprisingly, significant data have been found for total emissions and flaring for the ACG field in Azerbaijan. Flaring volumes are also available for all Nigerian fields, as well as production and flaring emissions for key Danish fields comprising the DUC MCON.

Table 3-34 Sources of measured and reported emissions data organized per process country and MCON

Country	Actual emissions data sources												
	Country level data						Representative MCON	MCON (or field) specific data					
	Production	VFF	Transport	Refining	Distribution	Total		Production	VFF	Transport	Refining	Distribution	Total
Iran							Iranian Heavy						
Iraq							Basrah Light						
							Kirkuk						
Kuwait							Kuwait Blend						
Saudi Arabia							Arab Light						
							Arab Heavy						
Algeria							Saharan Blend						
Angola	BP	BP				BP	Dalia						
							Girassol						
							Greater Plutonio						
Libya							Es Sider						
							El Sharara						
Nigeria		NNPC					Bonga		NNPC				
							Forcados		NNPC				
							Bonny light		NNPC				
							Escravos		NNPC				
Azerbaijan		EBRD, BP				BP	Azeri light	BP	BP				BP
							Azeri BTC	BP	BP				BP
Kazakhstan		EBRD, BP				BP	Tengiz	BP	BP				BP
							CPC blend	BP	BP				BP
Russia		EBRD, KPMG, UNFCCC	UNFCCC		UNFCCC		Druzhba						
							Siberia Light						
							Urals						
Denmark	DEA	DEA	UNFCCC	EEA	UNFCCC		DUC	DEA		DEA			MAERSK OIL
Norway	NPD,	NPD,	UNFCCC	EEA,	UNFCCC	NPD	Statfjord						

Country	Actual emissions data sources												
	Country level data						Representative MCON	MCON (or field) specific data					
	Production	VFF	Transport	Refining	Distribution	Total		Production	VFF	Transport	Refining	Distribution	Total
	UNFCCC	UNFCCC		UNFCCC			Ekofisk						CDP/STATOIL
							Troll						CDP/STATOIL
							Asgard Blend						CDP/STATOIL
							Oseberg						CDP/STATOIL
							Gullfaks blend						CDP/STATOIL
UK	DEFRA, UNFCCC	DEFRA, UNFCCC	UNFCCC	DEFRA, EEA, DECC, UNFCCC	UNFCCC	DEFRA	Forties	NEXEN	DECC, NEXEN				NEXEN
							Brent Blend		DECC				
							Captain		DECC				
Mexico							Maya						
Venezuela							Boscan						

3.6.12 Data for OPGEE

According to the data collection strategy, in the absence of direct CI actual data the Consultant has used the OPGEE model for the assessment of GHG emissions for the upstream and midstream lifecycle stages. OPGEE is a complex engineering model that requires a large amount of data as inputs. The collection of such data has been a rather time consuming task since it requires research in a large amount of sources, as well as validation of their reliability. The effort and the resources that have been committed by the Consultant for the collection of OPGEE input data, which are actual data, have been based on the parametric analysis which is described in Section 4.1.3. For the missing inputs smart default values or Consultant's estimations have been used based on country averages and expert opinion.

The most significant source of information for filling in OPGEE inputs has been the **companies' websites.** Usually these included detailed data regarding partners and their share on specific oil fields, crude oil assays, API, sulphur content, field depth, commingling fields comprising an MCON, the terminal that oil is loaded etc. Furthermore, it can be assumed that these data are up-to-date and fully reliable. In addition, crude oil assays for MCONs are found published on company websites.

Another significant and fully reliable source of information has been **public databases of national authorities** and more specifically DECC for the UK, DEA for Denmark, NPD for Norway and NNPC for Nigeria. These include information regarding oil production volumes, gas production volumes, water production for all major fields in the relevant countries, field depth, gas injected water and other critical parameters for an oil field.

The **California Air Resources Board (CARB)** has published in its website the bulk assessment sheet of OPGEE for the crudes imported in California, which does not only provide technical information for a number of fields, but also methodologies for estimating inputs for OPGEE when no values are available. Apparently this approach is available for MCONs, which are imported in California; however several of these MCONs are also imported in Europe. Similarly, reservoir parameters for significant crude oils can be found in other studies (e.g. Jacobs).

The **NOAA/GGFR database** has been a typical source of flared natural gas volume (in bcm) used in several studies. Using the EIA crude oil production volumes the flaring to oil ratio (FOR) has been calculated on a country basis, which provides a sufficient approximation of the FOR compared to the generic values, when there are no field specific data. Actual flaring to oil ratio has been available only for Nigerian Oil fields, provided by NNPC. Another source of flaring and venting emissions has been the submitted **UNFCCC reports** of countries of Annex I (UK, Russia, Germany, Netherlands and Norway). The UNFCCC data include also reported data for exploration, production, transport, refining/storage and distribution of oil products on a country basis.

Private websites[14] dealing with offshore oil and gas engineering, construction projects and procurement have also been useful for data collection. These websites included detailed data for several oil fields as well as a better understanding of oil extraction and production techniques used specifically for each field.

Table 3-35 summarizes the main sources of OPGGE input parameters and the ease of finding the specific type of information. The last column of the Table indicates whether the Consultant has used own estimations based on background data in order to better approach the input, compared to OPGEE's default values.

[14] Offshore technology and Subsea IQ

Table 3-35 Overview of literature sources for OPGEE inputs

OPGEE input	Ease of finding information	Operator's Website	OGJ	NOAA	UNFCCC	Offshore tech.	Subsea IQ	DECC	NPD	NNPC	DEA	CARB	Own estimation
1. Production methods													
1.1 Downhole pump													√
1.2 Water reinjection								√			√		√
1.3 Gas reinjection										√			√
1.4 Water flooding													√
1.5 Gas lifting													√
1.6 Gas flooding													√
1.7 Steam flooding													√
2. Field properties													
2.1 Field location (Country)		√	√			√	√	√	√	√	√	√	
2.2 Field name		√	√			√	√	√	√	√	√	√	
2.3 Field age		√	√			√	√	√	√	√	√	√	
2.4 Field depth						√	√				√	√	
2.5 Oil production volume		√	√			√	√	√	√	√	√	√	
2.6 Number of producing wells						√	√				√	√	
2.7 Number of water injecting wells											√	√	
2.8 Well diameter													
2.9 Productivity index													
2.10 Reservoir pressure												√	
3. Properties													
3.1 API gravity		√				√	√			√			
3.2 Gas composition													
4. Production practices													
4.1 Gas-to-oil ratio (GOR)								√	√	√	√	√	√

OPGEE input	Ease of finding information	Operator's Website	OGJ	NOAA	UNFCCC	Offshore tech.	Subsea IQ	DECC	NPD	NNPC	DEA	CARB	Own estima-tion
4.2 Water-to-oil ratio (WOR)								√		√	√	√	
4.3 Water injection ratio											√		
4.4 Gas lifting injection ratio													
4.5 Gas flooding injection ratio													
4.6 Steam-to-oil ratio (SOR)													
4.7 Fraction of required electricity generated onsite													
4.8 Fraction of remaining gas re-injected													
4.9 Fraction of water produced water re-injected													
4.10 Fraction of steam generation via cogeneration													
5. Processing practices													
5.1 Heater/treater											√		
5.2 Stabilizer column													
5.3 Application of AGR unit													
5.4 Application of gas dehydration unit													
5.5 Application of demethanizer unit													
5.6 Flaring-to-oil ratio				√	√					√	√		√
5.7 Venting-to-oil ratio					√								
5.8 Volume fraction of diluent													

3.6.13 Data for PRIMES-Refinery

The key input data that are required for the PRIMES-Refinery model are the capacities of the refining processes within the refinery configuration per EU country and the various amounts of MCONs that enter European refineries. The Oil and Gas Journal Worldwide Refining Survey presents analytical data for the worldwide refineries and their capacities. A list of the refineries located in the EU countries is presented in Table 3-36. In particular, the survey provides information on the number of active refinery industries in Europe, the main operations as well as charge and production capacity for every single refinery. The various MCONs are aggregated and characterized by their API gravity and sulphur content. This part is particularly important for allocating the different MCONs entering the refinery gates of each EU country with the representative crude type categories simulated in the PRIMES-Refinery model.

Feedstock supply for the refineries operations, as well as consumption of electricity and gas are derived from the Eurostat energy balances. The total refined petroleum products that are produced at a national level over the EU countries is also provided by the Eurostat balances. The quantities of refined petroleum products imported in the EU are provided in the Section 3.1.2. The survey of Oil and Gas Journal and the study of Jacobs Consultancy will be used for the identification of the representative configuration of the refineries exporting refined products to EU. A more detailed presentation of the key input data to the PRIMES-Refinery model is included in Section 3.6.13.

Table 3-36 List of refineries located in the EU countries (Source: Oil and Gas Journal, 2013)

Country	Number of refineries	Company	Location
Austria	1	OMV AG	Schwechat
Belgium	4	AB Nynas Petroleum NV	Antwerp
		ExxonMobil Refining & Supply Co.	Antwerp
		Vitol Group	Antwerp
		Total SA	Antwerp
Bulgaria	1	Neftochim	Bourgas
Croatia	3	Ina-Industrija Nafte d.d.	Rijeka
		Ina-Industrija Nafte d.d.	Sisak
		Ina-Industrija Nafte d.d.	Zagreb
Czech Republic	3	Czech Refining Co.	Kralupy
		Czech Refining Co.	Litvinov
		Paramo AS	Pardubice
Denmark	2	AS Dansk Shell	Fredericia
		Dansk Statoil AS	Kalundborg
Finland	2	Neste Oil	Naantali

Country	Number of refineries	Company	Location
		Neste Oil	Porvoo
France	10	Calos	Dunkirk
		ExxonMobil Refining & Supply Co.	Fos sur Mer
		ExxonMobil Refining & Supply Co.	Port Jerome/NDG
		Petrolneos Refining Ltd.	Lavera
		LyondellBasell Industries	Berre l'Etang
		Total SA	Donges
		Total SA	Feyzin
		Total SA	Gonfreville l'Orcher
		Total SA	Grandpuits
		Total SA	La Mede
Germany	15	Bayernoil Raffineriegesellschaft GMBH	Vohburg/Ingolstadt/Neustadt
		BP PLC	Gelsenkirchen
		Hestya Energy BV	Wilhelmshaven
		Deutsche BP AG Erdol Raffinerie GMBH	Lingen
		Deutsche Shell AG	Rheinland
		Deutsche Shell AG	Harburg
		H&R Chemisch-Pharmazeutische Spezialitaeten GMBH	Salzbergen
		H&R Oelwerke Schindler GMBH	Hamburg
		Holborn Europa Raffinerie GMBH	Harburg
		Klesch & Co.	Heide
		Mineraloelraffinerie Oberrhein GMBH	Karlsruhe
		OMV AG	Burghausen
		PCK Raffinerie GMBH	Schwedt
		Gunvor Group Ltd.	Ingolstadt
		Total SA	Leuna, Spergau
Greece	4	Hellenic Petroleum SA	Aspropyrgos
		Hellenic Petroleum SA	Elefsis
		Hellenic Petroleum SA	Thessaloniki
		Motor Oil (Hellas) Corinth Refineries SA	Aghii Theodori
Hungary	1	MOL Hungarian Oil & Gas Co.	Szazhalombatta
Ireland	1	Phillips 66	Whitegate
Italy	15	Eni SPA	Gela, Ragusa
		Eni SPA	Livorno
		Eni SPA	Sannazzaro, Pavia

Country	Number of refineries	Company	Location
		Eni SPA	Taranto
		Api Raffineria di Ancona SPA	Falconara, Marittima
		Arcola Petrolifera SPA	La Spezia
		ERG Reffinerie Medditerranee North	Priolo, Sicily
		ERG Reffinerie Medditerranee South	Melilli, Sicily
		ExxonMobil Refining & Supply Co.	Augusta, Siracusa
		ExxonMobil Refining & Supply Co.	S. Martino Di Trecate
		Iplom SPA	Busalla
		Italiana Energia E Servizi SPA	Mantova
		Raffineria di Milazzo SPA	Milazzo, Messina
		Raffineria di Roma SPA	Rome
		Saras SPA	Sarroch
Lithuania	1	AB Mazeikiu Nafta	Mazeikiai
Netherlands	6	BP PLC	Rotterdam
		ExxonMobil Refining & Supply Co.	Rotterdam
		Kuwait Petroleum Europoort BV	Rotterdam
		Shell Nederland Raffinaderij BV	Pernis
		Smid & Hollander Raffinaderij BV	Amsterdam
		Total SA	Vlissingen
Poland	4	Grupa Lotos SA	Gdansk
		Nafta Polska SA	Gorlice
		Nafta Polska SA	Jaslo
		PKN Orlen SA	Plock/Trezebina
Portugal	2	Galp Energia	Leca da Palmeira, Porto
		Galp Energia	Sines
Romania	9	Astra SA	Ploiesti
		Petrobrazi SA	Ploiesti
		Petrolsub SA	Bacau
		Petromidia SA	Midia
		Petrotel SA	Ploiesti
		Rafinaria Darmanesti SA	Darmanesti
		Rafo SA	Onesti, Bacau
		Rompetrol SA Vega Refinery	Ploiesti
		Steaua Romania SA	Cimpina
Slovakia	1	Slovnaft Joint Stock Co.	Bratislava
Slovenia	1	Nafte Lendava	Lendava
Spain	9	BP PLC	Castellon de la Plana
		Cia. Espanola de Petroles SA	Cadiz

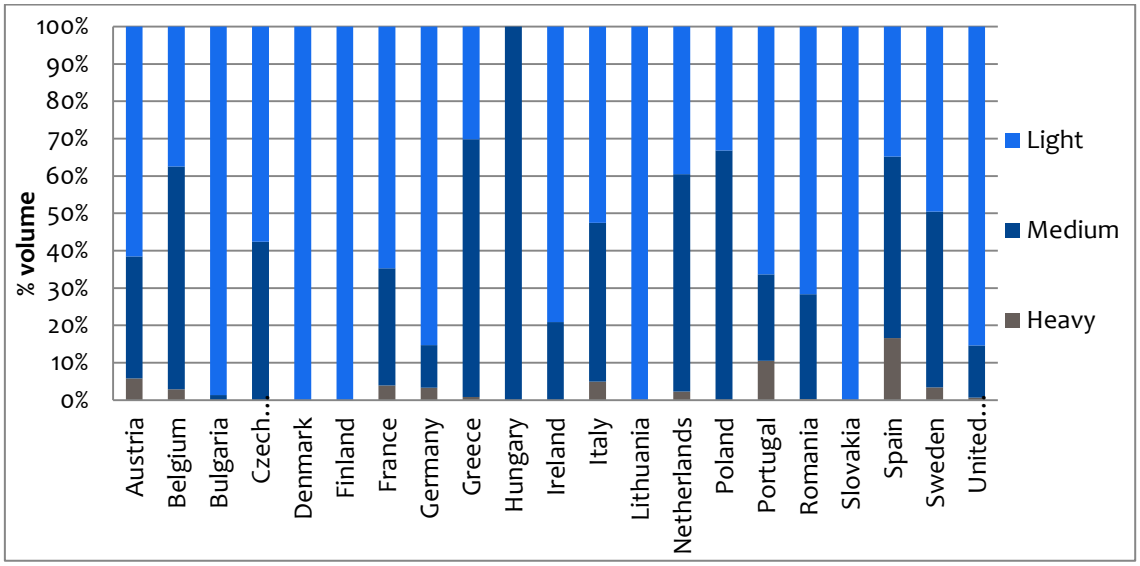
Country	Number of refineries	Company	Location
		Cia. Espanola de Petroles SA	Huelva
		Cia. Espanola de Petroles SA	Tenerife
		Petronor SA	Muskiz Vizcaya
		Repsol YPF SA	Cartagena Murcia
		Repsol YPF SA	La Coruna
		Repsol YPF SA	Puertollano, Ciudad Real
		Repsol YPF SA	Tarragona
Sweden	5	AB Nynas Petroleum	Gothenburg
		AB Nynas Petroleum	Nynashamn
		Preem Raffinaderi AB	Brofjorden-Lysekil
		Preem Raffinaderi AB	Gothenburg
		Shell Raffinaderi AB	Gothenburg
United Kingdom	9	AB Nynas Petroleum	Eastham
		Phillips 66	South Killingholme
		Essar UK Ltd.	Stanlow
		ExxonMobil Refining & Supply Co.	Fawley
		Total SA	Killingholme South Humberside
		AB Nynas Petroleum	Dundee
		Petrolneos Refining Ltd.	Grangemouth
		Murco Petroleum Ltd.	Milford Haven
		Valero Energy Corp.	Pembroke, Dyfed

Input of MCONs in the EU refineries

European refineries process various blends of many different crude oils and produce a given slate of products from the available crudes. The sources of crude oils show significant fluctuation and changes in the characteristics of crude oil inputs affecting the refining intensity and the products slates in European refineries.

For modelling purposes, the various MCONs have been classified into three categories according to their key characteristics. Figure 3-62 gives schematically the distribution of types of crude oils (heavy, medium, light) that are imported to Europe as shares of the total volume imported by EU MS after the disaggregation of MCONs by their characteristics. It is apparent from the figure that light and medium crudes account for the largest shares of the refinery intake.

Figure 3-62 Distribution of the three types of crude oils per EU country



Light crude type: average API 40.7 and S 0.51%
Medium crude type: average API 32.9 and S 1.27%
Heavy crude type: average API 22.3 and S 2.47%

In reality, refineries process mixtures of crude and adapt the operating conditions to optimize the production yields. Average blends of crude derived from the Figure 3-62 represent the crude mix refined in each country (Table 3-37). The properties of the crude mix refined in each country affect the level of processing by changes in the inputs and outputs of the processes and the severity levels of desulphurization units that require hydrogen consumption.

Processing capacity and product yield by EU MS in the PRIMES-Refinery Model

From the European Union, 22 countries feature refining capacities. Despite the fact that there is high diversity among the European refinery configurations and the product slates, the modelling approach aims to take into account the physical relationships between inputs and outputs of the various processes and adjust the existing charge capacities of the process units, as provided by the Oil and Gas Journal survey, into a single stylized refinery configuration for each country (Figure 3-62). The stylized refinery by country has been adapted to replicate an averaging of the actual refineries that exist today in the EU MS. This calibration process of the model also involves the production of a given product slate based on the actual inputs of the MCONS.

A range of possible configurations reflecting the operating refineries is shown in Table 3-38, where the capacities of the major process units are given as percentages of crude throughput. The refinery configurations reflect the level of complexity and the use of separation, upgrading and conversion processes. The processing capacity of a refinery is an indicator of the level of crude processing and reflects implicitly the refinery energy requirements.

Table 3-37 Overview of the average API and sulphur content of the MCONs at the refinery gate by EU MS

EU MS	Average API	Average S (%)wt)
Austria	35.6	0.8
Belgium	34.5	1.0
Bulgaria	38.5	0.3
Czech Republic	36.1	0.7
Denmark	38.6	0.3
Finland	38.6	0.3
France	36.0	0.7
Germany	37.3	0.5
Greece	34.3	1.0
Hungary	32.6	1.4
Ireland	37.4	0.5
Italy	35.2	0.9
Lithuania	38.6	0.3
Netherlands	34.7	1.0
Poland	34.6	1.0
Portugal	35.4	0.8
Romania	36.9	0.6
Slovakia	38.6	0.3
Spain	32.7	1.2
Sweden	35.2	0.9
United Kingdom	37.7	0.4

Table 3-38 Processing capacities as shares of crude distillation capacity (100%) by EU country

Country	Vacuum distillation	Coking	Visbreaking	Fluid Catalytic cracking	Catalytic reforming	Hydrocracking	Hydrotreating
Austria	36.0%	-	9.7%	13.7%	16.2%	4.7%	68.1%
Belgium	39.0%	-	7.4%	14.6%	14.2%	-	76.4%
Bulgaria	42.0%	-	16.4%	20.6%	15.0%	-	56.8%
Czech Rep.	43.0%	-	9.9%	3.6%	16.1%	18.5%	55.9%
Croatia	36.0%	2.2%	9.0%	18.0%	16.1%	4.3%	46.3%
Denmark	20.0%	-	16.0%	-	12.6%	3.0%	48.0%
Finland	48.0%	-	11.0%	15.5%	17.7%	19.2%	70.3%
France	41.0%	-	9.0%	20.6%	16.6%	4.5%	73.2%
Germany	45.0%	5.0%	10.8%	15.8%	17.8%	8.6%	77.5%

Country	Vacuum distillation	Coking	Visbreaking	Fluid Catalytic cracking	Catalytic reforming	Hydrocracking	Hydrotreating
Greece	36.0%	-	10.1%	14.4%	15.3%	9.7%	77.6%
Hungary	47.0%	9.9%	9.9%	15.5%	17.9%	-	72.5%
Ireland	-	-	-	-	15.5%	-	67.6%
Italy	35.0%	1.4%	10.5%	11.2%	12.6%	11.2%	57.1%
Lithuania	45.0%	-	16.7%	22.5%	24.6%	-	76.3%
Netherlands	49.0%	4.4%	10.8%	10.8%	13.4%	15.2%	66.7%
Poland	52.0%	-	-	8.9%	12.3%	30.7%	49.3%
Portugal	30.0%	-	8.7%	12.9%	15.8%	3.6%	68.2%
Romania	47.0%	8.9%	8.5%	20.2%	15.7%	-	57.5%
Slovakia	46.0%	-	-	13.4%	18.2%	30.4%	63.2%
Spain	34.0%	3.7%	8.8%	11.6%	14.4%	9.5%	65.8%
Sweden	32.0%	-	12.2%	6.8%	16.3%	10.6%	60.8%
UK	48.0%	5.8%	8.2%	25.0%	19.8%	3.4%	72.3%

All refinery configurations used in the model contain atmospheric (crude) distillation, hydrotreating and catalytic reforming processes. Atmospheric distillation is assumed to be the most emitting process as it is the predominant process in every refinery scheme and treats all the crude fed (100%) in the refinery. Hydrotreaters and reformers are key refining units met in the vast majority of refineries. Reforming is the main process for petrol production and a significant producer of hydrogen. Reforming capacity usually accounts for 10-20% of the total capacity. Hydrotreating units, which include naphtha, middle distillates and gas oil hydtrotreatment, pre-treat catalytic process feeds and upgrade the different streams with respect to products specifications. Hydrotreaters process the largest share of distillates and intermediates and have high relevant capacities.

Under reduced pressure vacuum distillation separates the atmospheric residue into more fractions and forwards the heavy gas oil to other processes in order to produce larger amounts of light products. Light and heavy vacuum gas oil is successively fed into Catalytic Cracking and/or Hydrocracking units that increase the ratio of light to heavy products. Fluid Catalytic cracking is combined with an Alkylation unit which produces high quality petrol (alkylate) and does not exceed 6-7% of total production (depending on the capacity of FCC).

Visbreaking is the most common process of thermal cracking of the heavier material of vacuum distillation and produces small amounts of petrol blendstocks and gas oil. Coking presents a more severe form of thermal cracking process and is more efficient in the production of light products; however, it requires more energy.

Hydrotreating and hydrocracking are hydrogen addition technologies and consume large amounts of hydrogen which is provided either by catalytic reforming or by a hydrogen

production unit for the residual hydrogen requirements – in the model we considered a steam methane reforming unit as the most widespread method at refining industry.

More stringent sulphur specifications for oil products (compatible with Euro-V), particularly diesel and petrol have stimulated European refiners to expand the capacities or the severity levels of upgrading units. The most common processes that achieve the quality control at a refinery are the various hydrotreatment (desulphurization) units for intermediate and final streams. Blending in petrol and gas oil pools plays also a significant role for the quality control of finished products as desulphurised and non-desulphurised fractions are appropriately mixed in blending pools to meet the requested specifications of the final products.

The fuels concerned in this study are produced from a sequence of different processing units. PRIMES-Refinery is based on the structure of Figure 3-63 to simulate the production flows within the refinery. Processing streams going through Catalytic reforming, Fluid catalytic cracking combined with alkylation unit and hydrocracking are mixed in the petrol pool for the final production of petrol. Diesel is mainly derived from diesel hydrotreating unit (with straight-run and intermediates from other units feeds), hydrocracking and Catalytic cracking. Kerosene mostly comes from the atmospheric distillation unit and the (low severity) kerosene hydrotreater.

Not all refining processing capacities are available for all countries; the latter depends on the actual configuration of the refineries which are different among the EU countries. According to the Table 3-38, sixteen countries feature hydrocracking units and eight countries use coking units.

The number of refineries in each country and the diversity among the configurations complicate the task of representing them by a single refinery. Austria, Bulgaria, Hungary, Lithuania and Ireland are countries with one refinery, while for the rest of the countries the capacities were aggregated in the representative refinery. Germany, Italy, United Kingdom, France, Spain and Netherlands are the countries with the highest available refining capacities while Bulgaria and Ireland have low crude distillation capacities. Most of the representative refineries are regarded as high or medium conversion refineries including the main processes of heavy fractions of crude (Fluid Catalytic Cracking, Hydrocracking, Thermal cracking) apart from Ireland which has a hydroskimming configuration (no further processing of the atmospheric residue).

Demand for petroleum products in EU

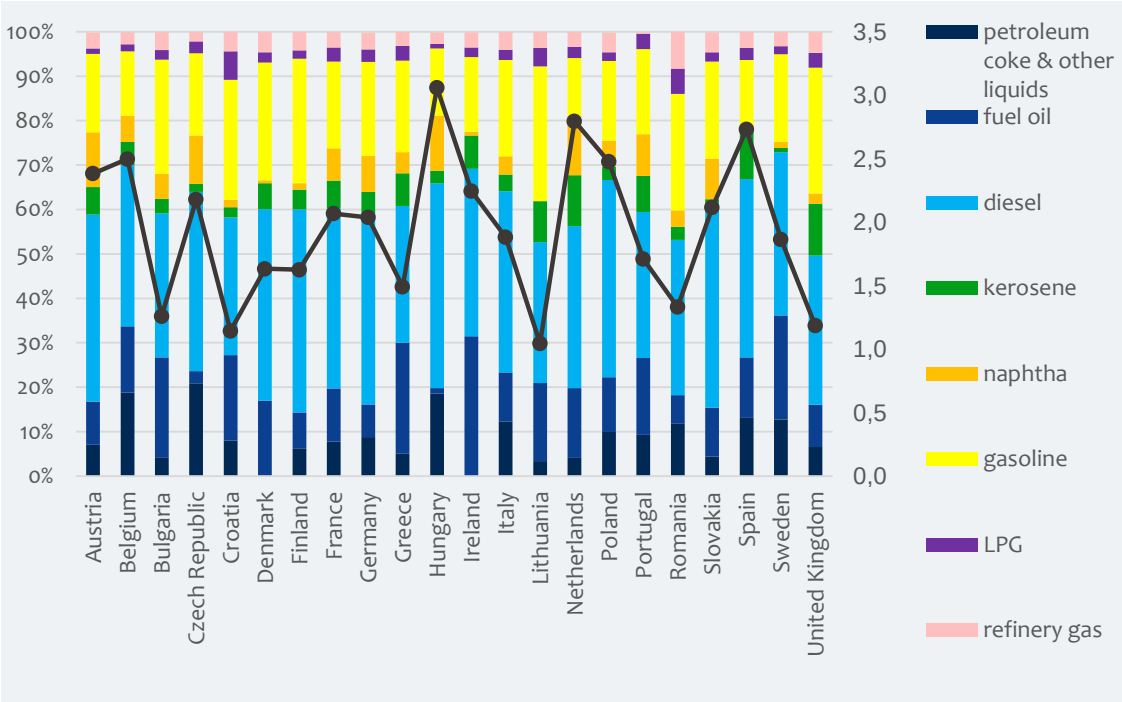
The petroleum products demand determines the product slates in refineries. The yield of finished products, i.e. LPG, petrol, naphtha, kerosene, diesel and heavier products, of a refinery is strongly correlated with the crude feed and the refining intensity.

A graphical presentation of the aggregated product yields of European refineries based on the databases of Eurostat alongside the diesel to petrol ratio ('D/P' line) is provided in Figure 3-63. These quantities have been used as input data for the demand-driven PRIMES-Refinery. Diesel and petrol are the two main refinery products with diesel production

ranging from 31 to 46% of total products while petrol's share is in general lower, ranging from 13 to 30%. The percentage of kerosene production is under 10% in most countries.

The diesel to petrol ratio varies from one country to another and ranges from 1 to 3. It is worth noting that countries with lower diesel to petrol ratio, hence higher production of petrol, such as United Kingdom, Romania, Croatia, Lithuania and Bulgaria have relatively high Fluid catalytic cracking capacity (over 17%).

Figure 3-63 Product yields (%) of European refineries



3.6.1 Estimating the GHG emissions due to transportation from refineries to filling stations

Methodology

The transportation of the refined petroleum products from the refineries to the filling stations in the EU Member States usually takes place via road freight, freight rail and inland waterways, which are currently operating mainly on fossil fuels. The use of fossil fuels is responsible for GHG emissions which take place during the transportation of the refined petroleum products and should be included in the lifecycle carbon emissions of diesel, petrol and kerosene. To calculate the carbon intensity $CI_{c,k}$ per transport mode k and country c used to transport the refined petroleum products Rpp we use the formula in Eq1. This formula is based on the activity of the transport mode, usually measured in ton-kilometers (tkm), the emission factor of the mode (in gCO2/tkm) and the total quantity of refined petroleum product transported (in MJ).

$$CI_{c,k} = \frac{Rpp\ transported_{c,k}(tkm) \times Emission\ factor_{c,k}(\frac{gCO_2}{tkm})}{quantity\ transported_{c,k}(MJ)}$$ Eq 1

To derive the average carbon intensity of the transportation of the refined petroleum products from the refinery to the filling stations, we calculate the weighted average based on the activity in tkm of each respective transport mode using the following formula (Eq2).

$$CI_c = \frac{\sum_k CI_{c,k} \times Rpp\ transported_{c,k}}{\sum_k Rpp\ transported_{c,k}}$$ Eq 2

Further, to account for the fugitive GHG emissions at the level of the filling stations, we have used typical emission factor from literature. As these emissions are relatively small compared to the LCA GHG emissions, for simplicity, we have assumed the same emission factor for the fugitive GHG emissions for all the EU countries. The most recent emission factor found in the technical report published by the National Environmental Research Institute has been utilized; the emission factor used is equal to 0.46 kg NMVOC/ ton petrol.

Input data

The required input for these calculations is the activity of each respective transport mode transporting refined petroleum products, the amount of products transported, and the emission factors per transport mode. The resolution of the data is at a national level.

Data on the activity of road freight, freight rail and inland waterways transporting refined petroleum products has been derived from Eurostat database. For road freight we have used the element "road_go_na_tgtt" which includes statistics on both the activity and the tons of refined petroleum products transported. As regards freight rail, Eurostat did not provide the activity and the tons of refined oil products transported at a national level. Therefore, we derived shares from the element "rail_go_natdist" which only reported data until 2002 and applied these shares to the total goods transported by rail at a national level in 2012 (element "rail_go_typeall"). Regarding inland waterways, we used the values on activity and the tons of refined petroleum products from the element "iww_go_atygo" from Eurostat. The emission factors per transport mode used in our calculations are drawn from the PRIMES-TREMOVE[15] transport model, developed and maintained by E3MLab. The values used have also been validated with the values reported in the TRACC[16]S database.

[15] http://www.e3mlab.ntua.gr/e3mlab/PRIMES%20Manual/The%20PRIMES-TREMOVE%20MODEL%202013-2014.pdf
[16] http://traccs.emisia.com/

Table 3-39 Estimated carbon intensity of refined petroleum products due to transportation from refineries to filling stations (also including fugitive emissions at the level of filling stations). Source: E3MLab calculations

Country	Carbon intensity ($grCO_2eq/MJ$)
Belgium	0.41
Bulgaria	0.37
Czech Republic	0.27
Denmark	0.63
Germany	0.24
Estonia	0.26
Ireland	0.77
Greece	0.41
Spain	0.47
France	0.45
Italy	0.60
Cyprus	0.65
Latvia	0.45
Lithuania	0.16
Luxembourg	0.81
Hungary	0.20
Netherlands	0.20
Austria	0.19
Poland	0.21
Portugal	0.40
Romania	0.50
Slovenia	0.23
Slovakia	0.13
Finland	0.37
Sweden	0.33
United Kingdom	0.59
Croatia	0.61
EU average	**0.38**

The resulting values of the carbon intensity due to the transportation of refined petroleum products from the refineries to the filling stations by EU country are presented in Table 3-42. According to our calculations we observe some variations in the resulting values which are attributed to the different shares of transport modes used to transport refined petroleum products to the filling stations and different emission factors per EU country. For the purposes of the present study the average value for the carbon intensity at the EU level is estimated to be about 0.38 $grCO_2eq/MJ$.

3.7 Actual data for natural gas

3.7.1 Regional Natural Gas Supply/Demand

Natural gas supply and demand data for each EU country have been extracted and elaborated from the IEA database for the year 2012. The model input is the quantities of gas supplied by each producer. The data are shown in Table 3-40.

Table 3-40 EU Gas Supply (million cm)

Consuming countries - EU28	Producing countries																
	Germany	Denmark	Netherlands	Poland	Hungary	Norway	Norway LNG	UK	Italy	Romania	Russia	Algeria pipeline	Algeria LNG	Libya	Nigeria LNG	Qatar LNG	Other	TOTAL
Bulgaria	0	0	0	0	0	0	0	0	0	0	2485	0	0	0	0	0	0	**2485**
Greece	0	0	0	0	0	0	0	0	0	0	2453	0	734	0	0	0	0	**3187**
Croatia	60	0	0	0	0	0	0	0	667	0	0	0	0	0	0	0	0	**727**
Italy	2904	0	2466	0	0	2726	0	0	7.877	0	18071	20843	1110	6469	0	5925	3850	**72241**
Romania	0	0	0	0	0	0	0	0	0	10935	2469	0	0	0	0	0	0	**13404**
Slovenia	0	0	0	0	0	0	0	0	61	0	365	139	139	0	0	0	0	**704**
Belgium	0	0	6780	0	0	7009	0	1690	0	0	0	0	0	0	0	2158	2158	**19795**
Czech Republic	0	0	0	0	0	3	0	0	0	0	7468	0	0	0	0	0	0	**7471**
Germany	5239	0	25952	0	0	24482	0	0	0	0	32632	0	0	0	0	0	5335	**93640**
Estonia	0	0	0	0	0	0	0	0	0	0	670	0	0	0	0	0	0	**670**
Latvia	0	0	0	0	0	0	0	0	0	0	1716	0	0	0	0	0	0	**1716**
Lithuania	0	0	0	0	0	0	0	0	0	0	3320	0	0	0	0	0	0	**3320**
Luxembourg	0	0	14	0	0	627	0	0	0	0	290	0	0	0	0	0	129	**1060**
Hungary	0	0	0	0	1.456	0	0	0	0	0	3576	0	0	0	0	0	4597	**9629**
Netherlands	586	1309	30.223	0	0	15868	761	4380	0	0	2931	0	0	0	0	0	0	**56058**
Austria	0	0	0	0	0	1981	0	0	0	0	8950	0	0	0	0	0	3239	**14170**
Poland	1888	0	0	6193	0	0	0	0	0	0	9769	0	0	0	0	0	0	**17850**
Slovakia	0	0	0	0	0	0	0	0	0	0	4801	0	0	0	0	0	0	**4801**
Denmark	0	3.345	0	0	0	622	0	0	0	0	0	0	0	0	0	0	0	**3967**

Consuming countries - EU28	Producing countries																
	Germany	Denmark	Netherlands	Poland	Hungary	Norway	Norway LNG	UK	Italy	Romania	Russia	Algeria pipeline	Algeria LNG	Libya	Nigeria LNG	Qatar LNG	Other	TOTAL
Ireland	0	0	0	0	0	0	0	4522	0	0	0	0	0	0	0	0	0	**4522**
Finland	0	0	0	0	0	0	0	0	0	0	3683	0	0	0	0	0	0	**3683**
Sweden	0	1130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1130**
United Kingdom	0	0	9566	0	0	26812	0	30222	0	0	0	0	0	0	0	13091	0	**79691**
Spain	0	0	0	0	0	2348	1684	0	0	0	0	10835	4014	0	5422	4675	0	**28978**
France	2156	0	9664	0	0	18380	158	0	0	0	6441	0	4160	0	3715	1886	0	**46560**
Portugal	0	0	0	0	0	0	0	0	0	0	0	2090	0	0	1853	164	0	**4107**
TOTAL	**12833**	**5784**	**84665**	**6193**	**1456**	**100858**	**2603**	**40814**	**8605**	**10935**	**112090**	**33907**	**10157**	**6469**	**10990**	**27899**	**19308**	**495566**

3.7.2 Natural Gas production data

The data for the energy use and emissions for each of the different natural gas supply sources are presented below. The major sources of data for all countries are Government sources, the country energy balances and the National Inventory Reports (NIR) for GHG emissions submitted to the UNFCCC. In other cases countries publish more detailed energy balances for the oil and gas sector and the additional detail has been helpful. In some cases company emissions were used and occasionally actual facility data were available.

There is some variation in data quality even within the same generic data set. The NIR for some countries is Tier 3 type data with country specific emission factors and very detailed activity data available, for other countries Tier 1 IPCC estimates are used in the NIR.

Where country specific data have not been available, estimates from published papers have been used. In some cases, IPCC Tier 1 emission factors have been used when other data sources are not available.

National energy balance data are almost always aggregated. Energy use has been allocated between oil and gas production on an energy basis, assuming that the same amount of energy is used to produce a GJ of natural gas as a GJ of crude oil. This is certainly appropriate for associated gas production (oil and gas produced from the same well) but may not be entirely true for dry gas production. The proportion of gas production vs oil production does vary from country to country and there is no obvious pattern with the energy use form the observed data.

Not only are the data aggregated between oil and gas production but they are often aggregated by stage. In most cases, energy for well drilling is included in the gas extraction energy use. Similarly, for offshore production the energy for the transport of the gas from the platform to the shore is included in the extraction data. In no case was separated energy use for well drilling found, so the energy use for this stage has been entered as zero in the model for all of the EU gas suppliers. These emissions are real but are included in the gas production stage.

For gas transport, the available data are generally in the form of joules consumed/joule transported. This the value that the model uses to calculate the emissions but it is generally preferable if users can change the transmission distance to model large consumers close to the main transmission systems. Data are generally available on the total length of the transmission system but not on the average distances that gas moves through the system, as many of the transmission lines are in parallel. To overcome this, energy use in pipelines has generally been estimated at 0.000030 j/j-km. This is a typical value for the United States and was proven to be a good value for Canada, before gas volumes transported dropped as US gas production increased. This value and the estimated pipeline distance will equal the joules consumed/joule transported data that are available. In some cases the standard j/j-km value has been reduced due to reduced flow through the systems from declining production. We can also calculate the kJ/ton of

gas so that the transport gas can be subtracted from the reported energy use for the gas production stage so that there is no double counting of emissions.

For some countries the energy consumed in gas processing was reported separately from the gas production stage but for some countries an assumption was made based on the estimated gas clean-up required.

Energy Consumption Gas Producers

The energy consumed in the production and processing of the natural gas is a key input into the emission calculations. Data were collected on the energy use in well drilling, gas extraction, and gas processing stages for each gas producing region. The input data table in the GHGenius model looks like Table 3-41. Not all fuels were used in all stages in all producing regions. The energy use was considered to be natural gas in most cases, while some electricity and diesel fuel were also consumed.

Table 3-41 Typical Energy Consumption Data for NG Stages

	Energy Use in Gas Production Stages		
Fuel	**Well Drilling, Testing and Servicing**	**Gas Extraction**	**Gas Processing**
	Fuel used, kJ/ton gas		
Crude oil	0	0	0
Diesel fuel	35,792	0	0
Residual fuel	0	0	0
Natural gas	43,541	2,200,000	1,755,137
Coal	0	0	0
Electricity	0	0	79,741
Petrol	93	0	0
Coke	0	0	0
Total	**79,426**	**2,200,000**	**1,834,877**

Regional Electric Power – Gas Producers

Some electricity is used in the natural gas upstream stage, i.e. in gas production and processing stages. The power generation mix has been added to the model for all of the producing regions, but the model uses the distribution efficiency and the generation efficiency from the consuming region. Some of the producing countries have the information required as they are part of the Eurostat database. The rest of the data for other producers have been obtained from the IEA database. The power mix for all considered natural gas producing countries is presented in Table 3-42.

Table 3-42 Natural Gas Producers Power Mix

NG producing country	Coal	Oil	Gas	Nuclear	Other Carbon	Renewables		
						Wind	Biomass	Hydro
UK	0.39	0.01	0.28	0.19	0.01	0.06	0.04	0.02
Norway	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.96
Netherlands	0.24	0.01	0.54	0.04	0.05	0.05	0.07	0.00
Denmark	0.34	0.01	0.14	0.00	0.02	0.34	0.15	0.00
Germany	0.46	0.01	0.12	0.16	-	0.08	0.08	0.04
Italy	0.09	0.38	0.42	0.00	-	0.11		
Romania	0.34	0.01	0.12	0.19	-	0.33		
Poland	0.90	0.02	0.02	0.00	-	0.01	0.04	0.01
Hungary	0.17	0.01	0.31	0.42	-	0.08		
Algeria	0.00	0.06	0.94	0.00	-	0.00	0.00	0.01
Libya	0.00	0.00	0.98	0.00	-	0.00	0.00	0.00
Nigeria	0.00	0.00	0.80	0.00	-	0.00	0.00	0.20
Qatar	0.00	0.00	1.00	0.00	-	0.00	0.00	0.00

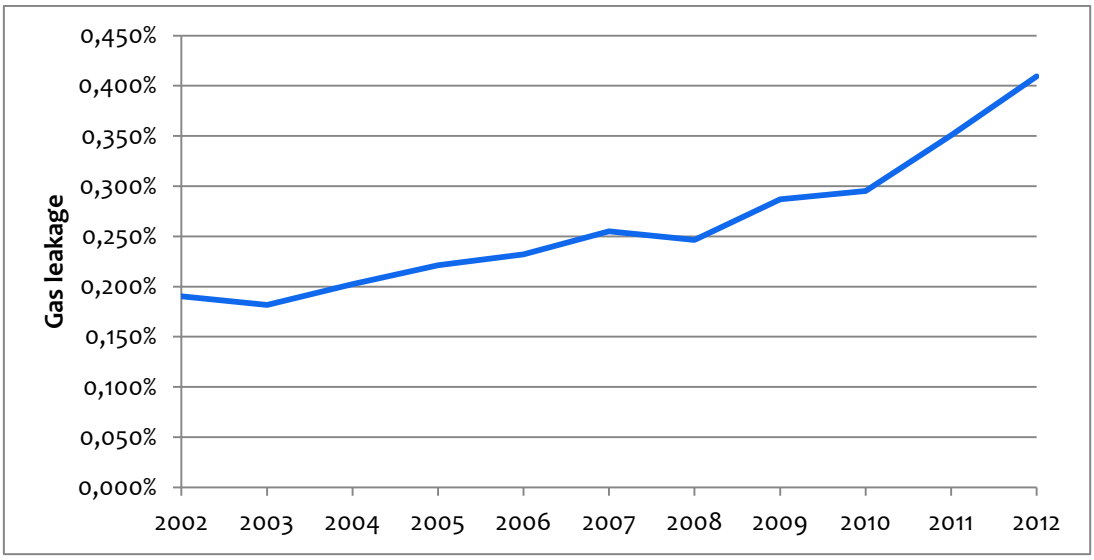
Gas that is supplied as LNG has been tracked separately in the model. The liquefaction energy and any regasification energy nave been added to the gas processing energy requirements.

Methane Losses Gas Producers

Methane losses from the natural gas supply chain are a key differentiator in the emission profile of different gas producing regions. GHGenius inputs the methane emission losses as a percentage of gas produced for the well drilling and gas extraction stage, the gas processing stage, the gas transmission stage, the gas distribution stage and during the gas compression and dispensing stage. These data have been collected for every gas producer in the model.

Wherever possible the data that have been used were consistent with the year 2012. Some of the developed producing countries report this data by year. The following Figure 3-64 on gas leakage reported for UK gas production shows how these emissions can change over time.

Figure 3-64 UK Gas Leakage Rate over the years 2002 – 2012 (source: DECC)



LNG losses will be dealt with in a similar manner to the energy consumption for LNG production. Any additional losses will be added to the gas processing losses for each LNG producer.

Solution Gas

A gas processing plant can remove higher hydrocarbons and contaminates from the raw field gas. Some gas fields can have CO_2 contents of 10% or greater. The CO_2 content of these fields must be reduced to between 1 and 2% before the gas can enter the pipeline system. This source of GHG emissions needs to be identified for every gas producer. For some producers the rate will be zero.

In the following paragraphs the data used as inputs to GHGenius for natural gas producing countries are presented in detail. The results for the EU gas suppliers in order of production volumes are presented first, followed by the other gas suppliers by pipeline, again in order of sales to the EU, and finally the LNG suppliers by sales rank.

3.7.3 Netherlands Natural Gas Supply

The Netherlands is the second-largest producer and exporter of natural gas in Europe, following Norway. Most of its natural gas fields are located offshore in the North Sea, although a number of them are located onshore, including Groningen, one of the ten largest natural gas fields in the world. Natural gas produced in the Netherlands is shipped via an extensive domestic and export pipeline system, which connects the country with United Kingdom, Germany, and Belgium.

Pipeline gas from the Netherlands contributed 17.08% of the EU natural gas supply in 2012.

The Dutch government publishes annual energy balances[17] for the country and also, since Netherlands is a UNFCCC Annex 1 country, annual GHG inventory reports[18] are filed. These sources provide much of the data required for modelling.

Oil and Gas Production

The production of oil and gas in the Netherlands in 2012 as reported in the national energy balance is shown in Table 3-43. Natural gas production contributes 97% of the total hydrocarbon energy production making the available data very specific to natural gas production.

Table 3-43 Netherlands Oil and Gas Production

Fuel	Oil and Gas Production	
	PJ (HHV)	%
Crude oil	50.3	1.82%
Nat Gas	2,694.8	97.57%
LPG	16.7	0.61%
Total	**2,761.8**	**100.00%**

Energy Use - Gas Production

The energy use for the extraction of crude petroleum and gas is in the energy balance data as shown in the Table 3-44. The gas flared is calculated from the Netherlands Statistics data.

Table 3-44 Dutch Energy Use in Oil and Gas Production

Fuel	Consumption in the Fields	
	PJ	%
Crude Oil	0.03	0.08%
Natural gas	32.57	76.45%
Gas Flared	2.24	5.26%
Diesel	0.19	0.47%
Power	6.75	17.74%
Total	**41.78**	**100.00%**

[17] Statistics Netherlands. Energy balance sheet; supply, transformation and consumption.

[redacted]

[18] National Inventory Report. 2014.

[redacted] and [redacted]

The energy use is allocated between the products based on their energy content as shown in the Table 3-45. The energy use is very low compared to other producing countries.

Table 3-45 Energy Use for Gas Production

Fuel	Energy use for gas production	
	kJ/ton Natural Gas	%
Crude Oil	599	0.08%
Natural gas	655,414	83.31%
Diesel	3,592	0.46%
Power	127,093	16.16%
Total	**786,698**	**100.00%**

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG inventory reports submitted to the UNFCC. In 2012, the rate was 0.002 vol. % of the gas produced.

Methane Losses

The 2014 GHG Inventory Report (with 2012 data) reported fugitive and venting emissions for natural gas of 14.55 Gg. This equates to a methane loss rate of 0.030%. This is assigned to the gas production.

This fugitive rate is low, reflecting the effort that the country applies to reducing GHG emissions.

Energy Use - Gas Processing

The Netherlands produces two types of natural gas, one with a low-range calorific value below 37.8 MJ/m³ (L-gas), mainly from Groningen, and one with a high calorific value from 37.8 to 46 MJ/m³ (H-gas), from smaller fields. H-gas and L-gas must be transported on separate networks. Both residential and commercial gas users in the Netherlands are equipped to burn the Groningen-quality L-gas, while industry and power generators use mostly H-gas. The L gas has higher CO_2 and higher nitrogen contents. There are no data on gas processing in the Netherlands to remove the CO_2, nitrogen or higher hydrocarbons.

Natural Gas Transport

Natural gas transport data are required for the movement of gas from the Netherlands to the UK. For gas that is moved to Germany and Belgium, the gas is moved through the domestic transmission system and is reported in the section below. Specific segregated data on the shipments to the UK were not identified; this energy use has been estimated using generic emission factors (0.00003 j/j-km) and the pipeline length (230 km).

Netherlands Production Summary

The data used for energy consumption for gas production in the model are summarized in Table 3-46.

Table 3-46 Energy Use Dutch Natural Gas Production

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	4,191	655,414	127,093	786,698	0.030
Processing	0	0	0	0	0

The non-energy CO_2 emissions from the gas production are 0.002% of the gas production volume.

Gas Transmission and Distribution

Gasunie operates the gas transmission and distribution system within the Netherlands. They produce an environmental report[19] with energy use and emissions data and an annual report[20] with gas transport volumes. The data extracted from the reports and the NIR are shown in the Table 3-47.

Table 3-47 Gas Transmission Data

Netherlands natural gas transmission data	
Gas Transmission Energy, j/j-km	0.000027
Distance, km	150
% Electric energy in transmission	25
Transmission Fugitive Losses, %	0.028
Distribution Fugitive Losses, %	0.043

LNG Regasification

It has been assumed that the regasification energy requirements in the Netherlands are 1.5% of the natural gas throughput. This is the same value as used in the UK, where an official estimate is available.

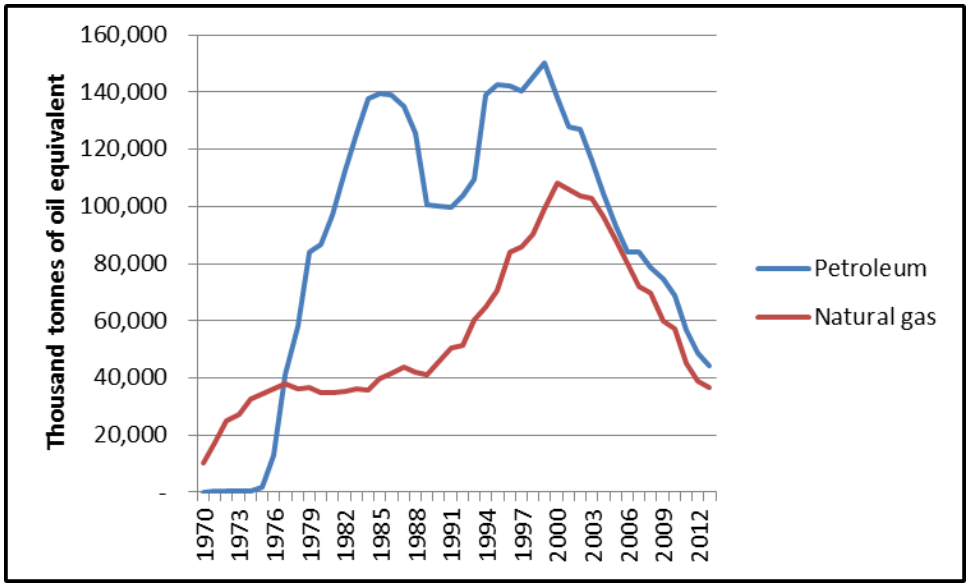
[19] Gasunie. 2013 Environnent Report. [redacted]

[20] Gasunie. 2012 Annual Report. [redacted]

3.7.4 UK Natural Gas Supply

The UK petroleum and natural gas production is located almost exclusively in the North Sea. Production of oil and natural gas are in decline as these are mature fields. The historical production rates are shown in Figure 3-65 below[21].

Figure 3-65 UK Oil and Gas Production



Energy Production

The oil and gas production industry produces crude oil, natural gas liquids and natural gas. The natural gas is produced both as dry gas and as associated gas (co-produced with crude oil). The 2012 production levels are shown in the Table 3-48[22, 23].

Table 3-48 UK Energy Production (2012)

Energy production			
		Energy Basis, PJ (HHV)	% of total
Dry Gas	20,384 million cubic meters	809.2	22.02%
Associated gas	20,654 million cubic meters	820.0	22.31%
On shore	16 million cubic meters	0.6	0.02%
Crude Oil	42,052 thousand tons	1,921,.8	52.29%
NGL	2,508 thousand tons	123.6	3.36%
Total		**3675.2**	**10.000%**

[21] Availability and consumption of primary fuels and equivalents.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/338413/dukes1_1_2.xls
[22] Gas production.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/338461/dukesf_2.xls
[23] Crude Oil and NGL Production.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/338443/dukesf_1.xls

Energy Use

The energy use in the oil and gas extraction sector is reported in the UK Aggregate Energy Balances[24]. The data are shown in the Table 3-49. The UK uses an energy content of 41.868 GJ/ton of oil equivalent. Most of the energy that is consumed is natural gas, which is not surprising given the offshore nature of the industry.

Table 3-49 Energy Use in the UK Oil and Gas Extraction Sector

Type	1000 tons of Oil Equivalent	Energy basis, PJ (HHV)	% by type
Petroleum products	670	28.0	13.7%
Natural gas	4,167	174.5	85.3%
Electricity	49	2.0	1.0%
Total	**4,886**	**204.5**	**100%**

The oil and gas extraction sector will comprise the oil well drilling, the production stage, the gas processing stage, and the transport of the products through pipelines from the production platforms to onshore terminals. Some oil is loaded on ships at the platforms but this would not be captured by the sector data.

Energy Allocation

There is a need to allocate the energy consumed by the sector to the individual products that are produced. In cases where there are not enough data available to determine the energy used for each of the operations that make up the sector totals, the normal practice for this sector is to allocate on the basis of energy produced. With 44.35% of the energy produced being natural gas, then 44.35% of the energy consumed would be allocated to this production.

A second level of allocation is required to allocate some of the energy to the gas production stage and some to the gas processing stage. Since both of these operations are "upstream" operations for this work the allocation can be somewhat arbitrary. UK natural gas has a low level of CO_2 that must be removed from the gas and about 50% of the gas is dry gas production which would require very little processing to achieve pipeline specifications we have assigned 75% of the natural gas energy to the production stage and 25% of the energy to the processing stage. We have further assigned all of the petroleum products to the production stage and all of the electric power to the gas processing stage since this can be done onshore.

Some fuel will be flared on the production platform without any energy recovery and this will not be included in the energy balance data. This information can be extracted from the National GHG Inventory Reports submitted to the UNFCCC. The UK data for 2012 are

[24] Aggregate Energy Balances.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337553/dukes1_1-1_3.xls

also available from a UK website (National Atmospheric Emissions Inventory) and it has been used for this work[25].

The results of this energy allocation are shown in Table 3-50.

Table 3-50 Energy Allocation Results

	NG Production	NG Processing
	kJ/ton gas	
Gas flared	40,150	0
Gas consumed	1,758,405	586,135
Diesel	376,972	0
Electric Power	0	27,570
Total	**2,175,527**	**613,705**

Natural Gas Transport

The typical pipeline distance from the fields to the onshore terminals is 600 km. The energy required to transport this gas is included in the above energy use. Based on the pipeline energy use in North America we have assumed that the pipeline energy use in the UK is 0.000015 j/joule-km[26]. For a 600 km distance this means 468,000 kJ/ton natural gas. This energy needs to be removed from the energy shown in the previous table. Table 3-51 shows the energy use assumptions used for the model where the transport energy is calculated separately.

Table 3-51 Upstream Energy Use for Modelling

	NG Production	NG Processing
	kJ/ton gas	
Gas flared	40,150	0
Gas consumed	1,290,405	586,135
Diesel	376,972	0
Electric Power	0	27,570
Total	**1,707,527**	**613,705**

Process Gas Emissions

Carbon dioxide is released during the gas processing stage as the raw natural gas is purified to pipeline specification. These emissions are reported as part of the UNFCCC reporting process. The data reported for 2012 are equivalent to an emission rate of 0.052% v/v CO_2 in the natural gas. There is a small discrepancy between the quantity of natural gas produced in the data supplied to the UNFCCC and the UK gas production data. The

[25] http://naei.defra.gov.uk/data/data-selector

[26] From GHGenius. Calculated from Statistics Canada data.

gas production data are taken from the same source as the process gas emissions so that the rates are internally consistent.

Methane Losses

The methane losses can also be calculated from the data submitted to the UNFCCC. The methane loss rates are available for a number of stages and the data for 2012 are shown in the Table 3-52. In general these rates are increasing as gas production declines.

Table 3-52 Methane Emission Rates

Stage	Value, volume %
Natural gas supply	0.551
Well testing	0.005
Processing	0.010
Terminal & storage	0.000
Transmission	0.022
Use	0.008
Venting	0.071

For the model, the gas supply and venting values are combined (0.622%), the well testing and processing values are entered separately, the terminal and storage value is used for gas transport, and the transmission value is used for the high pressure portion of pipeline distribution stage

Production Summary

The data used for energy consumption in the model are summarized in the Table 3-53.

Table 3-53 Energy Use for Gas Production

	Units	Value
Gas Production	kJ/ton gas	1,707,527
Gas Processing	kJ/ton gas	613,705
Gas Transport	Joules/joule-km	0.000014

The non-energy CO_2 emissions from the gas processing are 0.052% of the gas production volume.

Transmission and Distribution

There are data on the energy use and emissions in the downstream sector available from the UK[27].

[27] UK continental shelf and onshore natural gas production and supply. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337631/dukes4_3.xls

Energy Use

The own use of natural gas energy in the national transmission system is 0.00492 joules/joules delivered, however this includes the regasification energy which is entered separately in the model. The consumption without the regasification energy is 0.00289 joules/joules delivered. The gas transmission system operator (National Grid PLC) reports a total of 7,600 km of high pressure pipeline and 23 compressor stations[28] (2 are electric drive). The gas transmission system move gas from one of eight coastal receiving stations to one of eight local distribution systems.

If we assume that the average transmission distance is 200 km, then the energy use factor is 0.000014 joules/joule-km. This value is consistent with other data in the model for other regions, see Table 3-54.

National Grid PLC own and operate four of the eight regional gas distribution networks in Great Britain. Their networks comprise approximately 131,000 kilometers of gas distribution pipeline. The system operates mostly from the pressure of the gas transmission system.

Table 3-54 UK Downstream Gas Data

UK natural gas transmission data	
Gas Transmission Energy, j/j-km	0.000014
Distance, km	200
% Electric energy in transmission	8.7
Transmission Fugitive Losses, %	0.020
Distribution Fugitive Losses, %	0.192

Regasification of LNG

The regasification energy of the UK terminals is estimated at 1.5% of the gas process by the UK Department of Energy and Climate Change[29] We have assumed that minimal additional electric power is required for LNG receiving facilities, except in cases where sea water is used as the source of regasification energy.

3.7.5 Germany Natural Gas Supply

Germany is a modest producer of oil and gas. German gas contributes 2.6% of the gas consumed in the EU. Within Germany approximately 86% of Germany's natural gas

[28] National Grid Annual Report, [redacted]

[29] UK Department of Energy and Climate Change. Energy Trends. June 2014. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/326368/ET_June_2014.pdf

demand is met with imports, only 14% is produced domestically and domestic production has declined continuously in recent years.

Oil and Gas Production

The production of oil and gas in the Germany in 2012, as reported in the national energy balance[30], is shown in Table 3-55. Natural gas production contributes 78% of the total petroleum energy production.

Table 3-55 German Oil and Gas Production

Germany Oil and Gas production		
	PJ (HHV)	%
Crude oil	117	21.2%
Nat Gas	438	78.8%
Total	**555**	**100.0%**

Energy Use - Gas Production

The energy use for the extraction of crude petroleum and gas is in the energy balance data as shown in Table 3-56.

Table 3-56 German Energy Use in Oil and Gas Production

Fuel	Consumption in the fields	
	TJ (HHV)	%
Fuel Oil	6	0.05%
Natural gas	8,959	75.73%
Gas Flared	435	3.67%
Power	2,431	20.55%
Total	**11,831**	**100.00%**

The energy use is allocated between the products based on their energy content as shown in the Table 3-57. The energy use is low compared to other producing countries and it is low considering the fact that 40% of the gas production is high in CO_2. It is possible that the energy for petroleum and natural gas production does not include the energy for gas processing.

[30] Energy Balance 2012. [redacted]

Table 3-57 Energy Use for Gas Production

Fuel	kJ/ton Natural Gas	%
Fuel Oil	596	0.05%
Natural gas	839,342	75.73%
Gas Flared	40,713	3.67%
Power	227,756	20.55%
Total	**1,108,407**	**100.00%**

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG National Inventory Report (NIR) submitted to the UNFCCC[31]. 40% of the production of German natural gas is acid gas with high CO_2 levels. The CO_2 emission factor applied to this acid gas is 0.23 t/1000 m^3 based on an emission factor from Austria. This is equivalent to an emission rate of 12.5%. The emissions calculated from the inventory and the production is 13.2%, but the 12.5% is supposed to be just applied to the acid gas and not the total production. The NIR notes that these emissions are at the high end of the range from all countries reporting to the UNFCCC. We have applied a value of 5.3% for the modelling (40% of 13.2%).

Methane Losses

The 2014 NIR (with 2012 data) reports fugitive and venting emissions for natural gas for production and processing of 1.89 Gg of methane. This is a loss rate of 0.0034%.

Energy Use - Gas Processing

We have added 1,000,000 kJ/ton of gas of natural gas to gas processing for Germany, as it does not appear that this energy use is captured in the energy for oil and gas production. A relatively high value is used because of the high CO_2 solution gas emission rate.

Natural Gas Transport

German natural gas is delivered in Germany so there is no gas transport stage for the indigenous production.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-58.

[31] National Inventory Report for the German Greenhouse Gas Inventory. 1990 – 2012.

Table 3-58 Energy Use German Gas Production and Consumption

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	596	880,055	227,756	1,108,407	0.0030
Processing	0	1,000,000	30,000	1,000,000	0

The non-energy CO_2 emissions from the gas production are 5.3% of the gas production volume.

Gas Transmission and Distribution

The German gas distribution network consists of approximately 30 regional gas utilities that distribute natural gas from the producers and transport pipeline to local gas suppliers (municipal companies) and in some cases to final customers. The retail market for delivery to final customers (households, commerce and industry) is done by local re-distributers.

The energy consumption for the transmission system is reported in the NIR. It amounts to 0.0076 j/joule consumed in Germany. Assuming an average transmission distance of 300 km, the energy use is 0.000025 j/j-km, see Table 3-59.

The methane loss factor for transmission is calculated from the NIR and the volume of gas consumed in Germany. It is 0.0254%, but this could be too high as the volume of gas transported through Germany could be higher than the volume used in Germany.

The methane loss rate for distribution in the NIR is 0.2957%. Germany also reports methane losses at the end users and these emissions total 0.0824% of the gas distributed.

Table 3-59 German Downstream Gas Data

Germany natural gas transmission data	
Gas Transmission Energy, j/j-km	0.000025
Distance, km	300
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.0254
Distribution Fugitive Losses, %	0.3781

3.7.6 Romania Natural Gas Supply

Romania is a modest producer of oil and gas. Romanian gas contributes 2.21% of the gas consumed in the EU. Within Romania approximately 80% of Romania's natural gas

demand is met with domestic supply, domestic production has been declining in recent years.

Oil and Gas Production

The production of oil and gas in the Romania in 2012, as reported in the national energy balance[32], is shown in the Table 3-60. Natural gas production contributes 68% of the total petroleum energy production.

Table 3-60 Romania Oil and Gas Production

Romania oil and gas production		
	PJ (HHV)	%
Crude oil	182,042	30.9%
Nat Gas	407,150	69.1%
Total	**589,193**	**100.0%**

Energy Use - Gas Production

The energy use for the extraction of crude petroleum and gas from the energy balance data are shown in Table 3-61. The National Inventory Report (NIR)[33] does have the emissions for gas flaring which can be used to calculate the energy in the flared gas. Much of the data in the Romanian NIR use IPCC Tier 1 estimates combined with the appropriate activity data.

Table 3-61 Romania Energy Use in Oil and Gas Production and Processing

	Consumption in the fields	
	TJ (HHV)	%
Diesel Fuel	2,943	14.11%
Natural gas	13,593	65.19%
Gas Flared	441	2.11%
Power	3,874	18.58%
Total	**20,851**	**100.00%**

[32] Eurostat Energy Statistics. Supply, transformation, consumption - all products - annual data (nrg_100a).

[redacted]

[33] Romania's Greenhouse Gas Inventory. 1989-2012

[redacted]

The energy use is allocated between the products based on their energy content as shown in Table 3-62. This information will include the gas production and gas processing, most (95%) of the energy is allocated to gas production in the model.

Table 3-62 Energy Use for Gas Production

	kJ/ton Natural Gas	%
Diesel Fuel	375,807	14.11%
Natural gas	1,736,113	65.19%
Gas Flared	56,302	2.11%
Power	494,776	18.58%
Total	**2,662,998**	**100.00%**

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG National Inventory Report (NIR) submitted to the UNFCCC. The value calculated from the data is 0.10%.

Methane Losses

The 2014 NIR (with 2012 data) reports fugitive and venting emissions for natural gas for production and processing of 34.36 Gg of methane. This is a loss rate of 0.443%.

Energy Use - Gas Processing

Gas processing energy use is not segregated in the energy balance or in the NIR. It will be assumed that 5% of the energy use for production and processing is processing energy, see Table 3-63.

Table 3-63 Energy Use for Gas Processing

	kJ/ton Natural Gas	%
Diesel Fuel	18,790	14.11%
Natural gas	86,806	65.19%
Gas Flared	2,815	2.11%
Power	24,739	18.58%
Total	**133,150**	**100.00%**

Natural Gas Transport

Gas produced in Romania is delivered in Romania and the energy and emissions are reported in the gas transmission data.

Gas Production Summary

The data used for energy consumption in the model are summarized in the Table 3-64.

Table 3-64 Energy Use Romania Gas Production and Consumption

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	357,017	1,702,794	470,037	2,529,848	0.443
Processing	18,790	89,621	24,739	133,150	0

The non-energy CO_2 emissions from the gas production are 0.10% of the gas production volume.

Gas Transmission and Distribution

Romania's gas transmission network consists of more than 12,500 kilometers of high pressure pipelines. The network includes six compressor stations. The network is used to transport natural gas for Romania's domestic consumption and for transit. Transgaz is the transmission system operator.

Energy use data for gas transmission is 443 TJ in the Romania national energy balance that is included in the NIR. This is 0.00122 joule/joule. This is quite high. It is calculated in the NIR using the pipeline length (12,528 km) and an IPCC emission factor. For the gas transmission in Romania we will use the default value of 0.000030 j/j-km and an average transmission distance of 250 km, see Table 3-65.

The methane loss rate in the NIR is 0.200% for the gas transmission sector. The loss rate for the gas distribution system is 0.253%. Both are IPCC Tier 1 emission factors.

Table 3-65 Romania Downstream Gas Data

Romania natural gas transmission data	
Gas Transmission Energy, j/j-km	0.000030
Distance, km	250
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.200
Distribution Fugitive Losses, %	0.253

3.7.7 Italy Natural Gas Supply

Italy is a modest producer of oil and gas. Italian gas contributes 1.74% of the gas consumed in the EU. Within Italy, approximately 10% of Italy's natural gas demand is met with domestic supply; domestic production has declined significantly in recent years.

Oil and Gas Production

The production of oil and gas in the Italy in 2012, as reported in the national energy balance[34], is shown in Table 3-66. Natural gas production contributes 58% of the total petroleum energy production.

Table 3-66 Italy Oil and Gas Production

Italy Oil and Gas production		
	PJ (HHV)	%
Crude oil	256,436	43.7%
Nat Gas	330,474	56.3%
Total	**586,910**	**100.0%**

Energy Use - Gas Production

The energy use for the extraction of crude petroleum and gas from the energy balance data is shown in Table 3-67. The National Inventory Report (NIR)[35] does have the emissions for gas flaring which can be used to calculate the energy in the flared gas. Much of the data in the Italian NIR use IPCC Tier 2 and Tier 3 estimates combined with the appropriate activity data.

Table 3-67 Italy Energy Use in Oil and Gas Production

Fuel	Consumption in the fields	
	TJ (HHV)	%
Diesel Fuel	0	0.0%
Natural gas	39,099	96.1%
Gas Flared	343	0.8%
Power	1,231	3.0%
Total	**40,673**	**100.0%**

[34] Eurostat Energy Statistics. Supply, transformation, consumption - all products - annual data (nrg_100a).

[redacted]

The energy use is allocated between the products based on their energy content as shown in Table 3-68.

Table 3-68 Energy Use for Gas Production and Processing

	kJ/ton Natural Gas	%
Diesel Fuel	0	0.0%
Natural gas	3,464,173	96.1%
Gas Flared	30,365	0.8%
Power	109,066	3.0%
Total	**3,603,604**	**100.0%**

This information will include the gas production and gas processing.

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG National Inventory Report (NIR) submitted to the UNFCCC. The value calculated from the data is 0.005%. This is very low and would suggest that little energy is expended in the gas processing stage.

Methane Losses

The 2014 NIR (with 2012 data) reports fugitive and venting emissions for natural gas for production and processing of 13.61 Gg of methane. This is a loss rate of 0.22%, see Table 3-69.

Energy Use - Gas Processing

Gas processing energy use is not segregated in the energy balance or in the NIR. It will be assumed that 5% of the energy use for production and processing is processing energy.

Table 3-69 Energy Use for Gas Processing

	kJ/ton Natural Gas	%
Diesel Fuel	0	0.0%
Natural gas	173,209	96.1%
Gas Flared	1,518	0.8%
Power	5,453	3.0%
Total	**180,180**	**100.0%**

Natural Gas Transport

Italian gas is consumed within Italy so there is no gas transport to another country.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-70. The energy use in gas production is higher than many of the other countries but it is based on Italian data and not generic emission factors.

Table 3-70 Energy Use Italy Gas Production and Consumption

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	0	3,319,811	103,613	3,423,424	0
Processing	0	174,727	5,453	180,180	0.22

The non-energy CO_2 emissions from the gas production are 0.005% of the gas production volume.

Gas Transmission and Distribution

Energy use data for gas transmission is 13,827 TJ in the Italy NIR. This is 0.00454 joule/joule. We will use the emission factor of 0.000030 j/ton-km and a transmission distance of 150 km for the modelling.

The methane loss rate in the NIR is 0.068% for the gas transmission sector. The loss rate for the gas distribution system is 0.688%, see Table 3-71. Both are based on detailed Italian data. There is a significant difference in the volume of gas moved through the transmission system compared to the distribution system, indicating a large number of large gas consumers who withdraw gas from the high pressure transmission system.

Table 3-71 Italy Downstream Gas Data

Italy Natural Gas transmission data	
Gas Transmission Energy, j/j-km	0.000030
Distance, km	150
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.068
Distribution Fugitive Losses, %	0.688

LNG Regasification

Italy receives LNG from offshore supplies. The LNG must be regassified before it enters the distribution system. There are three LNG terminals in the country they use both Open Rack Vaporizers (ORV) that use seawater to heat and vaporize the LNG and Submerged Combustion Vaporizers (SCV) that use send-out gas as fuel for the combustion that

provides vaporizing heat. The SCV systems use about 1.2% of the gas for vaporization[36]. The power requirements for a ORV system range from 0.008 kWh/kg LNG[37] to 0.09 kWh/kg LNG (Taglia).

For Italy it will be assumed that 310,000 kj/ton of natural gas and 30,000 kj of electricity are used for regasification.

3.7.8 Poland Natural Gas Supply

Poland is a modest producer of oil and gas. Polish gas contributes 1.25% of the gas consumed in the EU. Within Poland approximately 34% of Poland's natural gas demand is met with domestic supply, domestic production has been relatively stable in recent years.

Oil and Gas Production

The production of oil and gas in the Poland in 2012, as reported in the national energy balance[38], is shown in Table 3-72. Natural gas production contributes 85% of the total petroleum energy production.

Table 3-72 Polish Oil and Gas Production

Poland Oil and Gas production		
	PJ (HHV)	%
Crude oil	30,350	14.5%
Nat Gas	179,480	85.5%
Total	**209,830**	**100.0%**

Energy Use- Gas Production

The energy use for the extraction of crude petroleum and gas is in the energy balance data as shown in Table 3-73. In the Polish energy statistics gas flared appears to be captured in the natural gas consumption data.

[36] European Gas Imports: GHG Emissions from the Supply [redacted]

[37] Morosuk, T., Tsatsaronis. LNG – Based Cogeneration Systems: Evaluation Using Exergy-Based Analyses. Chapter 11 in Natural Gas - Extraction to End Use. [redacted]

[38] Eurostat Energy Statistics. Supply, transformation, consumption - all products - annual data (nrg_100a). [redacted]

Table 3-73 Polish Energy Use in Oil and Gas Production

	Consumption in the fields	
	TJ	%
Diesel Fuel	231	2.38%
Natural gas	9,093	93.65%
Gas Flared	0	0.0%
Power	385	3.97%
Total	**9,709**	**100.00%**

The energy use is allocated between the products based on their energy content as shown in Table 3-74.

Table 3-74 Energy Use for Gas Production and Processing

Fuel	kJ/ton Natural Gas	%
Diesel Fuel	57,266	2.38%
Natural gas	2,253,494	93.65%
Gas Flared	0	0.0%
Power	95,941	3.97%
Total	**2,406,701**	**100.00%**

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG National Inventory Report (NIR) submitted to the UNFCCC[39]. The value calculated from the data is only 0.003%. The segregated data on methane emissions also indicate that very little gas processing is done for the Polish gas.

Methane Losses

The 2014 NIR (with 2012 data) reports fugitive and venting emissions for natural gas for production and processing of 15.83 Gg of methane. This is a loss rate of 0.446%; it is almost entirely from gas production.

[39] Poland's National Inventory Report 2014.

[redacted]

Energy Use - Gas Processing

Gas processing energy is included in the energy use shown above. It appears from the data that very little energy is used for gas processing. We have allocated 95% of the energy consumption to gas production and 5% to gas processing.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-75.

Table 3-75 Energy Use Polish Gas Production and Consumption

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	54,403	2,140,820	90,640	2,285,863	0.446
Processing	2,863	112,675	4,771	120,309	0.000

The non-energy CO_2 emissions from the gas production are 0.003% of the gas production volume.

Natural Gas Transport

Polish gas is consumed within Poland so there is no gas transport to another country.

Gas Transmission and Distribution

The Polish gas distribution network consists of an independent Transmission System Operator fully owned by the state – OGP GAZ-SYSTEM, and six regional distribution companies were legally unbundled from the Polish Petroleum and Gas Mining Company (PGNiG), which is the dominant producer of gas and crude oil in Poland, and granted the status of distribution system operators (DSOs), see Figure 3-66.

Natural gas transport data for the high pressure pipelines from the processing plants are included in the NIR. The value calculated based on the gas consumed is 0.019 joules consumed/joule transported. This is a high value because it includes energy consumed on the Yamal pipeline, which has four compressor stations in Poland, but the volume of gas used in the calculation is just the quantity used in Poland.

Figure 3-66 Gas Infrastructure of Poland (source IEA[40])



For the gas transmission in Poland we have assumed an average transmission distance of 300 km. This equates to 0.000064 j/j-km, see Table 3-76.

The methane loss rate in the NIR is 0.25% for the gas transmission sector. The loss rate for the gas distribution system is 1.45%. This high value probably reflects an aging distribution system with some cast irons mains.

Table 3-76 Poland Downstream Gas Data

Poland Natural Gas transmission data	
Gas Transmission Energy, j/j-km	0.000064
Distance, km	300
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.250
Distribution Fugitive Losses, %	1.45

3.7.9 Denmark Natural Gas Supply

Denmark is a modest natural gas producer, it supplies 1.17% of the EU supply. Most of its natural gas fields are located offshore in the North Sea. Natural gas produced in Denmark

[40] IEA. Energy Supply Security 2014.
https://www.iea.org/media/freepublications/security/EnergySupplySecurity2014_Poland.pdf

is used in Denmark and excess production shipped via a pipeline system, which connects the country with Sweden and the Netherlands.

The Danish government publishes annual energy balances[41] for the country and are a UNFCCC Annex 1 country and file annual GHG inventory reports[42]. These sources provide much of the data required for modelling.

Oil and Gas Production

The production of oil and gas in Denmark in 2012 as reported in the national energy balance is shown in Table 3-77. Natural gas production contributes 97% of the total hydrocarbon energy production making the available data very specific to natural gas production.

Table 3-77 Denmark Oil and Gas Production

Denmark Oil and Gas production		
	PJ (HHV)	%
Crude oil	454,888	65.1%
Nat Gas	243,661	34.9%
Total	**698,549**	**100.0%**

Energy Use - Gas Production

The energy use for the extraction of crude petroleum and gas is in the energy balance data as shown in Table 3-78.

Table 3-78 Danish Energy Use in Oil and Gas Production

	Consumption in the fields	
	PJ	%
Natural gas	25.02	100%
Total	**25.02**	**100%**

[41] Danish Energy Agency. Energy Statistics 2012. [redacted]

[42] Denmark's National Inventory Report 2014. [redacted]

The energy use is allocated between the products based on their energy content as shown in Table 3-79. This energy use will include the transport energy from the fields to the onshore processing plants.

Table 3-79 Energy Use for Gas Production

	kJ/ton Natural Gas	%
Natural gas	2,011,826	100.00%
Total	**2,011,826**	**100.00%**

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG inventory reports submitted to the UNFCC. In 2012, the rate was 0.038 vol. % of the gas produced.

Methane Losses

The 2014 GHG Inventory Report (with 2012 data) reported fugitive and venting emissions for natural gas of 1.67 Gg. This equates to a methane loss rate of 0.040%. This is assigned to the gas production.

Energy Use - Gas Processing

The NIR reports gas flaring for the gas processing plants. The energy used for the processing plants is low, 295,000 kj/ton of gas produced. The reported methane loss rate for the gas processing stage is 0.0014%.

Natural Gas Transport

The energy for the transport of the gas from the platforms to the shore is included in the production energy. We will use the default assumption of 0.00003 j/j-km and a distance of 200 km to estimate the emissions for this stage.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-80.

Table 3-80 Energy Use Danish Natural Gas and LNG Production

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	0	1,700,000	0	1,700,000	0.040
Processing	0	295,000	0	295,000	0.0014

The non-energy CO_2 emissions from the gas production are 0.038% of the gas production volume.

Gas Transmission and Distribution

The gas transmission and distribution information is from the energy balance and the NIR. The energy balance reports 118 TJ of electric power used for pipelines. This is a rate of 0.000484 j/j. We will use a pipeline distance of 100 km and an energy rate of 0.0000048 j/j-km and 100% electricity, see Table 3-81.

The methane loss rate for transmission is 0.0014% and for distribution is 0.040% calculated from the NIR.

Table 3-81 Denmark Downstream Gas Data

Denmark Natural Gas transmission data	
Gas Transmission Energy, j/j-km	0.0000048
Distance, km	100
% Electric energy in transmission	100
Transmission Fugitive Losses, %	0.0014
Distribution Fugitive Losses, %	0.040

3.7.10 Hungary Natural Gas Supply

Hungary is a modest producer of oil and gas. Hungarian gas contributes 0.29% of the gas consumed in the EU. Within Hungary approximately 20% of Hungary's natural gas demand is met with domestic supply, domestic production has been declining in recent years.

Oil and Gas Production

The production of oil and gas in the Hungary in 2012, as reported in the national energy balance[43], is shown in Table 3-82. Natural gas production contributes 65% of the total petroleum energy production.

Table 3-82 Hungary Oil and Gas Production

Hungary Oil and Gas Production		
Fuel	**PJ (HHV)**	**%**
Crude oil	45,002	35.2%
Natural Gas	82,910	64.8%
Total	**127,913**	**100.0%**

[43] Eurostat Energy Statistics. Supply, transformation, consumption - all products - annual data (nrg_100a).

Energy Use- Gas Production

The energy use for the extraction of crude petroleum and gas in the energy balance data is incomplete as it only includes electricity. The National Inventory Report (NIR) does have the emission factors for gas production and processing which can be converted back to fuel consumption. The emission factors are mostly IPCC Tier 1 factors. The gas flared is from the NIR, see Table 3-83.

Table 3-83 Hungary Energy Use in Oil and Gas Production

Fuel	Consumption in the fields	
	TJ (HHV)	%
Natural gas	4,162	77.4%
Gas Flared	231	4.3%
Power	986	18.3%
Total	**5,379**	**100.0%**

The energy use is allocated between the products based on their energy content as shown in Table 3-84.

Table 3-84 Energy Use for Gas Production

Fuel	kJ/ton Natural Gas	%
Natural gas	1,691,969	77.4%
Gas Flared	93,908	4.3%
Power	400,836	18.3%
Total	**2,186,713**	**100.0%**

CO2 from Solution Gas

The quantity of CO_2 that is vented is reported in the annual GHG National Inventory Report (NIR) submitted to the UNFCCC[44]. The value calculated from the data is 2.32%. The segregated data on methane emissions also indicate that very little gas processing is done for the Polish gas.

Methane Losses

The 2014 NIR (with 2012 data) reports fugitive and venting emissions for natural gas for production and processing of 7.74 Gg of methane. This is a loss rate of 0.485%.

[44] National Inventory Report for 1985-2014. Hungary. May 2014.

[redacted]

Energy Use - Gas Processing

Gas processing energy is also based on the emission factors in the NIR, see Table 3-85.

Table 3-85 Energy Use for Gas Processing

	kJ/ton Natural Gas	%
Natural gas	498,810	100.0%
Gas Flared	0	0.0%
Power	0	0.0%
Total	**498,810**	**100.0%**

Natural Gas Transport

Gas produced in Hungary is delivered in Hungary and the energy and emissions are reported in the gas transmission data.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-86.

Table 3-86 Energy Use Hungary Gas Production and Consumption

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	0	1,785,877	400,836	2,186,713	0.485
Processing	0	498,810	0	498,810	0

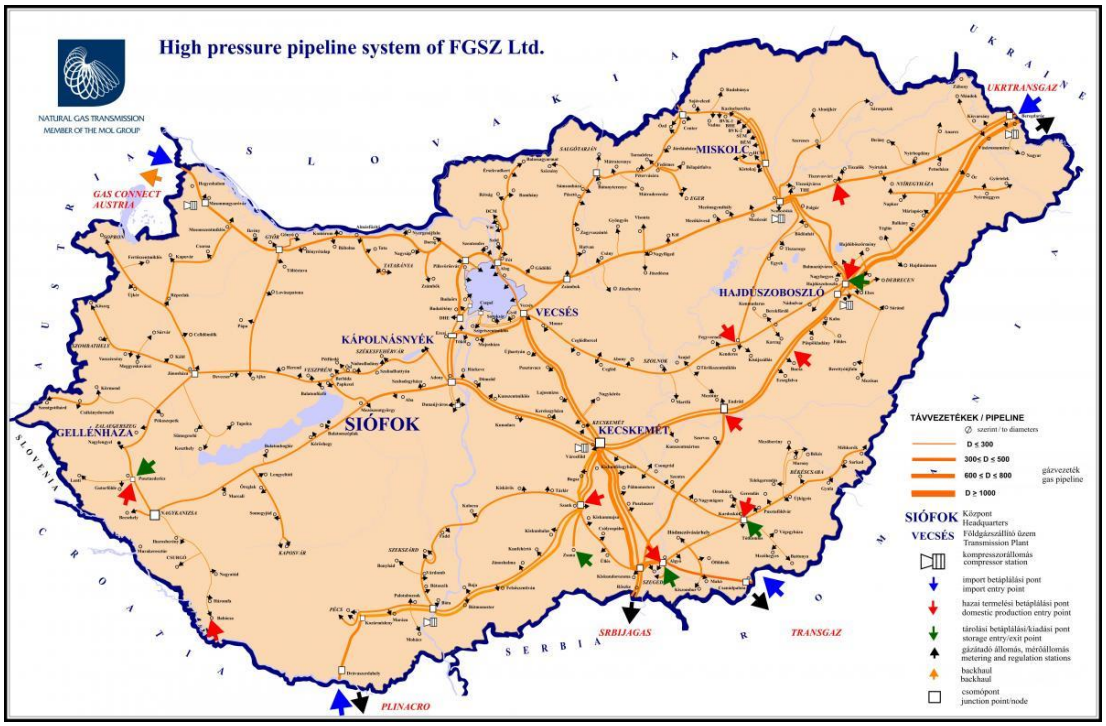
The non-energy CO_2 emissions from the gas production are 2.32% of the gas production volume.

Gas Transmission and Distribution

Hungary's gas transmission network consists of more than 5,700 kilometers of high pressure pipelines but there are twinned lines and parallel lines. The network includes five compressor stations with a total installed capacity of 187 MW. The network is used to transport natural gas for Hungary's domestic consumption and for transit. Around 12 to 15 bcm are transported annually, while around 4.25 bcm are reserved for transit through the grid. FGSZ is the transmission system operator. There are six regional distribution companies.

The gas pipeline system in Hungary is shown in Figure 3-67.

Figure 3-67 Hungary Gas Pipeline System



Energy use data for gas transmission are not provided in the NIR. For the gas transmission in Hungary we will use the default value of 0.000030 j/j-km. We have assumed an average transmission distance of 200 km.

The methane loss factor for transmission is calculated from the NIR and the volume of gas consumed in Hungary. It is 0.247%, but this could be too high as the volume of gas transported through Hungary could be higher than the volume used in Hungary, see Table 3-87.

The methane loss rate in the NIR is 0.247% for the gas transmission sector. The loss rate for the gas distribution system is 0.543%.

Table 3-87 Hungary Downstream Gas Data

Hungary Natural Gas transmission data	
Gas Transmission Energy, j/j-km	0.000030
Distance, km	200
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.247
Distribution Fugitive Losses, %	0.543

3.7.11 Russia Natural Gas Supply

Russia holds the largest natural gas reserves in the world, and is the largest producer and exporter of dry natural gas. The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezh'ye fields alone accounting for about 45 % of Russia's total reserves. Natural gas produced in Russia is shipped via an extensive domestic and export pipeline system, which connects the country with the European Union.

Pipeline gas from Russia contributed 22.61% of the EU natural gas supply in 2012. Russia is an UNFCCC Annex 1 country and file annual GHG inventory reports[45]. The Russian company Gazprom dominates the production and transportation of natural gas in Russia and produces an annual environmental report[46] and data on their operations[47]. The data for modelling are derived mostly from these sources.

Oil and Gas Production

The production of oil and gas in Russia in 2012 is shown in Table 3-88[48]. The Gazprom data are also shown to demonstrate their dominant position in the natural gas sector. In some cases better data are available for the total Russian gas sector (from the UNFCCC submission) and in other cases the Gazprom data provide a more comprehensive overview. Since Gazprom is responsible for more than 80% of the gas production it is reasonable to extrapolate this information to the Russian gas sector.

Table 3-88 Russia Oil and Gas Production

Russia Oil and Gas Production			
	Russia PJ (HHV)	Gazprom PJ HHV)	Gazprom % Russian Production
Crude oil	21,794	2,078	9.5%
Natural Gas	22,604	18,507	81.9%
Total Petroleum	**44,398**	**20,585**	

[45] National Inventory Report. 2014.

[46] Gazprom. Environmental Report 2013.

[47] Gazprom in Figures 2009–2013.

[48] IEA. Russian Federation Balances for 2012.
http://www.iea.org/statistics/statisticssearch/report/?country=RUSSIA&product=balances&year=2012

Energy Use- Gas Production

The energy use for the extraction of Gazprom crude petroleum and gas is in the energy balance data as shown in Table 3-89. The Gazprom data include all company operations from gas production through to the delivery of the gas to the end user.

Table 3-89 Gazprom Energy Use in Oil and Gas Production

	Consumption for all Stages	
	PJ	%
Natural Gas	1,985.2	87.86
Gas Flared	220.7	9.77
Power	53.6	2.37
Total	**2,259.5**	**100.00**

The UNFCCC data indicate that gas flaring for the country is about three times higher than what Gazprom reports. The Gazprom data also indicate that their gas flaring is much lower than the national rates. This is not unexpected since the gas flared is associated gas and will be more prevalent with oil production rather than gas production. The Gazprom rate is used for modelling.

The energy use is allocated between the products based on their energy content as shown in Table 3-90.

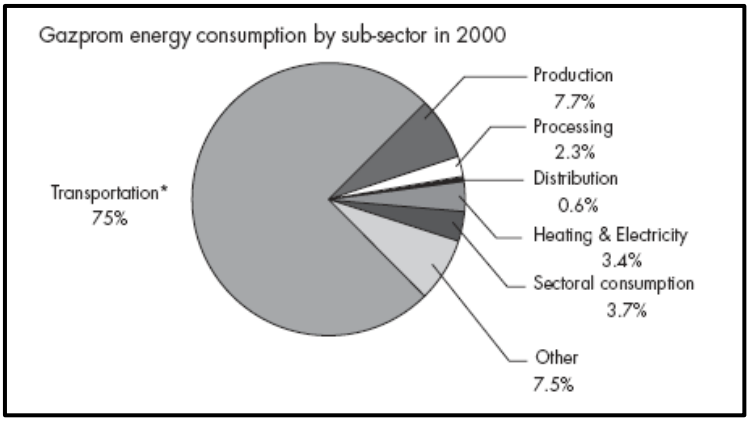
Table 3-90 Energy Use for Gas Production, Processing, Transport and Transmission

	kJ/ton Natural Gas	%
Natural Gas	5,015,000	87.86
Gas Flared	558,000	9.77
Power	135,000	2.37
Total	**5,708,000**	**100.00**

The breakdown of energy consumption in the Russian gas sector is shown in the following Figure 3-68[49].

[49] IEA. 2006. Optimizing Russian Natural Gas.
www.iea.org/publications/freepublications/publication/russiangas2006.pdf

Figure 3-68 Distribution of Energy Use in Russian Supply Chain



If we distribute the heating and electricity, sectoral consumption, and other proportionately to the production, processing, and transmission sectors then 9.06% of the energy is consumed in gas production, 2.71% in gas processing and 88.24% in gas transport. All of the flaring energy is attributed to gas production and the total energy use for gas production is shown in Table 3-91.

Table 3-91 Energy Use for Gas Production

	kJ/ton Natural Gas	%
Natural Gas	454,300	44.34%
Gas Flared	558,000	54.46%
Power	12,229	1.19%
Total	**1,024,529**	**100.00%**

CO2 from Solution Gas

Russian gas is relatively low in CO_2. The quantity of CO_2 that is vented is reported in the annual GHG inventory reports submitted to the UNFCC. In 2012, the rate was 0.006 vol. % of the gas produced.

Methane Losses

The 2014 GHG Inventory Report (with 2012 data) reported fugitive and venting emissions for natural gas of 2,375 Gg for the gas production and processing stages. This equates to a methane loss rate of 0.50%. This is assigned to the gas production.

Energy Use - Gas Processing

The gas processing energy is calculated in a similar manner to the gas production energy use and is shown in Table 3-92. The energy use is very low reflecting the low level of CO_2 in the gas and the low level of LPG recovered.

Table 3-92 Energy Use for Gas Processing

	kJ/ton Natural Gas	%
Natural Gas	135,700	97.38%
Power	3,653	2.62%
Total	**139,353**	**100.00%**

All of the methane losses were attributed to the production stage.

Natural Gas Transport

Natural gas transport data are required for the movement of gas from Russia to Europe. The transport distances are large, typically 3,400 km. The IEA report on optimizing the Russian gas system noted that the energy intensity of Russia's gas transmission system is 30-60% higher than comparable foreign systems. This is mainly due to:

- Russian natural gas having to travel long distances.
- The relatively low energy efficiency of compressor units leading to 10-20% overconsumption of gas according to Gazprom.
- The insufficient power capacity of booster compressor stations leading to increasing energy consumption on the main compressor stations. A deficit of each kW of power capacity on the booster compressor stations results in an additional use of 4kW on the compressor stations along the transmission system.
- The initial design of the system, influenced by low energy prices during Soviet times, mainly aimed at saving pipe metal and limiting the number of compressor units.
- The compressor ratio of gas in Russia (1.45) is higher than in comparable foreign systems (1.3 to 1.35) and thus results in higher energy needs. The lower compression of gas in foreign systems is due to the larger diameter of pipelines and lower internal pipe roughness.

The calculated energy use in the gas transport stage is calculated the same as the energy use for gas processing, see Table 3-93.

The gas transport system supplies gas inside and outside of Russia and thus it is difficult to determine the total ton-km of gas moved. If we assumed that the average distance inside Russia is 1,000 km and the distance to destinations outside Russia is 3,400 and using the sales volumes from Gazprom, then the energy use in the gas transport system is 0.000045 joules/joule-km. This is higher than the values in GHGenius for the United States (0.000029 joules/joule-km) and for Canada (0.000014 joules/joule-km), consistent with the IEA observation of high energy use in the Russian system.

Table 3-93 Energy Use for Gas Transport

	kJ/ton Natural Gas	%
Natural Gas	4,425,000	97.38%
Power	119,118	2.62%
Total	**4,544,118**	**100.00%**

The methane loss rate calculated from the UNFCCC data is 1.02%. This rate is too low as it will only include the emissions inside Russia and it is not weighted between the losses for the domestic gas which moves a shorter distance than the longer gas. Making that adjustment would increase the loss rate to 1.77% for that portion of the gas that is exported.

There are some differences between the National Inventory methane losses and those published by Gazprom[50]. The National Inventory values reported here are double the values reported by Gazprom in the referenced publication. Furthermore, the Gazprom values should include some distribution emissions which are a separate item in the National Inventory. A value of 1% is used for the modelling.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-94.

Table 3-94 Russian Gas Summary

	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas			
Drilling	0	0	0	0
Production	1,012,300	12,229	1,024,529	0.50
Processing	135,700	3,653	139,353	0
Transport	4,425,000	119,118	4,544,118	1

The calculated pipeline energy efficiency is 0.000045 j/j-km. The non-energy CO_2 emissions from the gas production are 0.006% of the gas production volume.

Gas Transmission and Distribution

The gas is not used in Russia so the transmission and distribution energy and emissions are not relevant to this work.

[50] Gazprom Greenhouse Gas Emissions Study: Accounting, Monitoring and the Best Available Technologies of Emissions Reduction. http://members.igu.org/old/IGU%20Events/wgc/wgc-2012/wgc-2012-proceedings/speaker-presentations/committee-session/tuesday/cs-6-2-pgca-ghg-emission-reduction-efforts/gazprom-greenhouse-gas-emissions-study-accounting-monitoring-and-the-best-available-technologies-of-emissions-reduction/@@download/download

3.7.12 Norway Natural Gas Supply

Norway, the largest holder of oil and natural gas reserves in Europe, provides much of the oil and natural gas consumed on the continent. The U.S. Energy Information Administration (EIA) estimates that Norway was the 3rd largest exporter of natural gas in the world after Russia and Qatar. Pipeline gas from Norway contributed 20.34% of the EU natural gas supply in 2012. LNG from Norway contributed a further 0.53%. The Norwegian government publishes annual energy balances[51] for the country and, since Norway being a UNFCCC Annex 1 country, files its annual GHG inventory reports[52]. These sources provide much of the data required for modelling.

Norway exports natural gas via pipelines and on tankers in the form of liquefied natural gas (LNG). It has two export gas pipelines to the UK, two to the Netherlands and one each to France and Belgium.

Table 3-95 illustrates the releases of major pollutants to the air (CO_2, CH_4 and NO_X) for two major natural gas fields Snøhvit and Troll. It is evident that CO_2 emissions for Snøhvit have significantly decreased over the last decade, while for Troll field CO_2 emissions have dropped down by 35% from 2009 to 2013.

The emissions from two other significant Norwegian gas fields, Kvitebjørn and Åsgard, are illustrated in Table 3-96. The cumulative emissions from Kvitebjørn have increased over the last years as a result of increased gas production, even though it has to be stated that emissions per unit of gas produced have decreased from 25 tons CO_2 equivalent per million cubic meter in 2008 to approximately 11 tons CO_2 equivalent per million cubic meter in 2013. On the other hand, the emissions from Åsgard gas field have slightly decreased over time, but have increased per unit of output. In general emissions per unit of output for Åsgard are much higher compared to Kvitebjørn.

[51] Energy account and energy balance.

[redacted]

[52] National Inventory Report. 2014.

[redacted]

Table 3-95 Releases of major pollutants for Snøhvit and Troll oil fields (source: Norwegian Environment Directorate)

Year	Snøhvit: Releases of major pollutants to the air (in 1000 tons per year)			Year	Troll : Releases major pollutants the air (CO_2) (in 1000 tons per year)		
	CO_2	CH_4	NO_x		CO_2	CH_4	NO_x
2004	1.60	0.00	35.08	2004	-	-	-
2005	29.64	0.00	447.82	2005	-	-	-
2006	51.75	3.25	449.26	2006	-	-	-
2007	-	-	-	2007	-	-	-
2008	-	-	-	2008	-	-	-
2009	-	-	-	2009	689.35	1,594.24	4,498.87
2010	-	-	-	2010	705.61	1,446.13	4,396.74
2011	2.11	0.00	46.61	2011	713.37	1,441.18	5,438.67
2012	-	-	-	2012	685.46	1,435.92	4,631.69
2013	0.24	0.00	5.27	2013	443.50	1,560.64	3,852.90

Table 3-96 Carbon emissions for Kvitebjørn and Åsgard oil fields (source: Norwegian Environment Directorate)

Year	Kvitebjørn			Åsgard		
	Emissions in CO_2-equivalents (in tons per year)	Production volume of gas (in m^3 per year)	Emissions per unit of gas produced (tons/million m^3 per year)	Emissions in CO_2-equivalents (in tons per year)	Production volume of gas (in m^3 per year)	Emissions per unit of gas produced (tons/million m^3 per year)
2008	77,176	3,139.538	24.58	1,008,090	21,694.066	46.47
2009	80,112	5,310.39	15.09	1,041,109	21,413.73	48.62
2010	77,324	6,331.126	12.21	1,011,688	20,189.455	50.11
2011	65,975	6,745.399	9.78	1,011,383	18,090.706	55.91
2012	65,961	7,232.191	9.12	1,058,664	18,453.788	57.37
2013	81,029	7126.765	11.37	933,613	15,829.225	58.98

Oil and Gas Production

The production of oil and gas in Norway in 2012 as reported in the national energy balance is shown in Table 3-97. Natural gas production contributes slightly over 50% of the total hydrocarbon energy production.

Table 3-97 Norway Oil and Gas Production

Norway Oil and Gas Production		
Fuel	**PJ (HHV)**	**%**
Crude oil	3,377	38.76%
Nat Gas	4,733	54.34%
LPG	370	4.24%
Condensate	232	2.66%
Total	**8,712**	**100%**

Energy Use- Gas Production

The energy use for the energy sector has some segregation as shown in Table 3-98.

Table 3-98 Norwegian Energy Use in Oil and Gas Production

	Consumption in the fields	
	PJ	%
Natural gas	169	72.3%
Gas Flared	21	8.8%
Diesel	20	8.8%
Power	24	10.9%
Total	**234**	**100%**

The gas processing plants in Norway are located on shore and are part of the gas transport system. The data in the previous table can be used to determine the gas production energy use. While all of the gas production is offshore, Norway does have undersea power distribution to help reduce GHG emissions. The energy use is lower than some of the other countries supplying gas to Europe. The energy use is allocated between the products based on their energy content, see Table 3-99.

Table 3-99 Energy Use for Gas Production

	kJ/ton Natural Gas	%
Natural Gas	1,133,244	80.73%
Diesel	116,801	8.32%
Power	153,755	10.95%
Total	**1,403,800**	**100%**

CO2 from Solution Gas

The carbon dioxide content of Norwegian natural gas is reported to be up to 45 vol.%[53]. Norway does remove some of the CO_2 and re-injects the gas in a number of fields. In other cases the gas is blended with low CO_2 fields to meet the pipeline specification of 2.5% CO_2 and in some cases some of the gas is vented.

The quantity of CO_2 that is vented is reported in the annual GHG inventory reports submitted to the UNFCC. In 2012, the rate was 0.23 vol. % of the gas produced.

Methane Losses

The 2014 GHG Inventory Report (with 2012 data) reported fugitive and venting emissions for natural gas of 1,842 kg of methane per PJ of gas production. This equates to a methane loss rate of 0.01%. This will be split equally between production and processing.

This fugitive rate is very low, reflecting the effort that the country applies to reducing GHG emissions. It is only 20% of the low end of the IPCC default values for gas processing and production.

Energy Use - Gas Processing

Norway has two gas processing plants that remove LPG and condensate from the gas. These plants are managed by Gassco and they provide some basic information for the year 2012[54], see Table 3-100.

Table 3-100 Gas Processing Data

		PJ
Gas Production	107.6 billion m^3	4,304
Condensate and LPG Production	7.96 million tons	374
CO_2 emissions	1,389,000 tons	

Statoil provided more detailed information on these operations in their 2009 annual report[55]. The Kollsnes plant data include just the gas processing plant, whereas the larger Karsto plant data include the plant and some pipeline activities. However the Kollsnes plant is highly electrified as shown in Table 3-101.

[53] CO_2 Storage Atlas. Norwegian Petroleum Directorate. [redacted]

[55] Environmental Data. Statoil. 2009. [redacted]

Table 3-101 Knolsnes Gas Processing Data

	kJ/ton	%
Power	163,237	78.3%
Natural Gas	45,215	21.7%
Diesel	74	0.0%
Total	**208,526**	**100.0%**

For modelling we have used the energy requirements from the Kollsnes plant but the energy mix from the combined operations. The gas processing data for Norway used for the modelling are shown Table 3-102. The energy use is quite low reflecting the fact that some of the CO_2 is removed at the production platforms and that a significant portion of the gas is dry gas.

Table 3-102 Norway Gas Processing

	kJ/ton	%
Power	51,242	24.6%
Natural Gas	157,187	75.4%
Diesel	97	0.0%
Total	**208,526**	**100.0%**

Natural Gas Transport

No separate reporting of the energy used in the transport of the gas was identified. Gassco, the system operator reported the energy use for a gas plant and pipeline in 2009. The pipeline energy use is estimated as 0.000010 j/joule km of gas moved. This is a relatively low value. Norway does not report a separate leakage value for gas transmission.

Gas Transmission and Distribution

Transmission and distribution energy use and emissions do not occur within the EU and thus are not applicable to the Norwegian gas data in the model.

Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-103.

The non-energy CO_2 emissions from the gas processing are 0.23% of the gas production volume for pipeline gas.

Table 3-103 Energy Use Norwegian Natural Gas

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	116,801	1,133,244	153,846	1,403,800	0.005
Processing	97	157,187	51,242	208,526	0.005
Total	**123,582**	**1,291,100**	**205,088**	**1,619,770**	**0.01**

LNG Production

Norway became an LNG exporter in 2007 with the beginning of commercial production from the Snøhvit gas field, Norway's first natural gas development in the Barents Sea. CO_2 from the gas removed in the liquefaction process is re-injected. Operating data from 2009 are available from Statoil. This is a single LNG train with a capacity of 4.3 million tons per annum (mpta).

Energy Use

The energy use in the LNG plant was reported in the 2009 annual report. That data is shown in Table 3-104. LNG production in 2009 appears to be significantly less than capacity which would have a negative impact on the energy efficiency.

Table 3-104 Norwegian LNG Plants – Energy Use

Energy Type	Energy Use, kJ/ton LNG
Natural gas	5,474,696
Electricity	157,895
Diesel	1,670
Total	**5,634,261**

The 2013 Statoil Sustainability Report[56] stated that the CO_2 intensity level of LNG production in 2012 was 224 kg/ton of LNG. This would be equivalent to an energy use of about 4.5 GJ/ton of LNG. The 2009 fraction of energy supplied by each source has been applied to the 4.5 GJ/ton value to arrive at the modelling inputs for Norwegian LNG. The plant re-injects the CO_2 removed rather than emitting it.

