UK GHG Inventory Improvement: Upstream Oil and Gas

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Glossary

AD	Activity Data
BEIS	Department of Business Energy and Industrial Strategy
BAT	Best Available Techniques
BREF	Best Available Techniques Reference documents
CH_4	Methane
CLRTAP	Convention on Long-Range Transboundary Air Pollution
CO_2	Carbon Dioxide
CS	Country Specific
DA	Devolved Administration
Defra	Department of Environment, Food and Rural Affairs
DUKES	Digest of UK Energy Statistics
E&P	Exploration and Production (of oil and gas)
EA	Environment Agency (of England)
EEMS	Environmental Emissions Reporting System
EF	Emission Factor
EMEP/EEA	European Monitoring and Evaluation Programme/ European Environment Agency
EUETS	European Union Emissions Trading System
FPSO	Floating Production Storage and Offloading (vessel)
GHG	Greenhouse Gas
GHGI	Greenhouse Gas Inventory
IED	Industrial Emissions Directive
IEF	Implied Emission Factor
IPCC	Intergovernmental Panel on Climate Change
LDAR	Leak Detection And Repair
N_2O	Nitrous Oxide
NAEI	National Atmospheric Emissions Inventory
NCV	Net Calorific Value
NECD	National Emissions Ceiling Directive
NMVOC	Non-Methane Volatile Organic Compound
NOx	Oxides of Nitrogen
NPD	Norwegian Petroleum Directorate
NRW	Natural Resources Wales
OGA	Oil and Gas Authority
OGUK	Oil and Gas UK (*trade association, formerly UKOOA)*
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
OT	Overseas Territory
PI	Pollution Inventory *(managed by the EA)*
PPC	Pollution Prevention and Control
PPRS	Petroleum Production Reporting System
PRTR	Pollutant Release and Transfer Register
QA/QC	Quality Assurance / Quality Control
RIs	Regulator Inventories *(refers to the PI, SPRI and WEI)*
SEPA	Scottish Environment Protection Agency
SPRI	Scottish Pollutant Release Inventory *(managed by SEPA)*
UKCS	United Kingdom Continental Shelf
UKOOA	United Kingdom Offshore Operators Association
UNFCCC	United Nations Framework Convention on Climate Change
VRU	Vapour Recovery Unit (*NMVOC mitigation on shuttle tankers*)
WEI	Welsh Emissions Inventory *(managed by NRW)*

Executive summary

The UK's GHGI is the national reference dataset for GHG emissions. It is submitted under the UNFCCC and used to report progress against UK targets under the Kyoto Protocol, the Paris Agreement, and national requirements under the Climate Change Act 2008, including carbon budgets. The GHGI must comply with the requirements of the IPCC methodological guidance and the UNFCCC Reporting Guidelines. The GHGI is subject to continuous improvement; it is scrutinised annually by national experts and periodically by UNFCCC Expert Review Team reviews who identify areas for improvement.

This report summarises the results of a programme of work to improve the completeness, accuracy and time series consistency of upstream oil and gas estimates in the UK GHGI through: (i) a review of new and emerging datasets, (ii) a critical review of pre-existing reports and data used to inform estimates across the inventory time series, and (iii) consideration of the IPCC 2019 Refinement inventory methods for fugitive emissions, including to address any reporting gaps by applying the new methods.

The work was commissioned by BEIS in order to develop improved inventory models to address the significant data management, quality checking, calculation and reporting of GHG emission estimates for the upstream oil and gas sector. The model development reflects the need to develop an improved evidence base for the sector which is under increased scrutiny from NGOs, financial institutions and other stakeholders to develop viable net zero pathways. Further, numerous oil and gas companies operating in the UK have signed up to emission mitigation commitments and there is a sector-wide drive towards reducing methane emissions and aiming to achieve zero routine flaring across the UKCS.

The report provides an overview of the research scope and method, an insight into the key data sources used to derive inventory estimates, a summary of the inventory methods that have been developed for use in the 2022 UK GHGI submission and a summary of the results and key findings from the study, including areas for future work.

The research has developed new inventory models to utilise the best available data for all emission sources in the upstream oil and gas sector, comprising emissions from mobile and stationary assets offshore, onshore terminals, onshore oil and gas wells and from the transport of crude oil and natural gas from the upstream installations to terminals. Methods have been developed to utilise the best available data from reporting mechanisms including the EUETS, EEMS, PPRS and from the regulator inventories for onshore installations. Revised estimates have been generated across the time series from 1990 to 2020 for source categories within IPCC sectors *1A1cii Energy Industries: Oil and Gas Extraction* and *1B2 Fugitives from Oil and Gas Exploration and Production*, applying methods that are consistent with the 2006 IPCC Guidelines for National GHG Inventories, and (where appropriate) the updated fugitives methods presented in the 2019 Refinement to the 2006 IPCC Guidelines.

The results are a more complete and accurate time series of GHG emissions. Compared to the 2021 UK GHGI submission, recalculations are notable for estimates in the 1990s due to a method change to utilise emissions data reported (in 2005) to UK Government by the UK Offshore Operators Association (UKOOA). Further recalculations have been made through use of EUETS National Allocation Plan data from 2005 and 2007, and improvements in the tracking of installation-level reported data across the EEMS and EUETS reporting systems. The scope of installations allocated to the upstream source categories has also been reviewed and updated.

Recommendations for further work focus on the improvement of the evidence base for methane emissions, notably from flaring and from fugitives, where current estimates are based on sector-wide assumptions that are uncertain and warrant validation through a programme of monitoring of methane emissions per source. In addition, the study team has noted that improvements to the regulatory reporting systems for offshore and onshore facilities may help to develop an improved evidence base to deliver more highly resolved emissions data per source and greater assurance that the reported emissions data are complete, accurate and consistently reported across operators and installations.

Table of contents

1 Introduction 1

2 Research Scope and Method 1
2.1 Territorial coverage 2
2.2 UK Regulatory Landscape and Key Data Sources 2

3 UK GHGI Inventory Methodology 8
3.1 Data preparation: pre-processing of raw data 8
3.1.1 Field to Installation Mapping 8
3.1.2 Installation-level Data Labelling: Metadata tables 9
3.1.3 Emissions Data Reporting: Source allocations and consistency checking 11
3.1.3.1 EUETS Pre-processing 12
3.1.3.2 EEMS Pre-processing 12
3.1.3.3 Pre-Processing of National Allocation Plan (NAP) Data 13
3.1.4 PPRS Data Pre-Processing 14
3.1.4.1 PPRS Reporting for Onshore Terminals 15
3.1.4.2 PPRS Reporting for Oil and Gas Fields: Onshore and Offshore 16
3.1.4.3 Comparison of PPRS and DTI Brown Book Data 16
3.1.4.4 Outputs from the PPRS Pre-Processing 17
3.1.5 UKOOA 2005 Pre-Processing 18
3.1.5.1 Analysis of the time series consistency per source 18
3.1.5.2 Method development per source, to use the UKOOA 2005 dataset 19
3.2 Development of UK Inventory Methods Per Source 21
3.2.1 Scope: Upstream Oil and Gas Source Categories in the UK Inventory 21
3.2.2 Time series consistency: UK energy statistics for the upstream sector 21
3.2.3 Source Category Methods 23

4 Results and Discussion 26
4.1 Updated UK GHG Inventory Oil and Gas Sector Totals 26
4.2 Key outcomes and findings 26
4.2.1 Improved understanding and use of oil and gas sector data 26
4.2.2 Development of installation-level information 27
4.2.3 High-emitting source estimates are underpinned by good quality data 27
4.2.4 Improved estimates for the Base Year and through the 1990s 27
4.2.5 More complete UK GHGI estimates through use of 2019 Refinement methods 28
4.2.6 Limited evidence base for some methane emission sources 28
4.2.7 Completeness of reporting 28
4.3 Recalculations 29
4.3.1 All pollutants 29
4.3.2 Carbon Dioxide 35
4.3.3 Methane 38
4.3.4 Nitrous Oxide 41
4.3.5 NMVOC 41
4.4 Priorities for future research and development 42

5 Acknowledgements 43

6 References 43

Appendices

Appendix 1 UKOOA 2005 Reference Data

Appendix 2 UK Upstream Fuel Gas Composition Data

Appendix 3 Inventory Source Category Methods

1 Introduction

The UK's GHGI is the national reference dataset for GHG emissions. It is submitted under the UNFCCC and used to report progress against UK targets under the Kyoto Protocol, the Paris Agreement, and national requirements under the Climate Change Act 2008, including carbon budgets. The UK now has a 2050 net-zero emissions target, as well as sub-national statutory commitments to mitigate GHGs, with targets set for Scotland and Wales. In addition, the upstream oil and gas industry is under increased scrutiny from NGOs, financial institutions, and other stakeholders to develop viable net zero pathways, with several oil and gas companies signing up to emission mitigation commitments and a sector-wide drive towards reducing methane emissions and aiming to achieve zero routine flaring.

The GHGI must comply with the requirements of the IPCC methodological guidance and the UNFCCC Reporting Guidelines. The GHGI is subject to continuous improvement; it is scrutinised annually by national experts and periodically by UNFCCC Expert Review Team reviews who identify areas for improvement. In recent UN reviews the completeness and transparency of upstream oil and gas emissions, especially of fugitive methane, has been questioned. There is a limited annual budget for routine UK GHGI updates and a recognition in BEIS that periodically a greater investment is needed to develop inventory models that can accurately estimate emissions from complex sources such as those evident in the upstream oil and gas sector.

This research seeks to make use of improvements in oil and gas sector data availability in recent years, such as a new software platform established (in 2017) for emissions reporting by upstream oil and gas operators (via EEMS) and the OGA's new national online data repository 'Open Data', which includes field-level oil and gas production data. In addition, the 2019 Refinement to the 2006 IPCC Guidelines for National GHG Inventories ('the 2019 Refinement') includes several new or updated inventory methods for the estimation of fugitives from oil and gas production.

This report summarises the results of a programme of work to improve the completeness, accuracy and time series consistency of upstream oil and gas estimates in the UK GHGI through: (i) a review of the new and emerging datasets, (ii) a critical review of pre-existing reports and data used to inform estimates across the inventory time series, and (iii) consideration of the 2019 Refinement suite of inventory methods for fugitive emissions, including to address any reporting gaps by applying the new methods.

The report provides an overview of the research scope and method, an insight into the key data sources used to derive inventory estimates, a summary of the inventory methods that have been developed for use in the 2022 UK GHGI submission and a summary of the results and key findings from the study, including areas for future work.

2 Research Scope and Method

The exploration and production (E&P) of oil and gas in the UK across the inventory time series, 1990 onwards, is predominantly offshore on the UK Continental Shelf (UKCS) in the North Sea, Irish Sea and (more recently) in the sea to the West of Shetland. There are also a small number of onshore oil and gas well sites although these are minor producers in the UK context. Since 2010 a small number of onshore unconventional gas sites have been drilled and explored but with no subsequent gas production, and there is now a moratorium on UK unconventional gas E&P.

The study team has consulted extensively with a wide range of stakeholders to access key data and to develop resources that enable mapping between datasets. The UK regulatory system for upstream oil and gas is complex with different regulations and regulatory agencies for onshore versus offshore installations; there are systems in place in the UK to gather data on production and other activity data (at the geological field level), as well as environmental reporting systems in place to gather operator data on annual emission estimates (at the installation or "asset" level). In all cases there have been changes in the data reporting scope and resolution across the inventory time series, with less detailed information available for the early part of the time series.

The inventory methods have been developed to make the best use of the available data, seeking to use the most accurate activity and emissions data where available in order to minimise uncertainty in UK inventory estimates. IPCC good practice gap-filling methods have been deployed where necessary to deliver time-series consistent, complete inventory estimates from 1990 to the latest year.

2.1 Territorial coverage

The UK inventory submission to the UNFCCC comprises emission estimates from the UK, UK Crown Dependencies (Jersey, Guernsey, Isle of Man) and UK Overseas Territories (Bermuda, Cayman Islands, Gibraltar, Falkland Islands). The study team reviewed information for each of the UK's Overseas Territories. There has been no oil and gas exploration nor production in any of these territories except for in the waters around the Falkland Islands. We contacted the Falkland Islands Government to seek information pertaining to oil and gas activities, and the current and future prospects for the sector.

To date there have been three phases of exploration activity[1], all offshore:

- 1998: 6 oil wells drilled
- 2010-2012: a total of 20 wells drilled (2010: 2 gas, 5 oil; 2011: 9 oil; 2012: 4 gas)
- 2015-2016: a total of 3 wells drilled (2015: 2 oil; 2016: 1 oil)

None of these wells have subsequently been developed and brought into production, and hence there is no oil and gas production to date in the Falkland Islands. Noting that the 2019 Refinement asserts that there are no EFs available to estimate emissions from offshore oil and gas exploration, and that emissions are considered negligible, there are currently no exploration (nor production, transport etc.) oil and gas sector emissions estimated. Further, it has not proven possible to access any data specific to gas oil use by the drilling units; our working assumption is that any such fuel use will already be accounted for in the Falkland Islands energy data.

This is an area with potential for future improvement, noting that there is potential for some of the oil and gas reservoirs around the Falkland Islands to be brought into production in the next few years, though none is evident to the end of 2021.

Therefore, the focus of this research is on the emissions from oil and gas production within UKCS waters and onshore in the UK. The UK inventory reports emissions from within the UK geographical boundaries, including the UKCS. In some instances, in the upstream oil and gas sector there are median line oil or gas fields, i.e. mineral resources that straddle national boundaries in the North Sea, primarily either the UK-Norwegian or the UK-Netherlands borders. In a small number of cases, the oil or gas is extracted from one side of the border but processed and exported from an installation on the other side of the border. In these cases, the UK statistics on oil or gas production will only reflect the proportion of oil or gas that is extracted from the UK share of the oil or gas field, and/or will report an export of oil or gas to the country where it is processed. In developing emission inventory estimates, all emissions (whether from processing UK, Norwegian or Dutch product) at installations on the UKCS are considered within the scope of reporting for the UK GHG inventory. Where this impacts upon the UK GHG inventory data or method selection is noted in individual method descriptions (see section 3 and Appendix 3).

2.2 UK Regulatory Landscape and Key Data Sources

The UK regulatory landscape for the oil and gas E&P sector is complex, with financial, energy and environmental reporting obligations across a range of onshore and offshore regulators. There are separate regulations (and regulatory agencies) governing the requirements for permits to operate or perform certain activities (e.g. well drilling, production activities, flaring, venting) and company reporting of activity data (e.g. production data) and environmental emissions data. As a result, there are numerous permitting and data reporting systems in place across the sector that may provide useful data to inform inventory estimates; systems for onshore installations (well sites, terminals) often differ from those for offshore installations. Furthermore, some data reporting mechanisms provide a high degree of source resolution in annual (or more frequent) operator reporting, whilst others provide no source resolution but rather present activity and/or emissions totals per year per field or per installation.