[56] 2013 Sustainability Report. Statoil.

[redacted]

Methane Losses

The low IPCC value for LNG facilities is used for the modelling. The methane loss for the LNG plant and the regasification will be assumed to be 0.005% of the gas throughput.

LNG Summary - Norway

The data for modelling LNG production in Norway are shown in Table 3-105.

Table 3-105 Norway LNG production data

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	116,801	1,133,244	153,846	1,403,800	0.005
Processing	97	157,187	51,242	208,526	0.005
LNG production	1,350	4,372,650	126,000	4,500,000	0.005
Total	**215,151**	**5,663,081**	**331,088**	**6,112,326**	**0.015**

3.7.13 Algeria Natural Gas Supply

Algeria is the leading natural gas producer in Africa, the second-largest natural gas supplier to Europe, and is among the top three oil producers in Africa. Pipeline gas from Algeria contributed 6.84% of the EU natural gas supply in 2012. LNG from Algeria contributed a further 2.05%. The Algerian government published annual energy balances for the country and has published a GHG inventory report[57] in 2010, however the data are for the year 2000. The 2012 Energy Balance[58] report is used for this work.

Algeria exports natural gas via pipelines and on tankers in the form of liquefied natural gas (LNG). It has three transcontinental export gas pipelines: two transport natural gas pipelines to Spain and one to Italy. Algeria's LNG plants are located in the coastal cities of Arzew and Skikda. Algeria was the first country in the world to export LNG in 1964. The LNG plants are relatively old but new facilities are under construction.

Oil and Gas Production

The production of oil and gas in Algeria in 2012 is shown in Table 3-106. Natural gas production contributes slightly over 50% of the total hydrocarbon energy production.

[57] Inventaire national des émissions de gaz à effet de serre de l'année 2000.

[redacted]

[58] Bilan Énergétique National, année 2012. (National Energy Balance). http://www.mem-algeria.org/fr/statistiques/Bilan_energetique_national_2012_edition_2013.pdf

Table 3-106 Algerian Oil and Gas Production

Algerian Oil and Gas Production		
	1,000 Tons of Oil Equivalent	%
Crude oil	56,323	36.2%
Condensate	10,553	6.8%
Nat Gas	81,323	52.3%
LPG	7,255	4.7%
Total	**155,454**	**100%**

Energy Use

The energy use for the energy sector has some segregation as shown in Table 3-107.

Table 3-107 Algerian Energy Use in Oil and Gas Production

Fuel	Consumption in the fields	Gas / Oil Pipeline	Other*	Total
	K TOE			
Crude oil	114			114
Natural gas		676	819	1,583
LNG			20	20
High stove gas			117	117
Power			1,201	1201
Total	**114**	**676**	**2,157**	**3,035**

The National Energy Balance also identifies 3,868 TOE of natural gas that is flared in the production process. Separating the pipeline energy, adding the gas flared, and allocating the energy use in the sector by energy the following data for modelling are derived. The LNG and stove gas will be modelled as natural gas consumption. The values are low compared to some other regions but the energy use is highly electrified, whereas other regions consume natural gas to produce the energy, see Table 3-108.

Table 3-108 Energy Use for Gas Production and Processing

Fuel	kJ/ton Natural Gas	%
Crude oil	38,133	1.9%
Nat Gas	1,613,648	78.5%
Power	401,739	19.6%
Total	**2,053,521**	**100%**

CO_2 from Solution Gas

The carbon dioxide content of Algerian natural gas is reported to be 1.0 to 10.0 vol.%[59]. There is one project that captures the gas removed from the high CO_2 fields and re-injects the gas into the water layer of a gas field.

It has been assumed that 1% CO_2 is removed from the gas for the pipeline natural gas and 2% CO_2 is removed for the LNG systems.

Methane Losses

The 2010 GHG Inventory Report reported fugitive and venting emissions for natural gas of 940,000 tons of methane. Gas production in 2000 was 65,000 kTOE. This equates to a methane loss rate of 2.1%. The Inventory Report identifies the natural gas fugitive emissions to account for 9.29% of the total GHG emissions in the country.

This fugitive rate is about three times higher than the IPCC guidance for natural gas production and processing systems for national GHG inventories[60] . They provide a range of gas loss estimates for natural gas facilities. These are summarized in Table 3-109.

Table 3-109 IPCC Gas Loss Rates

	Low	Medium	High	Units
NG Production and Processing	0.05	0.2	0.7	%
Gas Transmission Pipeline	200	2000	20,000	M^3/km/year
LNG Plant (Liquefaction or regasification)	0.005	0.05	0.1	%

[59] The In-Salah CCS Experience Sonatrach, Algeria. http://www.opec.org/opec_web/static_files_project/media/downloads/press_room/HaddadjiSonatrach_Algeria.pdf

[60] 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2 Energy. [redacted]

Natural Gas Transport

The oil and gas pipeline energy use is segregated in the National Energy Balance. The results are shown in Table 3-110 when the energy used is allocated across products by their energy content.

Table 3-110 Algerian Natural Gas Transport Energy

	TOE	joules/joule
Natural Gas	676	0.0043
Power	23	0.0001
Total	**699**	**0.0045**

With pipeline distances of 1000 to 2283 km (to the SW and SE regions, the energy consumption is very low. We have assumed the default value of 0.00003 j/j-km for the modelling.

Transmission and Distribution

Transmission and distribution energy use and emissions occur within the EU and thus are not applicable to the Algerian gas data in the model.

Natural Gas Production Summary

The data used for energy consumption in the model are summarized in Table 3-111.

Table 3-111 Energy Use Algeria Natural Gas

	Crude Oil	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	38,000	807,000	201,000	1,046,000	1.8
Processing	0	807,000	201,000	1,008,000	0.2
Total	**38,000**	**1,614,000**	**402,000**	**2,054,000**	**2.0**

The non-energy CO_2 emissions from the gas processing are 1.0% of the gas production volume for pipeline gas.

LNG Production

Algeria has liquefaction units located along the Mediterranean Sea at Arzew and Skikda. New plants are under construction at both Arzew and Skikda. LNG Production in 2012 was 11.1 million tons[61], see Table 3-112.

Table 3-112 Algerian LNG Plants – 2012

Location	Start-up	Trains	Capacity, MTA
Arzew	1964-1981	12	17.3
Skida	1972	3	2.9
Total			**31**

Energy Use

The energy use in the LNG facilities is reported in the National Energy Balance statistics, when these data re combined with the LNG production data, Table 3-113 is produced. The energy use is higher than the more modern plants in Qatar and Nigeria but it is reflective of the fact that Algeria was the first LNG exporter in the world.

Table 3-113 Algerian LNG Plants – Energy Use

Energy Type	Energy Use, kJ/ton LNG
Natural gas	12,390,000
Electricity	89,700
Total	**12,479,700**

Methane Losses

The high IPCC value for LNG facilities is used due to the age of the facilities but this is applied to the combined liquefaction and re-gasification activity. The methane loss for the LNG plant and the regasification will be assumed to be 0.10% of the gas throughput.

LNG Summary

The data used for energy consumption in the model are summarized in the following table. It has been assumed that all of the energy is supplied by natural gas. The processing stage includes the gas processing plus the liquefaction and the re-gasification energy. The re-gasification energy will be assumed to be natural gas and equal to 1.5% of the throughput (780,000 kj/ton). These data are summarized in Table 3-114.

The non-energy CO_2 emissions from the gas processing are 2.0% for LNG.

[61] Bilan des Réalisations du Secteur de l'Energie et des Mines 2012. [redacted]

Table 3-114 Energy Use Algeria LNG Production

	Crude Oil	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	38,000	807,000	201,000	1,046,000	1.8
Processing	0	807,000	201,000	1,008,000	0.2
LNG production	0	12,363,000	89,700	12,273,300	0.10
Total	38,000	13,977,000	491,700	14,327,300	2.1

3.7.14 Libya Natural Gas Supply

Libya is a significant producer of oil and gas. Libyan gas contributes 1.30% of the gas consumed in the EU. Gas from Libya is transported by pipeline to Italy.

Oil and Gas Production

The production of oil and gas in Libya in 2012, as reported in the IEA energy balance[62], is shown in the following table. Natural gas production contributes 12% of the total petroleum energy production.

Table 3-115 Libya Oil and Gas Production

Libya Oil and Gas Production		
Fuel	PJ (HHV)	%
Crude oil	3,433	88.0%
Nat Gas	467	12.0%
Total	**3,900**	**100.0%**

Energy Use- Gas Production

Very little information is available on the energy use in gas production in Libya. The data in the IEA energy balance are not consistent with other published data. The primary data source used for the work is the paper by Taglia and Rossi (2009)[63].

The paper reports emissions in production, processing, and pipeline transport. We have assumed that natural gas use is 90% of the energy consumed and diesel fuel and power are 5% each. The energy use is back calculated from the reported emissions.

The energy use for production is shown in the Table 3-116.

[62] Libya Energy Balance 2012.
http://www.iea.org/statistics/statisticssearch/report/?country=LIBYA&product=balances&year=2012
[63] Taglia, A., Rossi, N. 2009. European Gas Imports: GHG Emissions from the Supply Chain.

Table 3-116 Energy Use for Gas Production

Fuel	kJ/ton Natural Gas	%
Diesel Fuel	53,560	4.77%
Natural gas	1,016,080	90.46%
Power	53,560	4.77%
Total	**1,123,200**	**100.00%**

CO_2 from Solution Gas

The CO_2 content of Libyan gas is very high and the CO_2 that is removed in the gas processing plants is 12%.

Methane Losses

The IPCC default values for gas production are used. The IPCC range is 0.05 to 0.7% for the combined production and processing. The value for production has been set at 0.5%.

Energy Use - Gas Processing

The high CO2 level in the gas requires significant energy to remove it. The energy use calculated from Taglia is shown in Table 3-117.

Table 3-117 Energy Use for Gas Processing

	kJ/ton Natural Gas	%
Diesel Fuel	0	0.0%
Natural gas	166,400	5.00%
Gas Flared	2,995,200	90.00%
Power	166,400	5.00%
Total	**3,328,000**	**100.00%**

The methane loss for gas processing is assumed to be 0.20%, making the combined production and processing gas loss at the high end of the IPCC range.

Natural Gas Transport

The gas from Libya is transported 516 km to Italy. The data from Taglia suggest that the pipeline energy is 0.05 joules/joule transported. This would be 0.000097 j/j-km, significantly higher than the figure found in other regions; however the 516 km pipeline distance is from Mellitah to Sicily and doesn't include the pipeline distance from the field to the gas complex at Mellitah. If we use a 1000 km pipeline distance to account for the field to processing plant, then the energy is 0.000050 j/j-km, a value in line with some other countries.

The IPCC emission factor for transmission fugitive emissions is 200 to 20,000 m^3/km/year,

with a mean value of 2,000. For Libya, assuming 1000 km total transmission line distance, this would be a loss rate of 0.016%.

Gas Transmission and Distribution

Libya is outside of the gas use regions and thus the gas transmission and distribution emissions are captured in the use region (Italy).

Summary

The data used for energy consumption in the model are summarized in Table 3-118. The energy use in gas production is higher than many of the other countries but it is based on Italian data and not generic emission factors.

Table 3-118 Energy Use Libya Gas Production and Consumption

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	53,560	1,016,080	53,560	1,123,200	0.50
Processing	166,400	2,995,200	166,400	3,328,000	0.20
Transmission					0.016

The non-energy CO_2 emissions from the gas production are 12% of the gas production volume.

3.7.15 Qatar Natural Gas Supply

LNG from Qatar contributed 5.63% of the EU natural gas supply in 2012. Only the LNG production and transportation data are required for modelling since the downstream emissions are within the EU and are not specific to the gas production location.

There are two production companies, Qatargas and RasGas. Both companies operate multiple facilities and some facilities have multiple production trains. Both companies publish an annual sustainability report which has detailed information on their environmental performance[64,65]. Multiple years of reports are available from Qatargas; however only the 2013 report from RasGas was available but it has previous year's data.

[64] Qatargas Sustainability Report 2012.

[redacted]

Energy Production

The LNG production from both companies in 2012 is shown in the following table. Each company has other operations including gas processing for gas sales, condensate production, refining, helium production and other activities. The Qatargas sustainability provides some segmented data on energy use and emissions by plant. The RasGas data are less detailed and does not have the same degree of segmentation (Table 3-119).

Table 3-119 Qatar LNG Production in 2012

	No. Plants	No. Trains	Million Tons	% of total
Qatargas	4	7	40.0	51.9%
RasGas	1	7	37.1	48.1%
Total			**77.1**	**100%**

Energy Use

Both companies report the energy use and the flaring rates and the total production so the energy rate can be calculated, see Table 3-120.

Table 3-120 Energy Use for LNG Production

Type	NG for Energy, GJ/ton LNG	Flare gas, GJ/ton LNG	Total, GJ/ton LNG
Qatargas	6.50	0.98	7.48
RasGas			7.62

The Qatargas data are segregated by plant and they cover the gas production, gas processing and LNG production stages although the data are not segregated by stage. There is no purchased electricity in the Qatargas plants. The system boundaries for the RasGas data are less transparent and there is a small amount of electricity that is purchased. The total energy requirements for the two companies are very close. 7.5 GJ/ton will be used for modelling.

CO_2 from Solution Gas

Carbon dioxide is released during the gas processing stage as the gas solidifies at a higher temperature than the LNG. Qatargas reports the percent of the GHG emissions that arise from this source. It is equivalent to 2.8% of the gas throughput. RasGas re-inject about 1 million tons per year of the solution gas.

Methane Losses

The total methane emissions are reported for both Qatargas and for RasGas. The Qatargas emissions are 4.8 g/GJ of natural gas consumed. This emission rate is very low and is likely just from the combustion of the natural gas.

The IPCC provides guidance for developing national GHG inventories[66] . They provide a range of gas loss estimates for natural gas facilities. These are summarized in Table 3-121.

Table 3-121 IPCC Gas Loss Rates

	Low	Medium	High	Units
NG Production and Processing	0.05	0.2	0.7	%
Gas Transmission Pipeline	200	2000	20,000	M^3/km/year
LNG Plant (Liquefaction or regasification)	0.005	0.05	0.1	%

Natural Gas Transport

Both LNG companies own their own fleets of LNG tankers. The Qatargas vessels range in size from 137,500 m^3 to 266,000 m^3 (62,700 to 121,300 tons). The RasGas vessels are in the same range. The newer vessels for both companies have re-liquefaction plants to return boil-off gases to the cargo. The fuel use in the Qatargas vessels is 73.4% heavy fuel oil, 0.7% marine gas oil, and 25.9% LNG. A portion of the LNG is consumed in port. Qatargas provides the total distance travelled, the total tons shipped, the energy used, and the emissions but not the tons-km shipped so it is not possible to determine the exact energy use factor from the supplied data.

Transmission and Distribution

Transmission and distribution energy use and emissions occur within the EU and thus are not applicable to the Qatar LNG data in the model.

Summary

The data used for energy consumption in the model are summarized in the following table. It has been assumed that all of the energy is supplied by natural gas. The processing stage includes the gas processing plus the liquefaction. The allocation of the total energy use between production and processing is somewhat arbitrary, since the emissions are all upstream emissions for this project, but it has been chosen to model the methane emissions from the combustion close to the reported values. The energy use for gas production in Qatar is shown in Table 3-122.

The low IPCC value for gas loss for gas production and processing has been chosen because of the compact, high volume nature of the Qatar gas fields. The medium IPCC value for LNG facilities is used but this is applied to the combined liquefaction and re-gasification activity. The non-energy CO_2 emissions from the gas processing are 2.8% of the gas production volume. The shipping vessel size will be chosen to be 100,000 tons.

[66] 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2 Energy, [redacted]

Table 3-122 Energy Use Gas Production

	Natural gas	Total	Gas lost, % of stage output
	kJ/ton of gas		
Production	500,000	500,000	0.05
Processing	7,000,000	7,000,000	0.05
Total	**7,500,000**	**7,500,000**	**0.1**

3.7.16 Nigeria Natural Gas Supply

LNG from Nigeria contributed 2.22% of the EU natural gas supply in 2012. Only the LNG production and transportation data are required for modelling since the downstream emissions are within the EU and are not specific to the gas production location.

Nigeria LNG Limited operates the only LNG facility in Nigeria. It has been in operation since 1999. The company now operates six liquefaction units (LNG trains) producing 22 million metric tons of LNG per year (mtpa). The facility is fed by six dedicated natural gas pipeline and it includes a gas processing plant that produces 5 tons per year of LPG and condensate. Nigeria LNG Limited provides only limited environmental data for their operations.

Gas Production

The Nigerian Petroleum Corporation does supply some data on gas production and utilization. This information is summarized in Table 3-123. The total production volume is aligned with the US DOE EIA production data for 2012.

Table 3-123 Nigerian Gas Production

	(MSCF)	%
Gas Produced	2,580,165,626	
Gas Used as Fuel	115,677,106	4.48
Gas Lift	72,904,179	2.83
Gas for LNG	329,863,144	12.78
Gas Re-injected	462,875,916	17.94
Gas Utilized (other)	1,010,178,556	39.15
Gas Flared	588,666,724	22.82

Twenty-two percent of the natural gas in Nigeria is flared as there is no market for this associated gas production.

Energy Use

The gas used for gas production calculated from the above data would be 2,330,000 kJ/ton of gas. It is not clear if this will include gas used in all of the gas processing facilities. We have assumed that it does include the gas processing and we allocate 50% to gas production and 50% to gas processing. This gas would also include gas used for power production in the facilities and it would include the gas pipeline energy use.

CO_2 from Solution Gas

The carbon dioxide content of Nigerian natural gas is reported to be 1.5 to 2.0 vol%[67]. We have taken the mid-point for modelling and since the gas is used for LNG production all of this gas is removed in the process.

Methane Losses

No data have been found on fugitive emissions for gas processing. The IPCC provides guidance for developing national GHG inventories[68]. They provide a range of gas loss estimates for natural gas facilities. These are summarized in Table 3-124.

Table 3-124 IPCC Gas Loss Rates

	Low	Medium	High	Units
NG Production and Processing	0.05	0.2	0.7	%
Gas Transmission Pipeline	200	2000	20,000	M^3/km/year
LNG Plant	0.005	0.05	0.1	%

Nigeria's Second National Communication for the UNFCCC[69] reports that fugitive emissions in the energy sector account for 14.3% of the GHG emissions in the energy sector. Given the high fugitive emissions in the Nigerian petroleum sector a high value of 0.7% has been assumed for fugitive emissions for gas production and processing. This has been allocated 0.70% to gas production and 0.05% to gas processing. This will include the fugitive emissions from the pipelines feeding the LNG plant.

LNG Production

The company now operates six liquefaction units (LNG trains) producing 22 million metric tons of LNG per year (mtpa). The facility includes a gas processing plant that produces 5 tons per year of LPG and condensate. The company states that the gas intake is 3.5 billion scf/day[70], however this would appear to be less energy than they report producing unless

[67] Gas Flaring and Venting Associated with Petroleum Exploration and Production in the Nigeria's Niger. [redacted]

[68] 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2 Energy. [redacted]

[69] Nigeria's Second National Communication. [redacted].

it is post the gas processing plant. If that is the case then the energy use for the liquefaction plant is 6 GJ/ton of LNG.

Energy Use

There have been a number of benchmarking studies done on global LNG facilities. These are often quoted in the EIA studies for new LNG plants. Woodside Petroleum[71] reported 0.35 t CO_2/ton of LNG for the plant GHG emissions for the Nigeria LNG plant. KPMG[72] reported emissions of 0.29 t CO_2/ton but this work just quoted a number of other studies. Both of these sources would have estimated the emissions just from the facility and not have included any upstream emissions. A value of 0.30 t CO_2/ton would be equivalent to an energy use 6 GJ/ton of LNG. This value will be used for the modelling.

Methane Losses

The medium IPCC value for LNG facilities is used but this is applied to the combined liquefaction and re-gasification activity. The methane loss for the LNG plant and the regasification will be assumed to be 0.05% of the gas throughput.

Natural Gas Transport

Nigeria LNG has a total of 23 ships on long-term charter for its six-train operation. In 2012, 214 cargoes[73] were loaded which suggests an average cargo size of 100,000 tons. This will be used in the modelling.

Transmission and Distribution

Transmission and distribution energy use and emissions occur within the EU and thus are not applicable to the Nigerian LNG data in the model.

Summary

The data used for energy consumption in the model are summarized in the Table 3-125. It has been assumed that all of the energy is supplied by natural gas. The processing stage includes the gas processing plus the liquefaction.

The non-energy CO_2 emissions from the gas processing are 1.75% of the gas production volume.

[71] Woodside (2007), Pluto LNG Project, Greenhouse Gas Abatement Program – September 2007.

[72] KPMG. 2014. Pacific Northwest LNG Limited Partnership, Summary: Independent Review of Power Options Evaluation and Selection Process.

Table 3-125 Energy Use Nigeria LNG Production

	Natural gas	Total	Gas lost, % of stage output
	kJ/ton of gas		
Production	1,165,000	1,165,000	0.70
Processing	1,165,000	1,165,000	0.05
LNG production	6,000,000	6,000,000	0.05
Total	**8,330,000**	**8,330,000**	**0.8**

3.7.17 Azerbaijan Natural Gas Supply

Azerbaijan was not a gas supplier to the EU in 2013 but it is expected to be a supplier in 2030. Azerbaijan has been an oil and gas producer for over 150 years but natural gas exports only started in 2006 (to Turkey). Recent gas discoveries and pipeline expansions are expected to increase gas export volumes and destinations.

Oil and Gas Production

The production of oil and gas in the Azerbaijan in 2012 as reported by the US EIA is shown in the following table. Natural gas production contributes 24% of the total hydrocarbon energy production (Table 3-126).

Table 3-126 Azerbaijan Oil and Gas Production

Azerbaijan Oil and Gas Production		
	PJ (HHV)	%
Crude oil	2,092	75.8%
Nat Gas	669	24.2%
Total	2,761	100.00%

Energy Use- Gas Production

One of the largest operators in Azerbaijan is BP. They publish a sustainability report[74] for their activities in the country. BP production is about one third gas and two thirds oil. BP report the energy consumption for all activities and their GHG emissions by facility. The energy use data have been allocated on the basis of the product energy content as shown in the following table. The energy use is very low compared to other producing countries, see Table 3-127.

[74] BP in Azerbaijan Sustainability Report 2013. [redacted]

The GHG emissions reported by BP suggest that about half are from gas processing and half are from the other activities. The emissions in the model have therefore been allocated to the two stages equally.

Table 3-127 Energy Use for Gas Production and Processing

	kJ/ton Natural Gas	%
Natural gas	1,270,000	96.1%
Diesel	52,000	3.9%
Power	1,000	0.04%
Total	1,323,000	100.00%

CO2 from Solution Gas

The quantity of CO_2 that is vented from gas processing plants is not readily available. Gomez[75] reports CO_2 in the pipeline gas of 0.2%, a low value such as this would suggest that there is little CO_2 in the raw gas as gas plants wouldn't remove more gas than necessary to reach meet the pipeline quality specification. We have assumed that only 0.1% of the volume of gas is emitted as CO_2.

Methane Losses

The BP report shows methane losses of only 0.0216% for gas production and processing activities. This is very low for activities in the developing world. We have used values of 0.2% for both gas production and processing, which are more in line with the available data from other countries.

Natural Gas Transport

The natural gas transmission distance from the field to SE EU is estimated at 3,400 km. The pipeline energy requirements are set at 0.000030 j/j-km, a standard value used in the model. The gas loss is set to 0.5%, a relatively low value for the length of the pipeline, reflecting the fact a significant portion of the pipeline is new. It is assumed that 5% of the pipeline energy is electricity.

Azerbaijan Production Summary

The data used for energy consumption for gas production and processing in the model are summarized in Table 3-128.

[75] Gomez et al. 2008. South Caucasus Pipeline Technical Details and Political Background.

Table 3-128 Energy Use Azerbaijan Natural Gas Production and Processing

	Diesel	Natural gas	Power	Total	Gas lost, % of stage output
	kJ/ton of gas				
Production	26,000	635,000	100	661,500	0.20%
Processing	26,000	635,000	100	661,500	0.20%

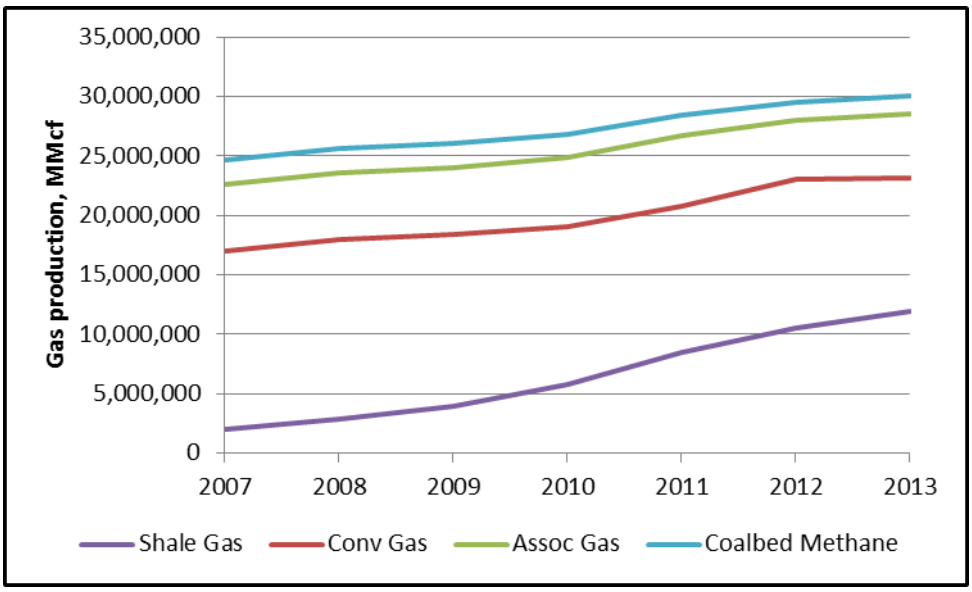
3.7.18 Unconventional Natural Gas Supply

Unconventional gas reservoirs often refers to low permeability rock where the pores are poorly connected, making it difficult for oil and natural gas to move through the rock to the well. New drilling technologies, such as horizontal drilling and hydraulic fracturing are making it possible to economically extract gas and oil from these low permeability reservoirs.

Gas Production

Unconventional oil and natural gas—shale gas in particular—has been called the future of gas supply in North America but shale gas resources are widely distributed around the world. It is just that production is more advanced in North America. Shale gas production in the United States reached almost 40% of total gas production in 2013, as shown in Figure 3-69.

Figure 3-69 US Gas Production by Type



GHGenius has data on the average US natural gas production. The data in the model are

derived from two sources, the Energy Information Administration (EIA)[76], and the US EPA. The EIA data are used for the energy requirements for gas production, processing, and transport. The EIA data consist of a time series of data from 1990 to 2013. The EPA dataare used for methane and CO_2 emissions. These are derived from the 2013 National GHG Inventory Report[77]. This report contains actual data up to 2011 and it involved a major recalculation of the emissions associated with natural gas production. The two reports released since then have only minor recalculations. The data are also entered into the model as a time series. Emission factors are calculated in the model from the two data sources.

The scenario that has been modelled is US shale gas production in the North East that is pipeline to the coast, liquefied, and transported to Europe. Minor adjustments to the data have been made to model shale gas instead on the average US natural gas.

Well Drilling

Well drilling and hydraulic fracturing data in GHGenius were obtained from actual well data from two companies. These data have been used for this US shale gas pathway. The energy use is shown in the following table. It is a relatively small portion of the total lifecycle energy use.

Table 3-129 Energy Use Well Drilling

Fuel	Well Drilling
	kJ/ton gas
Diesel	55,000
Natural gas	55,000
Power	5,000
Total	115,000

Methane Losses

One of the areas of controversy with hydraulic fracturing is the rate of methane loss during the well completion when the chemicals used for fracturing are removed from the well. This is actually one of the few actual differences between a shale gas well and a conventional well. The methane loss for the year 2012 was 138,000 tons of methane. This is a rate of 0.10% of the shale gas produced. This is added to the model as the methane loss rate for well drilling.

[76] US EIA. Natural Gas [redacted]

[77] U.S. Greenhouse Gas Inventory Report: 1990-2011.
http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf

Energy Use- Gas Production

The energy use for the gas production is from EIA data. These data have some segregation as shown in Table 3-130.

Table 3-130 US Energy Use in Gas Production

Fuel	Energy Use in Gas Production
	kJ/ton gas
Crude oil	58,590
Diesel	125,777
Residual oil	27,227
Natural gas	1,936,927
Power	321,810
Petrol	44,840
Total	581,107

No data were identified related to the energy use and emissions from well drilling although the data on energy use and emissions for the sector in total would appear to include well drilling. The energy use for well drilling has been entered as zero in the model since this information is captured in the production energy use and emissions.

The methane loss rate for gas production in the US is 0.56% of the gas production.

Energy Use - Gas Processing

Energy use in gas processing is from EIA data for US gas plants (Table 3-131).

Table 3-131 US Energy Use in Gas Processing

Fuel	Energy Use in Gas Processing
	kJ/ton gas
Diesel	383
Natural gas	800,519
Power	25,931
Petrol	280
Total	827,113

CO2 from Solution Gas

The CO_2 removed from the natural gas is taken from the EPA GHG Inventory. For the LNG case it is the reported emissions plus the 0.8% CO_2 in the pipeline gas, as this will be removed in the LNG plant. The total is 2.36%

Methane Losses – Gas processing

Methane losses from the gas processing are from the EPA GHG Inventory. They are 0.21% for the year 2012.

Natural Gas Transport

In this scenario the gas is pipelined 500 km from the production field to the coast. This is the distance from Scranton PA to Boston MA.

Energy Use – LNG Production

The US has traditionally been an importer of LNG. The industry there is now looking at building LNG plants for gas export. It has been assumed that 5,000,000 KJ of gas are consumed in the liquefaction process. This is not the lowest of the plants that have been studied for this work but it is towards the low end of the range.

Methane Losses – LNG Production

The low IPCC value for LNG facilities is used due for the modelling. The methane loss for the LNG plant and the regasification will be assumed to be 0.005% of the gas throughput.

LNG Transport

The LNG transport distances from Boston to the receiving terminals in the EU regions are presented in Table 3-132.

Table 3-132 LNG Transport Distances

	LNG Transport Distance
	km
EU North -UK	5,000
EU Central - Rotterdam	5,730
EU Southeast - Italy	5,200
EU Southwest - Portugal	8,700

3.7.19 Natural gas transport data

Transportation Distances

The calculation of the energy consumed for gas transport and transmission is generally a difficult exercise since natural gas pipelines can cross many transmission systems before reaching delivery points. It may be necessary to calculate this energy use and emissions from the transport and transmission line distances and an energy consumption rate. A matrix has been developed with the transport distances of each major pipeline transporting natural gas to the EU from every gas producing region to the main delivery points and transmission system lengths for every EU consuming region. The model

calculates the appropriate distance and energy use based on the sources of gas used in each consuming region.

In order to calculate the GHG emissions related to natural gas transport from producing countries to the EU, the transport distances have to be calculated for both modes of transport: major pipelines and LNG. Separate matrices are developed for pipeline and LNG supply systems. LNG shipping distances and an assumed size of the tankers is used to calculate the energy consumption and emissions associated with these gas sources.

Pipeline distances

The starting and ending points and lengths of all major pipeline routes arriving to the EU are presented in Table 3-133. These distances derive from various sources, notably the pipelines' operators' websites. After arrival to the corresponding ending point, the natural gas flows in the interconnected EU transmission systems.

Table 3-133 Lengths of major natural gas pipelines supplying the EU

Producing Country	Pipeline name	Starts	Ends	Length (km)
Algeria	MEDGAZ	Hassi R'Mel, Algeria	Almeria, Spain	787
	TRANSMED	Hassi R'Mel, Algeria	Bologna, Italy	2,283
	MEG Pipeline	Hassi R'Mel, Algeria	Cordoba, Spain	1,327
Russia	Brotherhood	Urengoy, Russia	Baumgarten, Austria	3,963
	Yamal-Europe	Yamal, Russia	Germany	4196
	Nord Stream	Vyborg, Russia	Greifswald, Germany	1,140
	South-eastern Europe transport route	Urengoy, Russia	Greece	4,500
Norway	Franpipe	North Sea	Dunkirk, France	840
	Zeepipe (total)	North Sea	Zeebrugge, Belgium	1,416
	Europipe (total)	North Sea	Dornum, Germany	1,328
	Norpipe	North Sea	Emden, Germany	354
	Vesterled	North Sea	Peterhead, Scotland	360
	Langeled	North Sea	UK	1,666
UK	Interconnector	UK	Zeebrugge, Belgium	153
Libya	Green Stream	Melita	Sicily	516

LNG transportation distances

The distances between the major LNG exporting terminals of the LNG suppliers and the major LNG importing terminals in the EU are presented in Table 3-134 and are calculated based on the distances between the relevant ports.

It must be noted that the LNG streams from Algeria and Libya to the EU include also a transport distance by pipeline from the main gas producing field to the liquefaction plants, in addition to the distance travelled by LNG carrying vessels. These distances are presented inTable 3-135.

Table 3-134 LNG transport distances from LNG suppliers to importers in the EU

LNG transportation distances to the EU in kilometers				LNG Producers				
				Norway	Algeria		Nigeria	Qatar
				Liquefaction terminals				
LNG Importers				Snohvit	Arzew	Skikda	Bonny	Ras Laffan
South East EU	GR - Greece	Receiving Terminals	Revithoussa	-	-	1963	-	-
	IT - Italy		Adriatic LNG	-	-	-	-	9310
			La Spezia	-	-	978	-	-
	SI - Slovenia		La Spezia	-	-	978	-	-
Central EU	BE - Belgium		Zeebrugge	-	3502	-	9099	13290
	NL - Netherlands		Rotterdam	2571	-	-	9160	-
North EU	UK - United Kingdom		Isle Of Grain	-	3317	-	-	-
			Milford Haven	-	-	-	-	12614
South West EU	ES - Spain		Ferrol (Mugardos)	-	1880	-	-	-
			Barcelona	6595	-	876	7791	9728
			Cartagena	-	278	783	7195	9806
			Bilbao	-	-	-	7902	12093
			Huelva	5274	-	1428	6787	10560
			Sagunto	-	-	-	7532	9819
	FR - France		Fos-sur-Mer	-	-	954	8230	-
			Montoir de Bretagne	3850	2698	-	8295	12486
	PT - Portugal		Sines	-	-	-	6765	10838

Table 3-135 Pipeline lengths from gas fields to liquefaction plants in Algeria and Libya

Producing Country	Pipeline	Starts	Ends	Distance (km)
Algeria	Hassi R'Mel - Arzew	Hassi R'Mel, Algeria	Arzew	515
	Has Rmel Si - Skikda	Hassi R'Mel, Algeria	Skikda	616
Libya	Wafa - Melita	Wafa, Libya	Melita, Libya	598

3.7.20 Natural Gas downstream data

There are a number of EU countries that do not produce natural gas but are consumers of gas. Data on the transmission and distribution of gas in these countries are required for the modelling. For all of these consuming only regions the energy used in the gas transmission system is required, the proportion that is supplied by electricity and the fugitive emissions in the transportation and distribution systems are required. Where a country is a producer and a consumer, this information was provided in the previous section.

Regional Electric Power – EU

Electric power will be used for the compression of the natural gas to be used in CNG compressors. This requires the emission profile for the average mix of electric power used in each of the 26 countries considered by the model. These data are being extracted and compiled from Eurostat data for the year 2012. The data are analyzed by country and are aggregated by EU region as it is shown in Table 3-136.

Table 3-136 Regional EU Power Supply (the percentage of power supplied by each type of generation)

	Electric Power Supply								
EU Region	Coal	Oil	Gas	Nuclear	Wind	Other Carbon	Biomass	Hydro	Other
North	0.100	0.025	0.120	0.523	0.104	0.007	0.015	0.104	0.001
Central	0.385	0.016	0.175	0.168	0.081	0.029	0.065	0.078	0.002
SE	0.247	0.069	0.333	0.048	0.102	0.017	0.029	0.152	0.002
SW	0.277	0.007	0.436	0.000	0.024	0.008	0.002	0.237	0.000

The electric power calculations also require the efficiency of the thermal power plants; these data are also extracted from Eurostat. Power plants that are combined heat and power plants have their efficiencies calculated by allocating the energy input to the heat and power on an energy basis. The results are analyzed by country and aggregated to EU regions as it is shown in Table 3-137.

Table 3-137 Regional EU Power Generation Efficiency

	Electric Power Efficiency							
EU Region	Coal	Oil	Gas	Nuclear	Wind	Other Carbon	Biomass	Hydro
North	0.395	0.615	0.557	0.350	1.000	0.395	0.329	1.000
Central	0.394	0.685	0.540	0.350	1.000	0.394	0.373	1.000
SE	0.354	0.461	0.548	0.350	1.000	0.354	0.191	1.000
SW	0.357	0.452	0.501	0.350	1.000	0.357	0.250	1.000

Finally the electrical distribution losses are calculated on a country basis and aggregated on a regional basis. The results are shown in Table 3-138. The GHGenius model uses all of this information to calculate the GHG emission intensity of the power consumed in each region. The resulting carbon intensities of EU countries' electric power systems are presented in Table 3-139.

Table 3-138 Electric Power Distribution Losses

EU Region	Power Distribution Losses
North	8.03%
Central	5.69%
SE	8.19%
SW	9.45%

Table 3-139 Carbon Intensities of Member States' electric power systems

EU Region	Country	Electric power Carbon Intensity (gCO_2eq/kWh)
South-East	Bulgaria	584
	Greece	844
	Croatia	356
	Italy	440
	Cyprus	907
	Malta	1,147
	Romania	487
	Slovenia	349
	SE EU Average	**487**
Central	Belgium	196
	Czech Republic	515
	Germany	483
	Estonia	719
	Latvia	118
	Lithuania	217

EU Region	Country	Electric power Carbon Intensity (gCO_2eq/kWh)
	Luxembourg	246
	Hungary	334
	Netherlands	422
	Austria	153
	Poland	768
	Slovakia	196
	Central EU Average	**466**
North	Denmark	259
	Ireland	604
	Finland	187
	Sweden	53
	United Kingdom	546
	North EU Average	**355**
South-West	Spain	374
	France	106
	Portugal	422
	SW EU Average	**218**
EU Average		**411**

Transmission systems

As mentioned previously, the GHG emissions related to natural gas transmission and distribution will be calculated as a function of the total pipeline length, by using emission factors. Table 3-140 provides the natural gas transmission systems length for each of the 26 EU countries supplied with natural gas. In addition to fugitive losses in transmission pipelines, the self-consumption of gas for transmission compressors will be assessed for the 26 national transmission systems based on Eurostat data, making the assumption that not all of the gas goes through each pipeline.

Table 3-140 The 26 Natural gas transmission systems length (Source: ENTSOG)

Country	Natural gas transmission system length (km)
Bulgaria	2,645
Greece	1,218
Croatia	2,184
Italy	31,531
Romania	13,000
Slovenia	1,018
Belgium	3,900
Czech Republic	3,643

Country	Natural gas transmission system length (km)
Germany	29,216
Estonia	878
Latvia	320
Lithuania	2,007
Luxembourg	300
Hungary	5,564
Netherlands	11,500
Austria	1,595
Poland	9,709
Slovakia	2,270
Denmark	800
Ireland	2,105
Finland	1,186
Sweden	620
United Kingdom	7,880
Spain	9,236
France	37,200
Portugal	1,299

Distribution Systems

The methane losses for the distribution systems have been developed for the 26 EU countries. These are the losses for the gas once it leaves the high pressure transmission system up to the CNG compressors through the local distribution systems.

In the following sections, the data used for the calculation of downstream GHG emissions for Natural Gas are presented on a country-by-country basis.

3.7.21 Ireland

Ireland receives almost all of its gas from the UK, which augments a small quantity of domestic production. The information in the National Inventory Report[78] is limited to an estimate of methane leakage in the distribution system, which is not measured but based on a trend of an estimated loss of 0.2% in 1990 being reduced to zero in 2020. The transmission system operator, Gaslink, supplies more information in their annual reports[79]

[78] Ireland National Inventory Report 2014.

[redacted]

[79] Gaslink. Transmission and Distribution System Performance Report. 2012.

h[redacted]f

and from this information the transmission energy can be calculated. There are three gas fired compressor stations in the country. The modelling data are shown in Table 3-141.

Table 3-141 Ireland Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000019
Distance, km	600
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.0
Distribution Fugitive Losses, %	0.0822

3.7.22 Finland

Finland receives all of its natural gas from Russia. The natural gas transmission and distribution system is operated by Gasum OY. The data for modelling is from the Finish National Inventory report[80]. The energy use is calculated from the reported CO_2 emissions and the methane loss rates are calculated directly from the reports. The data in the reports come from measurements undertaken by Gasum and Helsinkikaasu Oy (Table 3-142).

Table 3-142 Finland Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000003
Distance, km	300
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.0097
Distribution Fugitive Losses, %	0.6057

3.7.23 Sweden

The Swedish National Inventory Report is the source of the data for Sweden[81]. The

[80] Greenhouse Gas Emissions in Finland 1990-2012.

[redacted]

[81] National Inventory Report Sweden. 2014.

[redacted] and

transmission fugitive emissions in the NIR are based on information provided by Swedegas, the operator of the transmission pipeline and storage of natural gas in Sweden. The distribution fugitive emissions are estimates based on emission factors from the literature. The energy used in transmission of the gas is from the NIR, see Table 3-143.

Table 3-143 Sweden Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000006
Distance, km	200
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.0028
Distribution Fugitive Losses, %	0.2266

3.7.24 Belgium

Belgium imports gas from the Netherlands, Norway, and has bidirectional connection with the UK. It also receives LNG from Qatar. Gas moves through Belgium to other countries. The transmission system operator, Fluxys[82] reports the volume of gas in the transmission system and in the distribution system. The Belgian National Inventory Report[83] has information on methane loss rates and energy consumed in the transmission of the gas (see Table 3-144). It has been assumed that the LNG regasification energy use is the same as the UK.

Table 3-144 Belgium Downstream Gas Data

Gas Transmission Energy, j/j-km	0.0000054
Distance, km	300
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.0087
Distribution Fugitive Losses, %	0.1189

[redacted]

[82] Fluxys Annual Financial Report. 2012.

[redacted]

[83] Belgium's Greenhouse Gas Inventory (1990-2012).

[redacted]

3.7.25 Austria

Austria is a small gas producer but most of the gas consumed in Austria is imported. A small amount of gas flows through Austria to Italy and Slovenia for consumption there. Information on energy consumption in the transmission system and the methane loss rates for transmission and distribution were developed from the data in the National Inventory Report[84]. The report uses a Tier 2 method for methane emissions from the transmission system and a Tier 3 method for the distribution emissions. The majority of the pipe in the distribution system is plastic, which has the lowest loss rate of any of the types of pipe that has historically been used. These are presented in Table 3-145.

Table 3-145 Austria Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000041
Distance, km	500
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.0041
Distribution Fugitive Losses, %	0.0378

3.7.26 Czech Republic

The Czech Republic produces a small quantity of natural gas that is considered in the "other" category in this work. Information on energy use in gas transmission and fugitive emissions is available in the National Inventory Report.[85] Some gas moves through the countries transmission system and is consumed elsewhere. The gas transmission energy for the model is calculated based on the energy consumed in the country since it is difficult to assign it to another country. The transmission distance is an estimate but like the other countries the sum of the distance and the energy in j/j-km is the reported energy use in j/j, see Table 3-146.

Table 3-146 Czech Republic Downstream Gas Data

[84] Austria's National Inventory Report 2014.

[redacted]

[85] National Greenhouse Gas Inventory Report of the Czech Republic. 2014.

[redacted]

Gas Transmission Energy, j/j-km	0.000022
Distance, km	200
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.124
Distribution Fugitive Losses, %	0.280

3.7.27 Slovakia

The information on fugitive methane emissions is taken from the National Inventory Report[86]. It does not include the energy use for the transmission pipeline. It reports a transmission distance of 2,270 km. The transmission system operator in Slovakia is Eustream and their system comprises four or five parallel pipelines. The average length of a pipeline would be about 500 km. The total installed compressor capacity is 600 MW. We have assumed that the compressors operate for 8000 hours/year. These data are shown in Table 3-147.

Table 3-147 Slovakia Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000012
Distance, km	500
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.169
Distribution Fugitive Losses, %	0.601

3.7.28 Lithuania

The information on fugitive emissions and transmission energy was obtained from The National Inventory Report[87]. The total length of transmission line is 1900 km but the system has twinned lines and is rectangular in nature. It will be assumed that the average

[86] Slovak Republic National Inventory Report 2014.

[redacted]

[87] Lithuania's National Greenhouse Gas Inventory Report 2014.

[redacted]

distance is 350 km. The fugitive emissions in the NIR were calculated using the Tier 1 approach and the emission factors from the IPCC 2000 Good Practice Guidelines, see Table 3-148.

Table 3-148 Lithuania Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000034
Distance, km	350
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.280
Distribution Fugitive Losses, %	0.212

3.7.29 Latvia

The Latvian National Inventory Report[88] has information on fugitive emissions for transmission and distribution. The estimates use country specific activity data and emission factors from Russia. The national system operator, Latvijas Gaze, reports 1,239 km of gas transmission line in the country. The lines are branched and twinned in some regions. Latvia has an underground storage facility which includes a compressor station. A total of 34 MW of compression is available. The gas transmission energy has been calculated from this and the assumption that the compressor operates 8000 hrs/year (Table 3-149).

Table 3-149 Latvia Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000088
Distance, km	200
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.067
Distribution Fugitive Losses, %	0.272

[88] Latvia's National Inventory Report 1990 – 2012.

[redacted]

3.7.30 Luxembourg

The Luxembourg National Inventory Report[89] states that there are no gas pipeline compressors in the country. The fugitive methane emissions are reported for transmission and distribution of natural gas as shown in Table 3-150. They are developed using the IPCC Tier 1 approach.

Table 3-150 Luxembourg Downstream Gas Data

Gas Transmission Energy, j/j-km	0
Distance, km	0
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.061
Distribution Fugitive Losses, %	0.140

3.7.31 Estonia

Information on fugitive methane emissions for Estonia can be found in the National Inventory Report[90]. There are no gas compressor stations in Estonia and the country does not report any fugitive emissions in the gas transmission sector. The distribution emission factor is from Finland (Table 3-151).

Table 3-151 Estonia Downstream Gas Data

Gas Transmission Energy, j/j-km	0
Distance, km	0
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.0
Distribution Fugitive Losses, %	0.747

[89] Luxembourg's NIR 1990-2012.

[redacted]

3.7.32 Greece

Greece has a very small amount of natural gas production but it is allocated to the "other" category for this work. The gas production is quite sour and will have high energy requirements for processing. The information on energy use in gas transmission and the fugitive methane emissions comes from the National Inventory Report[91]. The emissions are based on Tier 1 emission factors.

There is a single gas compressor on the system and the energy use is 0.00133 j/j. We have assumed a pipeline distance of 500 km and 0.000003 j/j-km. These are shown in Table 3-152.

Table 3-152 Greece Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000003
Distance, km	500
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.106
Distribution Fugitive Losses, %	0.091

There is an LNG receiving terminal in Greece. It uses both submerged combustion heaters and open rack vaporizers using seawater for regasification. It has been assumed that the gas use 0.75% of the throughput and that 30,000 kJ of power is used per ton.

3.7.33 Croatia

The Croatia National Inventory Report contains information on fugitive methane emissions and some data on the energy use in the processing and transmission sector. Croatia produces about 50% of the gas consumption and the domestic gas has a CO_2 content of 15%, resulting in high emissions, but this gas is not included in this modelling exercise, due to the low volume of production.

The total length of the gas transmission system is 2,662 km. There are parallel lines and branches. There are eight entry points and there is the domestic production. Since there isn't a breakout of gas used for transmission from processing, we have assumed that the average transmission distance is 300 km and the energy use is 0.000015 joules/joule-km.

[91] Greece – National Inventory Report 2014.

[redacted]

These assumptions allocate most of the gas use to the processing sector because of the high CO_2 content, see Table 3-153.

Table 3-153 Croatia Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000015
Distance, km	300
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	1.47
Distribution Fugitive Losses, %	1.18

3.7.34 Bulgaria

The information on energy use and methane emissions is drawn from the Bulgarian National Inventory Report[92]. The emissions are calculated from IPCC Tier 1 emission factors. The pipeline energy use is from the national energy balance. Transmission line length is 2,465 km but there are essentially three parallel lines and some side branches. An average distance of 600 km is assumed (Table 3-154).

Table 3-154 Bulgaria Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000139
Distance, km	600
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.302
Distribution Fugitive Losses, %	0.882

3.7.35 Slovenia

Information on the energy use and methane emissions for the natural gas transmission and distribution in Slovenia are available from the National Inventory Report[93]. There is

[92] Bulgaria's National Inventory Report 2014.



1,094 km of transmission line but there are some parallel legs. A distance of 300 km is chosen and that is used to calculate the transmission energy per km. Activity data in the NIR are very useful but the emission factors used with the activity data come generally from sources outside the country, see Table 3-155.

Table 3-155 Slovenia Downstream Gas Data

Gas Transmission Energy, j/j-km	0.0000023
Distance, km	300
% Electric energy in transmission	0.0
Transmission Fugitive Losses, %	0.034
Distribution Fugitive Losses, %	0.1279

The LNG regasification energy has been assumed to be the same as in Greece.

3.7.36 France

The loss rate data for the French system are from the National Inventory reports[94]. The energy use, as presented in Table 3-156, comes from GRTGaz[95], a transmission system operator.

Table 3-156 France Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000001
Distance, km	322
% Electric energy in transmission	13.7
Transmission Fugitive Losses, %	0.038
Distribution Fugitive Losses, %	0.135

There are three regasification terminals in France. They use a combination of submerged combustion and open rack vaporization. The natural gas consumption varies from 0.2 to 0.5%[96], we have assumed an average value of 0.3% and electric power of 30,000 kj/ton.

[redacted]

3.7.37 Spain

The Spanish Transmission System Operator has published a Carbon Footprint report for their operations in 2013[97]. It has data for 2012 and 2013. The energy consumption is 0.00596 joules consumed per joule delivered. If we assume that the transmission distance is 300 km then the energy use 0.000020 joules/joule-km.

The methane loss rates for Spain are from the National Inventory Report[98]. The emissions are very low. The regasification gas use is included in the carbon footprint and it amounts to 65,000 kJ/ton of LNG regassified. The electric power is assumed to be 30,000 kJ/ton of LNG. These data are presented in Table 3-157.

Table 3-157 Spain Downstream Gas Data

Gas Transmission Energy, j/j-km	0.00002
Distance, km	300
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.0020
Distribution Fugitive Losses, %	0.0880

3.7.38 Portugal

REN operates a number of natural gas infrastructure assets under public service concessions awarded to three of its companies:

- REN Gasodutos – high-pressure transmission network;
- REN Armazenagem – underground storage;
- REN Atlântico – reception terminal, storage and LNG regasification.

There are two interconnections with the Spanish gas pipeline network, the Sines LNG terminal and the underground storage infrastructure. The network supplies natural gas to distribution networks, power plants and industries.

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[96] Commission De Regulation De L'Energie. Public consultation on the next tariffs for the use of the Fos Cavaou, Fos Tonkin and Montoir-de-Bretagne LNG terminals as from 1 April 2013.

[redacted]

[97] Enagás Carbon Footprint.

[redacted]

[98] Spain National Inventory report.

[redacted]

The National Inventory Report[99] includes methane emissions for gas transmission only. The emissions are calculated using the Tier 1 emission factors from the 2000 IPCC Good Practice guide. The energy use has been calculated from the CO_2 emissions (Table 3-158). The methane emissions are from the NIR. The regasification energy in Portugal is assumed to be the same as in Spain.

Table 3-158 Portugal Downstream Gas Data

Gas Transmission Energy, j/j-km	0.000011
Distance, km	300
% Electric energy in transmission	0
Transmission Fugitive Losses, %	0.3194
Distribution Fugitive Losses, %	1.1

3.7.39 Distribution of CNG and small scale LNG

The final step in the lifecycle of natural gas required for transport is the distribution of CNG and small scale LNG to end consumers. CNG compressors are usually connected to the medium pressure distribution system and use electricity for compression. In most cases the fuel is consequently transported to the CNG refilling stations by trucks. Small scale LNG, on the other hand, is taken directly from the LNG receiving terminals and transported to the corresponding small scale filling stations by trucks or vessels. The associated GHG emissions to this lifecycle stage will be calculated as a function of distances to potential CNG and small scale LNG refilling stations by using emission factors.

It is worth mentioning that in the baseline year of 2012 only CNG activity to transport means might be traced and consequently assessed in terms of GHG emissions. The use of LNG as transport fuel will only be considered as an option within the projections of the PRIMES model and therefore will be assessed as part of Task f.

[99] Portuguese National Inventory Report On Greenhouse Gases, 1990 – 2012.

4 TASK C: GHG EMISSIONS MODELLING

The presentation of the work carried out in the context of Task c concentrates on the main methodological aspects of the models prepared for the calculation of the WTT GHG emissions of petroleum fuels (diesel, petrol and kerosene) and natural gas. Three models, namely OPGEE, GHGenius and PRIMES-Refinery, have been employed for the estimation of total GHG emissions of the aforementioned refined petroleum products and natural gas from the stage of the extraction process to their production and distribution to the fill tanks in every EU country. The models will largely depend on the data collected, as presented in Task b. Due to the large uncertainty endorsed to the reliability of certain areas of data, minimum and maximum values of the GHG emissions associated with the WTT supply chain of diesel, petrol, kerosene and natural gas will be provided. The WTT supply chain of the petroleum products and natural gas, as has already been stated, is divided into three sections:

- **Upstream** emissions are classified into three broad categories: emissions during exploration and field development, emissions during production and surface processing emissions. The OPGEE model is a spreadsheet tool which covers the feedstock extraction emissions and provides calculations of emissions relevant to the exploration and drilling, the production and surface separations, the secondary and tertiary recovery, water treatment and waste disposal and the venting, flaring and fugitive emissions. The OPGEE model has the capability to also calculate GHG emissions from unconventional oil sources such as oil sands. The GHGenius model includes a module for the estimation of the emissions resulting from the natural gas lifecycle chain (e.g. producing, processing, transporting and transforming the gas for use). The GHGenius model, for the purposes of the current study, has been expanded to simulate the region of the European Union.
- **Midstream** emissions pertain to emissions resulting from the feedstock transportation from the extraction source to the refinery gate. Emissions mainly occur due to the energy consumption during the transportation of petroleum and its products. Emissions from oil transportation are derived using the OPGEE model which has been updated with actual Origin-Destination Matrices data and the methods used to transport oil to Europe from extra-EU regions. GHGenius is able to calculate GHG emissions related to the transportation of natural gas from the gas supplier to the gas consuming region. The model is able to calculate both emissions related to the transportation of natural gas through pipelines and through shipping (the case of LNG).
- **Downstream** emissions in the case of oil refer to the emissions during the processing of crude oil in the refineries. In the case of natural gas, the downstream stage refers to the emissions related to gas transmission and distribution within the

Member States and, where applicable, regasification of LNG. The resulting GHG emissions from the crude oil refining are influenced by specific crude oil properties, the amount of processing required and the energy input. Energy consumption in the refineries refers to both own consumption and purchased fuels (mainly electricity and natural gas). To allocate the GHG emissions during refining to each petroleum product we will use the PRIMES-Refinery model. The allocation of the emissions to individual products will be based on the marginal emission content following the methodology developed by the Institut Français du Pétrole (IFP). Furthermore, the present analysis will take into account emissions from transportation of both refinery feedstock and of ready-to-use fuels. The latter case applies mainly where refined petroleum products are imported to the EU from Russian or US refineries. This study will also provide estimates on the GHG emissions which take place during the transportation of the refined petroleum products from the European refineries to the European filling stations, as well as the fugitive emissions at the stage of the filling stations.

4.1 The OPGEE Model

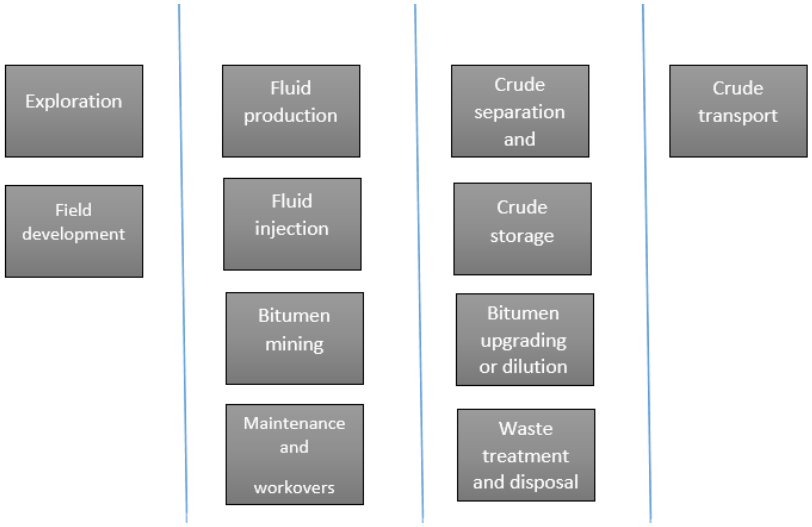
4.1.1 Model rationale and structure

The Oil Production Greenhouse gas Emissions Estimator (OPGEE) is an engineering based lifecycle assessment (LCA) spreadsheet tool that estimates greenhouse gas emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery gate.

The development of the OPGEE model was funded by the California Air Resources Board. The model has been incorporated into the California's Low Carbon Fuel Standard (LCFS) and has been applied for the calculation of the GHG intensity for crude oil baseline analysis. For the purposes of the present study, the OPGEE model is modified to account for the EU petroleum fuel supply system, by using specific input data related to the various MCONs imported to the European refineries.

The OPGEE model provides a very detailed platform for the evaluation of carbon intensity and energy consumption at the upstream and midstream stages. OPGEE includes emissions from all production operations required to produce and transport crude hydrocarbons to the refinery gate. The production technologies included are the: primary production, secondary production (water flooding), and major tertiary recovery technologies (also called enhanced oil recovery or EOR). In addition, bitumen mining and upgrading is included in a simplified fashion. The OPGEE model makes all the calculations and correlations of the values utilizing various standard data about fuels specifications, emissions factors and other conversion factors. A schematic chart showing the various stages of the lifecycle assessment included in the OPGEE model are presented in Figure 4-1 below:

Figure 4-1 Schematic chart with the various stages of the LCA analysis included in the OPGEE model (Source: OPGEE model documentation)



Type of processes included in OPGEE

OPGEE is modular in structure, with interlinked worksheets representing each production stage. Within each major production stage, a number of activities and processes occur (e.g., fluid production or fluid injection). The functional unit of OPGEE is 1 MJ of crude petroleum delivered to the refinery entrance (a well-to-refinery, or WTR process boundary). This functional unit is held constant across different production and processing pathways included in OPGEE. OPGEE uses data from a variety of technical reference works and its spreadsheet structure makes it a fully transparent modelling tool. The main calculations for the total carbon intensity estimation focus on the following processes:

- **Exploration**, which contains pre-production emissions that occur during primary exploration for petroleum.
- **Drilling and development,** including emissions that occur during development of crude oil production facilities.
- **Production and extraction**, which models the work required to lift fluids from the subsurface and to inject fluids into the subsurface.
- **Surface processing**, which models handling of crude, water, and associated gas with a set of common industry technologies.
- **Maintenance**, regarding the venting and fugitive emissions associated with maintenance.
- **Waste disposal,** referring to the emissions about waste disposal.
- **Crude transport,** allowing variation in the transport modes used to transport crude oil from extraction to the refinery stage and the distance travelled.
- **Bitumen extraction and upgrading,** modelling the extraction of crude bitumen separately from the production of conventional crude oil.

All the processes of the upstream stage contribute to the total carbon intensity of each MCON with its own percentage of GHG emissions.

Flaring, venting and fugitive emissions represent the most important source of GHG emissions from oil production operations. Venting and fugitive emissions arise from oil field operations and devices. Sources include well work-overs and clean-ups, compressor start-ups and blowdowns, pipeline maintenance, gas dehydrators, AGR units, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). Flaring of gas, either as a means of disposal or as a safety measure, is a significant source of air emissions from oil and gas installations. Even if continuous flaring ended, occasional burning of small amounts of gas will still be necessary for safety reasons.

Another major factor is the use of the energy-intensive secondary and tertiary recovery technologies, such as water flooding, gas lifting, gas flooding etc. For the application of these technologies, additional energy is required in order to lift the crude oil from oil well. Other emissions take place due to increased pumping and separation work associated with increased fluid handling in depleted oil fields (i.e., fields with a high water-oil ratio). At the midstream level, GHG emissions due to transportation can have a significant share in the total GHG emissions assessed, especially when considering crudes imported from distant world areas to the EU refineries.

4.1.2 Required Inputs

Key input data

In order to calculate the carbon intensity of the imported MCONs in European refineries, a significant amount of data is needed to make the OPGEE model functional. The data required relate to:

- **Production methods,** such as downhole pump, water reinjection, gas reinjection, water flooding, gas lifting, gas flooding, and steam flooding. The selection of the production method depends on the difficulty that crude oil appears in pumping up of the oil well.
- **Field properties** referring to the field location, field name, field age, field depth, oil production volume, number of producing wells, well diameter, productivity index and average reservoir pressure. These field properties are determining characteristics for the production process of the oilfield.
- **Fluid properties** considering API gravity of crude oil, which characterize the crude oil as "heavy" or "light" and composition of produced associated gas.
- **Production practices** including gas-to-oil ratio (GOR), water-to-oil ratio (WOR), water-injection ratio, gas lifting injection ratio, gas flooding injection ratio, steam-to-oil ratio (SOR), fraction of required electricity generated on site, fraction of remaining gas reinjected, fraction of water produced reinjected, fraction of steam generation via co-generation and volume fraction of diluent. The information about the production practices correlate with these of the production methods and have significant role in the resulting emissions.

- **Processing practices** that represent the use of heater/treaters, stabilizer columns and gas processing units (AGR, dehydrator and demethanizer), the ratio of gas flared to oil produced, and the ratio of gas vented to oil produced. According to the quality of produced oil mixture, certain treating processes are applied for further treatment of gas, oil and water, which include in the oil mixture.
- **Land use impacts** including ecosystem carbon richness and relative disturbance intensity. This parameter relates to the additional emissions of the wider oilfield that are caused due to the disturbance of land during the drilling and production processes.
- **Crude oil transport** which determine transport modes and distances. Crude oil transport covers the tracks (marine or by road) from the oil well to the European refineries gates presenting the distances as well as the suitable mode that is utilized for each distance.

The user is allowed to insert the desired data in the "User Inputs" section of the 'User Inputs & Results' worksheet. This sheet enables the calculation of the carbon intensity of one specific MCON. However, OPGEE has a built-in capability to analyze a number of fields or oil production projects and book-keep the results for comparison and further analysis. The 'Bulk Assessment' worksheet has a similar structure to the 'User Inputs & Results' worksheet, but is expanded to allow multiple projects to be assessed in one computational run. In addition to running a number of fields in sequence, the bulk assessment machinery has a built-in feature to programmatically resolve errors that arise from input data inconsistencies.

All required inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or marketable crude oil blend. If only a limited amount of information is available for a given facility, most input values will remain equal to defaults. Otherwise, if detailed field-level data are available, a more accurate emissions estimate can be generated.

Table 4-1 presents the actual form of the input data required to operate the OPGEE model and produce the lifecycle GHG emissions per field type. The table presented includes the input data of the generic field type included in the OPGEE model.

4.1.3 Parametric significance

The Consultant has performed a sensitivity analysis over the most critical parameters that can influence the outcome of the carbon intensity of the various crude types. The scope of this analysis is to show the importance of specific oil field characteristics for the calculations of the GHG emissions. A sensitivity analysis has been performed over specific parameters while keeping all other inputs unchanged; the calculations refer to the generic type of field considered in OPGEE (for the typical characteristics of the generic type of field see Table 4-1). The main parameters included in the sensitivity runs are the following:

- API gravity
- Water to oil ratio (WOR)
- Flaring to oil ratio (FOR)
- Venting to oil ratio (VOR)
- Marine transport distance

Table 4-1 Typical input to the OPGEE model for the calculation of the GHG emissions per field (values for the generic type of field included in OPGEE)

Parameter	Unit	Value
Downhole pump		1
Water reinjection		1
Gas reinjection		1
Water flooding		0
Gas lifting		0
Gas flooding		0
Steam flooding		0
Field location (Country)		Generic
Field name		Generic
Field age	yr.	35
Field depth	ft	7,240
Oil production volume	bbl/d	1,500
Number of producing wells	[-]	8
Number of water injecting wells	[-]	5
Well diameter	in	2,775
Productivity index	bbl/psi-d	3
Reservoir pressure	psi	1,557
API gravity	deg. API	30
Gas composition		
N_2	mol%	2
CO2	mol%	6
C_1	mol%	84
C_2	mol%	4
C_3	mol%	2
C_4+	mol%	1
H_2S	mol%	1
Gas-to-oil ratio (GOR)	scf/bbl oil	908
Water-to-oil ratio (WOR)	bbl water/bbl oil	4,31
Water injection ratio	bbl water/bbl oil	5,31
Gas lifting injection ratio	scf/bbl liquid	1,500
Gas flooding injection ratio	scf/bbl oil	1,362

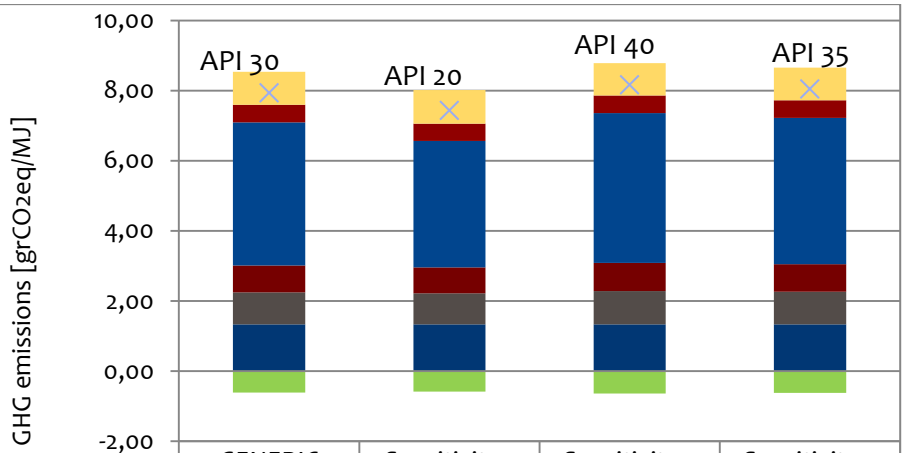
Parameter	Unit	Value
Steam-to-oil ratio (SOR)	bbl steam/bbl oil	3
Fraction of required electricity generated onsite	[-]	0
Fraction of remaining gas reinjected	[-]	0
Fraction of water produced water reinjected	[-]	1
Fraction of steam generation via cogeneration	[-]	0
Heater/treater	NA	0
Stabilizer column	NA	1
Application of AGR unit	NA	1
Application of gas dehydration unit	NA	1
Application of demethanizer unit	NA	1
Flaring-to-oil ratio	scf/bbl oil	182
Venting-to-oil ratio	scf/bbl oil	0
Volume fraction of diluent	[-]	0
Transport distance (one way)		
Ocean tanker	Mile	5,082
Rail	Mile	800
Ocean tanker size, if applicable	Ton	250,000
Small sources emissions	$grCO_2eq/MJ$	0,5

Sensitivity analysis on the API gravity

API gravity is a measure of how "heavy" or "light' the crude oil is relative to water. The generic field considered has an API equal to 30. The resulting carbon intensity of this field is equal to 7.93 $grCO_2eq/MJ$ according to the OPGEE results. Three sensitivity runs have been performed for the API values while keeping all other input unchanged relative to the generic field. The values picked for the API sensitivity analysis are within the range found in literature; the range of API provided in Task B for the various fields range from 22 to 44. In the 1st sensitivity, an API of 20 has been considered which eventually results in a carbon intensity of 7.43 $grCO_2eq/MJ$ and represents a reduction of about 6% relative to the generic field (Figure 4-2). In the 2nd sensitivity run, an API of 40 has been assumed resulting to a carbon intensity of 8.15 $grCO_2eq/MJ$ which represents an increase of about 3% relative to the generic field. In the 3rd sensitivity test, an API of 35 was assumed resulting to a carbon intensity of 8.04 $grCO_2eq/MJ$ which represents an increase of about 1% relative to the generic field.

According to the model runs, it has been observed that an increase in the API gravity (lighter crude oil), results in an increase of the total carbon intensity. This happens because in the sensitivity runs the OPGEE model calculates the emissions without changing any other parameter. However, in reality, oil fields with lower API gravity usually involve different production methods and processes which will eventually results in overall higher carbon intensity than lighter oil.

Figure 4-2 Sensitivity analysis on the API gravity: results obtained using the OPGEE model

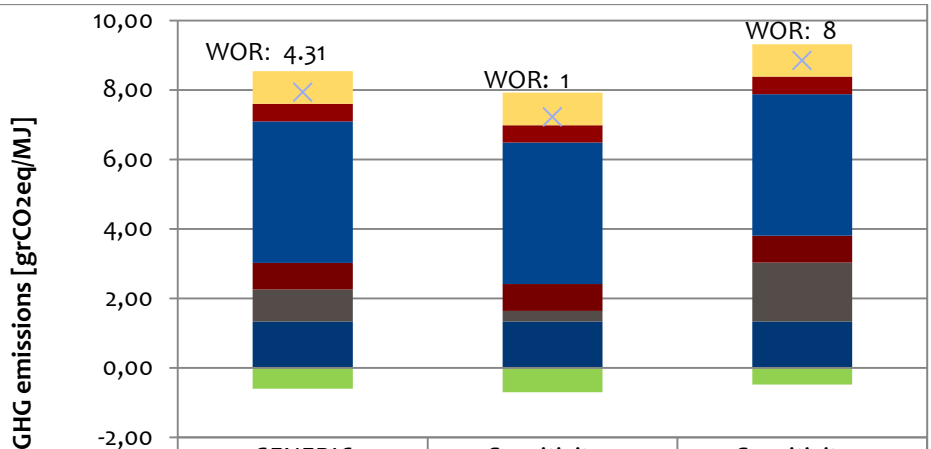


	GENERIC	Sensitivity 1	Sensitivity 2	Sensitivity 3
Offsite emissions	-0,61	-0,58	-0,64	-0,62
Transport	0,94	0,96	0,93	0,93
Misc.	0,50	0,50	0,50	0,50
Diluent	0,00	0,00	0,00	0,00
VFF	4,08	3,60	4,27	4,17
Waste	0,00	0,00	0,00	0,00
Maintenance	0,00	0,00	0,00	0,00
Upgrading	0,00	0,00	0,00	0,00
Processing	0,77	0,73	0,80	0,79
Production	0,92	0,89	0,95	0,93
Drilling	1,33	1,34	1,34	1,33
Exploration	0,00	0,00	0,00	0,00
Net lifecycle emissions	7,93	7,43	8,15	8,04

Sensitivity analysis on the Water to Oil Ratio (WOR)

Water-oil-ratio (WOR) is the ratio between the volume of water that comes out of the crude oil mixture and the volume of oil at standard conditions. The generic field considered has a WOR equal to 4.31 bbl water/bbl oil. Two sensitivity runs were performed on the WOR values. The values picked for the WOR sensitivity analysis are within the range found in literature; the range of WOR provided in Task B for the various fields range from 0,6 to 8,3 bbl water/bbl oil. In the 1st sensitivity, a WOR of 1 bbl water/bbl oil and eventually results in a carbon intensity of 7.22 $grCO_2eq/MJ$ which represents a reduction of about 9% (Figure 4-3). In the 2nd sensitivity test performed, a WOR of 8 bbl water/bbl oil was assumed resulting to a carbon intensity of 8.84 $grCO_2eq/MJ$ which represents an increase of about 11% relative to the generic field. Increasing the WOR implies that additional operations are required during the production process which results in an increase in the GHG emissions during the production phase and eventually the overall GHG emissions.

Figure 4-3 Sensitivity analysis on the Water to Oil Ratio (WOR): results obtained using the OPGEE model



	GENERIC	Sensitivity 1	Sensitivity 2
Offsite emissions	-0,61	-0,71	-0,48
Transport	0,94	0,94	0,94
Misc.	0,50	0,50	0,50
Diluent	0,00	0,00	0,00
VFF	4,08	4,08	4,08
Waste	0,00	0,00	0,00
Maintenance	0,00	0,00	0,00
Upgrading	0,00	0,00	0,00
Processing	0,77	0,77	0,77
Production	0,92	0,31	1,70
Drilling	1,33	1,33	1,33
Exploration	0,00	0,00	0,00
Net lifecycle emissions	7,93	7,22	8,84

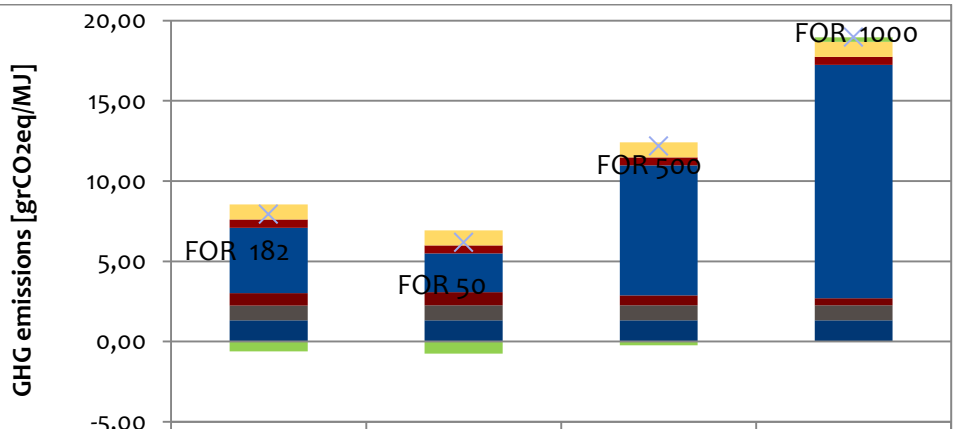
Sensitivity analysis on the Flaring to Oil Ratio (FOR)

Flaring is used to dispose of associated natural gas where there is no economic use for the gas. Associated gas evolves from crude oil as it is brought to surface temperatures and pressures, and is separated from oil before transport. Flaring mainly produces carbon dioxide and water as waste products of combustion; however, combustion is often incomplete which can result in emissions of carbon monoxide, nitrous oxide, unburned hydrocarbons, particulate matter (including soot or black carbon), and VOCs. Because of the hydrocarbon content, a flaring rise results to a significant increase in the carbon intensity.

The generic field considered has a flaring to oil ratio equal to 182 scf/bbl oil. Three sensitivity runs were performed on the flaring to oil ratio values because the range of values found in literature varies between some hundreds of scf and thousands of scf. In the 1st sensitivity, a flaring to oil ratio of 50 scf/bbl oil was considered which results in a carbon intensity of 6.14 $grCO_2eq/MJ$, a reduction of about 22% relative to the generic field. In the 2nd sensitivity, a flaring to oil ratio of 500 scf/bbl oil was assumed resulting to a

carbon intensity of 12.19 $grCO_2eq/MJ$ which represents an increase of about 54% relative to the generic field. In the 3rd sensitivity test performed a flaring to oil ratio of 1000 scf/bbl was performed resulting to a carbon intensity of 18.97 $grCO_2eq/MJ$ which represents an increase of about 139% relative to the generic field. It is evident from the modelling runs that the flaring to oil ratio is a critical parameter for the calculation of the total GHG emissions per MCON. Figure 4-4 illustrates the results obtained from OPGEE.

Figure 4-4 Sensitivity analysis on the Flaring to Oil Ratio (FOR): results obtained using the OPGEE model



	GENERIC	Sensitivity 1	Sensitivity 2	Sensitivity 3
Offsite emissions	-0,61	-0,76	-0,23	0,28
Transport	0,94	0,94	0,94	0,94
Misc.	0,50	0,50	0,50	0,50
Diluent	0,00	0,00	0,00	0,00
VFF	4,08	2,41	8,11	14,54
Waste	0,00	0,00	0,00	0,00
Maintenance	0,00	0,00	0,00	0,00
Upgrading	0,00	0,00	0,00	0,00
Processing	0,77	0,83	0,62	0,46
Production	0,92	0,92	0,92	0,92
Drilling	1,33	1,33	1,33	1,33
Exploration	0,00	0,00	0,00	0,00
Net lifecycle emissions	7,93	6,17	12,19	18,97

Flaring efficiency

There is a wide range of emission estimates due to flaring that are presented in relevant studies. Most of these estimates have been developed at laboratory for industrial flares and not necessarily for flares that may not be steam assisted or operate in a well controlled environment. It has been widely reported (various EPA studies, MacDonald, 1990) that the flare combustion efficiency for industrial flares typically exceeds 98 % with dependence on the following factors for efficient performance:

- excess steam assist (i.e. steam/fuel gas ratio less than 2);
- sufficient gas heating value (i.e. greater than 10 MJ/m3);
- low wind speed conditions (i.e. below? 10 m/sec.);
- sufficient gas exit velocity (i.e. above 10 m/sec.).

The OPGEE model calculates flaring emissions based on a 95% flaring efficiency and includes CO2, methane and oxidized VOC emissions. The NETL model characterizes each producing region as being low methane or high methane emitters and develops the emissions based on profiles developed for each case. The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 2006) suggest the emission factors for direct estimation of CH4, CO2 and N2O emissions from reported flared volumes are 0.012, 2.0 and 0.000023 Gg, respectively, per 106 m3 of gas flared based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (i.e. 91.9% CH4, 0.58% CO2, 0.68% N2 and 6.84% non-methane hydrocarbons by volume). The JEC report (July 2013) follows the Gogolek[100] approach, which uses a specific Flaring Test Facility, and assumes flare gas composition of 50%m/m (65%v/v) methane and 50%m/m (35%v/v) ethane and combustion efficiency of 98%.

It is worth considering that these values are for operations in developed countries and are tested simulating industrial flares (refineries, chemical industry, etc.) and not crude oil production installations. Similarly, different types of flare burners, designed primarily for safety requirements, may result in different efficiencies. The International Flame Research Foundation published some real world results of refinery flares that show while flare efficiency is above 98% most of the time, there can be times where the efficiency is as low as 50 %. For solution gas flares in Alberta, Johnson (2008) determined that the average annual flare efficiency was about 95%.

Given that the crude oil production flaring takes places mostly in third countries, which do not implement rigorous regulatory regimes towards control and reduction of flaring GHG emissions, and that the exploitation conditions are often worse than the laboratory or the well regulated industrial conditions, we consider that the value of flaring efficiency (95%) found by Johnson[101] and used in the two models, namely OPGEE and GHGenius, is reasonable and closer to the actual operational conditions.

Sensitivity analysis on the Venting to Oil Ratio (VOR)

Venting is the controlled release of gases into the atmosphere in the course of oil and gas production operations. These gases might be natural gas or other hydrocarbon vapours, water vapor, and other gases, such as carbon dioxide, separated in the processing of oil or natural gas. In venting, methane is released directly into the atmosphere.

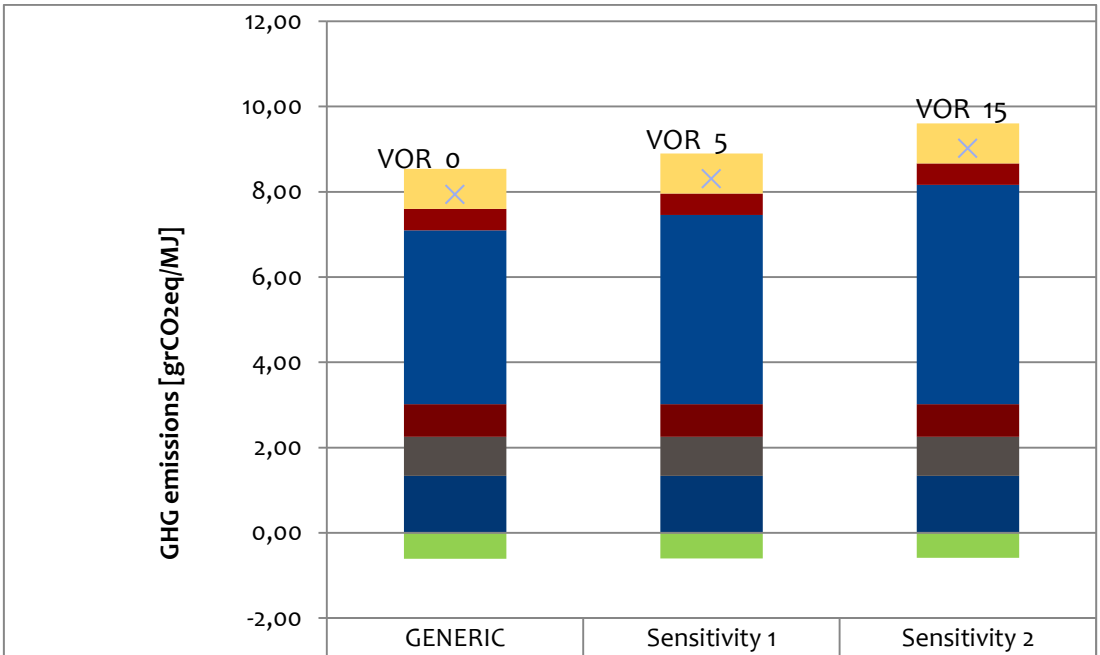
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[100] Experimental Studies on Methane Emmissions from Associated Gas Flares, P. Gogolek, Natural Resources Canada, CanmetENERGY

[101] Johnson, D. 2008. Flare Emissions and Efficiency—Past and Current Research http://www.flaringreductionforum.org/downloads/20081205-830/Johnson.pdf

The generic field considered has venting to oil ratio equal to 0 scf/bbl oil. Two sensitivity runs were performed on the venting-to-oil ratio values while keeping all other input unchanged relative to the generic field. In the 1st sensitivity, a venting to oil ratio of 5 scf/bbl oil was considered which eventually results in a carbon intensity of 8.30 $grCO_2eq/MJ$ which represents an increase of about 5% (Figure 4-5). In the 2nd sensitivity run, a venting to oil ratio was assumed of 15 scf/bbl oil resulting to a carbon intensity of 9.02 $grCO_2eq/MJ$, which represents an increase of about 14% relative to the generic field. Figure 4-5 illustrates the results obtained from OPGEE.

Figure 4-5 Sensitivity analysis on the Venting to Oil Ratio (VOR): results obtained using the OPGEE model



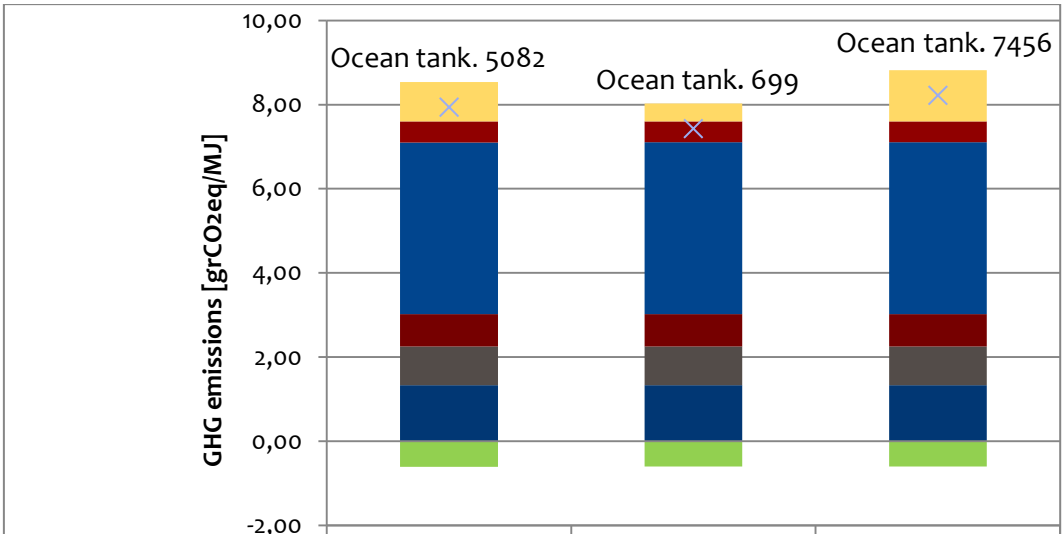
	GENERIC	Sensitivity 1	Sensitivity 2
Offsite emissions	-0,61	-0,60	-0,59
Transport	0,94	0,94	0,94
Misc.	0,50	0,50	0,50
Diluent	0,00	0,00	0,00
VFF	4,08	4,44	5,15
Waste	0,00	0,00	0,00
Maintenance	0,00	0,00	0,00
Upgrading	0,00	0,00	0,00
Processing	0,77	0,77	0,76
Production	0,92	0,92	0,92
Drilling	1,33	1,33	1,33
Exploration	0,00	0,00	0,00
Net lifecycle emissions	7,93	8,30	9,02

Sensitivity analysis on the maritime shipping distance

The transportation of crude oil from the extraction point to the refinery of a European country is responsible for a part of the total lifecycle GHG emissions of this specific crude. GHG emissions occur due to the consumption of fossil-based fuels during the transportation usually by ocean tankers. An important variable for determining the GHG emissions due to transportation by ships is the actual Origin - Destination (O-D) distance. For the purposes of this sensitivity analysis, we have assumed different O-D distances for the generic field considered in OPGEE, while keeping all other variables unchanged.

We assumed two differentiated O-D distances for two sensitivity runs; our assumptions draw largely from data provided in Task B and refer to the distances from two major exporting countries to EU ports. For the 1st sensitivity run, the shipping distance was 699 miles from Samotlor to Gdansk. After running the OPGEE model, the resulting carbon intensity was found to be 7.4 $grCO_2eq/MJ$, which represents a decrease of about 7% relative to the generic field. In the 2nd sensitivity run, a distance of 7,456 miles from Gwahar to Rotterdam. The overall carbon intensity of the crude considered increased to the levels of 8.2 $grCO_2eq/MJ$ which represents an increase of about 3% relative to the generic field. Indeed, the shipping distance represents an important variable for the calculation of the GHG emissions using the OPGEE model. For the 1st sensitivity where the distance was assumed to be 699 miles, the transport related GHG emissions where found to be 0.43 $grCO_2eq/MJ$, while in the 2nd run they were found to be about 2.8 times higher. Figure 4-6 illustrates the results obtained from OPGEE.

Figure 4-6 Sensitivity analysis on the marine shipping Origin- destination (O-D) distance: results obtained using the OPGEE model



	GENERIC	Sensitivity 1	Sensitivity 2
Offsite emissions	-0,61	-0,60	-0,60
Transport	0,94	0,43	1,22
Misc.	0,50	0,50	0,50
Diluent	0,00	0,00	0,00
VFF	4,08	4,08	4,08
Waste	0,00	0,00	0,00
Maintenance	0,00	0,00	0,00
Upgrading	0,00	0,00	0,00
Processing	0,77	0,77	0,77
Production	0,92	0,92	0,92
Drilling	1,33	1,33	1,33
Exploration	0,00	0,00	0,00
Net lifecycle emissions	7,93	7,43	8,22

4.1.4 Typical produced outputs

Table 4-2 presents a typical presentation of the OPGEE model outputs. As it can be obtained these are organized per lifecycle process and for each process the total energy consumption and total GHG emission are given.

Table 4-2 Typical output of the OPGEE model

Output variables	Level 1	Level 2	Unit	Values
Field name				Generic
2.1 Exploration (e)				
	2.1.1 Total energy consumption		MJ/MJ	0
	2.1.2 Total GHG emissions		grCO2eq/MJ	0
		2.1.2.1 Combustion/land use	grCO2eq/MJ	0
		2.1.2.2 VFF	grCO2eq/MJ	0
2.2 Drilling & Development (d)				
	2.2.1 Total energy consumption		MJ/MJ	0.001
	2.2.2 Total GHG emissions		grCO2eq/MJ	1.33
		2.2.2.1 Combustion/land use	grCO2eq/MJ	1.33
		2.2.2.2 VFF	grCO2eq/MJ	0
2.3 Crude production & extraction (p)				
	2.3.1 Total energy consumption		MJ/MJ	0.012
	2.3.2 Total GHG emissions		grCO2eq/MJ	0.94
		2.3.2.1 Combustion/land use	grCO2eq/MJ	0.92
		2.3.2.2 VFF	grCO2eq/MJ	0.02
2.4 Surface processing (s)				
	2.4.1 Total energy consumption		MJ/MJ	0.046
	2.4.2 Total GHG emissions		grCO2eq/MJ	4.74
		2.4.2.1 Combustion/land use	grCO2eq/MJ	0.77

Output variables	Level 1	Level 2	Unit	Values
		2.4.2.2 VFF	grCO2eq/MJ	3.97
2.5 Maintenance (m)				
	2.5.1 Total energy consumption		MJ/MJ	0
	2.5.2 Total GHG emissions		grCO2eq/MJ	0.09
		2.5.2.1 Combustion/land use	grCO2eq/MJ	0
		2.5.2.2 VFF	grCO2eq/MJ	0.09
2.6 Waste disposal (w)				
	2.6.1 Total energy consumption		MJ/MJ	0
	2.6.2 Total GHG emissions		grCO2eq/MJ	0
		2.6.2.1 Combustion\land use	grCO2eq/MJ	0
		2.6.2.2 VFF	grCO2eq/MJ	0
2.7 Diluent				
	2.7.1 Total energy consumption		MJ/MJ	0
	2.7.2 Total GHG emissions		grCO2eq/MJ	0
2.8 Non-integrated upgrader				
	2.8.1 Total energy consumption		MJ/MJ	0
	2.8.2 Total GHG emissions		grCO2eq/MJ	0
2.9 Crude transport (t)				
	2.9.1 Total energy consumption		MJ/MJ	0.013
	2.9.2 Total GHG emissions		grCO2eq/MJ	0.94
	2.9.3 Loss factor		NA	1
2.10 Other small			grCO2eq/MJ	0.5

Output variables	Level 1	Level 2	Unit	Values
sources				
2.11 Offsite emissions credit/debit			grCO2eq/MJ	-0.61
2.12 Lifecycle energy consumption			MJ/MJ	0.071
2.13 Lifecycle GHG emissions			grCO2eq/MJ	7.93

4.2 The PRIMES-Refinery Model

The present study takes into consideration the GHG emissions during the refining stage of the crude oil in the European countries and the emissions associated to imported final oil products. The GHG emissions that take place during the refining process are not included in the lifecycle analysis provided by the OPGEE model. Therefore, for the purposes of the present study we use the PRIMES Refinery model for the estimation of GHG emissions resulting from the processing of petroleum in the refineries of Europe. The current section presents an overview of the main features of the PRIMES-Refinery model and a brief presentation of the main refining processes considered, as well as the obtained results for GHG emissions of petrol, diesel and kerosene during refining and a relevant discussion.

4.2.1 Model rationale and structure

Coverage of the model

The PRIMES Refinery supply model is an economic supply modelling tool developed and maintained by E3MLab. The model takes demand for petroleum products as given, either from statistics of past years or from projection to the future by the other sub-models (demand models and power sector models) of PRIMES. The refinery sub-model optimizes economically the structure of stylized refineries, the use of processes, the consumption of crude oil, feedstock and fossil fuels as needed to produce given demand. The model endogenously estimates investment in processing and refining capacity of needed to meet future demand. The model runs also for past years for data calibration purposes and so it produces detailed (pseudo) data on the past in order to estimate consumption of energy and emissions in detail. The refinery sub-model is linked with the PRIMES large scale energy system model and can be solved either as a satellite model, thus forming a closed loop, or as a standalone model. The model is designed to perform sensitivity analyses based on different demand estimations, crude oil types and import-exports of

refinery products, and includes representations to handle legislative and policy regulations on the refinery processes.

The model covers all EU-28 Member States. It provides dynamic projections in 5-year time periods with the time horizon of the model being 2050. Years 2000, 2005 and 2010 are reproduced by the model for calibration purposes and so the model is updated until 2010. Alongside with the calculation of GHG emissions at the refinery stage, the model seeks to minimize total cost so as to satisfy a fixed demand for petroleum fuels, which is derived from the PRIMES core model. It therefore determines the optimal use of resources and calculates the investment in technologies, the costs, and the pre-tax prices of final refinery fuels. The total petroleum commodity supply system cost includes annuity payments of capital cost, variable and energy costs, fixed O&M costs, as well as the cost of imports. The cost optimization is performed for all EU Member States in parallel and is inter-temporal thus having perfect foresight.

Model structure

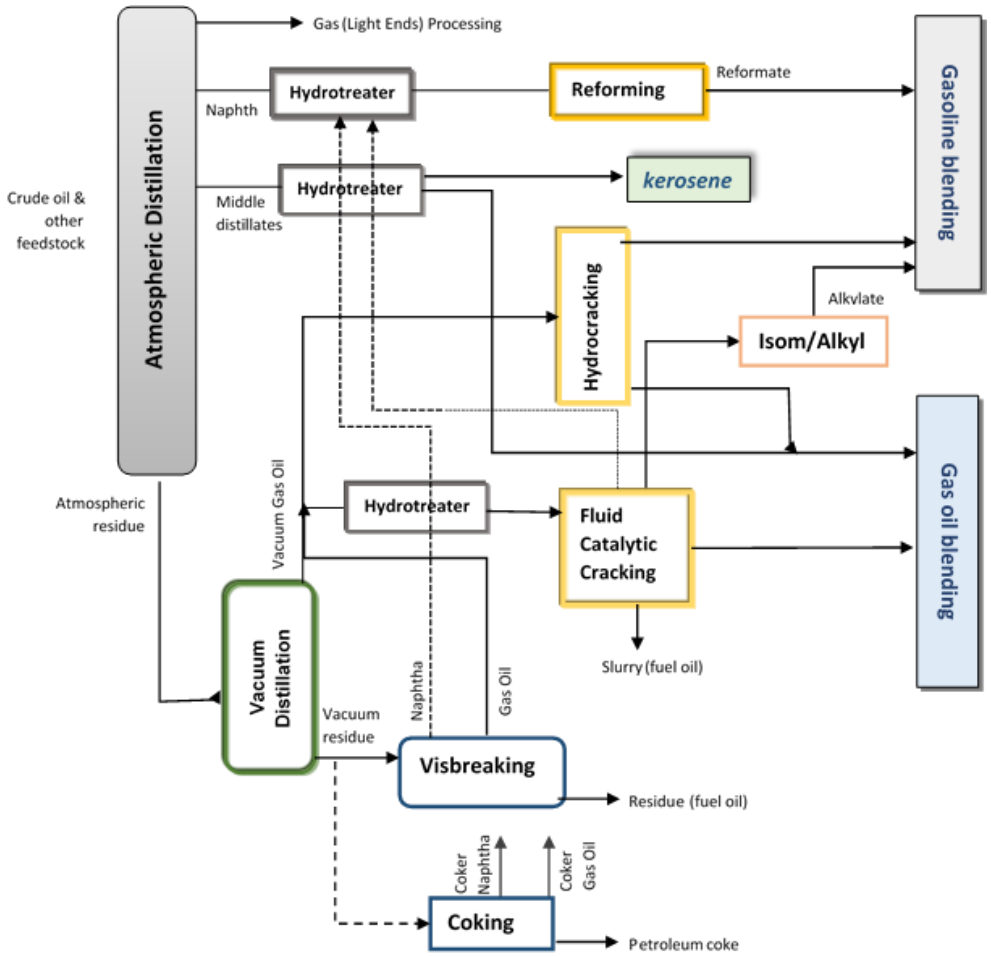
In a nutshell, the refinery supply system is structured in the model as follows: the primary energy commodity (i.e. crude oil and other feedstock) is transformed into final commodities in a stepwise manner, via a variety of transformation processing units/technologies included in the model. The final commodities are then distributed to the fuel market of the EU Member States (final energy consumption) and to the EU power or heat production plants. The schematic representation of the representative refinery configuration is presented in Figure 4-7.

The demand for petroleum products is met through domestic production in the EU refineries and through trade (imports-exports), the latter determined endogenously in the model based on relative prices and depending on elasticity parameters. Trading in the model includes both final refinery fuels and refinery feedstock, which is consequently used in the EU refineries, and is performed internally in the EU and internationally. EU countries and extra EU locations are connected through a transportation matrix that describes distances and transportation mean options. The international trade mainly simulates trade between the EU, the Middle East region, the North America region and a few other regions aggregated. The relation of imported quantities to the respective import prices is described via non-linear cost-supply curves, thus different market behaviors regarding import patterns can be simulated. The minimization problem is subject to constraints associated with limitations of the feedstock supply, as well as blending requirements on the crude oil and intermediate streams, product specifications and capacities.

The refinery feedstock in the model is divided into 2 main categories: crude oil and other feedstock. The feedstock supply is described by country specific cost-supply curves. Feedstock produced internally in the EU is subject to resource limitations. Given the large diversity of the various crude types imported at the European refineries, it was decided to improve the modelling and the resolution of the PRIMES-Refinery model regarding the crude types imported. E3MLab has upgraded the model to simulate three different crude

oil types instead of the one category previously implemented. We present in more detail the extensions of the model towards this direction, further in the current section.

Figure 4-7 Schematic representation of the main processes included in the representative refinery structure of the PRIMES-Refinery model



The model includes a variety of refinery generic processing unit types used to separate the distillates from the crude feedstock and convert the intermediate products into lighter valuable products. Technology heat-rates (energy conversion factors) are assumed to improve over time following technology developments. The main European refineries configurations have been derived from the refining survey of Oil and Gas Journal. We present the main refining processes included in the model, further in the current section.

The model computes endogenously the investment in technologies and the respecting processing capacities, derived as a result of investment accumulation. Available capacity is a constraint to the petroleum commodities production. Technology vintages, that define the time a processing capacity was installed, are used for the specification of the technical characteristics of the processing units, as well as the decommissioning of capacities. To determine the prices of the final petroleum products, the PRIMES Refinery

model includes a pricing module. To this scope, the model formulates a Ramsey-Boiteux pricing rule which consist of two parts, namely a marginal cost pricing part and an average cost pricing one the latter being used to recover all fixed and capital costs.

Allocation of GHG emissions per refined petroleum product

The key objective of using a model based analysis for simulating the European refineries is to allocate the refinery GHG emissions to the following refined petroleum products: petrol, diesel and kerosene (all refinery outputs are included in the model). The allocation of the GHG emissions to the abovementioned petroleum products is based on marginal emission coefficients for each refinery product. The refined fuel-specific emission factors are calculated by allocating total refinery emissions based on the marginal emission content methodology (as developed by the Institut Français du Pétrole).

The marginal emission coefficients for each refinery product are derived by the measuring of the variation of emissions after the marginal change of the demand for a specific fuel. Marginal content refers to the additional emissions generated from one additional unit of production of the specific product, which depends on refinery configuration that varies in the EU countries. The resulting coefficients are consequently applied to the average GHG emissions to receive an individual fuel-specific emission factor.

E3MLab also provides estimates on the lifecycle GHG emissions of the major refined products imported to EU, apart from the calculations of the GHG emissions resulting from petroleum products refined in European refineries. The evaluation of the GHG emissions from the imported oil products, mainly from Russia and US, is on the methodology followed for the calculation of emissions generated in European refineries. To account for the GHG emissions of these imported fuels during their refining process in Russia and US, E3MLab derives proxy values for their respective GHG emissions from other European countries with similar refinery configuration.

Extensions of the PRIMES-Refinery model related to crude oil types

For the purposes of the present study, E3MLab performed modelling upgrades to allow for a more enhanced simulation of the refineries configuration in the EU. Drawing largely from data retrieved in Task B, we have identified that a number of different MCONs enter the refinery gates of the various European refineries. The key characteristics of the various MCONs entering the EU refineries are related to the API gravity and the sulphur content.

To account for the large diversity of the various MCONs used in the EU refineries, E3MLab extended the PRIMES-Refinery model to include three different categories of crude types entering the representative refinery configuration. The classification of the different crude types is based on the API gravity and sulphur, as can be seen in Table 4-3. The differentiation of the crude types allows the different handling and simulation of the respective processes, product yields and energy consumption by the properties of crude oil.

Table 4-3 Representative crude oil types considered in the PRIMES-Refinery model: classification by API gravity and sulphur content

Representative crude oil types in PRIMES-Refinery	Classification by API gravity	Average API gravity	Classification by sulphur content (wt%)	Average Sulphur content (wt%)
Type 1 - Light	>35	40.7	<0.8	0.51
Type 2 - Medium	28-35	32.9	0.8-2	1.27
Type 3 - Heavy	<28	22.3	>2	2.47

Heavier or lower quality crude oils (with lower API gravity) require energy intensive processing to upgrade the higher volume of the 'bottom of the barrel'. They go through expanded carbon rejection and hydrogen addition processing, thus the energy required for that additional processing increases the energy consumption of the refinery. Vacuum distillation, catalytic cracking (including fluid catalytic cracking and hydrocracking) and thermal cracking are the main processing units that are influenced by the API gravity of the crude oil. Processing of crudes with high sulphur content increases energy consumption as hydro-treating and desulphurization processes require additional hydrogen consumption and, as a consequence, additional energy use by the hydrogen production plant.

In the modelling, the level of processing and the blending constraints for the input and output of the various processes are differentiated by each type of crude. The three types of crude oil have different volume distribution between the fractions derived from the atmospheric distillation (i.e. naphtha, middle distillates and residue), different processing capacities and product yields. The calibration of the model has been updated in order to suite the scope of the study and determine the production level for each type of crude oil.

Extensions of the PRIMES-Refinery model related to the refining processes

This section presents the main refining processes that have been considered in the PRIMES-Refinery model. Partitioning of the refinery's processes on a country basis largely draws on the refining survey of Oil and Gas Journal. The modelling approach is based on the fact that different products go through different processes within the refinery, thus production flows are used to simulate the various streams leading to the products of interest (petrol, diesel and kerosene). The typical refining processes included in the PRIMES-Refinery model are presented in Table 4-4.

The refining flow through the different processes is described as follows: the crude oil feed (including the crude and the other feedstock components) is initially separated into various fractions according to its boiling points in the *atmospheric distillation* unit. Light fractions including gas to C5 molecules of hydrocarbons and light and heavy naphtha are used to produce LPG and petrol blending components. *Catalytic reforming* converts low octane straight run heavy naphtha into a high octane reformate. Middle distillates including kerosene and light gas oil are processed to produce refined products (kerosene and diesel).