The scope and detail of data available varies considerably across the time series, which reflects the evolution of regulations in the UK and consequent changing reporting requirements on plant operators. There are long-standing data collection and reporting systems evident for activity data, such as from UK energy statistics and from the regulations governing oil exploration and production; even these however exhibit changes in scope, completeness and resolution through time.

[1] Falkland Islands Department of Mineral Resources, historical activity https://www.falklands.gov.fk/mineralresources/exploration/historical-activity and recent activity https://www.falklands.gov.fk/mineralresources/exploration/current-activity

For example the UK energy balances published annually in the Digest of UK Energy Statistics were restructured from 1998 onwards; prior to 1998 the energy balance presented information on fuel gas use in "gas separation plant" (i.e. oil stabilisation plant at oil terminals), whereas this dataset is not reported from 1998 onwards, with merely one line of data for natural gas use in the sector "oil and gas extraction", supplemented by occasional (i.e. not every year) reporting of sector gas oil and fuel oil use.

Also around the end of the 1990s there was an overhaul to the reporting to oil and gas regulators regarding oil and gas production, venting and flaring, as a new system, the *Petroleum Producers Reporting System* (PPRS) was implemented from 2000 onwards, to replace systems that had previously informed the UK Government statistical annual called "*Development of the Oil and Gas Resources of the UK*", known universally as the *DTI Brown Book*, production of which ceased from 2004. Much more granular data are now available from the PPRS system than were published in the Brown Book, although analysis of aggregate data across the overlap years (2000 to 2003) between the PPRS and the Brown Book indicates a highly consistent overall scope of reporting.

Therefore, a key challenge to compile accurate and complete inventory activity and emissions estimates is to assess the scope and quality of data reported across these mechanisms and determine how best to integrate them. This project has enabled the inventory agency to review the data in detail, consult with key stakeholders and thereby to identify where there are high quality data that should be prioritised for use for specific emission sources, and where there are opportunities to use inter-comparisons (between reporting mechanisms) to validate or improve (e.g. gap-fill) inventory data.

Key regulatory and data reporting mechanisms that help to inform UK inventory estimates include:

- **EU Emissions Trading Scheme (EUETS)**
  - The EU Emissions Trading Scheme is transposed into UK legislation via the Greenhouse Gas Emissions Trading Scheme Regulations 2012 and the Greenhouse Gas Emissions Trading Scheme (Amendment) Regulations 2018;
  - Operators of upstream installations submit annual estimates of CO_2 emissions from combustion of fuels (i.e. fuel gas and diesel) since 2005, and from flaring since 2008;
  - Scope of reporting includes all high emitting offshore and onshore fixed installations, and reporting is per installation (i.e. per platform, FPSO or terminal);
  - Scope of reporting does not include smaller sites such as onshore well sites and smaller offshore platforms where the annual combustion and flaring emissions fall below the EUETS threshold; nor does EUETS include mobile installations such as drilling units;
  - Data are subject to Third Party verification checks and the system is managed via UK regulatory agencies for onshore (i.e. EA, SEPA, NRW) and offshore (BEIS OPRED). The UK system of data reporting and QAQC under EUETS is consistent with the wider Monitoring Reporting and Verification guidelines of the EU-wide trading system;
  - The EUETS provides a large, detailed dataset that includes the mass or volume of fuel burned, the fuel NCV, carbon emission factors, oxidation factors. Whilst there are statutory provisions for the detailed EUETS data to be made available for the purposed of the national energy statistics and the national GHG inventory[2], otherwise the data are commercially confidential, so cannot be published alongside the inventory;
  - The monitoring and reporting methods agreed across the sector include assumptions such as that flaring efficiency is 98%; sampling and analysis of fuel gas samples is required for high emitting source streams.
- **EUETS National Allocation Plans (NAPs) for Phase I and Phase II**
  - The NAPs for EUETS Phase I (combustion sources only) and Phase II (combustion and flaring) were prepared in the early 2000s in order to enable trading scheme allocations to reflect the recent historical emissions per installation;
  - The NAPs data present installation totals of CO_2 emissions only for 1998 to 2003, with no breakdown by source or by fuel; however, due to the different scope of the NAP I and NAP II, an assessment of the emissions from *all combustion* and from *all flaring* per installation can be calculated (i.e. flaring by difference between NAPI and NAPII);
  - NAPs data were based on operator activity data and installation-level fuel gas sampling and analysis, to improve the accuracy compared to previous estimates where default

[2] https://www.legislation.gov.uk/uksi/2012/3038/regulation/46/made

carbon emission factors had been applied (e.g. within EEMS reporting) by some operators;
    - Where oil or gas fields were scheduled to cease production pre-EUETS (which began in 2005), the NAPs excluded the emission estimates from installations for those production streams, to ensure that the NAPs did not over-estimate site allocations.

- **Environmental and Emissions Monitoring System (EEMS)**[3]
    - EEMS is an emissions reporting system managed by BEIS OPRED that has evolved from a voluntary industry system to accommodate statutory reporting obligations such as those under PPC/IED for reporting of GHG and air quality pollutants from combustion installations above 50MWth;
    - Scope of reporting is from offshore fixed and mobile installations (i.e. it encompasses platforms, FPSOs, mobile drilling units), and includes reporting from the smaller platforms that may fall below the EUETS reporting threshold;
    - Operators submit annual returns of emissions of CO_2, CH_4, N_2O, NMVOC, NO_X, CO and SO_2 as well as activity data (where appropriate) in tonnes per year;
    - Activity and emissions are reported per source, per installation, i.e. with separate estimates provided for emission sources that may occur on the installation, including: fuel combustion (fuel gas, diesel consumption), gas flaring, gas venting, well testing, fugitives, direct process sources (e.g. acid gas treatment) and from oil loading;
    - Operators report to EEMS through to the decommissioning phase of offshore assets. As a site is decommissioned, EEMS data typically reports a down-turn in emissions from “operational” sources such as gas combustion to generate power, whilst other sources, such as venting to purge production lines, or the use of diesel to generate power once produced fuel gas has declined, typically increase. *We note that other activities and emissions associated with decommissioning (e.g. fuel oil or gas oil use by support vessels) are not typically reported in EEMS but are reported in the UK GHGI where fuel is purchased in the UK and hence is reflected in the UK energy balances;*
    - Operator guidance provides information to advise on method choice and to present a series of default EFs per source. Within annual EEMS returns, operators may apply installation-specific EFs or simply report the relevant activity data and the EEMS system will apply the default EFs for that source-pollutant;
    - Operators of *onshore* oil and gas facilities and terminals are not mandated to use the EEMS system but report their total emissions to the Regulator Inventories (RIs) of the onshore regulatory agencies in England, Scotland and Wales. The data in the RIs is less granular than EEMS as it is not broken down by source (see below). Up to 2010, however, the onshore terminals did voluntarily report emission estimates per source to EEMS which provides useful insight to the key sources per pollutant at terminals;

- **Pollution Prevention and Control Regulations / Industrial Emissions Directive (PPC/IED)**
    - The UK has transposed a series of EU Directives through the Pollution, Prevention and Control Act 1999 and associated Regulations across the different domains (offshore, England, Scotland, Wales, Northern Ireland). The PPC regulations were first made in 2001 and served to implement the European IPPC Directive in relation to qualifying installations; subsequently the regulations have been updated to reflect the EU Industrial Emissions Directive (IED) and to transpose the requirements of the EU Medium Combustion Plant Directive. Operators apply to the UK regulators to establish PPC permits per installation, which include requirements to maintain records (e.g. of fuel use, running hours and loads for combustion equipment) and to report annual emission estimates. These annual reports enable the UK to submit emissions data (together with EU Member States) to the Pollutant Release and Transfer Register (PRTR), whilst the installation permits are periodically updated to reflect new guidance, best practice and developments in Best Available Techniques (BAT);
    - Offshore the annual emissions are reported via EEMS (see above), whilst all onshore terminals and most other onshore facilities (e.g. Natural Gas Liquid processing plant, onshore well sites, transit terminals where crude oil and oil products are stored and

[3] https://www.gov.uk/guidance/oil-and-gas-eems-database

transferred between vessels, terminals, refineries, other sites) report to the relevant Regulator Inventory (RI) according to their location;
  - The onshore installations are regulated by the EA (in England), SEPA (in Scotland) and NRW (in Wales). Under the terms of PPC permits, operators submit annual emission estimates per pollutant for all emissions sources (combined) within the boundary of the permitted installation. These annual emission submissions are verified by the regulatory agencies onshore and are then published on public registers. However, note that for onshore facilities the resolution of emissions data *per source* is not available, with a single value for each pollutant *per facility*;
  - The scope of pollutant reporting is as per EEMS (above), but there are pollutant reporting thresholds which limit the completeness of operator reporting, i.e. annual returns to the RIs may not provide any estimate of pollutant emissions if the operator determines that the sum of emission across all sources falls below the reporting threshold. In addition, reporting of activity data (e.g. fuel use data, production or throughout data, flaring or venting mass or volumes) is not required under PPC/IED;
- **Petroleum Production Reporting System (PPRS)**
  - The OGA's Petroleum Production Reporting System (PPRS) collects monthly data from operators of onshore and offshore hydrocarbon production in the UKCS, per oil or gas field and per terminal. Operators submit data to the OGA Energy Portal using a series of reporting tables with defined parameters according to the unit type (e.g. oil field, gas field, oil / dry gas / associated gas terminal);
  - The data reported are useful activity data for inventory purposes, such as crude oil and/or gas production per month, own gas use, venting and flaring volumes, and (in some forms) there are other useful parameters reported such as gas density, gas NCV;
  - The data are not collected with environmental reporting in mind, and the underlying basis for the data collection and reporting is to discharge the OGA's duties under the Energy Act (1976) as amended by the Energy Act (2016) and the Petroleum Act (1998);
  - The data gathered via the PPRS are the basis for BEIS energy statistics reporting for data such as crude oil production, dry gas and associated gas production, NGL production, as well as statistics on gas flaring and gas venting volumes. The high level of resolution of data (to field level) and the reporting of similar units (fields or terminals) within one report enables ready analysis of key data that can support inventory estimates; for example, the sum of production at all Offshore Tanker Loader oil fields (i.e. oil fields not connected to pipelines, and hence reliant of crude oil export via shuttle tankers) directly provides an activity dataset for the annual transfers of crude oil to shuttle tankers, and onwards to UK or other refineries and terminals;
  - The detailed monthly data are available since the inception of the PPRS in 2000. Whilst the production data are aggregated and published, most of the data in the PPRS reports are not public domain and were provided solely for the purposes of this research;
  - PPRS oil and gas production data are gathered per individual field (i.e. per geological oil or gas or condensate field) whereas all of the reporting of environmental emissions (e.g. under EUETS, PPC/IED above) are at the installation level. Most offshore installations process material from several fields; hence a one-to-many mapping is needed to compare PPRS activity data to EEMS and EUETS emissions data.
- **DTI annual statistical publication "Development of Oil and Gas Resources of the United Kingdom", known historically as the DTI Brown Book**
  - Until 2004 the UK Department of Trade and Industry (now part of BEIS) published annual statistics gathered from across the upstream oil and gas sector, which brought together statistics from upstream operators that were then rolled into the PPRS reporting system (above) from 2000 onwards;
  - The scope of data reported in those annual publications is similar to the data that can now be derived from the PPRS system, and similarly it underpins the long-term oil and gas production time series that are included in the Digest of UK Energy Statistics (DUKES). Whilst the PPRS data are more granular (e.g. monthly data), for the overlapping years (2000-2003) there is close consistency, even at the field-level aggregate annual production data. The data resolution is not consistent back to 1990, however, with some aggregation of reported production data, e.g. all associated gas

production that is delivered to the CATS and SAGE terminals from North Sean oil fields are presented as one line, whereas other gas and oil field production data are presented explicitly per field back to 1990;

- The study team has reviewed the DTI Brown Book information across 1990-2003, which includes more detail and qualitative information which has proven useful in establishing material flow mapping from oil/gas fields to platforms/FPSOs and then onto specific oil and/or gas terminals. This is critical information to enable the development of the field to installation to terminal mapping that is needed to aggregate and compare field-level Brown Book/PPRS data against reported activity and emissions data. As a result, the study team has been able to perform cross-comparisons to help identify where there may be data gaps or double-counts, and to build a more detailed understanding of production and emissions sources across the UKCS. For example, the Brown Book notes where an installation offshore is not connected to a gas export line, which we then expect to see in the emissions datasets as a high flaring site.

- **Digest of UK Energy Statistics (DUKES)**
  - DUKES is arguably the primary input dataset to the UK GHGI, and the study team has worked with the DUKES datasets for many years, and has consulted extensively during this project with BEIS energy statistics leads for the upstream oil and gas sector, in order to understand the relationship between the "clean, final" data that are presented in DUKES, and the upstream data inputs from systems such as the PPRS;
  - DUKES includes numerous data time series that are ultimately derived from the upstream datasets outlined above, including data on UK crude oil production, gas production, and on the energy consumption across the sector, which is (in most years) limited to data entries for "oil and gas extraction" for two fuels: natural gas and gas oil. In addition, DUKES presents data such as GCVs and NCVs for "natural gas produced" as well as for "natural gas consumed" (i.e. in downstream sectors);
  - There are some data gaps evident within DUKES for some of the historic data, which all previous UK GHGI submissions have also sought to address, the most significant being an under-report in fuel gas activity data presented in DUKES up to the inception of PPRS in 2000. This research project has provided an opportunity to revisit the estimates for actual fuel gas use, based on analysis of other datasets and testing of the trends reported in different reporting mechanisms. Where the UK inventory methods deviate from DUKES data, this is outlined in the methodology sections (see section 3).
- **UKOOA 2005 oil and gas sector data submission**
  - The EEMS reporting system (see above) was developed from an emissions reporting system developed during the 1990s by the UK Offshore Operators Association (UKOOA) in conjunction with the offshore regulator (now OPRED) and managed by a team of consultants that conducted company surveys, data gathering and generated a database of emission estimates. This dataset from 1995 onwards was able to generate source-specific estimates for the sector, in a format closely comparable to the subsequent format of EEMS. Data for 1990-1994 were estimated and reported to UK Government based on industry surveys in 1991 and 1993, together with an analysis of the production trends across all years;
  - Subsequently the industry conducted further analysis of key emission sources, such as to derive more accurate carbon emission factors per installation, through the process to develop the National Allocation Plans (see above) to underpin allocations per installation for the EUETS. The 1990-2003 dataset (originally based on the early industry surveys, 1990-1994, the 1995-1997 data, and then the first few years of EEMS reporting, 1998-2003) were re-analysed to reflect the improvements in industry knowledge, and reported to UK Government (then Defra) in 2005;
  - The UKOOA 2005 data submission to Defra has been used in part to inform previous UK GHG inventory estimates, primarily to inform some of the fugitive source estimates. This research study has enabled a re-analysis of the data alongside the other datasets that are now available for the early part of the time series. Together with the time series (sector wide and per installation) of oil and/or gas production, and well drilling activity data, the study team has sought to use the UKOOA 2005 dataset and IPCC good practice methods to derive estimates per source for the sector back to 1990.

- **OGA Well Data records, Well Operations Notification System (WONS)**
  - The Oil and Gas Authority (OGA) is now the regulator responsible for managing the UK's well consent system for the oil and gas exploration sector. The OGA manages the data records[4] from well drilling activity (from well spudding, to testing, completions) and well status (e.g. when wells are suspended or abandoned by operators);
  - The study team consulted with the OGA throughout the project in order to access data held in the transactional databases used to manage the consent process, but it was not possible to develop suitable queries to extract useful annual data from these resources. This may become possible in future, however the existing online data resources for well drilling activity provides a good indication of the level of exploration activity on the UKCS across the time series, with data on numbers of wells drilled per year for exploration, appraisal and development purposes.

The items above are the most significant regulatory and other reporting mechanisms that have been used in the development of UK GHGI methods. Numerous other datasets have also been reviewed for their possible usefulness, either as a direct data input or to help corroborate reported data and trends in other datasets. The most potentially useful dataset in future (subject to review and improvement of data access, which we understand is being considered by the OGA) is outlined here:

- **OGA Flare and Vent consents**
  - Flaring and venting is regulated under the Petroleum Act 1998 and the Energy Act 1976 (as amended by the Energy Act 2016), which requires operators to have consents in place for the flaring and venting of hydrocarbons during production operations. The OGA is now the regulator for this system of permitting.
  - In applications for flare consents, guidance states that flaring should be quantified in accordance with EUETS requirements but does not provide any specific requirements for quantification of venting.
  - There are no readily accessible datasets from the flare and vent consents system and hence the main usefulness of these datasets is potentially as a check on completeness of reporting per installation. Given the limited resources and time in this project, this was not pursued, but it is a potential option for future improvement work.

[4] https://www.ogauthority.co.uk/data-centre/data-downloads-and-publications/well-data/

3 UK GHGI Inventory Methodology

The development of datasets and subsequent use in source-specific methods is outlined here, with an initial section that describes the pre-processing of data and development of cross-cutting data and information resources, followed by source-specific inventory method descriptions.

3.1 Data preparation: pre-processing of raw data

The raw data from reporting systems in many cases requires some level of pre-processing in order to derive a dataset in a suitable format and with data labels added to enable the inventory calculations to be performed. The pre-processing of the raw data includes:

- Aggregation of data from multiple years of reporting to develop a dataset in a consistent format, with data labels added to facilitate subsequent data processing within inventory models (e.g. spreadsheets, databases, coded models). Data labels may include:
    - Year of activity / emission
    - Unit of activity / emission
    - Numeric identifier to represent the installation or emission source / activity / pollutant
- Initial data consistency checking and 'cleansing' to identify and correct data gaps and/or outliers that may affect the accuracy of subsequent calculations.
- Initial data validation checks and enhancements, for example to conduct time series consistency checks through cross-comparison with other datasets, and to derive other useful parameters for use in inventory methods, e.g. unit conversions / other data transformations to derive weighted-average parameters across a source/sector to apply in inventory methods

The sections below describe the key raw data pre-processing steps and checks that the study team has conducted to generate data for input into the source-specific inventory methods.

3.1.1 Field to Installation Mapping

OGA data (on oil and gas production, own gas use, flaring and venting) is gathered in the monthly operator returns within the PPRS; these data are gathered *per individual oil or gas field*, i.e. at the level of each individual geological formation that has been developed for production.

All of the environmental data reporting, through EEMS or EUETS, is at the level of the top-side installation, i.e. *per oil or gas platform, mobile drilling unit or FPSO.*

Both types of dataset exhibit data quality problems (or potential problems) such as data reporting gaps and outliers, and both the *production / activity* and *emissions* datasets have notable step-changes in data availability across the time series. Inter-comparison of the OGA/PPRS and EEMS or EUETS datasets enables gaps and outliers to be checked, corrected where necessary, and uncertainties minimised. To do this, the study team researched documentation (e.g. DTI Brown Book section "*Review of Fields in Production and Under Development*") and online information to develop a mapping to link each geological oil or gas field to the platform or FPSO that receives and processes the oil and gas.

In many cases the mapping is a 1-1 relationship with low uncertainty. In cases where there was some uncertainty in the mapping, e.g. fields that may export to several installations, the study team shared the mapping table with the OGA to seek clarifications and corrections.

The mapping table links the Field Name, Field Type, Hydrocarbon Type and OGA ID of each oil or gas field to the NAEI Installation Name and Plant ID for the relevant platform or FPSO and is used within the oil and gas metadata tables and inventory model. An example of the mapping table is shown below.

There are a total of 486 oil, gas and condensate offshore fields listed in the OGA records, covering all of those that have been in production on the UKCS; some of these have ceased production.

Out of the 486, 51 are condensate fields, 184 are dry gas fields and 251 are oil fields. Of the oil and condensate fields, 88 are designated "OTLs" which means that the liquids produced must be offloaded and transferred to onshore terminals/refineries using shuttle tankers, whilst the remaining 214 are connected to undersea pipelines to offload the product.

To service the production from these 486 fields, there are 175 fixed installations, plus numerous mobile drilling rigs that come into and out of the UKCS year to year (as they operate globally).

Table 3.1: Excerpt from *Field to Installation Mapping* table

Field Name	Field Type	Hydrocarbon Type	OGA ID	Installation Name	NAEI Plant ID
AFFLECK	P	oil	203	Janice A FPU	12992
ALBA	OTL	oil	205	Alba FSU	12899
ALDER	P	condensate	207	Britannia	12929
ALISON	G	gas	208	Audrey B	40741

Where P = oil field linked to pipeline; OTL – oil field that is an Offshore Tanker Loader; G = gas field.

There are a total of 486 oil, gas and condensate offshore fields listed in the OGA records, covering all of those that have been in production on the UKCS; some of these have ceased production. Out of the 486, 51 are condensate fields, 184 are dry gas fields and 251 are oil fields. Of the oil and condensate fields, 88 are designated “OTLs” which means that the liquids produced must be offloaded and transferred to onshore terminals/refineries using shuttle tankers, whilst the remaining 214 are connected to undersea pipelines to offload the product. To service the production from these 486 fields, there are 175 installations.

This pre-processing step enables text (such as names of fields and installations) to be linked to numeric values for simpler data processing in databases and other models. The process of developing this mapping has also significantly enhanced the information resources available to the UK GHG inventory team, as the research has led to development of a resource of information to aid the understanding of the pipeline networks, outlier oil platforms/FPSOs that are not linked to gas export pipelines (and hence are likely to conduct more gas flaring), and those OTLs where oil loading emissions are expected to be reported within EEMS.

3.1.2 Installation-level Data Labelling: Metadata tables

Similar to the item above, the management of data from numerous reporting systems for a given installation requires the development of a series of translation tables that enable links to be made and calculations performed to compare and/or integrate data from those multiple data sources, to derive “the best” emission estimates per installation per source to minimise inventory uncertainty.

The outputs from UK inventory research include emission maps where the “point source” emissions from individual (typically high emitting) installations is one layer of information to combine with emission estimates from line or area sources (e.g. emissions from the UK road transport network, shipping routes, agricultural lands, forests and so on). The outputs from this study also provide such “point source” best annual estimates per installation, per pollutant, per source.

Over time, these installations may be opened / closed / mothballed, they may be sold to a new operator, have a change of name, a change of permit reference, they may re-locate (e.g. FPSOs may service one area of production and then be re-deployed to a new area), or they may be divested (one site sold and split into several smaller parts, with different operators and permits) or merged. Furthermore, underpinning regulations and guidance to operators evolves over time and hence the consistency of data reported year to year may change. For example, if there is a change to the reporting threshold for a given pollutant, then some sites may stop or start to report pollutant emissions part-way through the time series; consents and permits to operate will periodically be revised and updated, to reflect the latest BREF notes or regulatory requirements or site ownership.

All these potential changes to raw data provision may lead to difficulties for inventory compilers in accurately tracking emissions from a consistent scope of emission sources per installation over time. Hence for each installation, clear labelling of input data sources is needed, to provide the requisite references and audit trail for the input data, and to allow querying of the data to check for potential changes in scope.

To enable the data tracking, comparisons and (ultimately) the appropriate use of the data in inventory calculations, the study team has developed a series of data translation tables to document the data sources and enable the linkages and comparisons to be performed within databases, spreadsheets and coded models.

Examples are presented below, to illustrate the type of data fields held in these installation metadata tables.

For offshore installations, inter-comparisons and calculations are performed across data resources derived from the EUETS, from EEMS and also from the OGA-PPRS; for onshore installations the key data inputs are from the EUETS, OGA-PPRS and from the RIs.

Table 3.2: Excerpt from *Installation Codes* table

Installation Code	Installation Name	Installation Type	HC Type	Start Date	End Date
29_592	BHP - Point of Ayr Terminal	Gas terminal	Gas	1995	(open)
29_605	BP - CATS terminal	Gas terminal	Gas	1993	(open)
29_785	BP - Kinneil terminal	Oil terminal	Oil	1975	(open)
29_1241	Enquest -Sullom Voe	Oil terminal	Oil	1978	(open)
29_798	Fortum - Sullom Voe	Oil terminal power plant	Oil	1978	(open)
26_136	Shell - Goldeneye	Condensate	Gas	2004	2009
26_36	Total - Elgin	Condensate	Gas	2001	(open)
26_94	Conoco - Viking	Natural gas	Gas	1972	2016
26_78	BP – Ravenspurn North	Natural gas	Gas	1990	(open)
26_39	BP – Foinaven FPSO	Oil - OTL	Oil	1997	(open)
26_40	Apache – Forties Alpha	Oil - pipeline	Oil	1975	(open)

Table 3.3: Excerpt from *Installations to Plant IDs* table

Plant ID	Installation Code	Reference	Type	DUKES sector
11425	26_39	DTI_ETS_4600	EUETS	Oil & Gas
12965	26_39	(no ref)	EEMS	Oil & Gas
11423	26_36	DTI_ETS_3300	EUETS	Oil & Gas
12957	26_36	(no ref)	EEMS	Oil & Gas
14376	29_592	DP3934EW	IPPC	Oil & Gas
14702	29_592	UK-W-IN-13436	EUETS	Oil & Gas
6978	29_785	(no ref)	IPC	Oil & Gas
7850	29_785	(no ref)	EEMS	Oil & Gas
14928	29_785	UK-S-IN-13529	EUETS	Oil & Gas

The set-up and maintenance of these data tables and information resources is a very resource-intensive task, but it is essential to enable inventory compilers to track emissions accurately per installation over time as sites open, close, are sold etc., and ultimately to facilitate analysis that minimises the risk of gaps and double-counts. The development of these metadata tables and detailed enquiry of reported data from across the time series has helped to identify numerous errors and inconsistencies in the data used in previous inventory submissions. For example, it has led to revisions in some site allocations between reporting under "oil production" or "gas production" IPCC source categories, leading to (in general) equal and opposite recalculations between the oil and gas sectors.

Through the research and consultation with industry, the study team has also reviewed and updated the scope of installations that are "upstream" oil and gas sites, including the identification and removal of some double counts with downstream or other industrial sites. For example, one LNG terminal and one power plant (previously considered part of an adjacent terminal) were included within the scope of upstream estimates in previous submissions, and *also* the associated fuel use and emissions were included in other inventory sectors (i.e. 1A1ci and 1A2gviii in those two examples).

In order to facilitate information-sharing across the inventory agency and other data users, the study team has developed a simple installation-level issues log / library where notes (e.g. to document the scope of a permit/site, on allocations to inventory reporting categories, on changes to plant or other issues) can be logged and searched. *Examples are provided in the table below to illustrate the type of information gathered to help understand the scope and significance of installation activities / emissions.*

Table 3.4: Excerpt from *Installation Issue Log*

Open / Closed / Note	Installation Name	Field Name	Issue / Comment
Note	Magnus	n/a	Magnus is linked to the Ninian area for oil export, but it imports gas for Enhance Oil Recovery, from the Sullom Voe terminal (SVT), and for power.
Note	Ninian Central	Ninian area	Ninian Central is the hub platform for the area, taking inputs from Ninian Southern, Northern as well as Magnus (to the North) and Alwyn N (to the east). It outputs oil to SVT and gas is sent via the Brent Alpha platform to the St Fergus FLAGS terminal. There are a number of fields where gas is needed for uplift, so may expect lower levels of flaring.
Note	Tern	n/a	Oil fate: Tern - North Cormorant - Cormorant Alpha - SVT. The associated gas is compressed and used as fuel gas. It is also used as lift gas for Tern. May not be much gas exported.
Note	Hamilton North	Hamilton, E & N	Hamilton North Platform is unmanned; gas and condensate go via Douglas for processing, with Douglas OSI used for liquids, gas sent to Point of Ayr.
Note	Enquest Producer	Alma, Galia	An OTL where there doesn't seem to be any gas export, so presume higher gas use / flaring. Alma and Galia expected to be decomm. in 2020.
Closed	Sevan Hummingbird	n/a	EEMS oil loading data since 2016 was very high indeed. Consulted BEIS OPRED and the operator (now Spirit Energy). Updated data provided, matching PPRS data 2017 onwards. Oil loading AD corrected in EEMS dataset.
Open	Petrojarl FPSO	Bladon, Blenheim	Bladon's single development well is tied back to Petrojarl I FPSO which is developing the Blenheim Oil Field. Unclear on use of associated gas if any export - suspect that it is all flared.
Open	Aoku Mizu FPSO	Lancaster	Production from March 2019. Design work to link the Aoka Mizu FPSO to the West of Shetland Pipeline is ongoing (in 2020) to enable surplus gas to be transported to SVT for processing rather than being flared. Need to make sure this new field production is in EEMS and GHGI from 2021-.

The ongoing maintenance of the metadata tables is one of the key annual tasks for compilers, i.e. to identify any new or recently closed sites and changes to permits for pre-existing sites and add new entries in these metadata tables.

3.1.3 Emissions Data Reporting: Source allocations and consistency checking

As noted in section 2, there are a number of reporting mechanisms and studies that present data on GHG and other emissions from upstream oil and gas installations across the inventory time series. In each case their use within inventory models requires an initial assessment of the reporting scope and allocation of the data to installation codes and to UK inventory source categories and (where applicable) fuel types. In most cases this is a straightforward process to review the data and supporting documentation and allocate them to the appropriate installation code, and the emission source and fuel from a defined list of inventory categorisations.