Table 4-4 Main refining processes used in the PRIMES Refinery model

Refining Process	Short description
Atmospheric Distillation	First separation of crude into a series of boiling point fractions
Vacuum Distillation	Separation of the bottom of the atmospheric distillation under reduced pressure (vacuum)
Thermal Cracking (Visbreaking / Coking)	Thermal conversion of high-molecular weight hydrocarbons into lighter products
Fluid Catalytic Cracking	Catalytic Conversion of high-molecular weight hydrocarbons into lighter more valuable products
Hydrocracking	Catalytic cracking of hydrocarbons under high pressure in the presence of hydrogen
Catalytic Reforming	Low octane straight run naphtha is converted into a high octane liquid reformate /Hydrogen production
Isomerization/Alkylation	Conversion of low-octane n-paraffins to high-octane iso-paraffins and conversion of olefins to highly branched iso-paraffins
Hydrotreating	Removal of contaminants (sulphur, nitrogen, metals etc.) of the intermediate products through their contact with hydrogen, aromatics saturation

Heavy fractions (atmospheric distillation residue) are further distilled under vacuum to obtain vacuum gas oil (feed to fluid catalytic cracking or hydrocracking) and vacuum residue. The F*luid Catalytic Cracking* unit converts high-molecular weight hydrocarbons into lighter products (light ends, naphtha, light cycle oil). Fluid catalytic cracking is combined with an *alkylation* unit to convert light olefins into highly branched isoparaffins (alkylates). *Hydrocracking*, similar to catalytic cracking, converts the heavy fraction of vacuum gas oil into lighter saturated products under high hydrogen pressure. Hydrocracking is considered to operate in competition with Fluid Catalytic Cracking as both units convert vacuum gas oil. The vacuum residue is fed to a thermal cracking unit; visbreaking is the most common process for the reduction of viscosity of the residue and the production of lighter products. A part of vacuum residue may be processed by *coking* in order to achieve higher conversion of heavy hydrocarbon molecules and obtain petroleum coke as a final product. Hydrocracking and coking are going to be selectively included in refining operations of EU countries that use these units according to the data provided by the survey of Oil and Gas Journal.

Petrol and diesel are assumed to be produced in accordance with Euro V fuel specifications, requiring the sulphur content to be less than 10 ppm. In order to reach the sulphur specifications for petrol and gas oil pools, various hydro-treating units are required. Three distinct hydro-treaters are considered in the model: naphtha hydro-treater, distillates (kerosene and diesel) hydro-treater and gas oil hydro-treater which

prepares the feed for fluid catalytic cracking. For simplicity, whenever hydro-treating process is mentioned, it refers to these three units.

Reforming produces high purity hydrogen to satisfy the needs of hydro-treating processes. A hydrogen production unit via steam methane reforming is also considered to supplement the requirements for hydrogen associated with hydro-treating and hydrocracking processes.

4.2.2 Required Inputs and Outputs of the model

The key inputs required for the PRIMES Refinery model are the capacities of the refining processes within the refinery configuration per EU country. Oil and Gas Journal Worldwide Refining Survey includes analytical data for the worldwide refineries and their capacities. Valuable information is obtained regarding the number of active refinery industries, the main operations of European refineries and the capacity of each of them.

Apart from the crude oil capacity which is the main indicator of the size of the refinery, Oil and Gas Journal database provides information on the charge and production capacity in barrels per capital day (b/cd) for every single refinery worldwide. Production related capacities provide data associated with aromatics, lubes, oxygenates, hydrogen, sulphur, coke and asphalt production. The following charge processing units are included in the survey and taken into account for the stylization of the refinery configurations:

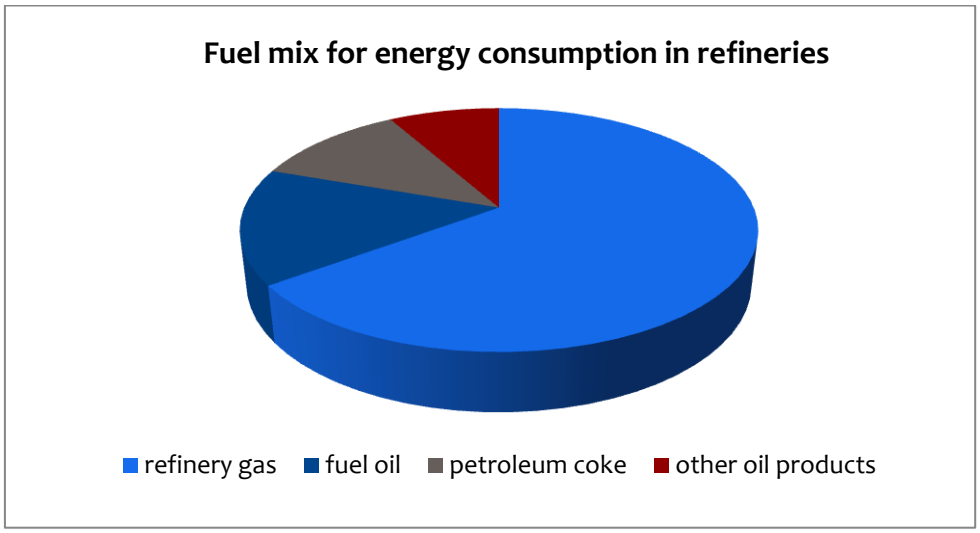
- vacuum distillation,
- coking,
- thermal operations,
- catalytic cracking,
- catalytic reforming,
- catalytic hydrocracking,
- catalytic hydro-treating.

PRIMES-Refinery runs under given constraints of refinery crude and feedstock input and demand-driven output of products. Further, data on the various MCONs entering the European refineries have been collected within Task B. The various MCONs are further disaggregated by key characteristics such as the API gravity and the sulphur content. This part is particularly important for allocating the different MCONs entering the refinery gates of each EU country with the representative crude type categories simulated in the PRIMES-Refinery model and presented in Table 4-4. Feedstock supply for the refineries operations, as well as consumption of electricity and gas are derived from the Eurostat energy balances.

The operation of the refining units requires the consumption of fuels, electricity and use of steam. The combustion of different fuels (usually by-products of processes) with various carbon content leads to different CO_2 emissions per unit of energy use. The fuel mix consumed in European refineries is depicted in Figure 4-8. Refinery gas, fuel oil and

petroleum coke are the main fuels used for refinery's energy self-consumption. Natural gas is also used in the model for the needs of hydrogen production.

Figure 4-8 Disaggregation of fuels consumption in European refineries



Electricity and gas consumption is further disaggregated into quantities purchased directly from external sources and quantities produced within the refinery boundary system. This split is important for the calculation of the GHG emissions related to the electricity and gas consumed. Different emission factors are used to derive the GHG emissions from the electricity and natural gas imported from external sources. For instance, in the case of electricity, the GHG emission factor assumed is related with the structure of the power generation sector of the country. As regards, the electricity and gas produced within the refinery, the emission factor is refinery specific and data is drawn from the Eurostat balances and the calibration of PRIMES database to past years.

The quantities of the refined petroleum products imported in the EU by major exporting countries such as Russia and US have already been identified during Task B. The total refined petroleum products that are produced at a national level over the EU countries is also provided by the Eurostat balances. Other techno-economic data regarding the heat-rates (conversion factors), utilization rates of the processes, operating and investment costs as well as the respective emission factors were updated using sources from literature and technical refinery reports.

4.2.3 Estimating the GHG emissions due to transportation from refineries to filling stations

Methodology

The transportation of the refined petroleum products from the refineries to the filling stations in the EU Member States usually takes place via road freight, freight rail and inland waterways, which are currently operating mainly on fossil fuels. The use of fossil fuels is responsible for GHG emissions which take place during the transportation of the refined petroleum products and should be included in the lifecycle carbon emissions of diesel, petrol and kerosene. To calculate the carbon intensity $CI_{c,k}$ per transport mode k and country c used to transport the refined petroleum products Rpp we use the formula in Eq 1. This formula is based on the activity of the transport mode, usually measured in ton-kilometers (tkm), the emission factor of the mode (in gCO_2/tkm) and the total quantity of refined petroleum product transported (in MJ).

$$CI_{c,k} = \frac{Rpp\ transported_{c,k}(tkm) \times Emission\ factor_{c,k}(\frac{gCO_2}{tkm})}{quantity\ transported_{c,k}(MJ)} \quad \text{Eq 3}$$

To derive the average carbon intensity of the transportation of the refined petroleum products from the refinery to the filling stations, the weighted average is calculated based on the activity in tkm of each respective transport mode using the following formula (Eq 2).

$$CI_c = \frac{\sum_k CI_{c,k} \times Rpp\ transported_{c,k}}{\sum_k Rpp\ transported_{c,k}} \quad \text{Eq 4}$$

Further, to account for the fugitive GHG emissions at the level of the filling stations, a typical emission factor has been used from literature. As these emissions are relatively small compared to the LCA GHG emissions, for simplicity, the same emission factor has been assumed for the fugitive GHG emissions for all the EU countries. The most recent emission factor found in the technical report published by the National Environmental Research Institute has been utilized; the emission factor used is equal to 0.46 kg NMVOC/ ton petrol.

Input data

The required input for these calculations is the activity of each respective transport mode transporting refined petroleum products, the amount of products transported, and the emission factors per transport mode. The resolution of the data is at a national level.

Data on the activity of road freight, freight rail and inland waterways transporting refined petroleum products has been derived from Eurostat database. For road freight the element "road_go_na_tgtt" has been used which includes statistics on both the activity and the tons of refined petroleum products transported. As regards freight rail, Eurostat did not provide the activity and the tons of refined oil products transported at a national level. Therefore, shares were derived from the element "rail_go_natdist" which only reported data until 2002 and applied these shares to the total goods transported by rail at

a national level in 2012 (element "rail_go_typeall"). Regarding inland waterways, the values on activity and the tons of refined petroleum products from the element "iww_go_atygo" were used from Eurostat. The emission factors per transport mode used in our calculations are drawn from the PRIMES-TREMOVE[102] transport model, developed and maintained by E3MLab. The values used have also been validated with the values reported in the TRACC[103]S database.

4.3 The GHGenius model

4.3.1 Model rationale and structure

The GHGenius lifecycle model is a publicly available, Excel based, model that considers the lifecycle energy use and emissions from transportation fuels and vehicles. The model has been developed over the past 15 years by (S&T)^2 Consultants Inc. Most of the development work has been funded by Natural Resources Canada.

The model can perform a lifecycle assessment for specific regions (east, central or west) of Canada, the United States and Mexico or for India as a whole. For Canada, it is also possible to model many of the processes by province. It is also possible to model regions of North America. It is the regional nature of GHGenius that makes it an appropriate tool for studying the emissions of producing, processing, transporting and transforming the gas for use in the transportation sector for Europe.

The spreadsheet structure of GHGenius makes it relatively easy to expand the model to other regions of the world, in this case the European Union. The model is fully transparent and users can easily trace all stages of the calculations.

There are over 200 vehicle and fuel combinations possible with the model. Although the focus of this work is just the natural gas fuel supply chain up to the point that the natural gas would be dispensed to a vehicle.

4.3.2 Model parameters and structure modification

The structure of GHGenius has been changed to provide the desired results of this project. The number of regions that the model is capable of analyzing has been expanded with the addition of 4 more regions for Europe. The expansion of the model has not resulted in any loss of functionality for any of the existing regions in the model.

The four new European regions are:

- **Northern Europe.** The gas supply in the region is from the North Sea fields, imported LNG, and some Russian gas.

[redacted]

[redacted]

- **Central Europe.** Significant gas suppliers to the region are Russia, the Netherland, and Norway. There are some indigenous supplies and imports of LNG as well.
- **South East Europe.** This region has Russia and Algeria as the major suppliers with a large number of smaller suppliers supplementing the two major suppliers.
- **South West Europe.** The significant gas suppliers include Norway, Algeria, the Netherlands, Russia and LNG from Qatar and Nigeria.

In addition to the four new consuming regions, new gas producers have been added to the model. Some of these gas supply regions were already in the model but the data was of very poor quality. That will be addressed as part of the project. The gas suppliers that will be included in the revised model are:

Countries with existing quality information:

- United States
- Canada
- Mexico
- India

Existing Countries that need updated information:

- Algeria
- Norway
- Russia
- United Kingdom

New Countries added to the model:

- Netherlands
- Denmark
- Libya
- Germany
- Belgium?
- Generic shale gas
- Other
- Qatar LNG
- Nigeria LNG
- Algeria LNG
- Trinidad and Tobago LNG
- Indonesia LNG
- Other LNG

Algeria will have two supply systems, pipeline gas and LNG. The model inputs for the two types of gas will be slightly different with the extra energy required to liquefy the gas included in the LNG supply options.

Not all of these LNG sources are currently gas suppliers to Europe, but they are large global suppliers and space has been made for them in the model. The other LNG suppliers will have average values so that the suppliers that contribute less than 1% of the gas supply can be accounted for. We will also add a generic EU shale gas supplier to the model so that can be considered as a future supply source as well. Data for this supply option may have more uncertainty.

Natural gas supply systems generally use mostly natural gas energy in the production system but there can also be electricity consumed and a small amount of liquid fuels. Electricity will also be used in the gas consuming regions for compression to CNG. The GHGenius model structure has therefore been expanded to include the specific regional electricity production data for the gas producing countries and the gas consuming regions. This will include the mix of energy sources used to produce the power, the efficiency of the thermal generating system, and the distribution losses in the grids.

The contribution of the production of liquid fuels to the complete lifecycle emissions is expected to be small and less effort will be expended to use regional specific data for liquid fuel production for this work.

GHGenius currently allows for the input of energy used for well drilling, gas production, and gas processing for gas production in Canada and the United States. The specific energy inputs that can be input are crude oil, diesel fuel, residual fuel, natural gas, coal, electricity, petrol, and coke. Other gas producing regions are estimated on a total quantity of energy consumed relative to energy consumed in the US. This same structure used for Canada will be introduced for all of the other gas supply regions.

The model will be modified to include two tables of transportation distances from the gas supplier to the gas consuming region. One table will have pipeline distances and the other will have shipping distances for LNG. The average distance for each consuming region will be used to calculate the energy consumed and the emissions from the transmission and transport of the gas.

An important part of the natural gas supply chain is the rate of methane loss from the system, this can be through venting, flaring, or equipment leaks. The new structure of the model will accommodate separate inputs for all of these emissions for all gas producers and for the gas consumers for the transmission losses.

The final emission source that is included in the model is the emission of carbon dioxide that is removed from the gas during processing to bring the gas to pipeline quality.

4.3.3 Required Inputs

In order to model the lifecycle GHG emissions from the supply of natural gas in Europe a significant amount of data is required. The data required includes;

- The gas production, imports and consumption for each of the EU countries.

- The carbon intensity of the electric power used in each of the producing countries, as some electricity can be used to produce and process the natural gas in the producing country.
- The carbon intensity of the electric power used in each of the EU countries as electricity is used to compress the natural gas to CNG.
- For each supplier of natural gas the data that will ideally be required are those for three stages of gas production, well drilling, gas extraction, and gas processing. The data required will include the quantity and type of energy required for each of the three stages, the methane loss rate of each stage, the quantity of gas flared, and the quantity of carbon dioxide released to the atmosphere to bring the field gas to pipeline specifications.
- For each supply source the pipeline or shipping distance of gas to the EU region will need to be identified so that the energy consumed in the gas transmission/transportation stage can be determined. For each of these activities the methane loss rate will be required.
- Within each of the EU countries energy use in gas distribution (medium pressure) and the relevant emissions will be assessed. Energy use in distribution is very small as compression is not required, like it happens in transmission; however the distribution gas loss as fugitive gas can be substantial. On the other hand electricity requirements of gas distribution systems are mostly related to compression of pipeline gas to CNG.

4.3.4 Parametric significance

There are three groups of GHG emissions in the natural gas supply chains. There are CO_2 emissions resulting from the purification of the raw gas to pipeline specifications. Depending on the gas composition of the specific fields these can be zero or some extreme cases these emissions might account for 4 or more $grCO_2eq/MJ$. In some gas fields the CO_2 may be re-injected into the reservoir to help maintain the field pressure. This will lower the direct emissions of CO_2, but the re-injection process will increase the energy consumption and thus there will be some energy related emission increase that will offset the savings from the re-injected gas.

The second category of emissions is energy related; those emissions resulting from the use of energy in all stages of the supply chain. Field pressure, gas composition, transmission distances, and pipeline characteristics can all influence the energy consumed in the natural gas supply chain. Energy is used in the well drilling, gas production, gas processing, gas liquefaction and regasification (for LNG supply), gas transmission, but only in rare instances the gas distribution stage. The contribution of energy related emissions is typically 5 to 10 $grCO_2eq/MJ$.

The third category of emissions is the leaks of methane from the system. Every stage has the potential for some methane emissions, and since methane has a GWP of 25, these emissions can become quite significant in "leaky" systems. In a few cases methane leaks are deliberate such as using the natural gas to actuate control values instead of using compressed air systems, but in most cases the methane emissions are unintended and

could be fugitive type emissions. Methane emissions are difficult to quantify accurately since there can be literally thousands of individual points of potential leaks in a supply chain. Every valve, meter, compressor, relief station, and connection can be a source. Methane emissions from less than 0.5% to 1.5% can be expected in most supply chains. These emissions are equivalent to 4 to 12 $grCO_2eq/MJ$.

4.3.5 Produced outputs

GHGenius can provide significant detail on the emissions for natural gas. The most common form of the output is the GHG emissions by stage per GJ of fuel. For natural gas systems the typical output is shown in Table 4-5. While the focus of the work is on the emissions for CNG, the model will also provide the natural gas emissions for gas supplied to power generators, fuel conversion facilities (e.g. methanol plants), and other end users.

Table 4-5 Typical GHGenius Output on the emissions of natural gas

Stage	Compressed Natural Gas	Natural Gas for Industry
	$grCO_2eq/GJ$ (LHV)	
Fuel dispensing	2,534	0
Fuel distribution and storage	961	862
Fuel production	2,787	2,778
Feedstock transmission	0	0
Feedstock recovery	3,007	2,997
Feedstock Upgrading	0	0
Land-use changes, cultivation	0	0
Fertilizer manufacture	0	0
Gas leaks and flares	3,214	1,605
CO_2, H_2S removed from NG	1,081	1,078
Emissions displaced	0	0
Total	**13,584**	**9,319**

The information can also be supplied by the total emissions of the individual gases as shown in Table 4-6

The emissions of these gases by stage can also be provided in a series of tables for each gas.

GHGenius also can report on the primary energy consumed for each stage of the process. Primary energy includes the energy required to produce the energy, it is the lifecycle energy used. Total primary energy and fossil primary energy can be reported. The typical energy use is shown in the Table 4-7. This output is only available on a higher heating value basis.

The type of energy used can also be provided as shown in Table 4-8. This energy use is reported as secondary energy. Secondary energy is the energy content of the electric power, or diesel fuel, or coal at the point that it is used.

Table 4-6 Typical GHGenius Output by Specific Gas

Stage	Compressed Natural Gas	Natural Gas for Industry
	$grCO_2eq/GJ$ (LHV)	
Carbon dioxide (CO_2)	9,251.1	6,718.3
Non-methane organic compounds (NMOCs)	3.7	3.0
Methane (CH_4)	170.6	102.2
Carbon monoxide (CO)	7.2	6.0
Nitrous oxide (N_2O)	0.2	0.2
Nitrogen oxides (NO_2)	52.7	44.6
Sulphur oxides (SOx)	15.9	7.0
Particulate matter (PM)	0.8	0.3
HFC-134a (mg)	0.0	0.0
CO_2-equivalent GHG emissions	**13,583.6**	**9,318.8**

Table 4-7 Typical GHGenius Output for the Total Energy Consumption

Stage	Compressed Natural Gas	Natural Gas for Industry
	Joules consumed/Joule Produced	
Fuel dispensing	0.0250	0.0000
Fuel distribution, storage	0.0143	0.0128
Fuel production	0.0392	0.0391
Feedstock transmission	0.0000	0.0000
Feedstock recovery	0.0416	0.0415
Feedstock Upgrading	0.0000	0.0000
Ag. chemical manufacture	0.0000	0.0000
Co-product credits	0.0000	0.0000
Total	**0.1202**	**0.0935**
EROEI (J delivered/J consumed)	**8.3186**	**10.7007**

Table 4-8 Typical GHGenius Output for the Secondary Energy Use by Type

Energy Type	Compressed Natural Gas	Natural Gas for Industry
	Joules consumed/Joule Produced	
Coal	0.0000	0.0000
Crude	0.0000	0.0000
Natural Gas	0.0832	0.0817
Diesel	0.0006	0.0006
Petrol	0.0000	0.0000
Biomass	0.0000	0.0000
Electricity	0.0187	0.0017
Other	0.0000	0.0000
Total	**0.10**	**0.08**

5 RESULTS ON DIRECT EMISSIONS

5.1 Carbon Intensity of Oil products

5.1.1 Results from the OPGEE methodology

Overview of carbon intensities by oilfield and MCON using OPGEE

This Section presents the results obtained for the various MCONs considered for the purposes of this study using the OPGEE model. Table 5-1 shows the upstream and midstream Carbon Intensities (CI) of the 40 more representative MCONs imported to EU countries that have been considered. The average upstream and midstream CI of all MCONs has been estimated 9.72 grCO2eq/MJ. Further in this section, we discuss about the key factors which influence the relevant carbon intensities.

Table 5-1 Carbon Intensity of worldwide MCONs imported to EU

MCONs	API	COUNTRIES	UPSTREAM GHG EMISSIONS ($grCO_2eq/MJ$)	OILFIELDS	UP- AND MIDSTREAM CI ($grCO_2eq/MJ$)
Boscan	11	VENEZUELA	8.02	Boscan	8.89
Grane	19	NORWAY	4.40	Grane	5.36
Captain	20	UK	19.76	Captain	19.81
Dalia	22	ANGOLA	7.45	Block 17/ Dalia	8.40
Maya	22	MEXICO	6.37	Cantarell	7.16
Arab Heavy	27	SAUDI ARABIA	23.38	Manifa	24.55
Basrah Light	30	IRAQ	12.94	Rumaila (South)	13.95
				West Qurna	13.97
Girassol	30	ANGOLA	7.55	Girassol	8.22
Bonga	30	NIGERIA	6.23	Bonga	7.03
Escravos	31		25.52	Escravos Beach	26.17
Forcados	32		8.75	Forcados Yokri	9.55
Iranian Heavy	32	IRAN	19.70	Gachsaran oil field	20.70
Kuwait	32	KUWAIT	5.34	Burgan	6.27

MCONs	API	COUNTRIES	UPSTREAM GHG EMISSIONS ($grCO_2eq/MJ$)	OILFIELDS	UP- AND MIDSTREAM CI ($grCO_2eq/MJ$)
Blend					
Forties	33	UK	5.67	Buzzard	6.16
Arab Light	33	SAUDI ARABIA	6.55	Gwahar	7.33
Greater Plutonio	33	ANGOLA	7.61	Greater Plutonio	8.28
Siberian Light	34	RUSSIAN FEDERATION	8.31	Povkhovskoye	11.45
				Samotlor	11.43
				Tevlinsko-Russkinskoye	6.69
				Uryevskoye	12.07
				Vat-Yeganskoye	5.50
Kirkuk	35	IRAQ	14.01	Kirkuk	14.64
Bonny Light	35	NIGERIA	13.90	Agbada	10.67
				Cawthorne Channel	18.70
Troll	36	NORWAY	5.34	Troll	5.63
Brent Blend	36	UK	10.46	Ninian	10.61
Azeri Light	36	AZERBAIJAN	6.42	Azeri-Chirag-Gunashli (ACG)	6.97
Azeri BTC	36			Azeri BTC	7.26
Druzhba	37	RUSSIA	9.24		
Es Sider	37	LIBYAN ARAB JAMAHIRIYA	11.86	Es Sider	12.47
Urals	38	RUSSIAN FEDERATION	9.71	Unvinskoye	9.65
				Pamyatno-Sasovskoye	9.69
				Romashkino	11.96
Oseberg	38	NORWAY	4.39	Oseberg	5.35
Ekofisk	38		4.61	Ekofisk	5.05
Gullfaks	39		4.61	Gullfaks	4.73
Statfjord	40		5.15	Statfjord	5.26
DUC	41	DENMARK	5.17	Halfdan	5.32
El Sharara	44	LIBYAN ARAB JAMAHIRIYA	11.61	El Sharara	11.93
Azeri CPC	45	AZERBAIJAN	6.61	Azeri CPC	7.37
Saharan Blend	46	ALGERIA	11.45	Hassi Messaoud	11.83
Tengiz	48	KAZAK	10.42	Tengiz	11.61
Asgard Blend	50	NORWAY	5.38	Tyrihans	5.47

These worldwide oilfields aim to assess either the regional average Carbon Intensity or assess single crudes to use as representative of regional production. Most of the countries have different oilfields with similar characteristics and therefore similar Carbon Intensities of their crudes.

However, it is evident from the underlying database that in Nigeria the results differentiate significantly. The Carbon Intensity of the regional oilfields ranges from 6.23 $grCO_2eq/MJ$ to 25.52 $grCO_2eq/MJ$. In general, Nigeria displays high levels of flaring emissions. Flaring of gas is an important source of air emissions and as a result it influences significantly the total GHG emissions of the respective oilfield. Due to different values of flaring emissions in different areas of Nigeria, the results show important fluctuations among oilfields.

Similarly, the oilfields in the UK present completely different Carbon Intensities. The data input values for the Flaring to Oil Ratio parameter have important deviations between three oilfields and given the different levels of Gas to Oil Ratio, the resulting GHG emissions vary significantly.

In Saudi Arabia two large oilfields, which have been investigated, appear to have noticeable differences in GHG emissions of crude oil extraction. This is attributed to different properties of the produced crude oil, as well as to the different characteristics of the oilfields, like field depth, number of producing wells, reservoir pressure.

According to the results obtained from the OPGEE model, the lowest values of GHG emissions are presented in Norway's oilfields. Lower values in flaring emissions combined with the low water-to-oil ratio of wells and also light producing crude oil, contribute to relatively lower total GHG emissions than other oilfields. On the contrary, in Nigeria, where flaring emissions are significant, GHG emissions are increased accordingly. Nigeria is one of the largest flaring countries in the world and also one of the biggest sources of crude oil for EU countries. It is deduced that the flaring-to oil-ratio is the dominant factor in determining of GHG emissions from crude mining operations and that the model results are particularly sensitive to slight differentiations in the assumptions.

Upstream and Midstream GHG emissions by MCON

Table 5-2 presents the total upstream and midstream GHG emissions of MCONs separately. The GHG emissions during transportation of crude oil from the production point to the refinery of a European country are responsible for a small part of the total Carbon Intensity of the MCON.

Table 5-2 Summary of results for upstream and midstream GHG emissions

MCON	Upstream emissions ($grCO_2eq/MJ$)	Midstream emissions ($grCO_2eq/MJ$)
Boscan	8.02	0.87
Grane	4.40	0.96
Captain	19.76	0.05

MCON	Upstream emissions ($grCO_2eq/MJ$)	Midstream emissions ($grCO_2eq/MJ$)
Dalia	7.45	0.95
Maya	6.37	0.79
Arab Heavy	23.38	1.18
Basrah Light	12.94	1.01
Girassol	7.55	0.67
Bonga	6.23	0.80
Escravos	25.52	0.65
Forcados	8.75	0.80
Iranian Heavy	19.70	1.01
Kuwait Blend	5.34	0.93
Forties	5.67	0.50
Arab Light	6.55	0.78
Greater Plutonio	7.61	0.67
Siberian Light	8.31	1.12
Kirkuk	14.01	0.63
Bonny Light	13.90	0.79
Troll	5.34	0.30
Brent Blend	10.46	0.15
Azeri Light	6.42	0.55
Azeri BTC	6.42	0.84
Druzhba	9.24	0.91
Es Sider	11.86	0.61
Urals	9.71	0.81
Oseberg	4.39	0.96
Ekofisk	4.61	0.44
Gullfaks	4.61	0.12
Statfjord	5.15	0.11
DUC	5.17	0.15
El Sharara	11.61	0.32
Azeri CPC	6.61	0.76
Saharan Blend	11.45	0.38
Tengiz	10.42	1.18
Asgard Blend	5.38	0.08

Estimated MIN-MAX values for combined upstream and midstream CI

This section presents some estimates on the expected lower and upper values of GHG emissions of the MCONs analysed within this study.

The underlying calculations for deriving the MIN and Max values presented in Table 5-3 are based on the elaboration in differentiated assumptions regarding the transportation distance of the crude from the production point to destination. Further, several parameters (e.g. the oil production volume, field depth, etc.) were found to fluctuate, so the estimates are based on the upper and the lower values of the data provided.

Table 5-3 Estimates on the MIN-Max values of the upstream and midstream GHG emissions (gCO2e/MJ) of the MCONs

MCON	MIN	MAX
Boscan	8.39	9.39
Grane	5.36	5.36
Captain	18.20	21.49
Dalia	8.27	8.53
Maya	7.14	7.18
Arab Heavy	24.30	24.81
Basrag Light	12.45	15.30
Girassol	8.13	8.31
Bonga	6.95	7.11
Escravos	26.10	26.30
Forcados	9.47	9.62
Iranian Heavy	20.45	21.08
Kuwait Blend	6.00	6.46
Forties	6.00	6.33
Arab Light	7.10	7.46
Greater Plutonio	8.19	8.37
Siberian Light	5.33	12.18
Kirkuk	14.41	14.90
Bonny Light	10.48	18.82
Troll	5.43	6.02
Brent Blend	10.60	10.62
Azeri Light	6.86	7.07
Azeri BTC	7.12	7.48
Es Sider	12.29	12.65
Urals	9.15	12.11
Ekofisk	4.68	5.43
Gullfaks	4.63	4.88
Statfjord	5.15	5.33
DUC	5.28	5.36
El Sharara	11.84	12.03

MCON	MIN	MAX
Azeri CPC	7.11	7.63
Saharan Blend	11.73	11.94
Tengiz	11.50	11.72
Asgard Blend	5.42	5.49

5.1.2 Comparison of CI results between the current study and the study of ICCT

This section of the study presents an overview of the results obtained using the OPGEE model with other estimates from literature. Table 5-4 summarizes the results of Carbon Intensities of the MCONs imported in EU countries, as they were estimated in the current study using the OPGEE model, as well as the results of ICCT study.

The aim of the comparison of the results obtained within this study with other estimates from the literature is to provide transparency. Further, whenever significant changes are observed, this section provides robust explanations which are mainly attributed to differences in the background assumptions and database rather than the methodological tools employed.

The estimates of upstream and midstream carbon intensities using the OPGEE model in the current study are examined and compared with the results obtained from ICCT study.

The regional oilfields, the flaring emissions, the gas/water/flaring to oil ratio and a number of critical parameters related to the oil production methods affect the final estimates on the carbon intensities of crude oils. Due to the lack of information on actual data regarding the oilfield and the oil production default values for certain parameters in the estimation of the carbon intensities were utilized. Moreover, the use of actual or default values for the modeling calculations results in different final outcomes.

The results of the present study are comparable to the results of ICCT study as both have used the OPGEE model for the determination of the GHG emissions by MCON imported to EU and the match between the representative MCONs presented in the studies is helpful for comparison. However, before comparing the results we should underline the following additions/updates regarding the modeling inputs:

- An updated (the most resent) version (v1.1) of OPGEE model has been used in the current study.
- In this study emphasis was put on the evaluations of VFF emissions by separate modules for flaring, venting and fugitive.
- The size of the ocean tanker was added as input in the transport section.
- The volume fraction of diluent was added as user input.
- Land use change emissions factors were modified to account for 30 years analysis period.

- Water to Oil ratio representation was improved with more detailed regional characteristics and a new functional form was included.
- Updated data for Venting and Fugitives was obtained from the California Survey Data.
- Generally the use of model default values was minimized and the effort focused in exploiting actual input data from all available sources.

Table 5-4 Comparison of the estimated upstream and midstream GHG emissions of MCONS with ICCT estimations

MCON	GHG emissions (gCO_2e/MJ)	ICCT (2010)
Boscan	8.89	8.40
Grane	5.36	
Captain	19.81	
Dalia	8.40	9.40
Maya	7.16	8.20
Arab Heavy	24.55	
Basrah Light	13.96	10.40
Girassol	8.22	10.30
Bonga	7.03	
Escravos	26.17	12.20
Forcados	9.55	
Iranian Heavy	20.70	11.50
Kuwait Blend	6.27	6.00
Forties	6.16	2.30
Arab Light	7.33	5.50
Greater Plutonio	8.28	8.00
Siberian Light	9.43	9.80
Kirkuk	14.64	9.00
Bonny Light	14.68	13.20
Troll	5.63	5.40
Brent Blend	10.61	8.80
Azeri Light	6.97	5.40
Azeri BTC	7.26	
Es Sider	12.47	13.60
Urals	10.52	12.50
Oseberg	5.66	6.40
Ekofisk	5.05	2.80
Gullfaks	4.73	5.90
Statfjord	5.26	6.40

MCON	GHG emissions (gCO2e/MJ)	ICCT (2010)
DUC	5.32	3.20
El Sharara	11.93	
Azeri CPC	7.37	
Saharan Blend	11.83	12.80
Tengiz	11.61	17.70
Asgard Blend	5.47	9.50

Having taken into consideration the abovementioned points, we compare the results of the two studies (Figure 5-1) and make the following comments regarding the carbon intensities for a number of MCONS.

A pronounced difference in the carbon intensities of 'Escravos' MCON is observed in the results of the two studies, as it has been estimated 26.17 $grCO_2eq/MJ$ in this study and 12.2 $grCO_2eq/MJ$ in the study of ICCT. Among the various parameters, the high value of flaring emissions considered in the calculations of this study is responsible for the difference. The regional oilfields in Nigeria are characterized by increased levels of flaring emissions. The flaring emissions in this study are much higher than those in ICCT.

The Carbon Intensity of "Iranian Heavy" crude was estimated at 20.70 $grCO_2eq/MJ$ in the present study and 11.5 $grCO_2eq/MJ$ in the ICCT study. The difference between the estimated values for 'Iranian Heavy' is attributed to the different oilfields producing this MCON and the emissions associated with them.

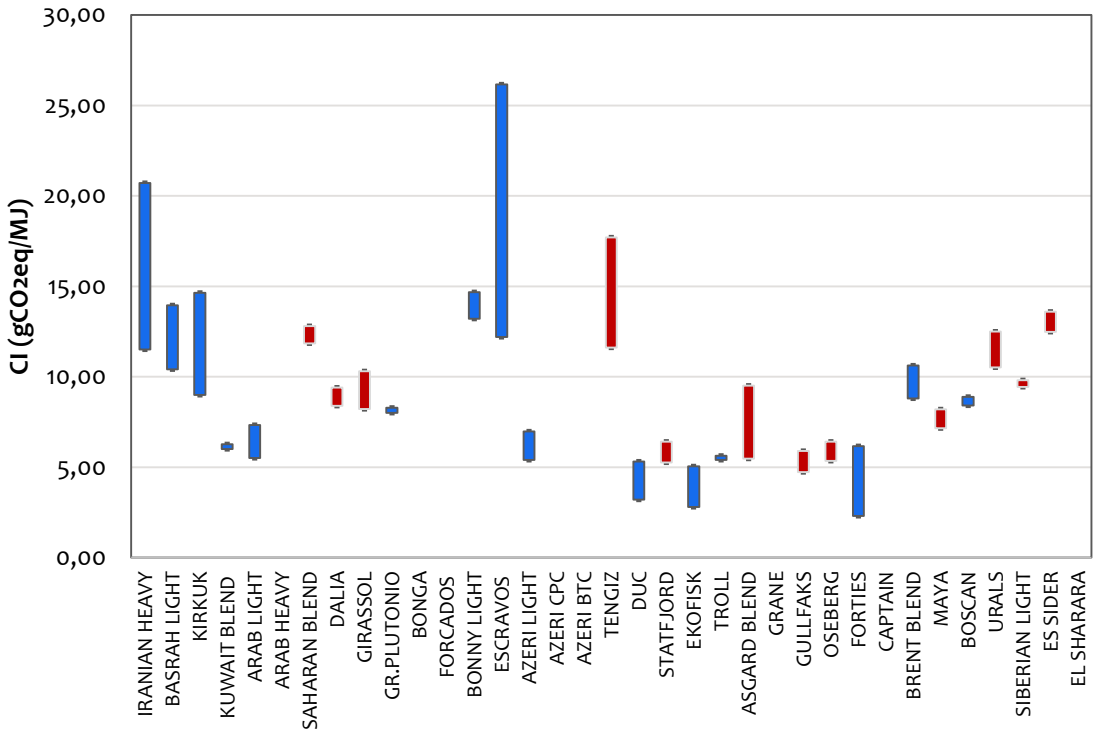
A significant difference is observed in the estimations of the CI of 'Kirkuk' MCON. In particular, according to the present study it has 14.64 $grCO_2eq/MJ$ while the value of ICCT is much lower (9.0 $grCO_2eq/MJ$). This differentiation is related to parameters associated with the production practices during the oil extraction such as the water to oil and gas to oil ratios..

MCON 'Tengiz' presents also higher emissions in this study (11.61 $grCO_2eq/MJ$) in comparison with ICCT (17.7 $grCO_2eq/MJ$). In this study the gas to oil and flaring to oil ratios were updated with actual values obtained from recent databases. These parameters are considered to have had great impact on the emissions. Flaring-to oil ratio was also the critical parameter in the evaluation of the CI of 'Arab Light' which differed in the two studies by ~1.8 $grCO_2eq/MJ$.

'Forties' appears more CO2 intensive in this study (6.16 $grCO_2eq/MJ$) than in the ICCT study (2.3 $grCO_2eq/MJ$). Gas lifting and water flooding were added as methods of production in this study and, thus, the gas to oil ratio was increased resulting in increased GHG emissions.

Figure 5-1 Comparison of GHG Emissions for the various MCONs between the current study and the ICCT study

*When the values of ICCT are higher than this study the differences are red colored



5.1.3 Split of the upstream and midstream GHG emissions of selected MCONS by stage

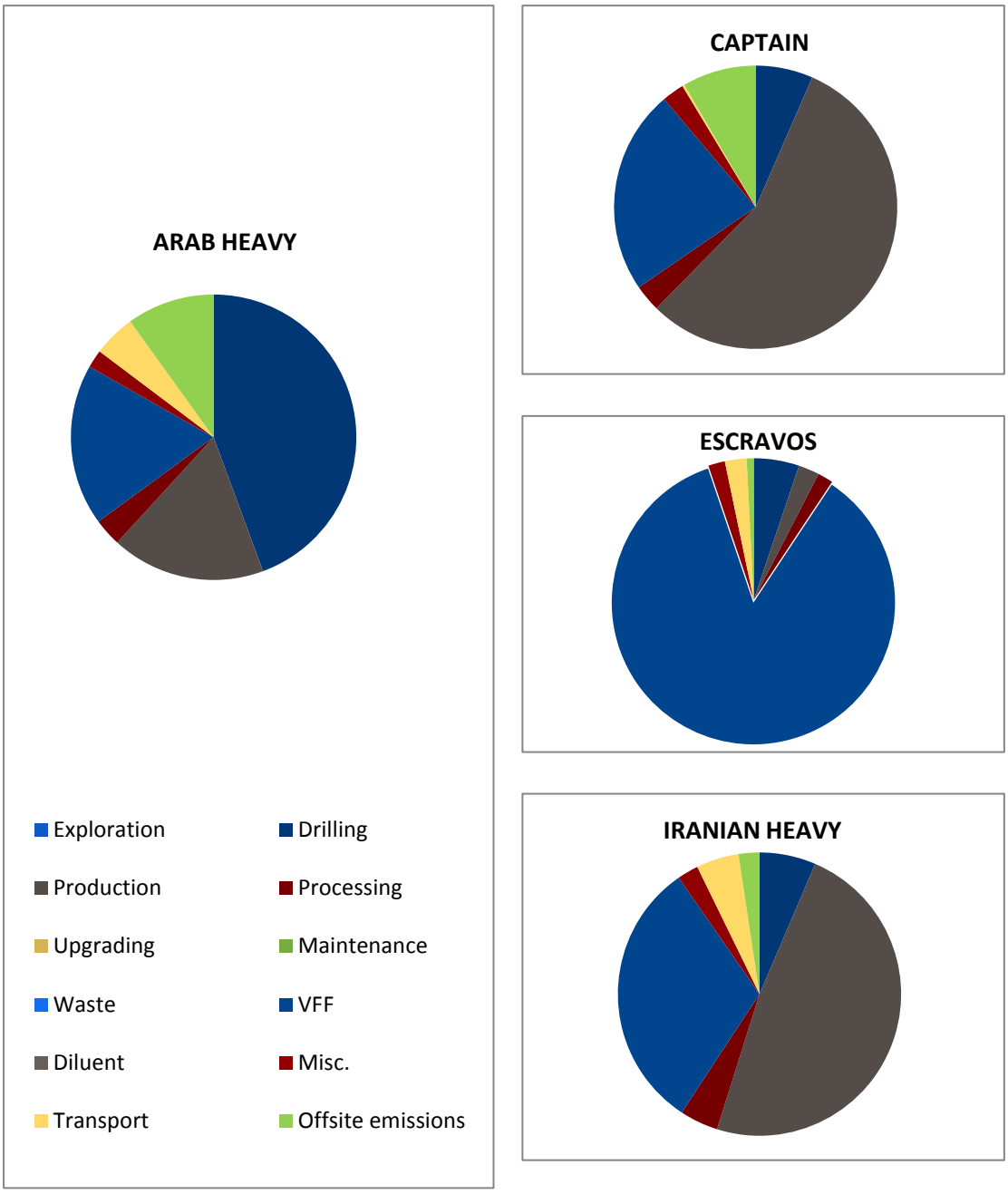
By presenting the upstream and midstream results in pie charts for individuals MCONs as depicted in Figure 5-2, we can figure out which stage is more energy and emissions intensive during oil production.

In the case of Nigerian 'Escravos' a carbon intensity of 26.17 $grCO_2eq/MJ$ was estimated mainly reflecting the high levels of flaring emissions (1510 scf/bbl oil). As previously mentioned, Nigeria is one of the countries with flaring emissions accounting for the largest shares of the total GHG emissions.

The CI of 'Arab Heavy' MCON is 24.55 $grCO_2eq/MJ$ and, 44% of it is associated with the drilling stage. According to the input data of the oilfield's characteristics, the field depth is counted around 30,000ft. The great depth of an oilfield delays the drilling progress. Hence, as a well gets deeper, the amount of fuel consumed per unit of depth drilled increases.

As regards Iranian Heavy and Captain MCONs the major part of emissions is related to their production methods, namely gas lifting and flooding which increase the gas-to-oil ratio and, consequently, the GHG emissions.

Figure 5-2 Graphical presentation of GHG emissions during the different upstream and midstream stages



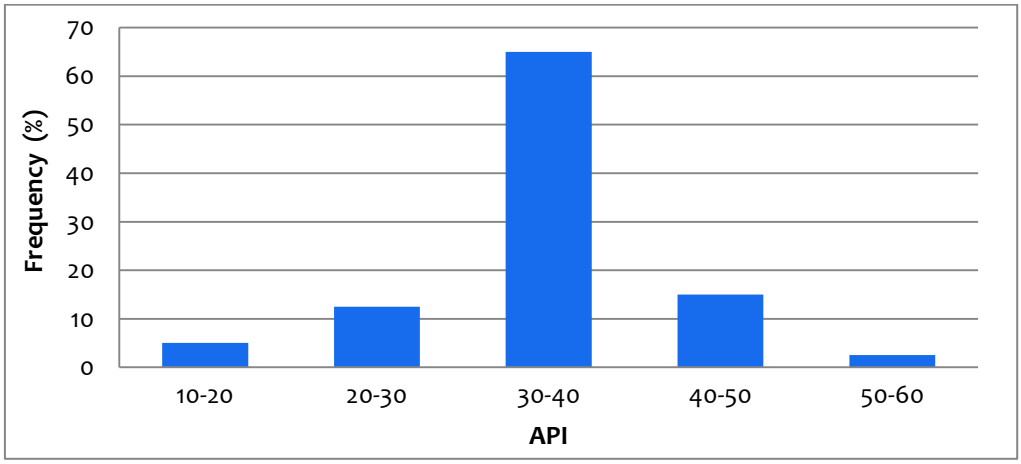
Deeper understanding of the influence of specific input OPGEE parameters on the respective GHG emissions

One of the most important quality characteristics of crude oil is the API gravity which indicates how 'heavy' a crude oil is. Heavier crudes have low API and light crudes have high values of API. This study has identified and analyzed 40 oil fields producing different types of crude oil. The density of the examined crudes varies between 10 and 50 API degrees. Figure 5-3 shows the frequency of the API gravities for the crudes taken into consideration in the study. Most oilfields produce medium-light crude oils with API

ranging between 30-40 degrees. Nevertheless, there are also crudes with very high or very low API accounting for smaller shares of the total production.

The 'heaviness' of a crude determines the choice of the extraction method as well as the need for secondary processes, i.e. gas/water/steam flooding. These processes facilitate the oil extraction by increasing the pressure of extraction but result in higher emissions associated with the production stage.

Figure 5-3 API gravity frequency distribution



5.1.4 Impact of the Flaring Emissions on the Carbon Intensities of crude oils

The contribution of flaring emissions to the total GHG emissions is of great importance, as they account for more than 50% of the total emissions in the vast majority of oilfields. Table 5-5 gives the flaring to oil ratio and the VFF emissions for the various MCONs as well as the estimated upstream GHG emissions.

Table 5-5 Contribution of flaring emissions to total GHG emissions

MCON	FLARING TO OIL RATIO (scf/bbl oil)	VFF EMISSIONS ($grCO_2eq/MJ$)	TOTAL UPSTREAM CI ($grCO_2eq/MJ$)
Boscan	147	3.50	8.02
Grane	22	3.42	4.40
Oseberg	22	2.07	4.39
Captain	198	4.63	19.76
Dalia	227	5.26	7.45
Maya	78	3.42	6.37
Arab Heavy	147	4.49	23.38
Basrah Light	346	7.20	12.94

MCON	FLARING TO OIL RATIO (scf/bbl oil)	VFF EMISSIONS ($grCO_2eq/MJ$)	TOTAL UPSTREAM CI ($grCO_2eq/MJ$)
Girassol	227	5.28	7.55
Bonga	129	4.27	6.23
Escravos	1510	22.36	25.52
Forcados	323	6.42	8.75
Iranian Heavy	272	6.44	19.70
Kuwait Blend	53	3.63	5.34
Forties	15	2.61	5.67
Arab Light	147	4.26	6.55
Greater Plutonio	227	5.60	7.61
Siberian Light	370	9.68	8.31
Kirkuk	346	7.50	14.01
Bonny Light	667	11.56	13.90
Troll	22	5.13	5.34
Brent Blend	108	3.72	10.46
Azeri Light	25	3.41	6.42
Azeri BTC	25	3.41	6.42
Es Sider	458	9.04	11.86
Urals	370	8.46	9.71
Ekofisk	22	3.53	4.61
Gullfaks	22	3.88	4.61
Statfjord	22	8.47	5.15
DUC	0	3.69	5.17
El Sharara	458	9.34	11.61
Azeri CPC	25	3.55	6.61
Saharan Blend	314	6.66	11.45
Tengiz	293	7.21	10.42
Asgard Blend	22	6.34	5.38

In a number of MCONs, i.e. Statfjord, Asgard Blend and Siberian Light, the VFF emissions exceed the aggregate Carbon Intensity estimate. This happens because the total Carbon Intensity is calculated in the OPGEE model by subtracting the offsite emissions of the regional oilfield. The offsite emissions are associated with the energy consumption during seismic processing or for waste disposal and other production-related processes.

If oil is produced in areas which lack gas infrastructure or a nearby gas market, a significant portion of this associated gas may be released into the atmosphere, un-ignited (vented) or ignited (flared). Flaring of gas either as a means of disposal or as a safety measure to relieve well pressure is the most significant source of air emissions from oil and gas installations.

With respect to Global-warming potential, venting of natural gas is also considered as a source of GHG emissions. The largest amount of methane is released during the various oil production and maintenance operations, such as gas dehydrators, acid gas removal (AGR) units, compressors, gathering pipelines, well workovers and cleanups. The extent of gas leakage is a function of the amount of gas produced with oil as well as the type of production equipment. On rare occasions methane venting is used instead of flaring. The access to information on venting gases emitted during operational processing is very limited.

Flaring Efficiency

The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, carbon monoxide, and other products of incomplete combustion (e.g. soot, volatile organic compounds, etc.) are emitted into the atmosphere. The unburned fuel causes an increase in GHG emissions in the form of CH_4.

The quantity of the generated hydrocarbon emissions is determined by the degree of combustion. According to the OPGEE model flare efficiency depends on flare exit velocities and diameters, cross wind speed, heating value and gas composition. If the required data is known, then the field-specific flaring efficiency can be determined. Otherwise, the OPGEE model populates a default flare efficiency of 95% in order to export the results.

When the burning efficiency of the flares is decreased a greater amount of the associated gas (methane) is released. Methane gas has a high global warming potential of 25 (against 1 of CO2) and, in turn, increases the concentration of total GHG emissions in the atmosphere. In order to assess the impact of flare efficiency on the total oilfield emissions, a sensitivity analysis has been conducted and the results are presented in Table 5-6. Three oilfields with different Flaring-to-Oil Ratios were used in the analysis where the flaring efficiency parameter changed by three values (90%, 95% and 99.5%).

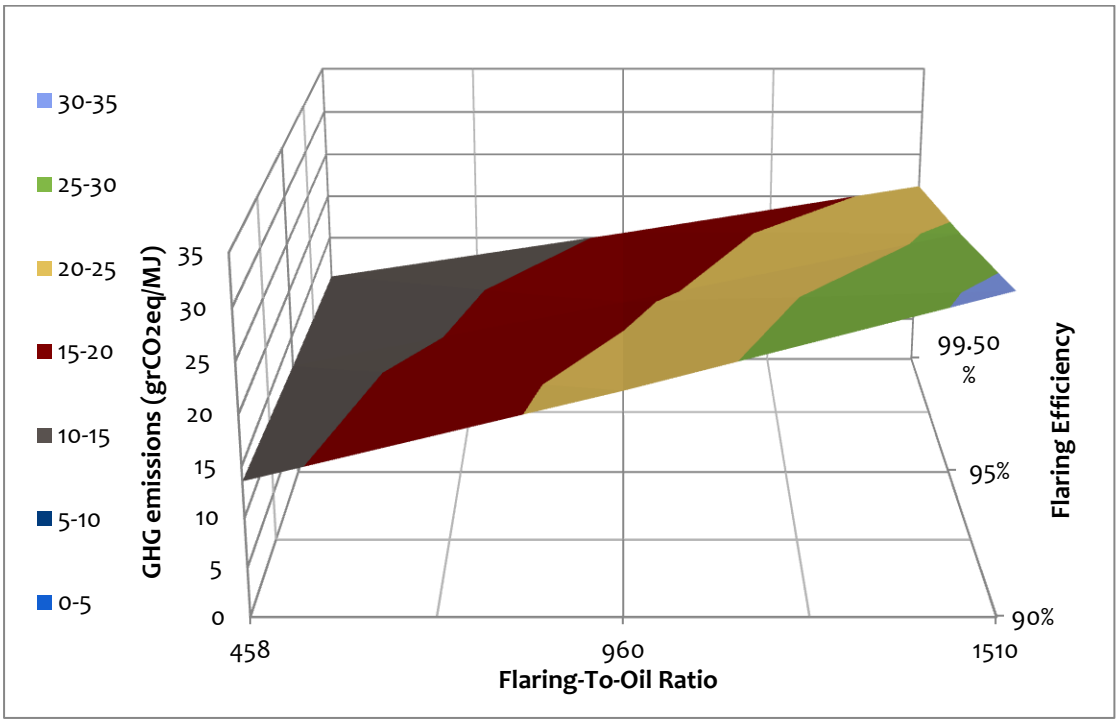
Table 5-6 Impact of flaring emissions to total GHG emissions

		Flaring Efficiency		
		90%	95%	99.5%
Oilfield	**Flaring–to-Oil Ratio (FOR)**	**GHG emissions ($grCO_2eq/MJ$)**		
El Sharara	458	13.59	11.84	10.27
Cawthorne Channel	960	22.26	18.75	15.58
Escravos Beach	1510	31.54	26.1	21.21

The flaring to oil ratio of El Sharara oilfield, in Libya, is 458 scf/bbl oil, while the Nigerian oilfields Cawthorne Channel and Escravos Beach have higher FOR, 960 scf/bbl and 1510 scf/bbl oil, respectively.

According to the results, the reduction of the flaring efficiency to 90% caused an increase in the carbon intensities of 15% for El Sharara, 19% for Cawthorne Channel and 21% for Escravos Beach. Increasing the flaring efficiency to 99.5% resulted in reduced GHG emissions for the three considered oilfields. In particular, the carbon intensity of El Sharara was decreased by 13%, and a larger decline of emissions was noticed for the Nigerian oilfields; 17% for Cawthorne Channel and 19% for Escravos Beach. Figure 5-4 illustrates the effect of the flaring efficiency over the carbon intensity of the oilfields in a variety of flaring-to-oil ratio values.

Figure 5-4 Impact of the flaring efficiency on the total GHG emissions of the oilfields



Unconventional oils

Besides conventional oilfields and traditional oil well extraction, there are also alternative sources of crude oil supply worldwide. Oil sands, tar sands and shales or rocks, are the most typical sources of unconventional oil formations.

Shales and similar rocks are oil reservoirs characterized by low porosity which hampers or even blocks the flow of the contained oil. The extraction of the shale/tight oil is achieved by natural or artificial fractures.

Oil sands as mixtures of sand, water, clay and bitumen are naturally occurring petrochemicals that can be upgraded into crude oil and other petroleum products. They are mostly located in Alberta (known as Alberta oil sands), but they may also be found in other regions worldwide, i.e. US, Russia, Venezuela etc.

Venezuela extra-heavy crude oil and Alberta bitumen are two typical examples of unconventional oils derived from oil sands. Alberta bitumen is produced by Canadian unconventional processes while Venezuela extra heavy oil deposits may be produced through conventional techniques. The carbon intensities of these two unconventional oils have been estimated by the use of OPGEE model. The Venezuela extra heavy crude oil from Petrozuata has been analyzed as conventional crude oil and an upgrading unit was added in the production practices. The Alberta bitumen was analyzed as unconventional oil with the selection of surface mining as extraction method. Table 5-7 gives the resulting Carbon Intensities of the two unconventional oils.

Table 5-7 OPGEE estimated Carbon intensities of unconventional crude oils

Unconventional crude oils	Carbon Intensity ($grCO_2eq/MJ$)
Venezuela crude	**23.74**
Alberta Bitumen	**23.83**

As expected, the carbon intensities of both unconventional oils are remarkably high. In the case of Venezuela crude the additional process of upgrading is responsible for the increased carbon intensity. Fuels combustion for heating and electricity generation and the methods used for hydrogen production are significant sources of GHG emissions. Alberta bitumen requires energy intensive processes for oil extraction and upgrading. More specifically, the fuel mix consumed during mining and the amount of fuel consumed per unit of bitumen produced affect the emissions intensity.

5.1.5 Results for the GHG emissions at the refinery stage

Results at the EU MS level

GHG emissions during the refining process depend particularly on the refinery configuration (operating units), the sources of energy required for the processes and the properties of the crude fed in the refinery (API and sulphur content).

In the current study GHG emissions during the refining stage have been computed using the PRIMES-Refinery model which uses as input demand for oil products, crude oil characteristics and capacities of processes as a result of a complex calibration process of the model. Self-consumption of the refineries is also an additional input from the Eurostat balances. Further, net imports and exports of crude and products and pricing of finished products are included in the model structure. The model is focused on the emissions from the fuels combustion and does not take into consideration the fugitive emissions; the latter however represent only a minimal fraction of the whole GHG emissions.

The refinery emissions in Europe are estimated to be on average 5.5 $grCO_2eq/MJ$ of crude. Average CO2 emissions refer to the total refinery emissions occurring during processing

and result from the model calculations accounting all refinery products, without any allocation. Table 5-8 gives the average refinery emissions at an EU country level.

Table 5-8 Average refinery emissions in EU

Average refinery emissions	($grCO_2eq/MJ$ of crude)
Austria	6.3
Belgium	3.3
Bulgaria	4.5
Croatia	8.3
Czech Republic	4.9
Denmark	3.2
Finland	5.5
France	4.3
Germany	5.0
Greece	5.1
Hungary	4.9
Ireland	2.8
Italy	6.2
Lithuania	4.4
Netherlands	4.4
Poland	7.5
Portugal	6.1
Romania	9.7
Slovakia	5.3
Spain	5.4
Sweden	2.6
United Kingdom	5.9

Within the context of the present study, overall CO2 emissions generated by the refining processes have been allocated to individual finished products. The allocation of emissions is particularly focused on the three transport fuels under consideration: petrol, diesel and kerosene. Table 5-9 displays the emission factors of petrol, diesel and kerosene derived from the allocation of GHG emissions according to the marginal emissions methodology as described in section 4.2.1. The marginal emissions contents of the products were directly obtained from the optimization results of the model. First, we present the marginal emission factors by transport fuel and country. Further in this section, we present how the marginal emissions are attributed according to the various MCON streams.

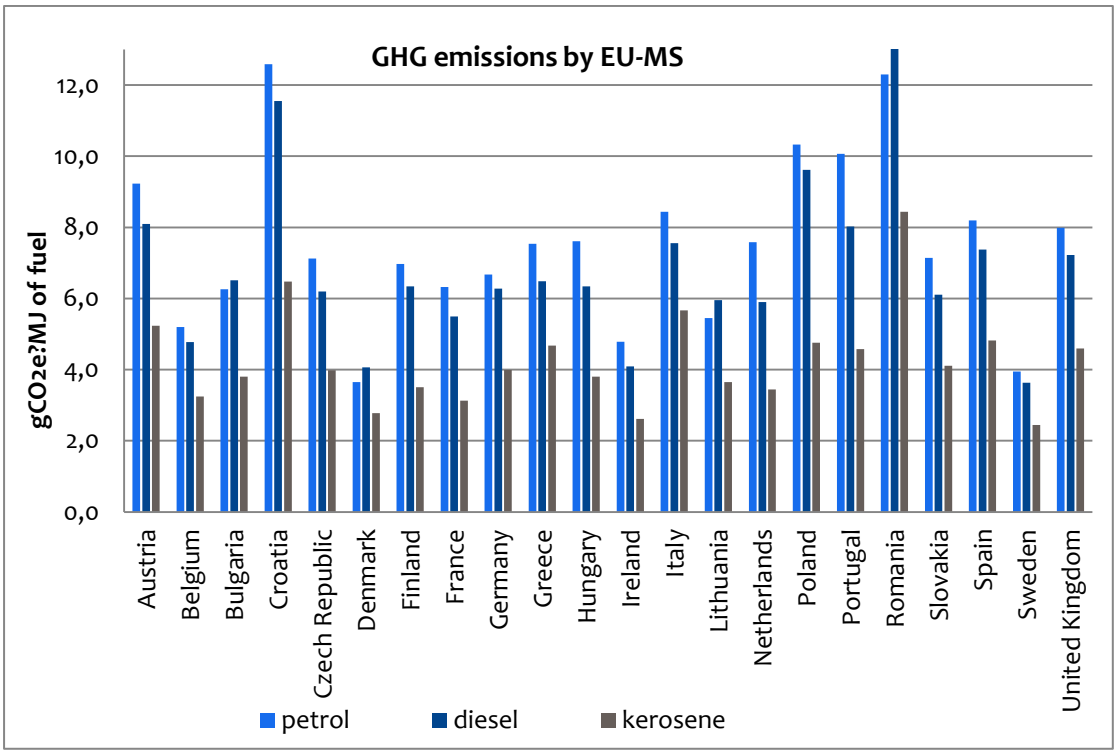
Table 5-9 Marginal emission factors for petrol, diesel and kerosene

$grCO_2eq/MJ$ product	Petrol	Diesel	Kerosene
Austria	9.23	8.09	5.23
Belgium	5.20	4.77	3.25
Bulgaria	6.26	6.51	3.80
Croatia	12.59	11.55	6.47
Czech Republic	7.13	6.20	3.98
Denmark	3.65	4.06	2.78
Finland	6.97	6.34	3.50
France	6.32	5.49	3.12
Germany	6.68	6.28	3.99
Greece	7.54	6.48	4.67
Hungary	7.61	6.34	3.80
Ireland	4.79	4.09	2.61
Italy	8.44	7.55	5.67
Lithuania	5.45	5.95	3.65
Netherlands	7.58	5.89	3.44
Poland	10.32	9.62	4.75
Portugal	10.06	8.02	4.57
Romania	12.30	14.25	8.44
Slovakia	7.14	6.11	4.11
Spain	8.20	7.38	4.82
Sweden	3.95	3.63	2.45
United Kingdom	7.98	7.22	4.59

The differences between GHG emissions of oil products vary widely by country and this diversity is indicative of the numerous parameters affecting the final carbon intensities of the refineries. The average EU CO2 coefficients for petrol, diesel and kerosene are **8.2, 7.6 and 4.7 $grCO_2eq/MJ$** of product respectively. It is deduced that petrol and diesel are the main contributors in refinery emissions.

A further analysis of the results shows that the emissions from petrol production are on average 9% higher than those from production of diesel while kerosene is characterized by significantly lower emissions. However, there are cases, such as Bulgaria, Denmark, Lithuania and Romania, where the emissions caused from diesel production exceed those from petrol production and in a number of countries these two products have slight differences in their GHG intensity. The emissions profiles per country are graphically presented in Figure 5-3.

Figure 5-5 GHG emissions for petrol, diesel and kerosene



In determining the GHG emissions, the total energy consumption in refinery sector of each country was modelled to reflect the energy requirements (fuels, electricity and steam) of the refining processes. The model calculations are based on an energy basis following the energy of the streams going through the different processes.

Although the emission profiles are not directly related to the refinery complexity, the difference between the allocated emissions can be interpreted to some extent by the variation in refinery configurations. Romania and Croatia are the countries with the highest emission factors per product while Sweden and Denmark are countries with the lowest emissions. For Romania and Croatia, the refinery complexity explain their high emissions and, more specifically, the high capacity of vacuum distillation (47%), catalytic cracking (~20%) and coking (~9%) contribute most to emissions in Romania. The relatively high capacity of catalytic cracking along with the presence of hydrocracking and coking units are responsible for the higher carbon intensities of fuels in Croatia. Similarly, the low emissions in Denmark are due to the very low vacuum distillation capacity and the absence of main emitting processes (catalytic cracking and coking).

However, it is admitted that the relation of the emissions to the refinery configuration cannot be generalized, as it is likely that small low-complexity refineries have high emissions due to the limited efficiency of processes.

Further examining the sources of emissions within the refinery operations, a considerable amount of GHG emissions arises from the coke burn-off in Fluid Catalytic Cracking unit. As

a consequence, this process is responsible for increasing the GHG emissions apart from the emissions directly linked to its operation.

Besides the energy requirements of the various operations, the hydrogen balance is also taken into consideration for the allocation of the refinery emissions to the petroleum products. GHG emissions during hydrotreating and hydrocracking are strongly related with the emissions derived from the production of hydrogen needed for these processes. A significant amount of hydrogen is produced by the reforming unit and the hydrogen production plant supplements the total hydrogen requirements. In this context, the catalytic reforming unit is not only associated with petrol production but with the production of hydrogen as well. The hydrogen consumption depends on the quality (i.e. sulphur and hydrogen content) of the streams (naphtha, middle distillates or heavier gas oil) going through the hydrotreaters and the relevant process unit yields.

Results disaggregated by stream

Further, additional model runs were necessary in order to provide consistent analysis regarding the GHG emissions by stream (i.e. MCONs). The resulting model runs ensure the comparability of the carbon intensities obtained on a country basis with the carbon intensities attributed by each MCON. The latter has been obtained by employing crudes with different characteristics (API and sulphur) as input in the operating system for a number of refineries of different complexity. As a result we approximated a relationship between the heaviness of crude and the associated GHG emissions. As expected, refinery CO2 emissions good correlation with the heaviness of the imported crude oil. The resulted 'linearity' between the values of emissions and the quality of crude was comparable to similar heuristic approaches from other studies (Jacobs, NETL).

Table 5-10 summarizes the GHG emissions of distillation per petroleum product assigned to various MCONS and their API as a result of the aggregation of emissions of all European countries. The average emission factors of petrol, diesel and kerosene with regard to MCONs are lower than those estimated per European country. This outcome results from the fact that countries with large refining capacity refine large shares of light crudes.

Given the variation of the results, an overall trend that is observed in Table 5-10 is that petroleum fuels produced from heavier crude oils (with lower API) have higher carbon intensities than those produced from light crudes.

Table 5-10 GHG emissions for petroleum products during refining sorted by MCON

$grCO_2eq/MJ$ product	API	Petrol	Diesel	Kerosene
Boscan	11	9.42	8.48	5.54
Captain	20	8.74	7.39	4.50
Dalia	22	10.03	8.59	5.34
Maya	22	9.46	8.51	5.55

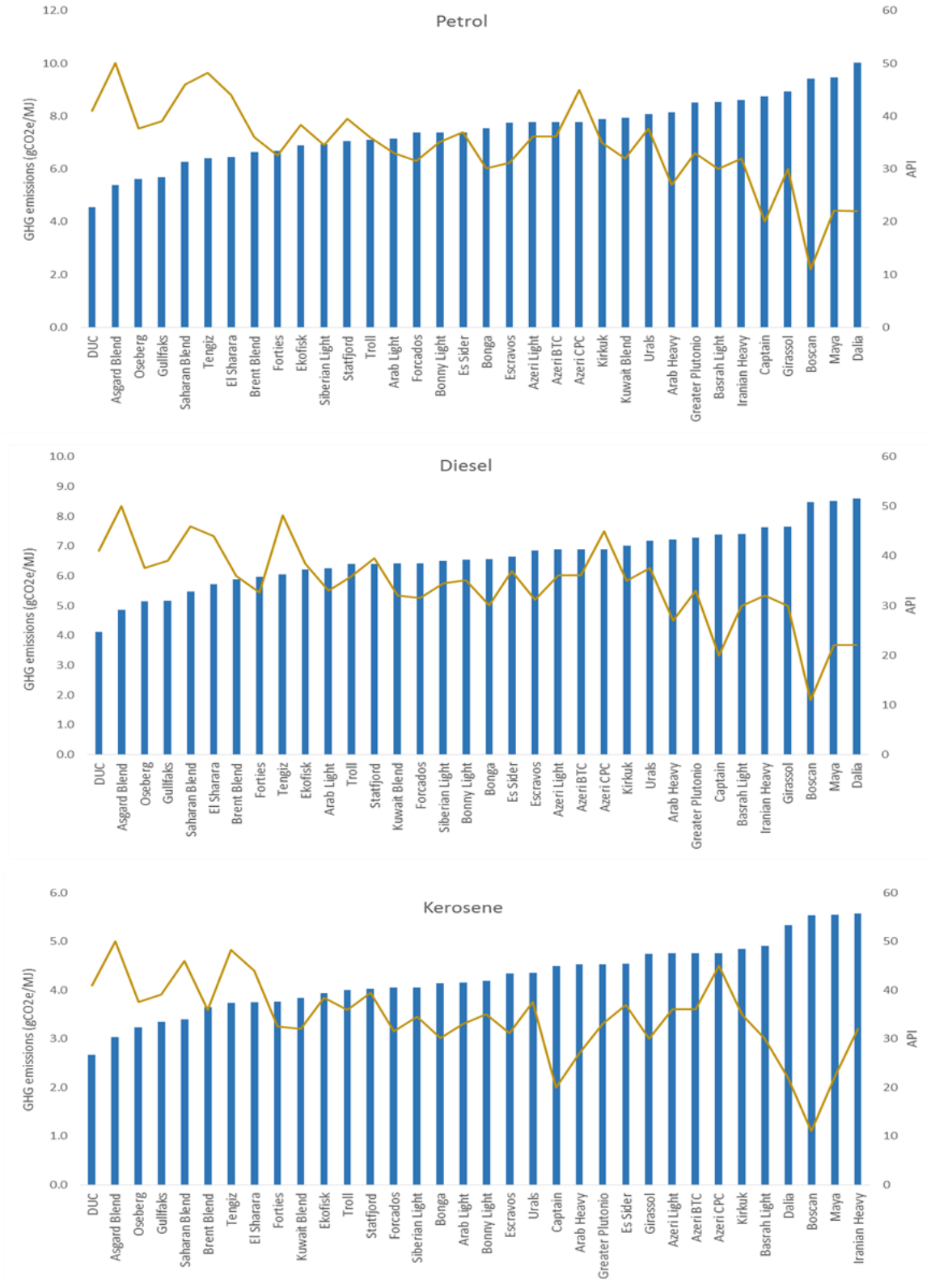
grCO$_2$eq/MJ product	API	Petrol	Diesel	Kerosene
Arab Heavy	27	8.15	7.21	4.52
Basrah Light	30	8.54	7.42	4.91
Girassol	30	8.93	7.65	4.75
Bonga	30	7.55	6.57	4.15
Escravos	31	7.76	6.86	4.34
Forcados	32	7.38	6.42	4.05
Iranian Heavy	32	8.62	7.64	5.57
Kuwait Blend	32	7.94	6.41	3.84
Forties	33	6.68	5.96	3.77
Arab Light	33	7.15	6.25	4.16
Greater Plutonio	33	8.52	7.29	4.53
Siberian Light	35	6.94	6.50	4.05
Kirkuk	35	7.90	7.01	4.84
Bonny Light	35	7.38	6.54	4.19
Troll	36	7.11	6.39	4.00
Brent Blend	36	6.63	5.88	3.65
Azeri Light	36	7.77	6.90	4.75
Azeri BTC	36	7.77	6.90	4.75
Es Sider	37	7.38	6.65	4.55
Urals	38	8.07	7.17	4.36
Oseberg	38	5.62	5.14	3.23
Ekofisk	38	6.89	6.21	3.94
Gullfaks	39	5.69	5.17	3.35
Statfjord	40	7.07	6.39	4.03
DUC	41	4.56	4.12	2.68
El Sharara	44	6.47	5.72	3.75
Azeri CPC	45	7.77	6.90	4.75
Saharan Blend	46	6.26	5.48	3.40
Tengiz	48	6.41	6.05	3.74
Asgard Blend	50	5.39	4.85	3.04

In addition to the results above, a graphical presentation of the variation of GHG emissions by MCON and their API is given in Figure 5-6, where the carbon intensities of each fuel are sorted from smallest to largest values and correlated with the API of the corresponding MCON.

Carbon intensities of petrol range from 4.6 grCO$_2$eq/MJ of product for "DUC" to 10 grCO$_2$eq/MJ of product for "Dalia" MCON. Diesel carbon intensities vary from 4.1 grCO$_2$eq/MJ of product for "DUC" to 8.6 grCO$_2$eq/MJ of product for "Dalia". CO2

emissions of kerosene are between 2.7 $grCO_2eq/MJ$ of product and 5.6 $grCO_2eq/MJ$ of product for "DUC" and "Iranian Heavy" respectively.

Figure 5-6 Estimated GHG emissions for petrol, diesel and kerosene per MCON in EU refineries.



5.1.6 Estimates on high and low GHG emissions by stream

The approach of minimum and maximum emission factors by MCON is based on the distribution of MCONs in European refineries and the relevant GHG emissions as they were presented earlier.

A more detailed presentation of CO2 emissions per MCON in terms of min/max values is given in Table 5-11 where the obtained values are associated with the variation in carbon intensities per MCON and country depending on the crude mixture and the refinery configuration. Minimum or maximum values of each MCON are associated with the European countries that treat this MCON and have low or high levels of GHG emissions.

5.1.7 Comparison with other studies in literature

The scope of the current section is to explore the GHG emissions of the basic transport fuels (diesel, petrol and kerosene) resulted from the refinery sector in Europe. Arbitrariness and expert subjectivity are inevitable in defining the system boundary of a refinery and the choice of methodology to reflect the interaction effects in it. Different allocation methods rely on various assumptions and it is likely to lead to controversial results. Given the lack of official publicly accessible data, we quote the results from similar studies (all contained in GHG literature database) in order to have a more complete picture. Table 5-12 summarizes the findings in relevant reports regarding the GHG emissions of the three fuels under consideration.

Undoubtedly the choice of the refinery configuration is of great importance for the allocation of GHG emissions of refinery products. European refineries structures cannot be covered by a single representative scheme and modelling methods have to face aggregation issues and rely on a number of assumptions to optimize the results.

Reviewing the existing literature, there is no agreement on which petroleum product (between petrol and diesel) causes more GHG emissions during its production. In general, petrol is considered more energy intensive and consequently more CO2 intensive, but such estimates may be reversed when applying a different allocation approach and different modelling inputs. Regarding kerosene, despite the limited available data, it is generally postulated that its contribution to the total emissions is low.

Table 5-11 Minimum and maximum values of GHG emissions per fuel and MCON

$grCO_2eq/MJ$	Petrol		Diesel		Kerosene	
	min	max	min	max	min	max
Boscan	5.32	12.18	4.89	11.01	3.29	7.01
Captain	5.67	12.05	5.21	10.57	3.51	7.28
Dalia	4.62	12.34	4.25	9.83	2.86	7.07
Maya	5.99	9.53	5.49	8.58	3.73	5.60
Arab Heavy	5.59	10.97	5.13	9.62	3.49	6.56
Basrah Light	4.13	12.42	3.80	11.57	2.56	6.25
Girassol	4.13	11.04	3.80	8.79	2.56	6.25
Bonga	4.13	11.04	3.80	9.21	2.56	5.96
Escravos	4.07	10.88	3.74	9.08	2.52	6.15
Forcados	4.04	10.79	3.72	9.01	2.50	5.82
Iranian Heavy	5.20	11.97	4.77	10.50	3.24	6.79
Kuwait Blend	7.20	10.20	6.06	8.94	3.54	5.78
Forties	3.98	7.72	3.65	6.71	2.46	4.26
Arab Light	5.12	10.55	4.42	9.39	2.58	5.95
Greater Plutonio	3.95	10.55	3.63	8.41	2.45	5.95
Siberian Light	3.83	14.29	3.52	16.56	2.37	9.81
Kirkuk	6.51	14.29	5.66	16.56	3.22	9.81
Bonny Light	3.82	10.21	3.51	8.52	2.37	5.73
Troll	3.77	9.61	3.46	8.95	2.33	5.64
Brent Blend	3.77	7.27	3.46	6.32	2.33	4.02
Azeri Light	6.41	10.06	5.57	8.40	3.17	5.64
Azeri BTC	6.41	10.06	5.57	8.40	3.17	5.64
Es Sider	4.71	9.90	4.03	8.27	2.57	5.54
Urals	4.13	15.56	3.80	18.04	2.56	10.68
Oseberg	3.67	9.36	3.37	8.72	2.27	4.65
Ekofisk	3.62	8.03	3.33	7.20	2.24	5.39
Gullfaks	3.59	7.94	3.30	7.12	2.22	5.33
Statfjord	3.53	8.99	3.24	8.37	2.18	4.44
DUC	3.46	7.57	3.18	6.85	2.14	4.36
El Sharara	4.25	8.76	3.84	7.32	2.45	4.82
Azeri CPC	5.45	8.55	4.70	7.14	2.69	4.69
Saharan Blend	3.53	8.44	3.78	7.05	2.42	4.62
Tengiz	3.94	10.98	3.61	12.73	2.46	7.54
Asgard Blend	2.92	7.44	2.68	6.93	1.81	4.21

Table 5-12 Literature data on Carbon intensities for petrol, diesel and kerosene in the refining stage

Unit ($grCO_2eq/MJ$)	Petrol	Diesel	Kerosene	Region
JACOBS (2012)	~9	~7.5		EU
JEC (2011)	7.0	8.6		EU
NETL (2009)	9.3	9.1	5.7	US
IEA (2005)	9.4 *	3.9		EU
IFP/ Babusiaux, Pierru (2007)	2.3-2.7	0.8- 1.1		case study (contribution to total emissions)
IFP/ Tehrani, Saint-Antonin (2007)	4.7	7.4	3.5	case study for France
*incl. naphtha				
Results of present study	**8.2**	**7.6**	**4.7**	

Hydrogen balance is one of the issues that differentiate the estimated values of GHG emissions allocated to the oil products. The consumption of hydrogen as processing stream and the difference between the hydrogen content of crude oil and refined products are critical factors in the allocation of total energy and emissions. Taking or not the hydrogen requirements into account for the allocation of the emissions influences significantly the results.

Another issue to be examined particularly refers to whether the emission factors for the electricity provided from the grid were considered as a single value or individual values per EU country. This consideration affects the evaluation of the total refinery emissions and subsequently their allocation to the products.

5.1.8 Increasing the robustness of the analysis using the PRELIM model

In our analysis, we also employ the use of the PRELIM model, in addition to the PRIMES-Refinery model, to increase the robustness of our findings regarding the quantification of the GHG emissions during refining.

The Petroleum Refinery Lifecycle Inventory Model (PRELIM) was built using Microsoft Excel by the Lifecycle Analysis of Oil Sands Technologies research group (University of Calgary) and constitutes a mass and energy based process unit-level tool for the estimation of energy use and greenhouse gas (GHG) emissions associated with processing a variety of crude oils within a range of configurations in a refinery. Combining a lifecycle approach with linear programming modelling methods, allows the user to select from a predetermined list of crude assays and define the level of processing in two main types of refineries: a hydrocracking and a coking refinery configuration.

We used PRELIM model to obtain the evaluation of GHG emissions for a number of crudes from its inventory and compare them to our results. The crude oils selected are similar to some representative of the present study or they fall in the categories we described in this section earlier. In addition to conventional crude oils, we deliberately quote two types of unconventional types of crude in order to have a view of the difference in emissions owing to the different sources.

The results in Table 5-13 are derived from calculations for the hydrocracking refinery in the mode of medium conversion, apart from the results taken for unconventional crudes where deep conversion was applied. Prior to comparing the results of emissions, the refinery production and the different yields of final products should be noticed. Contrary to our data, where diesel production accounts for the largest share of final production, PRELIM model is petrol-oriented and the production of middle distillates gives a high share of kerosene in light and medium crudes while diesel increases by the use of the heavier crude 'Angola Kuito'. The GHG emissions of petrol and diesel vary by the different types of crude but, in general, petrol appears more CO_2 intensive than diesel.

Table 5-13 Crude specific GHG emissions estimated by the PRELIM model

Crudes examined	API	S (%wt)	petrol	diesel (ULSD)	kerosene (Jet-A/ AVTUR)	
Conventional crude oils						
Tengiz	46.4	0.7	9.3	5.6	2.4	GHG emissions ($grCO_2eq/MJ$ product)
			48.8	15.9	31.6	Product slate (%)
Azeri Light (Statoil)	34.8	0.15	11.8	9.4	2.7	GHG emissions ($grCO_2eq/MJ$ product)
			46.2	20.4	28.3	Product slate (%)
Russia Sokol	36.4	0.37	10.0	7.0	2.5	GHG emissions ($grCO_2eq/MJ$ product)
			49.1	18.7	29.1	Product slate (%)
Angola Kuito	22.1	0.87	11.3	10.2	2.4	GHG emissions ($grCO_2eq/MJ$ product)
			42.6	35.5	18.5	Product slate (%)
Unconventional crudes						
Suncor Synthetic A_Crude Monitor	33.1	0.16	12.6	8.2	2.8	GHG emissions ($grCO_2eq/MJ$ product)
			36.9	36.3	24.2	Product slate (%)
Canada Cold Lake diluted bitumen	20.7	3.89	16.6	17.7	7.0	GHG emissions ($grCO_2eq/MJ$ product)
			43.2	35.8	10.7	Product slate (%)

Regarding the resulting emissions from unconventional crudes, there are two examples of unconventional crudes in Table 5-13, one with low API and high sulphur content (Canada diluted bitumen) and one lighter and sweeter crude (Suncor synthetic). In the case of refining the heavy unconventional crude, the estimated emissions were remarkably increased for the three fuels and diesel was more energy –intensive than petrol. The emissions corresponding to the lighter unconventional crude were comparable to those resulted from conventional crudes with similar characteristics.

In addition to the abovementioned unconventional crudes, we cite the assessment of GHG intensity for oil sands bitumen with API 8.4° and sulphur 4.8%wt as reported in the Jacobs study 'LCA Comparison of North American and imported crudes' (2009). The GHG emissions for petrol and ULSD were estimated 17.2 and 14.8 gCO2e/MJ of fuel.

5.1.9 GHG emissions from imported petroleum products

The main exporters of petroleum products to Europe are Russia and US. The imported fuels (mainly diesel) are associated with GHG emissions occurring during their production. The estimation of GHG emissions of the imported refinery products is linked to their origin, the refineries infrastructure and the crude oil intakes in the region.

Russia

The change in legislation on petroleum products duties has affected the Russian refining industry and led to an increase in investment in upgrading units. This general shift of Russian hydroskimming refinery configurations towards more complex schemes producing larger amounts of light products is enhanced by the constantly increasing demand for transport fuels and particularly ultra-low sulphur diesel (ULSD) in Europe.

Table 5-14 summarizes the most significant Russian suppliers of refined products to Europe. Modelling of the key characteristics of these refineries as provided by Oil and Gas journal leads to a stylized Russian refinery with considerable conversion units comparable to European ones. The assessment of the emission factors of petrol, diesel and kerosene refined in Russia draws substantially from the calculated emission factors resulted from similar refinery configurations in Europe (Urals taken for granted as exclusive crude feed and similar processing capacities and products output with those of the European refineries considered).

USA

A general overview of different LCA studies covering the United States refining industry shows that GHG emissions from petroleum fuels produced in US refineries are higher than those produced in European ones. The differences are possibly attributed to the different crude oil supply (including a remarkable portion of unconventional crude), refinery configurations (characterized by deeper conversion processes) and the purchased energy required for the refinery needs. Our estimates on the GHG emissions for the petroleum products imported from US are based on the assumption that US

average crude oil quality has API 30 and 1.4%wt sulphur (values obtained from US Energy Information Administration).

The National Energy Technology Laboratory (NETL) has analysed the full lifecycle GHG emissions of transportation fuels derived from US crude oil and crude oil imported to the US. Within the different stages of the analysis, the study determined the GHG emissions of petrol, diesel and kerosene during refining. The estimated emission factors were 9.3 gCO2e/MJ for petrol, 9.1 $grCO_2e$/MJ for diesel and 5.7 $grCO_2e$/MJ for kerosene.

Jacobs Consultancy has included in the report 'EU Pathway Study: Lifecycle Assessment of Crude Oils in a European Context' the emissions derived from imported refined products from Russia and US. Regarding the US refinery configuration, they considered a US representative refinery of high conversion, which was modelled to treat a number of crude oils of different quality. Average emissions of petrol and diesel production were approximately 13 $grCO_2e$/MJ and 12 $grCO_2e$/MJ of fuel respectively.

Table 5-14 Literature data on GHG emissions for petrol, diesel and kerosene during the refining stage (grCO2e/MJ)

	petrol	diesel	kerosene	Remarks
Russia	6.9	6.2	4.0	assessment based on PRIMES-Refinery calculations for similar European refineries (of low or medium conversion)
USA	10.1	8.9	5.6	assessment based on PRIMES-Refinery calculations for similar (high conversion) European refineries
Other assessments for USA	9.3	9.1	5.7	literature (NETL, JACOBS)
	13.2	12.2		

5.1.10 WTT GHG emissions for petrol, diesel and kerosene by stream

The average Well-To-Tank carbon intensities for petrol, diesel and kerosene including the upstream, midstream and downstream stages were estimated to **18.2, 17.4 and 15.0 gCO2e/MJ**, respectively. The estimated WTT GHG emissions for petrol, diesel and kerosene for all MCONs are presented in the Table 5-15 and graphically shown in Figure 5-10.

Table 5-15 Well-To-Tank GHG emissions for petrol, diesel and kerosene

Representative MCON ($grCO_2eq/MJ$ product)	API	Petrol	Diesel	Kerosene
Boscan	11	18.7	17.8	14.8
Captain	20	28.9	27.6	24.7
Dalia	22	18.8	17.4	14.1
Maya	22	17.0	16.0	13.1
Arab Heavy	27	33.1	32.1	29.5
Basrah Light	30	22.9	21.8	19.3
Girassol	30	17.5	16.2	13.4
Bonga	30	15.0	14.0	11.6
Escravos	31	34.3	33.4	30.9
Forcados	32	17.3	16.3	14.0
Iranian Heavy	32	29.7	28.7	26.7
Kuwait Blend	32	14.6	13.1	10.5
Forties	33	13.2	12.5	10.3
Arab Light	33	14.9	14.0	11.9
Greater Plutonio	33	17.2	16.0	13.2
Siberian Light	35	16.8	16.3	13.9
Kirkuk	35	22.9	22.0	19.9
Bonny Light	35	22.4	21.6	19.3
Troll	36	13.1	12.4	10.0
Brent Blend	36	17.6	16.9	14.6
Azeri Light	36	15.1	14.3	12.1
Azeri BTC	36	15.4	14.5	12.4
Es Sider	37	20.2	19.5	17.4
Urals	38	19.0	18.1	15.3
Oseberg	38	11.7	11.2	9.3
Ekofisk	38	12.3	11.7	9.4
Gullfaks	39	10.8	10.3	8.5
Statfjord	40	12.7	12.0	9.7
DUC	41	10.3	9.8	8.4
El Sharara	44	18.8	18.0	16.1
Azeri CPC	45	15.5	14.7	12.5
Saharan Blend	46	18.5	17.7	15.6
Tengiz	48	18.4	18.0	15.7
Asgard Blend	50	11.2	10.7	8.9
EU average		18.2	17.4	15.0

The upstream and midstream GHG emissions range from 5 grCO2eq/MJ to 26 grCO2eq/MJ of crude while the downstream GHG emissions range from 2 grCO2eq/MJ to 18 grCO2eq/MJ of product (product-specific values). The minimum and maximum values of

WTT GHG emissions are given in the Table 5-16, while Figures 5-7, 5-8 and 5-9 present GHG emissions for petrol, diesel and kerosene respectively per MCON and per process of the oil supply chain.

Table 5-16 Minimum and maximum values for Well-To-Tank GHG emissions (upstream, midstream and downstream) for petrol, diesel and kerosene

	Petrol		Diesel		Kerosene	
$grCO_2eq/MJ$	min	max	min	max	min	max
Boscan	14.1	22.0	13.7	20.8	12.1	16.8
Captain	11.4	17.8	10.9	16.3	9.2	13.0
Dalia	23.2	34.2	22.8	31.7	21.4	28.9
Maya	14.6	18.4	14.1	17.5	12.4	14.5
Arab Heavy	13.1	18.5	12.7	17.2	11.0	14.1
Basrah Light	28.8	37.6	28.5	36.8	27.2	31.4
Girassol	17.0	26.7	16.6	24.5	15.4	21.9
Bonga	12.6	19.7	12.3	17.9	11.1	14.6
Escravos	11.4	18.4	11.1	16.6	9.9	13.6
Forcados	30.5	37.5	30.2	35.7	29.0	32.5
Iranian Heavy	15.1	22.0	14.6	20.5	13.1	16.8
Kuwait Blend	28.0	31.7	26.9	30.4	24.4	27.2
Forties	10.4	14.6	10.0	13.5	8.8	11.1
Arab Light	11.5	17.3	10.8	16.1	9.0	12.7
Greater Plutonio	11.4	18.4	11.1	16.2	9.9	13.8
Siberian Light	12.4	23.0	12.1	25.3	10.9	18.6
Kirkuk	12.2	26.9	11.4	29.1	8.9	22.4
Bonny Light	18.6	25.5	18.3	23.8	17.2	21.0
Troll	14.6	28.8	14.3	28.2	13.2	24.8
Brent Blend	9.6	13.7	9.3	12.7	8.1	10.4
Azeri Light	17.4	21.1	16.6	19.4	14.2	16.6
Azeri BTC	13.6	17.5	12.8	15.9	10.4	13.1
Es Sider	12.2	17.8	11.5	16.1	10.1	13.4
Urals	16.8	28.6	16.5	31.1	15.2	23.7
Oseberg	13.2	21.9	12.9	21.2	11.8	17.1
Ekofisk	8.7	13.8	8.4	13.0	7.3	11.2
Gullfaks	8.6	13.2	8.3	12.4	7.2	10.6
Statfjord	9.1	14.7	8.8	14.1	7.7	10.2
DUC	9.1	13.3	8.8	12.6	7.8	10.1
El Sharara	16.5	21.2	16.1	19.7	14.7	17.2
Azeri CPC	12.9	16.6	12.2	15.2	10.2	12.7
Saharan Blend	15.6	20.8	15.9	19.4	14.5	16.9
Tengiz	15.8	23.1	15.5	24.8	14.3	19.6
Asgard Blend	8.7	13.3	8.5	12.8	7.6	10.1

Figure 5-7 Total GHG emissions for the MCONs examined per process of the supply chain for petrol (in grCO2eq/MJ)

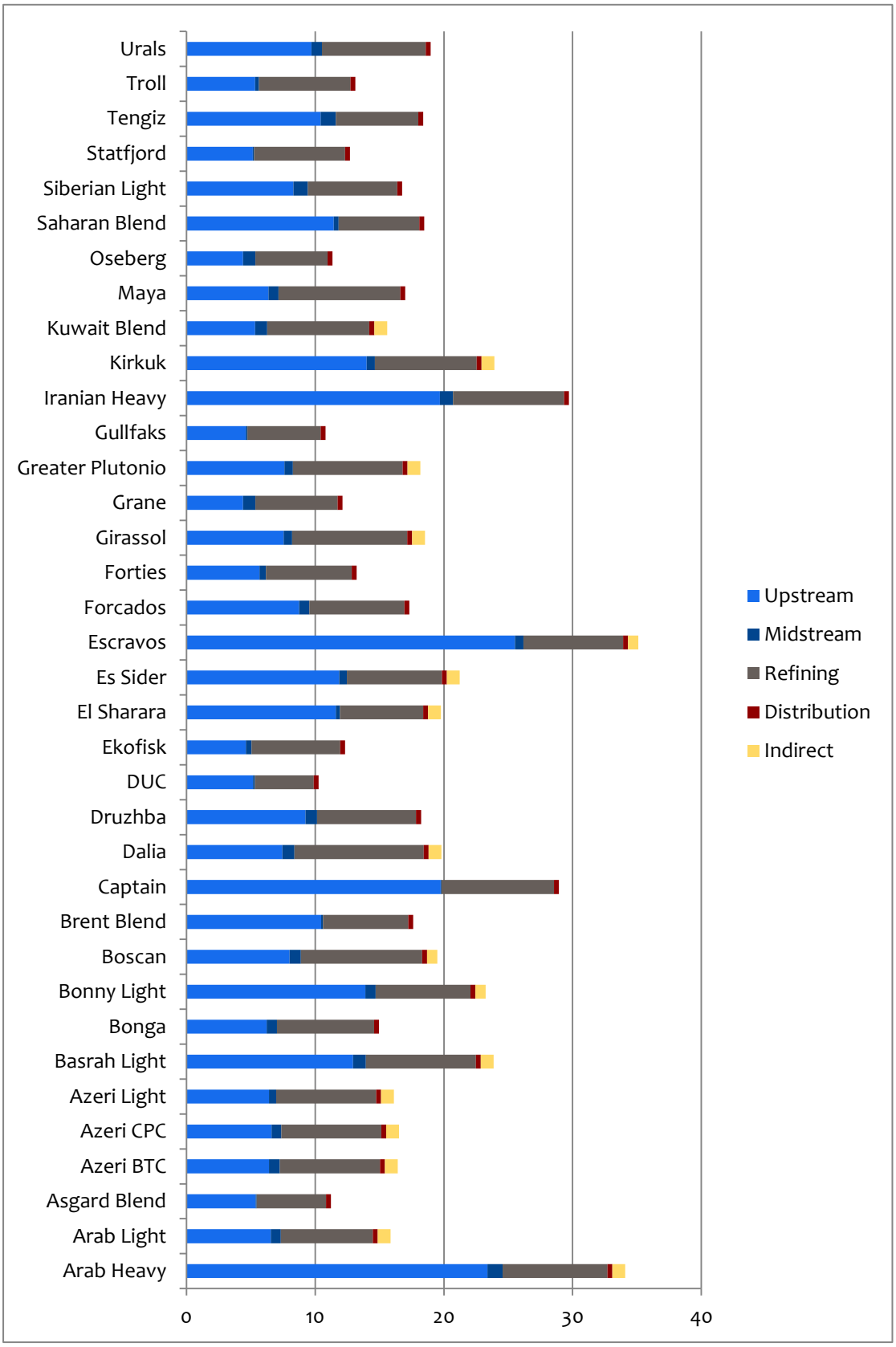


Figure 5-8 Total GHG emissions for the MCONs examined per process of the supply chain for diesel (in grCO2eq/MJ)

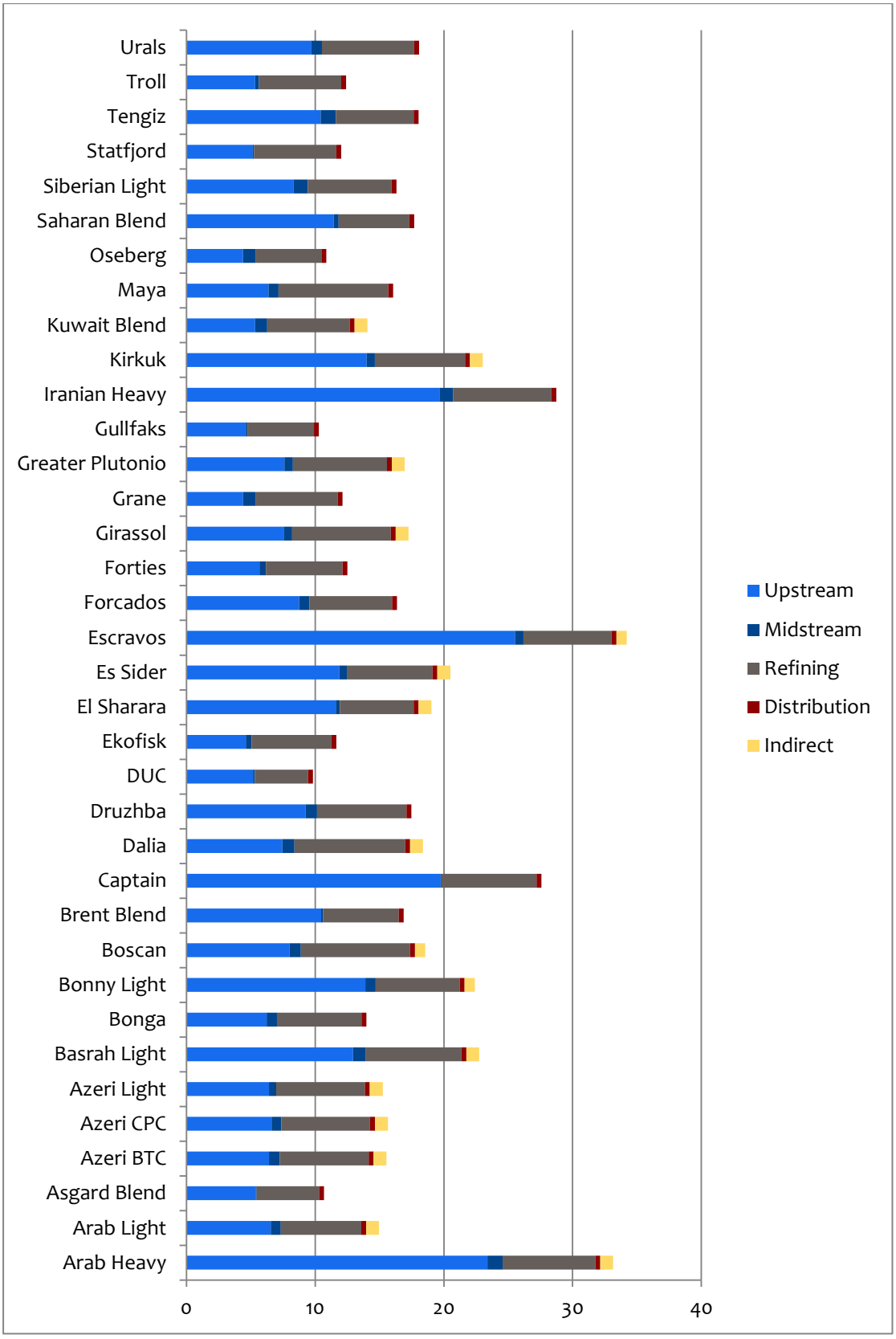


Figure 5-9 Total GHG emissions for the MCONs examined per process of the supply chain for kerosene (in grCO2eq/MJ)

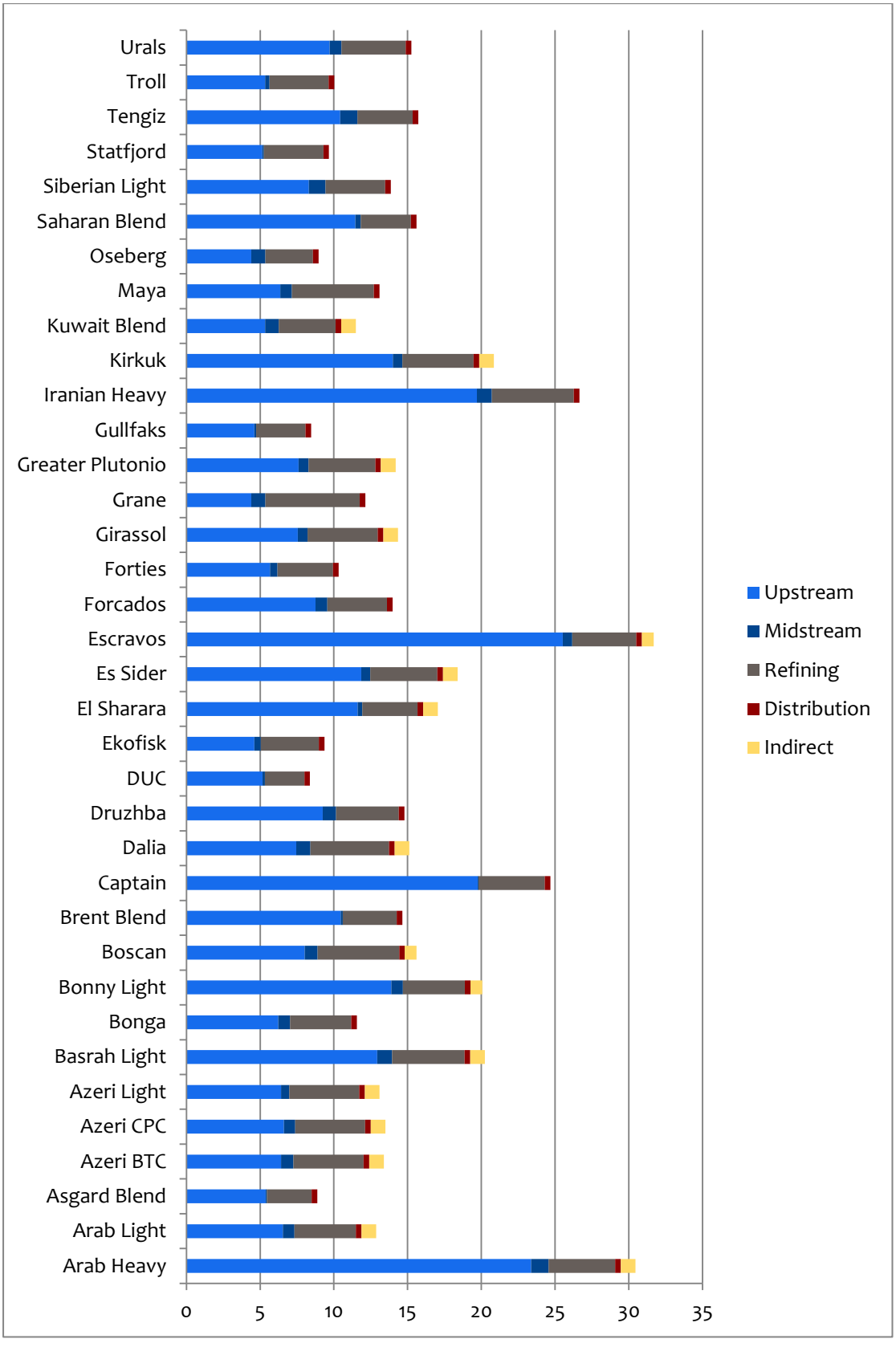
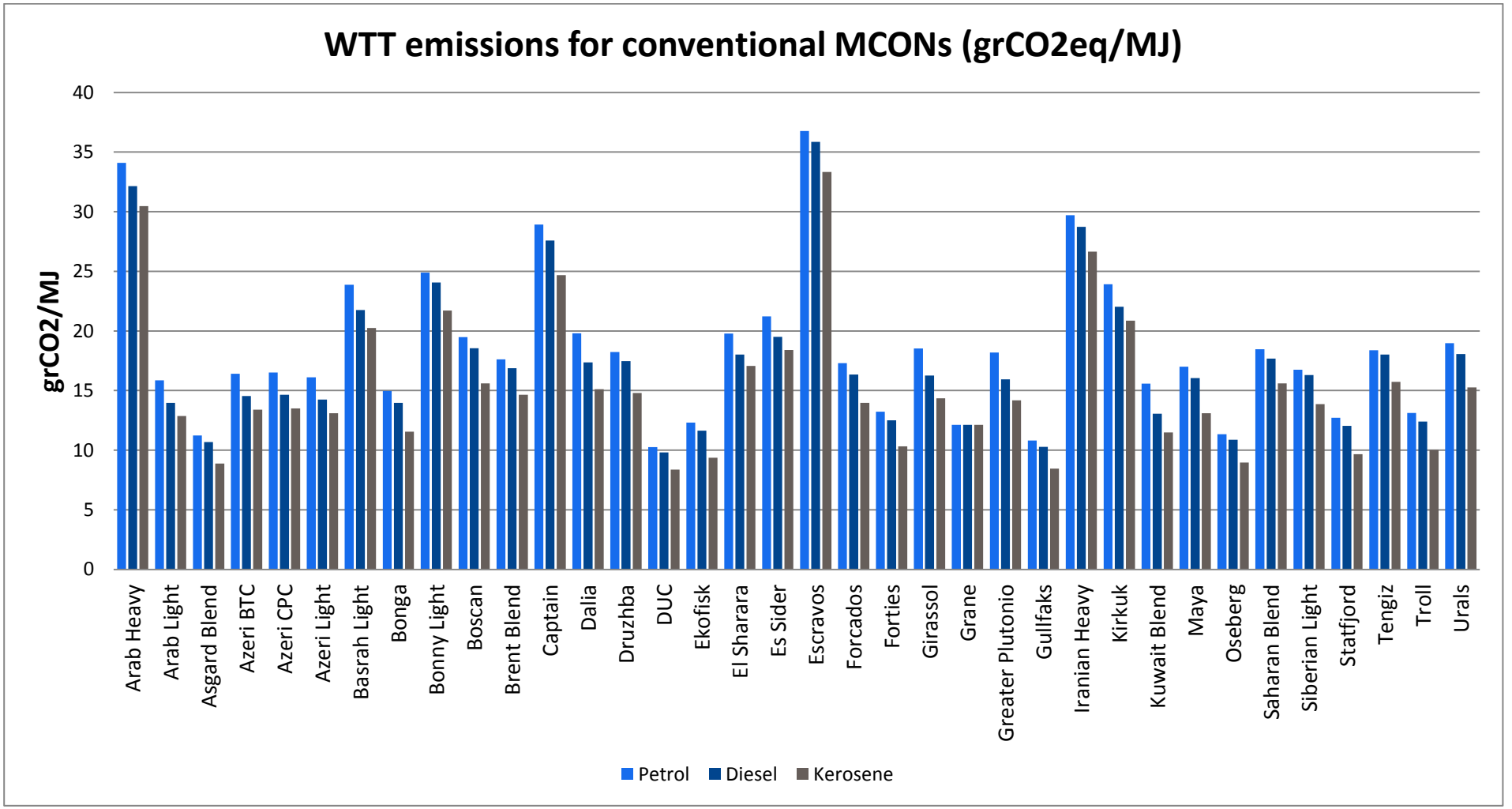


Figure 5-10 Well-To-Tank estimated GHG emissions for petrol, diesel and kerosene by MCON



5.2 Carbon Intensity of Natural Gas

All Natural Gas streams presented in Section 3.4.3 are modelled, considering that the gas arriving to each region is fed into the transport sector either in the form of CNG, or in the form of micro-scale LNG.