3.1.3.1 EUETS Pre-processing

The allocation of each installation to either *upstream oil* or *upstream gas* production reporting categories and also to a specific installation code draws on the installation metadata tables outlined in the section above. The information on site operator and installation name enables the inventory agency to allocate each line to the correct NAEI installation code. This enables the sites to be identified and allocated to *oil* or *gas* consistently.

The reported CO_2 emissions (and underlying AD and EFs) from the EUETS are from a very limited sub-set of inventory (mostly *key*) source categories, comprising:

- Upstream oil production; Upstream gas production
    - Fuel combustion
        - Fuel gas
        - Diesel
    - Gas flaring

The allocation of the EUETS data to flaring, fuel gas combustion or diesel combustion is then conducted manually by the inventory agency, through review of the reported parameters (activity data, emission factors, oxidation factors, NCVs) and the accompanying text descriptions provided by operators:

- An oxidation factor (OF) of 98% is used for flaring; an OF of 100% is used for combustion;
- Diesel use is identified through returns indicating *source type* "combustion: commercial standard fuels", *source stream description* "Gas/diesel oil" or "Diesel", and a CO_2 EF for diesel;
- Fuel gas is identified through returns indicating *source type* "combustion: other gaseous and liquid fuels", *source stream description* may be wide range of names but typically includes "fuel gas" or "export gas". The activity data, emission factors and NCVs show a wider range of variability, with typically EFs in the range ~2.5 to 2.8 tCO_2 per tonne

The inventory agency has access to detailed EUETS data available from 2013 onwards (i.e. Phase III of EUETS) and for some earlier years back to 2005, and hence there is a relatively large, detailed dataset and the emission sources and fuel types / qualities per installation show good time series consistency. For some earlier EUETS years the inventory agency does not have access to fully detailed data (i.e. information per source, per fuel, including EFs, NCVs) but does have the (public domain) EU Transaction Log emission totals per installation, and EEMS reporting for offshore installations which does present data split between combustion and flaring sources also.

Across the 2013-2020 EUETS data, around 90% of the activity data reported for flaring and combustion sources is in mass units, and hence the units of tonnes are the preferred working units for this dataset. (Note that EEMS operator reporting for combustion and flaring is also in mass units, tonnes, with EFs in units of tonnes of pollutant per tonne.) For the remaining 10% of EUETS operator data that are reported on a volume basis, where installation-level EFs are available on a mass basis (e.g. from EEMS reporting or from data from other fuel gas streams or years in EUETS) then these are used to estimate the AD in tonnes, or a default EF per fuel type may be applied. This approach minimises uncertainty as it aligns with operator emissions data, which are based on installation-level fuel gas and flare gas analysis which is third party verified.

3.1.3.2 EEMS Pre-processing

A similar, but simpler, data allocation process as applied for the EUETS data is conducted for the EEMS data reporting, in order to align the reported data to installation codes and to UK inventory source categories and fuels / activities.

The allocation of each installation to either upstream oil or upstream gas production reporting categories and also to a specific installation code draws on the installation metadata tables. The information on site operator and installation name enables the inventory agency to allocate each line to the correct NAEI installation code.

The EEMS data reporting documentation assigns each line of data to one emission source from a defined list of sources, together with the operator name, facility name and type (fixed or mobile). The annual emissions data and activity data ("Total use") are all presented in mass units (tonnes). The EEMS emission sources are used in the inventory for both upstream *oil* or *gas* installations, and include:

- **Gas consumption**: in either turbines, engines or heaters, each with different default EFs per pollutant. Scope of pollutants: CO_2, NO_X, N_2O, SO_2, CO, CH_4, NMVOC.
- **Diesel consumption**: Scope and resolution of data reported is the same as for gas consumption. Notably a high proportion of the diesel use is reported as used in engines within mobile drilling units.
- **Fuel Oil consumption**: Scope and resolution of data reported is the same as for gas consumption. Reporting of fuel oil use is limited to a small number of sites and years.
- **Gas flaring**: Scope of pollutants: CO_2, NO_X, N_2O, SO_2, CO, CH_4, NMVOC. Sub-categorisations of flaring (e.g. *gross, routine operations, maintenance, upsets/other*) are used by some operators but does not appear to be reported consistently.
- **Gas venting**: Scope of pollutants is typically: CO_2, CH_4, NMVOC. As with flaring, sub-categorisations of venting (e.g. gross, maintenance, operational, emergency) are used by some operators but does not appear to be reported consistently.
- **Well testing**: Reported under either *Emission Category* Oil or Gas, defining whether the well being drilled was for oil or gas exploration. Scope of pollutants: CO_2, NO_X, N_2O, SO_2, CO, CH_4, NMVOC. The EEMS operator guidance indicates that the emissions are primarily due to the flaring of gases as the liquid and gaseous materials eluted from a well test are separated, with the liquids collected for disposal.
- **Fugitive emissions**: Scope of pollutants: CO_2, CH_4, NMVOC. The vast majority of reported fugitives are described (sub-source) as gross, but in some cases more details are provided of the precise source (e.g. valves, connectors, open-ended pipes). The reported data are often identical year to year per installation, indicating that the operator estimates are based on an inventory of the numbers of fugitive sources (e.g. valves, connectors, flanges, compressors, open-ended pipes and vents etc.) and EFs per unit per year that do not change. This further indicates that the reported fugitive emissions do not include any estimate of releases from specific incidents or maintenance interventions, nor are they re-estimated based on the outcome of LDAR regimes.
- **Direct process**: Scope of pollutants: CO_2, NO_X, N_2O, SO_2, CO, CH_4, NMVOC. Many of the direct process entries have further information provided to clarify the source, which are typically: sour gas vent, thermal oxidiser, acid gas treatment, amine regeneration, incinerator.
- **Oil loading**: Scope of pollutants: CH_4, NMVOC. Analysis of the time series of EEMS data shows that the reporting of this source is especially inconsistent with many sites only reporting the source intermittently, other OTLs not reporting it at all, and others applying inconsistent EFs across the time series. This source is only reported by OTLs, and not by upstream gas producers nor oil sites connected to pipelines.
- **Storage tanks:** Scope of pollutants: CH_4, NMVOC. This source was used in the earlier years of EEMS reporting by the terminal operators. Since 2010 when reporting to EEMS was deemed not to be a mandatory requirement for terminal operators (as they also report to the RIs), this source is not reported consistently in EEMS.

The EEMS data as received from the BEIS OPRED team is annotated with the data labels for installation codes and for each source category and activity as reported within the UK GHG inventory and compiled into a multi-year table holding all historic EEMS data, i.e. from 1998 onwards. These data are then subject to automated quality checking, such as time series checks to identify gaps and outliers in AD and EFs, compared against the EUETS data (for flaring and combustion sources) and applied within the inventory source category calculations, as outlined in section 3.2.

3.1.3.3 Pre-Processing of National Allocation Plan (NAP) Data

In the period prior to commencement of the EUETS from 2005 onwards, the upstream sector operators re-analysed the available data from combustion and flaring emissions at offshore facilities (platforms and FPSOs) and onshore terminals. Updated installation-level CO_2 emission estimates over the years prior to 2005 for the source-activities per installation consistent with the EUETS scope were agreed with the UK Government and incorporated into the UK's National Allocation Plan for Phase I of the EUETS (Phase I NAP, Defra 2005)[5], the scope for which was fuel combustion only, and the National

[5] EU Emissions Trading Scheme, Approved Phase I National Allocation Plan 2005-2007, Defra (2005) https://webarchive.nationalarchives.gov.uk/ukgwa/20121024153024/http://www.decc.gov.uk/en/content/cms/emissions/eu_ets/phase_1/phasei_nap/phasei_nap.aspx

Allocation Plan for Phase II of the EUETS (Phase II NAP, Defra 2007)[6], the scope for which comprised combustion and flaring.

In compiling the NAPs, the sector (in common with other industrial sectors) generated a dataset of installation level total CO_2 emissions using the latest site-specific data on activity and emissions across the period 1998 to 2003 (Phase I NAP) and 2000 to 2004 (Phase II NAP). These data reflected the improvement in understanding of installation-level emission factors and activity data, after several years of running the EEMS data reporting system from 1998 onwards, and its predecessor datasets of similar structure and detail since 1995. The data held in the NAPs was therefore an updated estimate of combustion and flaring emissions compared to the originally submitted EEMS data.

Furthermore, in the development and agreement of the NAPs installation allocations with UK Government, the NAPs data were subjected to additional data checks to ensure the veracity of the emission estimates as they were to be used to establish allocations per installation in the financial trading mechanism; all sector and site allocations were subject to scrutiny to ensure the consistency and fungibility of the allocations across all participants. The NAPs data are therefore considered the better-quality dataset and where the NAPs data differ from EEMS, the NAPs estimates have been used to inform UK inventory estimates, for the first time in the 1990-2020 inventory dataset.

The study team has analysed the NAP I and NAP II datasets and compared them on an installation level against the original EEMS data submissions, to assure and/or improve the accuracy of the data for the upstream sector in the 1998-2003 period. By subtracting the NAP I data from the NAP II data for the overlap years (2000 to 2003 inclusive), the NAPs together can be used to derive best estimates for:

1. Total combustion emissions per installation, 1998 to 2003 inclusive; and
2. Total flaring emissions per installation, 2000 to 2003 inclusive.

For a large number of installations, the EEMS and NAPs data are consistent and this comparison has afforded a further quality check to assure that the EEMS data for those installations in the early years of EEMS were of sufficient quality to inform inventory estimates. However, in several cases the NAPs data indicated different combustion and/or flaring emission compared to the original EEMS data submissions; a small number of reporting gaps in the EEMS data were also identified and addressed.

This analysis and data comparison has led to a number of recalculations over the 1998 to 2003 period and in general has increased the sector estimates of total CO_2 emissions from combustion and flaring in this period; whilst this is mid-time-series from an inventory reporting perspective, the emission estimates in these years have wider significance as they represent the first years of reporting for the new EEMS system. Further, they cover the period that coincides with the shift in UK energy statistics to use PPRS to inform the sector fuel gas consumption data. In the previous UK inventory submissions, the 1998 to 2000 combustion emission estimates from EEMS were used to assess the level of under-reporting of fuel gas use within UK energy statistics, prior to the inception of PPRS, i.e. for all years up to 2000; the analysis of the gap in data between the sum of operator-reported fuel gas estimates and those reported in DUKES for the upstream oil and gas sector was then used to inform the uplift of DUKES fuel gas data back through the 1990s.

The updates (increases) to sector estimates of fuel use and emissions as a consequence of use of NAPs data undermines the methodology used previously to estimate the level of fuel gas use and hence combustion GHG emissions across the sector in the 1990s. The study team has also explored other datasets to minimise uncertainty in emission estimates from fuel use in the 1990s, see Appendix 1.

Details of the inventory recalculations as a result of this analysis are provided in section 4.2.

3.1.4 PPRS Data Pre-Processing

Since 2000, monthly data returns from individual oil and gas fields, and from oil, dry gas and associated gas terminals provide a wealth of useful data to inform or quality check inventory estimates. These data are confidential and have not been reviewed in detail previously for use in the UK inventory development. The study team was granted access to the data via BEIS (BEIS, 2021e) and reviewed the data in detail to identify opportunities to use the data to improve inventory estimates.

The monthly reports are available for defined unit types (see below), with a consistent scope of data fields reported by each operator per unit type. The OGA indicated during the project (OGA, 2019.

[6] EU Emissions Trading Scheme, Approved Phase II National Allocation Plan 2008-2012, Defra (2007) https://webarchive.nationalarchives.gov.uk/ukgwa/20121024154051/https://www.decc.gov.uk/en/content/cms/emissions/eu_ets/euets_phase_ii/phaseii_nap/phaseii_nap.aspx

Personal communication) that only very limited data quality checking is conducted on these monthly data submissions, and that they do not consider data prior to 2016 (when OGA was established) to be necessarily complete and accurate. The initial phase of work by our team therefore was to critically review the data across the time series and check for time series consistency, look at data reporting gaps per terminal or oil or gas fields, and assess whether it was feasible to obtain useful outputs for inventory compilation.

We note that these PPRS data underpin the UK energy statistics for the sector, with quality checks and data gap filling conducted by the BEIS energy statistics team. This project has enabled a useful parallel analysis of the data; in many cases we have been able to reproduce the data that is published in DUKES and hence understand more completely the processing that is conducted and the scope of data that is used to inform energy statistics, including not only the annual fuel use totals but also useful other parameters such as fuel calorific values and densities.

Deviations from UK energy statistics based on the analysis from PPRS are detailed in the inventory methodology sections, including for: (i) total upstream oil and gas fuel gas use, (ii) fuel gas NCVs, and (iii) oil loading activity data from Offshore Tanker Loaders (OTLs).

The initial analysis of the datasets was conducted in MS Excel, implementing numerous manual data checks (e.g. time series consistency, outlier identification, internal consistency checks such as mass balance on material flows though the terminals), gap-filling and aggregation of data to compare against other datasets, such as the industry summary data presented in DUKES or other BEIS statistical outputs. This detailed "deep dive" analysis was an important first step to allow the study team to assess the overall data quality per PPRS report, and to better understand the scope and potential usefulness of the different monthly returns, the parameters reported and the expected internal consistencies for each PPRS report. Once lessons had been learned and (for example) acceptable ranges of parameters identified, more automated approaches were developed, using code written in R to conduct data cleansing of the raw data, identifying data gaps or outliers, and applying assumptions to derive a revised, more complete and internally consistent dataset for subsequent use in inventory methods.

The PPRS monthly reports per unit type and their scope of data reported is outlined below.