In the following paragraphs the results of the GHGenius model regarding Carbon Intensities of natural gas are presented. The analysis starts with the values of CI on a country level for each individual EU gas consuming country. For reasons of computational economy and effectiveness of results presentation, the 26 EU countries (28 countries from which Cyprus and Malta are exempted as they do not consume natural gas) have been divided into four regions: South-East, North, South-West and Central. Following this analysis, the various gas flows have been synthesized into a selection of gas streams, each one originating from a supplying country and consumed within an EU region. This approach is described in Section 3.4 .

The GHG emissions attributed to each lifecycle stage are presented in detail. More specifically, the stages presented in the following tables include:

- Upstream:
  - Fuel production and recovery
  - Natural Gas processing
- Midstream:
  - Feedstock transportation
- Downstream:
  - Gas distribution, transmission and storage
  - Fuel dispensing

5.2.1 Country–by–country results

All calculations of Carbon Intensities for natural gas streams, presented in the following sections on a regional level, have been elaborated by analyzing all data on a country-by-country basis, as shown in the data collection strategy (Task B). The synthesis of Carbon Intensities corresponding to the natural gas mix consumed in the form of CNG by each EU country is presented in Table 5-17 to Table 5-20.

The GHG emissions related to the lifecycle of the natural gas mix consumed by each individual country range from 7.229 grCO_2eq/MJ (Denmark) up to 42.599 grCO_2eq/MJ (Bulgaria), as is shown in the following Tables. This wide range of Carbon Intensities is explained by the variation of amounts of emissions corresponding to the different suppliers (upstream), as well as the different distances and transporting methods between the supplying and the consuming countries. Downstream GHG emissions of natural gas represent only a minor fraction of the CI; therefore they do not influence significantly the total lifecycle emissions.

Table 5-17 South-East EU natural gas GHG emissions by country

Lifecycle Stage	EU South-East (grCO2eq/GJ)						
	Country Results	Bulgaria	Greece	Croatia	Italy	Romania	Slovenia
Downstream	Fuel dispensing	4,762	6,210	3,442	3,972	4,190	3,471
	Gas distribution, transmission and storage	8,572	1,160	12,872	6,527	2,403	913
Midstream	Feedstock transportation (pipeline, LNG)	25,443	21,212	178	8,821	6,391	15,024
Upstream	Fuel production and recovery	3,819	10,038	6,252	8,220	6,162	10,963
	CO2, H2S removed from NG (gas processing)	3	229	218	963	41	294
	Total CNG	**42,599**	**38,849**	**22,962**	**28,503**	**19,187**	**30,665**

Table 5-18 North EU natural gas GHG emissions by country

Lifecycle Stage	EU North (grCO2eq/GJ)					
	Country Results	Denmark	Ireland	Finland	Sweden	United Kingdom
Downstream	Fuel dispensing	2,992	4,838	2,669	1,903	4,535
	Gas distribution, transmission and storage	212	715	2,989	1,135	1,256
Midstream	Feedstock transportation (pipeline, LNG)	912	782	19,660	458	1,946
Upstream	Fuel production and recovery	2,875	5,969	3,808	2,974	4,945
	CO2, H2S removed from NG (gas processing)	238	26	113	1,380	1
	Total CNG	**7,229**	**12,330**	**29,239**	**7,850**	**12,683**

Table 5-19 South-West EU natural gas GHG emissions by country

Lifecycle Stage	EU South-West (grCO2eq/GJ)			
	Country Results	Spain	France	Portugal
Downstream	Fuel dispensing	3,648	2,185	3,895
	Gas distribution, transmission and storage	739	873	7,037
Midstream	Feedstock transportation (pipeline, LNG)	3,108	6,428	3,289
Upstream	Fuel production and recovery	14,552	6,282	13,698
	CO2, H2S removed from NG (gas processing)	714	379	695
	Total CNG	**22,761**	**16,147**	**28,614**

Table 5-20 Central EU natural gas GHG emissions by country

Lifecycle Stage	EU Central (grCO2eq/GJ)											
	Country Results	Belgium	Czech Republic	Germany	Estonia	Latvia	Lithuania	Luxembourg	Hungary	Netherlands	Austria	Poland	Slovakia
Downstream	Fuel dispensing	2,622	4,401	4,204	2,321	2,358	2,990	2,934	3,445	3,777	2,478	5,737	2,718
	Gas distribution, transmission and storage	1,098	2,098	2,162	3,593	2,225	2,774	967	3,986	2,324	2,484	8,786	3,102
Midstream	Feedstock transportation (pipeline, LNG)	2,013	24,652	8,597	24,486	24,257	24,400	8,289	10,022	2,274	15,563	12,337	24,438
Upstream	Fuel production and recovery	3,794	3,843	3,072	3,867	3,808	3,816	3,492	6,323	2,230	4,610	4,670	3,818
	CO2, H2S removed from NG (gas processing)	301	3	233	3	3	3	188	645	63	243	278	3
	Total CNG	**9,828**	**34,997**	**18,268**	**34,270**	**32,651**	**33,983**	**15,870**	**24,421**	**10,668**	**25,378**	**31,808**	**34,079**

5.2.2 CNG streams

This section presents the Carbon Intensities of the considered natural gas streams per EU region, as calculated by the GHGenius model. These results are shown in the following tables (Table 5-22 to Table 5-19). The average carbon intensity by consuming region has been estimated as follows:

- South-East EU: **28.852 $grCO_2eq/MJ$**
- North EU: **12.262 $grCO_2eq/MJ$**
- South-West EU: **19.166 $grCO_2eq/MJ$**
- Central EU: **18.756 $grCO_2eq/MJ$**

These results are shown in Table 5-21.

As can be observed in the above tables, the values of Carbon Intensities in the different regions vary widely, ranging from 6.576 $grCO_2eq/MJ$ up to 53.577 $grCO_2eq/MJ$. The most important GHG emissions appear in the South-East EU region, with an average CI of 28.582 $grCO_2eq/MJ$. This is mainly due to the fact that this region receives significant quantities of Natural Gas from countries with a big amount of upstream emissions, namely Algeria and Libya. In addition, the streams originating from Russia, which is an important supplier of the South-East region, have important midstream emissions, due to the length of the transport pipelines bringing gas to the consumers.

The lowest values of upstream emissions are observed in European supplying countries, such as Norway, Denmark and the Netherlands. However, Norwegian emissions are significantly higher when it comes to LNG production. In general, LNG streams have higher Carbon Intensities than pipeline streams, notably in the upstream stage, due to the fact that the liquefaction process is considered as part of this stage.

Table 5-21 Average Carbon Intensities of Natural Gas for the considered EU Regions

Reference scenario	EU average	EU North	EU Central	South East EU	South West EU
CNG	**grCO2eq/GJ**				
Fuel dispensing	**3,819**	3,519	4,112	4,221	2,790
Gas distribution, transmission and storage	**2,964**	1,249	2,804	6,616	1,158
Feedstock transportation (pipeline, LNG)	**6,633**	2,436	8,287	9,119	5,142
Fuel production and recovery	**5,395**	4,820	3,352	7,858	9,559
CO_2, H_2S removed from NG (gas processing)	**366**	238	201	768	517
Total	**19,177**	**12,262**	**18,756**	**28,582**	**19,166**
Methane Loss	**%**				
Dispensing station	**0.340%**	0.340%	0.340%	0.340%	0.340%
Distribution Loss	**0.000%**	0.197%	0.472%	0.610%	0.171%
Transmission Loss	**0.000%**	0.018%	0.062%	0.096%	0.039%
Transport Loss	**0.313%**	0.126%	0.392%	0.392%	0.195%
Processing	**0.047%**	0.013%	0.023%	0.104%	0.088%
Recovery	**0.403%**	0.248%	0.258%	0.720%	0.629%
Total	**1.103%**	**0.941%**	**1.547%**	**2.262%**	**1.462%**
Production Energy	**GJ/tn**				
Recovery energy	**1.219**	1.306	1.135	1.455	1.086
Processing energy	**1.154**	1.347	0.269	1.328	3.329
Regasification energy	**0.036**	0.115	0.011	0.025	0.033
Total	**2.409**	**2.768**	**1.415**	**2.8083**	**4.4481**
Transport Energy	**J/J**				
Transport energy	**0.0579**	0.0195	0.0746	0.0791	0.0421
Shipping	**0.0012**	0.0023	0.0002	0.0010	0.0032
Total	**3.109**	**1.147**	**3.934**	**4.213**	**2.383**
Total Energy, GJ/tn	**8.362**	**5.482**	**6.966**	**13.264**	**8.671**

Table 5-22 Carbon Intensity of Natural Gas streams arriving to South-East EU

Lifecycle Stage	EU South-East (grCO2eq/GJ)											
	CNG Streams	**Average**	Russia	Algeria pipeline	Romania	Italy	Libya	Qatar LNG	Other	Germany	Norway	Netherlands	Algeria LNG
Downstream	Fuel dispensing	**4,221**	4,328	4,237	4,134	4,101	4,262	4,219	4,161	4,148	4,103	4,068	4,500
	Gas distribution, transmission and storage	**6,616**	6,895	6,671	6,274	6,166	6,725	7,079	6,368	6,327	6,173	6,046	8,278
Midstream	Feedstock transportation (pipeline, LNG)	**9,119**	25,163	6,149	2,597	0	4,704	3,955	2,597	2,196	4,621	2,354	1,911
Upstream	Fuel production and recovery	**7,858**	3,826	12,193	6,814	6,338	10,310	11,273	8,257	5,828	2,288	1,338	37,882
	CO_2, H_2S removed from NG (gas processing)	**768**	3	493	49	2	5,915	1,380	986	2,613	113	1	986
	Total CNG	**28,582**	**40,215**	**29,743**	**19,868**	**16,607**	**31,916**	**27,906**	**22,369**	**21,112**	**17,298**	**13,807**	**53,557**

Table 5-23 Carbon Intensity of Natural Gas streams arriving to North EU

Lifecycle Stage	EU North (grCO2eq/GJ)							
	CNG Streams	**Average**	UK	Norway	Qatar LNG	Netherlands	Denmark	Russia
Downstream	Fuel dispensing	**3,519**	3,514	3,500	3,585	3,483	3,493	3,613
	Gas distribution, transmission and storage	**1,249**	1,114	1,111	2,237	1,108	1,110	1,129
Midstream	Feedstock transportation (pipeline, LNG)	**2,436**	802	2,403	4,383	684	479	20,214
	Fuel production and recovery	**4,820**	5,949	2,203	11,272	1,300	2,975	3,815
Upstream	CO2, H2S removed from NG (gas processing)	**238**	26	113	1,380	1	19	3
	Total CNG	**12,262**	**11,405**	**9,330**	**22,857**	**6,576**	**8,076**	**28,774**

Table 5-24 Carbon Intensity of Natural Gas streams arriving to South-West EU

Lifecycle Stage	EU South-West (grCO2eq/GJ)										
	CNG Streams	Average	Norway pipeline	Algeria pipeline	Nigeria LNG	Netherlands	Algeria LNG	Qatar LNG	Russia	Germany	Norway LNG
Downstream	Fuel dispensing	**2,790**	2,751	2,792	2,817	2,742	2,910	2,799	2,850	2,764	2,767
	Gas distribution, transmission and storage	**1,158**	1,090	1,100	1,285	1,087	1,351	1,272	1,112	1,093	1,252
Midstream	Feedstock transportation (pipeline, LNG)	**5,142**	4,326	2,698	3,790	3,185	2,022	4,211	27,066	624	744
Upstream	Fuel production and recovery	**9,559**	2,278	12,156	16,254	1,358	37,867	11,272	3,827	5,855	8,727
	CO2, H2S removed from NG (gas processing)	**517**	113	493	863	1	986	1,380	3	2,613	0
	Total CNG	**19,166**	**10,558**	**19,239**	**25,009**	**8,373**	**45,136**	**20,934**	**34,858**	**12,949**	**13,490**

Table 5-25 Carbon Intensity of Natural Gas streams arriving to Central EU

Lifecycle Stage	EU Central (grCO2eq/GJ)												
	CNG Streams	**Average**	Russia	Netherlands	Norway	Other	Germany	Poland	UK	Qatar LNG	Hungary	Denmark	Norway LNG
Downstream	Fuel dispensing	**4,112**	4,205	4,053	4,077	4,116	4,095	4,080	4,083	4,153	4,103	4,071	4,105
	Gas distribution, transmission and storage	**2,804**	2,833	2,764	2,776	2,795	2,785	2,778	2,779	3,924	2,785	2,773	3,787
Midstream	Feedstock transportation (pipeline, LNG)	**8,287**	25,018	151	3,375	2,694	0	0	370	4,469	2,694	1,429	362
Upstream	Fuel production and recovery	**3,352**	3,820	1,294	2,248	8,232	5,707	5,777	6,007	11,273	6,071	2,976	8,619
	CO_2, H_2S removed from NG (gas processing)	**201**	3	1	113	986	2,613	1	26	1,380	1,144	19	0
	Total CNG	**18,756**	**35,879**	**8,263**	**12,589**	**18,823**	**15,200**	**12,636**	**13,265**	**25,199**	**16,797**	**11,268**	**16,873**

Figure 5-11 to Figure 5-14 illustrate this variation of Carbon Intensities of the different streams in the four EU regions.

Figure 5-11 Carbon Intensities of Natural Gas streams arriving to the South-East EU region

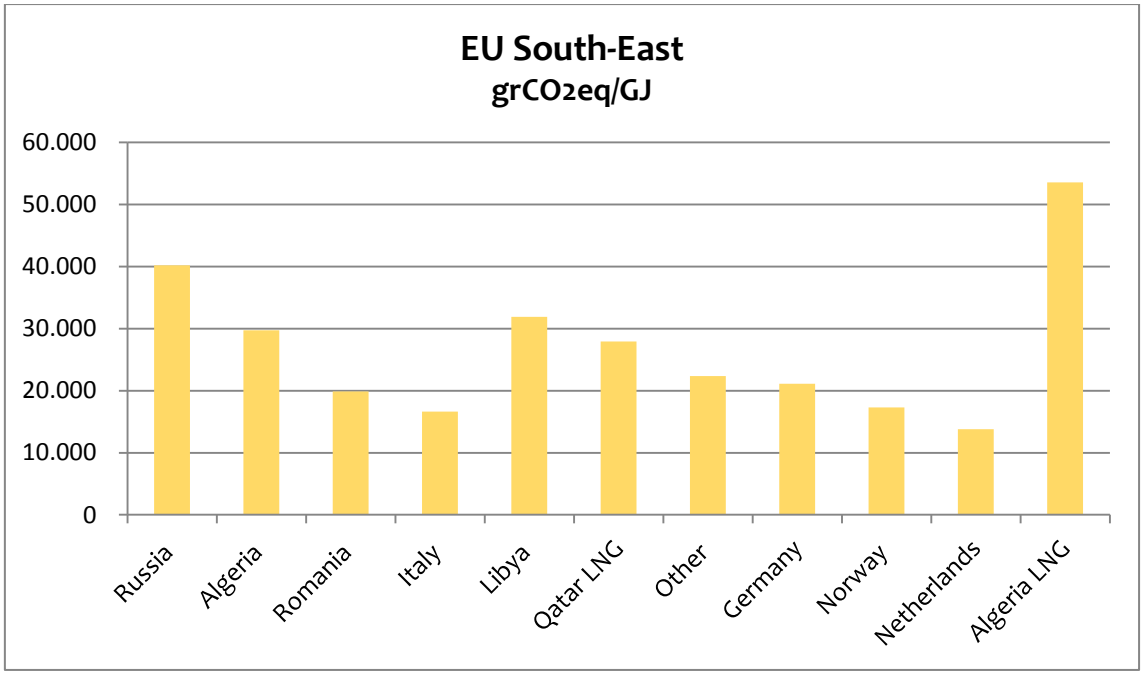


Figure 5-12 Carbon Intensities of Natural Gas streams arriving to the North EU region

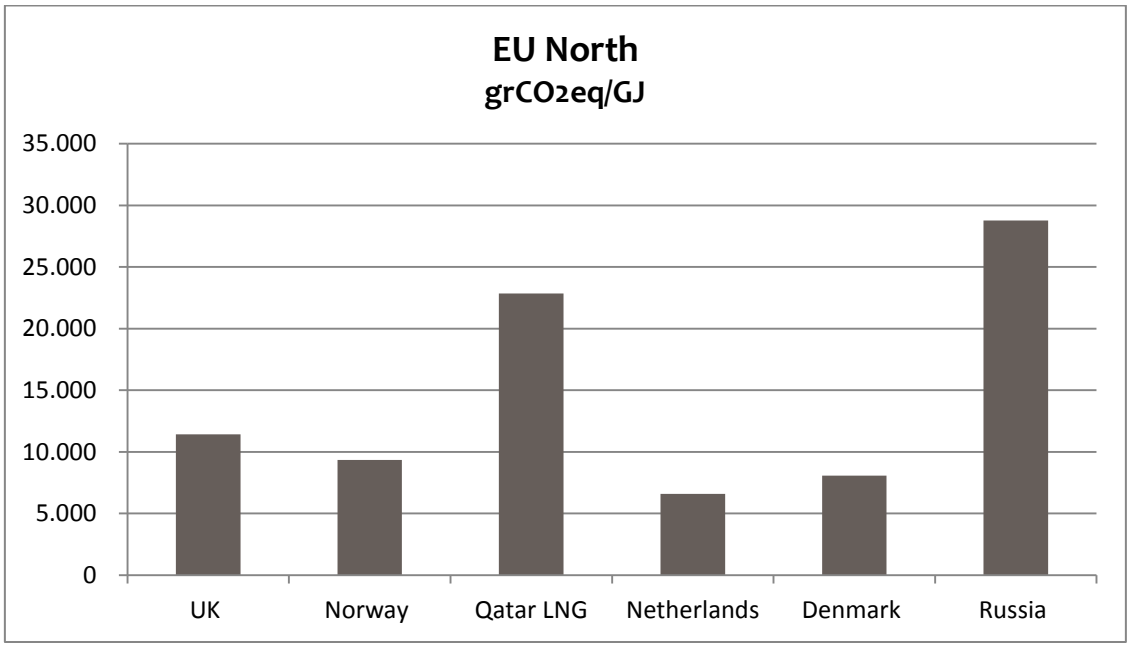


Figure 5-13 Carbon Intensities of Natural Gas streams arriving to the South-West EU region

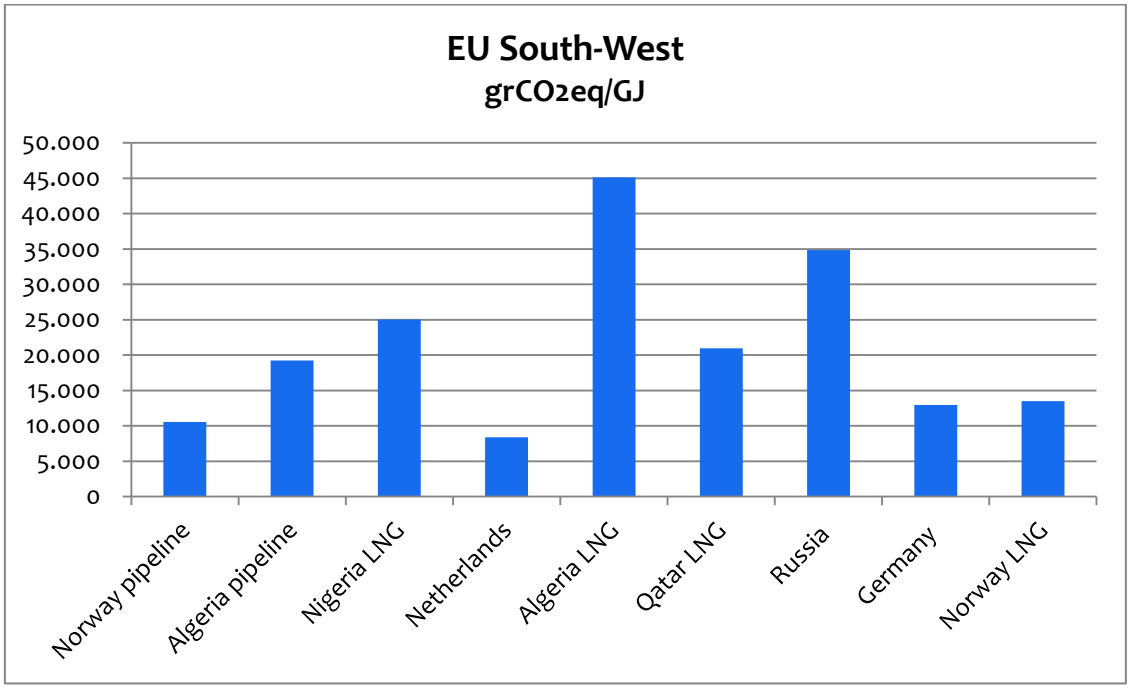


Figure 5-14 Carbon Intensities of Natural Gas streams arriving to the Central EU region

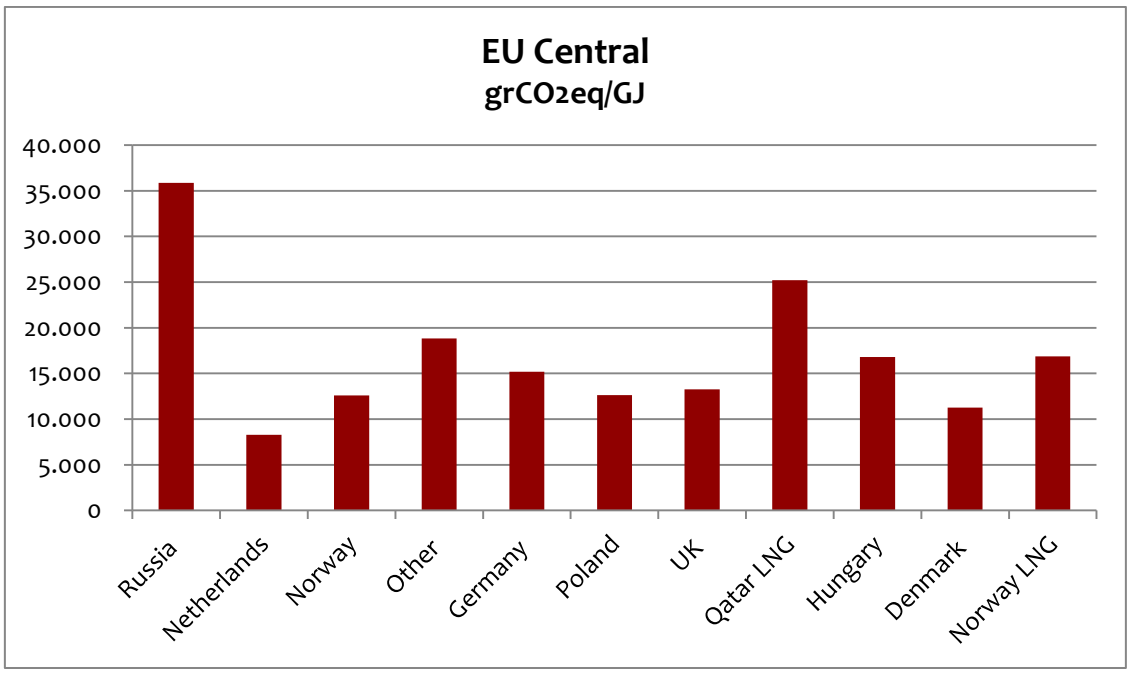


Table 5-26 presents the minimum and maximum carbon intensities for natural gas streams according to the supplying country. Only countries which supply more than one EU consuming region are included.

Table 5-26 Minimum and Maximum Carbon Intensities per gas supplying country

Supplying country	Minimum CI	Maximum CI
	$grCO_2eq/MJ$	
Germany	12.949	21.112
Denmark	8.076	11.268
Netherlands	6.576	13.807
Norway (pipeline)	9.33	17.298
UK	11.405	13.265
Russia	28.774	40.215
Algeria (pipeline)	19.239	29.743
Algeria LNG	45.136	53.557
Norway LNG	13.49	16.873
Qatar LNG	20.934	27.906

The most significant GHG emissions are observed in the streams originating from Algeria, both for pipeline and for LNG transportation. As Algerian gas production depends heavily on electricity and the amounts of flaring gas are important, the upstream emissions in this country are high compared to other African countries supplying the EU. Also, the pipelines crossing Algeria, transporting natural gas to the Mediterranean Sea have very high fugitive emissions, thus increasing the CI values in the midstream stage as well. The distribution of GHG emissions for the different stages of Algerian gas streams arriving to the South-East EU region are presented in Figure 5-15 and Figure 5-16.

Figure 5-15 Distribution of GHG emissions to the various stages of Algerian gas stream transported to South-East EU by pipeline

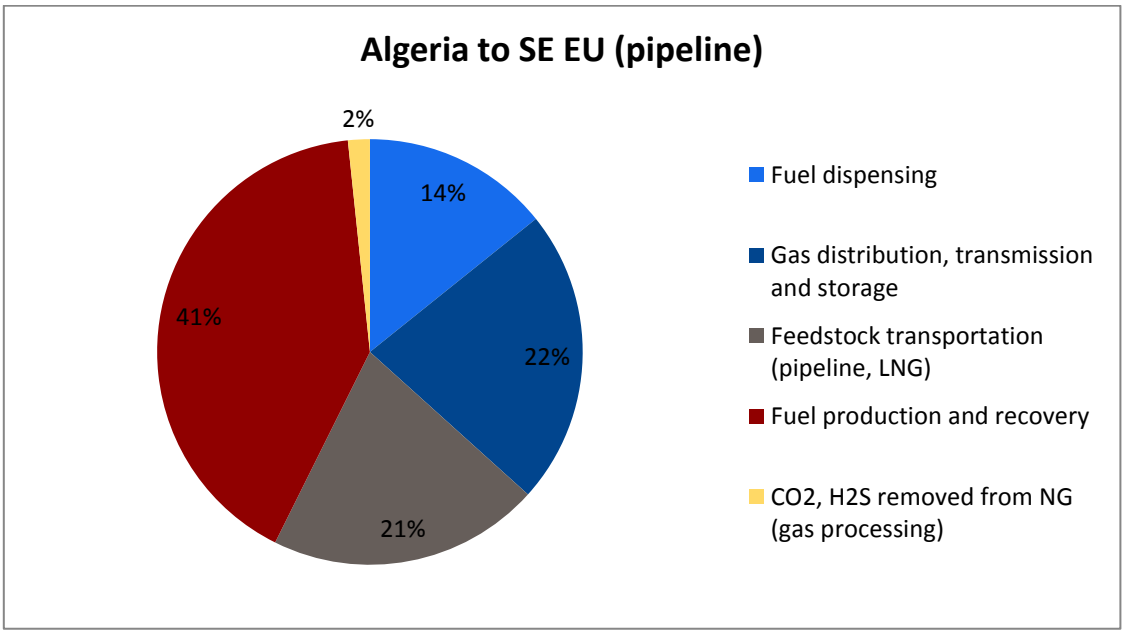
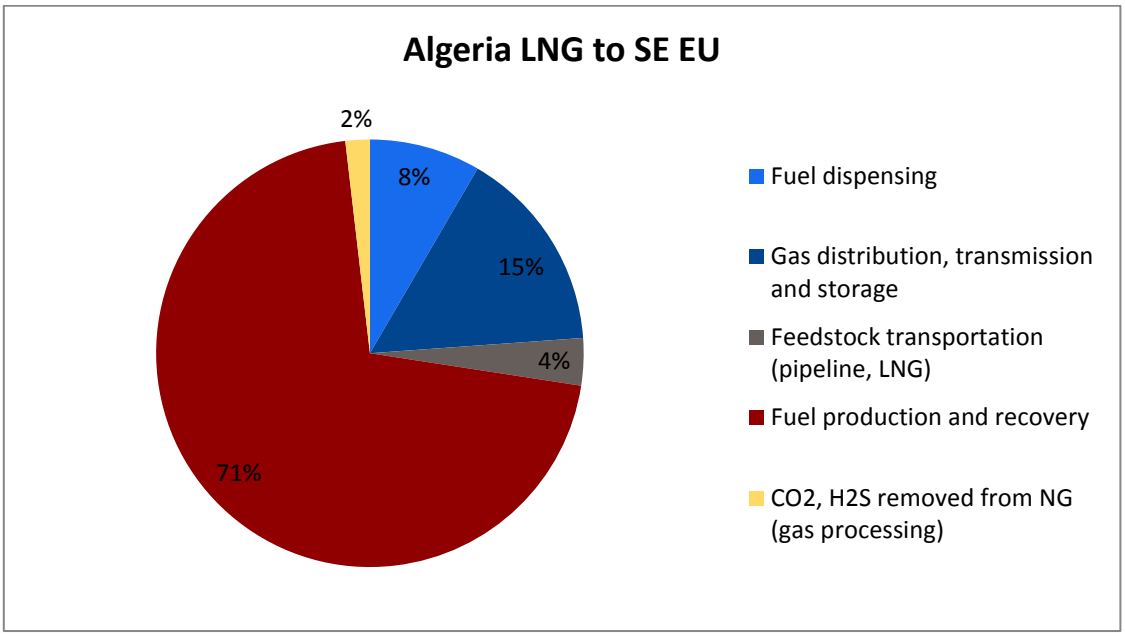


Figure 5-16 Distribution of GHG emissions to the various stages of Algerian gas stream transported to South-East EU as LNG



5.2.3 Small scale LNG streams

All four regions of Europe receive some LNG from various suppliers to supplement other sources of natural gas. Most of the LNG that is received is regassified for use in the gas pipeline network. This LNG can also be transported and used directly in the transportation system without regasification. The GHG emissions for this transportation fuel have been calculated for each of the LNG supply sources in each of the 4 regions.

In each case it has been assumed that the LNG is distributed by truck an average distance of 100 km. There are three product transfers required, once from the LNG tank at the port to the distribution truck, once from the truck to the dispensing station, and once from the station to the truck that uses the LNG. There is the potential for some gas loss at each transfer. It is assumed that a high degree of care is employed at each transfer and that the total gas loss over the three transfers is 0.4% of the volume consumed. It is also assumed that some electricity will be required at the final dispensing site, 0.005 kWh/kg specific power requirement is used.

LNG could also be distributed by barge from the main receiving terminals. Barge transport is more energy efficient than truck transport so that the GHG emissions would be lower or the transport distances could be greater. This mode may entail an extra transfer if truck transport is also employed and the extra transfer could increase methane losses.

The regasification energy has been set to zero for these calculations. The energy and emissions associated with the natural gas transmission and distribution systems have also been set to zero, since these systems are being bypassed with the truck distribution of LNG.

It is generally considered that small scale LNG to be used in the EU transport sector comes directly from LNG streams and no liquefaction of LNG originating from pipeline streams takes place within the consuming countries. The Carbon Intensities of these streams are presented in Table 5-27.

It can be observed that compared to CNG streams presented in the previous section, GHG emissions in the **dispensing stage** are two to three times lower for small scale LNG.

Table 5-27 Carbon Intensities of small scale LNG streams for the four EU regions

Lifecycle Stage	(grCO2eq/GJ)	EU North	EU Central		EU South-East		EU South-West			
	Small scale LNG Streams	Qatar	Qatar	Norway	Qatar	Algeria	Qatar	Nigeria	Algeria	Norway
Downstream	Fuel dispensing	1,971	1,983	1,982	1,983	1,989	1,955	1,955	1,957	1,954
	Gas distribution, transmission and storage	589	626	617	624	658	599	605	631	591
Midstream	Feedstock transportation (pipeline, LNG)	4,385	4,475	362	4,057	1,978	4,214	3,793	2,017	743
Upstream	Fuel production and recovery	11,272	11,273	8,614	11,273	37,808	11,272	16,254	37,862	8,726
	CO2, H2S removed from NG (gas processing)	1,380	1,380	0	1,380	986	1,380	863	986	0
	Total LNG	**19,597**	**19,737**	**11,575**	**19,317**	**43,419**	**19,420**	**23,470**	**43,453**	**12,014**

5.2.4 Parametric significance

In order to assess the significance of each individual parameter introduced to GHGeius as input, a sensitivity analysis has been elaborated on two representative natural gas streams, namely the one originating from Russia and consumed in the Central EU region and the natural gas supplied as LNG from Qatar to the South-West EU region.

Russia to Central EU stream – Sensitivity analysis

The parameters that have been tested individually are the following:

- CNG Compressor inlet pressure
- CNG Compressor methane loss rate
- Pipeline Distance
- Transmission and Distribution methane loss
- Transport pipeline energy consumption

Table 5-28 presents the fluctuation of values tested for the above parameters and the results of the analysis. The calculated Carbon Intensity for this specific Natural Gas stream is **35,878 grCO2eq/GJ.**

Table 5-28 Russia to Central EU stream: Sensitivity analysis

Parameter fluctuation				CI fluctuation		
Parameter	**Baseline value**	**Minimum value**	**Maximum value**	**Total CI with minimum value of parameter** (grCO2eq/GJ)	**Total CI with maximum value of parameter** (grCO2eq/GJ)	**Fluctuation**
CNG Compressor Pressure	0.448 Mpa	0.11 Mpa	1.4 Mpa	36,993	35,060	**-3.11% up to 2.28%**
CNG Compressor leakage	-0.17%	-0.34%	-0.68%	35,067	37,500	**-4.52% up to 6.36%**
Pipeline distance	3800 km	4200 km	4600 km	33,596	38,267	**-6.66% up to 6.36%**
Transmission and Distribution Leakage rates	0.264%	0.53%	2%	34,580	41,313	**-15.15% up to 3.62%**
Transport Energy	0.00003 J/J-km	0.000045 J/J-km	0.00006 J/J-km	28,309	44,755	**-24.74% up to 21.1%**

From the above Table 5-28, it is evident that the parameter among the ones tested that influences the final result in the most significant way is "transport energy". This is due to the fact that the streams originating from Russia include very long-distance transport pipelines. Therefore any fluctuation of GHG emissions at the midstream stage, which represent an important fraction of the total CI, would result in an important fluctuation of the carbon intensity of the whole stream. This consideration also explains the sensitivity of the final result to the "pipeline distance" parameter. A variation of this parameter of less than 10% results into a fluctuation of the total CI higher than 6%.

Qatar LNG to South-West EU stream – Sensitivity analysis

The parameters that have been tested individually are the following:

- CNG Compressor inlet pressure
- CNG Compressor methane loss rate
- Transmission and distribution methane loss
- Regasification energy
- Processing energy

Table 5-29 presents the fluctuation of values tested for the above parameters and the results of the analysis. The calculated Carbon Intensity for this specific Natural Gas stream is **20,935 grCO2eq/GJ.**

Table 5-29 Qatar to South-West EU stream: Sensitivity analysis

Parameter fluctuation				CI fluctuation		
Parameter	**Baseline value**	**Minimum value**	**Maximum value**	**Total CI with minimum value of parameter** (grCO2eq/GJ)	**Total CI with maximum value of parameter** (grCO2eq/GJ)	**Fluctuation**
CNG Compressor Pressure	0.448 Mpa	0.11 Mpa	1.4 Mpa	21,441	20,561	**-2.42% up to 1.79%**
CNG Compressor leakage	-0.17%	-0.34%	-0.68%	20,122	22,555	**-7.74% up to 3.88%**
Regasification Energy	0.125 J/J	0.062 J/J	0.249 J/J	20,846	21,108	**--0.83% up to 0.43%**
Transmission and Distribution Leakage rates	0.105%	0.21%	0.42%	20,429	21,942	**--4.81% up to 2.42%**
Processing Energy	5 GJ/ton	7 GJ/ton	9 GJ/ton	17,706	24,461	**-16.84% up to 15.42%**

As shown in the table, the most significant parameter in terms of influencing the total CI, is "processing energy". In LNG streams, the processing stage contributes an important part of the total GHG emissions of the stream, as it also includes the liquefaction process. Thus, any variation in the value of this parameter has a strong influence to the CI of the stream.

5.2.5 Uncertainty of results

In order to estimate the uncertainty of results of the GHGenius model, a Monte Carlo simulation has been carried out for the same two streams as the ones tested in the sensitivity analysis in the previous section. The parameters that have been examined are the same as in the sensitivity analysis.

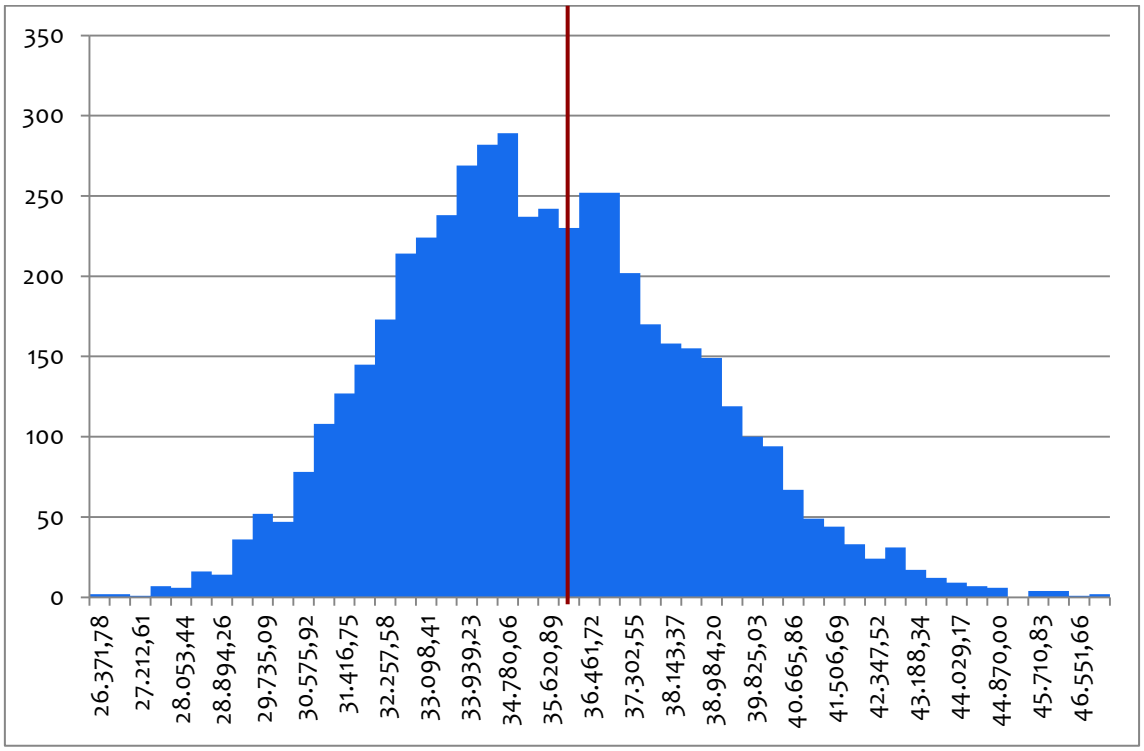
Russia to Central EU stream – Monte Carlo simulation

The parameters that have been tested are the following:

- **CNG compressor inlet pressure**: Mean value 0.448 MPa, normal distribution with a standard deviation of 0.01
- **CNG Methane loss rate**: Mean value 0.34%, normal distribution with a standard deviation of 0.1%
- **Pipeline distance**: Uniform distribution, min 3800 km, max 4600 km
- **Transmission and distribution methane loss**: Mean value 0.53%, lognormal distribution with a standard deviation of 0.1%
- **Transport energy**: Mean value 0.000045 J/J-km, normal distribution with a standard deviation of 0.000005 J/J-km

The results of the Monte Carlo simulation have indicated the amount of variation and the spread of CI around the mean value. The curve of the probability density function is presented in Figure 5-17. The mean value is calculated at **35.72 grCO2eq/MJ** and the standard deviation at **3.11 grCO2eq/MJ** indicating a considerable variation of the relevant CI values. This result illustrates the significance of uncertainty consideration and the need for standard rules when measuring and calculating the components characterizing the CI of gas streams and especially of the most significant ones for the EU that are the Russian pipeline streams.

Figure 5-17 Results of the Monte Carlo simulation on the Russia to Central EU stream (Red line represents the baseline CI of the stream)



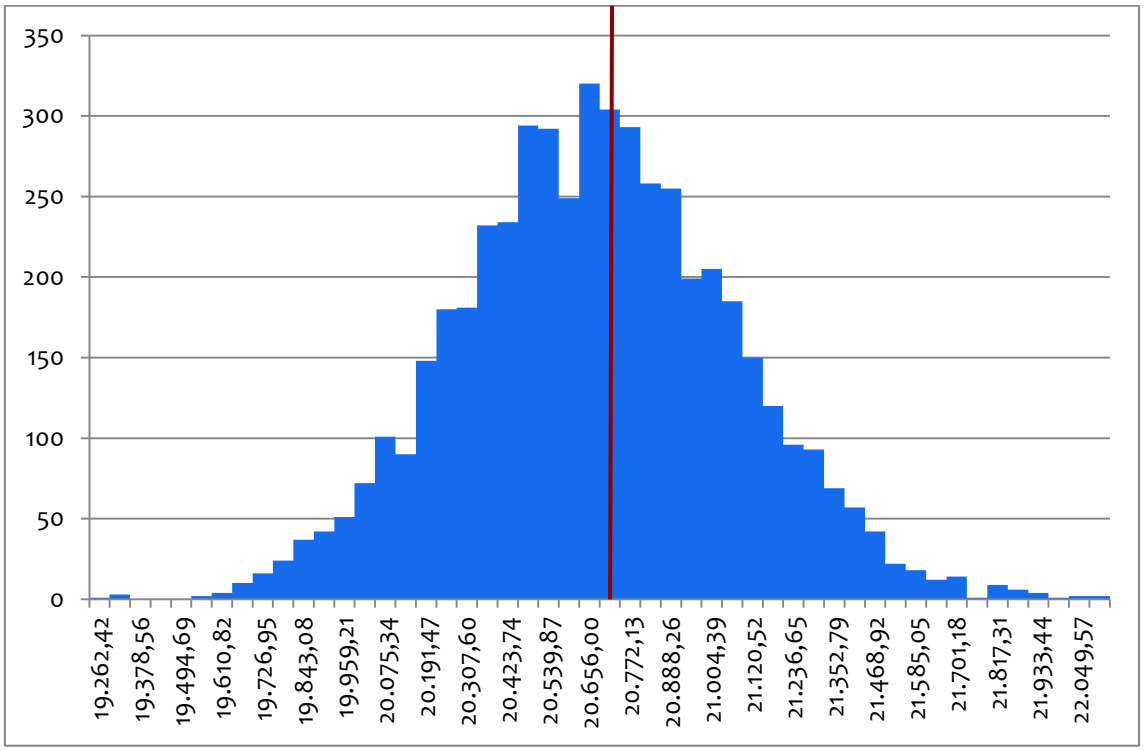
Qatar LNG to South-West EU stream – Monte Carlo simulation

The parameters that have been tested are the following:

- **CNG compressor inlet pressure**: Mean value 0.448 MPa, normal distribution with a standard deviation of 0.01
- **CNG Methane loss rate**: Mean value 0.34%, normal distribution with a standard deviation of 0.1%
- **Transmission and distribution methane loss**: Mean value 0.53%, lognormal distribution with a standard deviation of 0.1%
- **Transport energy**: Mean value 0.000045 J/J-km, normal distribution with a standard deviation of 0.000005 J/J-km
- Regasification energy: Mean value 0.062 J/J, lognormal distribution with a standard deviation of 20% of the mean value
- Gasification energy. Mean value 7 GJ/ton, lognormal distribution with a standard deviation of 0.2 GJ/ton

Similarly the results of the Monte Carlo simulation for the Qatar LNG case compose the curve of the probability density function, which is presented in Figure 5-18. The mean value is calculated at **20.70 grCO2eq/MJ** and the standard deviation at **0.39 grCO2eq/MJ** indicating a rather small variation of the relevant CI values, compared to the previous case of the Russian gas.

Figure 5-18 Results of the Monte Carlo simulation on the Qatar LNG to South-West EU stream (Red line represents the baseline CI of the stream)



Therefore in the above two indicative cases of uncertainty assessment using the Monte Carlo simulation tool of GHGenius it was clear that the level of uncertainty varies from stream to stream and characterizes in principle the midstream stage, which includes uncertainties on the CI due to the transportation of gas from the producing countries to the EU.

6 TASK D: INDIRECT EMISSIONS

For biofuels, the indirect GHG emissions related to land use, also known as ILUC (Indirect Land Use Change), originate from the release of CO_2 emissions due to land-use changes around the world induced by the expansion of croplands for ethanol or biodiesel. Because the rainforests store carbon in soil and biomass, clearance of rainforest translates to an increase in greenhouse gas emissions. For biofuels, this type of indirect emissions constitutes a substantial contribution to the CO_2 emissions.

In the case of fossil fuels, there may also be indirect emissions attributed to their lifecycle. These are often not taken into account when calculating GHG emissions from the lifecycle of fossil fuels.

In the following paragraphs, the method to estimate indirect emissions from fossil fuels is introduced and an assessment of the magnitude of indirect emissions from fossil fuels required for transport in the EU is presented.

6.1 System Boundary Definition

Along with the direct GHG emissions from the lifecycle (well-to-tank) of transport fossil fuels (diesel, petrol, kerosene and natural gas), this study will also include the "indirect emissions" in the analysis.

More precisely, the indirect emissions will be identified and assessed, and where possible these emissions will be included in the total estimates of the GHG emissions from the fuels.

The relevant stakeholders have not clearly defined indirect emissions. For the purpose of the present study, the following definition will be used:

Direct emissions are emitted from the processes used to produce and transport the fuel along the lifecycle. **Indirect emissions are those that are influenced or induced by economic, geopolitical or behavioral factors, but which are not directly related to extraction, processing, transportation and distribution of the fuels**[104]**.**

In order to make sure that all relevant emission sources are covered by the project, there is need to define clearly what is considered direct and indirect emissions sources respectively.

[104] Desk Study on Indirect GHG Emissions from Fossil Fuels, ICF International (page 2)

6.2 Attributional and Consequential Emissions

Indirect emissions can be divided into two types:

- **Attributional emissions:** Emissions that can be said to be related to the production of the fossil fuels and thus added to the direct emissions estimated by the traditional LCA approach. An example of attributional emissions is the case of emissions related to military activities to protect the resources.
- **Consequential emissions:** Emissions arising from changes at the level of production of fossil fuels. These are related to the forecasting of future emissions but not in terms of estimating the emissions from today's fuels. An example of a consequential emissions source is "price effects": Reduced demand for fossil fuels for transportation due to substitution by alternative fuels will lower fossil fuel prices, which in turn will tend to increase the demand for fossil fuels used for other purposes. Thus, the full positive impact from the fall in the demand for fossil fuels for transport will actually not occur.

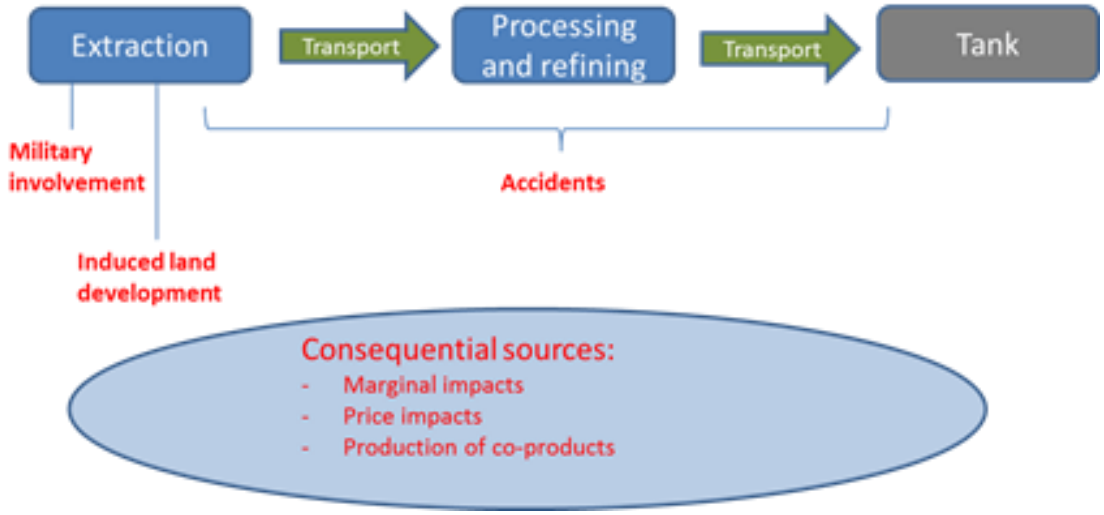
Attributional emissions are associated with the full estimation of the actual lifecycle emissions, whereas consequential emissions are associated with the projections on future GHG emissions. The study of indirect effects will focus on the attributional part, especially when it comes to the estimation.

Following a literature review, the indirect emissions sources identified and included in the study are listed below. These are described focusing on the boundaries to the direct emissions, where relevant.

- Attributional emissions sources:
  - Induced land development;
  - Military involvement;
  - Accidents.
- Consequential emissions sources:
  - Marginal effects;
  - Price effects;
  - Co-product production.

Figure 6-1 below illustrates the indirect emissions sources (marked in red) and the placement in the fossil fuel lifecycle.

Figure 6-1 Identification of indirect emissions sources related to oil and gas pathway from well to tank



6.3 Main Indirect Emissions

6.3.1 Attributional emissions sources

Induced land development

This issue covers the induced land development caused by adjacent developments facilitated by oil and gas production in remote areas.

It is important to distinguish between direct and indirect emissions from land development:

- The **direct emissions source** arises from the need for land to produce and transport fuels, thus the emissions related to clearing land for these purposes. These can be compared with the ILUC emissions for biofuels, although the impacts from fossil fuels are limited compared to the impacts from biofuels. The direct impacts of land use change are considered a direct effect and not covered in the study of indirect impacts.
- The **indirect emissions source** referred to as 'induced land development' covers the impacts caused by the access to remote areas. Extraction of the raw materials requires access to areas that would possibly otherwise be left untouched. The development of infrastructure will thereby cause disturbance to the area. The magnitude of the emissions impact will depend, among other things, on the type and location of the land involved. For example, it is generally accepted that oil activities opened up new agricultural frontiers in the northern Amazon region by building

penetration roads into primary forest areas[105]. Therefore, the question is naturally whether the deforestation is "additional" or whether a possible deforestation is just moved from one area to another.

In the study, the possible effects of induced land development will be investigated. This will include, among other things, exploring the differences between various types of raw materials and the geographic location.

Military involvement

This issue covers emissions from military activities to provide security and stability to oil-producing regions and to protect international oil supply routes. The key issue is to what extent military activity is motivated by efforts to secure petroleum and gas reserves?

Emissions from military activities arise from fuel combustion from military means of transport as well as from the energy used to construct military infrastructure and rebuild states affected by conflicts.

The emissions sources can be divided into two categories: security-related emissions (from long-term, sustained military presence in a geographic area) and conflict-related operations emissions (such as the Gulf War).

Accidents

Accidents may occur throughout the pathways followed by the fossil fuels and may have severe environmental impacts. Possible GHG emissions caused by accidents fall within the following categories:

- Blowouts (uncontrolled bursts or releases of oil and gas) during extraction. These certainly have a severe environmental impact, but they are not GHG emissions unless the oil is burnt or the blowouts involve release of methane.
- Accidents during transportation or storage at the ocean: clean-up may include surface burning of oil causing GHG emissions.

These possible impacts will be included in the analysis of indirect sources, where other possible emissions sources caused by accidents will also be investigated.

Fugitive emissions from sources such as sealing, well completions and work-overs (i.e. retrofitting a well) are "engineered losses" that occur during normal operation. These are considered direct emissions and are consequently not included in the analysis of indirect emissions sources.

[105] Desk Study on Indirect GHG Emissions from Fossil Fuels, ICF International, page 28

6.3.2 Consequential emissions sources

Marginal impacts

This issue covers impacts on the fossil fuel lifecycle that would result from large-scale economy-wide changes in the supply and demand of fossil fuels.

This may result in at least two different consequences:

- Changes in demand will alter the marginal fossil fuel resource consumed. This will change the types of fossil fuels extracted and the operation of refineries, all affecting the GHG emission profile.
- Increased demand for natural gas for transportation may reduce the use in the electricity sector, resulting in changes in the mix of fuels used in electricity production.

These impacts are expected to be modelled in the forecast models and are therefore not included in this section on indirect emissions sources.

Price impacts

Changes in the use of fossil fuels for transportation will affect the demand and thereby the prices, which in turn will affect the demand for fossil fuels in other sectors. This rebound effect is normally best modelled and assessed in economic models, especially in the field of "general equilibrium modelling".

Price impacts need to be taken into account in the forecasting. The models of E3M LAB capture such impacts, and this issue will thus not be handled within the area of indirect effects.

Production of co-products

The refinery process also results in various co-products besides the fossil fuels. Without fossil fuels, these have to be produced in other ways or replaced by other products in the use.

Two aspects of the production of co-products have to be considered in the analysis.

First, it can be argued that some of the emissions throughout the lifecycle should be assigned to the co-products, thus reducing the emissions from the fossil fuel part. There are different methods for doing that, and it is assumed that these emissions will be covered by the calculations of direct effects in the refinery model.

Secondly, changes in the production of fossil fuels will result in the need to find alternative ways of producing the co-products or substituting the use of the co-products with alternative products, which will affect the GHG emissions. This is a consequential indirect emissions source.

6.4 Methodology for Assessment of Indirect Emissions

Oil and gas consumed in the EU come from different locations and are transported by different means. The indirect emissions are relevant only for some of these locations and transport means. For instance, induced land development will only be relevant in areas where there is a potential for deforestation and potentially also later for use of land for alternative purposes. Military CO_2 emissions may only be relevant in areas with politically unstable conditions such as in the Middle East. In order to include these indirect GHG emissions, there is need to analyze which indirect GHG emissions are relevant for each of the locations supplying the EU with oil and gas.

Table 6-1 shows the relationship between oil extraction and transport and the specific, indirect emissions.

Table 6-1 Potential indirect GHG emissions for oil consumed in the EU

Region	Country of Origin	Name	Offshore /Onshore	Transport	Location	Political
	Iran	Gachsaran oil field	On	Pipeline / Tanker		Political issues
	Iraq	Rumaila (South)	On	Pipeline/ Tanker		Political issues
		West Qurna	On	Pipeline/ Tanker		Political issues
		Kirkuk	On	Pipeline/ Tanker		Political issues
	Kuwait	Burgan	On	Pipeline/ Tanker		Political issues
	Saudi Arabia	Kurais	On	Pipeline/ Tanker		Political issues
		Manifa	On	Pipeline/ Tanker		Political issues
Africa	Algeria	Hassi Messaoud	On	Pipeline/ Tanker		
	Angola	Block 17/Dalia	Off	Tanker		Political issues
		Girassol	Off	Tanker		Political issues
		Greater Plutonio	Off	Tanker		Political issues
	Libyan Arab Jamahiriya	Es Sider	Off	Tanker		Political issues

Region	Country of Origin	Name	Offshore /Onshore	Transport	Location	Political
		El Sharara	Off	Tanker		Political issues
	Nigeria	Bonga	Off	Tanker		
		Forcados Yorki	Off	Tanker		
		Agbada	On	Tanker	Rainforest	
		Caw Throne Channel	On	Tanker	Rainforest	
		Escravos Beach	On	Tanker	Rainforest	
FSU	Azerbaijan	Azeri-Chirag-Gunashli (ACG) field	Off	Tanker		Political issues
		Tengiz	On	Pipeline/ Tanker		Political issues
		Azeri-Chirag-Gunashli (ACG) field	Off	Tanker		Political issues
	Kazakhstan	Tengiz	On	Pipeline/ Tanker		Political issues
	Russian Federation	Povkhovskoye	On	Pipeline		
		Tevlinsko-Russkinskoye	On	Pipeline		
		Uryevskoye	On	Pipeline		
		Vat-Yeganskoye	On	Pipeline		
		Pamyatno-Sasovskoye	On	Pipeline		
		Unvinskoye	On	Pipeline		
	Denmark	Tyra south east	Off	Tanker		
	Norway	Statfjord	Off	Tanker		
	Norway	Ekofisk	Off	Tanker		
	Norway	Troll B/C	Off	Tanker		
		Tyrihans	Off	Tanker		
		Oseberg	Off	Tanker		
		Gullfaks	Off	Tanker		
	UK	Buzzard	Off	Tanker		
		Ninian	Off	Tanker		
		Captain	Off	Tanker		
	Mexico	Cantarell	Off	Tanker		
	Venezuela	Boscan	On	Tanker	Rainforest	

By combining the information from Table 6-1 with the amount of oil consumption from these locations, it will be possible to calculate the share that is relevant for the specific types of indirect GHG emissions. This is shown in Table 6-2.

Table 6-2 Share of oil production affected by specific indirect GHG emissions

Issues	Share of oil consumption in the EU (%)
Potential oil spills from oil tanker transport	58%
Induced land use in rainforest areas	6%
Military GHG emissions in areas with potential political instability	31%

As can be seen, more than half of the oil consumed is transported to the EU by oil tankers, with the potential risk of oil spills from oil tanker accidents. The rest is transported by pipeline from Russia and the North Sea oil fields.

Only a very small fraction of 6% of the oil consumed in the EU comes from areas with potential, induced land development effects in rainforest areas.

A percentage of 31% of the oil consumed comes from areas where politically unstable situations may justify military presence to secure stable energy supply.

A similar picture can be drawn for natural gas, transported to the EU by pipeline or in the form of LNG by marine vessels.

Table 6-3 shows the relationship between natural gas extraction and transport and the corresponding specific indirect emissions.

By combining the information from Table 6-4 with the amount of EU gas consumption originating from these locations it is possible to calculate the share that is relevant for the specific types of indirect GHG emissions. This is shown in the Table 6-4.

As can be seen, only a small fraction of natural gas consumed in the EU is transported by LNG tankers, with the potential risk of spills from LNG tanker accidents. Similarly, indirect emissions related to induced land use in forest areas and military involvement in areas with potential political instability present a relatively small likelihood. Thus, the indirect emissions from natural gas extraction and transport are expected to be insignificant.

Table 6-3 Potential, indirect GHG emissions for natural gas consumed in the EU

Region	Country of Origin	Transport	Location	Political
Europe	Germany (pipeline)	Pipeline		
	Netherlands	Pipeline		
	Belgium pipeline	Pipeline		
	Norway pipeline	Pipeline		
	Norway LNG	Tanker		
	Italy (pipeline)	Pipeline		
	Romania (pipeline)	Pipeline		
	UK (pipeline)	Pipeline		
FSU	Russia (pipeline)	Pipeline		
Africa	Algeria pipeline	Pipeline		Political issues
	Algeria LNG	Tanker		Political issues
	Libya pipeline	Pipeline		Political issues
	Nigeria LNG	Tanker	Rainforest	Political issues
Middle east	Qatar LNG	Tanker		Political issues
	Other (pipeline)	Pipeline		

Table 6-4 Share of oil production affected by specific indirect GHG emissions

Issues	Share of natural gas consumption in the EU (%)
Potential spills from LNG tanker transport	11%
Induced land use in rainforest areas	2%
Military GHG emissions in areas with potential political instability	18%

6.5 Data collection for indirect emissions

The data collection for GHG emissions from different indirect sources is based on the literature survey. The section below gives an assessment of the different GHG emissions one by one.

6.5.1 Induced land GHG emissions

This subsection covers induced land development and land use. In principle only the indirect component, namely induced land development should be included in this subsection.

However, since the major impact from both effects is due to deforestation, it is decided to include both effects here.

The induced land development and land use effect contain two GHG emission effects:

- GHG emissions effect from reduced rainforest
- GHG emissions effect from using the land after the rainforest was cleared

The reduced rainforest may be due to either clearance of rainforest, contamination leading to rainforest dead or induced land development. The induced land development comprises, in the present context, land modifications and creation of infrastructure caused by developments for the extraction of raw materials, such as oil and gas for fossil fuel production.

Such developments may open up access to remote, otherwise inaccessible, areas and besides the immediate deforestation they act as corridors and thereby open up for new activities such as industrial forestry/logging, and subsequent farming and/or ranching.

The most characteristic case of induced land development is related to the area of the Amazon rainforest.

Different types of fossil fuels result in varying degrees of land disturbance depending on the type and location of land involved in the production of the fuel. Concerning the drivers behind induced land development, factors including but not limited to social changes, demographic shifts, political unrest, and economic incentives must be examined.

For example, Unnasch et al (2009)[106], based on other work by among others Perz, Brilhante et al. (2008) and Wunder (1997), argue that road construction and expansion trigger logging on areas along the road, and when the areas are 'harvested', subsequent farming or ranching follows. In addition, other infrastructure and derived economic activity may follow.

However, regardless of how well induced land development can be concretised and delimited, there are obviously difficulties in assessing the resulting GHG emissions for the following reasons:

- It is very difficult to assess whether the actual, induced developments are "additional" or alternatively would have occurred somewhere else, without/regardless of the direct development in oil and/or gas production.
- If part of the land development is actually "additional" in the sense that it would not have occurred somewhere else, it will still be quite difficult to isolate development of land that is specifically induced by oil and gas production in affected areas from other facilitators of land use change and development in those areas.

[106] Lifecycle Associates, LLC (2009): Assessment of the Direct and Indirect GHG Emissions Associated with Petroleum Fuels, New Fuels Alliance, 2009

- The size/intensity of resulting GHG emissions will obviously depend on the geographical location of the induced land development – hereunder the type of vegetation or rainforest affected and the type of soil in the area. Different type of vegetation or rainforest will store different amounts of CO_2 and different soil types may have impact on how attractive it is to clear more forest to grow other crops.

The only actual estimate of such induced land development seems to be calculated by Unnasch et al. (2009).

Based on previously mentioned work by among others Perz, Brilhante et al. (2008) and Wunder (1997), Unnacsh et al. (2009), it is assumed that road building for petroleum extraction and production, besides the initial, relatively limited direct deforestation, facilitates further and more considerable, induced deforestation caused by industrial logging and/or subsequent agricultural activities.

Based on available data from a study by Viña, Echavarria et al. (2004) concerning such mechanisms along the border between Colombia and Ecuador, the extent of deforestation associated with road building is estimated based on the proximity of deforestation to the road network. The actual estimate obtained concerns a 5 km wide zone along specific roads and amounts to approximately 32,710 hectares.

Assuming that all deforestation within a certain distance from roads built for petroleum exploration and production in Ecuador is attributable to those roads during a certain time period, and using a carbon loss factor for Latin American rainforests, estimated at 422 Mgr CO_2eq/ha based on Searchinger, Heimlich et al. (2008), an estimate of the amount of CO_2 released is calculated to approximately 13.8 Tgr CO_2eq.

Comparing this estimate with an estimate of the total production of oil from this area, during a related period, Unnasch et al. (2009) estimated that the indirect emissions related to induced land development amount to between approximately 0.6 gr CO_2eq/MJ to approximately 1.0 gr CO_2eq /MJ.[107]

This example clearly illustrates that a straightforward estimation of emissions from induced land development is difficult; the emissions will depend largely on various assumptions on the extent to which oil and gas development in an area facilitates other indirect deforestation activities, such as:

- The extent to which road building in a given area is related to exploration and production of fossil fuels – or rather to other facilitators.
- The extent to which a certain activity such as deforestation, and possibly subsequent farming, is related directly to that road building. It could be, that the deforestation would have taken place at a later stage, even without the "fossil fuel" road building.

[107] This estimate is obviously dependent on the underlying assumptions such as the fractions of the deforestation attributed to petroleum extraction, or size of the buffer used, as the estimate will increase or decrease accordingly to an increase or decrease in the aforementioned factors.

- The level of carbon losses related to this certain activity, such as deforestation
- The associated production of fossil fuels, hereunder the extent in time, how many years of fossil fuel extraction is included in the denominator when calculating the indirect GHG per MJ fossil fuel.

The above described estimation of GHG emissions associated with induced land development may be considered as the maximum estimated value depending on the extent to which land development is additional. If not additional, the associated emissions may be considered zero.

Another case is the oil extraction in the Nigerian rainforest. In recent years, numerous surveys have shown that large areas of the rainforest here have been cleared or contaminated leading to a substantial reduction in the rainforest area.

Large amount of CO_2 is stored in rainforest, both in the trees and in the soil. Clearing the forest will free this CO_2. In Donato et al. (2011)[108] it is estimated that clearance of one ha of rainforest will release 1.023 tons of CO_2. I addition to this impact, the rainforest also contribute to CO_2 reductions by sequestration. This effect is estimated to reduce CO_2 emissions by 1.6 ton of CO_2 per hectare annually[109].

In total, the clearance of rainforest since 1958 has contributed to between 96.2 and 748.1 tons of CO_2 emissions. Relating this amount to the oil extracted in the same period we arrive at a total of 0.6 to 4.3 $grCO_2eq/MJ$ for oil extraction in the Nigerian rainforest.

Using the Unnasch results for rainforest in central America and the Donato results for land use effects in Nigeria we arrive at an average effect of 0.6 to 3.9 $grCO_2eq/MJ$.

Studies have found that sequestration potential is increasing when the CO_2 concentration in the air is increasing. In EPA (2004)[110] it is estimated that this effect will be between 10% and 25% present in the long run, dependent on the local conditions. On the other hand, other impacts, like rising sea level, may reduce the sequestration potential. These effects are uncertain and not included in the calculated GHG effect here.

6.5.2 Accidents and oil spills

Accidents may occur along the full lifecycle of fossil fuels, from extraction to tank. These accidents may have severe environmental impacts. The GHG emissions caused by accidents fall into the following categories:

- Blowouts
- Tanker accidents.

[108] Mangroves among the most carbon-rich forests in the tropics. Nature Geoscience, Donato et al., April 2011
[109] The impact of oil exploration, extraction and transport on mangrove vegetation and carbon stocks in Nigeria. Biomass Research report 1401, J.W.A. Langeveld, 2014
[110] Effects of Elevated Atmospheric Carbon Dioxide Concentration and Temperature on Forests, EPA, 2004

Blowouts (uncontrolled bursts or releases of oil and gas) during extraction certainly have a severe environmental impact, and they may require substantial clean-up activities resulting in additional GHG emissions. The release of oil itself may not result in GHG emissions, unless the oil is burnt or the blowouts concern release of methane.

Regarding GHG emissions related to outbursts, this effect should be calculated as gram of GHG per extracted ton of crude oil or natural gas.

Tanker accidents may result in GHG emissions from clean-up activities and burning of oil from the water surface. Furthermore, the upstream GHG emissions from the extraction/production and (partly) transport of the fuel that will replace the oil that was spilled should also be accounted for.

The probability of tank ship accidents and thus also the indirect GHG emissions from oil transport, depends on the distance oil is transported from the specific oil fields to Europe. The more kilometers of tanker transport, the higher the risk of accidents and indirect GHG emissions. However, since the overall indirect GHG emissions from tanker transport, as shown below, are negligible, this effect will also be negligible.

GHG emissions from oil tanker accident related oil spills are difficult to quantify due to lack of statistical data. This is because GHG emissions from oil spills are not the primary environmental concern in case of oil spills. The toxic components and local environmental impact have much higher priority, most likely because the cost of the local impact on the environment is much higher compared to the cost of the GHG emissions related to the spills.

Oil spills impact GHG emissions in several different ways. Part of the leaked oil evaporates shortly after the leakage, some part is burned and some part is broken down by microorganisms. All of these processes contribute to the GHG emissions.

Based on the ICF desk study on indirect GHG emissions from fossil fuels[111], it is estimated that GHG emissions from oil tanker oil spills are negligible. To provide an order of magnitude, this study assumes that the GHG emissions from oil spills are equal to the GHG emissions generated if total oil spill were incinerated. By combining the total amount of spilled oil of 1,671,240 barrels in the period 2000–2012 with the total oil consumption of approximately 398,103,525,350 barrels, we conclude that the share of oil spills from tanker transport amounts to 0.0004% of total oil consumption. Assuming that a barrel contains 140 kg crude oil, that the energy content of crude oil is 42 MJ/kg and that all spilled crude oil is burnt with a resulting CO_2 emission of 73 g CO_2/ MJ, we arrive at a CO_2 emission from oil spills of 0.0003 g CO_2/MJ.

Additional to the GHG emissions from oil spills, there will also be a contribution from the GHG emissions caused by extraction and transportation until the spill. New oil has to be extracted and transported to replace the oil that was spilled.

[111] ICF (2013); Desk study on Indirect GHG emissions from Fossil Fuels.

Based on the ICF desk study on indirect GHG emissions from fossil fuels, it is estimated that this contribution to GHG emissions is also negligible. According to the Jacobs 2009[112] lifecycle assessment of imported crude oil, upstream GHG emissions from Saudi Arabia crude oil amount to 11 $grCO_2eq/MJ$. Assuming that only 0.0004% of crude oil is spilled, the additional upstream emissions due to oil spills would amount to 0.00005 $grCO_2eq/MJ$.

According to literature, LNG spills from tanker transport of natural gas are considered negligible. One major reason is that an LNG tanker has many barriers. Even if both outer hull and inner hull are damaged, there are still two more barriers that have to be damaged before an LNG spill occurs. Even in the case of serious damage penetrating all barriers, it is most likely that the spill will be limited to small quantities of LNG, as the ship has four to six individual LNG compartments. If one compartment is damaged, the rest may still be unaffected. Thus, even in case of very serious accidents, a leakage may be limited to 15–25% of the total LNG cargo.

In order to have a clear estimation of the leakages from LNG tanker transport, the LNG tanker incidents reported in the last 20 years have been considered.

The safety record for LNG transportation by vessel is significant. The LNG tank ship fleet of 180 carriers has safely delivered over 33,000 shiploads, while covering more than 60 million miles. As of 2006, eight marine incidents worldwide had occurred, involving accidental spillage of liquefied natural gas. In these cases, only minor hull damage occurred, and there were no cargo fires. Seven additional marine-related incidents have occurred, with no significant cargo loss.

The following table shows the risk of leakage from LNG tanker incidents according to a risk study by Erik Vanem et al. (2007)[113].

Table 6-5 Risk of LNG leakage from LNG tanker accidents

Risk	Collision	Grounding	Contact	Explosion
Collision	1%	0%	0%	0%
Struck ship	50%	100%	100%	3%
Not in ballast	50%	50%	50%	50%
Damage cargo area	65%	70%	70%	100%
Critical damage	14%	8%	4%	100%
Total risk of LNG leakage	**0.0157%**	**0.0074%**	**0.0037%**	**0.0027%**

[112] Energy Research Institute and Jacobs Consultancy. Calgary, Alberta

[113] Erik Vanem, et al. (2007): Analysing the risk of LNG carrier operations. Reliability Engineering and System Safety 93 (2008) 1328–1344

As can be seen, the risk of LNG leakage from tanker transport is small, in the range between 0.0027 % and 0.00157 %. Summing up the risk of all four incidents, the total risk that some event leads to an LNG leak amounts to 0.03%. Assuming that evaporation of 1 MJ of natural gas from a LNG tanker will result in a GHG of 63 $grCO_2eq$, the contribution from LNG tankers would amount to 0.018 $grCO_2eq/MJ$. It should be noted that these results give an overestimation since it is assumed that all LNG from a tanker is leaked in case of an event. In most cases, the leak will only constitute a small fraction of the total LNG tanker cargo. One reason for this is that LNG tankers are divided into many smaller compartments. In case one of these is damaged, the rest of the compartments will most often stay unaffected.

The above risk model does not include events occurring while loading or unloading LNG at the terminal. LNG leakage from events while loading and unloading is based on a feasibility study for LNG filling station infrastructure[114]. The feasibility study concludes that events with significant LNG leakages are rare. The accident frequency decreased significantly from 1965 to 1995. From the list in the feasibility study, it can be seen that since 1990, very few accidents have occurred with LNG tankers while loading and unloading. One minor leakage occurred in Khannur in 2001 due to too high tank pressure. Another spillage occurred in 2002 with reports of medium- size spills related to overfilling during unloading[115]. Based on the above mentioned feasibility study, it is concluded that the contribution of LNG leakages in connection with loading and unloading to from the lifecycle emissions of natural gas is negligible.

For pipeline natural gas and LNG, the major indirect effect related to accidents is caused by methane evaporation.

According to a Wuppertal Institute report (2005)[116], there are substantial leaks of methane from the compressor stations. However, these emissions are considered direct emissions and treated within the context of Task C.

6.5.3 Military GHG emissions

Military operations are major industrial activities that use massive amounts of fuel and materials that significantly contribute to climate change. In some regions, military actions are necessary to secure oil extraction. In addition, military activities may be required to protect global maritime oil and gas distribution.
The emissions from military activities arise from fuel combustion by military means of transport as well as from the energy used to construct military infrastructure and rebuild states affected by conflicts.

[114] North European LNG Infrastructure Project, A feasibility study for an LNG filling station infrastructure, and test of recommendations. Appendix 9 Safety Aspects/Risk Assessment

[115] F.B. Natacci et al. (2012): Modelling the risk of product spills in LNG tankers, Maritime Engineering and technology, 2012

[116] Greenhouse Gas Emissions from the Russian Natural Gas Export Pipeline System, Wuppertal Institute for Climate, Environment and Energy in co-operation with Max-Planck-Institute for Chemistry, Mainz

There are two types of military effects:

- Military intervention in politically unstable areas
- Military enforcement to secure safe transportation of fuels.

The first type may be estimated by looking at the GHG emissions from military interventions, such as the Iraq War. Based on literature studies, this effect is estimated to be at the level of 1 grCO_2eq/MJ of oil produced in the Persian Gulf. This type of emissions should only be applied in regions with politically unstable situations.

The second type is due to military presence to secure safe transport of fossil fuels for instance from the Persian Gulf. This effect is also in the order of magnitude of approximately 1 grCO_2eq/MJ of fossil fuel.

In both cases, there is uncertainty, about the extent to which the military presence is solely due to the need to secure fossil fuel deliveries. In the context of the Iraq War, there might have been other reasons. Consequently, this assumption would point to an overestimation of the indirect GHG emissions. On the other hand, the estimate referred to above only includes GHG emissions from the US military forces. Since other countries may also have contributed, this may lead to an underestimation of the GHG emissions.

Considering the potential biases, it seems reasonable to assume an indirect effect accounting for approximately 1 grCO_2eq/MJ for both presence in the area and transport of fossil fuels.

6.6 Results

The resulting indirect GHG emissions are calculated as a weighted average of specific indirect GHG emissions based on the share of oil and gas consumption in the corresponding section for each type of indirect effect.

For instance, the land use effect and induced land development effect in rainforest areas is estimated to have an indirect effect of 0.6 to 3.9 gr CO_2eq /MJ. However, since this land use effect and induced land development effect is only relevant for oil and gas extracted in rainforest areas, this effect will only contribute a fraction of 6% to the total indirect effect. Consequently, the land use effect and induced land development effect contributes with approximately 0.04 to 0.23 gr CO_2eq/ MJ of fossil fuel.

As can be seen, the indirect emissions from fossil fuels consumed in the EU transport sector are relatively small both for oil and natural gas. This is because the indirect GHG emissions generating activities are relatively small compared to the amount of fossil fuels extracted and consumed. Furthermore, every type of indirect emissions is only relevant to a fraction of the fossil fuels consumed. Thus, the resulting overall average of indirect emissions from all fossil fuels required for transport and consumed in the EU is relatively small. For instance, the indirect emissions from oil and gas streams originating from the North Sea and transported to the EU by pipeline is zero. On the other hand, the indirect emissions

from Kuwait oil are estimated to be between 1 and 3 $grCO_2eq/MJ$ due to military activity aimed to secure oil extraction, pipelines and transport.

Table 6-6 presents the unitary GHG emissions for specific types of indirect sources.

Table 6-6 Unitary GHG emissions for specific indirect effects

Issues	Estimate
Induced land development and land use	0.6–3.9 $grCO_2eq$ /MJ
Oil tanker accidents	≈ 0 $grCO_2eq/MJ$
LNG Bunker accidents	≈ 0 $grCO_2eq/MJ$
LNG Bunker leaks	0 – 4.5 $grCO_2eq/MJ$
Military involvement to protect fuel extraction	0.5–1.5 $grCO_2eq/MJ$
Military involvement to protect fuel transport	0.5–1.5 $grCO_2eq/MJ$

Combining the above unitary emissions with the share of total transport fuel consumption in the EU where each issue is relevant, the following total indirect GHG emissions are calculated.

Table 6-7 Average indirect GHG emissions for oil consumption in the EU

Issues	Estimate ($grCO_2eq/MJ$)	Weight	Avg. indirect GHG emissions ($grCO_2eq/MJ$)
Induced land development and land use	0.6 – 3.9	6%	0.04 - 0.23
Oil tanker accidents	0	58%	0
Military involvement to protect fuel extraction	0.5 – 1.5	31%	0.16 – 0.47
Military involvement to protect fuel transport	0.5 – 1.5	31%	0.16 - 0.47
Total			**0.36 – 1.17**

The total indirect emissions from oil products consumed in the EU transport sector are estimated between 0.36 and 1.17 $grCO_2eq$ /MJ.

Indirect emissions from natural gas consumption are calculated using the same method as for indirect emissions from oil explained above. By combining the unitary emissions presented in Table 6-6 with the share of total oil consumption in the EU, where each issue is relevant, the total indirect GHG emissions are calculated as shown in Table 6-8.

Table 6-8 Average indirect GHG emissions for natural gas consumption in the EU

Issues	Estimate ($grCO_2eq/MJ$)	Weight	Avg. indirect GHG emissions ($grCO_2eq/MJ$)
Induced land development	0.6 – 3.9	2%	0.01 – 0.08
LNG Bunker accidents		11%	≈ 0
Military involvement to protect fuel extraction	0.5 – 1.5	18%	0.06 - 0.27
Military involvement to protect fuel transport	0.5 – 1.5	18%	0.06 - 0.27
Total			**0.19 - 0.62**

The indirect emissions from natural gas consumed in the EU are estimated to be between 0.19 and 0.62 $grCO_2eq/MJ$ of natural gas.

As can be seen, the indirect emissions from natural gas consumption are lower compared to indirect emissions from oil consumption. The main reason is that natural gas supply to the EU relies heavily on extraction from the North Sea and other regions with low, indirect emissions.

7 TASK E: OTHER ISSUES RELATED TO SUSTAINABILITY

Task e concentrates on sustainability implications, which are related to the findings of this assignment on actual data of GHG emissions for transport fuels and especially for diesel, petrol, kerosene and natural gas. Considering the wide spread emission levels found for various oil and gas streams supplying the EU transportation system, the challenge towards reducing the relevant carbon emissions, thus leading to improvement of sustainability becomes very complicated, especially when considering also the great economic interests of oil and gas industry. On the other hand most of the consumed quantities of oil and gas products are imported in the EU, so there could be concerns on the Carbon Intensity (CI) reduction policies implemented with regard to the international obligations to which the EU has committed itself, especially those in the field of international trade law under the auspices of the World Trade Organization (WTO). Therefore, the current task includes a twofold, legal and policy, exercise addressing these issues.

The objective of Task e is, in principle, to illustrate how EU sustainability perspectives are related to:

- the use of actual data as a foundation to adapt effective GHG well-to-tank reduction policies in the area of transport fuels;
- the compliance of eventually new policy initiatives based on actual data with the international trade obligations for avoidance of discrimination.

In order to obtain a broader view and the opinions of the EU stakeholders on the above mentioned issues, the Consultant prepared and disseminated a relevant questionnaire. The analyses and the presentation of the results and opinions of the stakeholders are presented in the next Sections of this Chapter.

7.1 The EU policy framework

The European Union is promoting the use of renewable energy in transport with an objective of 10% renewable energy in transport by 2020 as set out by the **Renewable Energy Directive (RED)**. The use of sustainable biofuels is one way of meeting these targets. Road transport depends almost entirely on oil as a fuel at present and corresponding greenhouse gas emissions continue to increase at a high rate. Transport is the only sector where energy consumption is not expected to decrease over the next two decades, if economic development follows business as usual scenarios. At present the main alternative to fossil based fuels in road transport are biofuels, whether liquid or gaseous.

The RED required Member States to submit by June 2010 National Renewable Energy Action Plans setting out inter alia the contribution expected of each renewable energy technology to meet the 2020 targets, including in the transport sector. According to the National Renewable Energy Action Plans, Member States collectively intend to slightly over-achieve the 10% target. They intend to use about 8.5% of first generation biofuels, 1% of second generation biofuels and 1% of renewable electricity, most of the latter in railways rather than in cars. In total this adds up to approximately 10.5% renewable energy in transport; with the different weight factors that the Directive applies to second generation biofuels and renewable electricity used in cars it would be counting as approximately 11.5%.

In June 2010 the European Commission issued a set of guidelines explaining how the RED should be implemented, including principles for schemes for certifying sustainable biofuels. This was based on two communications and a decision.

The **Fuel Quality Directive (FQD)** further sets a target of 6% (Article 7a) reduction of GHG emissions from road transport. Both Directives have specified identical sustainability criteria for the use of biofuels in the European Union and the FQD increased the volumetric limits of ethanol and FAME to 10 vol% and 7 vol% respectively in the EN 228 and EN 590 standards.

Moreover, the FQD (Article 7a(1)) obliges suppliers to report from 2011 information on, inter alia, the GHG intensity of the fuel they have supplied to authorities designated by the Member States. Furthermore the Commission is empowered to adopt implementing measures concerning the method for calculation and the mechanism to monitor and reduce GHG emissions of fuels used in transport. To this direction the recent Council Directive 2015/652 on "**laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC of the European Parliament and of the Council relating to the quality of petrol and diesel fuels**" was launched to support implementation of Article 7a of the FQD. The main features of the latter Directive regarding the method for calculating greenhouse gas emissions of fuels are based on average default values to represent the unit GHG intensity per fuel and the harmonized annual reporting by suppliers to MS and MS to the Commission. In other words the Directive assigns all suppliers a single, EU-wide average emissions intensity of all oil and gas streams supplied each year, regardless of the great spread of GHG emissions of particular fuel feedstocks and production pathways associated with an individual supplier.

Therefore the FQD does not include an explicit mechanism to favor the usage of conventional oil/gas over high carbon emitting unconventional oils/gases, even of some high emitting conventional oils/gases over other less emitting ones. Yet, operational factors related to flaring and venting are not clearly targeted as main drivers of high GHG emissions.

On the other hand, it is a positive step forward by obliging the suppliers to declare, from a list of 618 commonly traded crudes, the MCON or the **Feedstock Trade Name (FTN)** of the imported or produced crude oil in the EU. However, the lack of actual and reliable data doesn't allow the establishment of explicit full reporting of CI on the considered FTN level; a fact, if happened, that could lead to a more robust approach in implementing Article 7a.

Under a full reporting scheme the suppliers would have to report the CI of the upstream activities of the FTN (or MCON) produced or imported in the EU, the midstream transportation CI at the level of FTN (or MCON) and the CI of downstream refining, transmission, distribution and disbursing allocated by FTN (or MCON) to the fuels used by consumers. In such a case the suppliers would be obliged to declare either the verified CIs per stage of fuels transposition, or a minimum set of verified actual data, which would be appropriate to feed a model like OPGEE or GHGenius and thus calculate the required CIs per FTN (or MCON).

The GHG emissions calculations for biofuels in the EU legislation are based on the work undertaken by the **JRC-CONCAWE-ACEA**. The GHG data for biofuels are compared to diesel and petrol. However, although real and actual data are used for biofuels with a significant range of values and with maximum and minimum points, these are compared only to average singular points for diesel and petrol. No detailed information has been provided on how these average singular points have been determined and on which data they are based.

This project has made it possible to determine the actual GHG emissions from diesel, petrol, kerosene and natural gas and compare the GHG emissions of fuel streams originating from various geographical areas and different types of operations taking into account also indirect environmental concerns wherever appropriate.

7.2 Other approaches in GHG policy for reduction of GHG emissions of transport fuels

In the following two Sections the cases for CI reduction of fossil fuels in California and British Columbia will be presented in brief. The first low-carbon fuel standard mandate in the world was enacted by California in 2007, with specific eligibility criteria defined by the California Air Resources Board (CARB) in April 2009 but taking effect until January 2011. Similar legislation was approved in British Columbia in April 2008.

7.2.1 The case of California

California is a pioneer in establishing a system of calculating and reporting GHG emissions setting as objective the reduction of well-to-tank CI of fuels used in transport. The experience gained and the modelling tools developed have been also exploited and used in this study. The relevant regulation LCFS (California Low Carbon Fuel Standard) requires fuel providers to reduce the CI of transportation fuels by 10% by 2020. Since 2011 and after long discussions and implementation of first efforts to monitor and control the CI of oil products, the California Air Resources Board (CARB) decided the adoption of the **California Average Approach**. By that system the average emissions intensity of the California crude basket is to be calculated with OPGEE taking into consideration the CI of all crudes supplied to California in a year. In case the average CI of the California crude basket was higher than the baseline year CI, then an additional 'California average incremental

deficit' in GHG emissions is estimated. The deficit has to be covered by all oil suppliers by obtaining as offset the proper CA-LCFS credits. In case the California crude basket evolved to a lower average CI than in the baseline year, then the fuel suppliers were not benefited with any specific credit. A fuel provider for a list of predetermined alternative fuels (electricity, biogas CNG, biogas LNG, fossil CNG derived from North American sources, etc.) with low CI may generate LCFS credits for that fuels only by electing to opt into the LCFS.

Under this system the allocation of the cost of the poor performance of one year is implemented to all oil suppliers either achieving the CI reduction target individually or not. Therefore the increased costs of poor performance will be spread across the whole oil industry and evidently the California Average Approach will be particularly ineffective in preventing increase in fossil fuel GHG emissions. However, there is an incentive to support, through the offset system, of the low carbon fuels, which will increase penetration in the market and thus contribute to the decrease of the overall CI of the fuels used.

7.2.2 The British Columbia case

The British Columbia Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) includes both a minimum requirement for renewable content in petrol (5%) and diesel (4%) fuels and a carbon reduction requirement for these fuels by targeting a 10% reduction by 2020. A system of credit transactions for both renewable fuel supply and low carbon fuel supply between oil suppliers has been established under the auspices of the regulatory authority.

There is a methodology of RLCFRR allowing fuel CI to be calculated in one of three ways. The default CI values for fossil fuels are reported and publicized and the biofuel suppliers are allowed to report the default value for their corresponding fossil fuel rather than having feedstock specific defaults. Alternatively by the use of the GHGenius model specific CI values for fuels might be estimated, or the regulatory authority might, at its discretion, allow other approaches to be used.

Actually there is no incentive for a supplier of a higher than the default CI diesel or petrol to calculate a fuel specific carbon intensity value, thus diesel from tar sands would be not reported at its actual CI, but rather at the lower CI of the default value. On the contrary, for fossil fuels of CI below the defaults, there is an incentive to report a more accurate CI. There is also an incentive to reduce CI for a refining or production process in case the produced fuel CI becomes better than the default, or improves further the existing lower than the default CI. For some big oil suppliers operating in several jurisdictions and using various crudes, the RLCFRR system allows them the situation of fuel shuffling rather than actual CI reduction. In practice the oil companies were able to allocate on paper their lower carbon intensity fuel to the British Columbia market, while allocating all their higher CI fuels to other markets. This fact led the authorities to revise the RLCFRR towards considering single reportable petrol and diesel CI.

The RLCFRR complements other provincial and federal GHG policies. The federal vehicle emissions regulations are increasing the energy efficiency of the transportation sector,

while the carbon tax is affecting driver behavior and vehicle purchases. Meanwhile, the RLCFRR will ensure that each unit of energy that is consumed for transportation results in fewer GHG emissions from a full lifecycle perspective, including production, transportation and consumption of the fuels. Once the RLCFRR is well established, the carbon intensity of fuels can be further reduced to match the need for GHG reductions and create the demand for more low carbon fuels. The policy creates a larger market for biofuels and other low carbon fuels. The combined market creates larger reward opportunities, which spurs larger investments in new technologies and supply chains.

7.3 International trade issues

In the event that the European Union ("EU") decides to adopt legislation based on the results of the present study, the possible implications of the Agreements of the World Trade Organization ("WTO") would have to be taken into account.

The current legal opinion will examine what the possible WTO implications would be in the context of two hypothetical scenario's:

- the EU takes no action; and
- the EU adopts legislation restricting the production, sale, consumption, importation (or any one or more of the above) of fossil fuels not meeting a certain specified greenhouse-gas ("GHG") emission limit.

The pertinent WTO Agreements appear to be the *General Agreement on Tariffs and Trade 1994* ("GATT 1994") and *the Agreement on Technical Barriers to Trade* ("TBT Agreement").

Before the substantive analysis, a brief overview to the WTO will be provided.

7.3.1 The World Trade Organization

The WTO is an international organization governing the rules of international trade between its Members. Under the auspices of the WTO, its Members have entered into various binding agreements governing their trade in goods, services, etc.

WTO Members can enforce their rights through the WTO dispute settlement mechanism, which has been hailed as the most successful dispute settlement system in the field of international law. Indeed, rulings from the WTO adjudicator (WTO panels as well as the Appellate Body) are generally implemented by the WTO Member having been found in violation of its obligations. A WTO Member having been found in violation of WTO law that does not subsequently bring its measures at issue into conformity with its obligations risks WTO mandated retaliation, which may have severe economic implications.

While the EU as well as its Member States are WTO Members, on the basis of Article 207 of the Treaty on the Functioning of the European Union ("TFEU"), the EU has exclusive competence in the field of international trade. Therefore, it is the EU which sets out the policy on international trade. Furthermore, any measure adopted by the EU having a

(potential) effect on international trade may be subject to a challenge by a fellow WTO Member before the WTO dispute settlement system.

7.3.2 Substantive analysis

A. The European Union Takes no Action

As regards WTO law, the hypothetical scenario in which the EU takes no action is a relatively simple and straightforward situation. Indeed, as will further be explained below, as regards trade in goods the WTO is primarily concerned with measures affecting trade between like products.

In the situation where the EU would not take no action, neither EU fossil fuels, nor imported fossil fuels would be affected. Therefore, there would be no impact on the international trade in fossil fuels. The fact that, for instance, biofuels are subject to sustainability criteria, while fossil fuels are not, is generally of no concern to the WTO. Indeed, biofuels and fossil fuels are not like for the purposes of WTO law. A restriction imposed on biofuels is therefore as (ir)relevant from a WTO perspective as a restriction imposed on any other product, as regards fossil fuels.

In the light of the above, should the EU decide to keep the *status quo* and not adopt any measures on the basis of the findings of the present study, there would not appear to be any WTO implications as regards this specific issue.

B. The European Union Adopts Restrictions on Fossil Fuels

B.1 Introduction

Should the European Union adopt restrictions on fossil fuels, the assumption is that these will be adopted in conjunction with restrictions on domestic production or consumption. If not, it is very likely that any such measures would be found to be in violation of several non-discrimination provisions contained in the WTO Agreements.

However, even if such measures would be adopted in conjunction with restrictions on domestic production or consumption, there may nevertheless be WTO implications that should be taken into account. Indeed, a seemingly even-handed measure may impact the products of various WTO Members differently. Moreover, should the European Union adopt measures on the basis of the present study, it may decide to differentiate between the different sources of fossil fuel types, such as, for instance:

- onshore wells;
- offshore wells;
- oil sands;
- shale;
- etc.

As different WTO Members may produce more of one particular fuel type from one (or more) particular type of sources (if any), it is likely that such measures may have a

substantially different impact on different WTO Members producing fossil fuels. One affected WTO Member may primarily produce oil from oil sands, while another may primarily produce oil from onshore wells. This is likely to have WTO implications, as such measures would treat like products of various WTO Members differently.

The present analysis will examine such possible implications:

- under the GATT 1994; and
- under the TBT Agreement.

B.2 The GATT 1994

There appear to be three pertinent substantive GATT 1994 provisions that may be relevant to the present analysis, as well as two provisions containing exceptions to said substantive obligations:

- substantive obligations:
  - Article I:1;
  - Article III:4;
  - Article XI:1;
- exceptions:
  - Article XX(b); and
  - Article XX(g).

The examination will begin with the substantive obligations, after which it will consider whether there are any exceptions to (possible) substantive violations.

B2.1. Article I:1 of the GATT 1994

Article I:1 of the GATT 1994 provides:

> *With respect to customs duties and charges of any kind imposed on or in connection with importation or exportation or imposed on the international transfer of payments for imports or exports, and with respect to the method of levying such duties and charges, and with respect to all rules and formalities in connection with importation and exportation, and with respect to all matters referred to in paragraphs 2 and 4 of Article III,* any advantage, favour, privilege or immunity granted by any contracting party to any product originating in or destined for any other country shall be accorded immediately and unconditionally to the like product originating in or destined for the territories of all other contracting parties.*

The obligation contained in Article I:1 is commonly referred to as the "most-favored-nation" ("MFN") obligation. Its purpose is to ensure that one WTO Member does not discriminate between the like products originating in different WTO Members.

For the purpose of the present opinion, Article I:1 has been interpreted by the WTO adjudicator in such a way that a measure of a WTO Member must accord any favorable

treatment accorded to products originating in another WTO Member immediately and unconditionally to all like products of all other WTO Members.

A measure such as the envisaged measure(s), whereby the European Union would impose the discussed restrictions on fossil fuels, would trigger the MFN obligation.

The "like" products in question affected by the measure(s) are likely to be:

- domestic versus imported petrol;
- domestic versus imported diesel; and
- domestic versus imported natural gas.

Indeed, "like" products have generally been determined on the basis of (i) physical characteristics; (ii) consumer tastes and habits; (iii) tariff classification; and (iv) end uses. As such, it does not appear that different types of fossil fuel, such as petrol versus natural gas, or even petrol versus diesel, would qualify as like products. Indeed, they (i) have different (chemical) characteristics; (ii) are perceived differently by consumers; (iii) have a different tariff classification; and (iv) are not substitutable on the market.

Whereas Article I:1 appears to cover favorable treatment, it has been interpreted to also cover less favorable treatment. A measure such as the envisaged one(s) are likely to accord less favorable treatment to like products originating in different WTO Members. Indeed, whereas country A might primarily produce petrol from a source type which has received a higher GHG emission default value, countries B and C may primarily produce petrol from a source type which has received a lower GHG emission default value. In this example, country A could fault the EU for treating its products less favorably than those of countries B and C. All it would have to show is that, as a whole, its group of like products are treated less favorably than the group of like products of countries B and C.

The fact that, on the face of it, the measure is likely to be origin neutral is irrelevant, as Article I:1 does not only cover *de jure* discrimination (express discrimination on the basis of origin), but also *de facto* discrimination (discrimination arising from a seemingly origin neutral measure which nevertheless has a disparate impact on products originating in different WTO Members).

In the light of the above, it appears likely that the envisaged measure(s) would be in violation of the EU's obligations under Article I:1 of the GATT 1994.

B.2.2 Article III:4 of the GATT 1994

Article III:4 of the GATT 1994 provides:

> *The products of the territory of any contracting party imported into the territory of any other contracting party shall be accorded treatment no less favourable than that accorded to like products of national origin in respect of all laws, regulations and requirements affecting their internal sale, offering for sale, purchase, transportation, distribution or use. The provisions of this paragraph shall not prevent the application of*

> *differential internal transportation charges which are based exclusively on the economic operation of the means of transport and not on the nationality of the product.*

Whereas Article I:1 governs the measures of a WTO Member affecting products originating in one or more WTO Member vis-à-vis those originating in another, Article III:4 governs measures of a WTO Member affecting products originating in another WTO Member vis-à-vis its own products. The obligation contained therein is commonly referred to as the "national-treatment" ("NT") obligation.

For the purpose of the present opinion, Article III:4 has been interpreted by the WTO adjudicator in such a way that a measure of a WTO Member must accord no less favourable treatment to its products than the like products of any other WTO Member.

A measure such as the one(s) envisaged, whereby the European Union would impose the discussed restrictions on fossil fuels, would trigger the NT obligation.

The "like" product analysis would be virtually the same as under Article I:1, as the criteria for determining likeness are the same. These would therefore equally appear to be:

- domestic versus imported petrol;
- domestic versus imported diesel; and
- domestic versus imported natural gas.

The non-discrimination obligation under Article III:4 mandates that imported products may not receive less favorable treatment than domestically produced like products. It is likely that the envisaged measure(s) would result in less favorable treatment being accorded to domestically produced fossil fuels than that accorded to certain imported fossil fuels.

Indeed, whereas country A might, for instance, primarily produce petrol from a source type which has received a higher GHG emission default value, the EU may primarily produce petrol from a source type which has received a lower GHG default value. In this example, country A could fault the EU for treating its products less favorably than its domestic products. As under Article I:1, all it would have to show is that, as a whole, its group of like products are treated less favorably than the group of like products of countries B and C.

The fact that, on the face of it, the measure is likely to be origin neutral is irrelevant, as Article III:4 equally does not only cover de jure discrimination, but also de facto discrimination.

In the light of the above, it appears likely that the envisaged measure(s) would be in violation of the EU's obligations under Article III:4 of the GATT 1994.

B.2.3 Article XI:1 of the GATT 1994

Article XI:1 of the GATT 1994 provides:

> *No prohibitions or restrictions other than duties, taxes or other charges, whether made effective through quotas, import or export licences or*

> *other measures, shall be instituted or maintained by any contracting party on the importation of any product of the territory of any other contracting party or on the exportation or sale for export of any product destined for the territory of any other contracting party.*

For the purposes of the present opinion, Article XI:1 has been interpreted as applying to any restrictions on importation imposed on products originating in any WTO Member. On the face of it, it would appear that the measure(s) in question would be in violation of Article XI:1 of the GATT 1994, as the result would almost certainly be a restriction on importation imposed on fossil fuels not meeting a certain GHG emission limits.

However, for the purposes of the present opinion Article XI:1 only applies to measures imposed "at the border", and not to "behind the border" measures, which are covered by Article III:4. Indeed, it appears likely that the envisaged measure(s) would apply regardless of whether the products are imported or domestically produced.

In the light of the above, it appears uncertain whether Article XI:1 would apply to the present situation. However, depending on how the measure(s) would be phrased, the obligation therein could be triggered. In that case, it is likely that the EU would be in violation of Article XI:1.

B.2.4. Article XX of the GATT 1994

Article XX of the GATT 1994 provides, in relevant part:

> *Subject to the requirement that such measures are not applied in a manner which would constitute a means of arbitrary or unjustifiable discrimination between countries where the same conditions prevail, or a disguised restriction on international trade, nothing in this Agreement shall be construed to prevent the adoption or enforcement by any contracting party of measures:*
>
> *(…)*
>
> *(b) necessary to protect human, animal or plant life or health;*
>
> *(…)*
>
> *(g) relating to the conservation of exhaustible natural resources if such measures are made effective in conjunction with restrictions on domestic production or consumption;*

The fact that a WTO Member may be in violation of certain substantive GATT 1994 provisions, does not necessarily imply that the Member will be in violation of its WTO obligations. Indeed, as mentioned above, there are certain provisions of the GATT which contain exceptions.

Article XX contains the "general" exceptions to the GATT. Two of these are generally referred to as the "environmental" exceptions, namely Article XX(b) and Article XX(g). Any measures having been found in violation of one of the substantive GATT 1994 obligations

falling within the ambit of one of the subparagraphs of Article XX, may nevertheless be found not to be in violation of WTO law. For that to be the case, however, they must also meet the conditions of the chapeau of Article XX (i.e. the introductory paragraph).

It appears evident that the exception in Article XX(b) is harder to meet than that in XX(g), as measures meeting the conditions of Article XX(b) must be necessary to protect human, animal or plant life or health. The "necessity" test has appeared to be a very high standard to meet. It seems unlikely that it can be successfully argued that the envisaged measure(s) would be necessary, i.e. close to indispensable, "to protect human, animal or plant life or health".

However, to meet the conditions of Article XX(g), a measure must merely be related to "to the conservation of exhaustible natural resources", which has appeared to be a far easier condition to meet. The crux here is:

- whether the measure is intended for the conservation of exhaustible natural resources; and
- whether the measure is made effective in conjunction with restrictions on domestic production or consumption.

The phrase "exhaustible natural resources" has been interpreted in an evolutionary fashion, and now includes such "resources" as clean air, turtles, tuna, etc. As mentioned above, today it is referred to as one of the "environmental" exceptions of the WTO. It therefore appears likely that the measure(s) at issue could be argued to be "related to the conservation of exhaustible natural resources", in light of the environmental objectives which are likely to be the main cause of the envisaged measure(s).

As explained above, however, any such measure(s) would have to be imposed on domestic as well as imported like products.

Having determined that the measure(s) may fall within the ambit of Article XX(g), the next step is to determine whether the measure(s) would meet the conditions of the chapeau of Article XX.

In essence, the *chapeau* ensures that only legitimate measures, which are not more trade restrictive than necessary, and which do not discriminate arbitrarily, which may be found to be in violation of substantive GATT 1994 obligations, are nevertheless not in violation of WTO Law. Here, what will be important is the actual implementation and effect of the measure in question. At this stage, it is therefore impossible to determine whether the measure(s) would meet the requirements of the chapeau, as this would depend on how it is framed and how it is implemented.

However, there is no reason why the measure(s) should not meet the conditions of the chapeau, and it is indeed not impossible or over-burdensome to meet those conditions.

B.3 The TBT Agreement

There appear to be three pertinent substantive provisions of the TBT Agreement that may be relevant to the present analysis:

- Annex 1.1;
- Article 2.1; and
- Article 2.2.

There are no exceptions to the substantive obligations contained in the TBT Agreement, unlike those found in the GATT 1994. However, the substantive provisions of the TBT Agreement have nevertheless been interpreted in such a way as not to fault measures which may have a disparate impact on imported like products originating in other WTO Members, but which are nevertheless based on a legitimate regulatory objective.

B.3.1 Annex 1.1 of the TBT Agreement

Annex 1.1 of the TBT Agreement defines a technical regulation:

> *Document which lays down product characteristics or their related processes and production methods, including the applicable administrative provisions, with which compliance is mandatory. It may also include or deal exclusively with terminology, symbols, packaging, marking or labelling requirements as they apply to a product, process or production method.*

Annex 1 is the threshold provision in order to determine whether the TBT Agreement applies. For the purpose of the present legal opinion, it appears that Annex 1.1 is the relevant provision, as it defines "technical regulation", which is mandatory. Annex 1.2 defines "standard", which is voluntary, and would not appear to be relevant for the present purposes as it is not envisaged that the measure(s) in question would be voluntary.

For the purposes of the present opinion, Annex 1.1 has been interpreted to apply to measures of WTO Members laying down "product characteristics or their related processes and production methods". It would not appear that the measure would impose any requirements as to the physical characteristics of fossil fuels. Rather, the measure(s) would appear to apply to the processes and production methods of the fossil fuels. Indeed, it would impose restrictions on fossil fuels based on the results of the lifecycle-analyses of the present study, the results of which vary depending on the sources, i.e. the processes and production methods.

It is however, to date, unclear whether Annex 1.1 covers any measure(s) governing processes and production methods of products, or exclusively those which have an impact on the physical characteristics of said products. As it would not appear that the envisaged measure(s) would govern any processes or production methods having an impact on the final physical characteristics of the fossil fuels, it is not clear whether said measure(s) would be covered by Annex 1.1 of the TBT Agreement. Consequently, it is currently not clear whether the substantive provisions of the TBT Agreement would apply, and this is a matter which would have to be settled by the WTO adjudicator in future disputes.

The present opinion will nevertheless analyze whether, should Annex 1.1 be interpreted in such a way as to cover the measure(s) at issue, said measure(s) would be in conformity with the substantive provisions of the TBT Agreement.

B.3.2 Article 2.1 of the TBT Agreement

Article 2.1 of the TBT Agreement provides:

> *Members shall ensure that in respect of technical regulations, products imported from the territory of any Member shall be accorded treatment no less favourable than that accorded to like products of national origin and to like products originating in any other country.*

The language of Article 2.1 of the TBT Agreement is similar to that of Article I:1 and III:4 of the GATT 1994. However, Article 2.1 of the TBT Agreement has been interpreted differently by the WTO adjudicator.