3.1.4.1 PPRS Reporting for Onshore Terminals

- **Associated Gas Terminals.** Data are reported from six terminals: St. Fergus Frigg, St. Fergus SEGAL, St. Fergus SAGE, Teesside CATS, TGPP CNS and Wytch Farm. Key parameters reported are:
    - UK Share Oil (%) and Gas (%)
    - Mass (tonnes) and density (kg/m^3) data for: Associated Gas into Terminal, Gas Losses, Gas Flared, Gas Utilised, NGL Condensate into Terminal, Condensate and NGL losses
    - Mass (tonnes), density (kg/m^3) and CV for: Sales Gas from UK Production, non-UK production and total Sales Gas to NTS
    - Stock and disposal data (mass, density) for: ethane, propane, butane, C5 condensate
- **Dry Gas Terminals**. Data are reported for 14 terminals: Bacton ENI, Bacton Perenco, Bacton SEAL, Bacton Shell, Barrow, Dimlington, Easington West Sole, Easington York, Knapton, Morecambe South, Point of Ayr, Rough, TGPP SNS and Theddlethorpe. Key parameters reported are:
    - UK Share Oil (%) and Gas (%)
    - Mass (tonnes) and density (kg/m^3) data for: Dry Gas into Terminal, Gas Losses, Gas Flared, Gas Utilised, Gas Vented
    - Mass (tonnes), density (kg/m^3)) and CV for: Sales Gas from UK Production, non-UK production and total Sales Gas to NTS
    - Mass (tonnes), density (kg/m^3) for Dry Gas Condensate: into Terminal, Losses, Stock, Disposal
- **Oil Terminals**. Data are reported for 8 terminals: Flotta, Flotta West, FPS Kinneil, Hamble, Holybourne, Nigg, Sullom Voe and Teesside Norpipe. Key parameters reported are:
    - UK Share Oil (%) and Gas (%)
    - Mass (tonnes) and density (kg/m^3) data for: pipeline oil into terminal, stabilised crude oil receipts, stocks and disposals, gas flared, gas utilised, gas vented

- *Across all years and terminals, gas venting is reported as zero*
- *The BEIS energy statistics formula for oil production at terminal level is*
    - *(UK share/ 100) * (oil disposals + stock change)*
- *The oil terminal PPRS data are highly complete and time series consistent with very few reporting gaps or outliers evident*

3.1.4.2 PPRS Reporting for Oil and Gas Fields: Onshore and Offshore

- **Offshore Loaders**. Data are reported for 75 oil fields that are OTLs. Key parameters reported are:
    - UK Share Oil (%) and Gas (%)
    - Volume (m^3) and density (kg/m^3) data for: oil production, oil in tanker, oil in pipeline, tanker disposals, gas flared, gas used, gas vented, gas to pipeline
        - *The offshore loader PPRS data were generally complete with around a 1% incidence of gaps or outliers, typically in density data.*
        - *Pre-processing identified several reporting allocation errors which were corrected, improving completeness and accuracy of data for a small number of OTL fields, including: Donan Maersk, Guillemot NW, Guillemot W, Gannet E, Harding, Ness, Nevis and Teal.*
        - *The field to installation mapping shows that these 75 oil fields are handled at a total of 33 offshore installations, i.e. platforms and FPSOs.*
- **Oil Fields**. Data are reported for 211 oil fields that are OTLs. Key parameters reported are:
    - UK Share Oil (%) and Gas (%)
    - Volume (m^3) and density (kg/m^3) data for: oil production, stock oil in field, oil production to pipeline, associated gas production, gas flared, gas used, gas vented
        - *The oil fields PPRS data were generally complete with around a 2.5% of all data lines requiring an intervention to address gaps, outliers.*
        - *The field to installation mapping shows that these 211 oil fields are handled at a total of 68 offshore installations, i.e. platforms and FPSOs.*
- **Onshore Loaders**. Data are reported for 45 onshore oil fields. Key parameters reported are:
    - Volume (m^3) and density (kg/m^3) data for: oil production, stock of oil in tanker, stock of oil in pipeline, oil tanker disposals, gas flared, gas used, gas vented, associated gas to pipeline
        - *The onshore loader PPRS data were amongst the most incomplete with around 5% of data lines requiring an intervention to address gaps, outliers.*
        - *The onshore loaders together are very minor oil producers, orders of magnitude lower production per field than offshore oil fields.*
- **Gas Fields**. Data are reported for 32 onshore gas fields and 169 offshore gas fields. Key parameters reported are:
    - UK Share Oil (%) and Gas (%)
    - Volume (m^3) and density (kg/m^3) data for: gas production, gas condensate production, gas flared, gas used, gas vented, gas to pipeline, sales gas to NTS.
        - *The gas fields PPRS data were moderately complete with around a 4% of all data lines requiring an intervention to address gaps (mainly density), outliers.*
        - *The field to installation mapping shows that the 169 offshore gas fields are handled at a total of 70 offshore installations, i.e. platforms and FPSOs.*
        - *For context, the onshore share of total gas production across all PPRS years (2000 to 2020) is only 0.5% of the total.*

3.1.4.3 Comparison of PPRS and DTI Brown Book Data

Once the data quality checking and cleansing was completed, the study team conducted further data quality checks focusing on the time series consistency of field-level oil and (dry or associated) gas production data between the 1990-2003 datasets from the DTI Brown Book compared against the 2000 onwards PPRS data. Once the reporting issues (see above) were taken into account, the overlap years of 2000-2003 show very close consistency for all crude oil production data, not only at the overall level (as summarised below), but also for each individual field. The close comparability of the overlapping years in the two datasets gives a very high level of confidence that the data reported across the time series from the two data sources are on a consistent basis and scope.

- **Crude oil production at OTLs**: total production differences were less than 0.5% in any year between Brown Book and PPRS. [BB/PPRS: 2000 41.9 Mt / 41.8 Mt; 2001 40.9 Mt / 40.6 Mt; 2002 41.2 Mt / 41.3 Mt; 2003 38.5 Mt / 38.6 Mt.]
- **Crude oil production via oil pipelines**: total production differences were less than 0.7% in any year between Brown Book and PPRS. [BB/PPRS: 2000 68.6 Mt / 68.6 Mt; 2001 58.7 Mt / 58.6 Mt; 2002 52.2 Mt / 52.1 Mt; 2003 45.8 Mt / 45.5 Mt.]
- **Crude oil production from condensate sites**: total production differences were less than 0.5% in any year between Brown Book and PPRS. [BB/PPRS: 2000 3.92 Mt / 3.93 Mt; 2001 6.98 Mt / 6.94 Mt; 2002 11.9 Mt / 11.9 Mt; 2003 12.5 Mt / 12.5 Mt.]

There are larger differences evident of around 1-2% for the gas production data, but no systematic difference and an average difference of only 0.8% across the four years, so again the time series of gas production data from the two sources gives confidence that there are no step-changes in the scope of data. The analysis at the field level highlighted a small number of fields where the PPRS data appeared to be more complete and time series consistent than the Brown Book, including for the condensate site Alwyn North and dry gas sites Audrey A, Leman, Rough and Viking; in all other cases the approach was to use the Brown Book data to reflect that the first few years of the PPRS data reporting system in some cases required gap filling by the project team, and hence when there were small differences between PPRS and Brown Book it was assumed that the Brown Book data were likely to be more accurate.

- **Dry gas production**: annual differences in production of up to 2.5% between Brown Book and PPRS, but overall reasonable consistency in gross gas data. [BB/PPRS: 2000 60.8 Gm^3 / 59.7 Gm^3; 2001 56.2 Gm^3 / 57.6 Gm^3; 2002 48.5 Gm^3 / 48.2 Gm^3; 2003 48.8 Gm^3 / 50.0 Gm^3.]

3.1.4.4 Outputs from the PPRS Pre-Processing

The PPRS is a large, detailed time series (2000 onwards) dataset which provides a rich resource of field-level data; the data provide a detailed insight into the variable quality of the products and the eluted gases at each site, which in turn reflect the variability of the geological formations across the different areas in the UK Continental Shelf and the changes over time as production trends have shifted across the many individual oil and gas fields.

The use of the PPRS data was tested in various applications, such as to evaluate whether the emissions per unit production trends at the installation level could be used to extrapolate and fill gaps, for example for the pre-EEMS years, 1990 to 1997. Unfortunately, in that instance, it was determined that the shifts in production locations (from a smaller number of large oil and gas fields in 1990 to a larger set of oil and gas fields by 1998 onwards) and the limited coverage of emissions data for the installations servicing several large-producing fields back to 1990 was too uncertain; there was insufficient data to derive a trend from production data as a proxy. It is evident from the analysis that at most installations there is a general upward trend through time in the emissions per unit production, which is likely to reflect the increased energy requirements to extract oil and gas from increasingly depleted fields (e.g. due to greater demand to pump fluids into the well to maintain production).

The key outputs from the PPRS dataset that have been used in the inventory methods are:

- Time series of field, installation and sector-wide crude oil and natural gas production data, used primarily as a proxy dataset to address reporting gaps, i.e. to help identify where emissions data may be missing from EEMS, and in some cases estimating emissions in a missing year using production trends as the proxy to indicate activity and emission trends;
- Time series of fuel gas density and calorific values, derived for the different types of installation and fuel gas, to reflect whether the origin of the fuel gas was a dry gas field / installation / terminal, or associated gas from an oil field / installation / terminal.

See Appendix 2 for tables of fuel gas density, NCVs and carbon emission factors per source.

- Time series of production from Offshore Tanker Loaders (OTLs) to underpin the oil loading fugitive emissions from transfers of crude oil to shuttle tankers, for transport to shore.

3.1.5 UKOOA 2005 Pre-Processing

As noted in section 2, in February 2005 the UK Offshore Operators' Association (UKOOA) prepared an updated dataset of upstream oil and gas facility emission estimates for each year from 1990 to 2003 and submitted them to UK Government (Defra).

These data were prepared by the team of consultants that had developed the EEMS dataset over the preceding decade, and the update was based on the latest data from the industry, following work to develop the EUETS NAPs; the estimates were updated to use detailed analysis of AD and EFs from 1998 to 2003 per installation to derive the best estimates for each site for the NAPs.

The data provided to Defra are tabulated in Appendix 1. There were two datasets: 1995 to 1997 data follow a very similar structure to the EEMS 1998 onwards dataset, but rather than data per installation, each source-activity data point is aggregated, either to "onshore" or "offshore" totals per year. The 1990 to 1994 dataset is much more highly aggregated; this reflects the level of data resolution from the industry emission returns from operator surveys in the early 1990s. The 1990 to 1994 data are based on the first UKOOA emissions inventory study, using:

- **1990:** CO_2 and CH_4 data calculated from company reported data; VOC data estimated using export data; CO, NO_X and SO_2 estimated based on the reported CO_2 data and EFs.
- **1991:** Company reported data
- **1992 to 1994:** Calculated, scaled on production data.

This research project has afforded the study team the time and resources to evaluate the UKOOA 2005 dataset, compare it to other data from the period and seek to maximise its usefulness to inform UK GHG inventory estimates. There are no other, better industry data from this period from which to derive emission estimates, but of course the lack of data resolution impairs the transparency of these data; it is impossible for us to fully understand/confirm whether these data are complete and correct, but they are the best data available.

For each emission source, we have sought to (i) assess the data quality in the UKOOA 2005 dataset against the EEMS and NAPs data for the "overlap" years of 1998 to 2003, to identify any key outliers or step changes in the data, and (ii) to develop a time series per inventory emission source back to 1990 using the best available data and applying IPCC good practice gap-filling methods.

3.1.5.1 Analysis of the time series consistency per source

In order to assess the consistency between the data reported within the UKOOA 2005 dataset (1990-2003) and the EEMS dataset (1998 onwards), the study team compared the reported data at the source-specific level. Findings are noted below per source.

- **Drilling diesel consumption:** UKOOA 2005 data presents data specifically for "drilling diesel use". This can be compared against the diesel consumption reported in EEMS for the installations that are identified as Mobile Drilling Units (MODUs).
    - ✓ The result is that the activity data are identical between UKOOA and EEMS datasets for 1998-2002, with a small % difference in 2003.
- **Drilling well testing:** The UKOOA 2005 dataset presented total well testing AD and emissions; EEMS data presented data separately for well testing at oil wells and gas wells.
    - ✓ Comparing the total AD, the data are identical for 1999-2003, with a low % difference evident in 1998. Therefore, the data are regarded as closely consistent.
- **Gas flaring:** EEMS data holds data specific to flaring at oil sites and gas sites, UKOOA data is aggregated.
    - There is slightly more variable comparison between UKOOA and EEMS across the time series. E.g. in 1999 the UKOOA 2005 estimate for gas flaring offshore is notably higher than that in EEMS.
    - ✓ However, there is very close comparability in both 1998 (identical) and 2000 (within 1%). Therefore, the overall assessment is that there is no clear systematic difference between the two datasets for flaring. The two datasets are reasonably consistent.
    - There is a clear difference in reporting of N_2O across the UKOOA data time series. The use of N_2O default EFs is noted as sporadic across several sources within EEMS also.
    - Therefore, to be time series consistent, the estimates for N_2O in the earlier part of the time series will be revised to apply the EFs used in EEMS from 1998 onwards.

- **Gas Venting:** Estimates for venting are presented by gas, for onshore and offshore separately in UKOOA 2005.
    - The CO_2 data are identical for both onshore and offshore in 1998. The onshore venting data are within 1% in all years.
    - The offshore venting data are identical in 1998, 2001 and 2003; in the other years (1999, 2000, 2002) the EEMS data are all lower than the reported UKOOA 2005 data.
    - ✓ Therefore, the overall assessment is that the venting data are closely consistent between UKOOA and EEMS; they demonstrate good time series consistency.
- **Fugitive emissions:** The analysis focused on NMVOC as this is the key pollutant from this emission source.
    - The 1998 datasets are closely consistent once a "known error" was corrected, to add in data for Theddlethorpe - *a new site in 1998* - noted as missing from EEMS data;
    - In other years the estimates of NMVOC are all identical or within a very few % for both onshore and offshore estimates of fugitives, with one exception: in 1999 there is a ~400t difference between the two datasets.
    - ✓ Therefore, the overall assessment is that the fugitives data are closely consistent between UKOOA and EEMS; they demonstrate good time series consistency.
    - The 1999 outlier could be due to a single site reporting new data; our approach is to use the higher emission estimate, i.e. to take a conservative approach.
- **Fuel gas combustion:** In the UKOOA 2005 dataset, these emissions are presented split by >20MW and <20MW combustion units. There is also an assumption in the approach in UKOOA 2005 for 1998 onwards that the total NAPs emission is the best estimate for the sum of all >20MW installations. The comparison for these estimates is the most significant component of overall GHG emissions, as fuel gas combustion is by far the single most significant GHG emission source for the sector. The updated EEMS dataset, to align at installation level with NAPs data (see section above), is considered to be of good quality.
    - Across 1998 to 2001 in total the estimates are closely consistent, with 1% over those years, although the detail within those years is somewhat variable; 1998 data are remarkably consistent (within 0.1%), within 1% in both 1999 and 2001, but with a 3% difference between the data in 2000.
    - ✓ Therefore, the overall assessment is that the fuel gas combustion data are closely consistent between UKOOA and EEMS; they exhibit good time series consistency.

3.1.5.2 Method development per source, to use the UKOOA 2005 dataset

To develop time series consistent estimates, we have applied a range of proxy data to estimate the 1990 onwards emission totals per emission source per pollutant. The general overall approach is that the sum of the estimates will align with the UKOOA 2005 totals per pollutant, except where data outliers or gaps have been identified, such as the inconsistent use of N_2O EFs and the incomplete reporting of oil loading emissions evident in EEMS.