For the purpose of the present opinion, Article 2.1 has been interpreted in such a way that measures of one WTO Member may not accord less favorable treatment to products originating in WTO Members vis-à-vis like domestic products (NT) or like products originating in other WTO Members (MFN), unless if such less favorable treatment stems from a legitimate regulatory distinction.

As regards the measure(s) at issue, the like products analysis will again be the similar as that under Article I:1 and III:4 of the GATT 1994. It has also been established that it is likely that there will be less favorable treatment in respect of both the MFN and the NT obligations, as these are equally similar under Article 2.1 of the TBT Agreement. The crux of the issue here is whether the less favorable treatment stems from a legitimate regulatory distinction.

It would appear that the measure(s) would indeed be based on a legitimate regulatory distinction. Indeed, the distinction would be based on the differing GHG emissions of the fossil fuels in question. This, in turn, is a legitimate distinction which stems from a legitimate regulatory objective.

In the light of the above, it appears that the envisaged measure(s) would meet the conditions of Article 2.1 of the TBT Agreement and would consequently not be in violation thereof.

B.3.3 Article 2.2 of the TBT Agreement

Article 2.2 of the TBT Agreement provides:

> *Members shall ensure that technical regulations are not prepared, adopted or applied with a view to or with the effect of creating unnecessary obstacles to international trade. For this purpose, technical regulations shall not be more trade-restrictive than necessary to fulfil a legitimate objective, taking account of the risks non-fulfilment would create. Such legitimate objectives are, inter alia: national security requirements; the prevention of deceptive practices; protection of human health or safety, animal or plant life or health, or the environment. In assessing such risks, relevant elements of consideration*

> *are, inter alia: available scientific and technical information related processing technology or intended end-uses of products.*

The purpose of Article 2.2 is to ensure that technical regulations do not create unnecessary obstacles to international trade. In this respect, they should not be more trade restrictive than necessary to fulfil the legitimate regulatory objective in question. This necessity requirement does not appear to be as strict as the necessity requirement under Article XX(b) of the GATT 1994.

The crux of the issue here would be whether there are any other possible measures that could be less trade restrictive than the envisaged measure(s), while at the same time meeting the same objective.

Similarly to the analysis under the chapeau of Article XX of the GATT 1994, it is difficult to complete this analysis in the abstract. Much would depend on how the measure(s) in question would be phrased, as well as on their implementation. It would have to be shown that the measure is indeed the least trade restrictive option to fulfil the chosen legitimate regulatory objective.

It is important to note that the WTO does not impose any maximum or minimum level of protection on its Members. This means that any WTO Member, such as the EU, may chose its own level of protection, as long as it is objectively legitimate.

In the light of the above, similar to the situation under the chapeau of Article XX of the GATT 1994, there appears to be no reason why the measure(s) should not meet the conditions of Article 2.2 of the TBT Agreement, and it is indeed not impossible or over-burdensome to meet those conditions.

7.3.3 Concluding Remarks

In the light of the above, it appears clear that any possible measures adopted by the EU impacting the international trading conditions of fossil fuel as a result of restrictions being imposed on the basis of the present study, would have WTO implications.

The findings of the present legal opinion are that:

- there are likely to be substantive violations of the GATT 1994, in particular of:
  - Article I:1; and
  - Article III:4;
- any substantive violation may nevertheless be covered by one of the "environmental" general exceptions contained in Article XX of the GATT 1994;
- it is not clear whether the envisaged hypothetical measure(s) would fall under the TBT Agreement, as they may be considered as non-product related process and production method (npr-PPMs) in accordance to the relevant environment/trade terminology used.
- should they, however, be considered as falling under the TBT Agreement, they may or may not be found to be in violation thereof.

In sum, the crux of the issue would be whether the measure(s) at issue would be objectively justifiable, rather than arbitrary, and whether they would be the least trade restrictive option possible to fulfil the regulatory objective, i.e. to limit GHGs from the consumption of fossil fuels.

Indeed, with the right effort, there is no reason why such measures would not meet the EU's WTO obligations.

7.4 Formulation of the Questionnaire

In order to assess the impact of the methodology followed for the purpose of the present study, the project team in collaboration with the EC Project Officer has distributed a questionnaire to a great number of stakeholders concerned with the calculation of GHG emissions of transport fuels. The list of stakeholders concerned included organizations from the Oil and Gas sector, the Biofuels sector, research and consultancy on GHG emissions, Public Authorities related to the implementation and transposition of the relevant directives within Member States, etc. Wherever possible the questionnaire was addressed to specific persons while in other cases it was addressed to the organization.

The questionnaire was sent to not less than 300 people and it was redistributed and spread to a large number of stakeholders worldwide, thus being impossible to assess the number of people whom it reached. Finally, the project team received in total 114 replies.

The questionnaire starts with a short description of the study and its background and continues by providing the recipients with the necessary information on the objective of this questionnaire. The content of the questions addressed to stakeholders cover all aspects of the study, from calculation methods and actual data for GHG emissions for fossil fuels and biofuels, to further eventual policy formulation for the reporting of GHG emissions. More specifically, the Questionnaire is divided into 3 sets of questions covering the following topics:

1. Calculation of GHG emissions of biofuels and fossil fuels
2. Actual data for GHG for fossil fuels
3. Results of the Project

The questionnaire as sent to the stakeholders is presented in Annex G. The list of organizations represented by the respondents is presented in Annex F.

The responses have been treated in a confidential manner by the project team and the personal data of respondents will not be disclosed. A statistical analysis of the answers is presented in the following paragraphs. Apart from answering the questions, some of the respondents also addressed some additional comments and suggestions which will be discussed further on.

7.5 Results and statistics of completed Questionnaires

The respondents have been categorized into 6 distinguished categories of stakeholders:

- **Biofuels Industry**: Experts and officials representing the Biofuels sector, worldwide
- **Consumers**: Officials from large Consumers of fossil fuels, including automotive industries, airlines etc.
- **NGOs:** Experts involved in the area of energy and climate change issues
- **Oil and Gas Industry**: Stakeholders representing the fossil fuels industry, including Oil and Gas companies, refineries, distributors etc.
- **Public Authorities:** Officials from MS related to the implementation of FQD
- **Research-Technology-Consulting**: Experts on Biofuels, fossil fuels, GHG emissions etc. working in the research and/or consulting sectors.

The Number of questionnaires received by each category and in total is presented in Table 7-1. It is evident that the majority of responses are coming from the Biofuels Industry and the category of Research-Technology-Consulting.

Table 7-1 Responses to the Questionnaire by targeted category

Type of organization	Number of respondents
Biofuels Industry	39
Consumers	6
NGOs	3
Oil and Gas Industry	15
Public Authorities	13
Research-Technology-Consulting	38
TOTAL	**114**

In the following Sections the responses received will be analysed for each question of the Questionnaire.

7.5.1 Question 1.1

Question 1.1 investigated the satisfaction of the stakeholders on the way the GHG emissions of fossil fuel final products are presented (average singular points). In case the answer was negative then there were 5 options to be ticked as alternative to the existing one.

Question 1.1

Are you satisfied with the way the GHG emissions of fossil fuel final products are presented (average singular points)?

YES NO

If your answer is "NO" then how you recommend this compilation should be made?

a) Distinctive calculation of carbon intensities for each fuel stream in all phases of transformation and transportation from extraction up to the supply of final Consumers

b) Average carbon intensities based on geographical areas of fuels' origins

c) Average carbon intensities based on natural gas and crude oil technical characteristics (API, Sulphur, unconventional sources etc.)

d) Average carbon intensities based on combination of geographical and technical characteristics criteria

e) Other, please specify.

In Figure 7-1 the prevalence of negative answers to around 80% is presented. The distribution of these answers by category of stakeholder is presented in Figure 7-2. The two major groups of questionnaire respondents, namely Biofuels Industry and Research-Technology-Consulting, were unsatisfied stakeholders, whereas the Oil and Gas Industry declared its preference to the existing monitoring system. This result is reasonable and was expected given the specific interests of the biofuel and fossil fuel industries. The NGOs mostly followed the Biofuels Industry and Research-Technology-Consulting in their negation, whereas the Consumers and Public Authorities responses were shared to the two cases with small preference of "no" against "yes".

Figure 7-1 Question 1.1 - Distribution of answers for all respondents

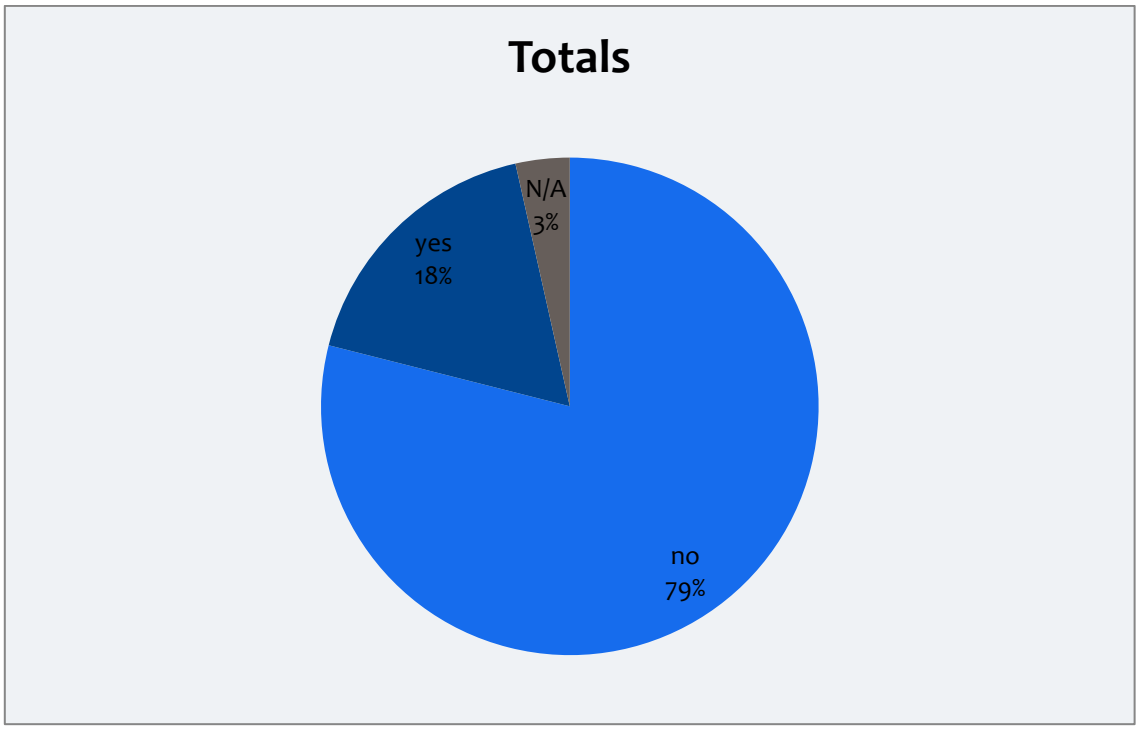
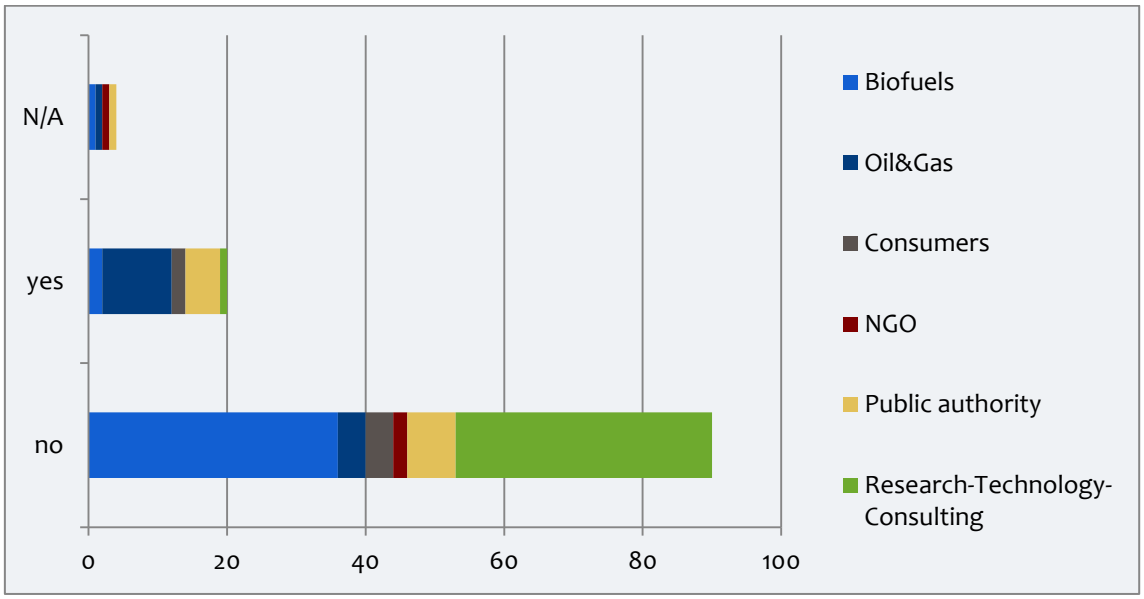
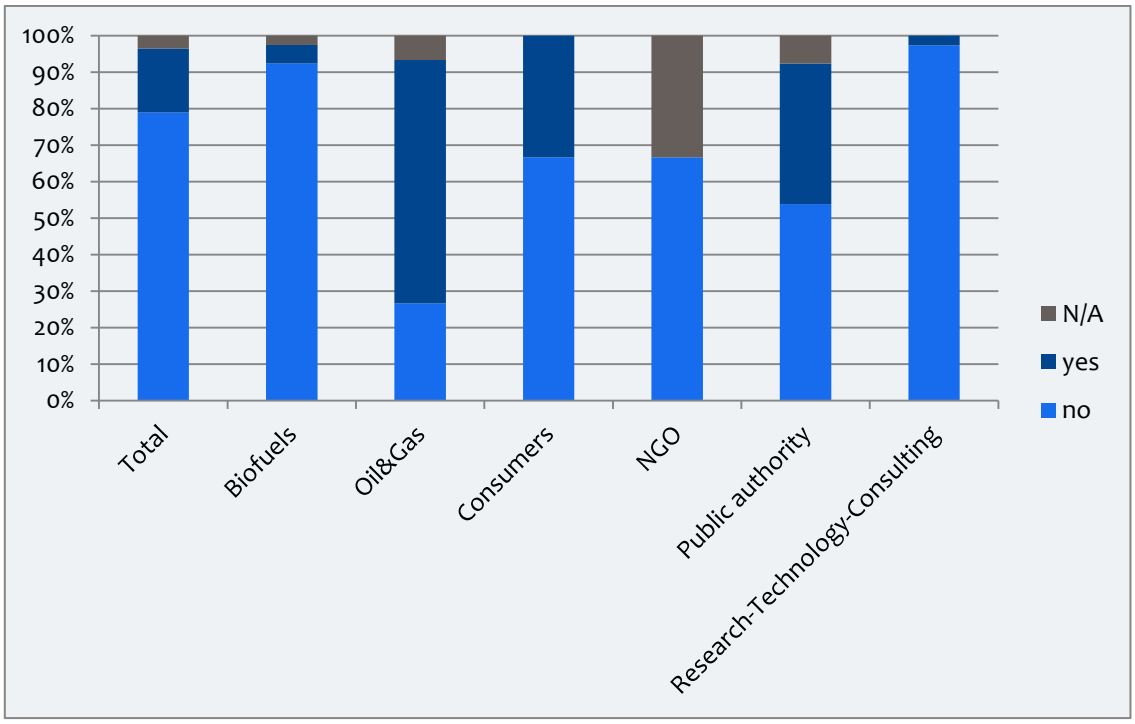


Figure 7-2 Question 1.1 - Number of questionnaire answers by reply and category of stakeholder117



In Figure 7-4 the percentages of yes, no and no answer are indicated for the six categories of stakeholders. The above mentioned remarks are confirmed.

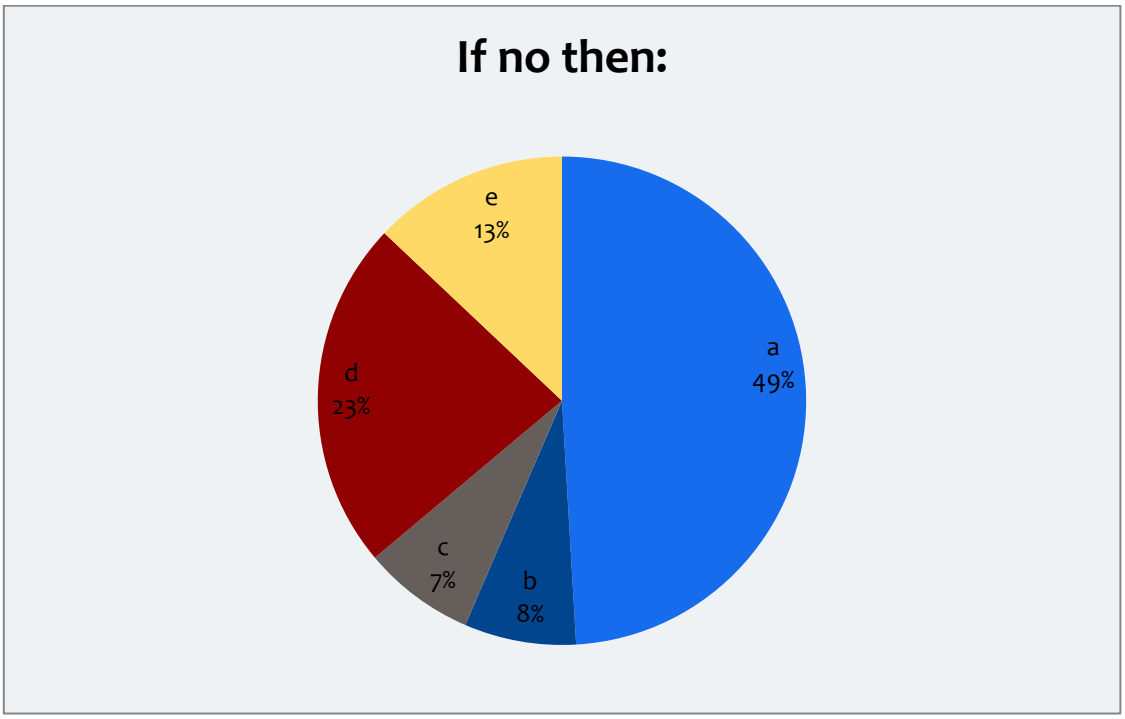
Figure 7-3 Question 1.1 - Distribution of answers by category of stakeholder



[117] N/A stands for "No Answer"

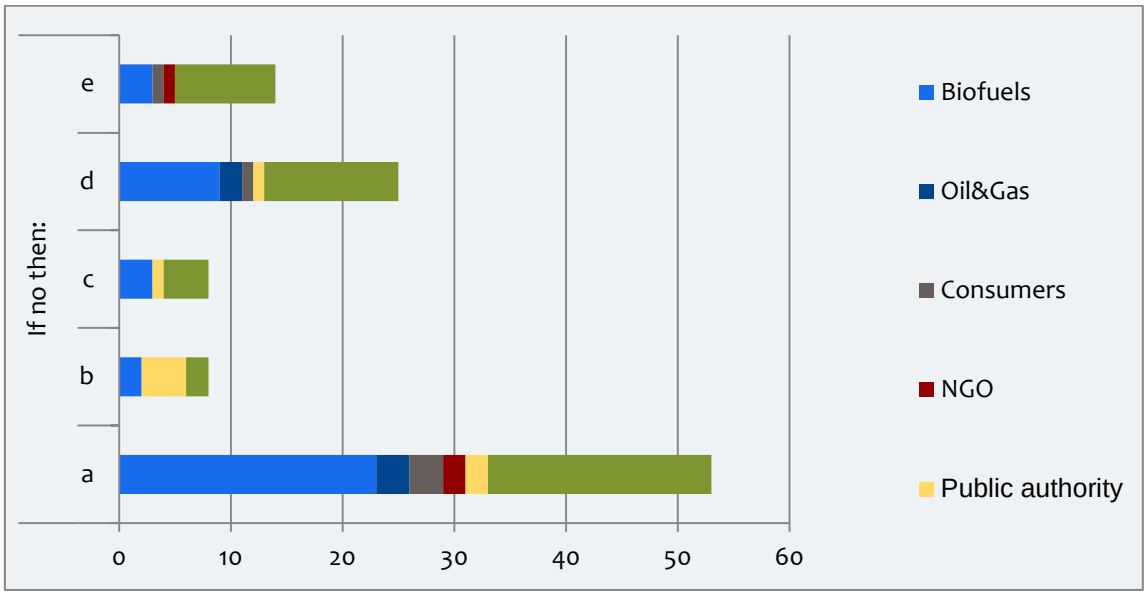
The distribution of negative answers to the five alternative ways (four proposed and one for respondent suggestion "other") for monitoring the GHG emissions is presented in Figure 7-4. The strong preference of the respondents, by half of the answers, was placed for the most disaggregated option a "distinctive calculation of CI", which actually is the fairer but at the same time the most difficult in implementation. The three types of "average calculation of CI" summed around 40% of the answers with a preference to option d, which indicates an approach similar to that one followed in the monitoring of biofuels for transparency purposes. The percentage of 13% suggesting other versions, further to those proposed in the questionnaire sounds interesting; however there were not so many innovative ideas expressed in the relevant comments requested in case option € was ticked.

Figure 7-4 Question 1.1 - Distribution of answers for all respondents



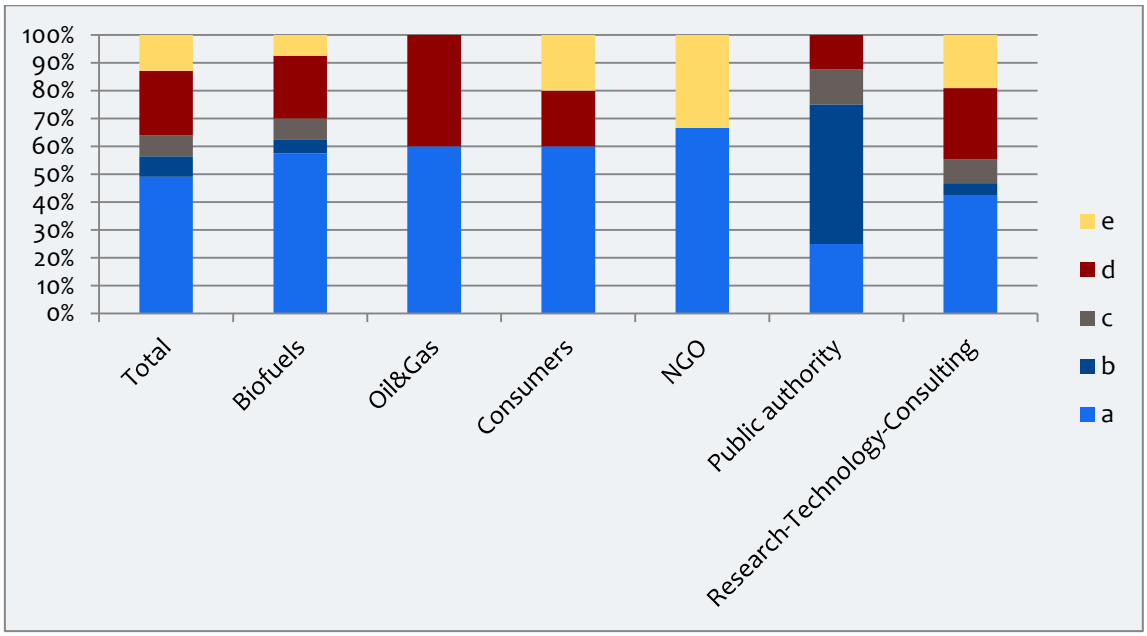
In Figure 7-5 the selections of the five options by each category of stakeholder is presented. The high percentages of the Biofuels Industry and Research-Technology-Consulting categories for option (a) is characteristic. Around similar percentages of these two categories are observed for option (d). These two options were also selected by the few respondents of the Oil and Gas Industry, who had opted for the negative reply. The selections of Public Authorities were spread to all proposed options and Consumers and NGOs favored option (a) in principle.

Figure 7-5 Question 1.1 - Number of answers by option for the 5 options and category of stakeholder



Finally the distribution of answers in percentages for the five options by each category of stakeholder is presented in Figure 7-6.

Figure 7-6 Question 1.1 - Distribution of answers in percentages for the 5 options by category of stakeholder



7.5.2 Comments on Question 1.1

The respondents had the possibility to comment on the proposed four options and suggest, according their opinion other ways for presentation and monitoring of the fossil fuel CI. The

most significant comments and statements of the stakeholders on the Question 1.1 of the Questionnaire are the following:

1. The CI calculation should be similar and equally transparent to what is followed with biofuels. The GHG emissions of fossil fuel final products should take into account the relevant geographical, technical, and other factors, to enable comparison to renewable fuels based on equivalent and transparent system boundaries. There should be no difference in the scope of CI calculations for renewable and fossil fuels. In addition, the verification requirements (certification etc.) for both types of fuels should be similar.
2. The way of treatment of GHG emissions of fossil fuels should be equivalent to the bio-based fuels. However, there is necessary to provide numerous values as reference for fossil fuels that, besides the need to be updated regularly (as regional markets can change quite rapidly), it is complicated and generates excessive burden. Therefore the focus could be placed on the control of CI of every pathway of fossil fuels (for penalties or just for accounting) in the same way that is made for bio-based fuels.
3. For transparency, surely the fossil fuel data should be compiled in the same way as with the biofuels data, i.e. a detailed analysis of complete value chains with maxima and minima and weighted average.
4. Ideally option (a) is preferable, as it is possible to do it for Biofuels also, but realistically option d could be implemented, under the condition of demonstrating best performance than the average.
5. It is needed to integrate the currently accounted (upstream) bio-component CO_2-emissions-saving contribution, by assessing and quantifying the potential additional emissions saving enabled at refinery fuel production operation level, as a result of the blending of the bio-component. Such additional saving, if confirmed and be significant, could then be allocated back to the bio-component to allow full valorization of the CO_2-emissions saving and its proper accounting in terms of FQD directive annexes and vs. the targets. While the effect in absolute terms (total refinery level) is anticipated to be minimal, the aim would be to assess it in terms of additional CO_2-emissions saving per unit of blended bio-component, which might instead be relevant.
6. Utilization of transparent and actual data originated from fuel streams is expected to encourage operators to publish their own detailed and traceable data - and as a consequence - improve their real CI performance in all stages, processes and fuel categories. The level of detail and the accuracy of calculations should be equal for fossil and bio streams. The monitoring mechanism should be able to make "visible" the environmental process improvements. Gas and oil shale should also be included.
7. Taking into account origins and technical characteristics of crude oil, to evaluate carbon intensities appears difficult, costly and will lead to a puzzle situation that is very difficult to manage and eventually creating uncertainty also for Biofuels producers, as they should evaluate GHG saving on regional basis and origin of fossil fuel they intend to displace. On the contrary, an average CI value for each type of

final fuel (petrol, diesel, CNG, LNG, etc.) would be simpler and able to compare individual Biofuels to the fossil fuel they are to replace (e.g. bioethanol vs petrol, biodiesel vs diesel, etc.).

8. Actually it should be better to first consider all present and future relevant fuels, their pathways, processes and transports. Second, to evaluate the individual well-to-tank emissions for each fuel pathway. Last, it should be good to be able to rate the environment impact via a reasonable average default value according to the relative proportions of each pathway; i.e. if LPG is sourced from natural gas and crude oil, it should be advisable to rate both pathways and use the average default value according to the weighted average.
9. The more disaggregation, the better, but there could be a progressive approach towards regulating the carbon intensity of fossil fuels. Default carbon intensity values could be a first attempt to present the various carbon intensities (with categories similar to the initial Commission FQD proposal from 2011 and possibilities to report actual values for high-carbon unconventional categories); if information is not available yet to have distinctive carbon intensities for each fuel stream from extraction to supply. But ultimately, the goal should be to have as much disaggregation as possible. Recently, the EU has adopted new reporting requirements from fuel suppliers. They will now report Market Crude Oil Names of the imported crude oil. This reporting could work as a basis, on the upstream side, to develop a range of different carbon intensities for each of these MCONs - quite similar to the system in place in California under the LCFS.
10. Averages can mislead and if they are used then the ranges and/or variances for these averages should also be reported. The calculation approach should be clearly stated and also the allocation basis and inventory basis.
11. Average singular points are easy in use and this is an advantage. However, they should be updated, as fossil fuels are produced in a more and more carbon intensive way.
12. The approach should be based on a complete lifecycle analysis (LCA), including also production and dismantling of facilities, and not only on well-to-tank.
13. The proposed options represent only attributional LCA approach to assessment of fossil fuel CI, while Biofuels are being de facto assessed through combination of attributional and consequential LCAs. For the purposes of policy discussion, it shall be defined what is the carbon footprint of marginal oil on the European market, and what are the indirect GHG emissions of oil. For the purposes of certification and day to day comparison, i.e. like in FQD process, the use of option (d) appears most adequate.
14. Regarding GHG emissions a subdivision into good (bio) and bad (fossil) is not suitable. The Lifecycle Analysis has to be considered and the most efficient supply chain irrespective of whether it is bio or fossil should be preferred.
15. The GHG emission estimate should be based on the marginal decrement of fossil fuels, as a biofuel displaces a relative low fraction. The best quality crudes, easiest to process and with refineries close to or with good logistics, will hold their market position when adding biofuels, whereas crudes with more costly extraction, processing and logistics are displaced first.

16. The JRC study calculates the CI for petrol and diesel based on LP modelling of a limited set of oil refinery configurations. The somewhat counter intuitive conclusion is that producing more petrol make refineries more efficient, which is true for an individual over diesel configured EU refinery. However, this approach does not reflect the global impact of petrol displacement. The EU approach should also consider the CI of different crude types.
17. The refining process has been optimized in the last 20 years under regional demand and technology criteria. Therefore it sounds reasonable to consider a representative location and technological configuration for each region in the globe in order to calculate and allocate the oil distillation GHG emissions. Particular attention needs to be given to tar oils from the US and Canada.

The above comments could be grouped in three main categories:

- Those ones arguing for **equal treatment of fossil fuels with bio fuels** in terms of calculating and reporting the CI and for this reason the preference of these stakeholders are for options (c) and (d).
- A group of stakeholders expresses either clearly the **preference to option (a)** of fully disaggregated monitoring of CI of Oil and Gas streams, as being the most transparent and fairer with prospects of better performance in reducing GHG emissions; or **the support to the options of average CI (b, c, d)** due to the difficulties in implementing option (a) in short term.
- A group suggesting and justifying **improvements in the existing and proposed methodology** and approach to be followed in fossil and bio fuels reporting and controlling the CI performance.

It is worth mentioning that the above mentioned comments are not coming only from stakeholders who ticked the option e "Other", as it was designed, but from stakeholders who have ticked any of the other options. Moreover, the main tendency of the comments by the biofuels industry is to stress transparency in the fuel market and the equal treatment of all, bio and fossil, fuels and then to suggest either the average CI options closer to the existing system for Biofuels under FQD, or advocate the need to follow option (a).

The comments coming from research and technology institutions were concentrated also to methodological and best approach issues which actually were not under the scope of this survey or even this project. Anyway some of these opinions and suggestions are very interesting and should be arisen in relevant discussions about the updating of FQD and the approach of CI identification of fuels.

Key Messages

- *The majority of stakeholders (79%) consider the present system or fossil fuels GHG presentation unsatisfactory.*
- *The majority of stakeholders have preference for a distinctive calculation of carbon intensities for each fuel stream in all phases of transformation and transportation*

7.5.3 Question 1.2

Question 1.2 concerned the addition of bio-methane in natural gas supplying the transpost sector and asked the opinion of respondents on whether the GHG emissions from bio-methane and natural gas should be included in the calculations. In case the answer was positive, then there were 4 options to be ticked as recommendations for the calculation of the emissions.

In Figure 7-7 the prevalence of positive answers with a percentage of 92% is presented. The distribution of these answers by category of stakeholder is presented in Figure 7-7. All categories of stakeholders support the positive answer.

Question 1.2

Recently bio-methane (either from upgraded biogas or produced synthetically from biomass) is added in natural gas pipelines that may supply CNG or LNG filling stations. Should information of GHG emissions from bio-methane and natural gas be included in the calculations of GHG emissions for transport fuels?

YES NO

If your answer is "YES" then how you recommend this compilation should be made?

a) Separate average carbon intensity for bio-methane and another separate average carbon intensity for natural gas

b) Average carbon intensity for natural gas, either in the form of pipeline gas or LNG, originating from geographical areas such as North Sea, Russia, Algeria, etc.

c) Include shale gas too based on geographical areas such as the USA

d) Other, Please specifies.

Figure 7-7 Question 1.2 - Distribution of answers for all respondents

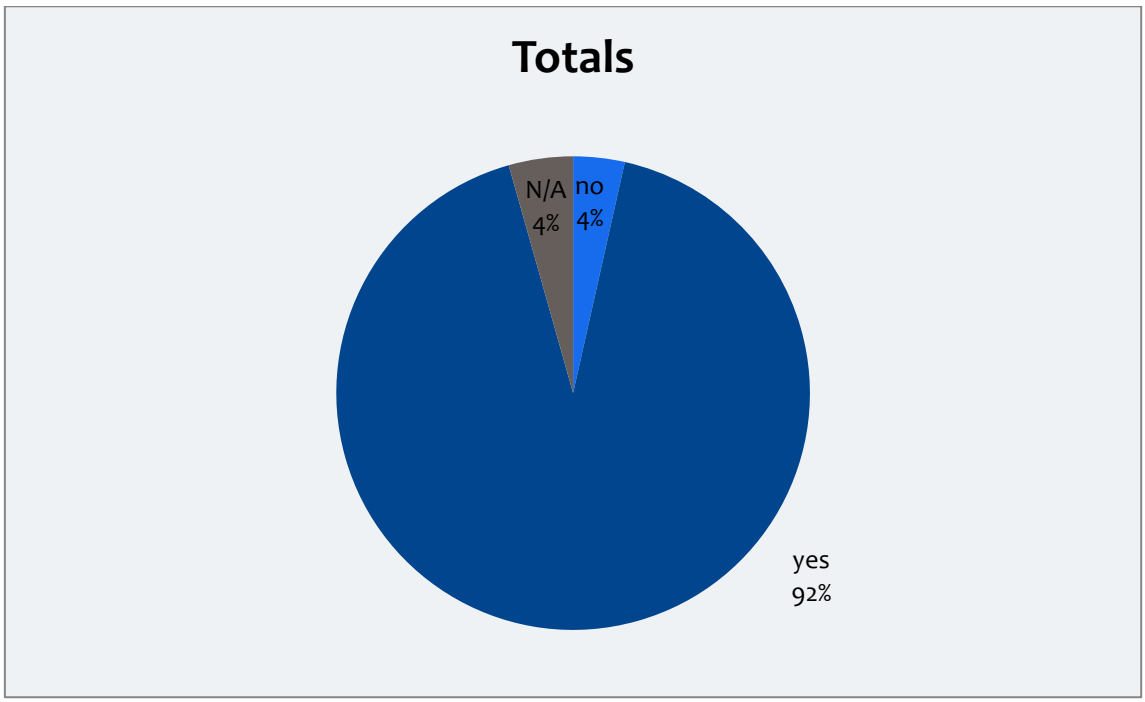


Figure 7-8 Question 1.2 - Number of answers by reply and category of stakeholder

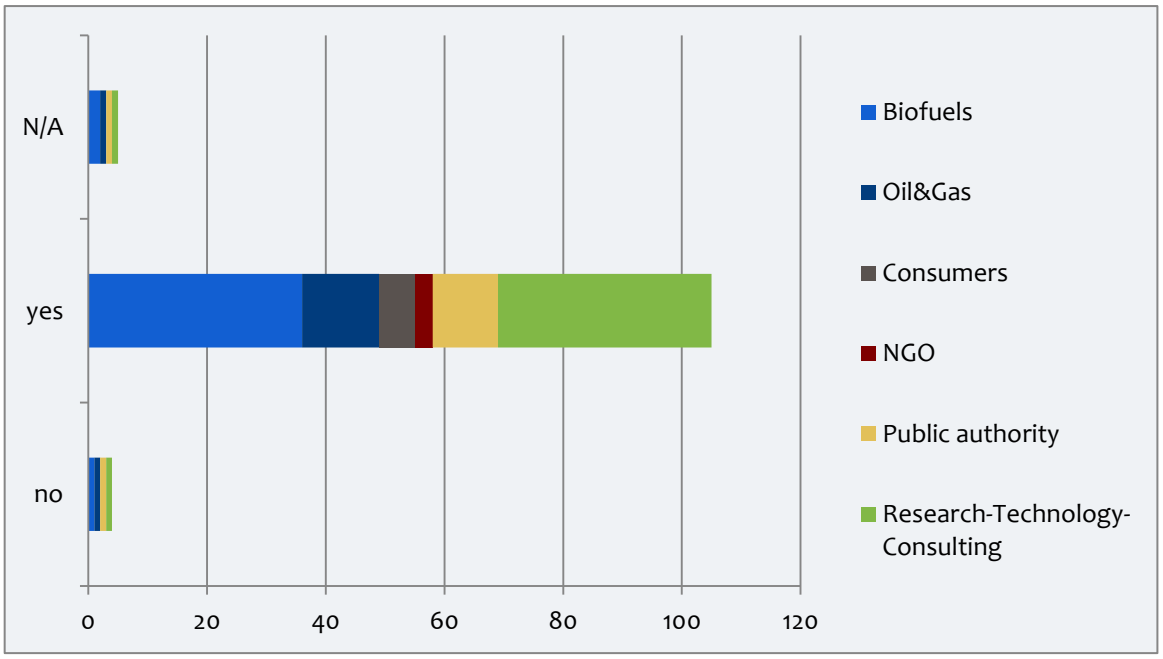
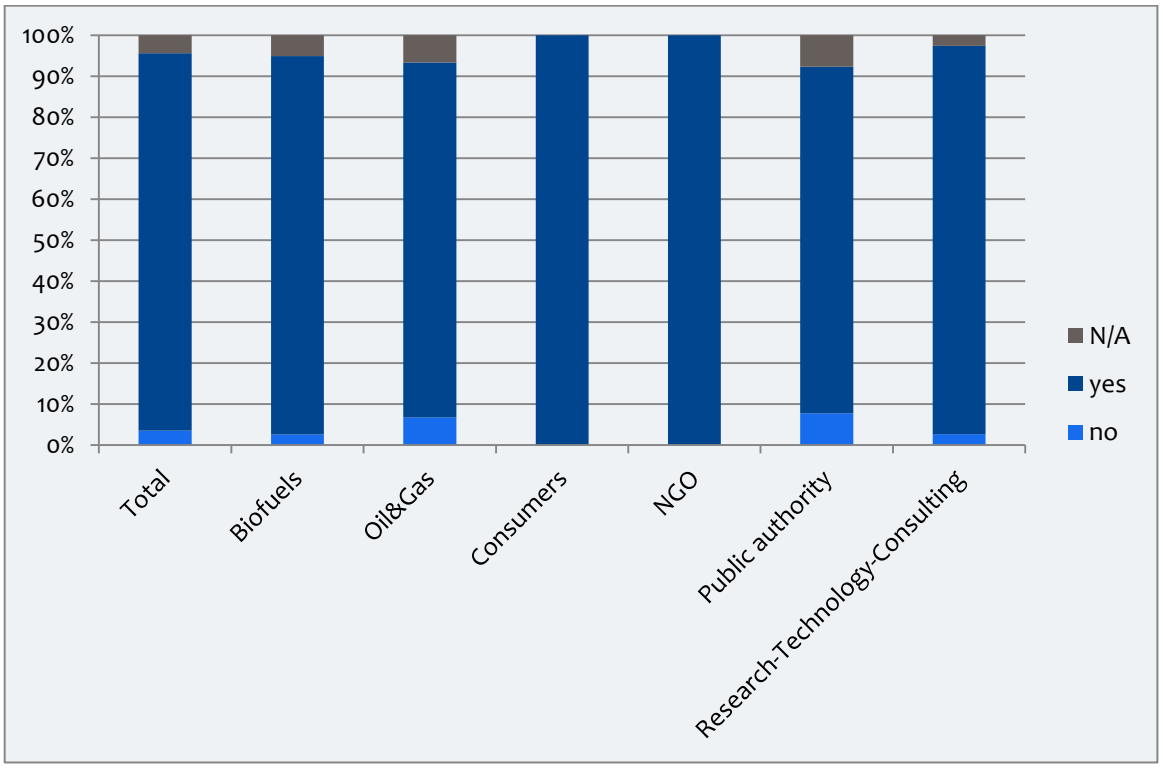


Figure 7-9 Question 1.2 - Distribution of answers in percentages by category of stakeholder



In Figure 7-9 the percentages of yes, no and no answer are indicated for the six categories of stakeholders. Although very small percentage answered that bio-methane and natural gas should not be included in the calculations, the strongest opposers were experts from the Oil & Gas industry and Public Authorities.

The distribution of positive answers to the four alternative ways (four proposed and one for respondent suggestion "other") for including bio-methane and natural gas in the calculations of GHG emissions in the transport sector is presented in Figure 7-10. At a percentage of 38% the respondents voted for option (a) "Separate average carbon intensity for bio-methane and another separate average carbon intensity for natural gas", while a large group of stakeholders chose option (d) "Other" and expressed their opinion in written. Their views on this matter are summarized further on. Figure 7-10 provides the number of times each option has been selected by each category of stakeholders. Finally the distribution of answers in percentages for the five options by each category of stakeholder is presented in Figure 7-10.

Figure 7-10 Question 1.2 - Distribution of answers for all respondents

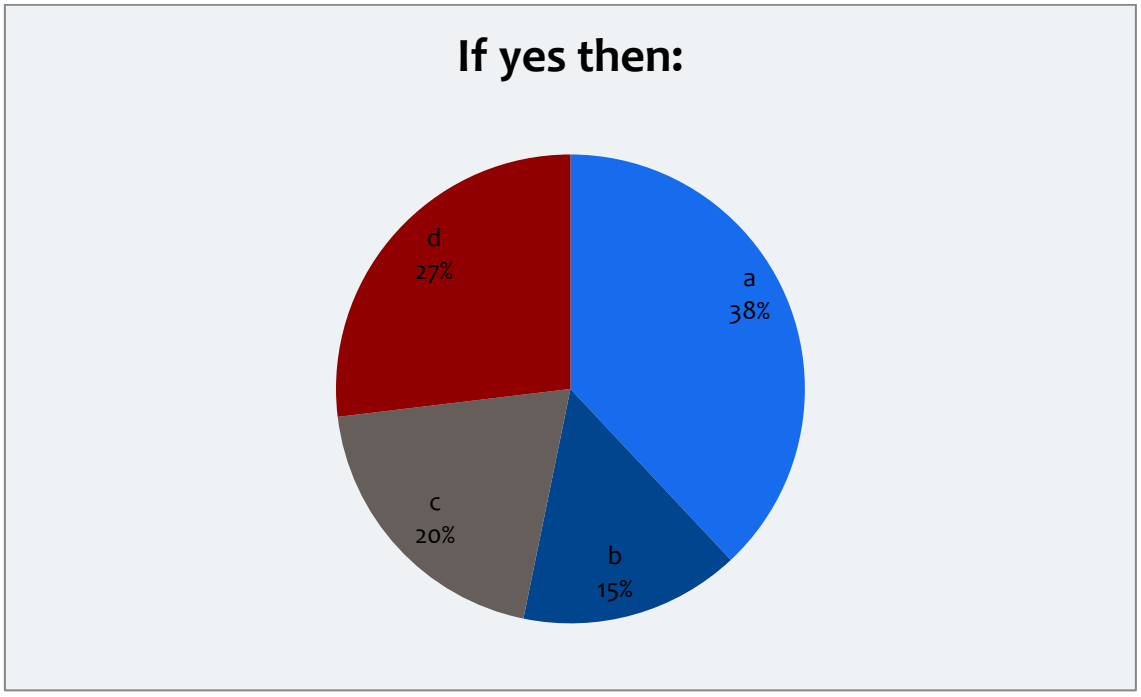


Figure 7-11 Question 1.2 - Number of answers by option for the 4 options and category of stakeholder

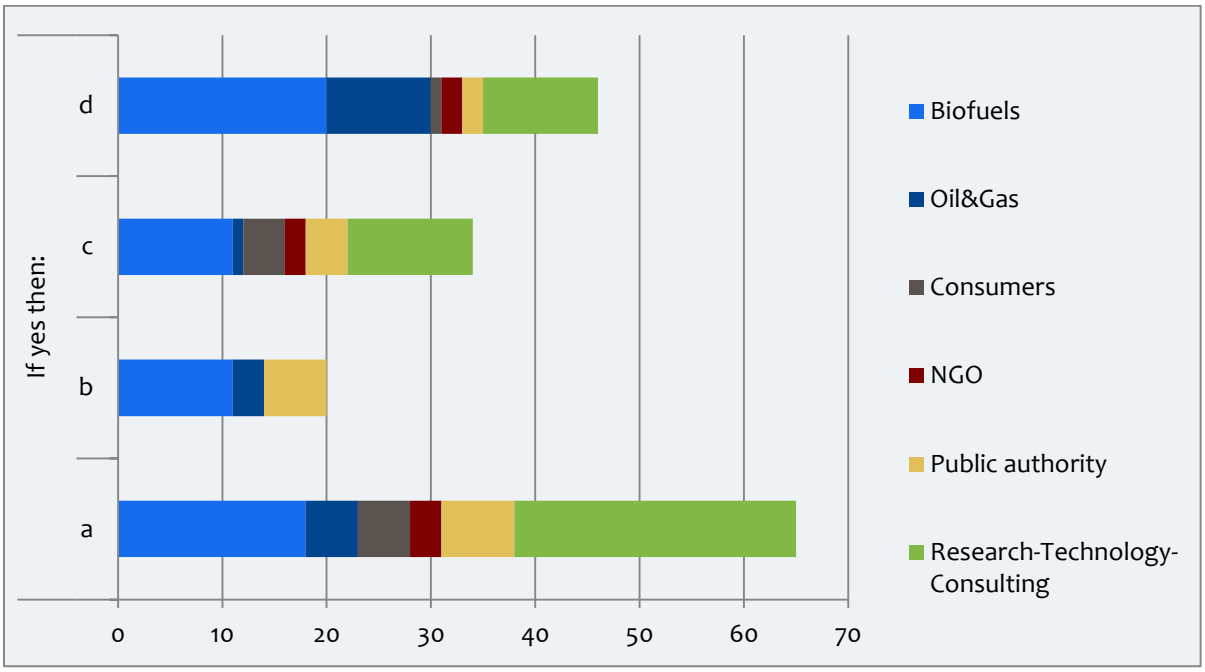
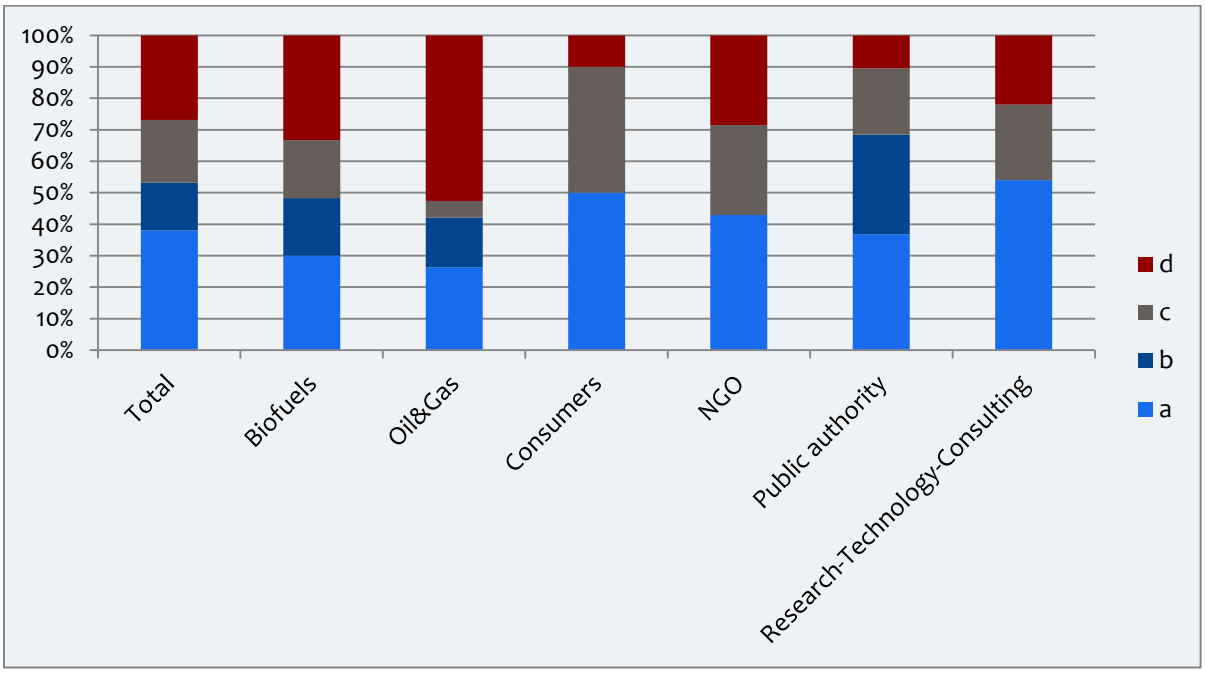


Figure 7-12 Question 1.2 - Distribution of answers in percentages for the 4 options by category of stakeholder



7.5.4 Comments on Question 1.2

The respondents had the possibility to comment on the proposed four options (a, b, c, d) and express their opinion on potential ways for presentation and monitoring of the natural

gas and bio-methane CI directed to transport. The most significant comments and statements of the stakeholders on the Question 2.1 of the Questionnaire are the following:

1. The calculation should reflect the reality but minor contribution could be overlooked (for example if a fuel represent less than 5% of the total). For gas, oil, bio-methane; etc. the calculation should be based on LCA analysis like for biofuels. With regard to natural gas, which is also a potential FQD compliance pathway, there is a case to allow/require reporting more disaggregated than a single value.
2. All transport fuels should be regulated in terms of their greenhouse gas emissions consistently and equally (a level playing field) whether they are bio-based or of fossil origin. The procedure to obtain the CI information should be the same for all the fuels, regardless if they come from fossil or biological origin.
3. Similar to the response to question 1.1, the GHG calculation should take into account the relevant geographical, technical, and other factors in a transparent way, to enable comparison between fuels from renewable and fossil sources. The GHG values of the products should be calculated based on equivalent system boundaries, incorporating potential 'indirect effects', including (but not limited to) ILUC.
4. Use the average carbon intensity for the mixture bio-methane and natural gas at the EU level, based on the EU-quantities of bio-methane and natural gas used in transport.
5. Calculate an average GHG intensity for LNG and CNG on the European market taking into account the CI of the different sources of gas (North Sea, Russia, Algeria, shale gas from USA) and including bio-methane added to the gas grid.
6. The "average" carbon intensity for natural gas in option (a) should be based on the "average" composition of the natural gas, based on geographic considerations.
7. There is a great deal of debate on shale gas emissions; the methane leakage from shale gas should be included, as well as cocktail effects on gases such as methane with aerosols.
8. Calculations should be done for various fuel categories/streams based on actual data. Direct CO2-emission factor for bio-methane ("use-phase") is zero, according to the biogenic origin of carbon and RED, Annex V, C13. However embodied /indirect emissions of bio-methane should be included, depending on the supply chain details and technology. Emissions from natural gas should be included, based on actual data and also in cases where natural gas is a hydrogen source.
9. In addition to 100% bio-methane and 100% fossil natural gas, it should be possible to consider blends of both (i.e. natural gas with x% bio-methane) and estimate the GHG emissions of a given blend. Also add liquefied bio-methane (liquefied at production site, distributed at LNG stations). Existing production sites in the UK and Sweden as well as expected technology improvements by 2020 in order to estimate future GHG emissions should be considered. Similarly, liquefied bio-methane is often blended with fossil LNG.
10. Bio-methane can be used for the production of bio-hydrogen, which is part of the fuel (diesel, petrol). GHG emissions from bio-hydrogen should be estimated on both a bio-methane and hydrogen generation unit basis.

11. The overall supply chain is related to multiple product outputs; the question is what is the share of a specific product compared to another and how the emissions are split into these multiple product outputs. This is also a question of "calculation" and it is referred in the ISO 14040/14044 as allocation. The separation/allocation could be based on mass, energy content, energy prizes etc. Therefore it is essential to include GHG + other emissions in the overall supply chain analysis.
12. Forecast calculations/assumptions should be made for 2020, 2030, 2050 expected fuel mixtures with increased percentages of bio-methane and progressive reduction of depleting or more polluting fossil sources.

The above comments could be grouped in three main categories:

- Those ones arguing for equal treatment of fossil fuels with bio fuels and also between gaseous and liquid fuels in terms of calculating and reporting the CI.
- A group of stakeholders expresses either clearly the **preference to option (a)** of fully disaggregated monitoring of CI of natural gas and bio-methane streams, as being the most transparent and fairer with prospects of better performance in reducing GHG emissions; or **the support to option (b) of average CI** due to the difficulties in implementing option a in short term and the need to follow similar approach as in liquid fuels.
- The major group of respondents suggests and justifies small or major **improvements in the existing and proposed methodology** and approach to be followed in reporting the CI performance.

It is worth mentioning that the above mentioned comments are not coming only from stakeholders who ticked the option (d) "Other", as it was designed, but from stakeholders who have ticked any of the other options. Moreover, the main tendency of the comments by the Biofuels industry is to stress the equal treatment and distinctive reporting of bio and fossil gas, whereas the Oil and Gas industry favors the average CI option.

The comments coming from research and technology institutions were concentrated in principle to methodological and best approach issues, most of which were not under the scope of this survey or even of this project. Anyway some of these opinions and suggestions are very interesting, like the idea of considering blending of bio and fossil gas, and should be arisen in relevant discussions about the updating of FQD and the approach of CI identification of gaseous fuels for transport.

Key Messages

- *The majority of stakeholders (92%) are of the opinion that the GHG emissions from bio-methane and natural gas should be included in the calculations of GHG emissions for transport fuels.*
- *The majority of stakeholders have preference for dedicated average carbon intensity for bio-methane and another separate average carbon intensity for natural gas.*

7.5.5 Question 2.1

Part 2 of the questionnaire starts with a statement: "*In general oil and natural gas companies do not disclose information on actual GHG emissions from the various operations and almost always decline to provide such information if they are asked to do so. The Commission has advised in the project's Invitation to Tender, that in case the consultant is not able to obtain actual data of GHG emissions on the production of oil and natural gas directly from the oil and natural gas companies, to use available simulation models to estimate such emissions.*"

Question 2.1

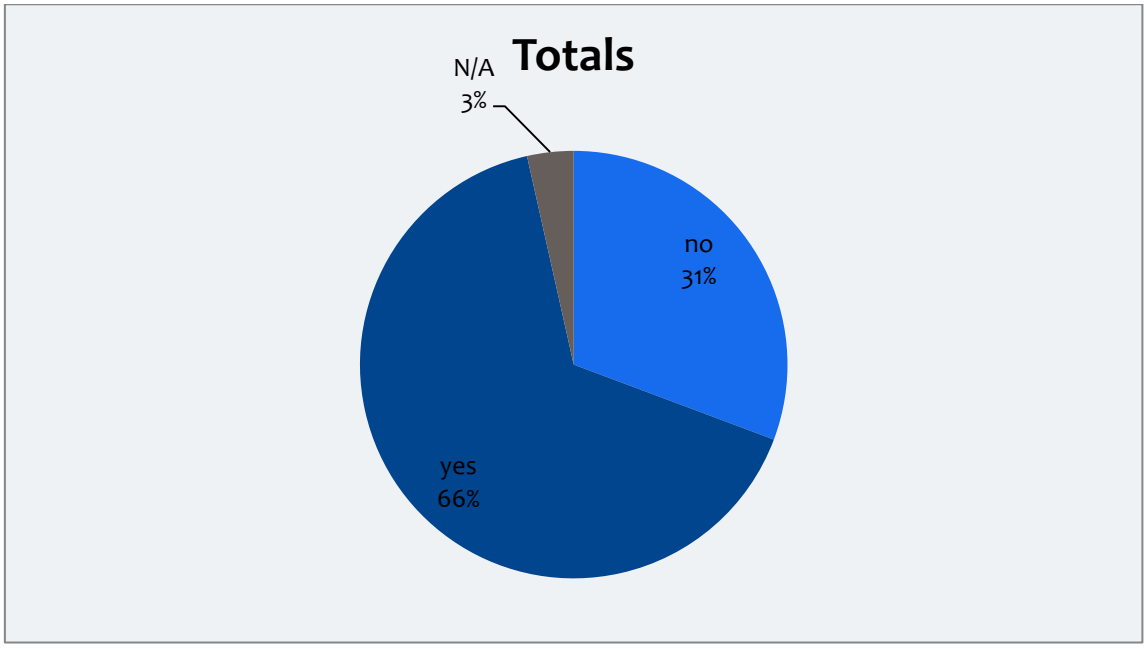
In case the oil and natural gas companies do not provide information on actual GHG emissions from their operations do you agree with the Commission's advice?

YES NO

Following the above statement, the respondents are invited to answer to a set of questions that will reflect their view on this issue. Question 2.1 investigates the view of stakeholders on the Commission's advice to the Consultant, i.e. whether they agree with the use of models to estimate GHG emissions in the case that Oil and Gas companies do not disclose such data.

The distribution of answers to this question by all stakeholders is presented in Figure 7-13.

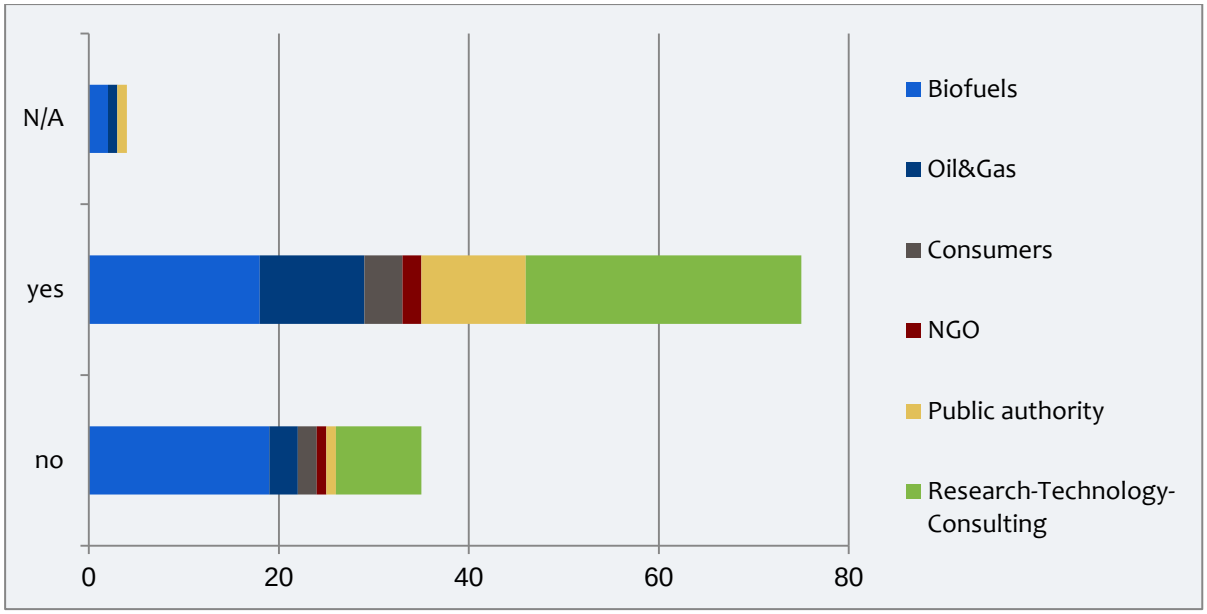
Figure 7-13 Question 2.1 - Distribution of answers for all respondents



As seen in the pie chart above, 2 out of 3 respondents agree with the use of models for GHG emissions estimation. From Figure 7-14 and Figure 7-15 it is obvious that the Biofuels industry is divided between the "yes" and "no" answers, whereas the Oil & Gas industry, as well as the Public Authorities are generally strong supporters of the option of modelling

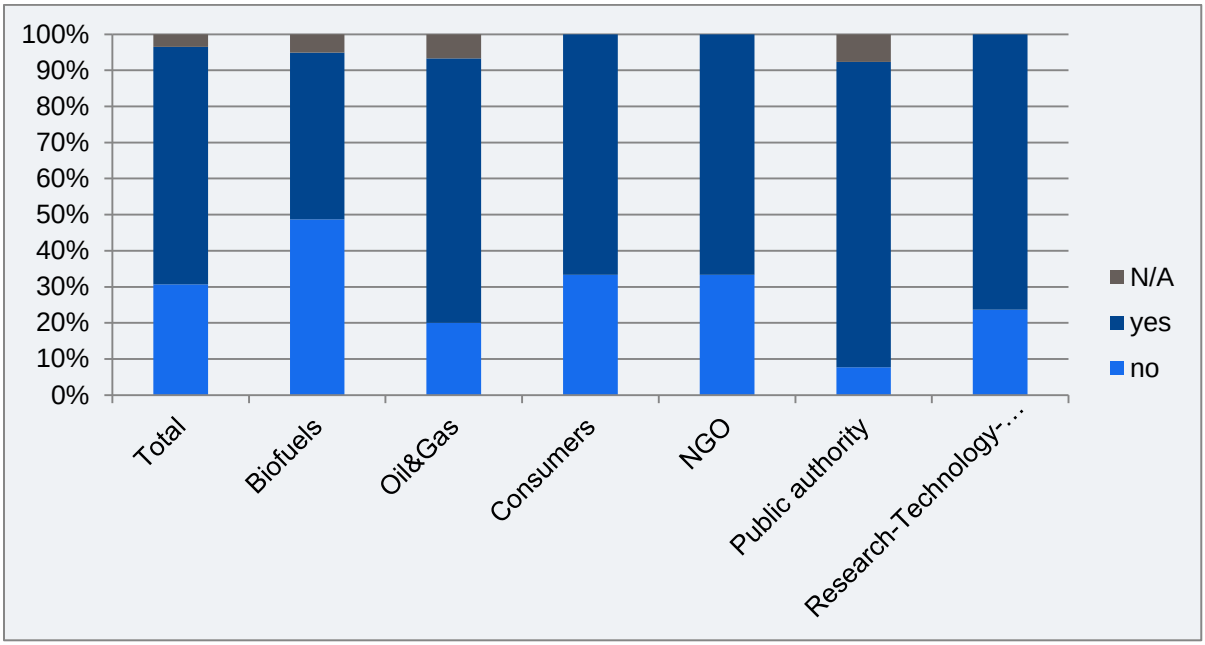
GHG emissions whenever actual data are not available. In addition, 3 out of 4 experts from the Research – Technology – Consulting sector agree with the use of models

Figure 7-14 Question 2.1 - Number of answers by reply and category of stakeholder



In the following sections the answers of stakeholders to Questions 2.1.1 to 2.1.4, which gave the stakeholders the opportunity to express their opinions in free text, are analyzed thoroughly.

Figure 7-15 Question 2.1 - Distribution of answers in percentages by category of stakeholder



7.5.6 Question 2.1.1

The respondents had the possibility to comment on Question 2.1 and select one of the two proposed options (yes, no). In this section we present the comments and opinions in the case of option "No", that is due to unavailability of actual data for CI of fossil fuel directed to transport, the Commission advises to use available simulation models and the respondent disagrees with this advice. The most significant comments and statements of the stakeholders on the Question 2.1.1 of the Questionnaire are the following:

Question 2.1.1
If your answer is "NO" do you have any other advice? Please specify.

1. In the short term yes (use models), as there is no alternative, although results are not reliable. In the medium-term no, as actual information based on a harmonized calculation methodology should become mandatory to get a more reliable picture, and to create incentives for improvement.
2. "Available simulation models", as they stand, may not be sufficiently up to date or detailed enough to pick up accurately these issues. The suggestion is therefore that available models suitably adapted should be used.
3. Simulation shall only be based on independent and scientific consultant agency (e.g. JRC) and based on most recent available data.
4. The models that the European Commission uses are not reliable, current models do not correspond to the actual values. We have seen from the ILUC debate that modelling science is immature, a fact even acknowledged by the Commission, and accepting modelling of fossil fuels will only lead to the same mistakes currently experienced with ILUC. We therefore strongly disagree with the use of simulation models to estimate such emissions. The oil industry should be bound to provide such information.
5. All transport fuel should be regulated in terms of the greenhouse gas emissions consistently and equally (a level playing field). Biofuels and bio liquids can only obtain market access through government obligations and these obligations require independently audited, lifecycle greenhouse gas emissions declarations, as prescribed in the sustainability criteria RED and FQD. If the fossil fuel industries are unwilling to provide the same information why are its fuel products considered sustainable and allowed into the single market by legislators, but the same renewable products are effectively barred? And why should they be counted towards the 6% greenhouse reduction requirement when bio products that fail to provide such information cannot?
6. For a proper 'level playing field' analysis one should not accept that for the Biofuels sector it is compulsory to provide data, and for the fossil fuel industry it is not. Regulations need to be set to make this happen. By allowing simulation models the opportunity is missed to get actual insights. For the longer term objectives (all road maps towards 2050) stress that we need to develop towards a low-carbon economy, including low-carbon intense fuels. The more accurate the understanding on actual performance is, the better policies can steer to achieving the targets. We have seen in the ILUC-developments that the outcomes of one model will always be debated by opposite-result providing other.

7. 'Hard legislation' appears to be the sensible way forward: fossil fuel GHG intensity should be reported, based on full LCA, as is the case for Biofuels. The legislation (FQD) should oblige this GHG reporting the same way the RED and FQD oblige the independent verification and certification of the GHG profile of Biofuels for them to account towards the RED and FQD targets.
8. Probably most oil and natural gas companies are able to produce empirical/real data. If not, they could also oblige their subcontractors in supply chain to give needed information (biofuel producers are already subjected to add requirements to their procurement contracts). If Oil and Gas companies do not monitor their data on a reliable way, they simply cannot present reliable traceable real/actual GHG-emission information to their customers (via product declarations) or authorities. It is not recommended that this kind of severe "missing or hidden data -problem" is fixed by means of model estimates in general (and parameters extrapolated e.g. from other "controlled" contexts). Instead data disclosure policy, programs and regulation should be developed to ensure "level playing field" also regarding "monitoring and reporting burden". In some cases conservative defaults (which do not underestimate emissions) could be utilized e.g. including some kind of penalty factor, see principle e.g. in Decision 601/2012 of 21 June 2012, Annex VIII, 5. Substituting missing data: the equation Substitute=arithmetic mean of known cases + 2 x standard deviation of the same data.
9. The oil & gas companies should be steeply taxed for their carbon emissions, and if they decline to provide data for them, they should be taxed at triple the rate estimated by simulation models. If we keep screwing around with weak carbon penalties, we not only fail to do any good, we run the risk of appearing to do good and therefore reducing public concern when there is nothing to justify such reduction.
10. Because of Art. 7a of the FQD fossil fuel suppliers are obliged to provide data on their actual GHG emissions since 2011. These provisions should be implemented in a way that fossil fuel companies need to provide this data.
11. Direct measurement through remote sensing and other measurement protocols should be used to determine actual GHG. The technology is available and relatively inexpensive. It should be used.
12. Available simulation models cannot be considered sufficient. Oil and natural gas companies should be obliged to provide such information to the Commission (or consultant) under non-disclosure agreement. Confidential information would only be used in the calculations and not disclosed in the report. Among other things, methane losses in the natural gas transport process should be re-evaluated.
13. Sufficient data is available from oil & gas companies to be provided to the consultant with no extra cost for such companies. Not providing data can be seen as non-transparent practice and should not be accepted by the Commission. Oil & gas companies supplying fuels to EU should be obliged to disclose GHG emissions from lifecycle of their products to the Commission under non-disclosure agreement. Some interviewed people do not understand how a simulation model should be able to generate the data needed. Moreover, in the U.S. there is information available regarding GHG emissions from all kinds of oil and gas industry operation. These data

should be explored first. It should be also advisable to consider that in most countries environmental risk studies have to be handed over to authorities before licenses to erect new production sites are granted. These publications are frequently public and provide good insights. Available simulation models cannot be considered sufficient. Confidential information would only be used in the calculations and not disclosed in the report.

14. Demand for origin and GHG calculations should be mandatory in order to get import permissions to EU. The alternative is a high GHG default value, set for the "worst case scenario" based on the actual type of fossil fuel and above mentioned calculations.
15. Simulation tools can be efficient, or not, depending on many parameters and on the accuracy of the reference data taken from real life. Today, we have doubts on the validity of these reference data. Thus, we need actual data from the field. Oil companies operating on the European territory claim their support to European clean policies. This is the very starting point for them to demonstrate their commitment: to allow field measurements of their GHG emissions.
16. Companies should be obliged to disclose the requested information for following reasons: (1) In general all transport fuels should be equally treated. Therefore, it should be stimulated that actual GHG emissions are disclosed, despite their origin. (2) The current modelling by the European Commission does not correspond with reality and it could be beneficial to oil and natural gas companies to not disclose the requested information.
17. At least a limited set of actual data should be made available to be used as a base for simulation models and estimation in order to ensure robustness and reliability of results possibly covering also leakages and fugitive emissions.

The above comments could be grouped in three main categories:

- A few respondents arguing for **equal treatment of fossil fuels with bio fuels** in terms of transparency and availability of detailed CI data.
- A small group of stakeholders expresses the **preference to the option of model use** in case fully disaggregated data of CI of fossil fuel streams are not available by Oil and Gas companies. However, most of the respondents argue about the reliability of the models used by the Commission.
- The major group of respondents suggests and justifies **the need for use of actual data** and relevant approaches to be followed in reporting the CI performance for immediate implementation.

It is worth mentioning that the above mentioned comments are coming only from stakeholders who ticked the option "No", as it was designed. Moreover, the main tendency of the comments by the Biofuels industry is to establish transparency and a system of availing actual data for fossil fuels, whereas the Oil and Gas industry expressed its support to the JRC modelling approach.

Key Messages

- *The major group of respondents agreed with the Commission's recommended position to use mathematical models although their accuracy and reliability can be questioned.*
- *For the other, the majority suggested and strongly justified the need for use of actual data and relevant approaches to be followed in reporting the CI performance for immediate implementation via legislation.*

7.5.7 Question 2.1.2

Question 2.1.2

If your answer is "YES" would you consider the results of the model reliable since there is sufficient published information in various sources?

The respondents had the possibility to comment on the Question 2.1 and select one of the two proposed options (yes, no). In this section we present the comments and opinions on the case of option "Yes" that is due to unavailability of actual data for CI of fossil fuel directed to transport, the Commission advises to use of available simulation models and the respondent agrees with this advice. The most significant comments and statements of the stakeholders on the Question 2.1.2 of the Questionnaire are the following:

1. Variations are expected due to regional and technical differences; the uncertainty should be calculated also.
2. Default values that are conservative enough are required (it means high emissions) in order to push oil companies to react.
3. Models might be used under the following conditions: a) the results obtained should be presented as a range defined by the model uncertainty; b) clearly state what assumptions have been taken in the models for simulations.
4. As long as variations in feedstock quality and processing requirements is reflected in the model results. A model that is too simple or attempts to be too comprehensive will not be rigorous enough.
5. The reliability of model results is dependent on the quantity and quality of data available to populate them. Using model results is appropriate in the absence of actual measurement, and can be useful to confirm/support reported results. It is important, however, to understand that system boundaries for modeled systems and measured systems are not always identical, and thus caution should be exercised if attempting to combine such results, especially if the measurements serve a different original purpose. Stanford have shown that it is generally possible to get useful improvement in CI estimates by using models with even a relatively small amount of data, but there will always be cases in which using a given data subset will be misleading.
6. It is the best you can do. The default values should be conservative which gives the sector an incentive to provide actual values. In other words: provided that you use the worst case scenario, avoiding benefiting companies that haven't helped providing information. Providing information should be incentivized.

7. Simulation models could be used as long as they go deep into details of the various multiple kinds of extraction sources/origin and supply chain patterns in order to be as accurate as possible. Such models should also be developed in coordination with Biofuels and biogas producers in order not to depend only on fossil fuels operators.
8. If there are sufficient sources of published information, modeling approach could be the first approach with understandable limitations to applicability of country/region level data. If this modeling approach is not sufficient for regulatory purposes refinery/oil company level certification of GHG emissions should be considered (as case for Biofuels already today) to reach better comparison for fossil vs bio.
9. The reliability of a model may always be improved. Some available published information sources are more reliable than others. However, overall, a good model, based on most accurate data available will provide the opportunity for data comparison whilst overcoming certain, possible inconsistencies in data reporting.
10. The Commission should use transparent, peer reviewed models that incorporate the best available, peer reviewed data. The Commission should take a similar approach to that used in the RED whereby conservative (high) default values were presented and the industry given the opportunity to provide their own data to recalculate (and potentially change) the value used to reflect actual GHG emissions. The approaches used in modelling, determination of acceptable data consistency, and establishing system boundaries for the GHG analysis should be equivalent for all energy options being considered.
11. The results need to be peer-reviewed and compared to similar studies that have already been conducted, for example in the context of FQD article 7a, on the carbon intensity of fossil fuels.
12. On-going efforts are required to validate / verify / refine the accuracy of the models. If required, governments must undertake whatever is required in terms of research or policy to get sufficient disclosure of data to occur such that meaningful validation of models can be performed. And this needs to be on-going, as the technologies and locations being examined continue to vary over time.
13. Models are less reliable because of the data on the processing, but also since sourcing of feedstocks varies over time, the refinery processing in terms of products slate (diesel, petrol, jet fuel, aromatics, fuel oil, chemicals) vary with season and the market. Therefore there is a limit in how reliable any model or historical data can be used over an extended period in the future.
14. In the absence of measured data, simulation models are the next best option for estimating such emissions. Models that have been validated with field data, if available, are recommended.
15. Agreement, provided that the simulation tools used are fit for purpose, based on scientifically sound assumptions, widely accepted, peer reviewed and transparent. Since simulation tools have only a predictive character, their results should only be used to determine averages.
16. The simulation models need to be based on sound scientifically assumptions, widely accepted and peer reviewed. Moreover their results should only be used to determine averages.

17. We support the model to determine default averages as long as it is drawn up on the basis of a plausible scientific approach that is accepted by stakeholders.
18. As an alternative option, this fallback solution should be used and considered as "reliable by convention" and in the absence of other data. For reporting purposes and to indicate managerial impact from end users, emission values should be split between their Well-to-Tank (production related) and Tank-to-Wheel (combustion related) emissions.
19. Engineering contractors usually have solid data available on conversion technologies. The greatest uncertainty and variability lies in upstream emissions.
20. There is relevant basic information available from raw oil to final fuels, maybe it is possible to convince some refineries that Case Studies are made on them. Generally the oil business has a very good developed system for benchmarks, e.g. energy consumption, that are good starting point for modelling.
21. Only Oil Companies have the real data, and I see very unlikely they will provide these. Nevertheless, they have to decide to comment on simulation results. The critical point will therefore become to verify their statements.
22. The important point is that the procedure for producers from fossil and biogenic sources should be comparable. If oil and natural gas companies do not provide information on actual data, the average values to be used should be calculated according to a "conservative" approach which might result in values above results from actual calculations. This is more important than a 100% perfect inventory data or a 100% reliable results (the default values for Biofuels are not very reliable either).
23. In the absence of real data, you are left with the models. But in the absence of data, models can't be verified, thus giving a wide range of results. This is correct, for the purposes of the policies, as if the range is much higher than actual emissions, and that sets the policy decision, oil companies should be incentivized to start providing real data. For certification purposes, the certification benchmark needs to be set at the lower range (as best practice) for the FQD type regulation (i.e. where savings along fuel supply chain are fostered). This is not the case currently, giving fossil fuel companies to hide information and then come up with "great" results.
24. The results of such models are reliable if the information they are based on is also reliable and broadly approved or used, like National or International inventories or approved studies, like the JRC study used for the Biofuels.
25. With experiences from using a "normal" value handling with reports supported by RED, we can see that after three years the companies started to use real values more often, because the normal values are conservative.

The above comments could be grouped in three main categories:

- Most of the respondents concentrated on **the reliability and the combination of characteristics of the models,** namely of transparency, technical evolution and uncertainty, under consideration. The main commenters under this point of view are coming from research institutions and consultants.

- A smaller group of stakeholders expresses the clear **preference to the option of model use** and in most of these cases the model of JRC was considered. Most of these answers come from the Oil and Gas industry.
- The third group of respondents focus on **the need for use of actual data** and stresses the requirements of a model providing reliable results to be based on reliable input data as a precondition to use such a model. The relevant replies come from all categories of stakeholders.

It is worth mentioning that the above mentioned comments are coming only from stakeholders who ticked the option "Yes", as it was designed for Question 2.1. Moreover, the main tendency of the comments by most commenters is to establish a system based on actual data for fossil fuels, whereas the use of models seems as a necessary tool when such data are not available.

Key Messages

- *In the absence of measured data, simulation models are the next best option for estimating such emissions. Models that have been validated with field data, if available, are recommended.*
- *It is recommended in general that the procedures for producers from fossil and biogenic sources should be comparable. If oil and natural gas companies do not provide information on actual data, the average values to be used should be calculate according to a "conservative" approach.*

7.5.8 Question 2.1.3

Question 2.1.3
Do you have any recommendation on how the reliability of the results of the models could be improved?

The respondents had the possibility to comment on the Question 2.1.3 about strengthening the reliability of the results of the models used for CI calculation. The most significant comments and statements of the stakeholders on the Question 2.1.3 of the Questionnaire are the following:

1. The preferred approach should be to generate industry references for each region. This will make the models more reliable.
2. Set up audits to main emission plants/operations and finance a Horizon 2020 study with researchers/consultants.
3. Use appropriate thermodynamic models for petrol, oil and natural gas. Rely as much as possible on experimental for physic-chemical properties of substances, especially for oil pseudo-components. Carefully model energy consumption of process units. Build a “model simulation” based on a process with all data available, in order to refine simulation process. Once ensure that the process is correct, model simulation can be used to predict data of unknown processes.
4. Oil and natural gas companies do disclose actual GHG emissions. They are included in the IOGP annual environmental performance indicator, and European Oil and Gas

producers are reporting actual GHG emissions through the EU ETS. In addition the production volumes for a large number of installations in Europe are made public.

5. Much of the data required to model oil extraction reflects physical properties of oil fields. While the oil industry is exceedingly hostile to disclosure of proprietary data, many of the data points of interest are often made available out of hand in academic articles, or published in incomplete datasets by consultancies. This suggests that the sensitivity of much of this data is in fact limited, and that a more comprehensive oil field data reporting requirement could be appropriate.
6. Only by reviewing the models and feeding them based on actual data.
7. Validation by field measurements taken over a range of conditions and technologies are preferred.
8. Oil & gas companies should be required to monitor & report actual values as a condition of being able to sell their oil & gas into the relevant jurisdiction.
9. Models such as OPGEE are a good start. Actual GHG emissions are often inconsistent with the system boundaries of the JRC study. "Actual" emissions typically include the scope of the inventory for the fuel producer and not the upstream emissions. An effort should be made to compare model results to "actual" emissions. A side by side comparison of a model result and actual oil and gas field should be compared to calibrate the model and identify areas of uncertainty.
10. Create a universal methodology for estimating GHG emissions in refineries at the EU level.
11. The reliability and accuracy of result of models can be improved through a commitment to transparency of the model itself, the values and sources of data used within the model, and the equations used to run the model. The models must be open to periodic review and improvement carried out through structured review sessions that both: 1) give the fuels suppliers (both fossil and renewable) stability on the CI values for a specified duration; and 2) ensure that the best available data is transparently incorporated into the model.
12. The models should be based on the most reliable scientific data and its reliability should be assessed by an independent international council of scientists established for this purpose. The model should reflect the worst case scenario with transparent calculation methods and data used in the calculation. The calculation should be verified by third party specialized in the field.
13. Tracking systems are already on the market. Through such systems the European Commission could track the GHG emissions as total or even from each process of specific production chains. These systems provide all the information regarding production chains; tracking processes from the origination till the end. Only by recording and assessing individual links in the production chain on a case by case examination, can models be improved. Also the consortium evaluating the models is so far one-sided, since it includes only car and oil industry with Commission's JRC. It should be opened to all stakeholders (biofuels, agriculture, etc.).
14. The choice of data and assumptions used as inputs should be clearly explained. The user of the model should be able to change the inputs if needed.

15. Using an approach of three strategies in data collection by combining a top-down model from national statistics and ETS reports with bottom-up model using available information from e.g. the IPPC Refinery BREF, refinery sustainability reports etc. and case studies of refinery systems and as the third element compare such data with refinery models.

The above comments include relevant recommendations, which could be summarized in following statements:

- **Actual data** should be the main input for CI estimation models and this way they support the reliability of the models to be used.
- The well-known methods of **model certification, monitoring and results verification** should be used transparently and under a management scheme with stakeholders' supervision.

The EU initiatives in using reliable modelling tools is interlinked with the overall approach in **information declarations and tracking on GHG emissions** at all the stages of fuel supply to final consumer of transport sector.

It is worth mentioning that the above mentioned comments are coming from all categories of stakeholders. Although there are coordinated replies from certain categories of stakeholders, it is worth mentioning also that many good ideas are coming from independent institutions and experts.

Key Messages

- *Oil & gas companies should be required to monitor & report actual values as a condition of being able to sell their oil & gas into the relevant jurisdiction.*
- *Only by recording and assessing individual links in the production chain on a case by case examination, can models be improved.*

7.5.9 Question 2.1.4

Question 2.1.4

The estimates of Oil and Gas carbon intensity could be expressed in terms of weighted average and min, max values in order to cope with uncertainty factors. Do you consider that this approach contributes to sufficient and reliable results?

The respondents had the possibility to comment on the Question 2.1.4 i.e. on the expression of CI results in terms of weighted average and min, max values. The most significant comments and statements of the stakeholders on the Question 2.1.4 of the Questionnaire are the following:

1. If geographical values and information on technology are used to provide a context to these values, then they would make them understandable.
2. The use of a range is a possible way of addressing uncertainty in the determination of Oil and Gas CI. Additionally the mix of feed stocks used, should also be considered

so that the final range of the average value is a reflection of the uncertainty of the components and their fraction in the mix. This uncertainty can, for example, be used to address statistical meaningful trends in variation of the averages.

3. Using averages and max /min in a range is a good way to handle uncertainty in a simulation. Both average and lower and upper bound range are meaningful. It helps to bound the range of uncertainty much better than single numbers will.
4. The question isn't clear - are we talking about single field results, average results, both, or something in between? Adding min and max estimates on average values, or quartiles, or confidence intervals etc. is fine, but in itself does not necessarily have any impact on implementation of policy, especially if the central value is still the only value with regulatory relevance. An understanding of uncertainty is much more important in policy design and policy assessment than in the text of the policy itself.
5. The value of such estimates depends on the accuracy of the weighting methodology and the degree of uncertainty; however this appears to be a practical approach.
6. The Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) - should be used as examples or benchmarks. It is good to express the results in terms of weighted average, min and max values. However the study should also provide detailed GHG information for each specific fuel when available. This should help ensuring coherency and transparency of GHG emissions calculations.
7. The problem will be that model estimates will be given statistical validity, when they are in fact estimates. An uncertainty analysis should be based on a tool such as a Monte Carlo simulation with a basis for the inputs. Weighting of known resource mix with guessed uncertainty does not improve the uncertainty.
8. We would recommend using the maximum values to give estimations of carbon intensities. This would give an incentive towards disclosure of more information by Oil and Gas companies.
9. The use of 'weighted average and min, max values' can be incorporated for each combination of geographical and technical characteristics criteria supplied by fossil fuel producers. There should be recognition that different fuel sources and production processes will have varying GHG results. The use of a single weighted average value for each finished fossil fuel product (e.g., diesel, petrol) must be avoided. A single value will erode any incentive to improve the GHG performance of the fuels along the entire supply chain.
10. LOSU could be added also, the level of reliability as well; a high range could be reliable not necessarily the sign of poor reliability.
11. The estimates of Oil and Gas carbon intensity can be expressed in terms of weighted average and min, max values, only if defined values are agreed by stakeholders and not by models.
12. Such measures are in themselves an evidence of the difficulties in establishing reliable data, but give an indication of the reliability. This is good, as it gives a better understanding of the difficulties in addressing carbon intensity issues. But if this approach is selected, how the uncertainty band would be reflected in the estimates and in comparisons must be clearly addressed, as otherwise the vested interest would refer to either of the extremes, depending on the cause being argued.

13. One could even consider when he is in the role of a consumer, to have only the weighted average value. For general understanding, the expression of average, minimum and maximum values is suitable. For use of the result, there should be a strong recommendation to use the weighted average factors in absence of better data to avoid "tuning" of factors by deliberately choosing minimum or maximum values depending on the purpose.
14. Carbon intensities can widely vary amongst the different fuels (coal, natural gas, oil) and fuel characteristics, as well as amongst the geographical sites and sizes of the reserves. Weighted average numbers and min, max values will enable meaningful comparisons across each fuel stream. They could also enable comparisons amongst fossil fuels and biofuels performances.
15. It could be a possibility on the bandwidth of results and given values, but it does not solve the aforementioned problem (see 2.1.2). Therefore the possible solution could be 2.1.3 (as mentioned) plus having min/max values or to identify the level of uncertainty. Only having min/max values omit the information on the distribution of values within min/max. It would be more accurate having e.g. an 80% range than exaggerating single min/max values too much.
16. The same approach as in RED is useful. To present a conservative "norm" value possible to use for each quality of crude oil, in case a LCA haven't been done, is a useful methodology.
17. It is necessary but not sufficient. Further discrimination based on feedstock quality, logistics, and processing severity would be valuable.
18. There would be no impact from the min/max values.
19. The range of carbon intensities of oil, gas and feedstocks should be considered only to revise each two - three years the estimation of the average default value for diesel and petrol.
20. This approach would be a reasonable compromise. However, the public is easily confused when presented with statistical scenarios. Adding confusion to the topic of climate change is not helpful.
21. Instead of min & max values we would recommend the use of 95% confidence interval to eliminate "outliers". Most of the primary data elements could be presented this way (mean, +-X% referring to 95% confidence interval). Also relatively simple formulas exist, which make it possible to apply this kind of "interval data" in simple arithmetic emission calculations to generate uncertainty range for results. This method is analogous with EU-ETS requirements, see REGULATION (EU) No 601/2012, article 3(6) and additional guidance[118] The average value is the only solution because of the lack of methodology for the calculation of GHG emissions at the refinery breakdown into products.

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1. [118] http://ec.europa.eu/clima/policies/ets/monitoring/documentation_en.htm: 11/10/2012 - Guidance document No. 4 - Uncertainty Assessment + GD No. 4a - Exemplar Uncertainty Assessment.

22. This is the worst option in terms of reliability and decision making. The best option is to have commonly accepted "scientific-based" average figures which are regularly updated (e.g. every 3 to 4 years).

Most of the above comments favor the weighted average, min, max approach, since uncertainty and variability issues of CI calculations could be treated. The technical issue mentioned is related to the regulatory issue of average or not value of CI as well. In this case there are negative recommendations in using this approach; however this is the minority of responses sent.

Moreover, the above mentioned comments come from all categories of stakeholders and in many cases there are coordinated replies from certain categories of stakeholders.

Key Messages

- *The weighted average value appears to be the most reliable tool for communicating the results to a wide spectrum of stakeholders.*
- *It appears that the same approach as in RED would be useful to use by presenting a conservative "norm" value possible to use for each quality of crude oil, in case a full LCA hasn't been done.*

7.5.10 Question 2.2

Question 2.2

Do you consider that tracking key GHG emissions data along the supply chain of Oil and Gas is a justifiable new cost for the Oil and Gas companies and operators?

YES NO

Are you able to provide an estimation about this additional cost for the suppliers? Please specify.

Following the suggestions of stakeholders on modelling the CI of fossil fuels, they are asked whether they find the cost for tracking GHG emissions along the supply chain for Oil and Gas justifiable. The distribution of positive and negative answers is shown in Figure 7-16. The majority of stakeholders consider that the extra cost for monitoring GHG emissions throughout the whole supply chain is indeed justifiable. As expected, the Biofuels industry experts were, in their vast majority, advocates of this position, while the Oil and Gas industry is of the opinion that this cost is not defensible. On the other hand, Public Authorities and Consumers of fuels seem rather divided on this issue, while the Research – Technology – Consulting sector and NGOs are in general supporters of the "yes" answer. These results are depicted clearly in Figure 7-17 and Figure 7-18.

Figure 7-16 Question 2.2 - Distribution of answers for all respondents

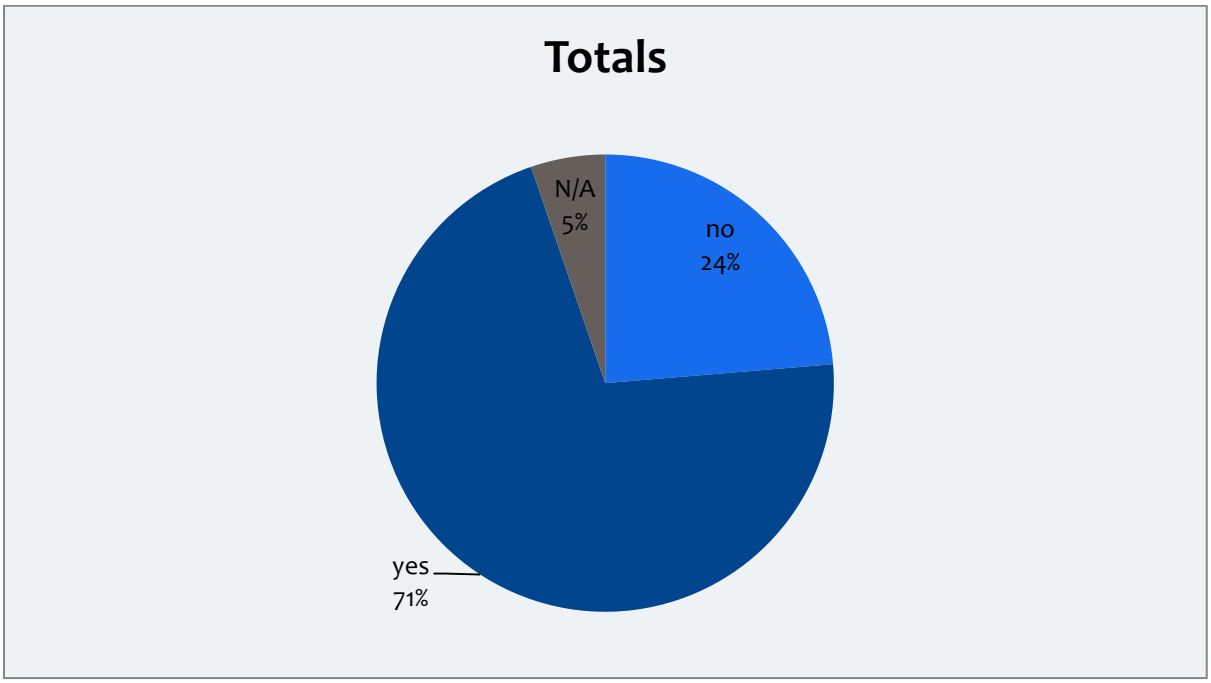


Figure 7-17 Question 2.2 - Number of answers by reply and category of stakeholder

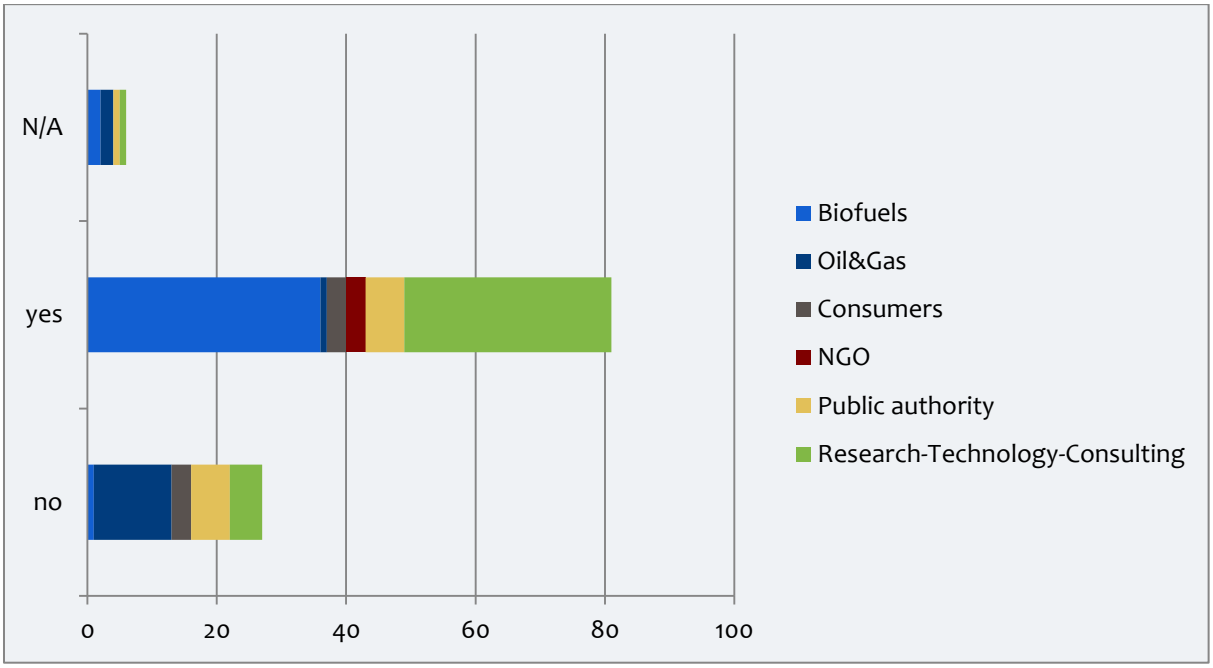
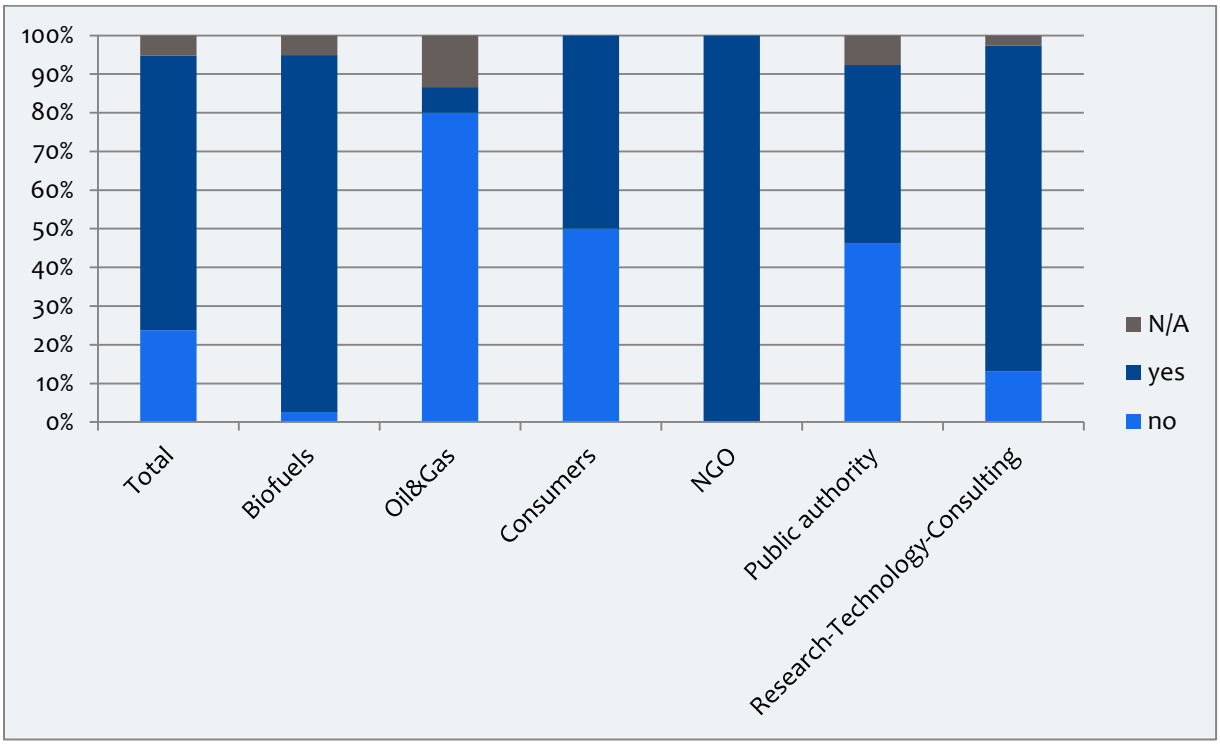


Figure 7-18 Question 2.2 - Distribution of answers in percentages by category of stakeholder



7.5.11 Comments on Question 2.2

The respondents had the possibility to comment on the Question 2.2 and select one of the two proposed options (yes, no). In this section we present the comments and opinions accompanying both selections and concentrating on the estimation of additional cost for tracking the CI of fossil fuel directed to transport. The most significant comments and statements of the stakeholders on the Question 2.2 of the Questionnaire are the following:

1. The cost depends on the way these emissions are calculated (overall study or detailed verification for every batch of oil). In Europe we have built a tremendous know-how on that kind of GHG evaluation and we can find compromise to keep cost acceptable.
2. It is hard to provide an estimate of these costs given the fact that they vary according to each specific supply chain.
3. The Oil and Gas industry, as with all large modern businesses, routinely handles vast amounts of information. For data that is already known at the oilfield, passing it along the chain of custody should be utterly trivial with modern technology. Auditing those data may be more expensive, potentially much more expensive depending on regulatory and depth of checks required, but given the volumes of material typically in transit the cost should still be negligible by comparison to the value of the oil/gas being audited.

4. Experience has shown that there is lot of resistance in the beginning and some costs but once established costs are not high and provision of actual verified information becomes common practice.
5. It is important to be able to know - with some accuracy - the GHG intensity of oils and gas provided. Probably this can be done without the Oil and Gas companies providing data other than source, transport distance and/or chemical composition (API, Sulphur). Total GHG emissions are determined by models using the data such as source, transport distance and chemical composition.
6. The upstream of oil & gas operations is one of the most profitable businesses in the world, and technology has made it much less risky than it was in decades past. With the risks now quite modest, there is no justification for excessive profits for successful projects. These suppliers are easily able to afford the necessary tracking & reporting. Where it affects their bottom line, as in the case of natural gas custody transfer, supplier manage to track things with exquisite precision, and I see no reason they cannot do the same with GHG emissions.
7. As it is required for biofuel production already. It should be possible for fossil fuel production as well.
8. Unable to provide guidelines on costing, but they should start with their mass and energy balances of their operations. It will be impossible to track them analytically. Cost will hence be limited and already covered by what these companies are supposed to do.
9. Max 1 cent per ton of fuel. Take a refinery of 10M ton output/year. A really expensive certification to track GHG emissions will cost 100,000 euro/year (more likely 20,000 but anyway). The unit cost is 100k/10M ton = 1 cent/ton.
10. The current situation where monitoring expenses and bureaucratic burden is laid only for Biofuels can be considered unjustifiable. It is not known why gas and oil companies couldn't collect similar data. In addition, strict monitoring systems are already installed to refinery processes (inside the EU-ETS). These companies also have several other useful information systems supporting real and traceable data-acquirement, processing and final calculations. "Level playing field" should be achieved in the near future as quickly as possible.
11. Existing environmental reporting requirements e.g. in Norwegian oil sector provide already majority of the required data for GHG emissions calculations and could be used as basis for new reporting methodology. Taking into account the financial strength of the sector, cost of reporting cannot be seen as prohibitive.
12. This cost is justifiable. The magnitude of this cost would be negligible as the information would be extracted from existing information channels that are used in the fossil fuel supply chain. Oil and Gas companies are aware of the source location of their products and the quantities of energy, water, and other materials used in their processing to finished products. Regulations in other jurisdictions may include this type of information requirement thereby making this data useful across operating regions.
13. The CE Delft study on the administrative costs of FQD implementation leads to the conclusion that for EU fuel suppliers the cost of establishing reporting, as described in the 2011 FQD proposal (different default values for different fossil fuels'

feedstocks) is very moderate. It equates to 0.8-1.6 euro cents per barrel of oil. The FQD 7a impact assessment also gives estimations of costs, for different reporting options.

14. It will probably be lower than 0.005 - 0.1% of the final price (based on other tracking and trace exercises we are aware about).
15. Nowadays, most large companies - especially in GHG intensive sectors - should be in a position to know and/or calculate the GHG emissions intensities of their core products already, so the add-on cost should be minimal.
16. A well-functioning company should already have collected or should already be collecting the basic data that can be used for GHG emissions calculations in order to make proper and well-informed investment and management decisions.
17. The cost of this would be similar as for Biofuels in absolute terms, while since fossil fuels are handled in far larger quantities per shipment, the cost per unit would presumably be less than for Biofuels.
18. There are already some industries providing yearly updates of their emissions data. The extra cost will take place in the first years by installing an emission reporting scheme, it will decrease by having a procedure ready and experience by measuring and calculating emissions. On the contrary, it will also add an additional benefit to the companies by knowing the main pollutants along the supply chain and to identify their environmental hot-spots etc. This will also help in identifying crucial points along the whole supply chain with potential GHG savings.
19. Monitoring requirements and methods could vary with accompanying variability in quality of information tracked. This could set up onerous oversight systems.
20. Tracking GHG emissions along the supply chain is creating both direct costs, but mainly indirect costs, related to the traceability issues relates. The complexity is intensified by the fact that from well to wheel the ownership of the crude/feedstock/oil product is changing several times. Also complexity is added by the various separation/blending operations involved. This will create a major cost disadvantage to the medium and small independent energy suppliers.
21. For a single data point, it would be EUR 10,000, and thousands of data points would be required. This gives regulation a bad reputation. Moreover, it comes at a disadvantage to new entrants and small independent energy suppliers.
22. We don't have any estimation of the additional cost for tracking key GHG emissions data along the supply chain of Oil and Gas. Anyway we think it is very huge and unjustifiable due the extraordinary complexity of the supply chain of Oil and Gas. Linking the GHG intensity of every liter of petrol and diesel sold at the service station to the feedstock of origin (light crude oil, natural bitumen, shale oil, heavy and extra heavy crude oil etc.) is practically impossible.

23. The problem of new cost is not the major issue. The 5 main issues are: a) It is technically very difficult to have representative and robust data. B) It would be very difficult to impose to crude producers / fuel exporters outside EU to give reliable / auditable data. c) It would be extremely difficult to track back the composition of blends (boats, storages, pipes, etc.). d) This complex tracking methodology would not deliver any worldwide CO2 reduction since there is little (if any) extra crude or

gas available by comparison to demand. Nevertheless it will induce an economical negative impact on EU industry (loss of competitiveness) link to the selection of "acceptable" crudes for EU.

The above comments could be actually grouped in two main categories:

- The majority of respondents who have selected already the "Yes" option and favour the tracking of CI data. This group comes from almost all categories with the exemption of Oil and Gas industry and estimate that **implementation is feasible at very low cost**. Some of them propose also the use of models based on actual data which come from the tracking system to be established.
- A smaller group of stakeholders, coming in principle from the Oil and Gas industry, argues on the **complexity of this exercise and the potential problems** which might come up; there is no estimation about the cost from this group. The respective selection of these respondents is "No".

Key Messages

- *It is important to establish a "Level playing field" between biofuels and fossil fuels in the near future as quickly as possible.*
- *Taking into account the financial strength of the oil and gas sector, cost of reporting cannot be seen as prohibitive and it is certainly justifiable. This has been concluded by other studies too.*
- *Considering that fossil fuels are handled in far larger quantities per shipment than biofuels, the cost per unit would presumably be less than for biofuels.*

7.5.12 Question 3.1

The third part of the questionnaire discusses the draft results of the study, drawing the attention on the wide range of carbon intensities for different well-to-tank streams of diesel, petrol, kerosene and natural gas consumed in the EU transport sector. In this context, Question 3.1 examined the views of stakeholders on whether the variation of carbon intensities should be taken into account in the FQD for assessing the reduction of GHG emissions.

Question 3.1

Do you consider that this variation of carbon intensities of fossil fuels for transport could be considered in the estimation of the reduction of GHG emissions mandated by the FQD?

YES NO

Please explain.

As shown in the diagrams in Figure 7-19, Figure 7-20 and Figure 7-21, 3 out of 4 stakeholders believe that the range of carbon intensities should be considered in the estimation of GHG emissions within the legislation, with the majority of promoters of this proposal coming from the Biofuels and the research and consulting sectors. In addition, all Consumers interrogated supported this view, while the Oil and Gas sector in its largest extent, replies to this question negatively. Finally, stakeholders coming from Public Authorities replied in general positively.

Figure 7-19 Question 3.1 - Distribution of answers for all respondents

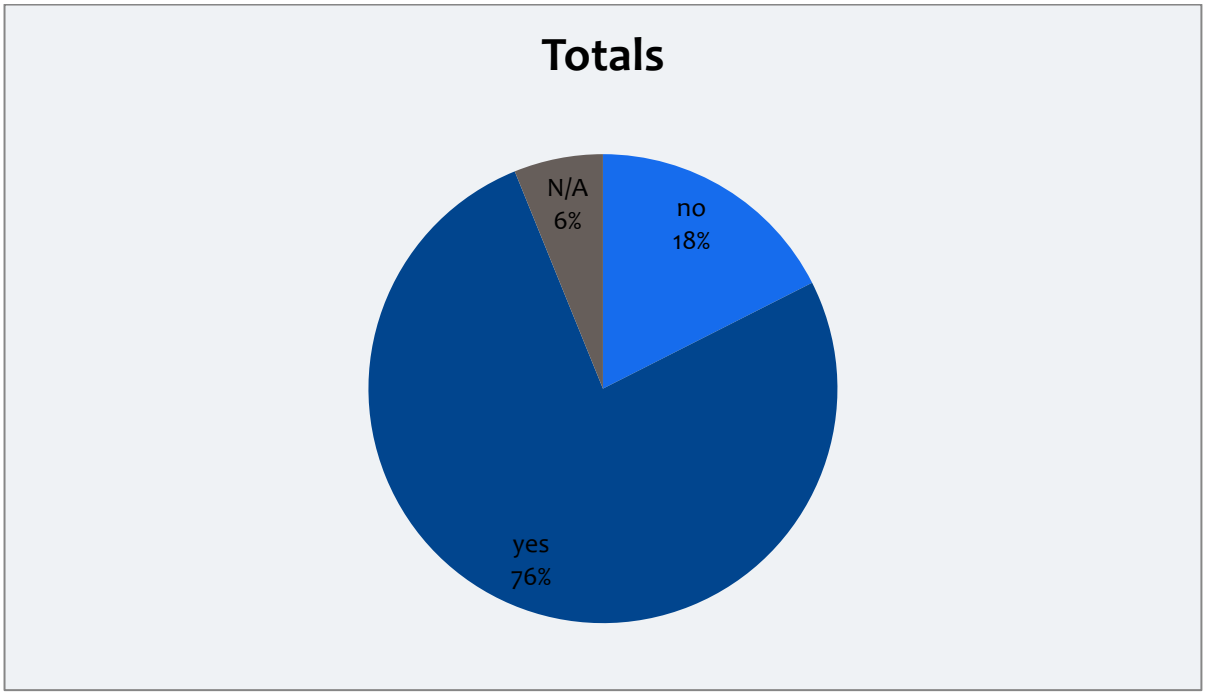


Figure 7-20 Question 3.1 - Number of answers by reply and category of stakeholder

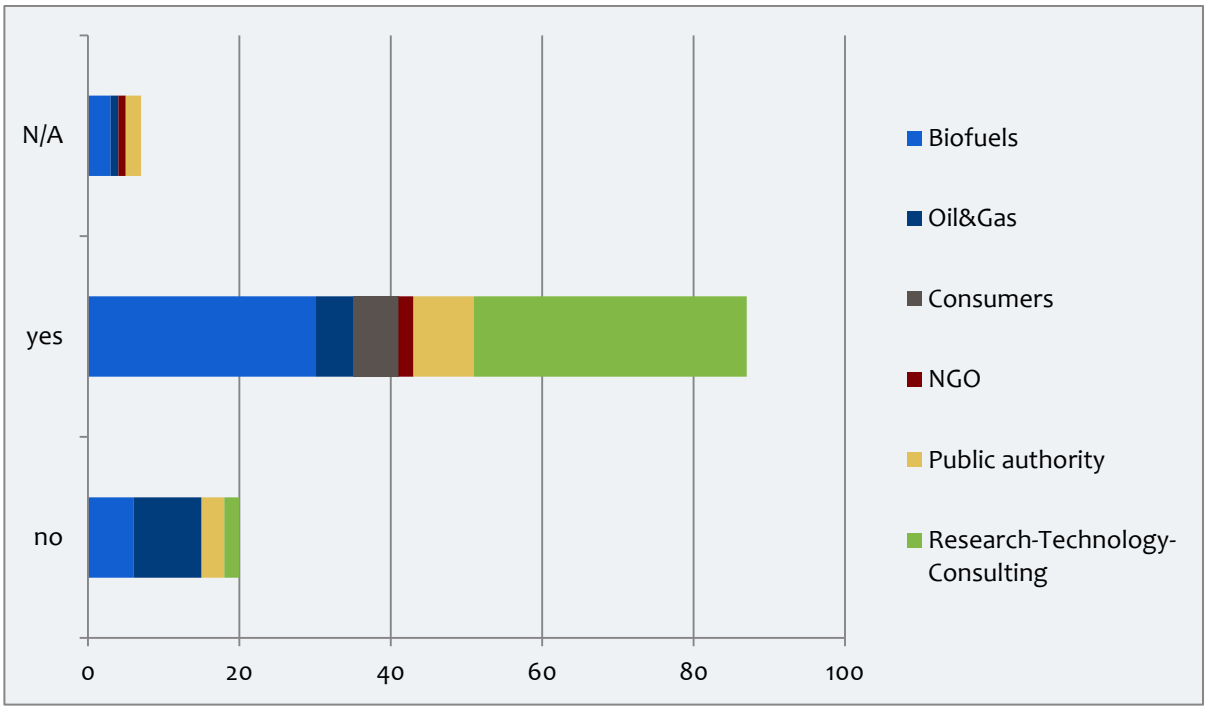
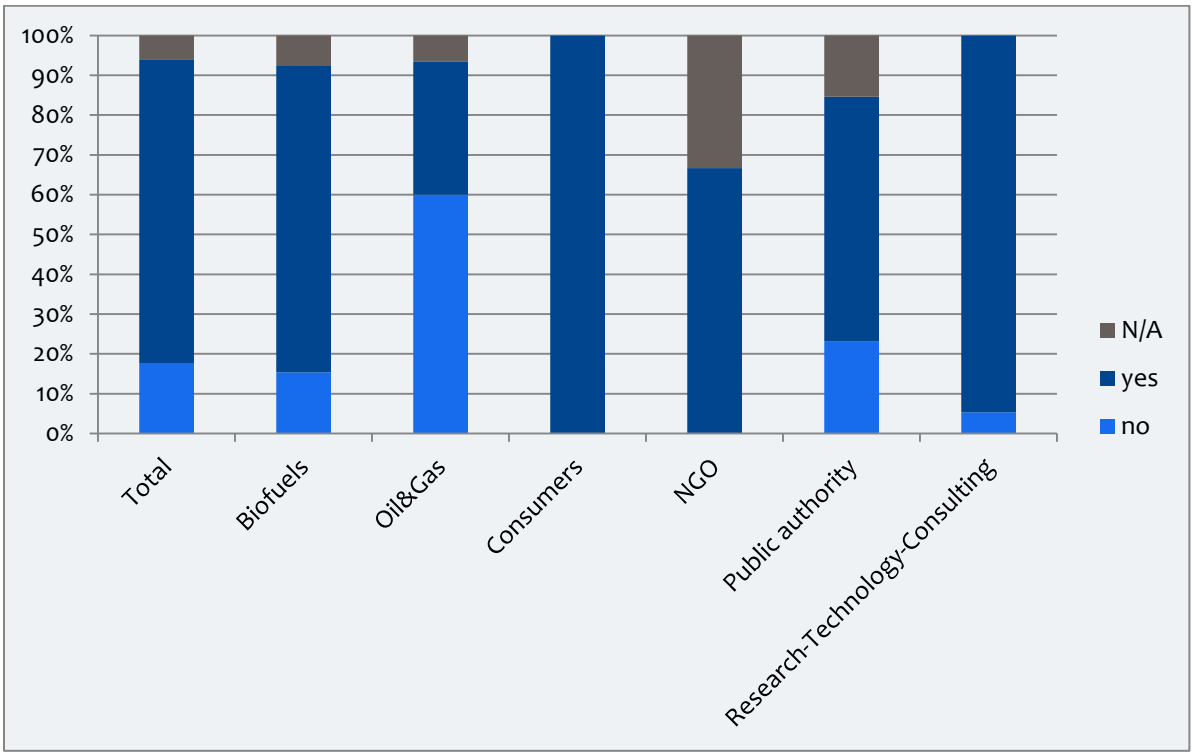


Figure 7-21 Question 3.1 - Distribution of answers in percentages by category of stakeholder



7.5.13 Comments on Question 3.1

The respondents had the possibility to comment on the Question 3.1 and select one of the two proposed options (yes, no). In this section we present the comments and opinions accompanying both selections and concentrating on ideas on the possibility the variation of the CI of fossil fuel directed to transport could be considered in the estimation of GHG reduction mandated by the FQD. The most significant comments and statements of the stakeholders on the Question 3.1 of the Questionnaire are the following:

1. Several ways to approach this: a) Ask oil refiners to calculate their own impact on GHG of their own process improvements at their refinery. This will push their own improvement, and on all applications of their crude oil, not just for transport. This will also address the risk of 'shuffling dirty crude oil' elsewhere in other applications and to other regions of the world which are less demanding on GHG emissions requirements. b) Instead of fixing a % savings target, consider comparing to a 'value range', which would also reflect the geographical and technical variations mentioned earlier. c) Consider setting a baseline for a particular region, and rewarding the oil refiner with a credit as they show up above the baseline, to push improvement. As more comply, the baseline goes up, and they are rewarded for it.
2. Not only a plausible finding, but useful in setting overall reduction targets. It would highlight all possible means of achieving the overall targets.

3. The variation of CI of fossil fuels for transportation for all sources of crude oil and for other significant conversion processes should be taken into account for the average CI for fuels in the EU. Furthermore, if a biofuel produced and used in a specific location in the EU were to replace a fossil fuel of known origin and whose CI is known, then the reduction of GHG emissions should be calculated not using the EU average CI, but using the location-specific value.
4. This is the best legislative tool to address GHG emissions of fossil fuels related to transport and consider these variations since they can have a positive or a negative impact on reaching the GHG emissions reduction target of 6% by 2020.
5. No fuel is either good or bad but its carbon intensity makes it so. There are other important factors, of course, but a fuel should not be branded as "bad" simply because it is a fossil fuel, or as "good" simply because its source is renewable. Fossil diesel burned in a modern, high-efficiency engine may be as good, or better than some biofuels, when all impacts are accounted for. We should not define solutions, but we should only define the criteria by which alternative solutions will be evaluated.
6. Operators might want to purchase fossil fuels with lower GHG intensity. This may induce indirect effects, i.e. Europe gets the better performing fossil fuels, while the GHG intensity of fossil fuels for other regions gets worse.
7. The public should be educated on the broad variation in both petroleum feedstocks and processing methods, and their impact on GHG emissions. In this way, "cleaner" options will be identified and (perhaps) promoted.
8. The FQD is there to assist in GHG emission reductions, if the results show some fuels to be of lower CI, then they should be used. However, it is important to also consider how co-products and allocation of emissions are performed during the analysis.
9. However, the overall framework should be designed carefully; e.g. "early mitigation actions" and emission savings should be rather rewarded than punished (initiation year?). Various base levels for emission reductions could be considered ("site", company, fuel category, other?"). Perhaps some kind of benchmarks (BAT) could be generated for various fuel categories.
10. Such variation of carbon intensity would help fossil fuel suppliers to reduce their overall GHG emissions by favoring the less GHG emitting fuel sources and contributing to the EU GHG reduction targets.
11. The point of the policy is to favor fuels with the lowest GHG intensity. The shuffling argument does not hold water. All fuels will shuffle if we favor ones with low GHG intensity. You may as well apply the requirement to petroleum fuels. The corollary to this approach is that the highest carbon fuels will go to regions with no GHG policy. Then we will need a border tariff on GHG intensity, which could be less fraud prone than cap and trade.
12. The incorporation of the variation in carbon intensity values of fossil fuels from different sources and processes will enable the FQD to reflect what is happening in the 'real world'. Reducing the carbon intensity of fossil fuels by selecting crude sources with lower CIs and/or improving the energy efficiency of the fuel production process are fundamental components of the FQD. The ability of the FQD to reduce

the carbon intensity of the fuels used in the EU is predicated on the ability to understand the actual CIs of the fuels used in the 'real world'.

13. All GHG in transport should be regulated consistently and equally in order to achieve the FQD target. Variations can have either a positive or negative impact on reaching the GHG emissions targets. It is the case for biofuels where different GHG profile exists, and so should be the same with fossil energy.
14. It is absolutely necessary to consider the variation of carbon intensities of fossil fuels for transport. In order to have a consistent and equal regulation for all transport fuels –from fossil or biological origin– as the variation of the carbon intensities of biofuels are considered for the calculation of the reduction of GHG emissions mandated by the FQD, also the variation of the carbon intensity for fossil fuels should be taken into account to comply with that target. The fact that the variations of carbon intensity for fossil fuels are not considered as it is for biofuels constitutes an unjustified and unfair discrimination against biofuels.
15. A lot of parameters need to be taken into account: what does the baseline carbon intensity value cover? Is it a company-specific baseline or not? For the moment, it is not the case and some fuel suppliers could be rewarded for using low-carbon fossil fuels when they haven't reduced the GHG intensity of their fuels in practice, compared to the baseline.
16. We need to be practical. What we want to achieve is a net decrease in the amount of Carbon element that is transferred from underground to the atmosphere and hydrosphere. In future, we hope to manage to make this equal to 0 (produce fuel from CO2 with renewable energy and materials) and then to go to negative (use alternative fuels, when we can produce them massively, as a new opportunity to capture CO2, and to store it as carbon chains underground to clean atmosphere and hydrosphere). Waiting for these futures to happen, we should consider any cleaner intermediate solutions as transitory options. And we should value them as such.
17. Yes, if actual (modeled) data is available for both reference year and the year being evaluated.
18. To limit the extent of global warming, potential GHG emissions reductions along all global supply chains should be seen as potential opportunities that may be assessed as to their cost and impact.
19. When the aim is reducing GHG emissions using a well-to-tank assessment, all fuels with considerably less GHG emissions should be stimulated.
20. Considering that a reduction of GHG emissions may be deduced from a variation of carbon intensities is already a strong assumption (see e.g. ILCD Handbook for LCA). Neglecting the variation of carbon intensities would thus be a further dramatic assumption.
21. In general, at the societal level, less carbon intense transports overall is the goal, so low carbon intensity streams should be given an added value relative to other streams.
22. Yes, if the bandwidth of results given is transparent, the calculation clearly stated and the boundary conditions for the values stated. There should also be a review for these values, as they are considered as the basis for further identification of reduction potentials for GHG and other emissions/impacts.

23. It is correct to promote the fossil fuels with the lowest carbon intensity. However, probably the high GHG intensive fuels will be sold outside the EU as well if they meet limitation within the EU, so this measure will not lead to a net reduction of GHG emissions on global level. But you have to make a start considering this.
24. For sake of simplicity, it is highly recommended to keep working with average values and not with ranges. Ranges are considered as a possible tool to address uncertainty should be used to identify meaningful statistical differences between pathways and/or trends. Any crude differentiation specific to the EU would restrict the supply and would lead to price differentials based on GHG content, resulting in a further loss of competitiveness of the EU refining industry.
25. Only in creating some broader feedstock types and using their average values (e.g., conventional crudes, non-conventional feedstocks, etc.), like in the proposal of DG Clima of October 2011, which was not approved. We would be against any further differentiation in crude types because that would restrict the crude supply options for European refining and would lead to unnecessary cost increases for the European Energy market.
26. There is considerable risk of causing perverse outcomes, if fossil fuel CI disaggregation were to be introduced without careful thought and a clear characterization of goals.
27. This should only be the case if this information is based on actual and verified/ certified calculations, based on an agreed methodology and clear verification mechanisms.
28. To comply with the reduction of GHG emissions mandated by the FQD, it is highly recommended to keep working with average values only and not use ranges. The administrative burden for verification and control by Competent Authorities will consistently increase with ranges.
29. This is not a local issue: even if EU only selected "low CO_2 crudes", the other crudes would still be used by the rest of the world. This discrimination would lead to a price increase of the "low CO_2 crudes" in EU and would impact the EU competitiveness. Furthermore there would be even a slight increase of CO_2 in the world due to crude shuffling and refining sub-optimization. This issue will be the same for imported fuels.
30. The way of actualization should include the fact that by the use of biofuels in transport sector conventional (Middle East) and unconventional (with higher GHG emission value) oil sources are being displaced. In this context the fossil fuel carbon intensities should be updated but only to "one average" fossil fuel carbon intensity and fossil fuel comparator.
31. Differentiating oil by its origin, would create and adverse selection. With mass balance systems, EU would just receive number of low GHG value certificates, but nothing will change on the ground. The biggest uncertainties in GHG emissions of oil are coming from flare gas leakage and utilization at the fields, extraction technologies used/type of oil. From environmental point of view, those issues can and should be addressed through other regulations.

32. In terms of climate change, any use of fossil fuels has an effect. There is little to gain in making the already complicated GHG emissions calculation process (IPCC / UNFCC) even more complicated by adding more components to the calculations.

The above comments could be actually grouped in two main categories:

- The majority of respondents has selected already the "Yes" option and favour the necessity for exploitation the variation of CI in fossil fuel to estimate GHG emissions reduction as by FQD. This group comes from almost all categories with the exemption of oil and gas industry and estimate that **this approach is endorsed with certain difficulties**. There is a broad concern about the global effect and the compliance with the objective of the FQD and RED to promote biofuels.
- A smaller group of stakeholders, coming in principle from the oil and gas industry, argues on the **potential problems of refining competition** and the expected changes in the oil market that might come up. This group has mostly selected the option "No" as it is expected.

The respondents had the possibility to comment on the Question 3.1 and select one of the two proposed options (yes, no). In this section we present the comments and opinions accompanying both selections and concentrating on ideas on the possibility the variation of the CI of fossil fuel directed to transport could be considered in the estimation of GHG reduction mandated by the FQD. The most significant comments and statements of the stakeholders on the Question 3.1 of the Questionnaire are the following:

1. Several ways to approach this: a) Ask oil refiners to calculate their own impact on GHG of their own process improvements at their refinery. This will push their own improvement, and on all applications of their crude oil, not just for transport. This will also address the risk of 'shuffling dirty crude oil' elsewhere in other applications and to other regions of the world which are less demanding on GHG emissions requirements. b) Instead of fixing a % savings target, consider comparing to a 'value range', which would also reflect the geographical and technical variations mentioned earlier. c) Consider setting a baseline for a particular region, and rewarding the oil refiner with a credit as they show up above the baseline, to push improvement. As more comply, the baseline goes up, and they are rewarded for it.
2. Not only a plausible finding, but useful in setting overall reduction targets. It would highlight all possible means of achieving the overall targets.
3. The variation of CI of fossil fuels for transportation for all sources of crude oil and for other significant conversion processes should be taken into account for the average CI for fuels in the EU. Furthermore, if a biofuel produced and used in a specific location in the EU were to replace a fossil fuel of known origin and whose CI is known, then the reduction of GHG emissions should be calculated not using the EU average CI, but using the location-specific value.
4. This is the best legislative tool to address GHG emissions of fossil fuels related to transport and consider these variations since they can have a positive or a negative impact on reaching the GHG emissions reduction target of 6% by 2020.

5. No fuel is either good or bad but its carbon intensity makes it so. There are other important factors, of course, but a fuel should not be branded as "bad" simply because it is a fossil fuel, or as "good" simply because its source is renewable. Fossil diesel burned in a modern, high-efficiency engine may be as good, or better than some biofuels, when all impacts are accounted for. We should not define solutions, but we should only define the criteria by which alternative solutions will be evaluated.
6. Operators might want to purchase fossil fuels with lower GHG intensity. This may induce indirect effects, i.e. Europe gets the better performing fossil fuels, while the GHG intensity of fossil fuels for other regions gets worse.
7. The public should be educated on the broad variation in both petroleum feedstocks and processing methods, and their impact on GHG emissions. In this way, "cleaner" options will be identified and (perhaps) promoted.
8. The FQD is there to assist in GHG emission reductions, if the results show some fuels to be of lower CI, then they should be used. However, it is important to also consider how co-products and allocation of emissions are performed during the analysis.
9. However, the overall framework should be designed carefully; e.g. "early mitigation actions" and emission savings should be rather rewarded than punished (initiation year?). Various base levels for emission reductions could be considered ("site", company, fuel category, other?"). Perhaps some kind of benchmarks (BAT) could be generated for various fuel categories.
10. Such variation of carbon intensity would help fossil fuel suppliers to reduce their overall GHG emissions by favoring the less GHG emitting fuel sources and contributing to the EU GHG reduction targets.
11. The point of the policy is to favor fuels with the lowest GHG intensity. The shuffling argument does not hold water. All fuels will shuffle if we favor ones with low GHG intensity. You may as well apply the requirement to petroleum fuels. The corollary to this approach is that the highest carbon fuels will go to regions with no GHG policy. Then we will need a border tariff on GHG intensity, which could be less fraud prone than cap and trade.
12. The incorporation of the variation in carbon intensity values of fossil fuels from different sources and processes will enable the FQD to reflect what is happening in the 'real world'. Reducing the carbon intensity of fossil fuels by selecting crude sources with lower CIs and/or improving the energy efficiency of the fuel production process are fundamental components of the FQD. The ability of the FQD to reduce the carbon intensity of the fuels used in the EU is predicated on the ability to understand the actual CIs of the fuels used in the 'real world'.
13. All GHG in transport should be regulated consistently and equally in order to achieve the FQD target. Variations can have either a positive or negative impact on reaching the GHG emissions targets. It is the case for biofuels where different GHG profile exists, and so should be the same with fossil energy.
14. It is absolutely necessary to consider the variation of carbon intensities of fossil fuels for transport. In order to have a consistent and equal regulation for all transport fuels –from fossil or biological origin– as the variation of the carbon intensities of

biofuels are considered for the calculation of the reduction of GHG emissions mandated by the FQD, also the variation of the carbon intensity for fossil fuels should be taken into account to comply with that target. The fact that the variations of carbon intensity for fossil fuels are not considered as it is for biofuels constitutes an unjustified and unfair discrimination against biofuels.

15. A lot of parameters need to be taken into account: what does the baseline carbon intensity value cover? Is it a company-specific baseline or not? For the moment, it is not the case and some fuel suppliers could be rewarded for using low-carbon fossil fuels when they haven't reduced the GHG intensity of their fuels in practice, compared to the baseline.
16. We need to be practical. What we want to achieve is a net decrease in the amount of Carbon element that is transferred from underground to the atmosphere and hydrosphere. In future, we hope to manage to make this equal to 0 (produce fuel from CO2 with renewable energy and materials) and then to go to negative (use alternative fuels, when we can produce them massively, as a new opportunity to capture CO2, and to store it as carbon chains underground to clean atmosphere and hydrosphere). Waiting for these futures to happen, we should consider any cleaner intermediate solutions as transitory options. And we should value them as such.
17. Yes, if actual (modeled) data is available for both reference year and the year being evaluated.
18. To limit the extent of global warming, potential GHG emissions reductions along all global supply chains should be seen as potential opportunities that may be assessed as to their cost and impact.
19. When the aim is reducing GHG emissions using a well-to-tank assessment, all fuels with considerably less GHG emissions should be stimulated.
20. Considering that a reduction of GHG emissions may be deduced from a variation of carbon intensities is already a strong assumption (see e.g. ILCD Handbook for LCA). Neglecting the variation of carbon intensities would thus be a further dramatic assumption.
21. In general, at the societal level, less carbon intense transports overall is the goal, so low carbon intensity streams should be given an added value relative to other streams.
22. Yes, if the bandwidth of results given is transparent, the calculation clearly stated and the boundary conditions for the values stated. There should also be a review for these values, as they are considered as the basis for further identification of reduction potentials for GHG and other emissions/impacts.
23. It is correct to promote the fossil fuels with the lowest carbon intensity. However, probably the high GHG intensive fuels will be sold outside the EU as well if they meet limitation within the EU, so this measure will not lead to a net reduction of GHG emissions on global level. But you have to make a start considering this.
24. For sake of simplicity, it is highly recommended to keep working with average values and not with ranges. Ranges are considered as a possible tool to address uncertainty should be used to identify meaningful statistical differences between pathways and/or trends. Any crude differentiation specific to the EU

would restrict the supply and would lead to price differentials based on GHG content, resulting in a further loss of competitiveness of the EU refining industry.

25. Only in creating some broader feedstock types and using their average values (e.g., conventional crudes, non-conventional feedstocks, etc.), like in the proposal of DG Clima of October 2011, which was not approved. We would be against any further differentiation in crude types because that would restrict the crude supply options for European refining and would lead to unnecessary cost increases for the European Energy market.
26. There is considerable risk of causing perverse outcomes, if fossil fuel CI disaggregation were to be introduced without careful thought and a clear characterization of goals.
27. This should only be the case if this information is based on actual and verified/ certified calculations, based on an agreed methodology and clear verification mechanisms.
28. To comply with the reduction of GHG emissions mandated by the FQD, it is highly recommended to keep working with average values only and not use ranges. The administrative burden for verification and control by Competent Authorities will consistently increase with ranges.
29. This is not a local issue: even if EU only selected "low CO2 crudes", the other crudes would still be used by the rest of the world. This discrimination would lead to a price increase of the "low CO2 crudes" in EU and would impact the EU competitiveness. Furthermore there would be even a slight increase of CO2 in the world due to crude shuffling and refining sub-optimization. This issue will be the same for imported fuels.
30. The way of actualization should include the fact that by the use of biofuels in transport sector conventional (Middle East) and unconventional (with higher GHG emission value) oil sources are being displaced. In this context the fossil fuel carbon intensities should be updated but only to "one average" fossil fuel carbon intensity and fossil fuel comparator.
31. Differentiating oil by its origin, would create and adverse selection. With mass balance systems, EU would just receive number of low GHG value certificates, but nothing will change on the ground. The biggest uncertainties in GHG emissions of oil are coming from flare gas leakage and utilization at the fields, extraction technologies used/type of oil. From environmental point of view, those issues can and should be addressed through other regulations.

32. In terms of climate change, any use of fossil fuels has an effect. There is little to gain in making the already complicated GHG emissions calculation process (IPCC / UNFCC) even more complicated by adding more components to the calculations.

The above comments could be actually grouped in two main categories:

- The majority of respondents has selected already the "Yes" option and favour the necessity for exploitation the variation of CI in fossil fuel to estimate GHG emissions reduction as by FQD. This group comes from almost all categories with the exemption of oil and gas industry and estimate that **this approach is endorsed with**

certain difficulties. There is a broad concern about the global effect and the compliance with the objective of the FQD and RED to promote biofuels.

- A smaller group of stakeholders, coming in principle from the oil and gas industry, argues on the **potential problems of refining competition** and the expected changes in the oil market that might come up. This group has mostly selected the option "No" as it is expected.

Key Messages

- *A significant majority agrees that the variation in CI should be taken into account in the estimation of the reduction of GHG emissions mandated by the FQD.*
- *For a proper implementation of the FQD it is necessary to understand and apply the correct CI of fossil fuel.*
- *It is advisable to promote the fossil fuels with the lowest carbon intensity.*

7.5.14 Question 3.2

Question 3.2

In view of forthcoming policies of the European Union and Member States to reduce GHG emissions and in accordance to the above mentioned variation of GHG emissions in transport fuels, what type of measures related to transport fuels do you think are more appropriate?

a) Combined measures, i.e. use of lifecycle GHG emissions reduction goals for final products of fossil fuels as an essential component of decarbonisation in combination with other relevant measures

b) Independent measures, i.e. use of lifecycle GHG emissions reduction goals for final products of fossil fuels in addition to other measures and GHG goals set by the UNFCCC and/or the EU to help drive the energy sector actions needed for decarbonisation

c) Inherent within general measures, i.e. use of GHG emissions of transport fuels as a component of energy sector policies and actions that reduce GHG emissions and may be motivated primarily by wider benefits such as energy security, air pollution, reducing energy bills, etc.

Question 3.2 examines the stakeholders' opinion on appropriate measures that should be taken by the EU and Member States in their forthcoming policies in order to reduce GHG emissions in the transport sector and provides the respondents with 3 options on suggested measures: a) combined measures, b)independent measures in addition to other measures and c) inherent with general measures.

The respondents appear divided on this particular issue, as can be seen in Figure 7-22, although with a slight preference to option c, which suggests that measures for reduction of GHG emissions in the transport sector should be inherent within general measures, i.e. use of GHG emissions of transport fuels as a component of energy sector policies and actions that reduce GHG emissions and may be motivated primarily by wider benefits such as energy security, air pollution, reducing energy bills, etc.

Figure 7-22 Question 3.2 - Distribution of answers for all respondents

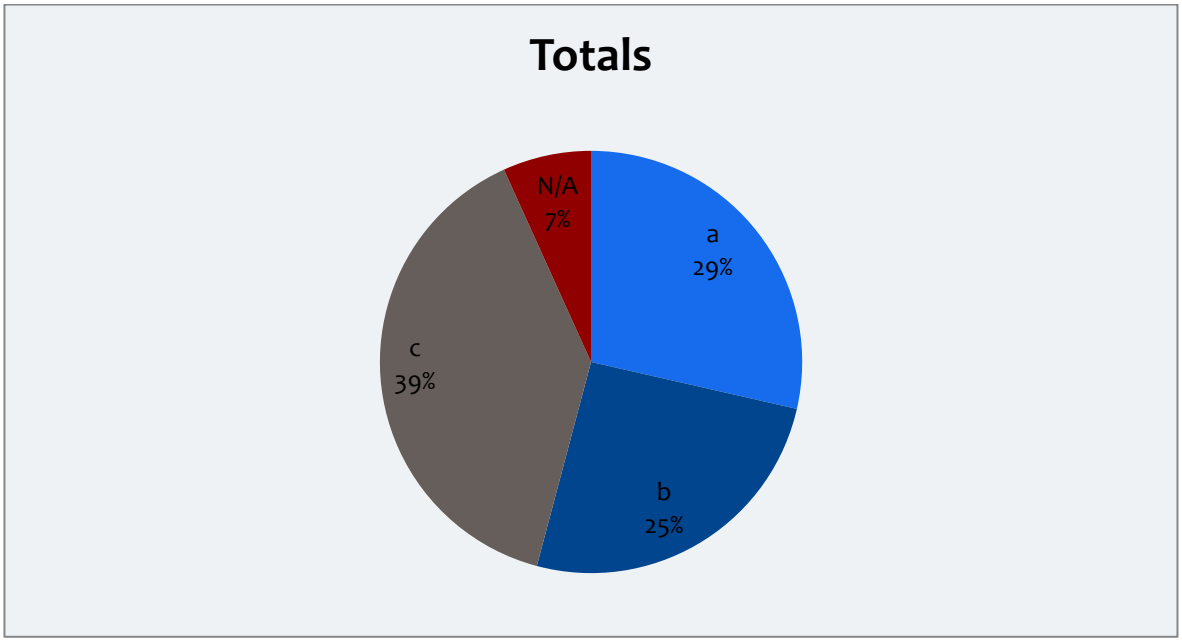


Figure 7-23 and Figure 7-24 illustrate this disunity of views within the different categories of stakeholders. The Oil and Gas sector as well as Public Authorities show a clear tendency towards option c, while all other categories of stakeholders do not incline as a whole group to any particular option.

Figure 7-23 Question 3.2 - Number of answers by reply and category of stakeholder

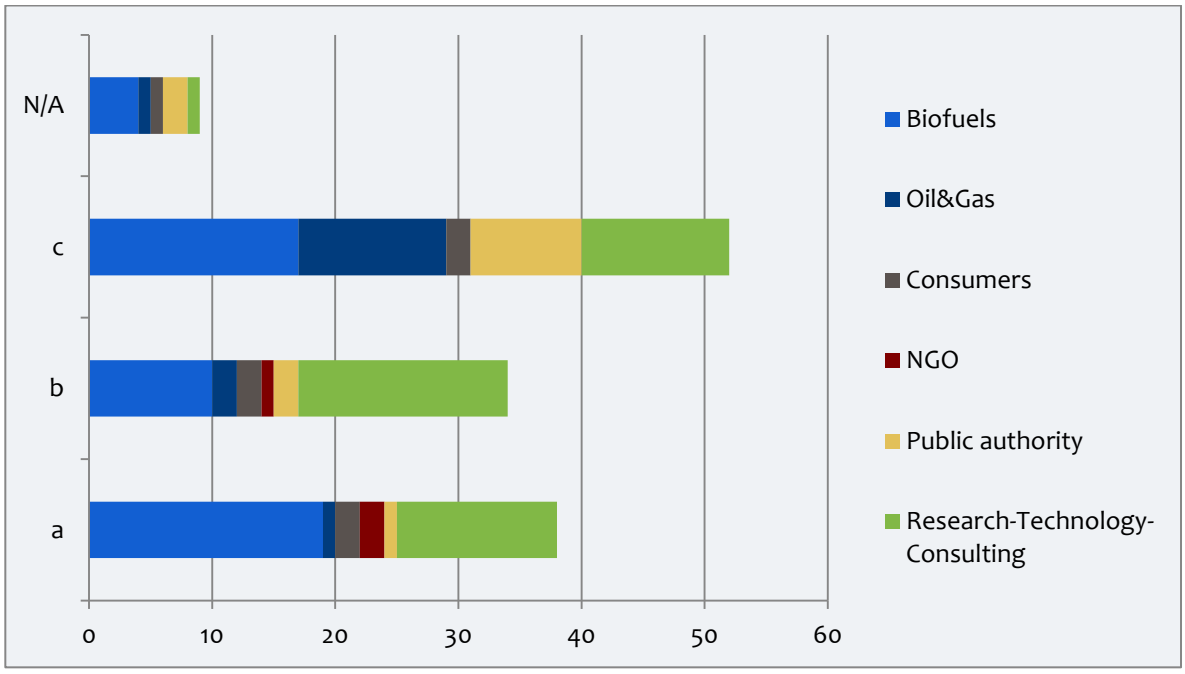
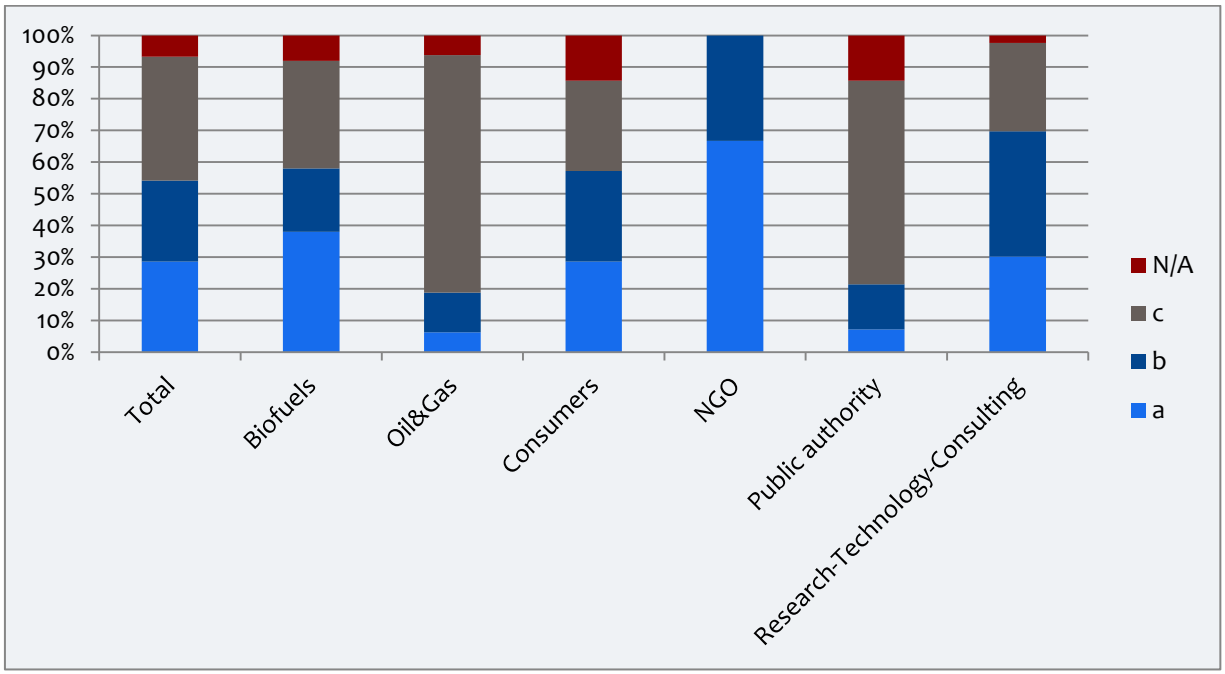


Figure 7-24 Question 3.2 - Distribution of answers in percentages by category of stakeholder



7.5.15 Question 3.3

Question 3.3 investigated the views of stakeholders on whether the results of the present study should influence the revision of the sustainability criteria in the RED and the FQD. In this case, the prevalence of the positive answer is evident, although a significant percentage of 27% did not support this opinion, as shown in Figure 7-25. The strongest adversaries of the idea of including the results of the study in the revision of the FQD and the RED were the members of the Oil and Gas sector, NGOs as well as Public Authorities (Figure 7-26 and Figure 7-27). The Consumers category appears unanimous on this issue, supporting the "yes" answer, while 4 out of 5 respondents from the Biofuels industry and the Research – Technology – Consulting sector are advocates of the "yes" answer.

Question 3.3

Are you of the opinion that the sustainability criteria for biofuels in the RED and FQD should be revised subject to the results of this study?

YES NO

What type of measures related to the revision of sustainability criteria do you think are more appropriate? Please specify.

Figure 7-25 Question 3.3 - Distribution of answers for all respondents

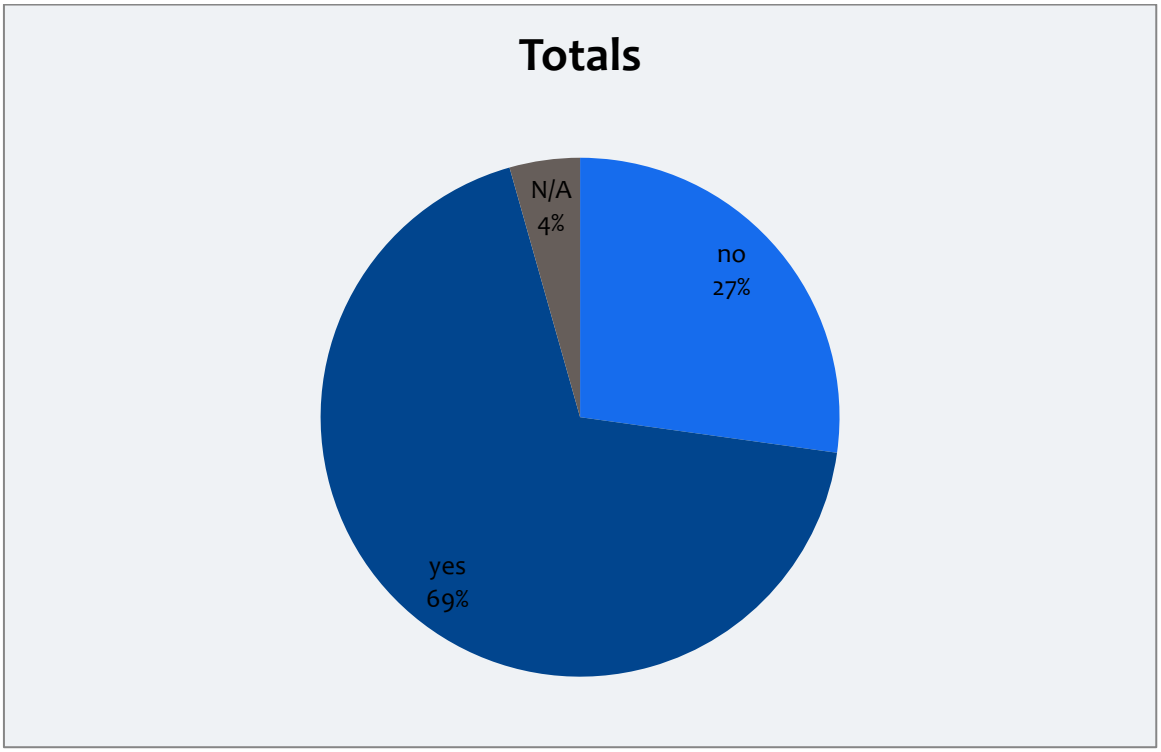


Figure 7-26 Question 3.3 - Number of answers by reply and category of stakeholder

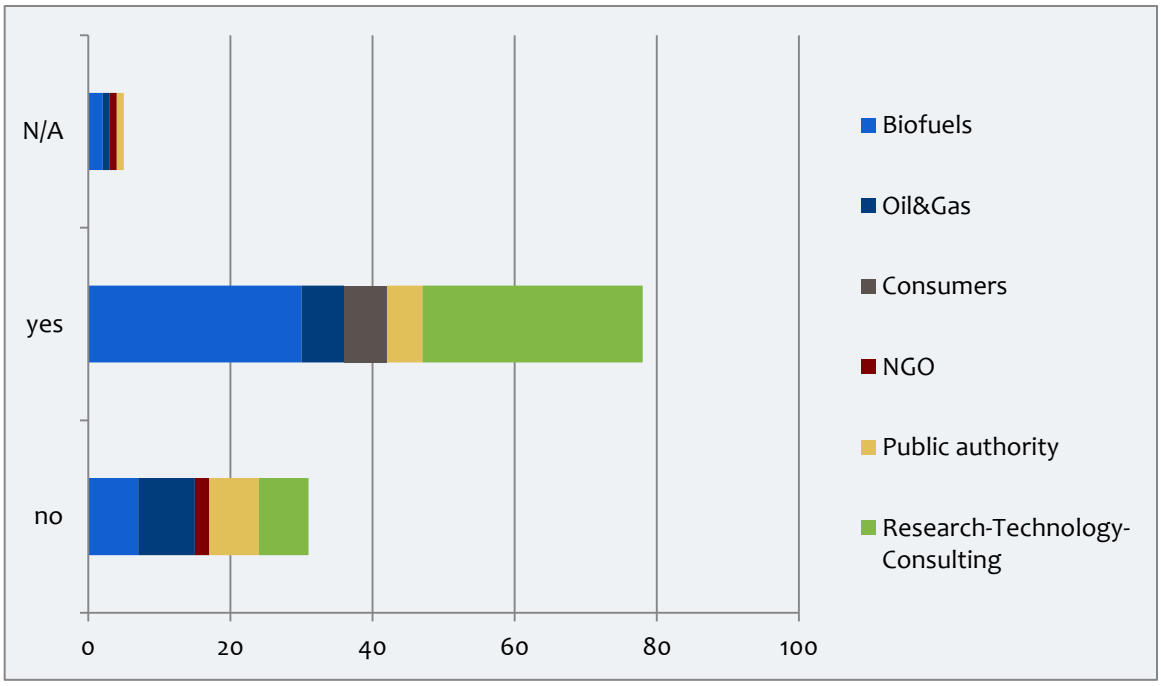
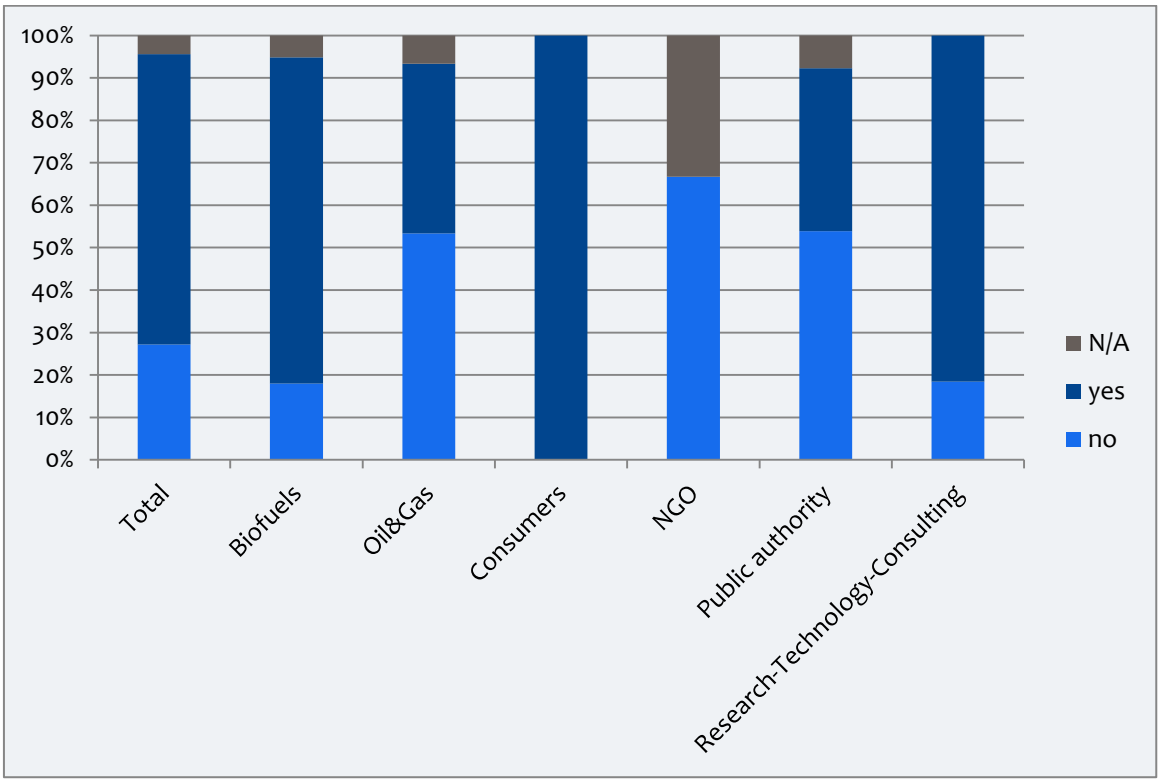


Figure 7-27 Question 3.3 - Distribution of answers in percentages by category of stakeholder



7.5.16 Comments on Question 3.3

The respondents had the possibility to comment on the Question 3.3 and select one of the two proposed options (yes, no). In this section we present the comments and opinions accompanying both selections and concentrating on recommendations on measures related to revision of sustainability criteria. The most significant comments and statements of the stakeholders on the Question 3.3 of the Questionnaire are the following:

1. Sustainability criteria should be extended to fossil fuels. Origin of oil/gas should be known with traceability. GHG emission of different types of oil/gas in the mix should be publicized.
2. These new results might require redefining reduction targets of EU, to adapt to each particular situation of fuel and performance in countries.
3. Focus on carbon reduction potential based on the technical conversion routes available from both fossil and renewable resources should be placed. It is better to avoid mixing highly complex regulatory criteria for sustainability in the FQD and RED. Those aspects, generally pertaining to feedstock sources rather than biofuels production processes, can be separately applied to the market for supply of qualified biomass.
4. Some biofuels save greenhouse gases in the end use phase of the lifecycle. This is neither recognized nor promoted by the FQD (or any other EU legislation). The sustainability criteria should reflect and measure the full lifecycle greenhouse gases "well-to-wheel" instead of "well-to-tank".

5. To stablish maximum emission intensity instead of comparison (%) with fossil reference, while applying a similar limit to fossil fuels. Beyond that a penalty should be established.
6. Beyond the sole focus on GHG-savings and on land issues, the need for thinking on water security, social security and on creating shared value in the supply chain is needed, but this related to all products that are used within the EU.
7. Links between biofuels production and biodiversity and carbon hot spots such as Indonesia and Malaysia should be carefully analyzed to address serious sustainability concerns. Focus should be on potentially most environmentally harmful feedstocks and location and simultaneously ease the sustainability pressure on European forestry and agricultural residue based production.
8. ILUC related measures, double or multiple counting for advanced generation biofuels. Most importantly, if such a revision were to be done, biogas GHG reduction should never be calculated in comparison to the use of natural gas alone. Using natural gas instead of oil in transport sector reduces GHG emissions significantly. Biogas can indeed replace natural gas as a transport fuel, however, since natural gas is an alternative fuel itself, with very limited market share, biogas should be looked upon as a substitute for oil rather than for natural gas. This needs to be reflected in the GHG reduction calculations. If biogas GHG reduction were to be calculated in comparison to natural gas alone, biogas would be "punished" (compared to other biofuels) for having a fossil counterpart (natural gas) that achieves significant GHG reduction compared to oil. Some interviewed people don't know at this stage. In their opinion, the revision of sustainability criteria should be considered, based on the results of this study.
9. Creating multiple GHG emission reductions from advanced biofuels along the lines of multiple accounting for share of energy from advanced biofuels (RED Directive).
10. Within the RED and FQD, sustainability criteria are solely applied to biofuels. The concept of sustainability must be applied to all fuels on an equivalent basis in recognition that all fuels have the potential to improve their sustainability performance via the use of certification. Additionally, it is necessary that 'indirect effects' are examined for all fuels, not only bioenergy. The current incorporation of indirect effect values (e.g., ILUC), for bioenergy into comparative GHG analysis (while omitting the potential for their existence for fossil fuels) is a breach of ISO principles of LCA which requires utilizing equivalent system boundaries. An ISO report states that "there has been more emphasis on sustainability and indirect effects of bioenergy than on baseline (generally fossil fuel) scenarios." (ISO 13065 WG 4 Final Report, 2013).
11. For a revision, more clarity about the chain of custody and governance should be considered in general. In more detail, better guidance on direct and indirect land use change and a holistic set of criteria (including impacts on soil, water, air, transformation, biodiversity, economic and social aspects) should be included.
12. More aggressive targets and policies to achieve them; e.g., targets commensurate with the scale and urgency of the problem (disruption of the global climate and especially the hydrological cycle on which life as we know it depends).
13. The existing sustainability criteria should be modified focusing more on:

a) reduction the contribution of land-based biofuels to the overall energy mix b) support and promotion of more sustainable fuels (2nd generation biofuel, algae, agricultural and forestry residues, municipal waste). c) addressing indirect land use change impacts with the introduction of binding ILUC factors.

14. The RED and FQD specify the main boundary conditions and the way how to become sustainable. It does not specify, e.g. how a bonus is given or what are the main hotspots within the supply chain. Therefore the sustainability criteria should be transparent, the calculation of the single stocks, raw materials, land use, energy source comprehensible. According to the actual RED (2009) only biomass based biofuels are accounted for. This prohibits new development mainly with regard to synthetic fuels, which might have lower impacts over the whole lifecycle than some biofuels. Therefore environmentally friendly fuels which are not based on biomass should be also part of the RED. The RED update should be performance based only without regard to the feedstock.
15. Regulatory stability should be assured as long as no sound scientific basis exists to initiate a change. We are convinced that policies should be kept simple and pragmatic. Simpler tools should be used to monitor the use of lower carbon alternative fuels.
16. Measures and policies should be kept simple and realistic. It is preferable to stay under current criteria on which our plans are based, because investment decisions need regulatory stability.
17. Regarding minimum GHG savings, a calculation based also on actual/ more realistic values for the fossil reference makes sense.
18. The existing sustainability criteria address land-use and biodiversity issues connected with biofuels - essentially the potential downsides of first generation biofuels. Any other set of sustainability criteria, for any other type of fuel, should be bespoke to that fuel.
19. The GHG requirements may be revised but other sustainability criteria (labor practices, environmental compliance) are difficult to monitor on a lifecycle basis. The efficacy of verification of non GHG stainability criteria should also be examined.
20. There is a general need to improve the situation of sustainability criteria as well as other requirements from RED and FQD especially regarding proper control mechanisms for GHG emissions calculation as well as requirements for further possibilities to reduce emissions (e.g. CCR, SCA) and to fulfill the target (e.g. UER).

The above comments could be actually grouped in two main categories:

- The majority of respondents has selected already the "Yes" option and favour the consideration of revised sustainability criteria This group comes from almost all categories with the exemption of oil and gas industry and argue on **various topics leading to amelioration of existing sustainability criteria** of FQD and RED.
- A smaller group of stakeholders, coming in principle from the oil and gas industry, is negative to criteria changes insisting that **regulatory stability should be maintained** with no changes at present. This group has mostly selected the option "No" as it is reasonable.

Key Messages

- *A wide majority of stakeholders are of the opinion that the sustainability criteria for biofuels in RED and FQD should be revised based on the results of this study.*
- *The concept of sustainability should be applied to all fuels on an equivalent basis.*

7.5.17 Question 3.4.1

Question 3.4.1

Do you agree with the statement above?

YES NO

Please explain.

Question 3.4.1 examined whether the stakeholders agree with a statement expressed at the beginning of this set of questions, concerning world trade restrictions: *"Depending on the measures possibly adopted by the EU, if any, related to the reduction of GHG emissions from transport fuels, there may be impacts on the international trading conditions of (certain types of) crude oil and natural gas. In other words, this may have an impact on the competitive conditions of (certain types of) crude oil and natural gas from certain sources vis-à-vis comparable products from other sources and/or countries."*

The majority of stakeholders replied that they agree with the fact that the measures to be adopted by the EU related to GHG emissions of transport fuels will possibly affect the competitive conditions of world trade, as illustrated in the following Figures. It must be noted that in all categories of stakeholders, the majority of respondents replied that they agree with the statement (Figure 7-28, Figure 7-29 and Figure 7-30).

Figure 7-28 Question 3.4.1 - Distribution of answers for all respondents

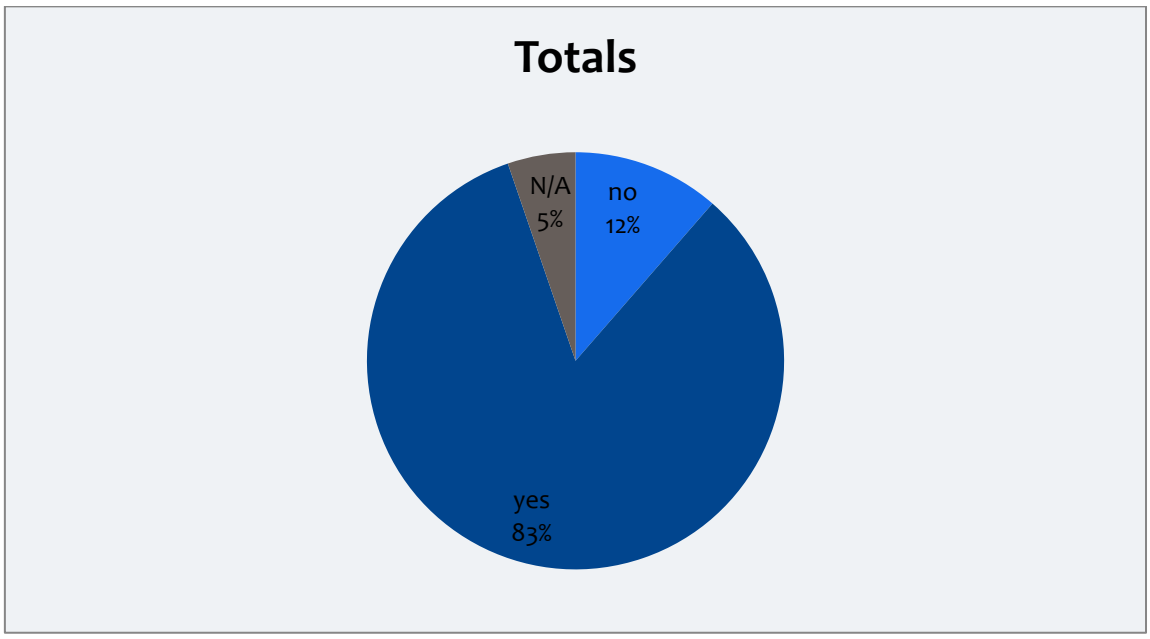


Figure 7-29 Question 3.4.1 - Number of answers by reply and category of stakeholder

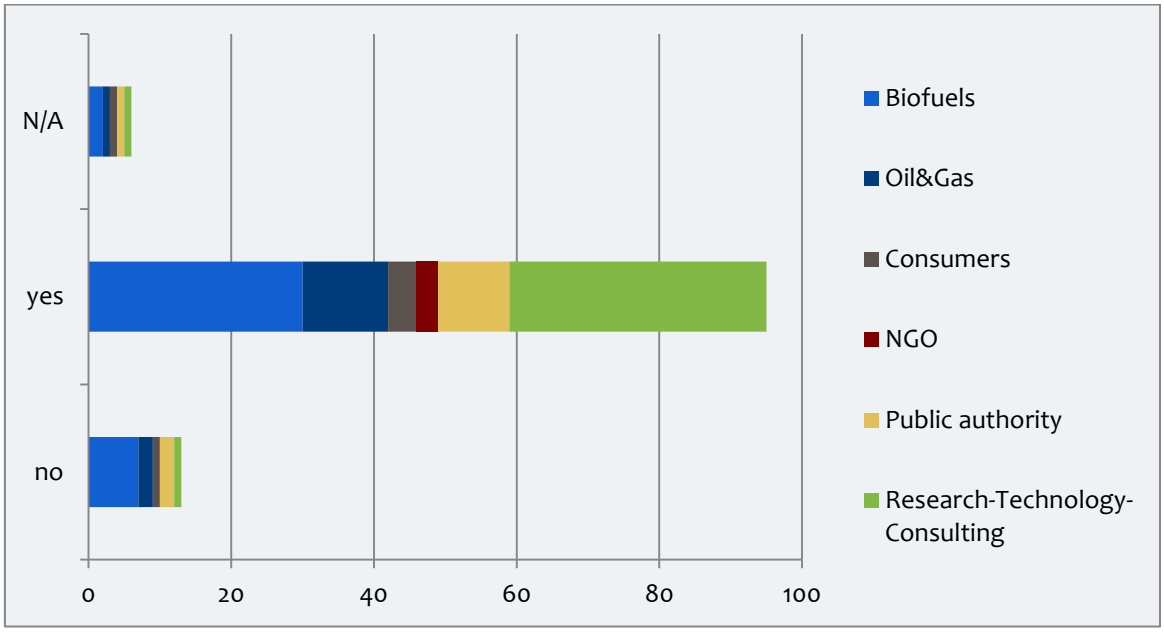
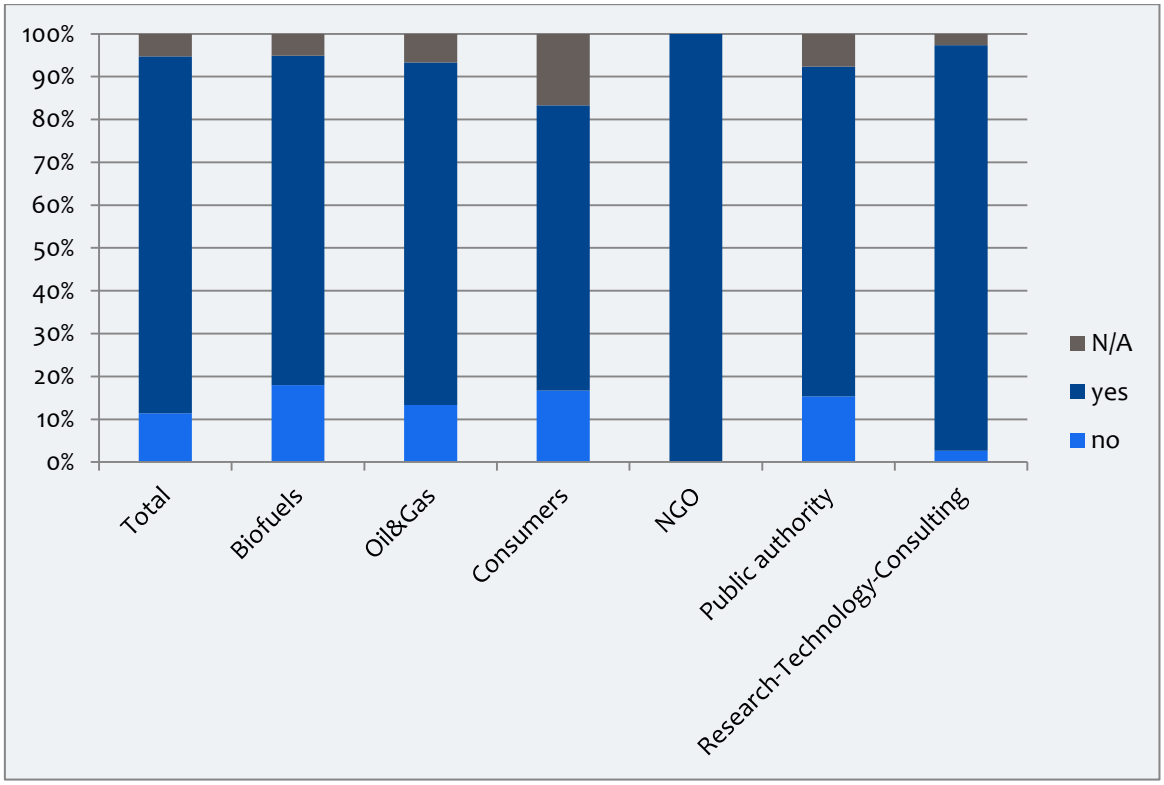


Figure 7-30 Question 3.4.1 - Distribution of answers in percentages by category of stakeholder



7.5.18 Comments on Question 3.4.1

The respondents had the possibility to comment on the Question 3.4.1 and select one of the two proposed options (yes, no). In this section we present the comments and opinions accompanying both selections and concentrate on considered effects on the competitive conditions of international trade. The most significant comments and statements of the stakeholders on the Question 3.4.1 of the Questionnaire are the following:

1. What might happen is that fossil fuel producers would need to invest both in better technology and practices to reduce emissions in order to be able to access EU markets as biofuels producers are doing now.
2. Any differentiation in the GHG intensity applied only in Europe will induce a change in trading conditions between regions having higher carbon intensity crudes or finished products thereof. The situation is even amplified by the unbalance between production of road fuels and their consumption, leading to important trade flows of fuels in and out of Europe.
3. Regulations always have market effects. Market forces, including any imposed targets for carbon reductions, will determine the values of various feedstock based on the degree the products meet market needs.
4. One good example is the amount of sulfur in the crude oils or the mercaptanes and sulfides in the Natural gas. More sulfur the crude less expensive, but with a temperate or worse distillation costs etc.
5. In essence, the measures compartmentalize global markets which usually lead to suboptimal supply/demand balances.
6. Measures that put a value on embedded carbon intensity would have some impact on comparative value of different material in the EU. Inevitably this would have some effect on competitive position of different oil/gas sources.
7. The market will dictate which sources of crude oil or finished fuel products will be displaced by new biofuel production.
8. A system based on actual GHG emissions will create a distortion to the international market of crude oils and other feedstocks with a real damage to the EU refining industry. The increased EU demand for low GHG crudes will raise the market price for such crudes. Conversely, the medium and high GHG feedstocks, heavily penalized in EU, will continue being used in the rest of the world: this will create a substantial competitive disadvantage for EU refineries which – in addition to paying more for energy than their competitors - will pay more also for its feedstocks.
9. Depending on the measures adopted this possibly could lead to EU demanding more fossil fuels from one region vs others and therefore having an impact on prices. However over time the consequences may be that European standards level up best practices of the global production in various regions.
10. It could have an impact on shale gas market opportunities, and certainly on oil sands.
11. The EU is a major end-user of these fuels, and some of them are more/less carbon intensive than others. Obviously this will affect the prices of various resources, and that in turn will encourage all suppliers to improve their GHG "footprints" as much as possible, driving innovation & investment.

12. The consequence may be a different fossil fuel sourcing policy for fuel distributors and Europe as a whole, as a price will be attached to the GHG intensity of the fuel. That is a reality already today in the biofuels market where the market is not looking just for 'sustainability compliant biofuels' but puts a different requirement and price tag to the GHG profile of biofuels (e.g. changes in the German biofuels legislation, moving away from volume quotas to GHG savings requirements). The societal impact is expected to be positive insofar it incentivizes best practices.
13. It will help grow the industries which we need globally for a low carbon society. Additionally, the fuels it will support will be those which have a greater future market as emission reductions proliferate globally. Essentially, these measures will make the EU invest in fuels which have a future, and not technological dead-ends.
14. We should consider that these mentioned impacts result from an earlier decision that we aim for a decarbonized energy sector (i.e. including the energy consumed in the transport sector). So that decision has been taken, and the EU should act from the need or urgency that lies beneath this decision. So if decarbonisation is wanted, why should the EU still allow the trading of fuels that do not contribute to that goal?
15. As some fuels are more supported than others, competitive advantages change. In consequence, demand changes the supply / trade. Consistency is important within Europe. Certain geographies have more lenient or no GHG reduction regulations at different stages of fuels production and distribution, more specifically in upstream O&G production, and it will reflect on the carbon intensity of fuels arriving from such regions to the EU, affecting competitiveness of those fuels in the EU market. But that is precisely how regulation should work to promote adoption of cleaner industry practices and increase competition. If emissions are treated seriously, it will impact the prices of the fossil hydrocarbons.
16. There will inevitably be an impact if new measures are adopted. Whether using default values or actual data, products sourced from different regions will be graded in terms of their GHG credentials which are likely to have an impact on availability and price, which will ultimately be passed onto the consumer. This could also have a negative impact on independent traders who may have difficulties in sourcing more desirable products from producers with their own integrated supply networks.
17. Any differentiation in the GHG intensity applied only in Europe will induce a change in trading conditions between regions having higher carbon intensity crudes or finished products thereof.
18. The EU's demonstrated leadership in policies to decarbonize transportation has encouraged other jurisdictions to follow similar courses. Policies that encourage favorable (e.g., lower GHG emissions) fuels will likely lead to changes in trade flows for both higher and lower CI fuels. The phenomenon of 'fuel shuffling' can exist in the short term when jurisdictions have varying environmental performance requirements for fuels.
19. That all depends on the measures. If any type of oil or gas would be allowed to be sold to EU, and lifecycle GHG emissions are just a way to meet FQD type targets, then nothing will really change. If, for example, EU adopts that oil or oil products

can't enter the EU if they are coming from oil fields with no/low flare gas utilization that might have an impact on the markets.

20. The oil and gas price is a political value, which is driven rather by the "market" than by the costs. GHG emissions shall be taken into account as a further political factor when negotiating the oil and gas price.
21. Similar impacts were also recorded in the international trade of biofuels, with the biofuels produced in the EU being less competitive than those coming from certain countries in Asia or Latin America and this mainly due to the higher costs of biomass production and the adopted sustainability criteria that limit the range of possible feedstocks.
22. Reduction of oil dependence comes first, and natural gas is the only available, affordable and cleaner alternative, complemented with the renewable biogas. These are the main actors of the problem, GHG detailed calculations come later.
23. in general it is hard to analyze the results of measures without defining them in the first place. However, the GHG-reduction targets which are currently discussed seem way too small to have a major effect on international trade flows. Furthermore, the costs of this exercise will be paid by the consumers.

The above comments could be actually grouped in two main categories:

- The vast majority of respondents has selected already the "Yes" option and present the estimation that there will be impacts on international trading by any policy measures of the EU based on disaggregated reduction of the CI content of fossil fuels. The stakeholders favouring or not this evolution **stress the pros and cons of such measures** on oil and gas industry and trade. It is interesting that similar policy examples are mentioned, as the sulphur content reduction in oil products.
- A very small group of stakeholders, which has selected the option "No", downgrades the potential influence on international trade and competition conditions in general, because for them these issues are more **dependent on other major policy issues** like security of supply, support of renewables, etc.

Key Messages

- *A significant majority of stakeholders are of the opinion that the measures to be eventually adopted by the EU related to GHG emissions of transport fuels will possibly affect their competitive conditions of world trade.*
- *The shale gas and oil sands market opportunities may be affected.*
- *Differentiation in the GHG intensity applied only in Europe will induce a change in trading conditions between regions having higher carbon intensity crudes or finished products.*

7.5.19 Question 3.4.2

Question 3.4.2 continues from the previous one exploring the judgement of stakeholders on whether the impact of the legislation on world trade could have repercussions on the international obligations of the EU, i.e. WTO obligations etc.

Question 3.4.2

Do you think that this could constitute a violation of the international obligations of the EU (including, but not limited to, the EU's WTO obligations)?

YES NO

Please explain.

Figure 7-31 presents the distribution of answers for all stakeholders who replied. More than half of them replied "no" to this question, while there were a non-negligible percentage of respondents (15%) who chose abstain from answering to this question.

Figure 7-31 Question 3.4.2 - Distribution of answers for all respondents

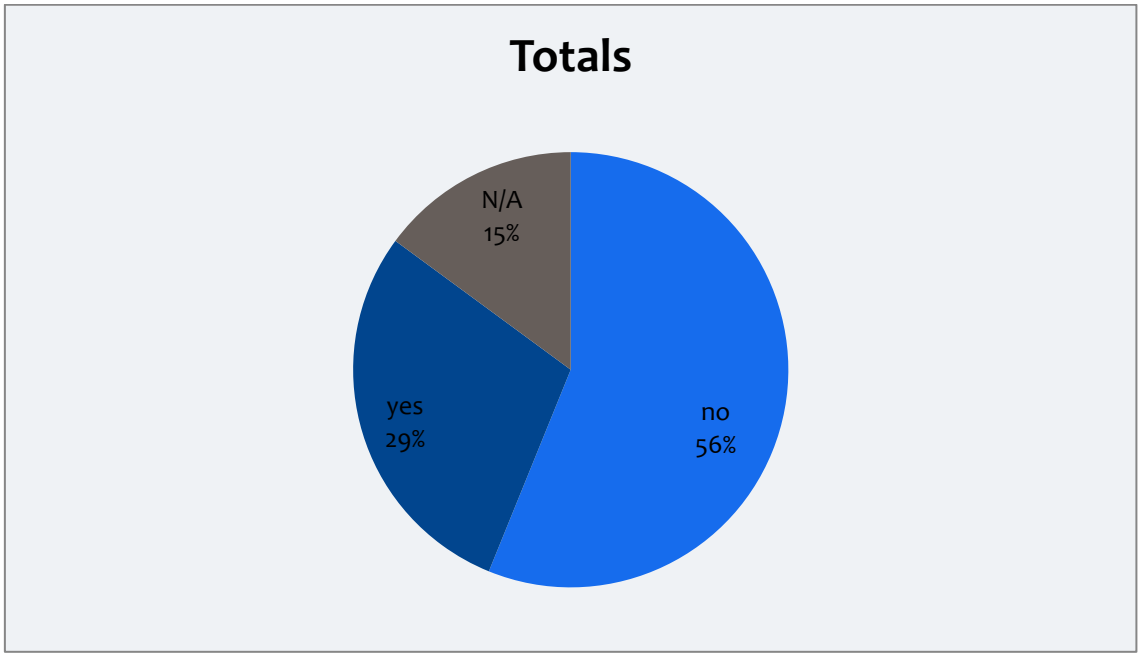


Figure 7-32 and Figure 7-33 show a tendency of the Oil and Gas sector and Public Authorities towards the "yes" answer. On the other hand, the Biofuels industry and NGOs in their majority believe that the revision of the legislation would not constitute a violation of the international obligations of the EU.

Figure 7-32 Question 3.4.2 - Number of answers by reply and category of stakeholder

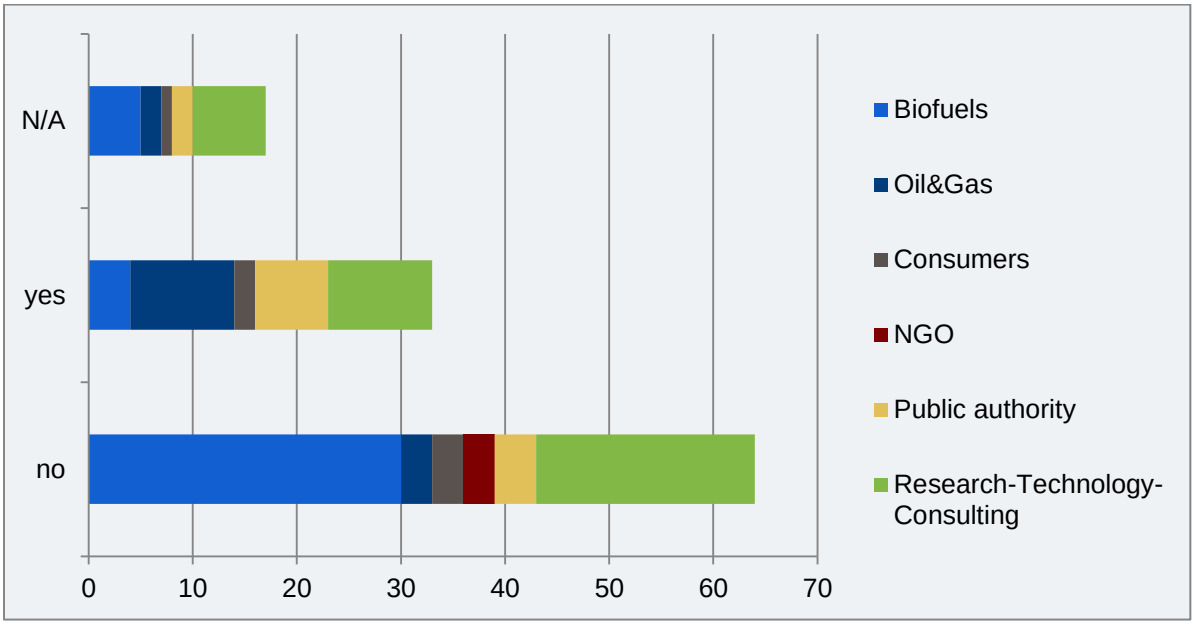
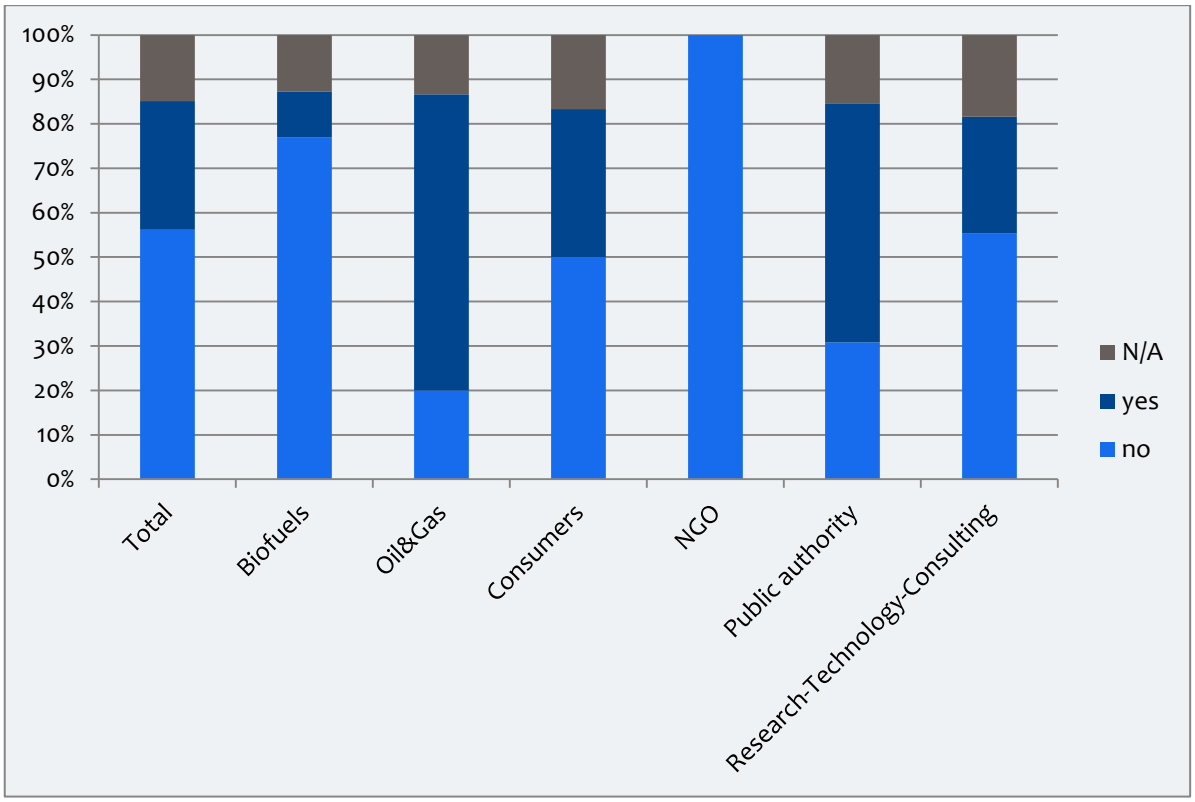


Figure 7-33 Question 3.4.2 - Distribution of answers in percentages by category of stakeholder



7.5.20 Comments on Question 3.4.2

The respondents had the possibility to comment on the Question 3.4.2 and select one of the two proposed options (yes, no). In this section we present the specialized comments and opinions expressed by stakeholders on the possibility of policies on CI reduction (3.4.1) could violate the EU compliance to the WTO obligations. The most significant comments and statements of the stakeholders on the Question 3.4.2 of the Questionnaire are the following:

1. Several legal studies have indicated that any form of crude differentiation is likely to raise WTO concerns over 4 WTO provisions: Article III.4, article I:1 and article XI:1 of the GATT and article 2.1 and 2.2 of the TBT.
2. Any crude differentiation policy is violating WTO rules. We have to notice, however, that according to an opinion issued by the EU legal services in December 2011, different GHG intensities by broader categories of feedstock types (as opposed to more detailed crude differentiation) is compatible to WTO rules.
3. A proposal based on actual GHG emissions is believed to raise significant concerns under at least 2 WTO agreements: the General Agreement on Tariff and Trade (GATT) and on the Agreement on Technical Barriers to Trade (TBT). These agreements seek to prevent discrimination against imports from a particular country vis-a-vis like import from another country or those from domestic producers (GATT) and to remove unnecessary obstacles to trade such as the imposition of needless complex compliance requirements or ill-tailored requirement measures (TBT). Furthermore it sets a wrong precedent of product discrimination depending upon its origin and alleged energy consumption in the manufacturing process.
4. The imminent destruction of the global environment demands action far beyond what it contemplated here, and if that means renegotiation the terms of the WTO, exiting the WTO, etc., that is more than amply justified. Europe is extraordinarily vulnerable both to direct (climate change) and indirect (immigration of climate-change refugees), and must act to preserve its future.
5. This does depend on if the EU signs up to TTIP (Transatlantic Trade and Investment Partnership), which if so, will have significant negative implications on all environmental regulations. If TTIP is not signed, then the answer is "no".
6. The WTO has not been designed to operate in the policy environment where the governments or policy makers are creating 'institutionalized markets', in which intangible (climate change) and individual overarching goals are strived for. On the other hand, free and unbiased trade is still possible for everybody as long as everybody needs to fulfill the entry conditions for products that are used in or imported to the EU.
7. The legal analysis is presented in Chapter 9 of the relevant ICCT published report for DG Clima on the upstream GHG emissions of crude oil supplied to Europe (Upstream Emissions of Fossil Fuel Feedstocks).
8. for Transport Fuels Consumed in the EU
9. Economic operators are still able to import and use these fossil fuels. It only leads to higher GHG emissions of their overall fuel pool that need to be balanced by other products, e.g. biofuels. This is similar to the sustainability requirements for biofuels.

In Germany the GHG quota system that is in place since 2015 also connects the GHG performance of biofuels with the quote fulfillment and therefore their attractiveness in the market.

10. There are still debates around whether the EU sustainability criteria violate WTO rules. They do not - although the critical issue is implementation, given that the policies in their design have done as much as possible to ensure WTO compliance. The same principle can apply to any other set of criteria drawn up for any other energy/fuel type.
11. The WTO General Agreement on Tariffs and Trade (GATT) may permit these types of measures under articles XX(b) and XX(g) that pertain to recognized purposes of product differentiation based on measures deemed necessary to protect human, animal or plant life or health and relating to the conservation of exhaustible natural resources. The ability to reduce the environmental impacts of transportation fuels will be aided by the ability of jurisdictions to differentiate between fuels based on their environmental performance (e.g., GHG emissions). The methods of comparing fuels must be transparent and based on equivalent system boundaries.
12. The biofuels policy is also differentiating between different biofuels feedstocks and presenting different carbon intensities but does not constitute a violation of EU international obligations. A legal analysis conducted on the FQD 7a implementation concludes that the European Union has a strong likelihood of success on the merits in a WTO challenge against its reporting measures setting out a default value for GHG emissions from tar sands. Other precedents on environmental files clearly show that the EU has the right to adopt regulations applying to international products, based on environmental concerns. Most relevant example is the ban on seal products based on moral grounds. The WTO recognized the EU right to enact such a ban.
13. To the extent it is an issue, the WTO policies should be revised. It is "tail wagging the dog" thinking to have WTO policies that hinder getting our society on a more sustainable resource base (including transport fuels and their water use and GHG emissions).

The above comments could be actually grouped in two main categories:

- About half of respondents has selected already the “Yes” option and **placed emphasis on potential discrimination measures on oil trading** that could be received negatively by the WTO. It is worth considering also that these stakeholders, coming mainly from the oil and gas industry, were rather not so optimistic on the idea that the compliance with the WTO could be an obstacle finally.

The other half of stakeholders is negative to the idea that such an EU policy could violate the WTO regulations on international trade; they place the emphasis on **justified opinions and recent studies** which analyze this specific topic and conclude that such an EU policy may be implemented in accordance to the WTO provisions placing emphasis on the social and environmental character of the policy measures.

Key Messages

- *A small majority of the stakeholders are of the opinion that such measures if taken into policy, will not result in WTO violations.*
- *It may be possible to justify such measures under existing WTO law.*

7.5.21 Question 3.4.3

Question 3.4.3

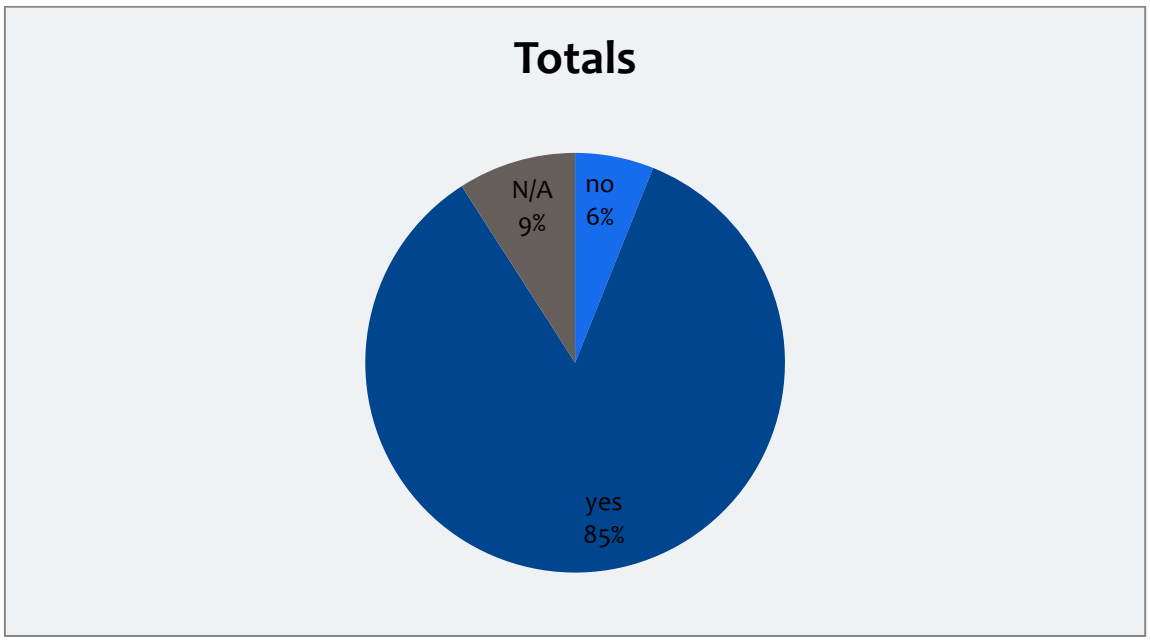
If your answer is "YES", do you think that the EU could adopt measures in such a way as to meet the regulatory objective of reducing GHG emissions from transport fuels for environmental purposes, without violating its international obligations?

YES NO

Please explain.

Question 3.4.3 is addressed to stakeholders who answered positively in Question 3.4.2, requesting their opinion on whether the EU could adopt measures in order to reduce GHG emissions from transport fuels without violating its international obligations. Figure 7-35 and Figure 7-36 present the replies of respondents, only for the stakeholders who answered "yes" in the previous Question. It is obvious that the vast majority of people who believe that the revision of the legislation on GHG emissions would constitute a violation of the international obligations of the EU ("yes" on Question 3.4.2), also believe that the EU could be in position of adopting measures for avoiding this violation.

Figure 7-34 Question 3.4.3 - Distribution of answers for all respondents who answered "yes" in Question 3.4.2



In Figure 7-35 and Figure 7-36, it is shown that the only respondents who answered "no" to Question 3.4.3 come from the Biofuels and the Oil and Gas sectors.

Figure 7-35 Question 3.4.3 - Number of answers by reply and category of stakeholder among those who answered "yes" in Question 3.4.2

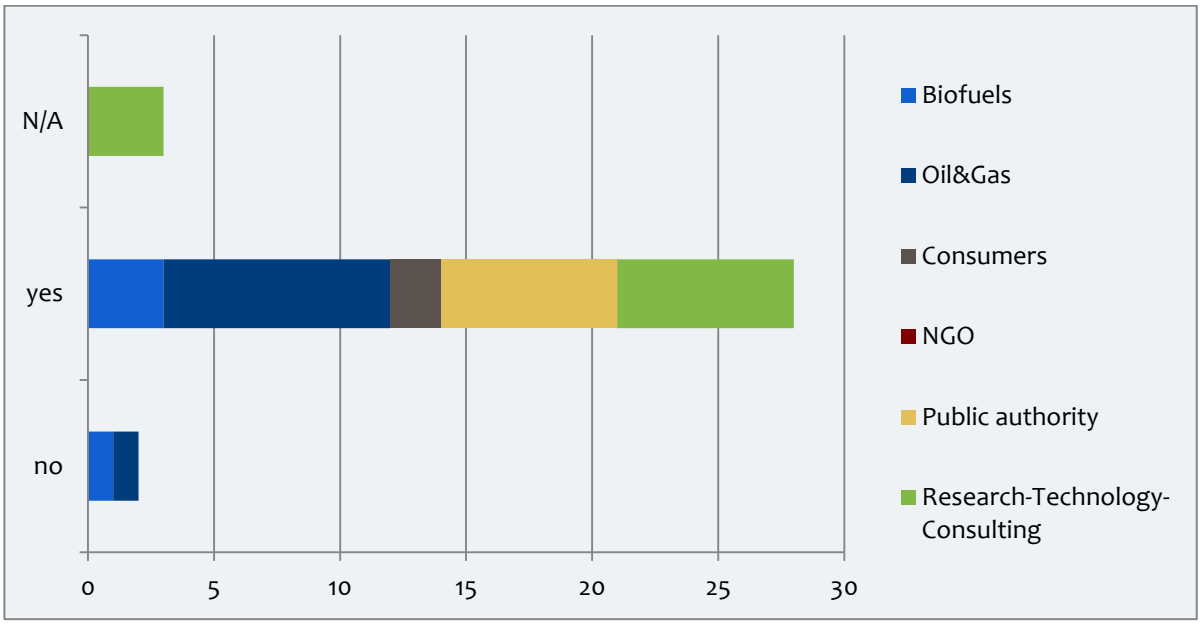
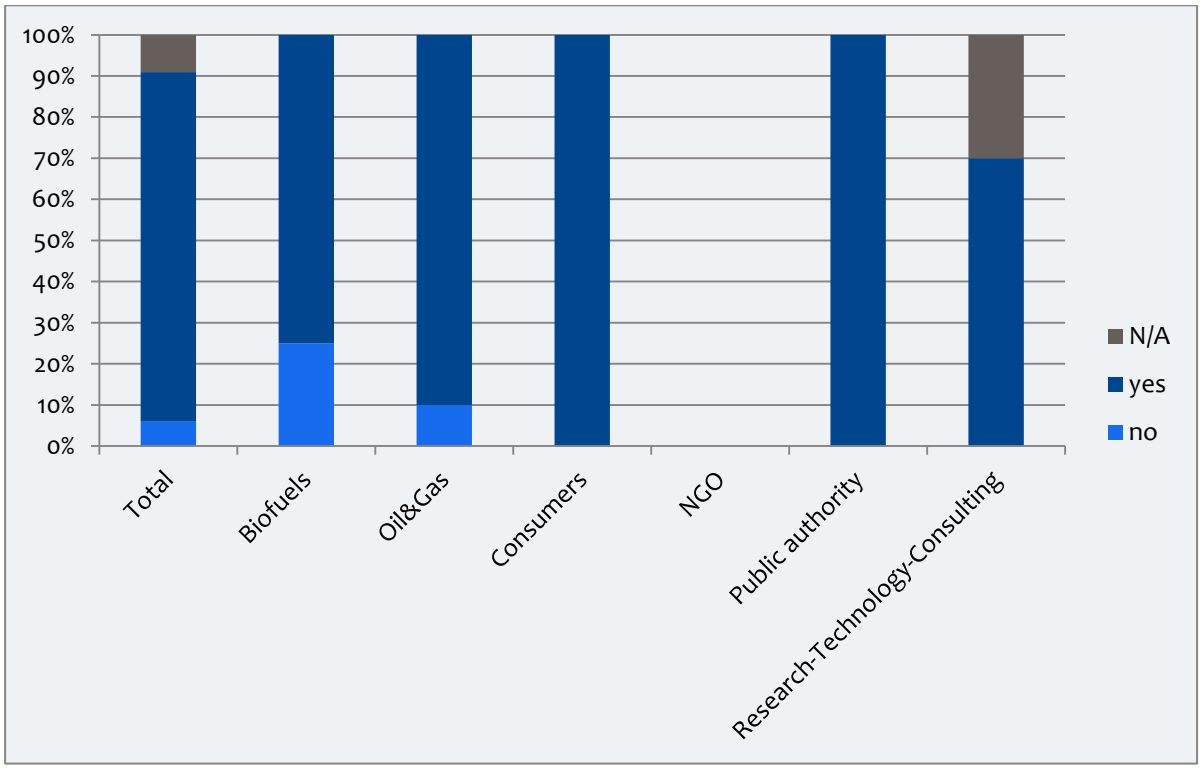


Figure 7-36 Question 3.4.3 - Distribution of answers in percentages by category of stakeholder among those who answered "yes" in Question 3.4.2



The overall conclusion arising from this section is that most stakeholders, no matter what kind of business they represent, believe that the revision of the EU legislation towards the reduction of GHG emissions in the transport sector would either **not jeopardize the EU's**

international trade obligations or that the EU would be able to overcome this kind of issues.

7.5.22 Comments on Question 3.4.3

The respondents had the possibility to comment on the Question 3.4.3 and select one of the two proposed options (yes, no). In this section we present the specialized comments and opinions expressed by stakeholders on the issue of detailing the Question 3.4.2 about the possibility of EU to take proper measures with no actual violation of international obligations. The most significant comments and statements of the stakeholders on the Question 3.4.3 of the Questionnaire are the following:

1. A requirement applied equally to the market to correctly count the greenhouse gas emissions of any product does not, of itself, contravene an international obligation. Did the Canadians or anyone else take the EU to the WTO over the biofuel sustainability criteria?
2. This will require global coordination and adoption by all suppliers. Difficult but no impossible.
3. The EU must not sign up to the Transatlantic Trade and Investment Partnership if it intends to reduce GHG emissions from transport fuels without violating international agreements. The EU would face legal challenges under TTIP's Investor-state dispute settlement (ISDS).
4. To set the right system boundaries and entry conditions for fuels, e.g. by capping the carbon intensity. Every company, whether from within or outside the EU that does comply is invited to do business!
5. There are numerous examples of environmental legislations that were found to be compatible with WTO obligations. Fairness in treatment of similar products is a key issue. In addition, if actual values can be reported, then there is no reason why a product and a region would be de facto excluded from the EU market.
6. Similar penalization as for carbon tax.

Almost all the comments of respondents presented above are coming from questionnaires with the "Yes" option selected on Question 3.4.3. The response was rather poor in terms of content and number of stakeholders due to the particular specialized content of the question. The few comments repeat more or less the statements of the previous questions and no new information could be exploited.

7.5.23 Question 3.4.4

The respondents had the possibility to comment on the Question 3.4.4 by expressing their opinion on the restrictive measures which could be undertaken by the EU without taking into account international obligations. The most significant comments and statements of the stakeholders on the Question 3.4.3 of the Questionnaire are the following:

Question 3.4.4

What, in your view, would be the least trade restrictive measures the EU could adopt in this regard, while at the same time meeting the regulatory objective of reducing GHG emissions from transport fuels for environmental purposes? Please only take into account the trade restrictiveness of such measures, without taking into account whether or not such measures may constitute a violation of the EU's international obligations.

1. Just having transparency in the beginning, adapting the reference values, publicize emissions and impacts of oil/gas, and such soft measures should be possible without any problem. On the base of the state of the art we can define more restrictive measures. GHG is not the only problem of fossil fuels (geopolitical tensions, oil pollution, social, corruption, etc.).
2. Promote dedicated tanks in the filling stations across Europe, and reduce the costs for tolls in all Europe depending on the use of transport fuels with less GHG emissions.
3. The least trade restrictive measures the EU could adopt, while at the same time meeting the regulatory objective of reducing GHG emissions from transport fuels for environmental purposes, is the use of average EU default values, as they are used today in the methodology approved in February 2015. The proposals of DG Clima of October 2011 are obviously much more trade restrictive.
4. Placing a carbon price on embedded carbon would not be trade restrictive, it would simply adjust value. It is not however clear that the least trade restrictive approach would be the best one.
5. Introduction of a tax credit / subsidy on locally produced fuels in proportion to their GHG reductions, as local production decreases the contribution of fuel transportation to the overall carbon footprint of fuels (improving the overall carbon footprint of those fuels), incentives production of lower carbon fuels, while contributing to energy security goals.
6. It is difficult to imagine a measure applied equally to the market that the EU could take in the field of fossil transport fuels that would be considered a restriction of imports or a restraint of trade. As stated above, a set of criteria, including greenhouse accounting, applied equally to individual deliveries of individual supply streams has worked perfectly well for biofuels. Why would it not work for fuels in general?
7. The best way would be to have international agreements on fuel quality, which could be included in the Paris climate negotiations in December 2015.
8. To apply a cost of carbon that could be linked with EUAs trade, to any transport fuel imported to the EU or produced in the EU (same treatment). Economic incentives / penalties versus banning any product are recommended.
9. In order to avoid distortion on competitiveness and additional costs for EU energy users, a fair and equal treatment should be applied to all fuels, being of fossil or renewable origin. For easier and simple application, we could suggest to: a) do not apply ILUC factors to biofuels as long as sufficient, robust and reliable scientific data can be obtained and assessed; b) compare biofuels to the worse marginal fossil fuels that they would be replacing/substituting, by setting the current Fossil Fuel Comparator values for Biofuels of FQD and RED Annex V at levels equal to the GHG emission value of products such as oil shale or oil bitumen.

10. A tax based on the GHG performance of different types of fuel (fossil and renewable), given that all fuels are assessed equally in terms of their sustainability, i.e. the same criteria should apply to fossil and renewable fuels alike.
11. Impose a max acceptable LCA/GHG emitted CO2eq/MJ fuel, not based on the assumption that biofuels emit "zero" CO2, but with each fuel self-sustaining its supply chain and considering the relevant acreage of land required to generate the fuel and its supply chain.
12. Demand GHG reporting and labeling to support consumer choice. Set a highest accepted limit for GHG emissions from fossil fuels used in the EU, like the biofuels lowest GHG reduction in RED and combine that with a stepwise decrease of the limit to support a positive development until 2030.
13. The potential measures adopted in the FQD that recognize the different GHG performances of fossil fuel can be incorporated in the least potentially trade restrictive way by utilizing LCA calculation methods, models, and data based on and in compliance with global LCA standards and incorporate equivalent system boundaries.
14. Requiring sustainability certification -- verifying that feedstocks/fuels being used meet or exceed minimum GHG reduction thresholds -- will by default be a restrictive policy, but it needs to be restrictive to be successful.

The above comments could be not actually grouped in categories; however the actual interests of the oil and gas industry and of biofuels industry are clearly implied. The proposed measures, although not innovative, cover a broad spectrum of potential policies to be followed and are based in principle on existing experiences of tax policy and climate change reduction frameworks.

7.5.24 Question 3.5

Question 3.5

Do you think that the FQD obligation of suppliers to provide information on lifecycle GHG emissions has to be strengthened in order all market participants in the oil and gas supply chain to measure, assess and confirm the carbon intensity of their activity?

YES NO

The final Question of the questionnaire is rather straight-forward and seeks to conclude the responses of stakeholders, by asking whether the FQD should be strengthened in order all market actors of the oil and gas lifecycle to measure, assess and confirm the CI of their specific activities.

In total, 8 out of 10 respondents answered "yes" to this question (Figure 7-37). As shown in the graphs represented in Figure 7-38 and in Figure 7-39, more than half the number of respondents who replied negatively to this question come from the Oil and Gas sector, while there are also stakeholders within Public Authorities, Research-Technology-Consulting and the Consumers category who also answered "no" to this Question.

Figure 7-37 Question 3.5 - Distribution of answers for all respondents

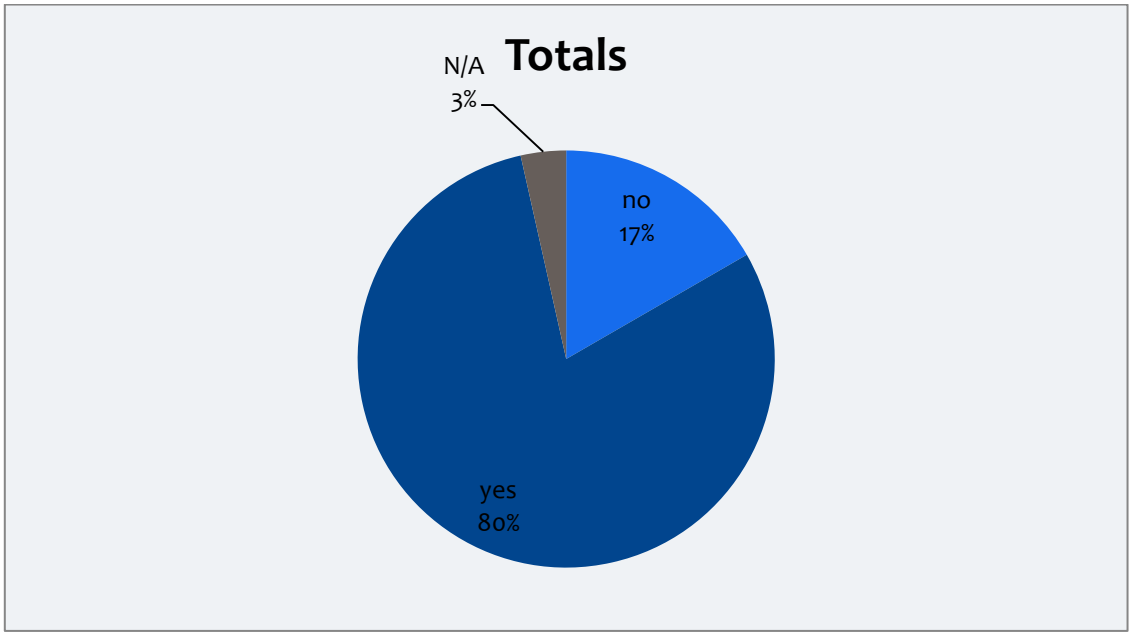


Figure 7-38 Question 3.5 - Number of answers by reply and category of stakeholder

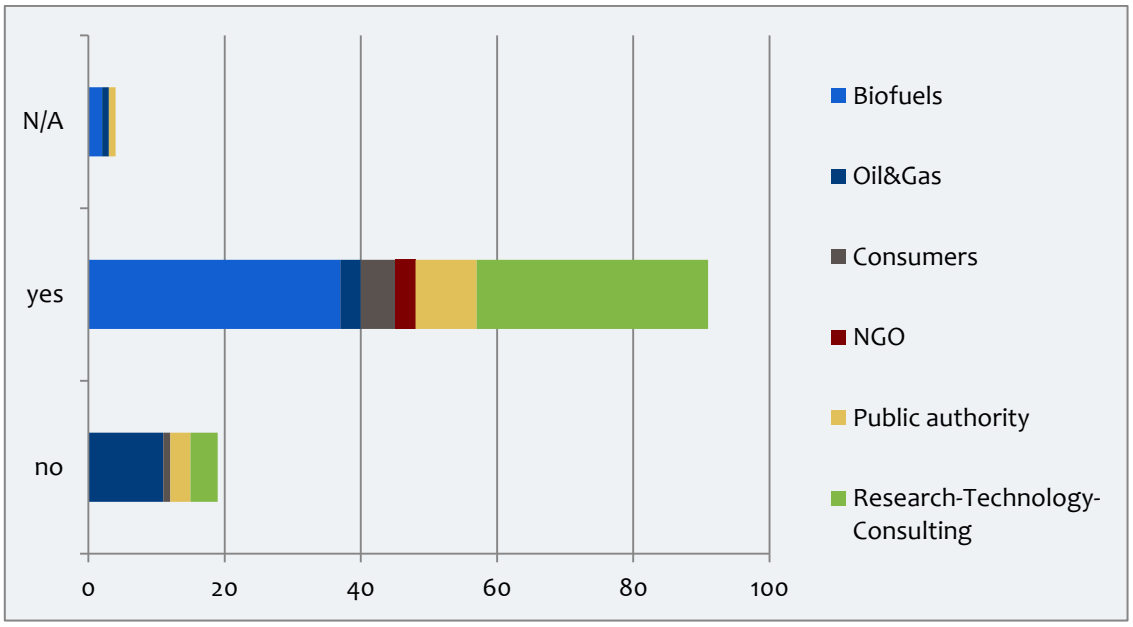
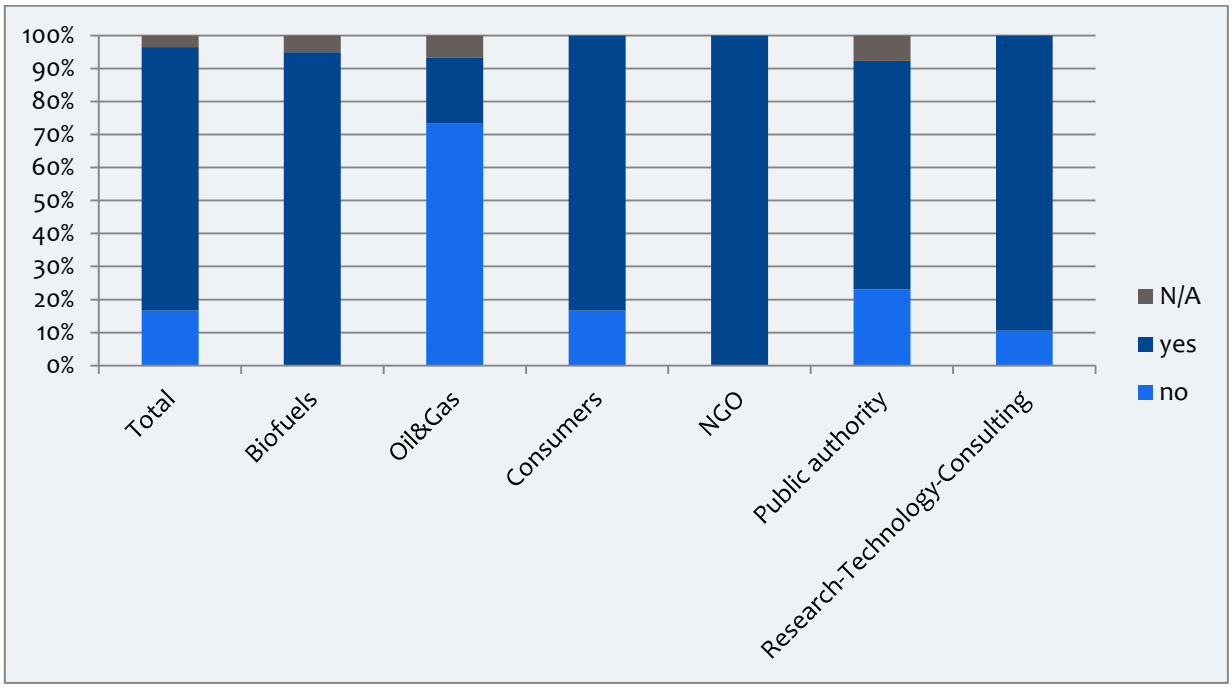


Figure 7-39 Question 3.5- Distribution of answers in percentages by category of stakeholder



7.6 Concluding Remarks

The elaboration of the responses of the questionnaire could be summarized in the following paragraphs. It is evident that the opinions of the stakeholders are contradicting a lot on some of the most crucial issues arisen. This outcome was expected and is confirmed through the survey; it happens due to the strong interests of the most significant categories of stakeholders, namely of the oil and gas industry and biofuels industry. Therefore it is worth considering that:

- The biofuels industry and other stakeholders insist that **actual GHG data should be collected for all the streams** supplying oil and gas to the EU transport consumers in order the European Commission to be able to organize a rigorous and effective policy, which aims at substantial and justified GHG emissions reduction. These data should be made publicly available and follow a standard procedure of calculation and verification. Moreover, the responsibility and the incentive to reduce the CI must not be assigned to the suppliers as a group, but to each one of the suppliers, thus the judgement of compliance to the targeted GHG reduction will be based on analytic calculations and not on assumptions and empirical estimations. The use of models, if necessary, should be based on input of actual and confirmed parameters and data; thus avoiding the use of default values, which at present are useful in cases of lack of actual data or when we need to cope with various uncertainties. Nevertheless, the EU initiatives in using reliable modelling tools should be harmonized with the overall

approach of information declarations of suppliers and tracking on GHG emissions at all the stages of fuel supply to final consumer of transport sector.