A more detailed read-out of the methods used to derive the inventory estimates from the EEMS 2005 dataset is presented in Appendix 1, together with tables of the raw data provided to UK Government.

The parameters used to inform trends are the DTI Brown Book data on UK oil production and gas production, as well as the OGA Well Operations Notification System records of wells drilled per year:

Table 3.5 Parameters used to inform the 1990-1998 time series per source

Parameter	Units	1990	1991	1992	1993	1994	1995	1996	1997	1998
Crude oil	kt/yr	86,234	83,129	85,222	90,213	114,383	116,743	116,679	115,340	118,919
Natural Gas	Mm^3/yr	49,506	55,051	55,738	65,109	69,343	75,158	89,514	91,170	95,171
∑ wells drilled	#wells	348	331	302	280	308	360	396	350	367

Gas oil consumption

Gas oil consumption at stationary installations producing crude oil is estimated using the time series of crude oil production, assuming the same IEF of CO_2 emissions per unit production from EEMS data (1998-). Gas oil consumption at stationary installations producing natural gas is estimated using the time series of natural gas production, assuming the same IEF of CO_2 emissions per unit production from EEMS data (1998-). Gas oil consumption in Mobile Drilling Units is derived by difference:

UKOOA Total drilling emissions = Well Testing emissions + Gas oil use by MODUs

Well Testing

Well testing (oil) and well testing (gas) emissions are estimated using the OGA data on total wells drilled (including exploration, appraisal and development wells), assuming the same level of well testing activity and emissions per # wells tested from EEMS data (1998-). The total emissions from 1995 onwards are aligned to the UKOOA 2005 estimates for well drilling emissions, which leads to a low outlier in 1996 (see graph in Appendix 1). Note that the OGA data (1990-1998) does not distinguish between wells drilled for oil or gas exploration; the overall trend from all wells drilled is applied to both.

Fugitives, Venting and Flaring

For each source, the total emissions from 1995 to 1997 across the oil and gas sector are aligned to the UKOOA 2005 dataset. The split of those total source emissions across "oil" and "gas" in 1995-1997 assume the same split between oil and gas as in the EEMS dataset (1998-) per source. Then the estimates for 1990-1994 are back-cast from 1995 using the oil production and natural gas production trends. Appendix 1 includes a series of graphs to illustrate the trends of emissions vs production.

Direct Processes

The estimates of emissions from direct processes are based on a series of assumptions and are in part a "residual" category for GHG emissions, to align the sum of source estimates across 1A1cii and 1B2 with the UKOOA 2005 dataset.

The installation-level reporting of direct process CO_2 emissions within the EEMS data from 1998 are dominated by a small number of installations: Tartan Alpha, SAGE-St Fergus terminal and Kinneil terminal. For each installation, an estimate of emissions is back-cast from the EEMS data (1998-) using the installation-specific crude oil production (Tartan), crude oil throughput (Kinneil) or gas throughput (SAGE St-Fergus). One-off direct process estimates are made to reflect emissions from process upsets and commissioning of the SAGE (in 1992) and CATS (in 1993) terminals and the upstream oil and gas fields that came on-stream in those years.

Finally, across the time series, the direct process source is used as a residual to align to the UKOOA 2005 data totals, calculated by difference from the sum of other sources. NMVOC and methane residual emissions are calculated for the offshore and onshore components:

Direct process = UKOOA (excl. loading) - ∑ (gas oil, fuel gas, flaring, fugitives, venting, well testing)

The allocation to "oil" and "gas" from these derived residuals is based on an assumption derived from historic reporting of methane and NMVOC from all sources aggregated, which indicates that methane emissions are around ~63% gas sector and ~37% oil sector, whilst NMVOC emissions are around ~21% gas sector, ~79% oil sector. The direct process estimates per source are thus derived by applying these %s and are subject to high uncertainty, but overall the totals align to the industry totals.

Fuel Gas Combustion

The CO_2 emission estimates from fuel gas use are reported within the UKOOA 2005 dataset for 1995 to 1997, aggregated across oil and gas. For 1990-1994 the fuel gas estimates are derived by difference from the UKOOA 2005 emission totals from production sources, for both offshore and onshore sites:

Fuel gas use = UKOOA (production) - ∑ (gas oil not drilling*, gas flaring, venting, direct processes)*

The total fuel gas emissions of CO_2 across oil and gas installations are then divided between "oil" and "gas" sectors by extrapolating back an estimate from the EEMS data (1998-) and using the production trends for crude oil and natural gas, and then aligning the derived interim estimates to the calculated "oil and gas" fuel gas total. This approach therefore seeks to reflect both the UKOOA 2005 CO_2 emissions total and the trends in oil and gas production.

3.2 Development of UK Inventory Methods Per Source

This section provides the source category method details for the UK GHGI estimates that have been prepared during the study for the 2022 submission (i.e. 1990-2020 dataset).

3.2.1 Scope: Upstream Oil and Gas Source Categories in the UK Inventory

The scope of emissions from the upstream oil and gas sector in the UK comprise a wide range of emission sources that are reported within the UNFCCC reporting taxonomy *Common Reporting Format* (CRF) tables under:

- 1A1cii (fuel combustion emissions); and
- 1B2 (fugitive emissions, including from flaring and venting).

As described earlier, for the early part of the inventory time series (i.e.1990 to 1997) the emissions data available to inform UK inventory estimates is limited in detail due to the limited source resolution in early industry-wide reporting. Since the inception of EEMS reporting in 1998, there are annual operator emission reports per source per facility.

As a result, the ability to generate a consistent time series of emissions per source from 1990 onwards is compromised. Source-specific estimates have been derived in this research through the use of IPCC good practice gap-filling techniques to provide estimates back to 1990; through access to and use of new data to estimate the emission trends across 1990-1997 this research has led to improved time series consistency for many sources. However, the assurance of time series consistency for the sector as a whole may only properly be assessed at an aggregate level (i.e. across 1A1cii and 1B2 combined).

The precise source allocation of emission estimates in the 1990-1994 period is subject to higher uncertainty than in the rest of the time series, but at an aggregate level the sector-wide estimates are based on the best available data from Government and industry and analysis indicates them to be time series consistent with data post-1997 at that aggregate level.

In developing methods for all sources in the upstream sector, there are several changes over time in data availability to address, most notably for UK energy statistics (due to changes in reporting requirements and data gathering systems managed by the UK Government over the period since 1990) and for atmospheric emissions data reporting.

3.2.2 Time series consistency: UK energy statistics for the upstream sector

The DUKES commodity balance tables are regarded as high quality and complete for most fuels and sectors, where the fuel allocations are based on fuel sales data (from tax records, from annual and periodic surveys), surveys of fuel suppliers and producers, import and export data. However, for the upstream sector a high proportion of fuel use (and hence combustion emissions) arise from operators' own use of fuels (mainly fuel gas, a mixture of methane and other hydrocarbons) that are generated and used on site and are therefore not 'bought and sold' (unlike most fuel use across the UK economy) nor are they metered or delivered through a system (e.g. pipeline network) where inputs and outputs are routinely monitored to track fuel use / sales to recharge the suppliers.

The DUKES long-term trends in producers' own fuel gas use by the upstream sector[7] exhibit a ~20% single year step-change from the year 2000 to 2001 that the UK Government (then DECC) energy statistics team confirmed was due to the more complete data capture after the PPRS system was implemented (DECC, 2012. Personal communication) and was not a 'real' change in fuel use. Prior to PPRS the data capture mechanisms in place under-reported the sector fuel use, with data gaps indicated by UK Government energy statisticians for fuel gas use at gas terminals and at oil terminals.

The UK energy statistics are still incomplete in recent years for fuel gas use, as confirmed during this project through analysis of the own gas use reported by UK terminals and consultation with the BEIS energy statistics team. Consultation with BEIS energy statistics (BEIS, 2021d. Personal communication) has confirmed that the own gas use reported via PPRS from oil terminals is not included in the DUKES data for oil and gas extraction natural gas use.

[7] UK energy statistics, DUKES Table 4.2 Natural Gas Production and Supply. Producers own use is reported in GWh for 1999-2000-2001-2002 thus: 64,634 – 65,555 – 78,457 – 79,364. The step change 2000 to 2001 is a 19.7% apparent increase, but reflect better data capture (Personal communication: BEIS, 2012)

Table 3.6 Upstream Oil and Gas Source Categories: UK Inventory

IPCC	Source Name(s)	Activity Name(s)	Pollutants
1A1cii	Upstream oil production: fuel combustion Oil terminal: fuel combustion Upstream gas production: fuel combustion Gas terminal: fuel combustion	Fuel gas* ("natural gas"); Gas Oil	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC, PM
1B2a1	Onshore oil well exploration Offshore oil well exploration Oil production: offshore well testing	# wells per year # wells per year Mass of flared gas	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC, PM
1B2a2	Upstream oil production: fugitives Upstream oil production: direct process Onshore oil production (conventional) Oil terminal: other fugitives Oil terminal: direct process	(No AD. ∑ emissions) (No AD. ∑ emissions) Crude oil produced (No AD. ∑ emissions) (No AD. ∑ emissions)	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC
1B2a3	Upstream oil production: onshore oil loading Upstream oil production: offshore oil loading Oil transport fugitives: pipelines Oil transport fugitives: road/rail tankers	Crude oil	CH_4, NMVOC, CO_2
1B2a4	Oil terminal storage	(No AD. ∑ emissions)	CH_4, NMVOC
1B2a6	Abandoned oil wells (onshore) Abandoned oil wells (offshore)	# wells per year	CH_4
1B2b1	Unconventional gas well exploration Onshore gas well exploration Offshore gas well exploration Gas production: offshore well testing	(No AD. ∑ emissions) # wells per year # wells per year Mass of flared gas	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC, PM
1B2b2	Onshore natural gas production (conventional) Onshore natural gas gathering	Natural gas produced	CO_2, CH_4, N_2O, NMVOC
1B2b3	Upstream gas production: fugitives Upstream gas production: direct process Gas terminal: other fugitives Gas terminal: direct process	(No AD. ∑ emissions)	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC
1B2b4	Gas terminal storage	(No AD. ∑ emissions)	CH_4, NMVOC
1B2b6	Abandoned gas wells (onshore) Abandoned gas wells (offshore)	# wells per year	CH_4
1B2c1i	Upstream oil production: venting Oil terminal: venting	(No AD. ∑ emissions)	CO_2, CH_4, NMVOC, N_2O
1B2c1ii	Upstream gas production: venting Gas terminal: venting	(No AD. ∑ emissions)	CO_2, CH_4, NMVOC, N_2O
1B2c2i	Upstream oil production: flaring Oil terminal: flaring	(No AD. ∑ emissions)	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC
1B2c2ii	Upstream gas production: flaring Gas terminal: flaring	(No AD. ∑ emissions)	CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC

* *Fuel gas: in all upstream facilities where fuel gas is used, the gas is predominantly methane and similar in composition to natural gas but may also contain more higher-chain hydrocarbons (e.g. ethane, propane, butane, C5 and above) and higher CO_2 and sulphur compounds compared to natural gas provided to downstream users via the National Transmission System (NTS) after processing at gas terminals.*

This supports the analysis that EUETS fuel gas use is higher than the DUKES fuel allocations, and hence, to ensure completeness, the UK GHGI method deviates from DUKES and uses the EUETS dataset as the primary data source to inform the fuel gas combustion data from the sector as a whole. This is a continuation of the method from the 2021 submission.

DUKES (BEIS, 2021b) reports **gas oil** use for the upstream oil and gas sector since 2005 but not for earlier years in the time series; the operator data from EEMS (1998-2004) and from UKOOA (1990-1997) shows that gas oil has been used by the sector throughout the time series. Therefore, the UK GHGI uses the operator-reported estimates directly for 1990-2004 and the DUKES data for 2005 onwards, which are based on operator returns to EEMS.

In addition, for the **natural gas use at compressors on gas interconnector pipelines**, including the Balgzand-Bacton Line (BBL), Langeled (NOR-Gassco Easington), Bacton-Zeebrugge (Interconnector UK), Vesterled and Heimdal -St Fergus, the BEIS energy statistics team (BEIS, 2021d) confirmed that whilst the throughput (i.e. import-export of natural gas) data are available from online resources, there are no data collected on own use of gas at these installations, as they are not part of the natural gas surveys that target the National Transmission System and downstream sections of the supply network. Therefore, the UK GHGI method deviates from DUKES and uses EUETS data for these sites, where available, to add to the estimates for the downstream gas fuel gas use, reported under 1A1ci. This is also a continuation of the 2021 submission method.

3.2.3 Source Category Methods

The inventory methods for each source category are detailed in Appendix 3 and are summarised below.

Table 3.7 Overview of UK GHGI methods per source category

IPCC	Source Category	Method Description
1A1cii	Energy Industries: Oil and Gas Extraction	**1990-1997**: UKOOA 2005 (Tier 2). Time series CO_2 estimates derived from oil and gas production trends, UKOOA reported totals (1995-1997) and estimates for other emission sources. AD then derived by back-casting CEF from EEMS (1998-). **1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a), National Allocation Plans (Defra, 2005), EUETS (BEIS, 2021c) and the OGA PPRS dataset (BEIS, 2021e). CEFs are derived from operator sampling and analysis for fuel gas. PPRS data informs fuel gas NCVs and densities per source. Other EFs from EEMS (1998-). Method deviates from UK energy statistics where they are incomplete.
1B2a1	Oil Exploration	**Onshore wells, all years**: IPCC Tier 1 (2019 Refinement) method. Emission = #wells drilled x IPCC default EF (per conventional oil well) **Offshore well testing, 1990-1997**: UKOOA 2005 (Tier 2). Assumptions to derive time series using well drilling time series. **Offshore well testing, 1998 – Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a), which includes well testing emissions per facility, per year. Tier 2/3 as EFs are from EEMS operator guidance (CS).
1B2a2	Oil Production	**Onshore oil production**: Hybrid Tier 2 method. ∑ Large + small sites. Larger sites, Emissions = ∑operator emissions per wellsite (EA, 2021) Smaller sites, Emissions = Production AD (PPRS) x EF derived from larger sites, IEF from (PI emissions / PPRS production data) **Offshore oil production, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends; residual category for CH_4. **Offshore oil production, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a). Tier 3 as emissions for process emissions are derived from operator reporting; fugitives derived from EEMS guidance EFs. **Oil terminals, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends; residual category for CH_4. **Oil terminals, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI, SPRI (EA, SEPA, 2021). Tier 3 as process emissions are based on operator reporting; fugitives derived from EEMS guidance EFs. 2011- only RI data, so estimates modelled on previous years share of RI total; source is also used to report residual CH_4.