- The approach based upon **disaggregated GHG intensities for each individual oil/gas stream requires** GHG emissions calculations in the whole value chain from well to tank. These data have to be verified and reported by suppliers in an accurate and differentiated manner. Such data are mostly available for European and North American upstream and downstream activities, whereas midstream information could be also characterized as properly accessible. There are many cases where poor data are publically available due to commercial sensitivity reasons of oil and gas companies and so suppliers may have difficulties in providing such information. Anyway, this approach requires oil/gas suppliers to put in force a more sophisticated traceability mechanism, similar to that one being in place for biofuel producers. Almost all categories with the exemption of Oil and Gas industry estimate the expected additional cost for data book keeping sounds affordable, given the turnover of the fossil fuels activity. The stakeholders, coming in principle from the Oil and Gas industry, argue on the complexity of this exercise and the potential problems which might come up.
- **A consistent and global system on verification of actual GHG data has to be developed**, especially for oil and gas originating from regions outside Europe and North America and for this reason a reliable methodology should be followed. Change of the oil companies' policy on data availability has to be achieved also. So the CI information will be based on measured data and relevant calculations which have to be verified. The existing examples of jurisdictions and implementation of such collection and elaboration of GHG data should be exploited before deciding the proper model to be followed under the EU acquis.
- There is a strong favour of most respondents to the necessity for **exploitation the variation of CI in fossil fuel to estimate GHG emissions reduction as by FQD**. This group comes from almost all categories with the exemption of oil and gas industry and estimate that this approach is endorsed with certain difficulties. On the other hand, the oil and gas industry argues on the potential problems of refining competition and the expected changes in the oil market that might come up. The same category is negative to sustainability criteria changes insisting that **regulatory stability should be maintained** with no changes at present. In addition a broad concern is expressed about the global effect and whether the compliance with the objective of the FQD and RED to promote biofuels is served or not by such a change.
- The vast majority of respondents estimates that there will be **impact on international trading** by any policy measures of the EU based on disaggregated reduction of the CI content of fossil fuels. The stakeholders favouring or not this evolution stress the pros and cons of such measures on oil and gas industry and trade. It is interesting that similar policy examples, coming from past policies, are mentioned, as the sulphur content reduction in oil products. Potential discrimination measures on oil trading that could be received negatively by the WTO, although the compliance with the WTO could be an obstacle finally. There are justified opinions and recent studies, which analyse this specific topic and conclude that such an EU policy may be implemented in accordance to the WTO provisions. Relevant policy measures, which

are proposed, although not innovative, cover a broad spectrum of potential implementation approaches and are based in principle on existing experiences of tax policy and climate change reduction frameworks.

Nevertheless, it is worth mentioning that the international pressure for the correct assessment of the fossil fuels CI will be intensified. The recent **Working Paper of IMF "How Large Are Global Energy Subsidies?"** provides an updated picture of energy subsidies at the global and regional levels. It focuses on the broad notion of post-tax energy subsidies, which arise when consumer prices are below supply costs plus a tax to reflect environmental damage and an additional tax applied to all consumption goods to raise government revenues. Post-tax energy subsidies are dramatically higher than previously estimated and are projected to remain high. Post-tax consumer subsidies arise when the price paid by consumers is below the supply cost of energy plus an appropriate "Pigouvian" (or "corrective") tax that reflects the environmental damage associated with energy consumption and an additional consumption tax that should be applied to all consumption goods for raising revenues. Environmental damage includes the harm caused to local populations by air pollution as well as to people across the globe affected by the floods, droughts and storms being driven by climate change.

The key findings of the study are the following:

- Post-tax energy subsidies are dramatically higher than previously estimated and will reach $5.3 trillion that is 6.5% of global GDP in 2015.
- Post-tax subsidies are large and pervasive in both advanced and developing economies and among oil-producing and non-oil-producing countries alike. But these subsidies are especially large (about 13%–18%) relative to GDP in Emerging and Developing Asia, the Middle East, North Africa, Pakistan and the Commonwealth of Independent States (CIS).
- The vast sum is largely due to polluters not paying the costs imposed on governments by the burning of coal, oil and gas. Coal is the dirtiest fuel in terms of both local air pollution and climate-warming carbon emissions and is therefore the greatest beneficiary of the subsidies, with just over half the total. Oil, heavily used in transport, gets about a third of the subsidy and gas the rest.
- Most energy subsidies arise from the failure to adequately charge for the cost of domestic environmental damage—only about one-quarter of the total is from climate change—so unilateral reform of energy subsidies is mostly in countries' own interests, although global coordination could strengthen such efforts.
- The fiscal, environmental, and welfare impacts of energy subsidy reform are potentially enormous. Eliminating post-tax subsidies in 2015 could raise government revenue by $2.9 trillion (3.6 percent of global GDP), cut global CO_2 emissions by more than 20%, and cut pre-mature air pollution deaths by more than half. After allowing for the higher energy costs faced by consumers, this action would raise global economic welfare by $1.8 trillion (2.2% of global GDP).

8 TASK F: PROJECTIONS UP TO 2030

Within the context of Task f, the study focuses on emissions associated with fuels projected to be consumed in the EU up to 2030, with particular emphasis on the years 2020 and 2030. The projections on future demand for petroleum refined products are based on projections drawn from scenarios quantified using the PRIMES model. Two scenarios already quantified using PRIMES are used: the Reference scenario 2013[119] and the GHG40 scenario[120] used for the Impact Assessment by the European Commission for the policy framework for climate and energy in the period from 2010 up to 2030.

This section presents an introduction to the methodological aspects of Task f, a brief overview of the PRIMES energy systems model and the key results obtained using the present methodological framework. The results present an outlook on GHG emissions for the Reference scenario in 2020 and the Reference and the GHG40 scenario for 2030.

8.1 Methodology and Assumptions

The current study addresses the objective of the Task f using the official projections provided by E3M-Lab to the European Commission in 2013 using the PRIMES energy systems model. For the purposes of this project, projections of demand and supply of oil fuels and natural gas have been used as quantified using the PRIMES energy system model for the EC, for a Reference and a Decarbonisation scenario. The Reference scenario is based on the Reference scenario 2013, while the decarbonisation scenario is based on the GHG40 policy scenario.

The estimation of the GHG emissions associated with the petroleum fuels and natural gas WTT value chain follows the methodology of Task c applying to the demand projected for years 2020 and 2030. GHG emissions that occur during the upstream, midstream and downstream sectors are assessed with the use of the enhanced and modified OPGEE and GHGenius emission accounting models, as already presented in Task c. The analysis for projection years is based on assumptions relevant to current trends and to future production/import projections. These assumptions have been harmonized with latest IEA World Outlook projection of global oil/gas trade flows and regional production. However, regarding the upstream and midstream GHG emissions, no changes were assumed relative to 2012 calculations (presented in Task c) due to the large uncertainty for the actual data input parameters for the OPGEE model.

[119] [redacted]

8.1.1 Model structure

PRIMES is a modelling system that simulates a market equilibrium solution in the European Union and its Member States involving economic decision making of various stylized actors. It determines energy consumption, transformation and supply of various sectors, the costs involved and market prices. The PRIMES model simulates the response of energy consumers and the energy supply systems to different economic developments, exogenous constraints and drivers.

The model determines the equilibrium by finding the prices of each energy form such that the quantity producers find best to supply match the quantity consumers wish to use. The equilibrium is forward looking and includes dynamic relationships for capital accumulation and technology vintages. The model is behavioral, formulating agents' decisions according to microeconomic theory, at the same time representing, in an explicit and detailed way, the available energy demand and supply technologies as well as pollution abatement technologies. The system reflects considerations about market competition economics, industry structure, energy /environmental policies and regulation. These are conceived so as to influence market behavior of energy system agents. The market integrating part of PRIMES simulates market clearing.

8.1.2 Model coverage

PRIMES is a partial equilibrium model simulating the entire energy system both in demand and in supply; it contains a mixed representation of bottom-up and top-down elements. The PRIMES model covers the 28 EU Member States, as well as candidate and neighbor states (Norway, Switzerland, Turkey, South East Europe). The timeframe of the model is 2000 to 2050 by five-year periods; the years up to 2010 are calibrated to Eurostat data. The level of detail of the model is large as it contains:

- 12 industrial sectors, subdivided into 26 sub-sectors using energy in 12 generic processes (e.g. air compression, furnaces)
- 5 tertiary sectors, using energy in 6 processes (e.g. air conditioning, office equipment)
- 4 dwelling types using energy in 5 processes (e.g. water heating, cooking) and 12 types of electrical durable goods (e.g. refrigerator, washing machine, television).
- 14 transport means including private passenger road (cars, light duty vehicles, powered two-wheelers), public passenger road (buses and coaches), road freight (heavy duty vehicles, light duty vehicles) rail passenger and freight, inland navigation and aviation) and vehicle technologies (e.g. internal combustion engine by euro class, conventional hybrids by euro class, plug-in hybrids, electric vehicles, fuel cells and others).
- 14 fossil fuel types, new fuel carriers (hydrogen, biofuels) 10 renewable energy types.
- Main Supply System: power and steam generation with 150 power and steam technologies and 240 grid interconnections.

- Other sub-systems: refineries, gas supply, biomass supply, hydrogen supply, primary energy production.
- 7 types of emissions from energy processing (e.g. SO_2, NO_x, PM).

8.2 General assumptions on crude oil projections

The estimation of GHG emissions in refining stage follows the methodology of task c with demand-driven refinery production and the future projections of refinery inputs and outputs taken from PRIMES depending on the fuels market trends.

8.2.1 Overall trends in the refining sector up to 2030

For the future estimates of GHG emissions in the refining sector the following issues were taken into consideration based on relevant assumptions:

- Refiners driven by the oil products market demand are going to boost their diesel production. European refineries have already turned their production to diesel at the expense of petrol and this trend becomes more intense the next years.
- Changes in global crude oil supply determine a different mixture of crudes fed in European refineries. The new mix of crudes imported to EU is assumed to have low impact on the quality of crude.
- Processing capacities adapted to the change in demand. Despite the refinery closures and the unavoidable reduction in total refining capacity in Europe, refinery schemes are assumed to be the same with those described in task c, but the capacities of individual processes follow the new demand in petroleum products.

The demand for petroleum fuels is projected to follow a declining path in the future and this trend affects the refining activity and reduces the refinery utilization. Refinery closures tend to increase and refinery production follows a downward trend.

Most European countries, except for Romania, Poland and Hungary, are expected to have a reduction in their refining capacity. In comparison with 2012 the reduction levels in crude distillation capacity by 2030 range from 3% to 22% according to the reference scenario and from 1% to 24% according to the decarbonisation scenario (Figure 8-1). Romania appears to have an increased crude throughput by 2030 which is related to a predictably large increase of naphtha production.

Figure 8-1 Change (%) in crude throughput in refineries by EU MS.

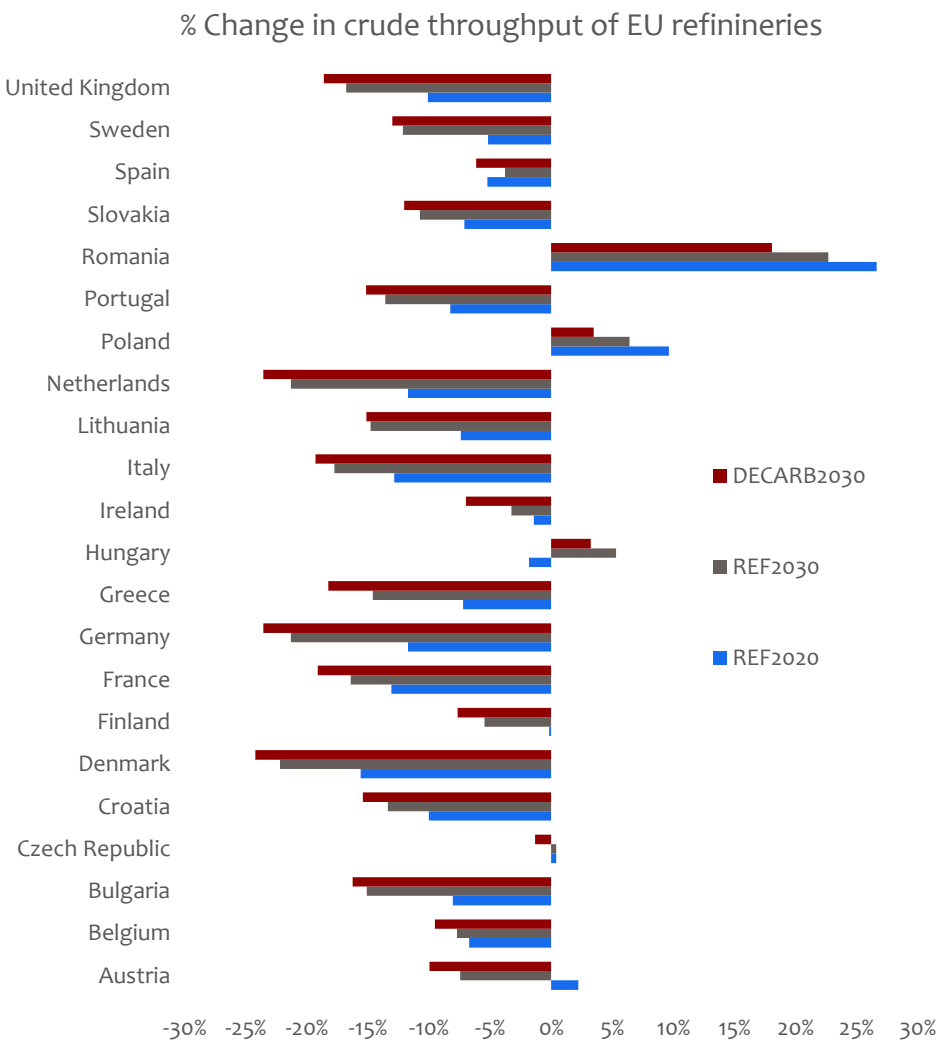


Figure 8-2 depicts the energy equivalent of the refineries production in the EU for 2012 and the projection years. The total refinery production falls by 7% in 2020 and by 12% and 14% in 2030 under the reference and the decarbonisation scenario respectively. The pronounced switch of petrol to diesel demand and the steadily increasing demand of kerosene (jet fuel) leads to a proportional change in refinery production. In detail, at EU MS level the future diesel production ranges from 30% to 59% of total production (2030 estimates) while petrol production does not exceed 20% of total production. The output of naphtha only has a small increase in relative yield while fuel oil production (including different grades of fuel oil) will see a decline by 2020 and 2030.

Figure 8-2 Current and forecast refinery production in EU

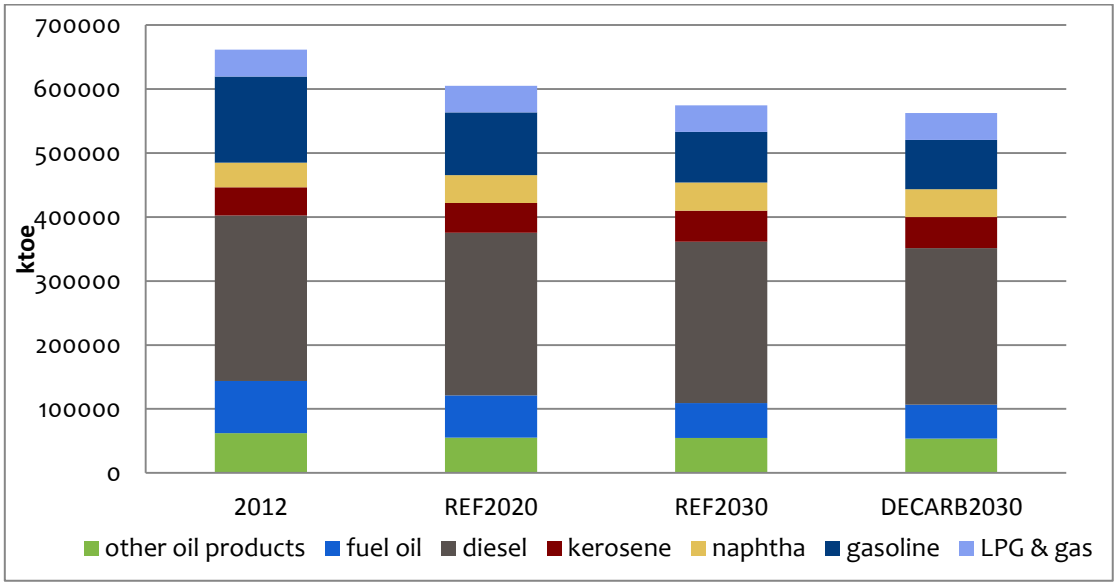


Table 8-1 Refinery production of fuels (percentage of the total refinery production)

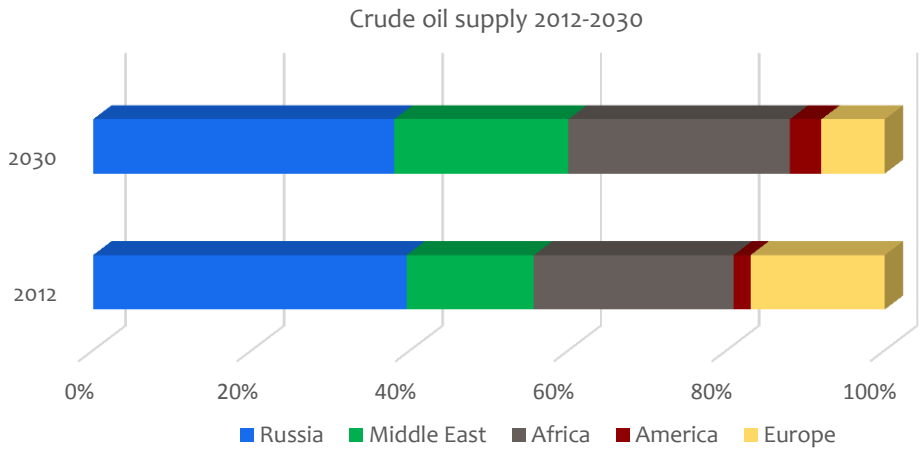
	2012			2020			2030		
	petrol	diesel	kerosene	petrol	diesel	kerosene	petrol	diesel	kerosene
Austria	18%	42%	6%	14%	44%	7%	11%	46%	9%
Belgium	15%	36%	5%	10%	37%	5%	9%	38%	6%
Bulgaria	26%	32%	3%	23%	35%	5%	20%	38%	7%
Czech Republic	19%	40%	2%	14%	44%	2%	11%	46%	3%
Croatia	27%	31%	2%	25%	37%	4%	21%	40%	5%
Denmark	26%	43%	6%	22%	48%	9%	20%	54%	10%
Finland	28%	46%	4%	23%	47%	5%	20%	49%	5%
France	20%	41%	6%	14%	45%	7%	12%	48%	7%
Germany	21%	43%	5%	16%	44%	6%	12%	44%	7%
Greece	21%	31%	7%	16%	37%	8%	13%	39%	10%
Hungary	15%	46%	3%	12%	49%	4%	10%	49%	4%
Ireland	17%	38%	8%	11%	54%	4%	10%	59%	4%
Italy	22%	41%	4%	19%	45%	5%	17%	46%	5%
Lithuania	30%	32%	9%	27%	33%	14%	24%	35%	17%
Netherlands	13%	36%	11%	12%	35%	12%	11%	36%	14%
Poland	18%	44%	3%	14%	47%	3%	11%	51%	3%
Portugal	19%	33%	8%	16%	38%	10%	14%	42%	12%
Romania	26%	35%	3%	16%	28%	4%	14%	30%	5%
Slovakia	22%	46%	1%	20%	51%	1%	18%	53%	1%
Spain	15%	40%	11%	11%	41%	13%	10%	44%	14%
Sweden	20%	37%	1%	14%	39%	1%	12%	41%	2%
United Kingdom	28%	34%	12%	22%	39%	12%	19%	41%	13%

As the refinery production in Europe is expected to decline the next years, the demand in crude oil will also be reduced. Along with the reduction in total crude oil supply, the sources of crudes are going to change.

According to IEA, European crude oil production will decline at an average rate of 6% per year. Europe, due to its favorable geographical position, is flexible to import crude oil from different regions and substitute the declining domestic supply. In terms of projections of crude oil supply to Europe by 2030, the main crude oil exporters to the EU will be Russia, Africa, Middle East and America and, in particular, increased amounts of crude are expected to be imported by Middle East, North Africa and Latin America. Figure 8-3 shows the percentage growth of crude oil sources compared with the current state (2012).

Following the projected changes in the origin of crude oil supply to the EU, the upstream emissions are estimated to increase over 2%. The midstream emissions are projected to remain relatively unchanged compared to 2012 levels. However, there is the possibility of a declining trend given the efiiciency improvements (10-20%) that may occur in maritime transportation from the origin of crude extraction to the destination.

Figure 8-3 Changes in supply of the crude oil mix refined in EU up to 2030



Based on the assumption that the future changes in crude supply will not have a significant impact on the quality of crude, which means that Europe will mostly treat medium/light sweet crudes, we set a framework within which an adapted refinery structure is defined. As also mentioned in task c, petrol production is mainly connected with reforming and fluid catalytic cracking units. Hydrocracking is used primarily to enhance diesel production. Regarding the future refinery schemes in the EU and the capacities of the processes, the model calculations have been based on the following assumptions:

- The European refineries configurations and the capacities of the processes in the future are endogenously adapted to meet the changes in demand of petroleum products. The average mix of crudes is assumed to be similar with that considered for

2012 estimates (no specific information on crude intake by EU country).

- The reduction of petrol production leads to a reduction in Fluid Catalytic Cracking capacity (one of the most emitting processes) while priority is given in the reforming unit to produce reformate (main constituent of petrol) and hydrogen as by-product.
- An increase in residue hydrocracking capacity will be related with the increased production of diesel the next years.
- Increased levels of kerosene production will be combined with a relevant increase in kerosene hydrotreating capacity. An additional stream will be occasionally derived from hydrocracking.
- Possible investments steps in the refining sector may occur towards the hydroconversion of residues and hydrotreating (desulphurization) units in order to meet the more stringent specifications related to the fuel oil production and expected to be introduced by the International Maritime Organization. No specific investment on new refining technologies is taken into consideration for the projections.

8.3 Outlook on GHG emissions from crude oil: 2020 and 2030 horizon

According to the projections, the reduced refining activity in Europe leads to a significant reduction in total CO_2 emissions from European refineries. More particularly, total refinery emissions are expected to be reduced by 11% in reference scenario for 2020 and by 18% in reference scenario for 2030 and 23% in decarbonisation scenario for 2030. Average refinery emissions (expressed per unit of energy equivalent of crude) are projected to be reduced by 4% in 2020 and by 6% and 9% up to 2030 under the reference and decarbonisation scenarios, respectively.

The emissions outlooks for petrol, diesel and kerosene are presented in Table 8-2 and Table 8-3. Regarding the estimated emission factors for 2020 under the two scenarios, there were no significant differences. In this section, we present the results for 2020 obtained from the Reference scenario. Both scenarios, Reference and decarbonisation, were used for the projections of 2030.

Both scenarios provide GHG emissions at the refinery stage which are comparable to those of the current refinery operations. The projected EU average values of emission factors for the three products are slightly different from those obtained for 2012. Average GHG emissions for petrol were estimated 8.28 $grCO_2eq/MJ$ for 2020 and 8.26 $grCO_2eq/MJ$ and 7.87 $grCO_2eq/MJ$ for 2030 under the reference and decarbonization scenario, respectively. GHG intensity of diesel was estimated 7.36 $grCO_2eq/MJ$ for 2020 and 7.16 $grCO_2eq/MJ$ and 7.02 $grCO_2eq/MJ$ for 2030 under the reference and the decarbonization scenario, respectively.

Average values of CO2 emissions could lead to a misguided conclusion that the diesel-oriented production results in slightly lower GHG emissions for diesel. However, the

increased diesel to petrol ratio does not affect the resulted allocated emissions in a standard way. Looking into the results country by country and comparing them to those for 2012, it becomes clear that the response of the marginal CO_2 emissions to the changes in the parameters of the system – mainly the changes in refinery inputs, outputs and capacities- is unpredictable. There are certain cases where the difference between the carbon intensities of petrol and diesel increases or even cases where the one fuel becomes more CO_2 intensive than the other, opposed to the results obtained from 2012 runs. At this point, it should be mentioned that the allocated CO_2 emissions are determined through the optimal solution of the model and change to reflect the changes in the refining system. The variation in the results enhances the conviction that the marginal emissions of the fuels are refinery specific and dependent of all the input modeling data considered for each country.

Table 8-2 GHG refinery emissions for petrol, diesel and kerosene up to 2020 according to reference scenario

2020	Reference scenario		
$grCO_2eq/MJ$	**Petrol**	**Diesel**	**Kerosene**
Austria	12.26	7.85	2.92
Belgium	5.90	5.51	2.85
Bulgaria	6.11	6.38	4.04
Croatia	11.45	10.99	5.89
Czech Republic	7.75	5.93	3.94
Denmark	3.47	4.09	2.82
Finland	6.46	6.31	3.94
France	6.09	5.19	3.65
Germany	6.90	6.47	3.31
Greece	7.01	6.13	4.30
Hungary	8.32	6.04	3.68
Ireland	4.12	3.49	2.41
Italy	8.94	7.38	5.38
Lithuania	5.75	6.10	3.48
Netherlands	5.39	6.11	3.88
Poland	10.46	10.31	5.48
Portugal	9.75	7.86	4.10
Romania	13.80	13.37	6.35
Slovakia	7.04	6.08	4.89
Spain	7.66	6.29	4.02
Sweden	4.11	3.68	2.43
United Kingdom	7.83	6.22	3.74

As regards 2030 projections, the differences between the estimated emissions under the reference and decarbonisation scenarios are attributed to the different crude input which induces different processing and energy consumption for the refinery operations. The results obtained from the decarbonisation scenario show an overall decline in marginal GHG emissions from the production of petroleum fuels in the EU. This reduction of marginal emissions is in line with the marked decline of the projected average refinery emissions under the decarbonisation scenario.

Table 8-3 GHG refinery emissions for petrol, diesel and kerosene up to 2030 according to reference scenario

2030	Reference scenario		
$grCO_2eq/MJ$	**Petrol**	**Diesel**	**Kerosene**
Austria	13.87	7.40	4.26
Belgium	5.73	4.99	3.44
Bulgaria	5.55	5.87	3.95
Croatia	11.46	10.29	5.82
Czech Republic	7.99	6.11	3.25
Denmark	3.29	4.12	2.74
Finland	7.48	5.87	4.03
France	5.42	5.25	3.85
Germany	6.79	6.42	3.25
Greece	6.83	5.38	4.01
Hungary	8.14	6.07	3.81
Ireland	3.48	3.25	2.38
Italy	8.34	7.92	4.84
Lithuania	5.85	5.78	3.36
Netherlands	6.64	6.02	3.76
Poland	10.90	9.91	4.72
Portugal	8.57	7.61	4.22
Romania	13.70	13.15	6.12
Slovakia	7.27	6.14	4.03
Spain	6.788	5.971	3.141
Sweden	3.706	3.669	2.588
United Kingdom	7.303	6.347	2.998

Table 8-4 GHG refinery emissions for petrol, diesel and kerosene up to 2030 according to decarbonisation scenario

2030	Decarbonisation scenario		
$grCO_2eq/MJ$	Petrol	Diesel	Kerosene
Austria	9.90	8.08	3.30
Belgium	5.15	4.78	2.48
Bulgaria	4.95	5.66	3.81
Croatia	10.63	10.54	6.63
Czech Republic	6.66	5.95	3.32
Denmark	3.10	3.72	2.57
Finland	6.32	6.08	3.32
France	6.21	4.94	3.56
Germany	6.69	6.29	3.28
Greece	6.31	5.06	3.44
Hungary	7.50	5.65	3.99
Ireland	3.30	3.09	2.27
Italy	8.31	7.62	4.90
Lithuania	5.66	5.66	3.24
Netherlands	7.35	5.44	2.91
Poland	11.06	9.20	5.59
Portugal	8.45	7.55	5.01
Romania	14.32	12.77	6.08
Slovakia	6.90	6.08	3.77
Spain	6.69	5.66	2.95
Sweden	3.29	3.43	2.27
United Kingdom	6.99	6.09	3.53

8.4 General assumptions on natural gas projections

Natural gas demand and consumption are driven by various factors that differ from country to country depending on their regional/national characteristics. The objective of the current section is to provide projections on the carbon intensity of natural gas supplied to EU to 2020 and 2030 horizons; hence it focuses on the factors mainly driving the GHG intensity of natural gas sorted by the four EU regions considered in the context of the study.

Regarding the projections on the future gas production, net imports and consumption for each region, we have utilized projections drawing from the PRIMES-Gas sub module of the PRIMES main model. The expected changes have been used as inputs to the GHGenius model which calculates the associated GHG emissions for natural gas.

8.4.1 Overview of expected changes in natural gas supply to EU

The forecast supply of natural gas up to 2030 declines by 7% in comparison with the amounts of 2012. Table 6.5 gives the contribution of the major natural gas producing countries to the total supply in Europe. Regarding the natural gas mix supplied in the EU, the domestic production falls from 35% to 24% while Russia and Norway remain the dominant suppliers representing around 50% of the total supply. LNG from Algeria and Norway is expected to increase up to 2030.

Among intra-EU producers of natural gas, Netherlands, UK, Germany and Italy are expected to reduce their production while Poland will see an increase in its production.

Regarding the transport of natural gas to European destinations, transport via pipelines is projected to decline while transport of LNG via marine vessels will increase the next years. The latter is due to the significant increase in supply from Algeria and Norway LNG plants.

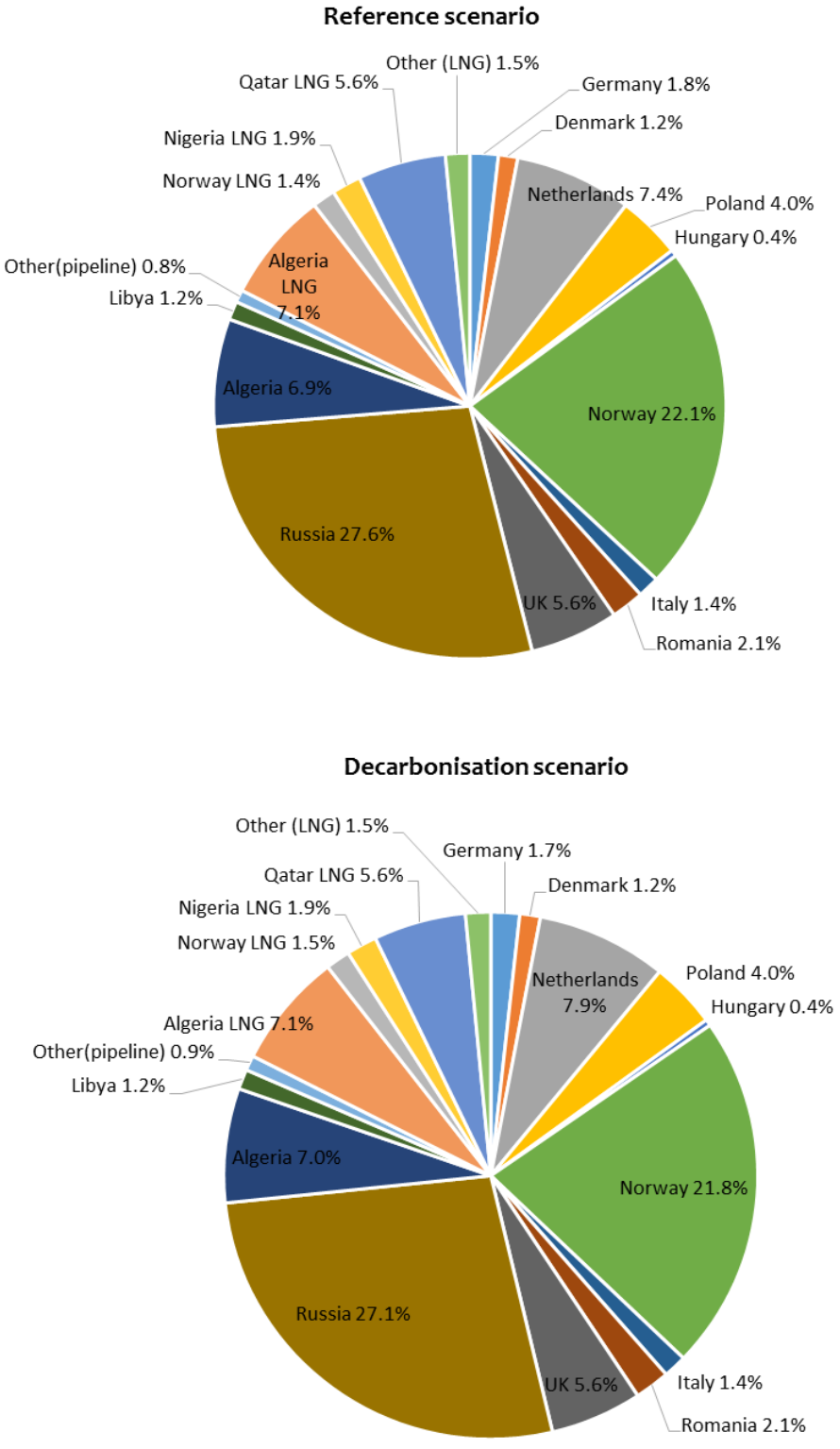
Table 8-5 Natural gas suppliers of EU by 2030 under the reference and decarbonisation scenarios

Mode of transport	Supplier	2012	2030 Reference	2030 Decarbonisation
Local production	Germany	2.6%	1.8%	1.7%
	Denmark	1.2%	1.2%	1.2%
	Netherlands	17.1%	7.4%	7.9%
	Poland	1.3%	4.0%	4.0%
	Hungary	0.3%	0.4%	0.4%
	Italy	1.7%	1.4%	1.4%
	Romania	2.2%	2.1%	2.1%
	UK	8.2%	5.6%	5.6%
Transport by pipeline	Russia	22.6%	27.6%	27.1%
	Norway	20.3%	22.1%	21.8%
	Algeria	6.8%	6.9%	7.0%
	Libya	1.3%	1.2%	1.2%
	Other	3.9%	0.8%	0.9%
LNG transported by marine vessels	Algeria LNG	2.1%	7.1%	7.1%
	Norway LNG	0.5%	1.4%	1.5%
	Nigeria LNG	2.2%	1.9%	1.9%
	Qatar LNG	5.6%	5.6%	5.6%
	Other	0.0%	1.5%	1.5%

Figure 8-4 presents the projections on the natural gas mix supplied in the EU obtained from the PRIMES-Gas model. According to the results, slight differentiations appear which are

mainly attributed to the different demand for natural gas in Europe between the two scenarios.

Figure 8-4 Projections in EU Natural Gas Supply for 2030 under the reference and decarbonisation scenarios



Without a growth of total natural gas consumption expected in our timeframe, the share of road or transport consumption is projected to rise the forecast years, as presented in Table 8-6 and Table 8-7.

Table 8-6 Projections for 2020 and 2030 shares of road consumption of natural gas according to reference scenario

EU region	Road consumption/Total NG consumption (%)			
	Consuming country	2012	2020	2030
South East EU	BG - Bulgaria	2.66	7.33	8.34
	EL - Greece	0.41	0.51	0.59
	HR - Croatia	0.03	0.26	0.33
	IT - Italy	1.23	2.66	4.28
	RO - Romania	0	0.16	0.20
	SI - Slovenia	0.1	0.03	0.06
Central EU	BE - Belgium	0.06	0.06	0.14
	CZ - Czech Republic	0.18	1.18	1.34
	DE - Germany	0.3	0.42	0.46
	EE - Estonia	0	0.15	0.32
	LV - Latvia	0	0.16	0.28
	LT - Lithuania	0.11	1.03	1.30
	LU - Luxembourg	0	0.27	0.20
	HU - Hungary	0.01	0.01	0.03
	NL - Netherlands	0.05	0.09	0.17
	AT - Austria	0.1	2.02	1.96
	PL - Poland	0	1.83	1.71
	SK - Slovakia	0	7.65	7.66
North EU	DK - Denmark	0	0.06	0.08
	IE - Ireland	0	0.04	0.12
	FI - Finland	0.18	0.80	1.18
	SE - Sweden	5.05	2.13	3.12
	UK - United Kingdom	0	0.05	0.15
South West EU	ES - Spain	0.29	0.59	0.71
	FR - France	0.23	1.03	1.31
	PT - Portugal	0.31	0.27	0.89

Table 8-7 Projections for 2020 and 2030 shares of road consumption of natural gas according to decarbonisation scenario

EU region	Consuming country	Road consumption/Total NG consumption %		
		2012	2020	2030
South East EU	BG - Bulgaria	2.66	7.39	8.51
	EL - Greece	0.41	0.53	0.84
	HR - Croatia	0.03	0.26	0.43
	IT - Italy	1.23	2.72	4.80
	RO - Romania	0	0.17	0.38
	SI - Slovenia	0.1	0.03	0.15
Central EU	BE - Belgium	0.06	0.07	0.16
	CZ - Czech Republic	0.18	1.22	1.66
	DE - Germany	0.3	0.45	0.56
	EE - Estonia	0	0.16	1.37
	LV - Latvia	0	0.17	0.56
	LT - Lithuania	0.11	1.05	1.69
	LU - Luxembourg	0	0.31	0.47
	HU - Hungary	0.01	0.01	0.12
	NL - Netherlands	0.05	0.11	0.22
	AT - Austria	0.1	2.09	2.23
	PL - Poland	0	1.83	1.83
	SK - Slovakia	0	7.69	8.13
North EU	DK - Denmark	0	0.06	0.13
	IE - Ireland	0	0.05	0.24
	FI - Finland	0.18	0.82	1.37
	SE - Sweden	5.05	2.28	5.37
	UK - United Kingdom	0	0.06	0.22
South West EU	ES - Spain	0.29	0.59	0.80
	FR - France	0.23	1.05	1.64
	PT - Portugal	0.31	0.30	1.06

8.5 Outlook on GHG emissions from natural gas: 2020 and 2030 horizon

This section presents the key results obtained for the horizon 2020 and 2030 for the natural gas streams within Europe. The average GHG emission factor for natural gas, obviously, depends on the mix of the natural gas flows in Europe by 2020 and 2030.

Despite the reduction of natural gas supply in the EU, the estimates on upstream and midstream GHG emissions show an overall increase in the EU regions examined. This contradiction is explained by the significant fall in European production of natural gas, and the projected changes in natural gas supply as presented previously. The resulted emissions of CNG are primarily linked to the expected increase in energy consumption during the production and transport of natural gas. Table 8-8 and Table 8-9 display the results for the estimated GHG emissions in 2030 under the two scenarios.

Table 8-8 GHG emissions for natural gas by EU region under the reference scenario

Reference scenario	EU average	EU North	EU Central	South East EU	South West EU
CNG	*grCO2eq/GJ*				
Fuel dispensing	**3,837**	3,541	4,128	4,228	2,808
Gas distribution, transmission and storage	**3,029**	1,299	2,857	6,679	1,193
Feedstock transportation (pipeline, LNG)	**7,993**	5,413	10,182	8,695	4,901
Fuel production and recovery	**6,752**	5,508	4,237	8,992	13,697
CO_2, H_2S removed from NG (gas processing)	**353**	249	188	670	579
Total	**21,964**	**16,010**	**21,592**	**29,264**	**23,178**
Methane Loss	%				
Dispensing station	**0.003**	0.003	0.003	0.003	0.003
Distribution Loss	**0.004**	0.002	0.005	0.006	0.002
Transmission Loss	**0.001**	0.000	0.001	0.001	0.000
Transport Loss	**0.003**	0.003	0.004	0.003	0.002
Processing	**0.001**	0.000	0.000	0.001	0.001
Recovery	**0.005**	0.003	0.003	0.008	0.008
Total	**0.017**	**0.012**	**0.016**	**0.022**	**0.017**
Production Energy	GJ/tn				
Recovery energy	**1.623**	1.324	1.221	1.635	1.199
Processing energy	**1.817**	1.556	0.696	2.080	5.092
Regasification energy	**0.065**	0.140	0.043	0.049	0.063
Total	**3.505**	**3.020**	**1.960**	**3.764**	**6.354**
Transport Energy	GJ/tn				
Transport energy	**3.521**	2.190	4.585	4.051	1.981
Shipping	**0.073**	0.115	0.026	0.052	0.183
Transmission and Distribution	**1.263**	0.156	0.395	5.397	0.153
Total	**4.857**	**2.462**	**5.006**	**9.500**	**2.317**
Total Energy, GJ/tn	**8.362**	**5.482**	**6.966**	**13.264**	**8.671**

Table 8-9 GHG emissions for natural gas by EU region under the decarbonisation scenario

Decarbonisation scenario	EU average	North EU	Central EU	South East EU	South West EU
CNG	*grCO2eq/GJ*				
Fuel dispensing	**3,835**	3,538	4,126	4,230	2,804
Gas distribution, transmission and storage	**3,028**	1,296	2,859	6,684	1,194
Feedstock transportation (pipeline, LNG)	**7,796**	5,363	9,807	8,759	4,693
Fuel production and recovery	**6,636**	5,165	4,240	9,015	13,273
CO2, H2S removed from NG (gas processing)	**356**	248	187	684	588
Total	**21,651**	**15,610**	**21,219**	**29,372**	**22,552**
Methane Loss	%				
Dispensing station	**0.340%**	0.340%	0.340%	0.340%	0.340%
Distribution Loss	**0.401%**	0.197%	0.472%	0.610%	0.171%
Transmission Loss	**0.057%**	0.018%	0.062%	0.096%	0.039%
Transport Loss	**0.340%**	0.291%	0.410%	0.330%	0.190%
Processing	**0.053%**	0.021%	0.020%	0.110%	0.130%
Recovery	**0.479%**	0.302%	0.320%	0.760%	0.820%
Total	**1.670%**	**1.169%**	**1.624%**	**2.246%**	**1.690%**
Production Energy	GJ/tn				
Recovery energy	**1.25**	1.31	1.21	1.35	1.17
Processing energy	**1.77**	1.36	0.72	2.11	4.88
Regasification energy	**0.07**	0.14	0.05	0.05	0.07
Total	**3.08**	**2.81**	**1.97**	**3.51**	**6.11**
Transport Energy	GJ/tn				
Transport energy	**3.44**	2.20	4.45	4.09	0.16
Shipping	**0.07**	0.10	0.05	0.05	1.89
Transmission and Distribution	**1.26**	0.15	0.39	5.40	0.16
Total	**4.77**	**2.46**	**4.90**	**9.54**	**2.20**
Total Energy, GJ/tn	**7.851**	**5.266**	**6.873**	**13.046**	**8.315**

According to the analysis using the detailed GHGenius model, the Reference scenario gives an outlook on higher emissions than the decarbonisation scenario. Total emissions of CNG are on average 15% higher in the EU compared to the estimated values for 2012. The most affected EU regions are projected to be North and South West EU. Fuel production and recovery as well as feed transportation are mainly responsible for the expected increased carbon intensities. Furthermore, we observe an increase of 52% under the reference

scenario and 43% under the decarbonisation scenario of total energy consumption including the energy consumed during the production and transport stages. The increase of production-related energy is higher in Central, South East and South West Europe while a large increase of transport-related energy is observed in North and South East regions of Europe. An overview of the energy consumption on a country basis is given in Table 8-10.

Table 8-10 2030 estimated GHG emissions disaggregated by EU country ($grCO_2eq/GJ$ LHV)

EU region	EU Country	Fuel dispensing	Gas distribution, transmission and storage	Feedstock transportation (pipeline, LNG)	Fuel production and recovery	CO_2, H_2S removed from NG (gas processing)	CNG total emissions
EU North	DK - Denmark	2991	212	597	2965	20	6785
	IE - Ireland	4972	996	1037	11925	254	19184
	FI - Finland	2669	2989	19660	3808	3	29129
	SE - Sweden	1904	1230	667	4864	109	8774
	UK - United Kingdom	4573	1304	5262	5549	280	16968
EU Central	BE - Belgium	2697	1346	7472	7257	440	19212
	CZ - Czech Republic	3477	2085	17684	3509	35	26790
	DE - Germany	4221	2202	12072	3755	282	22532
	EE - Estonia	2322	3622	23993	4488	26	34451
	LV - Latvia	2356	2249	23794	3938	31	32368
	LT - Lithuania	2984	2820	23506	4066	57	33433
	LU - Luxembourg	2927	967	8885	2685	57	15521
	HU - Hungary	3499	4000	19961	4281	211	31952
	NL - Netherlands	2435	2351	2530	2899	74	10289
	AT - Austria	2472	2475	14831	3976	76	23830
	PL - Poland	5726	8784	4974	6086	34	25604
	SK - Slovakia	2718	3102	24438	3818	3	34079
EU SW	ES - Spain	3679	787	3768	17580	750	26564
	FR - France	2191	887	6024	10005	397	19504
	PT - Portugal	3902	7042	3159	14915	740	29758
EU SE	BG - Bulgaria	4752	8407	19022	3688	23	35892
	EL - Greece	6157	1210	14021	10165	263	31816
	HR - Croatia	3561	12901	23889	3998	3	44352
	IT - Italy	3983	6605	7617	10072	889	29166
	RO - Romania	4189	2403	6348	6028	42	19010
	SI - Slovenia	3489	802	18119	7162	195	29767

Table 8-11 Energy consumption during the different stages of NG production and transport (GJ/tn)

		Energy consumption during Production				Energy consumption during Transport				
EU Region	EU Country	Recovery	Processing	Regasification	Production Total	Transport	Shipping	Transmission & Distribution	Transport Total	Total Energy
EU North	DK - Denmark	1.70	0.30	0.00	1.99	0.34	0.00	0.03	0.36	2.35
	IE - Ireland	1.55	3.67	0.19	5.40	0.53	0.04	0.60	1.17	6.57
	FI - Finland	1.02	0.14	0.15	1.31	7.81	0.00	0.05	7.86	9.17
	SE - Sweden	1.64	1.30	0.08	3.02	0.33	0.03	0.06	0.42	3.43
	UK - United Kingdom	1.30	1.63	0.16	3.09	2.09	0.13	0.15	2.37	5.46
EU Central	BE - Belgium	1.03	3.04	0.25	4.32	3.14	0.21	0.09	3.43	7.75
	CZ - Czech Republic	1.13	0.16	0.00	1.29	7.73	0.00	0.23	7.96	9.26
	DE - Germany	1.16	0.49	0.02	1.67	5.58	0.01	0.39	5.98	7.65
	EE - Estonia	1.03	0.45	0.02	1.50	9.73	0.01	0.00	9.73	11.23
	LV - Latvia	1.01	0.28	0.02	1.31	9.74	0.02	0.93	10.68	11.99
	LT - Lithuania	1.00	0.41	0.03	1.44	9.55	0.03	0.63	10.21	11.65
	LU - Luxembourg	1.17	0.15	0.00	1.32	4.41	0.00	0.00	4.41	5.73
	HU - Hungary	1.24	0.20	0.00	1.44	8.13	0.00	0.32	8.45	9.89
	NL - Netherlands	1.07	0.50	0.03	1.59	1.30	0.02	0.21	1.53	3.12
	AT - Austria	1.15	0.23	0.00	1.38	6.72	0.00	1.08	7.80	9.17
	PL - Poland	1.95	0.58	0.03	2.56	2.31	0.01	1.01	3.33	5.89
	SK - Slovakia	1.03	0.14	0.00	1.16	9.94	0.00	0.32	10.26	11.42

		Energy consumption during Production				Energy consumption during Transport				
EU Region	EU Country	Recovery	Processing	Regasification	Production Total	Transport	Shipping	Transmission & Distribution	Transport Total	Total Energy
EU SW	ES - Spain	1.21	6.64	0.09	7.94	1.13	0.27	0.32	1.72	9.66
	FR - France	1.19	3.60	0.04	4.83	2.94	0.08	0.02	3.04	7.86
	PT - Portugal	1.16	4.54	0.06	5.76	0.78	0.25	0.17	1.20	6.97
EU SE	BG - Bulgaria	0.87	0.36	0.00	1.23	0.84	4.39	0.00	5.22	6.46
	EL - Greece	0.94	3.72	0.11	4.78	5.80	0.06	0.08	5.94	10.72
	HR - Croatia	1.20	0.14	0.00	1.35	9.85	0.00	0.24	10.09	11.43
	IT - Italy	1.28	2.53	0.06	3.87	3.76	0.07	5.37	9.19	13.06
	RO - Romania	2.18	0.17	0.00	2.34	1.99	0.00	0.39	2.38	4.73
	SI - Slovenia	1.03	0.48	0.00	1.51	7.88	0.00	0.04	7.92	9.43

9 SUBSTANTIAL PROJECT FINDINGS

In this last Chapter of the report the Consultant tries to illustrate the most significant findings, which were identified in the context of this project. The issue of CI assessment for fossil fuels is substantially linked with the EU legislative framework but also with the implementation of climate change policies at EU and international level. For this reason the interests of the fossil fuels and biofuels industries are high, and in most cases contradictory since the substitution of fossil fuels by sustainable biofuels seems the most effective measure towards reducing the GHG emissions in transport sector.

In this project the major effort was put on the collection of actual data, which have been categorized according to the source of origin, which implies also the level of reliability. Actual CI Data gathered from existing databases of renowned national and international organizations, as well from certified data availed by oil and gas companies. These data were in principle based on direct measurements, mass balances, validated emission factors and relevant engineering calculations, which have been verified. Such data are used partly in the calculation of direct GHG emissions of oil and gas streams. The second category of data collection are the Actual Data for Models, collected likewise and utlized as input in the project models, namely OPGEE, GHGenius and PRIMES-Refinery. The outputs of these models, which are direct GHG emissions at various stages of oil and gas streams and could be considered the best approximation of the Actual CI Data. The third category are the Literature Data, collected from other studies in the GHG emissions area, to which the Consultant has no direct access on the detailed methodology these estimations have been carried out. Eventually, this latter source was used only for the estimation of the indirect GHG emissions in all streams.

Probably the most significant finding of this project is the great range of CI values depending on the fossil fuel streams supplying the EU transport sector, which is valid for both oil and gas streams. The results which have been analytically presented in previous Chapters and will be in brief presented below, incorporate both direct and indirect CI values for the base year 2012 and under the assumptions which have been considered. The direct CI values are assessed in principle on the basis of actual data collected and analyzed with the assistance of the three models, namely OPGEE, PRIMES-Refinery and GHGenius.

More specifically, the spread of the gas streams CI values (CNG case) for four EU regions are presented in Figure 9-1. The significant range of CI values could be easily observed among the streams of different producing countries, for example the lower value is calculated for the Dutch gas supplying Northern Europe in the order of 6.5 $grCO_2eq/MJ$ and the higher value for the Algerian LNG stream reaching up to 55 $grCO_2eq/MJ$. In general, the CI is high in gas streams related to long pipelines and/or long distances of

transportation in the form of LNG; therefore the CI of the Russian gas, which is the most significant gas importing stream in the EU is calculated in the range of 29 to 40 $grCO_2eq/MJ$ depending on the region directed. On the other hand, the less emitting gas streams belong to indigenous EU sources and Norway.

In Figure 9-2 the CI is assessed for the gas streams to small scale LNG for transport sector is presented. The highest CI values are calculated for the Algerian LNG streams reaching on average 44.5 $grCO_2eq/MJ$ and the lowest values for the Norwegian streams reaching 12.0 $grCO_2eq/MJ$. There are no remarkable differences among streams of the same origin directed to different EU regions and this happens because the differences in midstream (ship transport of LNG) may not justify considerable differences in GHG emissions. In Figure 9-3 the average gas streams (CNG case) for the whole EU and the four regions is presented. It is clear that the CI is generally higher in the EU south east region with an average CI calculated to 28.9 $grCO_2eq/MJ$, whereas the same average in the EU north region is only 12.6 $grCO_2eq/MJ$ and the EU average value is 19.54 $grCO_2eq/MJ$.

The respective results for the oil sector are presented in brief in Figure 9-4, Figure 9-5 and Figure 9-6. The total (direct and indirect) CI of the most significant crude oil MCONs for the EU, which have been considered in our study, are presented in Figure 9-4. In general, the CI of petrol is higher than the diesel oil CI, which is higher than the kerosene CI. The difference is subject to the characteristics (API and sulphur) of each MCON, the structure of the EU refineries and particularly of the assumptions on the choice of GHG allocation method to the refinery products. The range of CI values for petrol is really large, from around 37 $grCO_2eq/MJ$ for the Nigerian crude Escravos up to around 10 $grCO_2eq/MJ$ for the Danish crude (DUC). Proportional variations are observed for the other two oil products, namely diesel oil and kerosene. It also is evident that the highest CI values are observed for heavy crudes originating from regions with less care for reduction of GHG emissions in the upstream activities. On the other hand, the lower values are related to lighter crudes produced in countries with substantial environmental measures for the minimization of GHG emissions in the upstream and other oil stream stages.

The EU average CI WTT values of kerosene, diesel oil and petrol streams are estimated to be 18.97 grCO2eq/MJ for petrol, 18.17 grCO2eq/MJ for diesel oil and 15.77 grCO2eq/MJ for kerosene. The average CI of kerosene is estimated or around 15% lower than petrol. The comparison of the average CI values of oil products and gas streams of this study with the respective JEC values are presented in Figure 9-6. In general, the CI estimations of the present study are higher than the values of JEC. More specifically, the CNG CI value is higher by 49% compared to the JEC value, whereas the respective percentage is higher by 17% for diesel oil and 37% for petrol.

The comparison of the WTT CI values of fossil fuels estimated in this study increased with the average TTW values of the JEC study, the respective WTW values of JEC study for fossil fuels and the respective WTW CI values of a variety of bio fuels as they have been assessed by the JEC study (2013) are presented in Figure 9-5. It is worth considering that the CI of biofuels are based on the CI of fossil fuels, so actually the biofuels CI values used are based on the lower CI values of JEC. It is our assumption that the differences are very

small and cannot change the message of Figure 9-5 that focuses to indicatively illustrate the range of GHG savings, which could be achieved under disaggregated calculations. Min/max and weighted average of the conventional and the average CI values of the unconventional fossil fuels of this study are also presented. The spread of CI WTW values of conventional (this study) are presented in parallel with the respective CI spreads of conventional and advanced biofuels (as calculated in the JEC Biofuels study) and the relevant percentages of GHG savings are calculated.

More specifically, the lower CI conventional ethanol saves 71-78% of petrol GHG emissions depending on the min/max assessment of the CI values of petrol in this study, in parallel the calculated saving in the JEC study is 72%. Respectively, the higher CI conventional ethanol saves 47-59% of petrol GHG emissions and in parallel the JEC study estimates 49%. Similarly, the figures for the advanced ethanol from waste are estimated to 84-88% in the lower CI case and 58-68% in the higher CI case in relation to the results of this study. The saving figures for the JEC study are 85% and 60%. Similar estimations of saving percentages have been made for diesel oil and the relevant biofuels.

It is interesting that the advanced biofuels potentially substituting petrol and diesel exhibit WTT CI values which could justify the saving of GHG emissions, as provided by the sustainability criteria of FQD. However, the spread of CI values of this study related to the spread of CI values of advanced biofuels provide better opportunities for compliance with the FQD minimum GHG saving criteria. On the other hand, it is clear that the same message could be not obtained from the conventional bio fuels and especially of FAME, although the results of this study favor the GHG saving percentages due to higher estimations for the WTT GHG emissions of fossil fuels. It makes sense that the analysis of GHG savings based on the spread of CI values of fossil and bio fuels reveals a more complicated situation than the analysis based on average values.

What is clear due to this study is that the range of the estimated WTT CI values (but also of the WTW) of conventional fossil fuels is particularly large compared to the respective weighted average CI values, while the uncertainty reflected by the min/max concept intensifies further this range of CI values. The CI values of unconventional fossil fuels lie at the highest levels compared to the respective values of conventional fuels. Therefore, the consideration of weighted average values instead of actual aggregated values for fossil fuels might mislead GHG efficient reduction efforts in the context of pertinent EU policies, because the average CI values favor the high CI fossil fuels and the reasons for this situation (flaring, poor maintenance, fugitive, etc.) against the less emitting, well regulated fossil fuels.

The approach of using disaggregated CI for fossil fuels could be interpreted into policy options on GHG emissions reduction of transport fuels in the EU; a reasonable set of ideas to be discussed and further elaborated is presented below:

1. **Do nothing, leave things as they are**

This is an option maintaining the status quo. However, this most probably will result into two different but similar problems:

a. the biofuel producers and the NGOs may accuse the Commission that it treats biofuels in a differentiated way than fossil fuels even though biofuels have lower CI than fossil fuels. The argument will be that a valid solution to climate change in transport, -biofuels- are scrutinised under the legislator's microscope from all aspects including certification, while the problem-causing fuels –fossil- are not. This equates in a non transparent approach;
b. the NGOs and the civil society may accuse the Commission that although it could take actions to reduce the CI of transport, by limiting the use of high CI fossil streams into the EU, is actually doing nothing. This would be contrary to the EU policies on climate change and energy and it could tarnish the image of the EU being the leader in introducing effective climate change policies.

2. Update the fossil fuel comparator as reported by the FQD

Under Article 17 of the RED the GHG emission savings of biofuels must be at least 35% with effect from the adoption of the directive, 50% by January 2017 and 60% from 01/01/2018 for new installations which started production after 01/01/2017. The GHG emissions savings must be calculated in accordance with Article 19(1) of the RED:

$$\text{GHG Saving} = (EF-EB)/EF$$

Where EB= total emissions from the biofuel or bioliquid,

EF= total emissions (WTW) from the fossil fuel comparator

The fossil fuel comparator is specified in Annex V, C Methodology, (19) and is reported to the FQD with a value of EF = 83.8 grCO2eq/MJ. At present all biofuels and bioliquids are compared to this figure.

Under this value of the fossil fuel comparator, in order to meet the GHG-saving threshold of 35%, a biofuel has to emit:

$$\text{GHG Saving} = (83.8 \times 75)/100 = 54.47 \text{ grCO2eq/MJ}$$

or less.

According to the results of this study, the value of the fossil fuel comparator is too low and it should actually be 95 grCO2eq/MJ.

If the fossil fuel comparator would be raised to 95 grCO2eq/MJ as this study indicates, then the GHG-saving threshold of 35% makes that the maximum emissions of biofuels would increase to: 71.3 grCO2eq/MJ.

This would facilitate all biofuels and it would increase their actual effectiveness in mitigating GHG emissions. It may be also proven critical for some of the new value chains of advanced biofuels that require extensive processing such as biofuels from algae.

The correction of the fossil fuel comparator could be achieved with a simple technical revision of the FQD and subsequently it would be taken up by the RED. This appears to be

a relative simple revision based on new scientific evidence. It would change just one number: that of the fossil fuel comparator.

3. **Revision of the FQD with a max CI value for fossil fuels that are allowed to be used in the EU**

The FQD could be eventually revised to include a maximum value of CI of fossil fuels that would be allowed to be used in the EU. As an example this value could be set at 100 grCO2eq/MJ for fossil fuels. This would mean that the high CI MCONs as well as the Algerian LNG and some of the Russian natural gas streams could not be used any more in the EU, if producers and suppliers do not take GHG reduction measures.

The result of such an eventual policy would be a relative accelerated reduction of GHG emissions from the transport sector.

4. **Revision of the FQD with a max CI value for fossil fuels that are allowed to be used in the EU with security of supply considerations**

The security of supply is one of the pillars of the EU energy policy. Therefore any future policy should safeguard the security of supply of the energy needs of the EU.

The FQD could be eventually revised to include a maximum value of CI of fossil fuels that could be allowed to be used in the EU as in point 4 above. The legislation could include stipulations that for every MJ of fossil fuel used in the EU above the max value of 100 grCO2eq/MJ for fossil fuels, the Member State/oil company doing so, would be obliged to use 4 times the equivalent MJ of lignocellulosic and other advanced renewable liquid biofuels (excluding RES/nuclear electricity).

Such a stipulation would safeguard the security of supply for the EU and provide an incentive for accelerated deployment of lignocellulosic and other advanced renewable liquid biofuels.

5. **Unconventional fossil fuels**

Unconventional fossil fuels have significantly higher CI than convectional fossil fuels.

Under the so called ILUC revision of the RED it has been stipulated that crop-based biofuels may not receive any support post 2020 and that their contribution may not exceed 7% of renewable energy in transport by 2020. The 2030 framework for climate and energy policies has no specific provisions for renewable energy in transport post 2020.

However, crop-based biofuels have significant GHG benefits when compared to unconventional fossil fuels.

The FQD could be eventually revised to include a maximum value of CI of unconventional fossil fuels that would be allowed to be used in the EU. As an example this value could be set at 110 grCO2eq/MJ.

Similarly as with point 4 above, and in order to ensure the security of supply or the use of

local resources by Member States with important resources of unconventional fossil fuels, the legislation could stipulate that for every MJ of unconventional fossil fuel used in the EU above the max value of 110 grCO2eq/MJ, the Member State/oil company doing so, would be obliged to use 4 times the equivalent MJ of lignocellulosic and other advanced renewable liquid biofuels or the equivalent MJ of crop-based biofuels.

Such a policy would provide for security of supply as well as the accelerated reduction of GHG emissions in the transport sector.

One may question the use of crop-based biofuels especially after the long ILUC debate; however, from the point of view of climate change it would provide significant benefits when contemplating the use of unconventional fossil fuels in the EU.

6. Certification

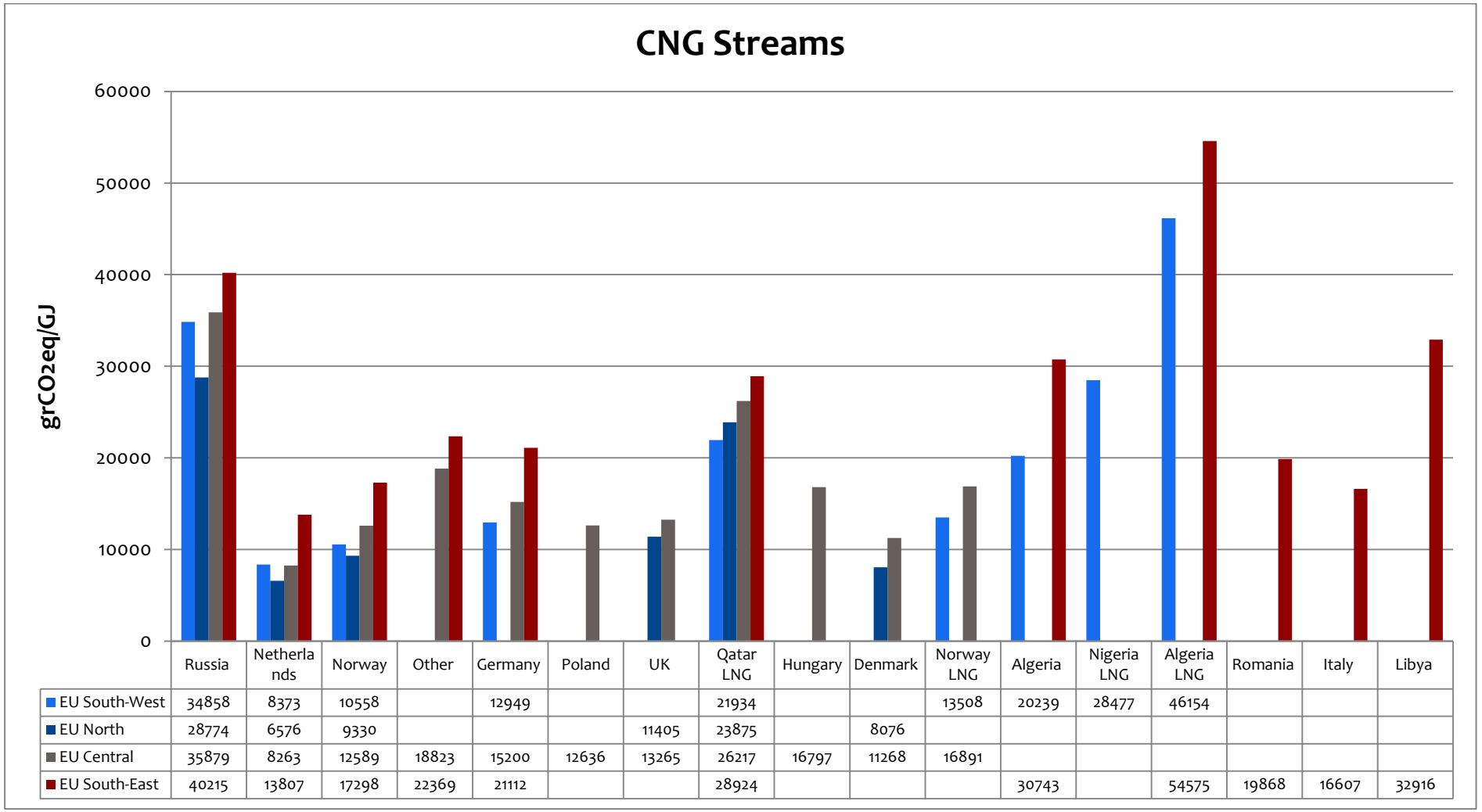
For any future policy development in this sector it will be necessary to develop a robust certification and verification system for all fossil fuels used in the EU similar to that developed for biofuels and bioliquids under the RED and FQD. Such a certification system would provide for transparency and equal treatment of biofuels, bioliquids and fossil fuels in the transport sector.

Furthermore such eventual policies would also result in reducing the CI of energy not only in transport but in all energy sectors with significant benefits for the EU society.

7. WTO considerations

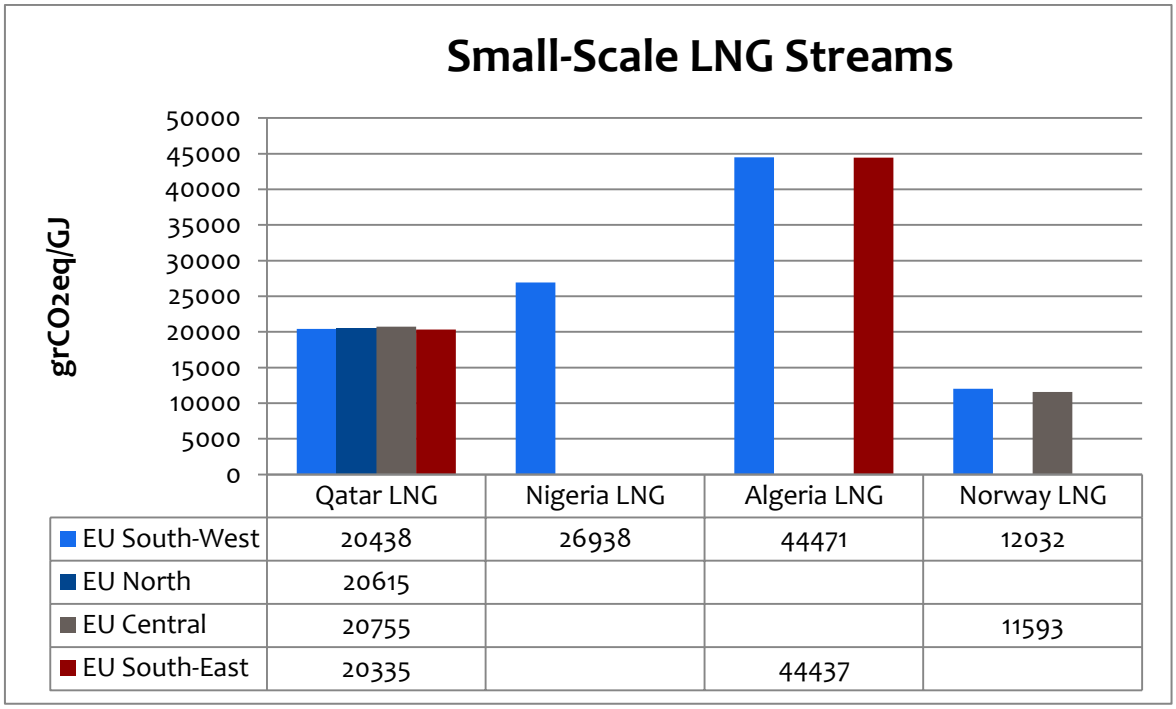
Any future policy development in this sector should apply to both EU production as well as imports in order to minimise incompatibility with WTO rules.

Figure 9-1 Spread of CI for well-to-tank (CNG) gas streams for EU regions



	Russia	Netherlands	Norway	Other	Germany	Poland	UK	Qatar LNG	Hungary	Denmark	Norway LNG	Algeria	Nigeria LNG	Algeria LNG	Romania	Italy	Libya
EU South-West	34858	8373	10558		12949			21934			13508	20239	28477	46154			
EU North	28774	6576	9330				11405	23875		8076							
EU Central	35879	8263	12589	18823	15200	12636	13265	26217	16797	11268	16891						
EU South-East	40215	13807	17298	22369	21112			28924				30743		54575	19868	16607	32916

Figure 9-2 Spread of CI for well-to-tank (LNG) gas streams for EU regions



	Qatar LNG	Nigeria LNG	Algeria LNG	Norway LNG
EU South-West	20438	26938	44471	12032
EU North	20615			
EU Central	20755			11593
EU South-East	20335		44437	

Figure 9-3 Average CI of gas streams (CNG case) for EU regions

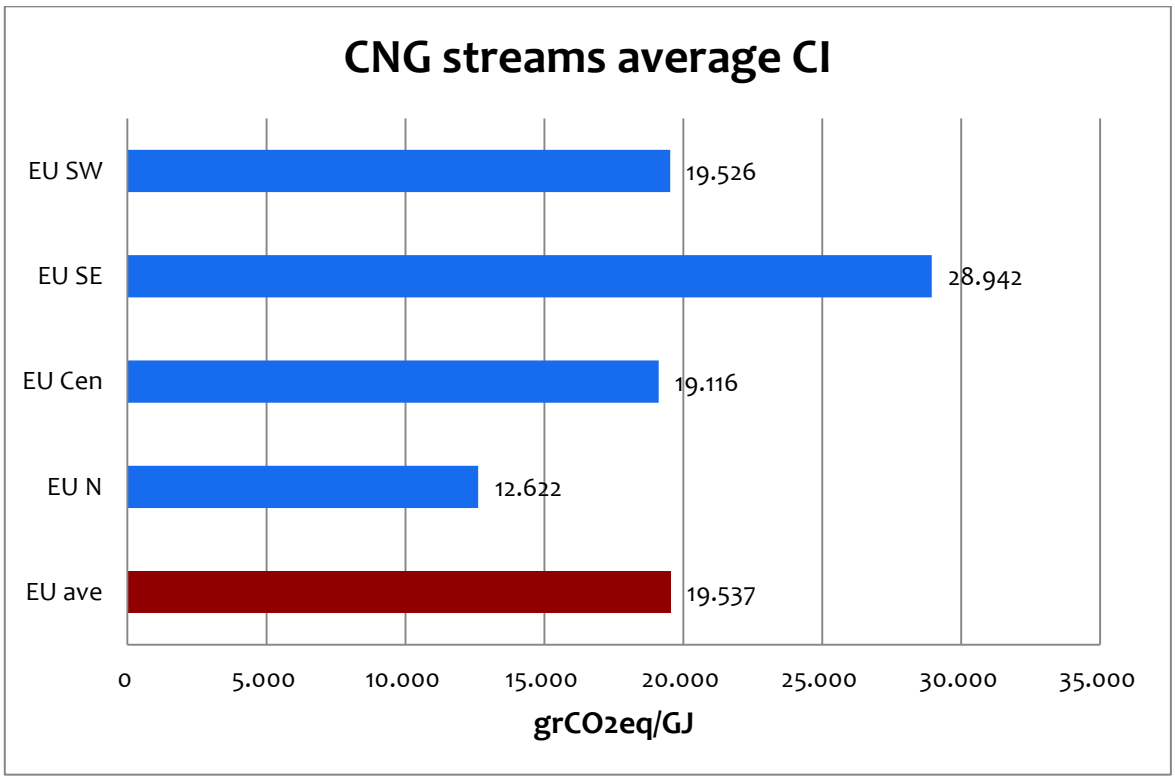


Figure 9-4 Average CI of kerosene, diesel oil and petrol streams of significant MCONs

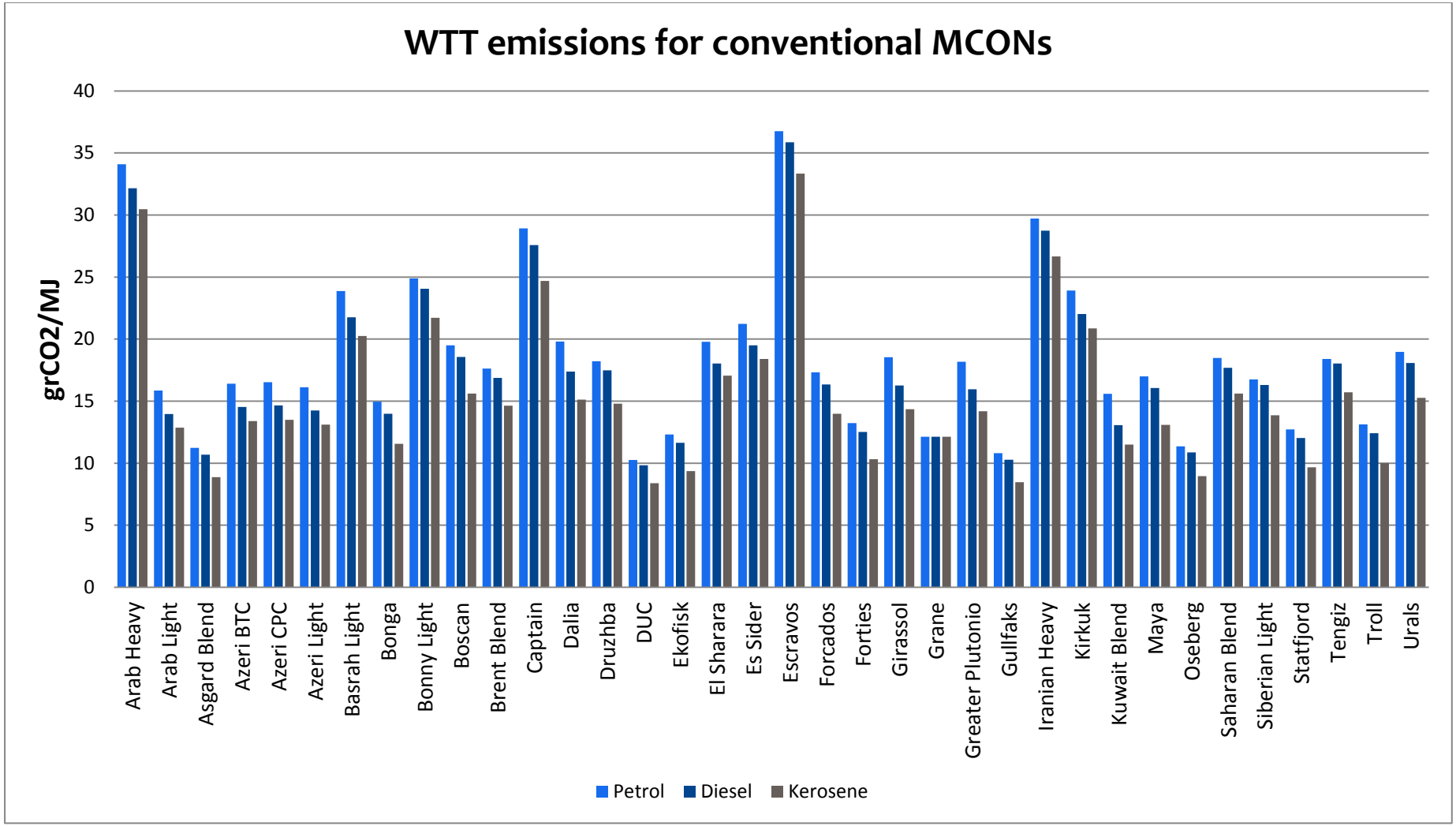


Figure 9-5 Comparison of CI values of fossil (this study) and bio fuels (JEC study), GHG savings of biofuels on average, min/max values of fossil fuels

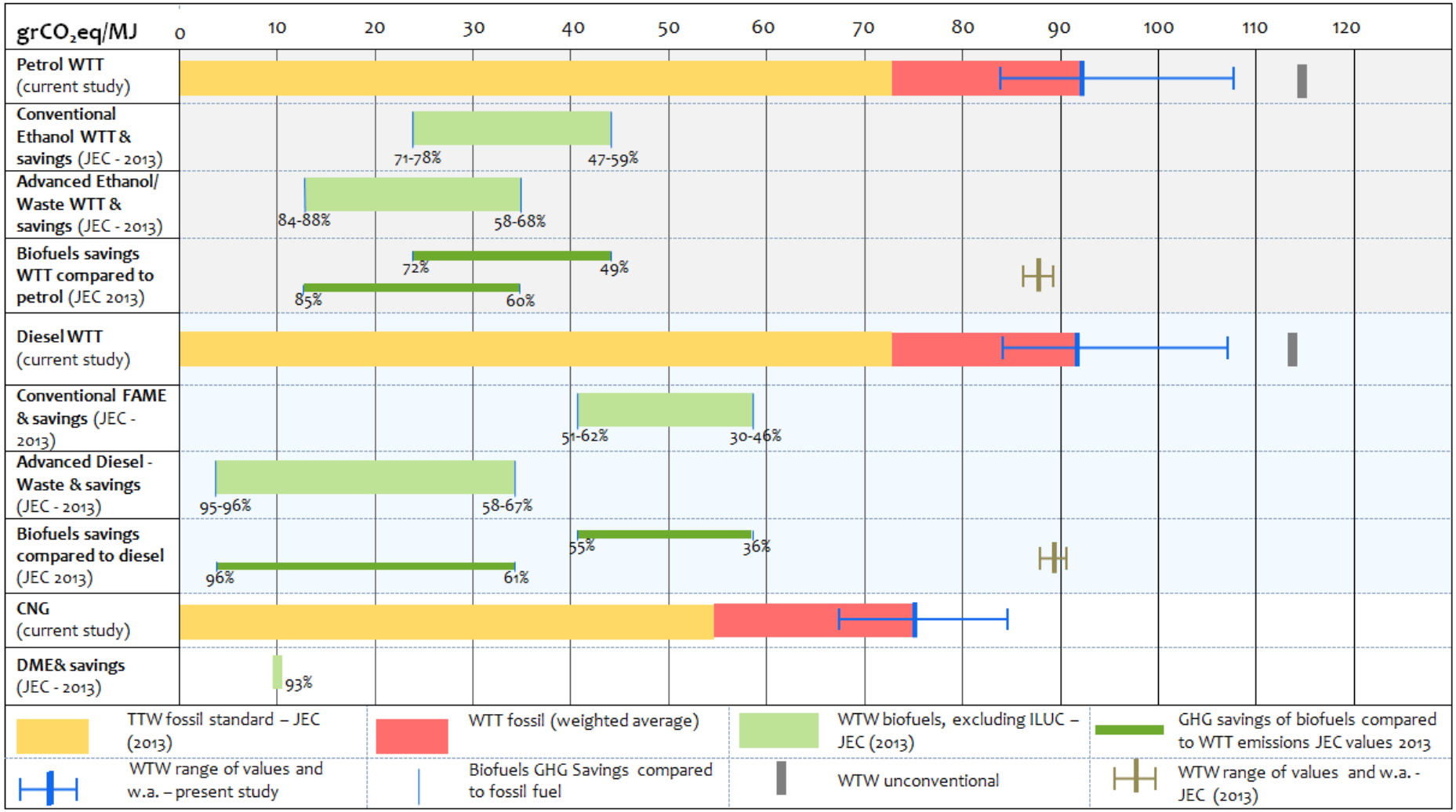


Figure 9-6 Comparison of average CI of oil products and gas streams with JEC values

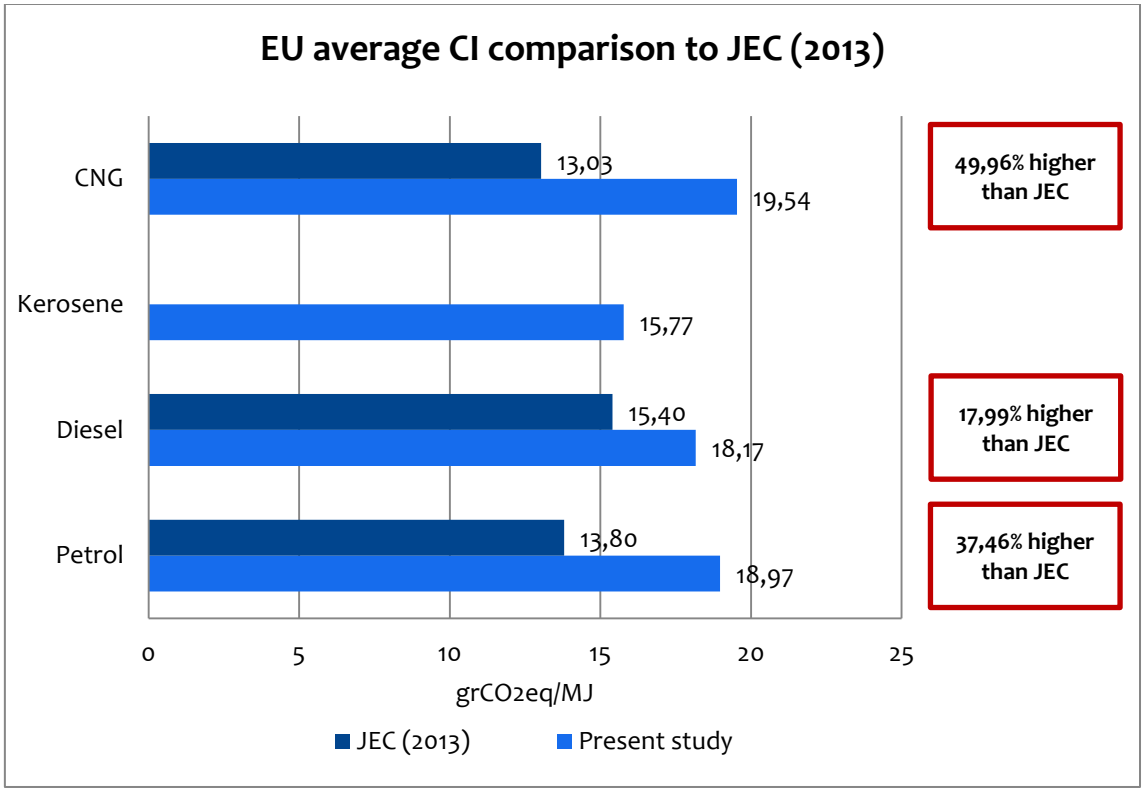
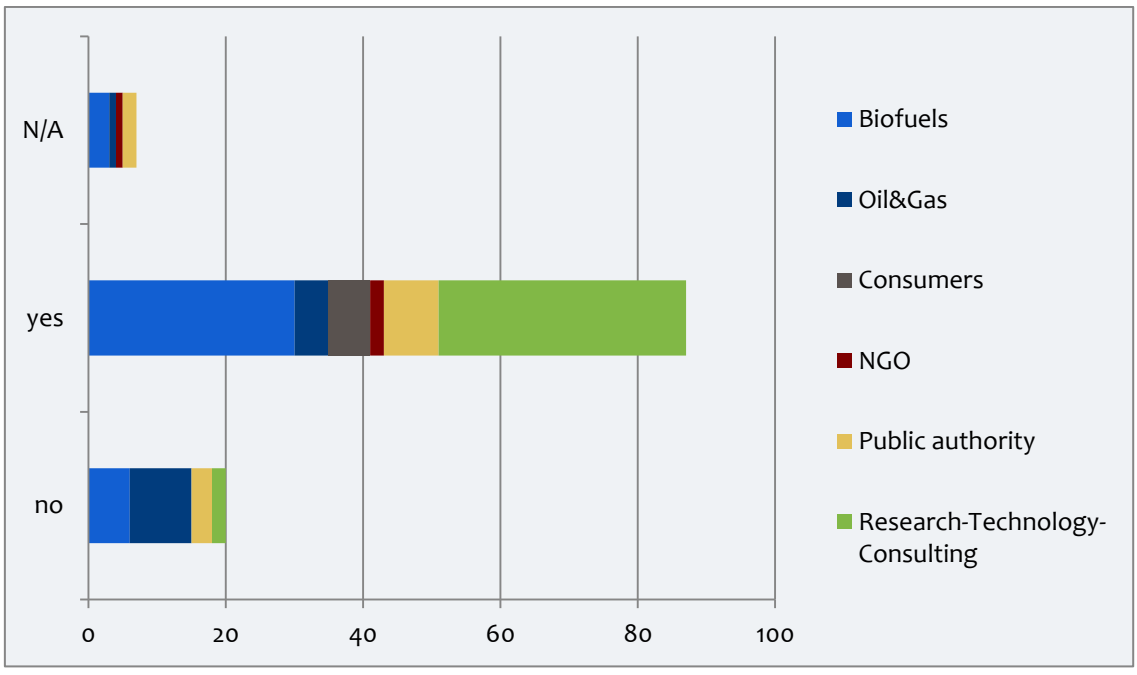


Figure 9-7 Number of answers category of stakeholder: question "whether the variation of CI of fossil fuels for transport could be considered in the reduction of GHG emissions"



ANNEX A: COORDINATES

Annex A.1: Oil fields

Table A.0-1 Geographical coordinates of representative oil fields (source: own elaboration)

Oil field Name	Latitude	Longitude	Offshore/Onshore
Gachsaran	30,350	50,800	On
Rumaila (South)	30,156	47,408	On
West Qurna	31,051	47,423	On
Kirkuk	35,467	44,317	On
Burgan	29,111	47,967	On
Gwahar	25,430	49,620	On
Kurais	25,263	48,170	On
Manifa	27,711	48,971	On
Hassi Messaoud	31,661	6,055	On
Block 17/Dalia	-7,630	11,760	Off
Girassol	-7,633	11,683	Off
Greater Plutonio	-7,810	12,110	Off
Es Sider	30,613	18,282	On
El Sharara	26,510	12,260	On
Bonga	5,100	5,100	Off
Forcados Yokri	5,346	5,349	On
Agbada	5,010	7,037	On
Caw Thorne Channel	4,604	7,017	On
Escravos Beach	5,589	5,178	On
Azeri-Chirag-Gunashli (ACG)	40,018	51,266	Off
Azeri-Chirag-Gunashli (ACG)	40,018	51,266	Off
Tengiz	46,153	53,383	On
Tengiz	46,153	53,383	On
Tevlinsko-Russkinskoye	62,266	73,708	On
Uryevskoye	62,270	74,752	On
Samotlor	61,186	76,655	On

Oil field Name	Latitude	Longitude	Offshore/Onshore
Vat-Yeganskoye	62,164	75,014	On
Povkhovskoye	57,246	66,793	On
Romashkino	56,014	53,673	On
Unvinskoye	59,218	56,758	On
Pamyatno-Sasovskoye	50,663	45,131	On
Halfdan	55,710	4,800	Off
Statfjord	61,256	1,854	Off
Ekofisk	56,549	3,210	Off
Troll B/C	60,646	3,726	Off
Tyrihans	64,900	7,000	Off
Oseberg	60,500	2,500	Off
Gullfaks	61,100	2,100	Off
Buzzard	57,783	-1,248	Off
Ninian	60,860	1,450	Off
Captain	58,200	-1,900	Off
Cantarell	19,753	-92,516	Off
Boscan	10,456	-72,041	On

Annex A.2: Terminals

Table A.0-2 Geographical coordinates of representative oil field terminals (source: own elaboration)

Oil field	Terminal		
Name	Name	Latitude	Longitude
Gachsaran	Kharg Island	29,25	50,31
Rumaila (South)	Al Basrah Oil Terminal	29,68	48,81
West Qurna	Al Basrah Oil Terminal	29,68	48,81
Kirkuk	Ceyhan	36,86	35,94
Burgan	Mina al Ahmadi	29,06	48,15
Gwahar	Ras Tanura	26,64	50,16
Kurais	Ras Tanura	26,64	50,16
Manifa	Ras Tanura	26,64	50,16
Hassi Messaoud	Algiers	36,79	2,99
Block 17/Dalia	Dalia FPSO	-7,63	11,76

Oil field	Terminal		
Name	Name	Latitude	Longitude
Girassol	Girassol FPSO	-7,63	11,68
Greater Plutonio	Greater Plutonio FPSO	-7,81	12,11
Es Sider	Es Sider	30,64	18,37
El Sharara	Zawiya	32,79	12,70
Bonga	Bonga FPSO	5,10	5,10
Forcados Yokri	Forcados Terminal	5,35	5,35
Agbada	Bonny Terminal	4,40	7,17
Caw Thorne Channel	Bonny Terminal	4,40	7,17
Escravos Beach	Escravos Terminal	5,59	5,18
Azeri-Chirag-Gunashli (ACG)	Supsa	42,02	41,77
Azeri-Chirag-Gunashli (ACG)	Ceyhan	36,86	35,94
Tengiz	Ceyhan	36,86	35,94
Tengiz	Novorossiysk	44,78	37,72
Tevlinsko-Russkinskoye	Novorossiysk, Primorsk, Ventspills		
Uryevskoye	Novorossiysk, Primorsk, Ventspills		
Samotlor	Novorossiysk, Primorsk, Ventspills		
Vat-Yeganskoye	Novorossiysk, Primorsk, Ventspills		
Povkhovskoye	Novorossiysk, Primorsk, Ventspills		
Romashkino	Novorossiysk, Primorsk, Ventspills		
Unvinskoye	Novorossiysk, Primorsk, Ventspills		
Pamyatno-Sasovskoye	Novorossiysk, Primorsk, Ventspills		
Halfdan	Fredericia	55,56	9,74
Statfjord	Statfjord	61,26	1,85
Ekofisk	Teesside	54,61	-1,17
Troll B/C	Mongstad	60,81	5,02
Tyrihans	Trondheim	63,44	10,35
Oseberg	Sture	60,62	4,84
Gullfaks	Mongstad	60,81	5,02
Buzzard	Hound Point	56,04	-3,31
Ninian	Sullom Voe	60,46	-1,29
Captain	FPSO	58,200	-1,900
Cantarell	Caya Arcas	20,20	-91,96
Boscan	Punta Cardon	10,37	-70,13

Annex A.3 Ports

Table A.0-3 Geographical coordinates of major European oil importing ports (source: own elaboration)

Port	Country	Latitude	Longitude
Aberdeen(GBR)	United Kingdom	57.1526	-2.11
Agioi Theodoroi	Greece	37.916667	23.083333
Algeciras	Spain	36.1275	-5.453889
Amsterdam	Netherlands	52.366667	4.9
Antwerp	Belgium	51.27	4.336667
Argostoli	Greece	38.183333	20.483333
Asnaesvaerkets Havn	Denmark	55.655213	11.097193
Aspropyrgos	Greece	38.066667	23.583333
Augusta	Italy	37.25	15.216667
Avonmouth	United Kingdom	51.501	-2.699
Barcelona	Spain	41.383333	2.183333
Bilbao	Spain	43.256944	-2.923611
Bourgas	Bulgaria	42.495278	27.471667
Brest	France	48.39	-4.49
Brofjorden	Sweden	58.348056	11.416667
Brunsbuttel	Germany	53.896389	9.138611
Cartagena(ESP)	Spain	37.6	-0.983333
Castellon	Spain	40.166667	-0.166667
Civitavecchia	Italy	42.1	11.8
Constantza	Romania	44.173333	28.638333
Copenhagen	Denmark	55.676111	12.568333
Corunna	Spain	43.365	-8.41
Coryton	United Kingdom	51.513	0.521
Cromarty Anch.	United Kingdom	57.681628	-4.037008
Donges	France	47.3242	-2.075
Dundee	United Kingdom	56.464	-2.97
Dunkirk	France	51.0383	2.3775
Eleusis	Greece	38.033333	23.533333
Enstedvaerkets Havn	Denmark	55.021283	9.442330
Escombreras	Spain	37.6	-0.983333
Falconara	Italy	43.633333	13.4
Fawley	United Kingdom	50.828	-1.352
Finnart	United Kingdom	56.115	-4.832
Fiumicino	Italy	41.766667	12.233333
Flushing	Netherlands	51.45	3.566667
Fos	France	43.2031	5.201
Fredericia	Denmark	55.566667	9.75
Frederikshavn	Denmark	57.441111	10.539722

Port	Country	Latitude	Longitude
Gela	Italy	37.066667	14.25
Genoa	Italy	44.411111	8.932778
Gothenburg	Sweden	57.7	11.966667
Hamble	United Kingdom	50.85694	-1.32084
Hamburg	Germany	53.565278	10.001389
Hook of Holland	Netherlands	51.981111	4.128611
Hound Point	United Kingdom	56.036117	-3.31225
Huelva	Spain	37.25	-6.95
Hvalfjordur	Iceland	64.383333	-21.666667
Immingham	United Kingdom	53.6139	-0.2183
Isle of Grain	United Kingdom	51.46	0.73
Kalamata	Greece	37.033333	22.116667
Kali Limenes	Greece	34.916667	24.8
Kalundborg	Denmark	55.681389	11.085
Karlshamn	Sweden	56.166667	14.85
La Pallice	France	46.158333	-1.227778
La Spezia	Italy	44.1	9.816667
Le Havre	France	49.49	0.1
Leghorn	Italy	43.55	10.316667
Leixoes	Portugal	41.183	-8.7
Liverpool	United Kingdom	53.4	-2.983333
Malta Anch.	Malta	35.818	14.54
Marsaxlokk	Malta	35.841667	14.544722
Megara	Greece	38	23.333333
Midia	Romania	44°05'.1N	028°43'.1E
Milazzo	Italy	38.216667	15.233333
Milford Haven	United Kingdom	51.71418	-5.04274
Naantali	Finland	60.466667	22.033333
Nigg Terminal	United Kingdom	57.705558	-4.029685
Nynashamn	Sweden	58.9	17.95
Oxelosund	Sweden	58.666667	17.116667
Pachi	Greece	37.974443	23.362741
Petit Couronne	France	49.3864	1.0283
Piraeus	Greece	37.95	23.633333
Portbury	United Kingdom	51.4699	-2.7163
Rostock	Germany	54.083333	12.133333
Rotterdam	Netherlands	51.916667	4.5
Rouen	France	49.44	1.1
Santa Panagia	Italy	37.122640	15.216326
Sarroch	Italy	39.066667	9.016667
Savona	Italy	44.3	8.483333
Setubal	Portugal	38.533333	-8.883333
Shell Haven	United Kingdom	51.5052	0.4902

Port	Country	Latitude	Longitude
Sines	Portugal	37.93	-8.77
Skoldvik	Finland	60.311737	25.541684
Stenungsund	Sweden	58.083333	11.816667
Sullom Voe	United Kingdom	60.451733	-1.310805
Taranto	Italy	40.466667	17.233333
Tarragona	Spain	41.115697	1.249594
Teesport	United Kingdom	54.604	-1.158
Terneuzen	Netherlands	51.333333	3.833333
Tetney Terminal	United Kingdom	53.499933	0.000533
Thessaloniki	Greece	40.646749	22.882513
Trapani	Italy	38.016667	12.516667
Trieste	Italy	45.633333	13.8
Tyne	United Kingdom	54.989907	-1.465280
Vassiliko Bay	Cyprus	34.724084	33.310287
Vasto	Italy	42.1118	14.7082
Venice	Italy	45.4375	12.335833
Wilhelmshaven	Germany	53.516667	8.133333

ANNEX B: MAPS

Annex B.1: Oil fields maps

Figure B.0-1 Nigerian pipelines oil and gas fields map

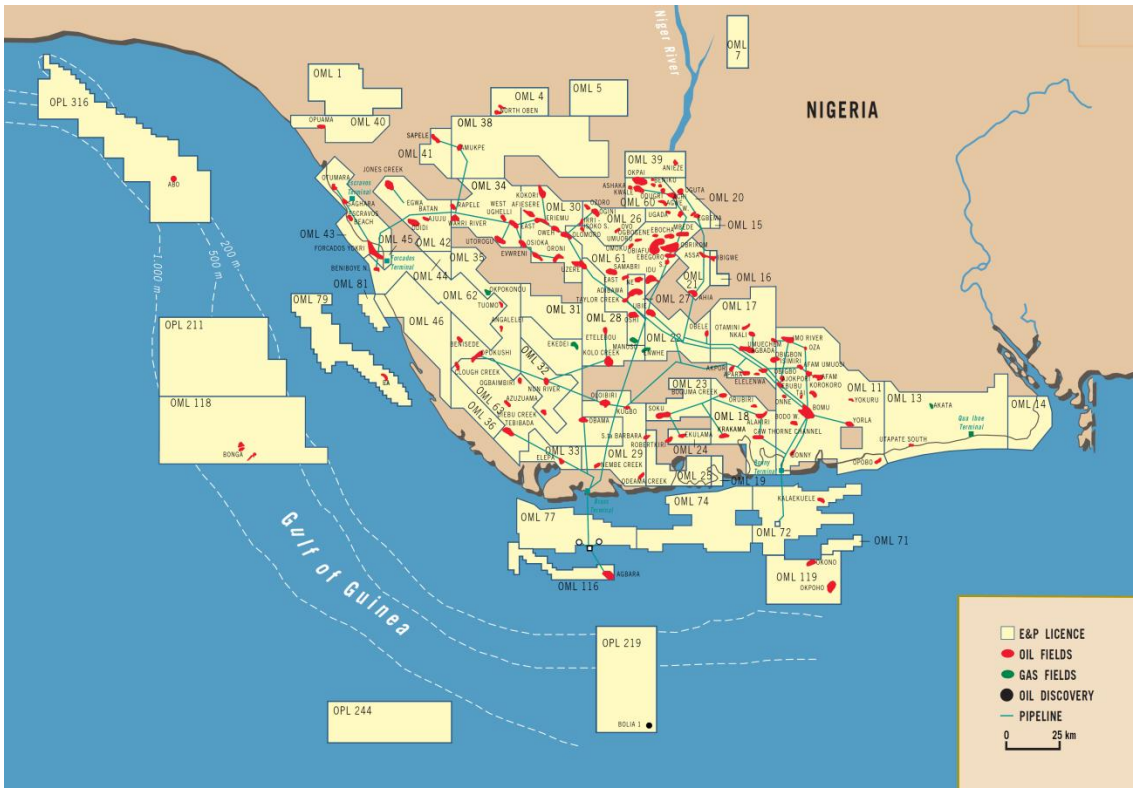


Figure B.0-2 Algerian pipelines, oil and gas fields map (source: Ministère de l'Energie et des Mines)

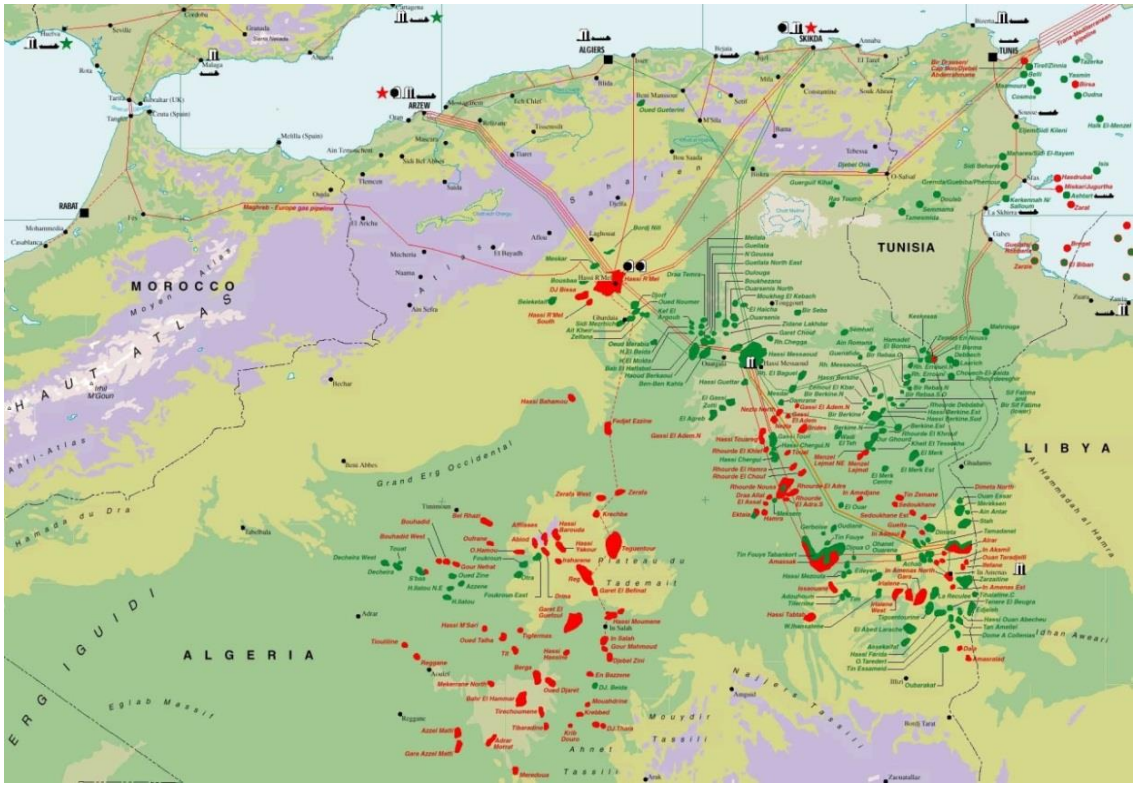


Figure B.0-3 Iraq's pipelines, oil and gas fields map (source: Platts)

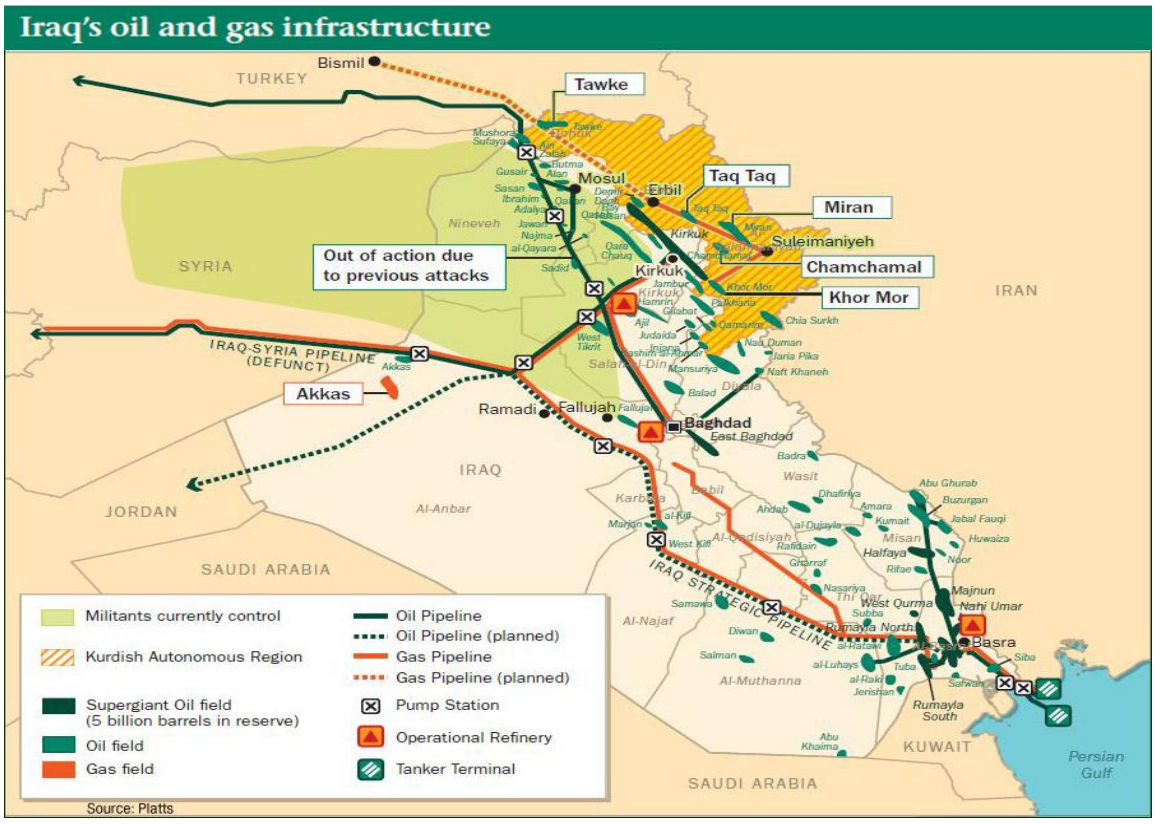
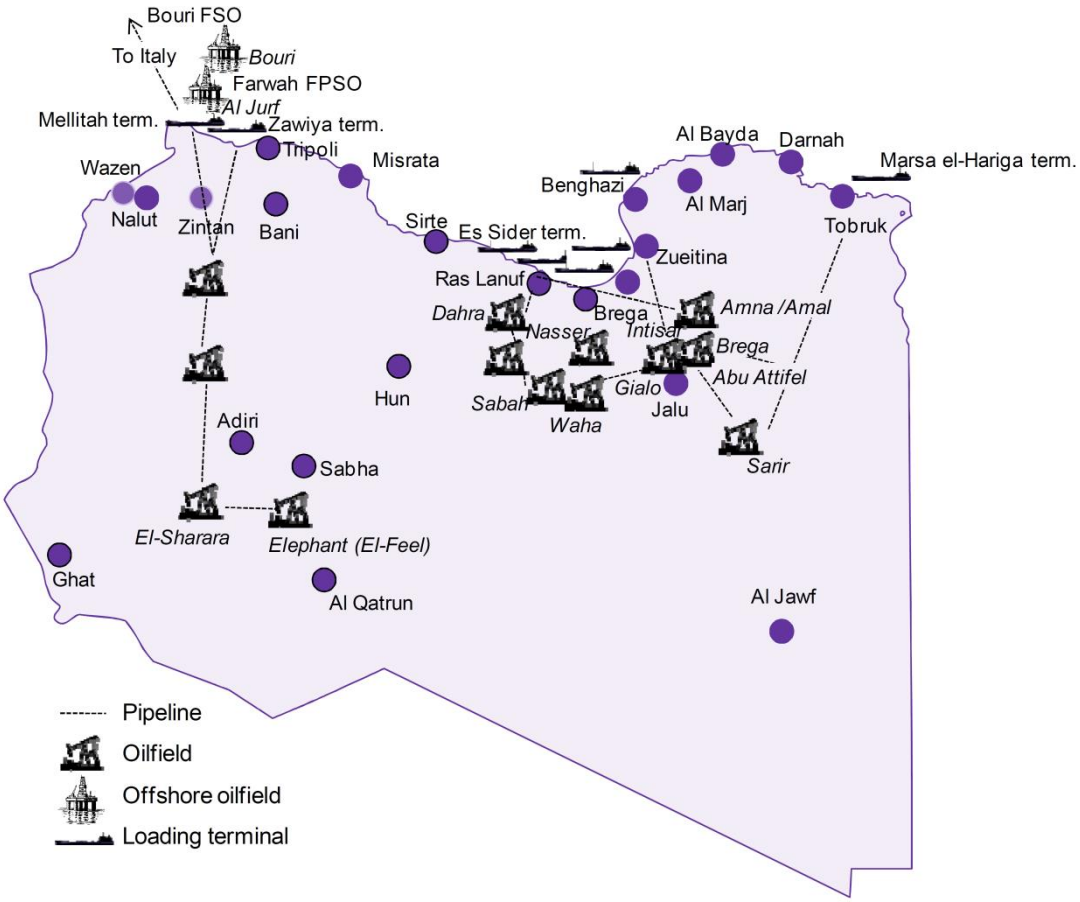


Figure B.0-4 Arabian oil and gas pipeline system



Figure B.0-5 Libyan pipelines, and oil fields map (source: Goldman Sachs)



Annex B.2: Oil pipeline maps

Figure B.0-6 Major Caspian oil and gas pipeline system (source: EIA)



Figure B.0-7 Russian oil and gas pipeline system (source: Theodora Maps)



Figure B.0-8 Balkan oil and gas pipeline system (source: Theodora Maps)



Figure B.0-9 Oil and gas pipeline system of Central Europe (source: Theodora Maps)



Figure B.0-10 Oil and gas pipeline system of North Africa (source: Theodora Maps)

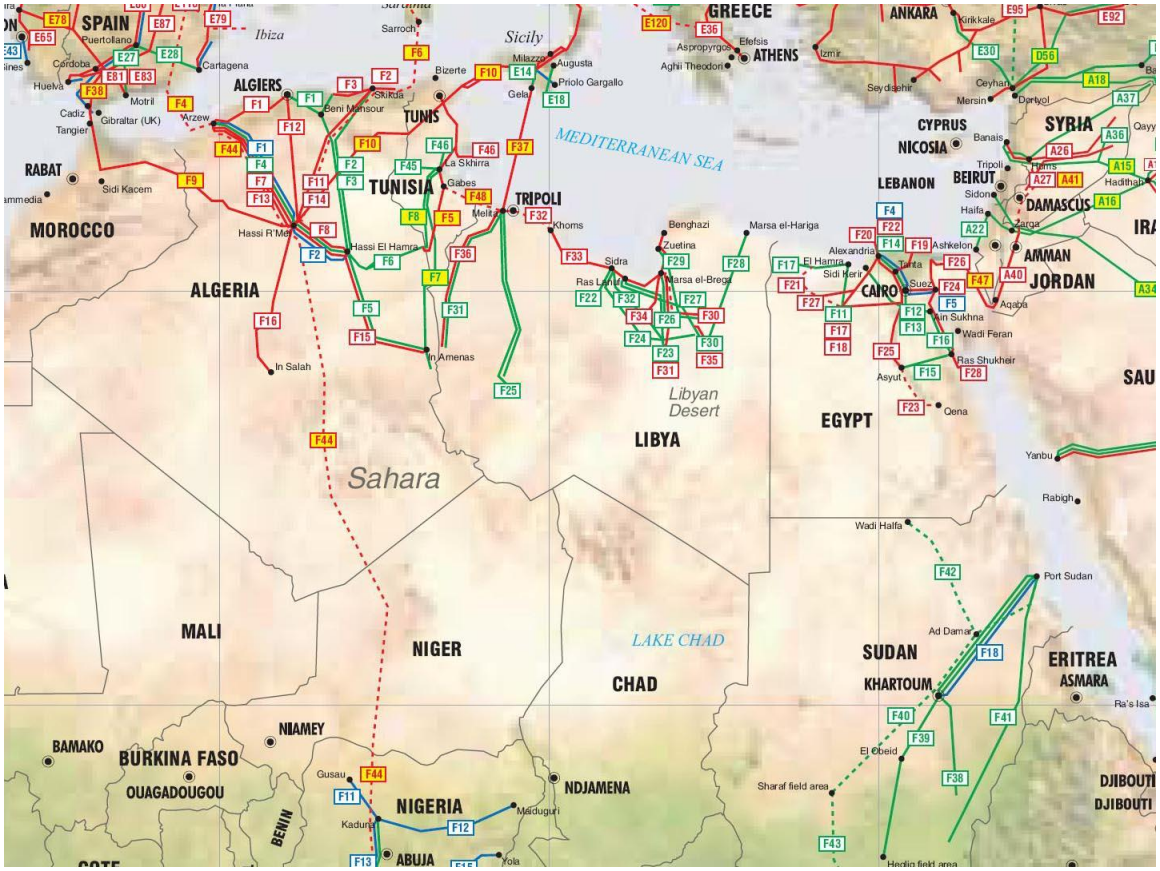


Figure B.0-11 Oil and gas pipeline system of Middle East (source: EIA)



ANNEX C: LITERATURE DATABASE EXTRACT

Table C.0-1 Extract from the generic literature database

Date	Publishing Organisation	Author(s)	Document Type	Key points
1/1/2008	Greenhouse Gas Protocol	Greenhouse Gas Protocol	Datasheet	In this document, a table with the direct (except for CH4) 100-year time horizon global warming potentials (GWP) relative to CO2 is included. This table is adapted from table 2.14 of the IPCC Fourth Assessment Report, 2007. The 4th assessment report values are the most recent (2007), but the second assessment report values (1995) are also listed.
1/1/2010	Global Gas Flaring Reduction, A Public-Private Partnership	The World Bank Group, Oil & Gas Policy Division	Report/Study	A technical glossary of terms was commissioned by the Oil & Gas Methodology Workgroup1 (WG) to compile and explain how specific oil and gas terms found and/or required in relevant CDM/JI Methodologies, are understood and applied by industry, and how the concepts should be interpreted in the context of project activities. The document is intended to help reduce possible misinterpretations that can lead to delay and additional transactions costs during the formulation, validation, registration and verification of CDM/JI projects. The glossary features industry references as appropriate, and is meant to serve as a useful guide when suggesting improvement and/or requests for clarification and/or revisions of the approved methodologies.
1/1/2013	Organization of the Petroleum Exporting Countries (OPEC)	Organization of the Petroleum Exporting Countries (OPEC)	Datasheet	This is the 48th edition of the Annual Statistical Bulletin (ASB), one of OPEC's principal publications and an increasingly important source of data for the oil industry. The aim of this report is to make available reliable and timely historical data on the global oil and gas industry. It is a useful and frequently cited reference tool for those working in the energy industry. OPEC's 12 Member Countries — namely Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela — are the central focus of the ASB. However, as in previous editions, the ASB also provides information and statistical data about non-OPEC oil producing countries, bringing together data on exports, imports, pipelines and shipping, as well as the petroleum industry in general. It has collected statistical information about exploration and production, as well as transportation and refining, and has made this available to other energy stakeholders.
11/6/2013	Society of Chemical Industry and John Wiley & Sons, Ltd - Biofuels,	Björn Pieprzyk, Paula Rojas Hilje and Norbert Kortlüke	Research Paper	In this report, the substitution of marginal oil with biofuels is analysed. For that, the effects that influence the substitution process in the short, mid and long term are evaluated. OPEC, resource nationalism, and geopolitical issues are identified as important influence factors. It is

Date	Publishing Organisation	Author(s)	Document Type	Key points
	Bioprod. Bioref.			concluded that in the short term biofuels will replace mainly OPEC oil but not the most expensive petroleum.
22/9/2013	InLCA/LCM 2003	Paul Worhach, Robert E. Abbott	Presentation	An important component of Lifecycle Assessment (LCA) is the methodology by which energy and emissions in multi-product production systems, such as petroleum refining, are attributed to the production of the different products. In this presentation, an alternative methodology called Co-Product Function Expansion (CFE) is proposed. CFE is an incremental approach in which selected co-products and a selected set of co-product functions are placed within the product system boundary, and the energy and emissions for upstream stages and co-product production are accounted for in the LCA. The downstream functions of the co-products are compared with alternative products serving the same functions, and the net energy and emissions, as either debits or credits, are assigned to the primary system products.
1/1/2014	IPCC WGIII AR5	Leon Clarke and Kejun Jiang	Report/Study	Stabilizing greenhouse gas (GHG) concentrations will require large-scale transformations in human societies, from the way that we produce and consume energy to how we use the land surface. A natural question in this context is what will be the 'transformation pathway' towards stabilization; that is, how do we get from here to there? The Document is primarily motivated by three questions: What are the near-term and future choices that define transformation pathways, including the goal itself, the emissions pathway to the goal, technologies used for and sectors contributing to mitigation, the nature of international coordination, and mitigation policies? What are the key characteristics of different transformation pathways, including the rates of emissions reduction sand deployment of low-carbon energy, the magnitude and timing of aggregate economic costs, and the implications for other policy objectives such as those generally associated with sustainable development? How will actions taken today influence the options that might be available in the future?
1/1/2014	IPCC WGIII AR5	Ralph Sims, Roberto Schaeffer	Report/Study	Reducing global transport greenhouse gas emissions will be challenging since the continuing growth in passenger and freight activity could outweigh all mitigation measures unless transport emissions can be strongly decoupled from GDP growth. Direct (tank-to-wheel) GHG emissions from passenger and freight transport can be reduced by: avoiding journeys where possible, modal shift to lower-carbon transport systems, lowering energy intensity (MJ/passenger km or MJ/ton km) and reducing carbon intensity of fuels. Both short- and long-term transport mitigation strategies are essential if deep greenhouse gas emissions reduction ambitions are to be achieved. Barriers to decarbonizing transport for all modes differ across regions, but can be overcome in part by reducing the marginal mitigation costs (medium evidence, medium agreement). There are regional differences in transport mitigation pathways with major opportunities to shape transport systems and infrastructure around low-carbon options. A range of strong and mutually-supportive policies will be needed for the transport sector to decarbonize and for the co-benefits to be exploited.

Table C.0-2 Extract from the specific literature database

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
UK Production Data Release	1/10/2014	Department of Energy and Climate Change (DECC) - Energy Group	Department of Energy and Climate Change (DECC) - Energy Group	Datasheet	› Oil	› Upstream	Europe		Production data regarding UK fields. Monthly data for oil, water, condensate and gas production are provided for the period from July 2013 to June 2014.
Lifecycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States	29/5/2014	United States Department of Energy (DOE), National Energy Technology Laboratory (NETL)	Timothy J. Skone, Gregory Cooney, Matthew Jamieson, James Littlefield, Joe Marriott	Report/Study	› Direct GHG Emissions; › Modelling; › Natural Gas; › Unconventional Gas	› Upstream; › Midstream; › Downstream; › Combustion	Europe; North America		A lifecycle assessment of the greenhouse gas emissions for regional coal and imported natural gas power in Europe and Asia. Exported LNG from the U.S.A. is compared with regional coal for electric power generation in Europe and Asia. Furthermore, natural gas produced in Russia and delivered to Europe and Asia via pipeline is also evaluated.
Facts 2014, The Norwegian Petroleum Sector	5/5/2014	Yngvild Tormodsgard, Ministry of Petroleum and Energy	Yngvild Tormodsgard, Ministry of Petroleum and Energy	Report/Study	› Oil; › Natural Gas	› Upstream	Europe		A report on Norvegian petroleum industry. A wide range of issues from Ekofisk, (the first discovered Norwegian oil field) to current industry status are analysed. Furthermore, future challenges and strategies are also provided.
Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil	1/5/2014	IHS Energy	IHS Energy	Report/Study	› Direct GHG Emissions; › Modelling; › Oil; › Unconventional oil	› Upstream; › Midstream; › Downstream	North America		The purpose of this report is to inform the dialogue surrounding the GHG emissions from US crude oil supply and Canadian oil sands. The origin of US oil supply since 2005 has changed significantly. However, the GHG intensity of the average crude oil consumed in the United States did not materially change. Common GHG intensity baselines—such as the average crude consumed in the United States—provide a useful reference point for

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									comparisons. However, they should be used with caution. They are theoretical values to enable comparisons, not absolute numbers. There are simply too many crude oils consumed in the United States to accurately track and quantify emissions for each. The almost 4% difference between the IHS and DOE/NETL results indicates the possible margin of error in estimating the GHG emissions for the average crude oil. The study uses a hybrid bottom-up method for estimating the average GHG emissions for the average US crude oil. It is followed by an Appendix analysing the methodology, data and calculations utilized.
Appendix to IHS Special Report: Comparing GHG Intensity of Oil Sands to the Average US Crude	1/5/2014	IHS Energy	IHS Energy	Report/Study	› Direct GHG Emissions; › Modelling; › Oil; › Unconventional oil	› Upstream; › Midstream; › Downstream	North America		Appendix to the referenced report including the methodology, data and calculations utilized.
OPGEE Documentation version 1.1b	11/3/2014	California Air Resources Board	Hassan M. El-Houjeiri, Kourosh Vafi, Scott McNally, Adam Brandt (Stanford University), James Duffy (CARB)	User's Manual	› Direct GHG Emissions; › Indirect GHG Emissions; › Modelling; › Oil; › Unconventional oil	› Upstream; › Midstream	Worldwide	OPGEE	Technical documentation to the Oil Production Greenhouse gas Emissions Estimator (OPGEE) explaining the calculations and data sources in the model.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions	23/1/2014	Congressional Research Service (CRS)	Michael Ratner, Mary Tiemann	Report/Study	› Policy; › Unconventional oil; › Unconventional Gas	› Upstream ›	North America		This report focuses on the growth in U.S. oil and natural gas production driven primarily by tight oil formations and shale gas formations. It reviews as well selected federal environmental regulatory and research initiatives related to unconventional oil and gas extraction. The motive for this study has been the rapid expansion of oil and gas extraction using hydraulic fracturing, both in rural and more densely populated areas. In general, this production method has raised concerns about its potential environmental and health impacts, i.e. groundwater and surface water quality, public and private water supplies and air quality.
Reduction of Methane Emissions in The EU Natural Gas Industry	1/1/2014	Marcogaz, Eni S.p.A, E.ON Ruhrgas AG	Jürgen Vorgang (E.ON Ruhrgas AG, Germany), Angelo Riva (Eni S.p.A, G&P Div. G&P, Italy), Alessandro Cigni (Marcogaz, Belgium), Daniel Hec (Marcogaz, Belgium)	Research Paper	› Direct GHG Emissions; › Indirect GHG Emissions; › Modelling; › Natural Gas	› Midstream; › Downstream	Europe		In the natural gas transmission sector, methane is released to the atmosphere. In this paper, a methodology for evaluating methane releases is proposed. Although the parameter values used for calculating methane releases vary from one transmission company to another, a specified range for such values is suggested. Furthermore data from seven major western European transmission companies are analysed. Finally suggestions for redaction of the methane releases are provided.
Upstream emissions of fossil fuel feedstocks for transport	30/11/2013	EC / DG CLIMA	Chris Malins, Sebastian Galarza, Anil Baral, Drew Kodjak	Report/Study	› Direct GHG Emissions; › Policy; › Modelling;	› Upstream; › Midstream	Europe	OPGEE	The report analyses the results of several desk studies on the EU fossil fuel feedstock market and associated empirical and modeled data on GHG emissions. It presents a new model for lifecycle analysis of crude oil

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
fuels consumed in the European Union			(International Council on Clean Transportation (ICCT)), Adam Brandt, Hassan El-Houjeiri (Stanford University), Gary Howorth (Energy Redefined), Tim Grabiel (Defense Terre)		› Oil				extraction and provides an estimate using that model of the carbon intensity of crude oil supplied to the European Union. The objective is to calculate the carbon intensity (CI) for the most important types of crude oil entering the EU. More specifically the study provides a comprehensive Lifecycle Emissions analysis using the OPGEE model for a large number of crudes imported in Europe, using the DG ENER list of crude imports. The analysis has been done on oil-field basis by collecting key data for each oil field. There can be found detailed analyses about available data sources (Chapter 7), as well as a comprehensive summary of findings from other LCA studies on crude oil (Chapter 4).
Environmental Performance Indicators - 2012 Data	1/11/2013	International Association of Oil and Gas Producers (OGP)	OGP	Report/Study	› Direct GHG Emissions; › Oil; › Unconventional oil	› Upstream	Worldwide		OGP has been collecting environmental data from its member companies for the past 14 years on an annual basis. The present report summarises information on activities related to exploration and production (upstream) carried out by OGP member companies in 2012. Data coverage is relatively low – 32% of 2012 world production – while regional coverage varies from 96% in Europe to 8% in FSU. Overall, data from 78 countries are represented in the report.
Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan	1/11/2013	European Bank for Reconstruction and Development	Carbon Limits AS	Report/Study	› Direct GHG Emissions; › Policy; › Oil; › Natural Gas	› Upstream	Former Soviet Union		This report summarizes the findings of the "Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan" which was initiated by the European Bank for Reconstruction and Development (EBRD) and co-managed by EBRD and the Global Gas Flaring Reduction Partnership (GGFR). The aim of the Study has been to review and analyse

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									appropriate technical solutions for the use of the associated petroleum gas (APG) and to identify bankable projects in the four countries covered. Flaring data from NOAA and other sources are provided and analysed.
Independent Assessment of the European Commission's Fuel Quality Directive's "Conventional" Default Value	9/10/2013	Natural Resources Canada	ICF Consulting Canada	Report/Study	› Direct GHG Emissions; › Modelling; › Oil	› Upstream; › Midstream; › Downstream	Europe	OPGEE	Based on the new Fuel Quality Directive, this report analyses the lifecycle GHG emissions for diesel and petrol. The objective of this study is two-fold: 1) analyse the methodology that has been used in the JEC reports (JEC v3c and v4) to determine the default conventional crude oil petrol and diesel GHG intensity values, 2) using that improved understanding, develop a more accurate default GHG intensity range for petrol and diesel from conventional crude oils (using OPGEE). Emphasis is given on data quality and availability which is limited.
Natural Gas Information 2013	13/8/2013	IEA	IEA	Book	› Natural Gas	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide		A detailed reference work on gas supply and demand covering not only the OECD countries but also the rest of the world, this publication contains essential information on LNG and pipeline trade, gas reserves, storage capacity and prices. The main part of the book, however, concentrates on OECD countries, showing a detailed supply and demand balance for each country and for the three OECD regions: Americas, Asia-Oceania and Europe, as well as a breakdown of gas consumption by end-user. Import and export data are reported by source and destination.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
Desk study on indirect GHG emissions from Fossil Fuels	1/8/2013	DG Clima	ICF International	Report/Study	› Indirect GHG Emissions; › Oil	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide		The overall objective of the study is to provide an overview that enables the European Commission to evaluate the indirect GHG emissions from fossil fuel origin. In the study the direct emissions are defined as the ones emitted from the processes used to produce, transport and combust the fuel along the lifecycle, whereas the indirect emissions are those that are influenced or induced by economic, geopolitical or behavioural factors, but which are not directly related to extraction, processing, distribution or final combustion of the fuels. The study identifies and evaluates six possible sources of indirect GHG emissions from fossil fuels: Induced land development, Military involvement, Accidents, Marginal effect, Price effects and Export of co-products. It is based on a thorough literature review in the field of indirect emissions. Where possible, estimates on the emissions are provided. The study is a central source for analysing and estimating indirect emission and will also provide the basis for defining the boundaries between direct and indirect sources in the current project.
Oil Information 2013	23/7/2013	IEA	IEA	Datasheet	› Oil	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide		A comprehensive reference book on current developments in oil supply and demand. The first part of this publication contains key data on world production, trade, prices and consumption of major oil product groups, with time series back to the early 1970s. The second part gives a more detailed and comprehensive picture of oil supply,

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									demand, trade, production and consumption by end-user for each OECD country individually and for the OECD regions. Trade data are reported extensively by origin and destination.
WELL-TO-TANK Report Version 4.0	1/7/2013	JEC	Robert EDWARDS (JRC), Jean-François LARIVÉ (CONCAWE), David RICKEARD (CONCAWE), Werner WEINDORF (LBST)	Report/Study	› Direct GHG Emissions; › Modelling; › Oil; › Unconventional oil	› Upstream; › Midstream; › Downstream	Europe	Other	This part of the study describes the process of producing, transporting, manufacturing and distributing a number of fuels suitable for road transport powertrains. It covers all steps from extracting, capturing or growing the primary energy carrier to refuelling the vehicles with the finished fuel. As an energy carrier, a fuel must originate from a form of primary energy which can be either contained in a fossil feedstock (hydrocarbons of fissile material) or directly extracted from solar energy (biomass or wind power). Generally a fuel can be produced from a number of different primary energy sources. In this study, we have included all fuels and primary energy sources that appear relevant within the timeframe considered (which broadly speaking is the next decade) and we have considered the issues and established comparisons from both points of view in order to assist the reader in answering the questions: 1) What are the alternative uses for a given resource and how can it best be used? 2) What are the alternative pathways to produce a certain fuel and which of these hold the best prospects?
GHGenius Model 4.03 - Model Background	15/6/2013	Natural Resources Canada	Don O'Connor	User's Manual	› Direct GHG Emissions; › Indirect	› Upstream; › Midstream;	Worldwide	GHGenius	Volume 1 of the report documents the development of the model and provides the user with an understanding of the primary functions of the model. Volume 2 is focused

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
and Structure - Data and Data Sources					GHG Emissions; › Modelling; › Oil; › Natural Gas; › Unconventional oil; › Unconventional Gas	› Downstream; › Combustion			on the data that is used in the model, the sources and where the data is used.
BP Statistical Review of world energy	1/6/2013	BP	BP	Datasheet	› Oil; › Natural Gas	› Upstream; › Downstream; › Combustion	Worldwide		It provides an annual opportunity to examine the latest data, country-by-country and fuel-by-fuel. This helps us discern the important trends and assess the challenges and the opportunities that lie before us. This edition of the review highlights the flexibility with which our global energy system adapts to rapid global change.
BP Statistical Review of World Energy June 2013	1/6/2013	BP	BP	Report/Study	› Oil; › Natural Gas; › Unconventional oil; › Unconventional Gas	› Upstream; › Downstream	Worldwide		Annual report providing data on oil and natural gas reserves, prices, production and consumption by country as well as trade movements.
Oil and Gas Production in Denmark and Subsoil Use, 2012	1/6/2013	Danish Energy Agency (Energi Styrelsen)	Danish Energy Agency (Energi Styrelsen)	Report/Study	› Oil; › Natural Gas	› Upstream	Europe		A report on oil and gas production in Danish. An overview of licences and exploration is given. Other uses of subsoil, such as produce salt, produce geothermal heat and store of natural gas are mentioned. Production and development as well as classification of resources and economy are analysed. Health

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									and safety regulations by the Danish Offshore Safety Act and Climate and environment issues are provided. Furthermore detailed actual data are given.
Crude Oil in Europe: Production, Trade and Refining Outlook	1/3/2013	Wood Mackenzie	Steve Cooper	Presentation	› Oil	› Upstream; › Midstream; › Downstream; › Combustion	Europe		Production, Trade and Refining Outlook of 2013 for Crude Oil in Europe by Wood Mackenzie.
Guidance Document - Flaring Estimates Produced by Satellite Observations	1/1/2013	The World Bank / NOAA	Global Gas Flaring Reduction	Report/Study	› Direct GHG Emissions; › Modelling; › Oil; › Natural Gas	› Upstream	Worldwide		This report provides general guidelines on the utilisation of satellite images in order to estimate the GHG emissions due to Associated Petroleum Gas (AGP) - flaring and venting emissions.
2012 Annual Statistical Bulletin of Nigerian oil and gas sector	1/1/2013	National Nigerian Petroleum Corporation	Corporate Planning & Strategy Division (CP&S)	Datasheet	› Oil; › Natural Gas	› Upstream	Africa		The specific datasheet contains detailed information regarding the Nigerian oil and gas sector published by the national responsible authority for the oil and gas sector (NNPC). Specifically, it contains information on the quantity of oil and produced, quantity of water produced, number of wells, API gravity, gas to oil ratio per oil field and operator. Furthermore, it contains information regarding quantities of gas produced, gas re-injected and flared per oil field and operator.
HANDBOOK ON THE ENERGY SECTOR Fugitive Emissions	1/1/2013	UNFCCC	Consultative Group of Experts (CGE) – National GHG	Report/Study	› Direct GHG Emissions	› Upstream	Worldwide		The aim of this handbook is to improve skills and knowledge regarding the preparation of greenhouse gas inventories. Specifically, this handbook focuses on the fugitives portion of the energy sector, in keeping with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories and taking into

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
			Inventory						consideration the Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.
Nexen Petroleum U.K. Limited Environmental Statement 2012	1/1/2013	Nexen	Nexen	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions; › Policy; › Oil; › Natural Gas	› Upstream	Europe		Nexen is an upstream oil and gas company. The environmental performance of Nexen's UK offshore operations during 2012 are reported. Actual data regarding atmospheric emissions, produced water, waste generation, production chemical usage, unplanned releases and emissions associated with drilling operations are analysed. Finally environmental objectives of 2012 and 3013 are provided.
Environmental Report, The Environmental Efforts of the Oil and Gas Industry with Facts and Figures, 2013	1/1/2013	Norwegian Oil and Gas Association (Norsk olje&gass)	Norwegian Oil and Gas Association (Norsk olje&gass)	Report/Study	› Direct GHG Emissions; › Policy; › Oil; › Natural Gas	› Upstream	Europe		The annual environmental report of the Norwegian Oil and Gas Association. Data on emissions/discharges are recorded continuously in Environment Web, a joint database for Norwegian Oil and Gas, Klif and the Norwegian Petroleum Directorate (NPD). Based on information from Environment Web, the Norwegian Oil and Gas environmental report provides an updated overview of reporting in 2012 on emissions to the air and discharges to the sea as well as waste generation from NCS operations. The report also contains data and research results from long-term projects related to the marine environment and environmental monitoring. All fields with production facilities on the NCS are included. Emissions/discharges from the construction and installation phase, maritime support services and helicopter traffic are excluded.

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UK Operations, Environmental Performance, Annual Report 2012	1/1/2013	CNR International	CNR International	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions; › Policy; › Oil; › Natural Gas	› Upstream; › Combustion	Europe		The annual environmental report of the CNR International. CNRI operations and environmental aspects are provided. Significant environmental aspects of CNRI are Carbon dioxide emissions from power generation and flaring, oil discharged in produced water, oil and chemical spills, solid waste generation and disposal and chemical use and discharge.
BP in Azerbaijan, Sustainability Report 2012	1/1/2013	BP Caspian	BP Caspian	Report/Study	› Direct GHG Emissions; › Oil; › Natural Gas	› Upstream; › Midstream	Former Soviet Union		An annual report of BP in Azerbaijan for 2012. Business performance, environmental record, safety requirements and impact on Society are covered. Furthermore detailed actual data regarding performance are provided.
Oil Sands, Greenhouse Gases, and US Oil Supply	1/11/2012	IHS CERA	IHS CERA	Report/Study	› Policy; › Oil; › Unconventional oil	› Upstream; › Midstream; › Downstream	North America		The purpose of this report is to generate a broad set of crude oil GHG emissions data to help inform the dialogue on GHG emissions from US crude supply. In these types of discussions, it is important that GHG estimates represent average values. It provides a meta-analysis of various GHG emissions estimates for crude oil, with a focus on oil sands, and concludes that differences between the carbon intensities calculated within each study depends on the unique assumptions made in each case. It is followed by an Appendix summarizing the method and data used for the meta-analysis.
Appendixes to IHS CERA Special Report, Oil	1/11/2012	IHS CERA	IHS CERA	Report/Study	› Policy; › Oil;	› Upstream; › Midstream;	North America		Appendixes summarizing the method and data used for the meta-analysis provided within the report entitled "Oil Sands, Greenhouse Gases, and US Oil Supply".

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Sands, Greenhouse Gases, and US Oil Supply—2012 Update					› Unconventional oil	› Downstream			
Lifecycle Greenhouse Gas Emissions of Natural Gas	1/10/2012	CNGI	ICF Consulting Canada	Report/Study	› Direct GHG Emissions; › Natural Gas	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide		The goal of this paper is to review the recent scientific literature on lifecycle GHG emissions from coal and conventional and shale gas production and their use for electricity generation. The motivation of the study was the rapid increase in production of shale gas in North America in recent years, which has focused attention on the increased role that low-priced, abundant natural gas can play throughout the economy. The results show that all of the research other than the Howarth study finds that lifecycle GHGs are less from gas than from coal and that there is relatively little difference between conventional and shale gas in lifecycle GHG emissions.
Lifecycle Assessment of Crude Oil Production within the LOW CARBON FUEL STANDARD	12/7/2012	California Air resources Board	John Courtis, Manager Alternative Fuels Section, Jim Duffy Air Resources Engineer Alternative Fuels Section	Presentation	› Modelling; › Oil	› Upstream; › Midstream	North America	OPGEE	Presentation within public meeting concerning the status of the methodology under development for determining the carbon intensity of crude oil, according to newly developed policy. Updates to OPGEE and modelling methods are being presented.
From Ground to Gate: A	1/6/2012	NTNU-Trondheim	Reyn OBorn	Report/Study	› Direct GHG Emissions;	› Upstream; › Midstream;	Europe	GREET	The scope of the study is to introduce a lifecycle analysis on the UK petroleum refining sector and clarify where emissions

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lifecycle assessment of petroleum processing activities in the United Kingdom					› Oil	› Downstream; › Combustion			occur along the process chain and which fuels cause the most pollution on a per unit basis. The motivation of the study has been the complexity of the petroleum process chain and the fact that the environmental impacts within the process chain are not always well understood. So, it is believed that a deeper understanding of where emissions come from along the process chain will help policy makers in the path towards a less carbon intensive society. Concluding, the results of the study show that the UK refining industry is typically more environmentally efficient than the average refinery in Europe according to Eco Invent data.
EU Pathway Study: Lifecycle Assessment of Crude Oils in a European Context	1/3/2012	Alberta Petroleum Marketing Commission	Bill Keesom, John Blieszner (Jacobs Consultnacy), Stefan Unnasch (Lifecycle Associates)	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions; › Oil; › Unconventional oil	› Upstream; › Midstream; › Downstream; › Combustion	Europe; North America	GREET	The goal of this Study is to evaluate the LCA GHG for potential pathways to Europe for producing petrol and diesel from representative heavy crude oils from Alberta, Canada. Another goal was to evaluate the LCA GHG emissions of representative crude oils refined in representative refineries and thereby gain a better understanding of the variability in LCA GHG emissions for different pathways for producing petrol and diesel for the EU market. The intent of this work is to better understand the carbon intensity of pathways for petrol and diesel from individual crude oils. Determining the carbon intensities of petrol and diesel from an average crude oil refined in an average refinery risks losing some of the granularity that helps explain the range in carbon intensities for petrol and diesel from different crude oils produced in different regions and refined in different

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									refineries. Representative crude oils ranging from light to heavy crude oils from the major supply regions were selected for the Study. Therefore the Study does not cover all crude oils imported in Europe, but only the ones treated in 3 representative refineries: FCC-Coking refinery – situated in Germany, FCC-Visbreaking refinery – situated in France, Hydrocracking-Visbreaking refinery – situated in Italy.
Indirect Land Use Change - how good are the models?	28/2/2012	Biorefinery Conference 2012	Don O'Connor	Presentation	› Indirect GHG Emissions; › Modelling	› Downstream	Worldwide		The scope of the presentation is a discussion of the indirect land use related to biofuels. Further the presentation looks at the issue of indirect impacts related to fossil fuel production, namely the issue of the production of co-products from fossil fuel production. The substitution of these products will result in emissions, and the magnitude depends of the source of substitution. For the purpose of the current project the presentation provides figures on the volume of the co-products and it refers to an European LCA study that have looked into to issue of taking into account alternative production of co-products.
Variability and Uncertainty in Lifecycle Assessment Models for Greenhouse Gas Emissions from	14/12/2011	Environmental Science and Technology	Adam R. Brandt	Research Paper	› Direct GHG Emissions; › Oil; › Unconventional oil	› Upstream; › Midstream; › Downstream; › Combustion	North America	GHGenius; GREET; Other	The scope of this paper is to review factors affecting energy consumption and GHG emissions from oil sands extraction. For this purpose, the author uses publicly available data to analyse the assumptions made in the LCA models to better understand the causes of variability in emissions estimates. The motive of this paper has been the raising interest in greenhouse gas (GHG) emissions from transportation fuels production. A

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Canadian Oil Sands Production									number of recent lifecycle assessment (LCA) studies have calculated GHG emissions from oil sands extraction, upgrading, and refining pathways, but the results from these studies vary considerably. Concluding, it is found that the variation in oil sands GHG estimates is due to many causes, e.g. scope of modelling and choice of projects analysed, differences in assumed energy intensities of extraction and upgrading, differences in the fuel mix assumptions, treatment of secondary non combustion emissions sources, such as venting, flaring, and fugitive emissions and treatment of ecological emissions sources, such as land-use change-associated emissions.
Lifecycle analysis of Shale Gas and Natural Gas	1/12/2011	Argonne	C.E. Clark, J. Han, A. Burnham, J.B. Dunn, M. Wang	Report/Study	› Direct GHG Emissions; › Modelling; › Natural Gas; › Unconventional Gas	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide	GREET	The scope of this study is to examine the size of the environmental impacts of shale gas production, by comparing it to natural gas. The motivation has been the technologies and practices that have enabled the recent boom in shale gas production and the fact that shale gas will provide the largest source of growth in the U.S. natural gas supply through 2035. The results of the base case scenario show that shale gas lifecycle emissions are 6% lower than those of conventional natural gas. However, the range in values for shale and conventional gas overlap, so there is a statistical uncertainty regarding whether shale gas emissions are indeed lower than conventional gas emissions.

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Lifecycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production	24/10/2011	U.S. Department of Energy / NETL	Timothy J. Skone (NETL), James Littlefield, Dr. Joe Marriott (Booz Allen Hamilton, Inc.)	Report/Study	› Direct GHG Emissions; › Natural Gas; › Unconventional Gas	› Upstream; › Midstream; › Downstream	North America		This report expands upon previous lifecycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy. The extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations.
Upstream greenhouse gas (GHG) emissions from Canadian oil	18/1/2011	Stanford University	Adam R. Brandt	Report/Study	› Direct GHG Emissions; › Oil; › Unconvent	› Upstream; › Midstream	Europe; North America	OPGEE	The report focuses on the following issues: First, it provides an overview and description of oil sands extraction, upgrading, SCO and bitumen, non-combustion process emissions and land use change associated emissions. Second, it compares a variety of recent

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sands as a feedstock for European refineries					ional oil				estimates of GHG emissions from oil sands and outlines the reasons for variations between the estimates in surface mining, in situ production, upgrading, refining and VFF. Finally, it outlines low, high and "most likely" estimates of GHG emissions from oil sands, given results from previously produced estimates, and compare these emissions to those of conventional EU refinery feedstock. This report focuses on the European context, and therefore uses EU-specific emissions factors for transport and refining of fuels. It results that, while the highest emissions conventional oil has higher upstream emissions than the lowest emissions oil sands estimate, the production-weighted emissions profiles are significantly different. The most important uncertainties mentioned are treatment of cogenerated electric power, treatment of refining and the interaction of markets with LCA results.
Petroleum industry guidelines for reporting greenhouse gas emissions	1/1/2011	IPIECA, Energy API, OGP	IPIECA, Energy API, OGP	Legislation	› Direct GHG Emissions; › Indirect GHG Emissions; › Policy	› Upstream; › Midstream; › Downstream	North America		This report's objective is to fulfil the need for industry guidance focused specifically on the accounting and reporting of GHG emissions at the facility through to the corporate level, for member companies of the American Petroleum Institute. They have been developed as a complement to the Compendium and the IPIECA Sustainability Guidance The Compendium has been written and published in order to meet the need of the petroleum industry for GHG accounting and reporting guidance, specifically focused on operations. The member companies of the American Petroleum Institute first published the Compendium of Greenhouse

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									Gas Emissions Estimation Methodologies for the Oil and Gas Industry in April 2001, with a third edition released in August 2009.
LCA of the European Gas Chain: Challenges and Results	1/1/2011	International Gas Union Research Conference 2011	A. Prieur-Vernat (GDF Suez – France), P. Pacitto (GDF Suez – France), D. Hec (Marcogaz – BELGIUM), V. Bichler (GDF Suez – France)	Research Paper	› Direct GHG Emissions; › Indirect GHG Emissions; › Modelling; › Natural Gas	› Upstream; › Midstream; › Downstream; › Combustion	Europe		A lifecycle assessment of the European gas chain with respect to environmental performance. Data validated by the European Gas Industry are analysed. Additionally, suggestions in order to improve the environmental performance are provided.
Carbon Intensity of Crude Oil in Europe	1/12/2010	ICCT	Energy Redefined LLC	Report/Study	› Direct GHG Emissions; › Modelling; › Oil	› Upstream; › Midstream; › Downstream; › Combustion	Europe		According to IEA projections in 2009, global consumption of crude oil will increase by 27% over the next two decades, from 83 million barrels per day in 2009 to 105 MMbbl/d in 2030. Since extracting, transporting, and refining crude oil on average account for about 18% of well-to-wheels greenhouse gas (GHG) emissions, on a global scale, that equates to a very large amount of GHG emissions: about 2.8 billion metric tons of CO_2 equivalent per year. Therefore, improvements in the processes of extracting and refining crude oil would mean substantial progress toward reducing overall transportation-sector GHG emissions. The scope of the study is to accurately quantify the GHG emissions from the wellhead to the refinery output gate. For this purpose, they have developed emission factors for five components of production: extraction, flaring and venting, fugitive emissions, crude oil transport, and

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									refining, in order to highlight the greatest potential opportunities for reducing or avoiding GHG emissions from oil extraction. Based on a lifecycle assessment of approximately 3100 oilfields in countries that supply oil to Europe, the study develops GHG emission factors for five elements of extraction-to-refining analysis: crude oil extraction, flaring and venting, fugitive emissions, crude oil transport, and refining. The focus of the study is on the European market, as the European Commission seeks the best way to address extraction-to-refining emissions from petroleum fuels under the Fuel Quality Directive.
Results of Crude Oil Marketing Name Analysis	9/9/2010	California Energy Commission	Gordon Schremp	Presentation	› Direct GHG Emissions; › Modelling; › Oil	› Upstream; › Midstream	North America	OPGEE	Presentation on Marketable Crude Oil Names. Provides critical information on available data and information resources regarding crude oil extraction and transport.
Greenhouse gas emissions reporting from the petroleum and natural gas industry	1/1/2010	EPA		Report/Study	› Direct GHG Emissions; › Oil; › Natural Gas	› Upstream; › Midstream; › Downstream; › Combustion	North America		A technical support document (TSD) that contains legally-binding requirements. It offers illustrative examples for complying with the minimum requirements indicated by the regulations, but it does not substitute for the regulations cited in this TSD, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA or the regulated community. The document describes the U.S. petroleum and natural gas lifecycle of raw gas and crude oil from the wells to the delivery of processed gas and petroleum products to consumers. Since these segments use energy and emit greenhouse gases (GHG), the document provides information on the calculation of minimum GHG emissions.

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DIRECTIVE 2009/30/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009	5/6/2009	European Parliament	European Parliament	Legislation	› Direct GHG Emissions; › Indirect GHG Emissions; › Policy; › Oil	› Natural Gas; › Unconventional oil; › Unconventional Gas	Europe		Fuel Quality Directive 2009/30/EC amending Directive 98/70/EC as regards the specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amending Council Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels and repealing Directive 93/12/EEC. Specific attention should be given to Article 7a.
Lifecycle Analysis of GHG and Air Pollutant Emissions from Renewable and Conventional Electricity, Heating, and Transport Fuel Options in the EU until 2030	1/6/2009	European Topic Centre on Air and Climate Change (ETC/ACC)	Uwe R. Fritsche (Öko-Institut), Lothar Rausch (Öko-Institut)	Report/Study	› Oil; › Natural Gas	› Upstream; › Midstream; › Downstream; › Combustion	Europe		Lifecycle emissions in Europe from fossil and nuclear energies as well as from renewable energies are identified. Furthermore, electricity generation technologies are compared. Future development prospects until 2030 are also provided.
An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Lifecycle Greenhouse Gas	27/3/2009	Department of Energy	National Energy Technology Laboratory	Report/Study	› Direct GHG Emissions; › Modelling; › Oil	› Upstream; › Midstream; › Downstream; › Combustion	South America; North America		The National Energy Technology Laboratory (NETL) has analysed the full lifecycle greenhouse gas (GHG) emissions of transportation fuels derived from domestic crude oil and crude oil imported from specific countries. The study takes into account particularly the impact of crude oil source on WTT GHG emissions from: 1) flaring and/or venting of associated natural gas during the crude oil extraction process,

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Emissions									2) alternative crude oil extraction techniques and pre-processing requirements required for oil sands and bitumen, (3) ocean transport distances for delivery of crude oil and (4) varying processing requirements within the refinery for crude oils of different quality.
Methane Emissions from Natural Gas Transport	1/3/2009	Open University of the Netherlands	S. Murrath	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions; › Natural Gas	› Midstream; › Downstream; › Combustion	Worldwide		In the natural gas transport sector, methane is released to the atmosphere. Quantify methodologies for methane emissions on a natural gas grid at high pressure are analysed. Furthermore, several abatement options to reduce the methane emissions are studied.
Assessment of the Direct and Indirect GHG Emissions Associated with Petroleum Fuels	1/2/2009	New Fuels Alliance	Lifecycle Associates, LLC	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide	GREET	Assessment of the lifecycle impact on GHG emissions from petroleum fuels. The estimation of the direct emissions is heavily based on the GREET model and includes the emissions from exploration, production, flaring, refining and transportation. Indirect emissions include emissions from: Protection of supply, Land use and market-mediated impacts (economic impacts primarily from price pressures) and refinery of co-products. The study will provide input to the current project in regard to defining boundaries for direct and indirect emissions and in regard to the analysis of the indirect emissions.
European gas imports: GHG emissions	1/1/2009		Antonio Taglia, Nicola Rossi	Report/Study	› Direct GHG Emissions; › Modelling;	› Upstream; › Midstream;	Europe		The aim of this paper is to analyse from the environmental and economical point of view the global impact of the gas that enters into Europe, investigating the contribution of all

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from the supply chain					› Natural Gas	› Downstream; › Combustion			the chain steps, starting from the production of the gas until the consumption in a "combined cycle gas turbine" (CCGT) plant for power generation. For this purpose, six different real cases are studied: three regard a pipeline-based transport and three regard LNG production, transport through tankers and regasification. These six real cases are compared to the GHG emissions of a reference case: power generated in a CCGT plant in North Africa and imported to Europe. The environmental impact of energy production from gas must be evaluated from the impact analysis of the supply chains, since it can reach the 20% of the CO2 emissions from gas combustion. Therefore, Europe, which aims to cut GHG emissions, should consider also the supply chain emissions, given that a remarkable reduction of overall emissions would be feasible.
Allocation of CO2 Emissions in Joint Product Industries via Linear Programming: a Refinery Example	1/1/2007	Institut français du pétrole (IFP)	A. Tehrani Nejad M.	Report/Study	› Direct GHG Emissions; › Oil	› Midstream	Europe		The paper outlines the application of the marginal allocation methodology to the oil refinery LP model, to evaluate and compare the CO2 emissions associated with different oil products. Also, it distinguishes the allocation procedures in retrospective (accounting) and prospective (change-oriented) LCAs. As mentioned in the report, the allocation in joint product systems is among the most critical issues specific to LCA and the assumptions about the allocation procedures influence considerably the results. In general, allocation tools in LCA are based on linear homogeneous and unconstrained models to relate the environmental burdens associated with a

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									product system to its economic outputs. Under particular conditions, the marginal allocation data generated by LP can also be applicable in retrospective LCA studies. Contrary to the arbitrary physical measurements (mass, volume, energy, etc.), the allocation coefficients which emerge from the LP model are based on realistic causal relations between oil products and the whole refinery system. In other words, the LP model itself detects the real type of causality between various inputs and outputs in the refinery and allocates the CO2 emissions accordingly without having to use any arbitrary measurements. The study uses an LP refinery model that describes a typical European fluid catalytic cracking refinery with predefined capacity. The oil production level of the refinery corresponds to the EU market structure of the year 2000 and the model is calibrated accordingly. The parametric results of the verification/calibration experiments confirmed the capability of the IFP model to correctly reproduce the logical evolution of the product mix. The study concludes that the allocated CO_2 emissions that are calculated are not fixed but change to reflect changes in the system parameters, such as the evolution of oil products demand and recommends to perform a parametric analysis to fully compare the evolution of the CO_2 allocations of various oil products.
Lifecycle Assessment of the European	1/1/2007	Eurogas–Marcogaz	Marion Papadopoulo (GDF SUEZ),	Report/Study	› Direct GHG Emissions; › Indirect	› Upstream; › Midstream;	Europe		A lifecycle assessment of the European Natural Gas Chain. Data for heat and electricity production in Europe in 2004 are collected. Furthermore impact

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Natural Gas Chain, A Eurogas–Marcogaz Study			Salam Kaddouh (GDF SUEZ), Alessandro Cigni (Marcogaz), Dirk Gullentops (Synergrid), Stefania Serina (Snam Rete Gas), Juergen Vorgang (EON-Ruhrgas), Tjerk Veenstra (Gasunie), François Dupin (DVGW)		GHG Emissions; › Natural Gas	› Downstream; › Combustion			assessment results and sensitivity analyses are provided. It is concluded that transmission distance affect the emissions significantly. Priorities to improve the natural gas chain environmental performances are suggested.
Fugitive emissions	1/1/2006	IPCC	John N. Carras (Coal Mining) et. al., David Picard (Oil and Natural Gas) et. al.	Research Paper	› Direct GHG Emissions; › Oil; › Natural Gas	› Upstream; › Midstream; › Downstream	Worldwide		As part of the "2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 4, Energy", the paper provides specific recommendations for improvements of the IPCC methodology for oil and gas systems. Furthermore, it identifies relevant new emission factors and methodological advancements made since the last update of the IPCC Guidelines. The paper also provides a summary of the major oil and gas producers, a summary of useful conversion factors for various common oil and gas statistics and presents typical compositions of processed natural gas and liquefied petroleum gas.

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									Summarizing, an opportunity has been provided to improve and build upon the existing IPCC methodology and to establish clearer directions on how to apply the IPCC Guidelines for the oil and gas sector (Chapter 4.2).
The Natural Gas Chain, Toward a Global Lifecycle Assessment	1/1/2006	CE Solutions for environment, economy and technology	M.N. Sevenster, H.J. Croezen	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions; › Natural Gas	› Upstream; › Midstream; › Downstream; › Combustion	Worldwide		A lifecycle analysis of the entire gas chain related to the costs and environmental impact of natural gas. As opposed to venting and flaring, fugitive emissions can be reduced significantly. For the study high quality lifecycle data are used.
Flaring & venting in the oil & gas exploration & production industry	1/1/2000	OGP	John Kearns, Kit Armstrong, Les Shirvill, Emmanuel Garland, Carlos Simon, Jennifer Monopolis	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions; › Oil; › Natural Gas	› Upstream	Worldwide		The option to release gas to the atmosphere by flaring and venting is an essential practice in oil and gas production, primarily for safety reasons. The essential point is that no single approach to dealing with associated gas will be appropriate for all projects or locations. Industry needs to be able to choose from among a variety of creative and common sense approaches to address flaring and venting concerns in specific operations. To achieve this, governments need to provide an energy policy framework which will encourage and allow companies to select from among very different approaches in order to achieve the best practicable outcome in particular circumstances. The specific report discusses various aspects of venting and flaring.
Gas Flaring: The Burning Issue	3/9/2013	Resilience	Zoheir Ebrahim, Jörg Friedrichs	Report/Study	› Direct GHG Emissions	› Upstream	North America; Africa; Former	OPGEE	Flaring of gas represents one of the most important sources of GHG emissions from oil production operations. Globally, gas flaring remains stubbornly high. This article examines the determinants of

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							Soviet Union		gas flaring in three prominent cases: Russia and Nigeria as the two largest emitters of flare gas, and the United States as a rapidly expanding newcomer to the club. Ultimately, it speaks about the wider phenomenon of the resource curse: an oversupply of associated gas in a place or at a time where the demand for gas is too low and commercialization is too difficult. While the resource curse is largely about socioeconomic development and institutions, fuel abundance comes with serious environmental challenges, especially when we consider climate change and it often confines countries to carbon intensive developmental pathways.
Allocation of the CO2 and Pollutant Emissions of a Refinery to Petroleum Finished Products	30/11/2003	Oil & Gas Science and Technology	D. Babusiaux	Research Paper	› Direct GHG Emissions; › Modelling; › Oil	› Downstream	Europe	Other	The paper presents the development of a linear programming model for the allocation of GHG emissions derived from refining industries. The CO2 emissions are allocated to the different refinery products and the allocation method is based on the "marginal emission content" of each product. The model was developed by Total and IFP and tested on a French refinery.
Emission Inventory For Fugitive Emissions In Denmark	1/9/2009	National Environmental Research Institute, Aarhus University - Denmark	Marlene S. Plejdrup, Ole-Kenneth Nielsen, Malene Nielsen	Report/Study	› Direct GHG Emissions	› Upstream; › Midstream; › Downstream	Europe		This report presents the methodology and data used in the Danish inventory of fugitive emissions from fuels for the years until 2007. The inventory of fugitive emissions includes CO2, CH4, N2O, NOx, CO, NMVOC, SO2, dioxin, PAH and particulate matter. The fugitive emissions of NMVOC originate for the major part from extraction, loading of ships, transmission and distribution of oil and to a much lesser degree from natural gas and fugitive emissions from gas stations. This report gives a table (3.9) including the

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									emission factors for reloading and refueling for the years 1985-2007, which are useful for the estimation of NMVOC from filling stations. Further, projections for the emissions are described for the years 2008-2030 and have been identified improvements in their values.
Energy Efficiency Improvement and Cost Saving Opportunities For Petroleum Refineries	1/2/2005	U.S. Environmental Protection Agency	Ernst Worrell and Christina Galitsky	Report/Study	› Oil › Technology	› Downstream			This research is an Energy guide that provides information in order to assist industry to improve competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR®, a voluntary program managed by the U.S. Environmental Protection Agency, stresses the need for strong and strategic corporate energy management programs. It provides energy management tools and strategies for successful corporate energy management programs focusing on the petroleum refining industry. This Energy Guide introduces energy efficiency opportunities available for petroleum refineries. It begins with descriptions of the trends, structure, and production of the refining industry and the energy used in the refining and conversion processes. The findings suggest that given available resources and technology, there are opportunities to reduce energy consumption cost-effectively in the petroleum refining industry while maintaining the quality of the products manufactured.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
The European Refinery Industry Under The Eu Emissions Trading Scheme	1/11/2005	International Energy Agency	Julia Reinaud	Report/Study	› Direct GHG Emissions; › Modelling	› Downstream	Worldwide		This study seeks to analyze the issue of emission constraints of all EU member States. The EU emissions trading scheme (EU ETS) is the primary instrument to control industrial CO_2 emissions from energy through an allocation of allowances to some 11 500 installations. As such, the EU ETS applies only to a subset of countries whose industry, in some cases, competes with producers without greenhouse gas constraints, a source of concern for industry and policy makers alike. The study is based on case studies that distinguish plant configurations, crude oil inputs, and production patterns, all specified within each of the three regions: northwest, central and Mediterranean. It also considers the economics of auto-production of electricity versus electricity purchases from the grid.
Impact of tightening the sulfur specifications on the automotive fuels' CO_2 contribution: A French refinery case study	15/4/2008	Energy Policy (Journal)	A.T.Nejad Moghaddam, V. Saint-Antonin	Research Paper	› Direct GHG Emissions; › Policy; › Modelling; › Oil	› Downstream	Europe	Other	A linear programming model developed by IFP is described in this paper for the calculation of CO_2 emissions associated with the marginal production of petrol and diesel. The model is applied to a typical French refinery that has to meet low sulfur specifications for the automotive fuels. Based on the optimal solutions of the model, the paper concludes that marginal production of diesel is more energy and CO_2 intensive. Moreover, useful information is provided to policy makers regarding the prospective WTT analysis.

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
Fuel specification, energy consumption and CO2 emission in oil refineries	17/5/2006	Energy (Journal)	A. Szklo, R.Schaeffer	Research Paper	› Direct GHG Emissions; › Policy; › Modelling; › Oil	› Downstream	Europe; North America; Worldwide	Other	The objective of this paper is to analyze the energy use at oil refineries and present trade-offs between emissions of pollutants with local and global impacts. It also suggests alternative treatment processes in order to reduce the energy consumption and adjust the quality of fuels to the stricter specifications on the sulfur content. The results for Brazil, as case study, are presented and commented.
Assessment of CO2 emissions and its reduction potential in the Korean petroleum refining industry using energy-environment models	1/6/2010	Elsevier Ltd	Sangwon Park, Seungmoon Lee, Suk Jae Jeong, Ho-Jun Song, Jin-Won Park	Report/Study	› Direct GHG Emissions; › Modelling; › Oil	› Downstream	Asia		In this study, potential future CO2 reduction in the Korean petroleum refining industry is estimated by investigating five new technologies for energy savings and CO2 mitigation using a hybrid SD-LEAP model: crude oil distillation units (CDU), vacuum distillation units (VDU), light gas-oil hydro-desulfurization units (LGO HDS), and the vacuum residue hydro-desulfurization (VR HDS) process. The current and future productivity of the petroleum refining industry was predicted, and this prediction was substituted into the LEAP model which analyzed energy consumption and CO2 emissions from the refining processes in the BAU scenario. This paper aims to predict the energy demand/consumption and the reduction potential of CO2 emissions from the refining industry for energy savings in the national and industrial sectors using a hybrid SD-LEAP model. Results of production and input amounts from the SD model were obtained for over the period of 2008-2030

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
Modelling and allocation of CO2 emissions in a multiproduct industry: The case of oil refining	29/3/2007	Applied Energy (Journal)	D.Babusiaux, A.Pierru	Research Paper	› Direct GHG Emissions; › Policy; › Modelling; › Oil; › Technology	› Downstream	Europe	Other	The paper focuses on the use of linear-programming models for the allocation of CO2 emissions in an oil refining industry. The proposed allocation method is associated with the marginal contribution of each product. As mentioned in the paper, this allocation rule is not applicable for short-run models with fixed capacity of processes while it is valuable for cases that the demand equations are the only binding constraints. Three distinct methods with numerical examples are presented and analyzed: the Aumann-Shapley cost-sharing method, the Ramsey pricing-formula and the use of proportionally-adjusted marginal contributions.
Fugitive Emissions From Oil And Natural Gas	1/7/2007	Clearstone Engineering Ltd.	David Picard	Research Paper	› Direct GHG Emissions; › Oil; › Natural Gas	› Upstream; › Midstream; › Downstream			This paper provides specific recommendations for improvements of the IPCC methodology for oil and gas systems relating to the assessing fugitive emissions from oil and gas activities and generally defines good practice in developing these inventories (including a discussion of key issues, and specific limitations and barriers). Fugitive emissions from oil and gas activities may be attributed to various primary types of sources: fugitive equipment leaks, process venting, evaporation losses, disposal of waste gas streams, accidents and equipment failures. Unfortunately, these emissions are difficult to quantify with a high degree of accuracy and there remains substantial uncertainty in the values available for some of the major oil and gas producing countries. The revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC Guidelines) provide a three-tier approach for

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									assessing fugitive emissions from oil and gas activities. Moreover. this paper identifies relevant new emission factors and methodological advancements made since the last update of the IPCC Guidelines. In the Annexes we can find a summary of the major oil and gas producers, a summary of useful conversion factors and typical compositions of processed natural gas and liquefied petroleum gas.
The impact of CO_2 taxation on the configuration of new refineries: An application to Brazil	1/7/2008	Energy Policy (Journal)	G.L.Gomes, A.Szklo, R.Schaeffer	Research Paper	› Direct GHG Emissions; › Oil;	› Downstream	South America	Other	The impact of pricing CO_2 emissions as well as the impact of GHG emission reduction policies on oil refining activities is evaluated in this article. A linear programming optimization model was applied for two refinery configurations: one that maximizes the output of high-quality diesel and one that integrates the production of fuels and petrochemicals. The proposed schemes represent new refinery projects to be located in Brazil. According to the findings of the study, for higher CO_2 prices refineries can reduce their emissions by increasing the consumption of natural gas (for hydrogen production) and/or through the implementation of a new CCS (carbon capture and storage) unit.
Analyzing the risk of LNG carrier operations	1/1/2007	Reliability Engineering and System Safety	Erik Vanem, et al.	Research Paper	› Indirect GHG Emissions; › Natural Gas	› Midstream	Worldwide		This paper presents a generic, high-level risk assessment of the global operation of ocean-going liquefied natural gas (LNG) carriers. The analysis collects and combines information from several sources such as an initial hazard, a thorough review of historic LNG accidents, review of previous studies, published damage statistics and expert judgement, and develops modular risk

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									models for critical accident scenarios.
A feasibility study for an LNG filling station infrastructure, and test of recommendations.	28/11/2011	Trans-European Transport Network (TEN-T)	Björn Forsman	Research Paper	› Indirect GHG Emissions; › Natural Gas	› Midstream	Europe		The study includes a compilation and statistical analysis of historical accident data in order to access the hazard for accidents in connection with LNG bunkering. The focus in the study is on human facilities for different types of accidents. However, the analysis also contains analysis and information on the severity of the LNG emissions for different accident types.
Modelling the risk of product spills in LNG tankers	26/11/2012	CRC Press	F.B. Natacci et al.	Research Paper	› Indirect GHG Emissions; › Natural Gas	› Midstream	Europe		The purpose of the present study is to develop the risk model associated with LNG spills during the whole shipping process, loading, unloading, storage, liquefaction and regasification of LNG, identifying their causes as well as the corresponding operations when spills are detected. The spillage frequencies of occurrence are also quantified. These activities are inherent part of the safety analysis procedure, employing the fault tree technique. Both, the cause identification and the frequency quantification are based on data collected earlier in IMO (2007): Formal Safety Assessment — Liquefied Natural Gas (LNG) Carriers, Details of the Formal Safety Assessment. MSC 83/INF. Article in Maritime Engineering and technology, 2012. Carlos Guedes Soares, Y. Garbatov, S. Sutulo, T.A. Santos, P 433 - 439. Maritime Engineering and Technology includes the papers from the 1st

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									International Conference on Maritime Technology and Engineering (MARTECH 2011, Lisbon, Portugal, 10-12 May 2011). MARTECH 2011 was held to commemorate 100 years of the Instituto Superior Técnico (IST) in Lisbon, and the contributions in the present volume reflect the internationalization of the maritime sector and its activities. The book is divided into 9 main subject areas: Ship Traffic, Ship Design, Ship Propulsion and Control, Onboard Systems, Ship Dynamics and Hydrodynamics, Ship Structures, Risk and Reliability, Wind and Wave Modelling, Renewable Energy, and includes two general papers.
Assessment of Direct and Indirect GHG emissions associated with Petroleum Fuels	1/2/2009	New Fuels Alliance	Lifecycle Associates, LLC	Report/Study	› Direct GHG Emissions; › Indirect GHG Emissions	› Upstream; › Midstream; › Downstream	Worldwide	GREET	This study reviews the range of activities associated with the production of petroleum fuels in order to assess their lifecycle impact on GHG emissions. This includes both direct petroleum emissions, and to the degree feasible, some indirect effects. Comparing the lifecycle for different fuel options, requires a clear and consistent definition of the system boundary both in terms of geography as well as the scope of effects that are compared. Calculations of the average emissions in the GREET model are examined and compared with those associated with marginal and unconventional petroleum resources. This study also examines how emissions from average production resources differ from more recent and costly resources on the margin. Emission sources associated with exploration, land use, co-product

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
									residual oil, and indirect effects such as the effects of the military activity and deforestation associated with road construction are also examined. Calculations in this study indicate that the fate of residual oil and petroleum coke is important, and a potentially significant source of GHG emissions, but require further economic modeling. The magnitude of carbon emissions associated with these products indicates that a detailed analysis of their fate and the effect on other fuel markets should be examined. Higher oil prices and dwindling light crude stocks induce development of more costly, energy intensive petroleum resources that have higher than average lifecycle GHG emissions. Once projects are completed and operational the oil produced becomes part of the world oil supply. Hence, the average GHG emissions are expected to increase and new marginal supplies are likely to have even higher greenhouse emissions. Nonetheless, high cost, energy intensive marginal resources must be factored into current and future projections of the impact of petroleum based transportation fuels to the extent that marginal considerations are taken into account for alternative fuels.
Factors driving refinery CO_2 intensity, with	23/6/2010	Int. J Lifecycle Assess	L.Bredeson, R. Quiceno-Gonzalez, X. Riera-Palou, A. Harrison	Research Paper	› Direct GHG Emissions; › Policy; › Modelling;	› Downstream	Worldwide		The article summarizes various allocation methods for CO_2 emissions from petroleum products as reported in the literature and estimates the impacts of changes in the refinery complexity to CO_2 emissions. The

Title	Date	Publishing Organisation	Author(s)	Document Type	Content	Lifecycle stage	Geographical coverage	Referenced Model	Key points
allocation into products					› Oil				CO_2 emissions were calculated by the use of a detailed model of refinery and the results illustrated the importance of H_2 content of the crude and the products. In addition, other factors driving the refinery energy requirement were the heaviness of crude and the severity of conversion, while the shift from gasoline to diesel production did not affect the final emissions of the refinery.
Bottom of the barrel, an important challenge of the petroleum refining industry	1/2/2011	Petroleum & Coal (Journal)	H.Bridjania, A. Khadem Samini	Research Paper	› Direct GHG Emissions; › Policy; › Oil	› Midstream;# Downstream	Worldwide		The petroleum refining industry faces various challenges on the use of processes to satisfy future needs related to crude oil and products market demand. The product slate and the prices of different types of crude oil are major factors in the selection of proper processes. The article outlines the most important concerns of the refiners and discusses the perspectives for the near future.

ANNEX D: MIDTSTREAM DISTANCES FOR THE EXAMINED MCONs

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
Iranian Heavy	Gachsaran	Kharg Island sea terminal	MIN	Gachsaran - Kharg Island - Asporpirgos	81	4993	0	5074	135000
			CENTRAL	Gachsaran - Kharg Island - Trieste	81	5940	0	6021	135000
			MAX	Gachsaran - Kharg Island - Rostock	81	9428	0	9509	135000
Basrah Light	Rumaila (South)	Al Basrah sea terminal	MIN	Rumaila -Al Basrah terminal - Aspopirgos	90	5122	0	5212	130000
			CENTRAL	Rumaila -Al Basrah terminal - Tarragona	90	6416	0	6506	130000
			MAX	Rumaila -Al Basrah terminal - Rotterdam	90	8631	0	8721	130000
Basrah Light	West Qurna	Al Basrah sea terminal	MIN	Rumaila -Al Basrah terminal - Aspopirgos	126	5122	0	5248	130000
			CENTRAL	Rumaila -Al Basrah terminal - Tarragona	126	6416	0	6542	130000
			MAX	Rumaila -Al Basrah terminal - Rotterdam	126	8631	0	8757	130000
Kirkuk	Kirkuk	Kirkuk Ceyhan pipeline and Ceyhan terminal	MIN	Kirkuk - Ceyhan - Aspropirgos	597	838	0	1435	100000
			CENTRAL	Kirkuk - Ceyhan - Genoa	597	1984	0	2581	100000
			MAX	Kirkuk - Ceyhan - Rotterdam	597	3812	0	4409	100000
Kuwait Blend	Burgan	Mina Al Ahmadi sea	MIN	Burgan - Mina Al Ahmadi - Milazzo	12	5589	0	5601	100000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
		terminal	CENTRAL	Burgan - Mina Al Ahmadi - Rotterdam	12	8612	0	8624	235000
			MAX	Burgan - Mina Al Ahmadi - Rostock	12	9538	0	9550	235000
Arab Light	Gwahar	Ras Tanura sea terminal	MIN	Ghawar oil field - Ras Tanura - Agioi Theodoroi	93	4375	0	4468	100000
			CENTRAL	Ghawar oil field - Ras Tanura - Le Havre	93	7171	0	7264	200000
			MAX	Ghawar oil field - Ras Tanura - Rotterdam	93	7456	0	7549	100000
Arab Light	Kurais	Ras Tanura sea terminal	MIN	Kurais - Ras Tanura - Agioi Theodoroi	156	4375	0	4531	100000
			CENTRAL	Kurais - Ras Tanura - Le Havre	156	7171	0	7327	200000
			MAX	Kurais - Ras Tanura - Rotterdam	156	7456	0	7612	100000
Arab Heavy	Manifa	Ras Tanura sea terminal	MIN	Manifa - Ras Tanura - Augusta	104	5315	0	5419	100000
			CENTRAL	Manifa - Ras Tanura - Rotterdam	104	8444	0	8548	100000
			MAX	Manifa - Ras Tanura - Rotterdam	104	8444	0	8548	100000
Saharan Blend	Hassi Messaoud	Pipeline to Arzew sea terminal	MIN	Hassi Messaud - Arzew - Tarragona	467	411	0	878	100000
			CENTRAL	Hassi Messaud - Arzew - Milford Haven	467	1756	0	2223	100000
			MAX	Hassi Messaud - Arzew - Milford Haven	467	1756	0	2223	100000
Dalia	Block 17/Dalia	Dalia offshore terminal	MIN	Dalia - Algeciras	0	4974	0	4974	100000
			CENTRAL	Dalia - Rotterdam	0	6497	0	6497	100000
			MAX	Dalia - Rotterdam	0	6497	0	6497	100000
Girassol	Girassol	Girassol offshore terminal	MIN	Dalia - Algeciras	0	4974	0	4974	100000
			CENTRAL	Dalia - Rotterdam	0	6497	0	6497	100000
			MAX	Dalia - Rotterdam	0	6497	0	6497	100000
Greater Plutonio	Greater Plutonio	Greater Plutonio offshore	MIN	Dalia - Algeciras	0	4974	0	4974	100000
			CENTRAL	Dalia - Rotterdam	0	6497	0	6497	100000
			MAX	Dalia - Rotterdam	0	6497	0	6497	100000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
		terminal							
Es Sider	Es Sider	Es sider sea terminal	MIN	Es Sider - Aspropirgos	0	811	0	811	80000
			CENTRAL	Es Sider - Trieste	0	1213	0	1213	80000
			MAX	Es Sider - Rotterdam	0	3899	0	3899	100000
El Sharara	El Sharara	Pipeline to Zwaziya sea terminal	MIN	El Sharara - Zwaziya - Saroch	435	308	0	743	80000
			CENTRAL	El Sharara - Zwaziya - Fos	435	1123	0	1558	80000
			MAX	El Sharara - Zwaziya - Wilhelmshaven	435	1915	0	2350	100000
Bonga	Bonga	Bonga offshore terminal	MIN	Forcados terminal - Savona	0	5088	0	5088	135000
			CENTRAL	Forcados terminal - Rotterdam	0	5551	0	5551	135000
			MAX	Forcados terminal - Trieste	0	6139	0	6139	135000
Forcados	Forcados Yokri	Forcados terminal	MIN	Forcados terminal - Savona	0	5088	0	5088	135000
			CENTRAL	Forcados terminal - Rotterdam	0	5551	0	5551	135000
			MAX	Forcados terminal - Trieste	0	6139	0	6139	135000
Bonny light	Agbada	Bonny light terminal	MIN	Agbada oil field - Bonny terminal - Huelva	42	4215	0	4257	135000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5704	0	5746	135000
			MAX	Agbada oil field - Bonny terminal - Gothenburg	42	6311	0	6353	135000
Bonny light	Caw Thorne Channel	Bonny light terminal	MIN	Caw Thorne Channel oil field - Bonny terminal - Huelva	17	4215	0	4232	135000
			CENTRAL	Agbada oil field - Bonny terminal - Trieste	42	5704	0	5746	135000
			MAX	Caw Thorne Channel oil field - Bonny terminal - Gothenburg	17	6311	0	6328	135000
Escravos	Escravos Beach	Escravos terminal	MIN	Escravos terminal - Algeciras	0	4053	0	4053	135000
			CENTRAL	Escravos terminal - Huelva	0	4101	0	4101	135000
			MAX	Escravos terminal - Finnart	0	5458	0	5458	135000
Azeri light	Azeri-Chirag-	Pipeline until Supsa sea	MIN	Chirag - Baku (Sangachal terminal) - Tbilisi - Supsa	628	1292	0	1920	80000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
	Gunashli (ACG)	terminal		terminal - Aspropirgos					
			CENTRAL	Chirag - Baku (Sangachal terminal) - Tbilisi - Supsa terminal - Trieste	628	2460	0	3088	80000
			MAX	Chirag - Baku (Sangachal terminal) - Tbilisi - Supsa terminal - Rotterdam	628	3122	0	3750	80000
Azeri CPC	Tengiz	CPC until Novorossiysk sea terminal	MIN	Tengiz - Novorossik - Costanza	982	504	0	1486	80000
			CENTRAL	Tengiz - Novorossik - Fos	982	2794	0	3776	100000
			MAX	Tengiz - Novorossik - Rotterdam	982	4999	0	5981	100000
Azeri BTC	Azeri-Chirag-Gunashli (ACG)	BTC pipeline until Ceyhan sea terminal	MIN	Chirag - Baku (Sangachal terminal) - Tbilisi - Ceyhan - Augusta	1208	1257	0	2465	80000
			CENTRAL	Chirag - Baku (Sangachal terminal) - Tbilisi - Ceyhan - Trieste	1208	1824	0	3032	80000
			MAX	Chirag - Baku (Sangachal terminal) - Tbilisi - Ceyhan - Rotterdam	1208	4387	0	5595	80000
Tengiz	Tengiz	Rail from Tengiz until Odessa sea terminal	MIN	Tengiz - Odessa - Elefsina	0	1056	1100	1056	80000
			CENTRAL	Tengiz - Odessa - Trieste	0	2226	1100	2226	80000
			MAX	Tengiz - Odessa - Tarragona	0	2573	1100	2573	80000
Siberia Light	Povkhovskoye	Novorossiysk	MIN	Povkhovskoye - Perm - Ufa - Samara - Saratov - Volgograd - Novorossiysk - Costanza	1527	504	0	2031	135000
			CENTRAL	Povkhovskoye - Perm - Ufa - Samara - Saratov - Volgograd - Novorossiysk - Trieste	1527	2436	0	3963	135001
			MAX	Povkhovskoye - Perm - Ufa - Samara - Saratov - Volgograd - Novorossiysk- Rotterdam	1527	4999	0	6526	135000
		Primorsk	MIN	Povkhovskoye - Perm - Primorsk - Gdansk	1509	699	0	2208	100000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
			CENTRAL	Povkhovskoye - Perm - Primorsk - Rotterdam	1509	1764	0	3273	100000
			MAX	Povkhovskoye - Perm - Primorsk - Megara oil terminal	1509	5495	0	7004	100000
		Germany	n.a.	Povkhovskoye - Perm - Plock - Leuna	2559	0	0	2559	-
		Poland	n.a.	Povkhovskoye - Perm - Plock	2175	0	0	2175	-
		Czech Republic	n.a.	Povkhovskoye - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2398	0	0	2398	-
		Slovakia	n.a.	Povkhovskoye - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2630	0	0	2630	-
		Hungary	n.a.	Povkhovskoye - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2339	0	0	2339	-
Siberia Light	Tevlinsko-Russkinskoye	Novorossiysk	MIN	Tevlinsko-Russkinskoye - Surgut - Perm - Ufa -Samara - Saratov - Volgograd - Novorossiysk - Costanza	1844	504	0	2348	135000
			CENTRAL	Tevlinsko-Russkinskoye - Surgut - Perm - Ufa -Samara - Saratov - Volgograd - Novorossiysk - Trieste	1844	2436	0	4280	135000
			MAX	Tevlinsko-Russkinskoye - Surgut - Perm - Ufa -Samara - Saratov - Volgograd - Novorossiysk- Rotterdam	1844	4999	0	6843	135000
		Primorsk	MIN	Tevlinsko-Russkinskoye - Perm - Primorsk - Gdansk	1826	699	0	2525	100000
			CENTRAL	Tevlinsko-Russkinskoye - Perm - Primorsk - Rotterdam	1826	1764	0	3590	100000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
			MAX	Tevlinsko-Russkinskoye - Perm - Primorsk - Megara oil terminal	1826	5495	0	7321	100000
		Germany	n.a.	Surgut - Perm - Plock -Leuna	2876	0	0	2876	-
		Poland	n.a.	Surgut - Perm - Plock	2492	0	0	2492	-
		Czech Republic	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2715	0	0	2715	-
		Slovakia	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2947	0	0	2947	-
		Hungary	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2656	0	0	2656	-
Siberia Light	Uryevskoye	Novorossiysk	MIN	Uryevskoye - Surgut - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk- Costanza	1855	504	0	2359	135000
			CENTRAL	Uryevskoye - Surgut - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk- Trieste	1855	2436	0	4291	135001
			MAX	Uryevskoye - Surgut - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk- Rotterdam	1855	4999	0	6854	135000
		Primorsk	MIN	Uryevskoye - Perm - Primorsk - Gdansk	1837	699	0	2536	100000
			CENTRAL	Uryevskoye - Perm - Primorsk - Rotterdam	1837	1764	0	3601	100001
			MAX	Uryevskoye - Perm - Primorsk - Megara oil terminal	1837	5495	0	7332	100000
		Germany	n.a.	Surgut - Perm - Plock -Leuna	2887	0	0	2887	-
		Poland	n.a.	Surgut - Perm - Plock	2503	0	0	2503	-
		Czech Republic	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr -	2726	0	0	2726	-

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
				Uzhgorod - Bratislava - Kralupy - Litvinov					
		Slovakia	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2958	0	0	2958	-
		Hungary	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2667	0	0	2667	-
Siberia Light	Vat-Yeganskoye	Novorossiysk	MIN	Tevlinsko-Russkinskoye - Surgut - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk-Costanza	1854	504	0	2358	135000
			CENTRAL	Tevlinsko-Russkinskoye - Surgut - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk-Trieste	1854	2436	0	4290	
			MAX	Tevlinsko-Russkinskoye - Surgut - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk-Rotterdam	1854	4999	0	6853	135000
		Primorsk	MIN	Vat-Yeganskoye - Perm - Primorsk - Gdansk	1836	699	0	2535	100000
			CENTRAL	Vat-Yeganskoye - Perm - Primorsk - Rotterdam	1836	1764	0	3600	
			MAX	Vat-Yeganskoye - Perm - Primorsk - Megara oil terminal	1836	5495	0	7331	100000
		Germany	n.a.	Surgut - Perm - Plock -Leuna	2886	0	0	2886	-
		Poland	n.a.	Surgut - Perm - Plock	2502	0	0	2502	-
		Czech Republic	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2725	0	0	2725	-
		Slovakia	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr -	2957	0	0	2957	-

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
				Uzhgorod - Bratislava					
		Hungary	n.a.	Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2666	0	0	2666	-
	Samotlor	Novorossiysk	MIN	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossiysk- Costanza	1880	504	0	2384	135000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossiysk- Trieste	1881	2436	0	4317	135000
			MAX	Samotlor - Surgut - Perm - Ufa - Samara - Saratov Volgograd - Novorossiysk- Rotterdam	1880	4999	0	6879	135000
		Primorsk	MIN	Samotlor - Perm - Primorsk - Gdansk	1862	699	0	2561	100000
			CENTRAL	Samotlor - Perm - Primorsk - Rotterdam	1862	1764	0	3626	100000
			MAX	Samotlor - Perm - Primorsk - Megara oil terminal	1862	5495	0	7357	100000
		Germany	n.a.	Samotlor - Surgut - Perm - Plock - Leuna	2912	0	0	2912	-
		Poland	n.a.	Samotlor - Surgut - Perm - Plock	2528	0	0	2528	-
		Czech Republic	n.a.	Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2751	0	0	2751	-
		Slovakia	n.a.	Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2983	0	0	2983	-
		Hungary	n.a.	Samotlor - Surgut - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2692	0	0	2692	-
Urals	Pamyatno-	Novorossiysk	MIN	Pamyatno-Sasovskoye -	575	504	0	1079	135000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
	Sasovskoye			Volgograd - Novorossik - Costanza					
			CENTRAL	Pamyatno-Sasovskoye - Volgograd - Novorossik - Trieste	575	2436	0	3011	
			MAX	Pamyatno-Sasovskoye - Volgograd - Novorossik - Rotterdam	575	4999	0	5574	135000
	Unvinskoye	Novorossiysk	MIN	Unvinskoye - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk- Costanza	85	504	0	589	135000
			CENTRAL	Unvinskoye - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk- Trieste	85	2436	0	2521	135000
			MAX	Unvinskoye - Perm - Ufa -Samara - Saratov Volgograd - Novorossiysk- Rotterdam	85	4999	0	5084	135000
		Primorsk	MIN	Unvinskoye - Perm - Primorsk - Gdansk	1840	699	0	2539	100000
			CENTRAL	Unvinskoye - Perm - Primorsk - Rotterdam	1840	1764	0	3604	100000
			MAX	Unvinskoye - Perm - Primorsk - Megara oil terminal	1840	5495	0	7335	100000
		Germany	n.a.	Unvinskoye - Perm - Plock - Leuna	2253	0	0	2253	-
		Poland	n.a.	Unvinskoye - Perm - Plock	1869	0	0	1869	-
		Czech Republic	n.a.	Unvinskoye - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	2092	0	0	2092	-
		Slovakia	n.a.	Unvinskoye - Perm - Ufa - Almetyevsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	2324	0	0	2324	-
		Hungary	n.a.	Unvinskoye - Perm - Ufa - Almetyevsk - Syzran - Unecha -	2033	0	0	2033	-

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
				Mozyr - Uzhgorod - Szazhalombatta					
	Romashkino	Novorossiysk	MIN	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossiysk- Costanza	1036	504	0	1540	135000
			CENTRAL	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossiysk- Trieste	1036	2436	0	3472	135000
			MAX	Romashkino - Perm - Ufa - Samara - Saratov Volgograd - Novorossiysk- Rotterdam	1036	4999	0	6035	135000
		Primorsk	MIN	Romashkino - Perm - Primorsk - Gdansk	1838	699	0	2537	100000
			CENTRAL	Samotlor - Perm - Primorsk - Rotterdam	1838	1764	0	3602	100000
			MAX	Romashkino - Perm - Primorsk - Megara oil terminal	1838	5495	0	7333	100000
		Germany	n.a.	Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock - Schwedt - Leuna	1888	0	0	1888	-
		Poland	n.a.	Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Plock	1504	0	0	1504	-
		Czech Republic	n.a.	Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava - Kralupy - Litvinov	1727	0	0	1727	-
		Slovakia	n.a.	Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Bratislava	1960	0	0	1960	-
		Hungary	n.a.	Romashkino - Almayetsk - Syzran - Unecha - Mozyr - Uzhgorod - Szazhalombatta	2040	0	0	2040	-
DUC	Halfdan	Pipeline until Fredericia sea	MIN	Halfdan - Fredericia - Gothenburg	193	256	0	449	80000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
		terminal	CENTRAL	Halfdan - Fredericia - Gothenburg	193	256	0	449	80000
			MAX	Halfdan - Fredericia - Houndpoint	193	872	0	1065	100000
Statfjord	Statfjord	Statfjord FPSO	MIN	Statfjord - Hound point	0	423	0	423	100000
			CENTRAL	Statfjord - Teeside	0	482	0	482	100000
			MAX	Statfjord - Gdansk	0	1132	0	1132	100000
Ekofisk	Ekofisk	Ekofisk FPSO	MIN	Ekofisk - Teeside - Humber Terminal	217	61	0	278	100000
			CENTRAL	Ekofisk - Teeside - Humber Terminal	217	61	0	278	100000
			MAX	Ekofisk - Teeside - Trieste	217	4162	0	4379	100000
Troll	Troll B/C	Mongstad sea terminal	MIN	Troll - Mongstad - Gothenburg	45	439	0	484	100000
			CENTRAL	Troll Mongstad - Rotterdam	45	583	0	628	100000
			MAX	Troll - Mongstad - Trieste	45	4055	0	4100	100000
Asgard Blend	Tyrihans	FPSO	MIN	Mongstad	0	330	0	330	80000
			CENTRAL	Rotterdam	0	900	0	900	80000
			MAX	Kalundborg	0	930	0	930	80000
Oseberg	Oseberg	Pipeline until Sture sea terminal	MIN	Oseberg - Sture - Willemshaven	80	557	0	637	100000
			CENTRAL	Oseberg - Sture - Rotterdam	80	655	0	735	100000
			MAX	Oseberg - Sture - Sarroch	80	3393	0	3473	100000
Gullfaks blend	Gullfaks	Mongstad sea terminal	MIN	Gullfaks - Mongstad - Wilhelmshaven	0	583	0	583	100000
			CENTRAL	Gullfaks - Mongstad - Rotterdam	0	682	0	682	100000
			MAX	Gullfaks - Mongstad - Finnart	0	952	0	952	100000
Forties	Buzzard	Forties pipeline system until Hound Point sea terminal	MIN	Buzzard - Cruden Bay - Grangenmouth - Hound point - Rotterdam	170	578	0	748	100000
			CENTRAL	Buzzard - Cruden Bay - Grangenmouth - Hound point - Rotterdam	170	578	0	748	100000

Representative MCON	Oil field	Terminal	Min/max	Pathway	Pipeline (miles)	Marine (miles)	Train (miles)	Total Distance	Tanker size (DWT)
			MAX	Buzzard - Cruden Bay - Grangenmouth - Hound point - Augusta	170	3474	0	3644	100000
Brent Blend	Ninian	Sullom Voe sea terminal	MIN	Ninian - Sullom Voe - Wilhelmshaven	101	800	0	901	100000
			CENTRAL	Ninian - Sullom Voe - Wilhelmshaven	101	800	0	901	100000
			MAX	Ninian - Sullom Voe - Le Havre	101	980	0	1081	100000
Captain	Captain	Captain FPSO	MIN	Captain - Dundee	0	140	0	140	80000
			CENTRAL	Captain - Wilhelmshaven	0	497	0	497	100000
			MAX	Captain - Le Havre	0	670	0	670	100000
Maya	Cantarell	Cayo Arcas sea terminal	MIN	Cayo Arcas - Corunna	0	6646	0	6646	100000
			CENTRAL	Cayo Arcas - Escombreras	0	6470	0	6470	100000
			MAX	Cayo Arcas - Rotterdam	0	6824	0	6824	100000
Boscan	Boscan	Bajo Grande sea terminal	MIN	Boscan - Bajo Grande - Tarragona	27	6259	0	6286	100000
			CENTRAL	Boscan - Bajo Grande - Tarragona	27	6259	0	6286	100000
			MAX	Boscan - Bajo Grande - Gothenburg	27	7787	0	7814	100000

ANNEX E: LETTER TEMPLATE FOR OIL AND GAS DATA REQUEST

eXergia MEMBER OF SESMA TÜV CERT EN ISO 9001

Athens, *Date*	To: Mr./Ms. *Name* *Position* *Company*

Dear Mr./Ms. ……,

Subject: Request for data

Within the framework of the Renewable Energy Directive (RED) which sets a target of 10% renewables in transport and the Fuel Quality Directive (FQD), which sets a target of 6% reduction of Green House Gas (GHG) emissions from road transport, the Directorate General for Energy has assigned to a consortium of the companies EXERGIA, E3M-Lab and COWI the project entitled "Study on actual GHG data for diesel, petrol, kerosene and natural gas" under a Framework Contract tendering procedure.

The overall objective of the study is to define the lifecycle GHG emissions of petroleum and natural gas products consumed in the European transport sector from "well-to-tank". To this end, we are currently gathering actual GHG emissions data and information regarding the crude oil upstream process of the most common crude oil grades imported in the EU.

In this context, we are writing to you in order to request measured data regarding GHG emissions from the oil fields operated by your company. Specifically, GHG emissions data from the following activities are needed:

- Exploration, production and processing of crude oil
- Venting, flaring and fugitive gas
- Crude oil transportation

For the above mentioned data, please include in your communication the methodology and standards utilized for the measurements / calculations.

We would appreciate your contribution to the project either by providing to the address below* the requested data, or by introducing us to the right contact persons who could give us this kind of information.

Sincerely Yours

[redacted]

Project Manager, Managing Director of EXERGIA

[redacted]

DG ENER

Technical Officer of contract: "Study on actual GHG data for diesel, petrol, kerosene and natural gas", Contract N°: ENER/C2/2013-643

**EXERGIA Energy and Environment Consultants,*
Vissarionos 1 & Omirou, 10672 Athens, GREECE
e-mail: [redacted]

ΣΥΜΒΟΥΛΟΙ ΕΝΕΡΓΕΙΑΣ & ΠΕΡΙΒΑΛΛΟΝΤΟΣ
Ομήρου & Βησσαρίωνος 1, 106 72 Αθήνα
τηλ. 210 6996 185, fax 210 6996 186, e-mail: office@exergia.gr

ENERGY & ENVIROMENT CONSULTANTS
Omirou Str. & Vissarionos 1, 106 72 Athens, Greece
tel. +30 210 6996 185, fax +30 210 6996 186, e-mail: office@exergia.gr

ANNEX F: LIST OF QUESTIONNAIRE RESPONDENTS' ORGANIZATIONS

Biofuels Industry

- AEBIOM
- Lanzatech
- Novozymes
- VERBIO Biofuel and Technology
- Herty
- SkyNRG
- WIP Renewable Energies
- Estonian Biomass Association
- Western Canada Biodiesel Association
- National Biodiesel Board
- BZK Group
- ePure (ethanol)
- Bio-Oils Huelva S.L.
- SEKAB
- BioDrive
- Springboard Biodiesel, LLC
- Acesur
- EBA
- CBA
- Low Carbon Fuels Coalition
- Ethanol Europe
- SNPAA
- Lyondellbasell
- FEDERCHIMICA
- UPM Biorefining
- PREOL a.s.
- Astra Bioplant
- biocom energia
- German Bioethanol Industry Association
- ecoMotion Biodiesel
- Hungrana

-
- APPA Biocarburantes
- NVDB
- Elin Biofuels SA
- VDB
- CIRAD
- DBFZ
- BDI
- BTW World

Oil and Gas Industry

- Fuels Europe
- Gasnam
- HELPE
- Motor Oil
- NGVA Europe
- AOP
- Union of European Petroleum Independents
- Grupa LOTOS S.A
- Neste Oil
- Lukoil
- Total
- Dourogs Natural
- Repsol
- Fox Petroli SpA
- Gasfin SA

Research-Technology-Consulting

- Dupont
- GTI, USA
- Hellenic Naval Academy
- Honeywell
- Honeywell/UOP
- Joanneum
- MEO-Carbon
- Michigan Technological University - Sustainable Futures Institute
- Netherlands Enterprise Agency
- Abengoa
- UC Berkeley
- Vito

- Narec
- Senasa
- VTT Technical Research Centre of Finland Ltd
- Biochemtex
- Studio Gear Up
- Poyry Management Consulting Oy
- PNNL
- Agricultural University of Athens
- CSAR - Centre for Sustainable Aquatic Research
- Swansea University
- EABA (algae)
- Imperium Renewables, Inc.
- Clariant
- APPA Biocarburantes
- National Renewable Energy Laboratory (NREL)
- CRES
- D'Appolonia
- IBP Fraunhofer
- ETA-Florence Renewable Energies

Public Authorities

- FAO
- Ministry of Economic Development
- Brazilian Ministry of External Relations
- DGEG
- Czech Statistical FALSEice
- Swedish Energy Agency

Consumers

- Louis Dreyfus Commodities Suisse S.A
- Westport
- Airbus Group Innovations
- Deutsche Post DHL Group

NGOs

- ICCT
- Transport & Environment

ANNEX G: SUSTAINABILITY QUESTIONNAIRE

Study on Actual GHG Data for Diesel, Petrol, Kerosene & Natural Gas

DG ENER Framework Service Contract

SRD MOVE/ENERSRD.12/2012-409-LOT3-COWI

COWI Consortium

EXERGIA, E3M-Lab, COWI

STAKEHOLDERS' QUESTIONAIRE

Brussels, March 2015

BACKGROUND

The European Union is promoting the use of renewable energy in transport with an objective of 10% renewable energy in transport by 2020 as set out by the **Renewable Energy Directive (RED).** The use of biofuels is one way of meeting these targets. Road transport depends almost entirely on oil as a fuel at present and corresponding greenhouse gas emissions continue to increase at a high rate. Transport is the only sector where energy consumption is not expected to decrease over the next two decades, if development follows business as usual scenarios. At present the main alternative to fossil based fuels in road transport are biofuels, whether liquid or gaseous.

The RED required Member States to submit by June 2010 National Renewable Energy Action Plans setting out inter alia the contribution expected of each renewable energy technology to meet the 2020 targets, including in the transport sector. According to the National Renewable Energy Action Plans, Member States collectively intend to slightly over-achieve the 10% target. They intend to use about 8.5% of first generation biofuels, 1% of second generation biofuels and 1% of renewable electricity, most of the latter in railways rather than in cars. In total this adds up to approximately 10.5% renewable energy in transport; with the different modification factors that the Directive applies to second generation biofuels and renewable electricity used in cars it would be counting as approximately 11.5%.

The **Fuel Quality Directive** (FQD) further sets a target of 6% reduction of Green House Gas (GHG) emissions from road transport.

Both Directives have specified identical sustainability criteria for the use of biofuels in the European Union and the FQD increased the volumetric limits of ethanol and FAME to 10 vol% and 7 vol% respectively in the EN 228 and EN 590 standards.

The impact on the GHG performance of bio-energy of emissions from land use change (direct or indirect) has been discussed extensively and although uncertainty exists on the various predictive models and their reliability there is general consensus that the issue has become important and needs to be addressed by the EU. In addition, emissions from land use (i.e., from carbon stock changes not involving land-use change) are also important, in particular for feedstock originating from forests.

In June 2010 the European Commission issued a set of guidelines explaining how the RED should be implemented, including principles for schemes for certifying sustainable biofuels. This was based on two communications and a decision.

Moreover, the FQD obliges suppliers to report from 2011 information on, inter alia, the GHG intensity of the fuel they have supplied to authorities designated by the Member States. Moreover the Commission is empowered to adopt implementing measures concerning the method for calculation and the mechanism to monitor and reduce GHG emissions of fuels used in transport.

ACTUAL AGAINST AVERAGE GHG EMISSIONS DATA

The GHG emissions calculations for biofuels are based on the work undertaken by the **JRC-CONCAWE-ACEA.** The GHG data for biofuels are compared to diesel and petrol. However, although real and **actual data** are used for biofuels with a significant

range of values and with maximum and minimum points, these are compared only to **average singular points** for diesel and petrol. No detailed information has been provided on how these average singular points have been determined and on which data they are based.

In order to have a transparent comparison between biofuels and fossil fuels it is necessary to determine the actual GHG emissions from diesel and petrol by comparing the GHG from oil originating from various geographical areas and different types of operations taking into account other environmental concerns wherever appropriate.

QUESTIONNAIRE OBJECTIVE

Recently, the European Commission assigned the project: "Study on actual GHG data for diesel, petrol, kerosene and natural gas", to be implemented by EXERGIA S.A. (Leader), in collaboration with E3M-Lab (Economics Energy Environment Modelling Laboratory) of the National Technical University of Athens and COWI A/S. The main project objective is to assess the range of well-to-tank GHG emissions of diesel, petrol, kerosene and natural gas consumed in the EU transport sector, based in principle on calculations of actual data. In the context of providing recommendations to the Commission the project team aims to consult the main stakeholders and would therefore like to know the views of public authorities, businesses, NGOs, industry, technology developers, researchers and other interested parties on how the results of the study should be considered.

Therefore, we welcome your views on the following set of concrete questions. For data protection reasons the project team will not process any specific personal data that you might include in your reply. An analysis of the responses will be published with the final report of the contract on an anonymous basis.

Responses should be sent to the project [redacted]
Email address: [redacted]@exergia.gr
by **15 April 2015**.

QUESTIONNAIRE

1 Calculation of GHG emissions of biofuels and fossil fuels

Question 1.1

Are you satisfied with the way the GHG emissions of fossil fuel final products are presented (average singular points)?

YES NO

If your answer is "NO" then how you recommend this compilation should be made?

- ☐ a) Distinctive calculation of carbon intensities for each fuel stream in all phases of transformation and transportation from extraction up to the supply of final consumers
- ☐ b) Average carbon intensities based on geographical areas of fuels' origins
- ☐ c) Average carbon intensities based on natural gas and crude oil technical characteristics (API, Sulphur, unconventional sources etc.)
- ☐ d) Average carbon intensities based on combination of geographical and technical characteristics criteria
- ☐ e) Other, please specify:

Question 1.2

Recently bio-methane (either from upgraded biogas or produced synthetically from biomass) is added in natural gas pipelines that may supply CNG or LNG filling stations. Should information of GHG emissions from bio-methane and natural gas be included in the calculations of GHG emissions for transport fuels?

YES NO

If your answer is "YES" then how you recommend this compilation should be made?

- ☐ a) Separate average carbon intensity for bio-methane and another separate average carbon intensity for natural gas
- ☐ b) Average carbon intensity for natural gas, either in the form of pipeline gas or LNG, originating from geographical areas such as North Sea, Russia, Algeria, etc.
- ☐ c) Include shale gas too based on geographical areas such as the USA

☐ d) Other, Please specify:

2 Actual data for GHG for fossil fuels

In general oil and natural gas companies do not disclose information on actual GHG emissions from the various operations and almost always decline to provide such information if they are asked to do so. The Commission has advised in the project's Invitation to Tender, that in case the consultant is not able to obtain actual data of GHG emissions on the production of oil and natural gas directly from the oil and natural gas companies, to use available simulation models to estimate such emissions.

Question 2.1

In case the oil and natural gas companies do not provide information on actual GHG emissions from their operations do you agree with the Commission's advice?

YES NO

2.1.1 If your answer is "NO" do you have any other advice? Please specify:

2.1.2 If your answer is "YES" would you consider the results of the model reliable since there is sufficient published information in various sources?

2.1.3 Do you have any recommendation on how the reliability of the results of the models could be improved?

2.1.4 The estimates of oil and gas carbon intensity could be expressed in terms of weighted average and min, max values in order to cope with uncertainty factors. Do you consider that this approach contributes to sufficient and reliable results?

Question 2.2

Do you consider that tracking key GHG emissions data along the supply chain of oil and gas is a justifiable new cost for the oil and gas companies and operators?

YES NO

Are you able to provide an estimation about this additional cost for the suppliers? Please specify:

3 Results of the Project

The draft project results present a broad range of carbon intensities for diesel, petrol, kerosene and natural gas supplied to the tanks of the transport means of the EU. In this context, there are oil and gas streams from extraction to final use, with considerably less GHG emissions than others, in our well-to-tank assessment. This fact might be considered in the existing and future climate change policies of the EU.

Question 3.1

Do you consider that this variation of carbon intensities of fossil fuels for transport could be considered in the estimation of the reduction of GHG emissions mandated by the FQD?

YES NO

Please explain:

Question 3.2

In view of forthcoming policies of the European Union and Member States to reduce GHG emissions and in accordance to the above mentioned variation of GHG emissions in transport fuels, what type of measures related to transport fuels do you think are more appropriate?

☐ a) Combined measures, i.e. use of life-cycle GHG emissions reduction goals for final products of fossil fuels as an essential component of decarbonisation in combination with other relevant measures

☐ b) Independent measures, i.e. use of life-cycle GHG emissions reduction goals for final products of fossil fuels in addition to other measures and GHG goals set by the UNFCCC and/or the EU to help drive the energy sector actions needed for decarbonisation

☐ c) Inherent within general measures, i.e. use of GHG emissions of transport fuels as a component of energy sector policies and actions that reduce GHG emissions and may be motivated primarily by wider benefits such as energy security, air pollution, reducing energy bills, etc.

Question 3.3

Are you of the opinion that the sustainability criteria for biofuels in the RED and FQD should be revised subject to the results of this study?

YES NO

What type of measures related to the revision of sustainability criteria do you think are more appropriate? Please specify:

Question 3.4

Depending on the measures possibly adopted by the EU, if any, related to the reduction of GHG emissions from transport fuels, there may be impacts on the international trading conditions of (certain types of) crude oil and natural gas. In other words, this may have an impact on the competitive conditions of (certain types of) crude oil and natural gas from certain sources vis-à-vis comparable products from other sources and/or countries.

3.4.1 Do you agree with the statement above?

YES NO

Please explain:

3.4.2 Do you think that this could constitute a violation of the international obligations of the EU (including, but not limited to, the EU's WTO obligations)?

YES NO

Please explain:

3.4.3 If your answer is "YES", do you think that the EU could adopt measures in such a way as to meet the regulatory objective of reducing GHG emissions from transport fuels for environmental purposes, without violating its international obligations?

YES NO

Please explain:

3.4.4 What, in your view, would be the least trade restrictive measures the EU could adopt in this regard, while at the same time meeting the regulatory objective of reducing GHG emissions from transport fuels for environmental purposes? Please only take into account the trade restrictiveness of such measures, without taking into account whether or not such measures may constitute a violation of the EU's international obligations.

Question 3.5

Do you think that the FQD obligation of suppliers to provide information on life-cycle GHG emissions has to be strengthened in order all market participants in the oil; and gas supply chain to measure, assess and confirm the carbon intensity of their activity?

YES NO