IPCC	Source Category	Method Description
1B2a3	Oil Transport	**Offshore oil loading, all years**: IPCC Tier 1 (2019 Refinement). Emission = OTL production (PPRS/BB) x IPCC default EF (*assumes no VRU*) **Onshore oil loading, 1990-1997**: UKOOA 2005 (Tier 2). Time series based on crude oil production trends. **Onshore oil loading, 1998-latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI/SPRI (EA, SEPA, 2021). Tier 2/3 as emissions for oil loading are derived from operator reporting and use of EEMS guidance EFs (CS). 2011- only RI data, so estimates modelled on previous years share of RI total; Seal Sands data from operator consultation. **Onshore oil transport (pipelines), all years**: IPCC Tier 1 (2019 Refinement). Emission = Wytch Farm production (PPRS/BB) x IPCC default EF **Onshore oil transport (road/rail), all years**: IPCC Tier 1 (2019 Refinement). Emission = Onshore production *less Wytch Farm* (PPRS/BB) x IPCC default EF
1B2a4	Oil Refining / Storage	**Oil terminal storage, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends. **Oil terminal storage, 1998 – latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI/SPRI (EA, SEPA, 2021). Tier 2/3 as emissions for oil storage are derived from operator reporting and use of EEMS guidance EFs (CS). 2011- only RI data, so estimates modelled on previous years share of RI total.
1B2a6	Oil - Other	**Oil wells abandoned, all years**: IPCC Tier 1 (2019 Refinement) method. Emission = #wells abandoned per year (cumulative) x IPCC default EF (*per well abandoned where it is unknown if plugged or not*) The AD are taken from the OGA wellbore database search facility. The AD comprise all historic oil and gas wells, so the estimates include abandoned gas wells. IPCC Refinement states that leaks from abandoned offshore wells are assumed to be 2% of those onshore, as 98% of the gases are dissolved in the water column. This assumption is applied in the method for offshore wells abandoned.
1B2b1	Natural Gas Exploration	**Onshore wells, all years**: IE, reported within 1B2a1, as there are no AD specific to gas wells drilled, only oil and gas combined. **Offshore well testing, 1990-1997**: UKOOA 2005 (Tier 2). Time series based on #wells drilled per year, from OGA. **Offshore well testing, 1998 – Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a), which includes well testing emissions per facility, per year. Tier 2/3 as EFs are from EEMS operator guidance (CS).
1B2b2	Natural Gas Production	**Onshore gas production, all years**: IPCC Tier 1 (2019 Refinement) method. Emission = natural gas produced (Mm^3) x IPCC default EF (for onshore activities with higher-emitting technologies and practices) **Onshore gas gathering, all years**: IPCC Tier 1 (2019 Refinement) method. Emission = natural gas produced (Mm^3) x IPCC default EF (for onshore activities with higher-emitting technologies and practices)
1B2b3	Natural Gas Processing	**Offshore gas production, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends; installation-level direct process emissions from key sites (i.e. Elgin, Rough) based on their gas production trends. Residual category for CH_4 and NMVOC. **Offshore gas production, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a). Tier 3 as process emissions are based on operator reporting; fugitives derived from EEMS guidance EFs. Also includes one-off estimate of emissions from Elgin blow-out, 2012, based on *Lee et al* publication from aircraft monitoring of methane, NMVOC plume. **Gas terminals, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends; installation-level estimates of process emissions from key sites (i.e. SAGE, CATS) based on gas throughput. Residual category for CH_4. **Gas terminals, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI/SPRI (EA, SEPA, 2021). Tier 3 as process emissions are based on operator reporting; fugitives derived from EEMS guidance EFs. 2011- only RI data, so estimates modelled on previous years share of RI total.

IPCC	Source Category	Method Description
1B2b4	Natural Gas Transmission & Storage	**Gas terminal storage, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends. **Gas terminal storage, 1998 – latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI/SPRI (EA, SEPA, 2021). Tier 2/3 as emissions for gas storage are derived from operator monitoring and use of EEMS guidance EFs (CS). 2011- only RI data, so estimates modelled on previous years share of RI total.
1B2b6	Natural Gas - Other	**Gas wells abandoned, all years**: Included Elsewhere. Reported within 1B2a6, as there are no AD specific to gas wells abandoned, only oil and gas wells combined.
1B2c1i	Venting & Flaring: Oil venting	**Offshore oil venting, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends. **Offshore oil venting, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a). Tier 3: venting emissions are based on operator monitoring. **Oil terminals venting, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends. **Oil terminals venting, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI/SPRI (EA, SEPA, 2021). Tier 3: venting emissions are based on operator monitoring. 2011- only RI data, so estimates modelled on previous years share of RI total.
1B2c1ii	Venting & Flaring: Gas venting	**Offshore gas venting, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends. **Offshore gas venting, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a). Tier 3: venting emissions are based on operator monitoring. **Gas terminals venting, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends. **Gas terminals venting, 1998- Latest year**: ∑operator emissions per facility, based on EEMS (BEIS 2021a) and PI/SPRI (EA, SEPA, 2021). Tier 3: venting emissions are based on operator monitoring. 2011- only RI data, so estimates modelled on previous years share of RI total.
1B2c2i	Venting & Flaring: Oil flaring	**Offshore oil flaring, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends. **Offshore oil flaring, 1998- Latest year**: ∑operator emissions per facility, based on EUETS (BEIS, 2021c), EEMS (BEIS 2021a). Tier 3: flaring emissions are based on operator reporting. CEFs from flare gas sampling, analysis, 98% oxidation factor. **Oil terminals flaring, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on crude oil production trends. **Oil terminals flaring, 1998- Latest year**: ∑operator emissions per facility, based on EUETS (BEIS, 2021c), EEMS (BEIS 2021a). Tier 3: flaring emissions are based on operator reporting. CEFs from flare gas sampling, analysis, 98% oxidation factor.
1B2c2ii	Venting & Flaring: Gas flaring	**Offshore gas flaring, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends. **Offshore gas flaring, 1998- Latest year**: ∑operator emissions per facility, based on EUETS (BEIS, 2021c), EEMS (BEIS 2021a). Tier 3: flaring emissions are based on operator reporting. CEFs from flare gas sampling, analysis, 98% oxidation factor. **Gas terminals flaring, 1990-1997:** UKOOA 2005 (Tier 2). Time series based on natural gas production trends. **Gas terminals flaring, 1998- Latest year**: ∑operator emissions per facility, based on EUETS (BEIS, 2021c), EEMS (BEIS 2021a). Tier 3: flaring emissions are based on operator reporting. CEFs from flare gas sampling, analysis, 98% oxidation factor.

Where BB = DTI Brown Book "*Development of the Oil and Gas Resources of the UK*"

4 Results and Discussion

This section presents an overview of the key outcomes and findings from the project, a read-out of the most significant recalculations per pollutant and source and also presents suggestions for future work in order to further improve the evidence base on GHG emissions from the upstream oil and gas sector.

4.1 Updated UK GHG Inventory Oil and Gas Sector Totals

The table below summarises the revised 1990-2020 UK GHGI totals for the upstream oil and gas sector, considering the scope across 1A1cii and 1B2 for upstream oil and gas source categories. These are the recommended emission estimates to be incorporated into the 2022 UK GHGI submission.

Table 4.1 UK GHG Inventory estimates, ∑1A1cii and 1B2, selected years 1990-2020

CRF	1990	1995	2000	2005	2010	2015	2018	2019	2020
1A1cii	13.18	15.76	19.39	17.82	15.16	13.06	12.59	12.99	12.49
1B2a1	0.416	0.418	0.106	0.080	0.040	0.081	0.048	0.106	0.008
1B2a2	0.726	1.046	0.305	0.164	0.262	0.105	0.131	0.101	0.079
1B2a3	0.054	0.069	0.104	0.072	0.043	0.028	0.044	0.047	0.038
1B2a4	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000
1B2a6	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
1B2b1	0.351	0.353	0.067	0.078	0.071	0.075	0.047	0.006	0.008
1B2b2	0.008	0.059	0.040	0.021	0.017	0.035	0.043	0.062	0.042
1B2b3	0.971	0.951	1.046	1.080	0.473	0.419	0.337	0.429	0.436
1B2b4	0.001	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1B2c1i	0.232	0.269	0.198	0.197	0.224	0.255	0.479	0.348	0.259
1B2c1ii	0.315	0.561	0.495	0.259	0.482	0.422	0.340	0.271	0.227
1B2c2i	4.604	6.303	4.913	4.487	3.692	3.621	3.634	3.320	2.575
1B2c2ii	0.242	0.430	0.735	0.608	0.562	0.440	0.429	0.704	0.532
∑1A1cii, 1B2	**21.10**	**26.22**	**27.40**	**24.87**	**21.02**	**18.54**	**18.12**	**18.38**	**16.70**

4.2 Key outcomes and findings

4.2.1 Improved understanding and use of oil and gas sector data

This project has involved detailed analysis and inter-comparisons between operator-reported activity and emissions data from reporting mechanisms including the PPRS, EEMS, EUETS and IED/PPC. This has led to an improved understanding of existing, new and emerging datasets, the scope and limitations of each dataset and how best to integrate them to derive accurate emission estimates per source. Whilst the work may not in all cases have led to a *reduction in inventory uncertainty*, it has led to a better understanding of the drivers and variability of sector emissions, and *improved estimates of the uncertainty* in the UK GHGI.

In particular, the access to PPRS data for the first time has led to a significant improvement in the understanding of the scope and limitations of the data that inform UK energy statistics for the oil and gas sector. Further, the PPRS has provided highly detailed data from every oil and gas field and every terminal, providing a thorough insight into the range and variability of produced materials and eluted gases that may be vented, flared or used as a fuel by operators. Key characteristics of fuel gas have been assessed (e.g. NCV, density) across the UKCS and at terminals, and used within the inventory methods to improve accuracy.

The study team has drawn upon the range of data reported by operators, regulators and statistical agencies to address reporting gaps, identify and resolve outliers and to generate more accurate, complete and consistent emission estimates as a result. Extensive consultation with the regulators and industry representatives has highlighted where the sector has good quality data, and where further industry research is ongoing to improve the evidence base, notably to improve the baseline estimates for the UK sector pathway towards net zero emissions.

4.2.2 Development of installation-level information

Through detailed analysis of the installation-level reported data and improvements in tracking the changes in installations and operators through time (e.g. when FPSOs have moved from one area of production to another), the research has led to the development of information resources that enable the inventory agency to: (i) identify and resolve reporting gaps and double-counts, *which were notably evident in the early years of the EEMS dataset (~1998-2003) as operators were learning how to use the system*; (ii) conduct inter-comparisons between reported data more quickly, to generate the "best" estimates of emissions per source / per installation, *including between EEMS and EUETS, and to compare activity data (e.g. from PPRS) to emissions data in different mechanisms e.g. to help identify where/when production started or ceased and to enable emission estimates to reflect production trends, where appropriate*.

The project has led to the development of a series of mapping tables to enable cross-checking of information, such as (i) field to installation mapping, (ii) installation permit identification tables to enable comparison across data sources such as EEMS, EUETS and PI/SPRI, and (iii) an installation-level library and issues log to aid communication across data users. The outputs of the research are designed to meet the requirements of UK inventory models that deliver outputs from the point source level, emission maps, data per Devolved Administration and for UK-wide data reporting. These improvements help to ensure completeness and accuracy of the UK GHGI and all sub-national inventory outputs.

4.2.3 High-emitting source estimates are underpinned by good quality data

A high percentage of total GHG emissions from the upstream oil and gas sector are estimated using high quality AD and EFs for recent years; however, the data for early years in the time series are more uncertain for all sources as the source resolution of industry estimates back to the Base Year is limited. Carbon dioxide emissions from combustion and flaring are reported via EUETS at installation-level with highly resolved data, by fuel and source. There is a long time series of good quality data, from 2008 (flaring) and 2005 (combustion). All high emitting installations, onshore and offshore, report to EUETS.

The UK GHGI Tier 3 methods for combustion and flaring uses installation-level data that are based on fuel-gas and flare-gas sampling and analysis to meet the stringent requirements of EUETS and hence are highly accurate and sensitive to changes in the origin of the fuel / flare gases.

Together, the combustion and flaring sources comprise ~93% of all sector emissions in 2020, and >85% of all sector emission across all years in the time series.

4.2.4 Improved estimates for the Base Year and through the 1990s

BEIS energy statistics also reports sector-wide activity data including 'own fuel use' and 'gas flaring volumes' across the time series. However, the scope of reporting in UK energy statistics does not cover all EUETS emission sources, and pre-2001 there are notable gaps in the UK energy statistics due to limitations in upstream data gathering systems in earlier years. This latter issue has been considered in detail during this research project, with a range of options considered in order to seek the least uncertain estimates of GHG emissions back to 1990. Whilst this issue is somewhat intractable, as there is a lack of complete activity (fuel use) data in energy statistics and only limited resolution industry estimates of emissions back to 1990, the use of the UKOOA 2005 dataset to inform estimates back to 1990 is regarded as the least uncertain approach as it is derived from bottom-up industry surveys that reflect the (notable) changes in the industry during the early 1990s. The UKOOA 2005 industry-wide data has also been found to be very closely consistent with EEMS and NAPs data for 1998 onwards, indicating good time series consistency with the methods and data selection for 1998 onwards where installation-level data (rather than aggregated sector data) is prevalent.

Whilst oil production was in full swing at a number of large installations / oil fields by 1990, there were many changes in the early 1990s as a number of new terminals and oil and gas fields were brought into production (notably around 1992-1993). Further, during the late 1990s there were a number of notable closures or down-turns in production at previously high-producing oil fields, and further fields were coming on-stream, and this is the point at which operator reporting, via the EEMS system and the EUETS NAPs, started to pick up and become routine. Therefore, the study team found that there was insufficient evidence to justify development of a method that sought to use *installation-level* production trends to inform emission estimates back to 1990.

Note that the use of production data as a proxy for fuel use and emissions at the installation-level is not considered good practice in this sector, as there may be significant changes in energy intensity of production from oil and gas fields over time.

Analysis of the UKOOA 2005 dataset, comparing against the NAP and EEMS data from 1998-2003 (i.e. the years where the two datasets overlap) shows a good level of consistency across most emission sources and aggregated across all sources. The UKOOA 2005 dataset presents somewhat limited resolution estimates for the 1990-1994 period, but a level of source resolution commensurate with later EEMS data for 1995 to 1997. The study team has sought to use the most appropriate proxy datasets to extrapolate source-specific estimates back to 1990 in order to derive as time series consistent an inventory dataset as possible, but we note that there remains a high level of uncertainty in the source-specific estimates back to 1990; this residual uncertainty is unavoidable but has been minimised by the use of IPCC good practice gap-filling methods.

4.2.5 More complete UK GHGI estimates through use of 2019 Refinement methods

There are several new fugitive emission sources defined in the 2019 IPCC Refinement. Where these were identified as occurring in the UK, we have developed new GHG estimates and included these emissions in the UK GHG inventory for the first time. The study team has identified sufficient UK data to develop a suitable method to apply at least the IPCC Tier 1 methods, for example for emissions from onshore well exploration and well abandonment.

As with other sources, the key challenge and uncertainty is to address variations in data availability across the time series, as there are better, more complete and transparent data sources in the recent years, but data are more scarce and therefore subject to higher uncertainty in the early part of the time series. None of these new sources emit significant GHGs in the UK oil and gas sector context, so their overall impact on inventory emission totals and uncertainty is low.

4.2.6 Limited evidence base for some methane emission sources

Through research and consultation with the industry and regulators, it is evident that there is limited evidence to inform accurate methane emission estimates from some sources.

In particular, emission estimates of methane from are based on a sector-wide assumption that all flares are 98% efficient in oxidising the flare gases, with calculated estimates (based on flare gas composition) to then derive a methane emission estimate. There is very little evidence of any operator monitoring to support / validate this assumption, and there is likely to be significant variability in performance of different flares, due to, for example: different flare stack designs (enclosed, open), weather conditions, level of accessibility and frequency of maintenance of flare stack, flare gas composition (e.g. CO_2 content), and the flare ignition system performance. Further, the accuracy of operator reporting for periods when flares are unlit (and hence the “flare” gases are being cold vented, not burned) is uncertain and may vary from one installation to another.

Other methane emissions sources are also uncertain; the EEMS reporting of fugitive from fugitive leaks from the equipment on each installation is based predominantly on inventories of the numbers of compressors, flanges, connectors etc per platform / FPSO, and the use of EFs that estimate the annual fugitive leaks from each component. There appears to be very little or no reporting of such fugitive emissions that are based on operator leak detection and repair (LDAR) surveys, and the accuracy of the EEMS fugitive emissions (for methane and also for NMVOC) is therefore uncertain.

4.2.7 Completeness of reporting

The UK methods for many sources are based on installation-level reporting via mechanisms such as PPRS, EEMS and EUETS. Where the reporting is from fixed installations, such as platforms, terminals and FPSOs, the completeness of reporting (i.e. by all such installations per year) can be assessed through time series consistency checks and cross-checks between mechanisms. For example, where a site reports production to PPRS, the inventory method will ensure that there are emission estimates for that installation, that year. However, there are some sections of the industry and some source estimates where opportunities to check, improve or validate the completeness of emissions data are limited.

In the case of MODUs, these mobile units may be deployed in the UKCS or in other regions from year to year and it is not viable to assess the completeness of the reported data (for gas oil use, for well testing emissions) through time series checks; in some years they will not have operated on the UKCS and so are (correctly) missing from EEMS. The activity of MODUs is not recorded in PPRS, as this is a system for reporting production activity, rather than exploration activity. The study team sought to review the OGA records of Consent to Locate permits, in order to cross-compare records from OGA against the reporting in EEMS per MODU, but these records are not available across the time series.

For offshore stationary units that report emission estimates to EEMS, the completeness of the annual submissions can be checked through time-series consistency of EEMS data and through cross-comparisons against PPRS. This enables assessment of whether the EEMS reporting is complete or not in terms of the sources and pollutants reported, i.e. it is feasible to assess whether a specific installation should have been reporting a specific source in a given year, and for the inventory agency to apply gap-filling methods where those data are missing.

For the emissions (of methane and NMVOC) from oil loading at OTLs, the study team assessed the available EEMS and PPRS data and has opted to derive a method that uses the PPRS activity data on oil production per month. The PPRS monthly operator reports provide a more time series consistent activity dataset for oil produced and loaded to shuttle tankers for export; hence for this specific source the PPRS is directly used to underpin a method that is associated with lower uncertainty than using EEMS data alone.

4.3 Recalculations

4.3.1 All pollutants

The following methodological changes have a notable impact on the estimates across all pollutants:

- **Alignment to UKOOA data for 1990-1997.** The previous method for estimating emissions in the 1990s, where there are scarce industry data and known gaps in energy statistics, was a hybrid approach that partly used analysis from the late 1990s to estimate the fuel gas gap in energy statistics, and partly used data from industry data submitted to Government in 2005 (UKOOA, 2005). The study team's analysis of data from EEMS and NAPs, however, has found that the previous estimate of industry fuel use from the late 1990s was *itself* an under-report and hence the method used in the 2021 submission to estimate the fuel gas gap in the 1990s needed to be updated and/or replaced. Following a detailed review of the available data and analysis of fuel combustion emissions per unit production across the UK sector, a more consistent method for the UK GHGI is to align the sum of 1A1acii and 1B2 estimates to the UKOOA 2005 reported totals. Overall, this method has been adopted, except where other data gaps or inconsistencies have been identified, *for example that the EEMS industry reporting for offshore oil loading (and related methane, NMVOC emissions) were incomplete*.

- Consultation with regulators and industry experts has led to a **review of the reporting scope** for "upstream" oil and gas sites. This has led to the re-allocation of some installations that were previously reported within the scope of the "upstream" sector, including:
    - nPower Cogen Seal Sands (now reported under 1A2gviii)
    - Brechin, South Hook LNG terminal and Gassco Easington (now reported under 1A1ci)

- Consultation with regulators and industry experts to review the **allocation of installations** between "upstream oil" and "upstream gas" sites, leading to changes in allocation in the UK GHGI, but not overall changes in total emissions, including:
    - Jade, Alwyn North, Elgin PUQ (all condensate sites): were allocated to oil, now to gas.
    - Golden Eagle was previously allocated to gas, but is now allocated to oil.

- **Revisions to estimates of well testing** activity across the time series, including:
    - <u>1990 to 1994</u>: Improved time series consistency of well testing estimates, to align to the trend in the number of wells drilled, leading to changes in allocation (but not overall estimates) with lower emissions assigned to IPCC 1B2a1 Oil exploration and 1B2b1 Gas exploration, and higher estimates in other IPCC source categories including from fuel combustion 1A1cii and flaring 1B2c2i (oil) and 1B2c2ii (gas).
    - <u>2017 to 2019</u>: Method change to revert to using the EEMS data from operators directly in the UK GHGI, leading to lower emission estimates in IPCC 1B2a1 Oil exploration and 1B2b1 Gas exploration. In the 2021 submission, we had considered that lower

reported emissions in EEMS may have been linked to a change in EEMS software, with a sharp decline in activity and emissions evident 2016-2017. We therefore took a conservative approach and extrapolated from 2016 using production data. Now that we have consistent data from 2017 to 2020, at a lower level, and following consultation with the BEIS OPRED team, we have reverted to using EEMS data directly, as there appears to be no reporting gap for this source, rather a sustained down-turn in well exploration since 2016.

The overall changes in emission trends are illustrated in the following graphs, with pollutant-specific details provided in the sections below.

Figure 4.3.1 2021 Submission: All GHG emissions from upstream oil and gas sources, ∑1A1cii and 1B2

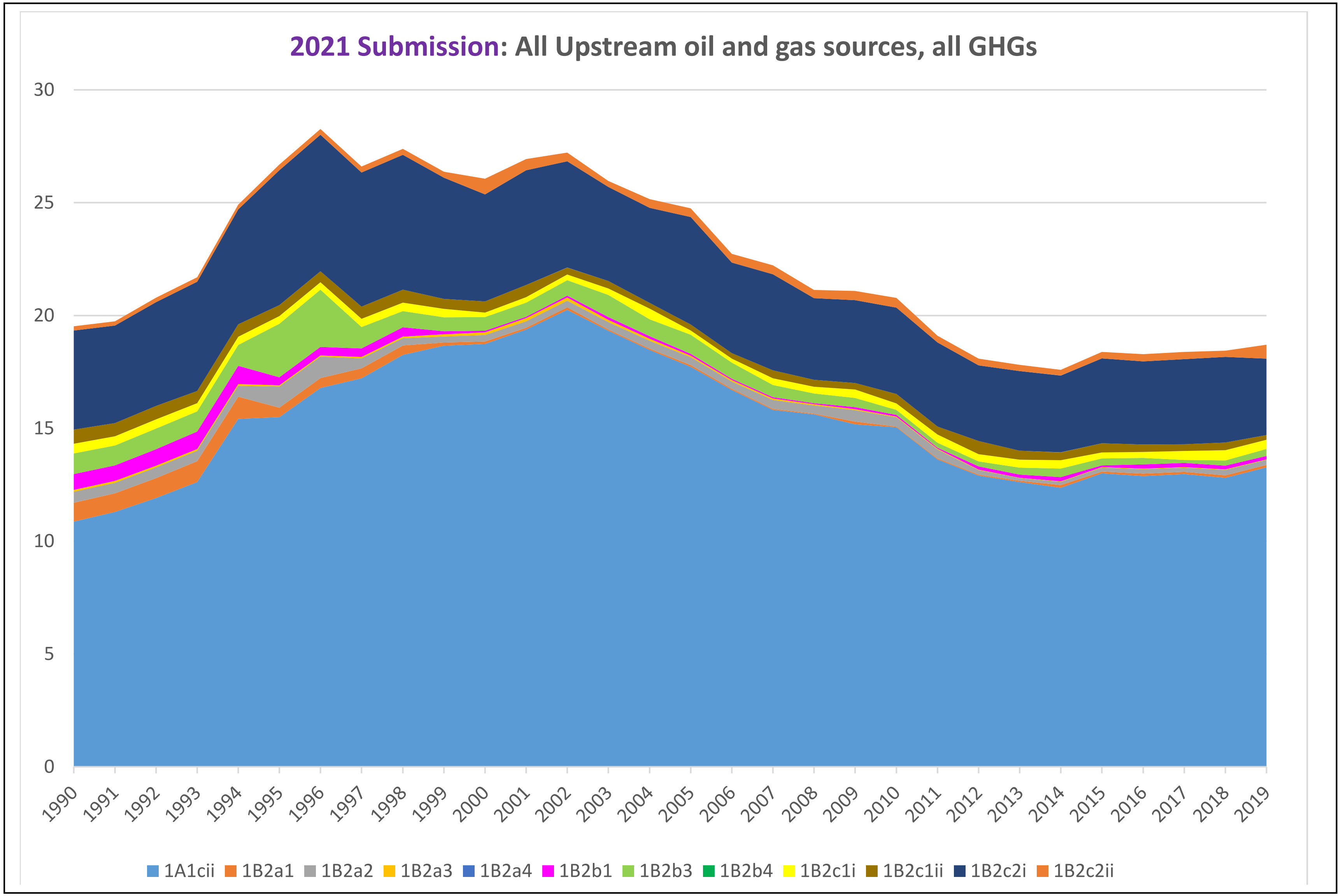


Figure 4.3.2 2022 Submission: All GHG emissions from upstream oil and gas sources, ∑1A1cii and 1B2

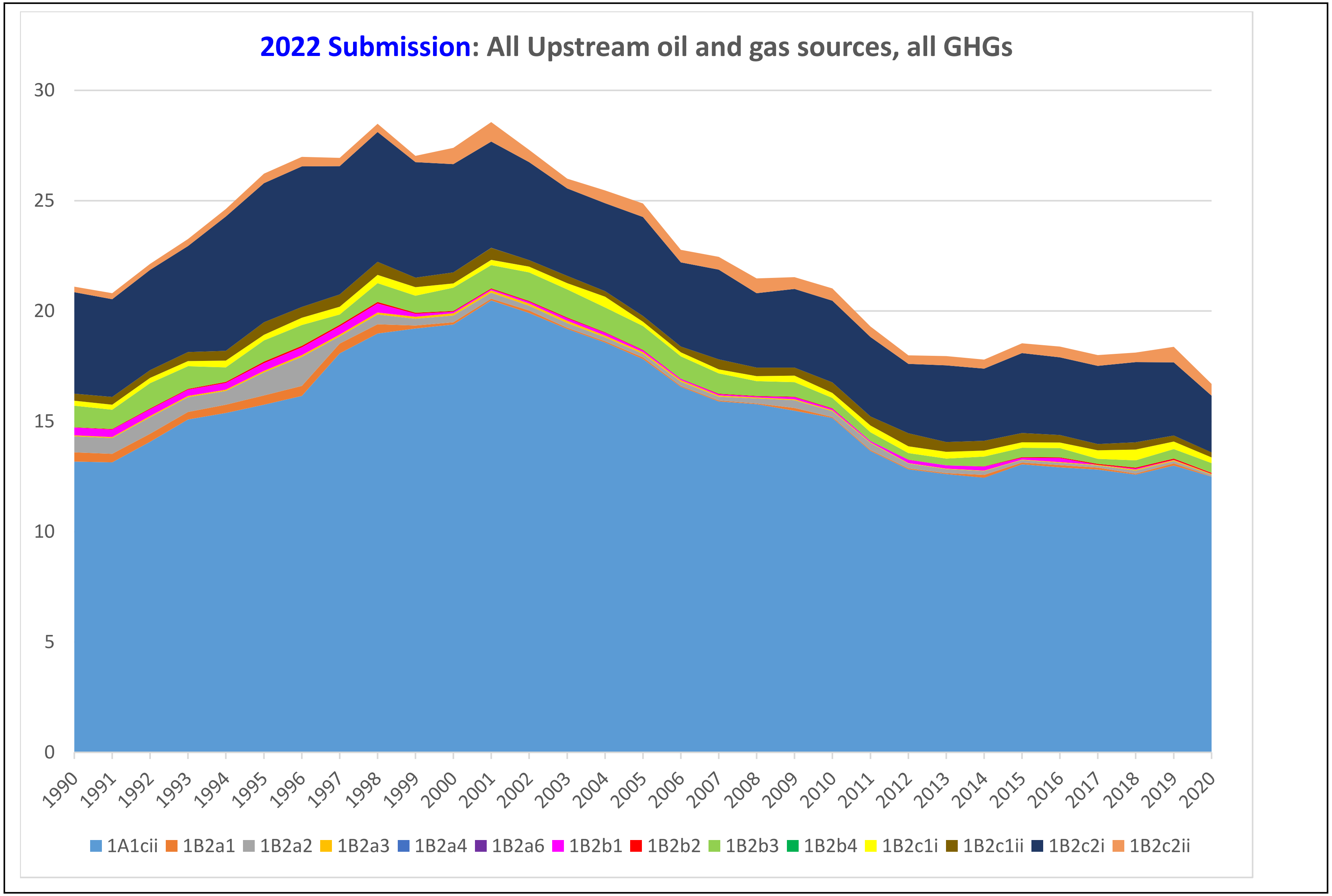


Figure 4.3.3 Recalculations to Upstream Oil and Gas Fuel Combustion, 1A1cii

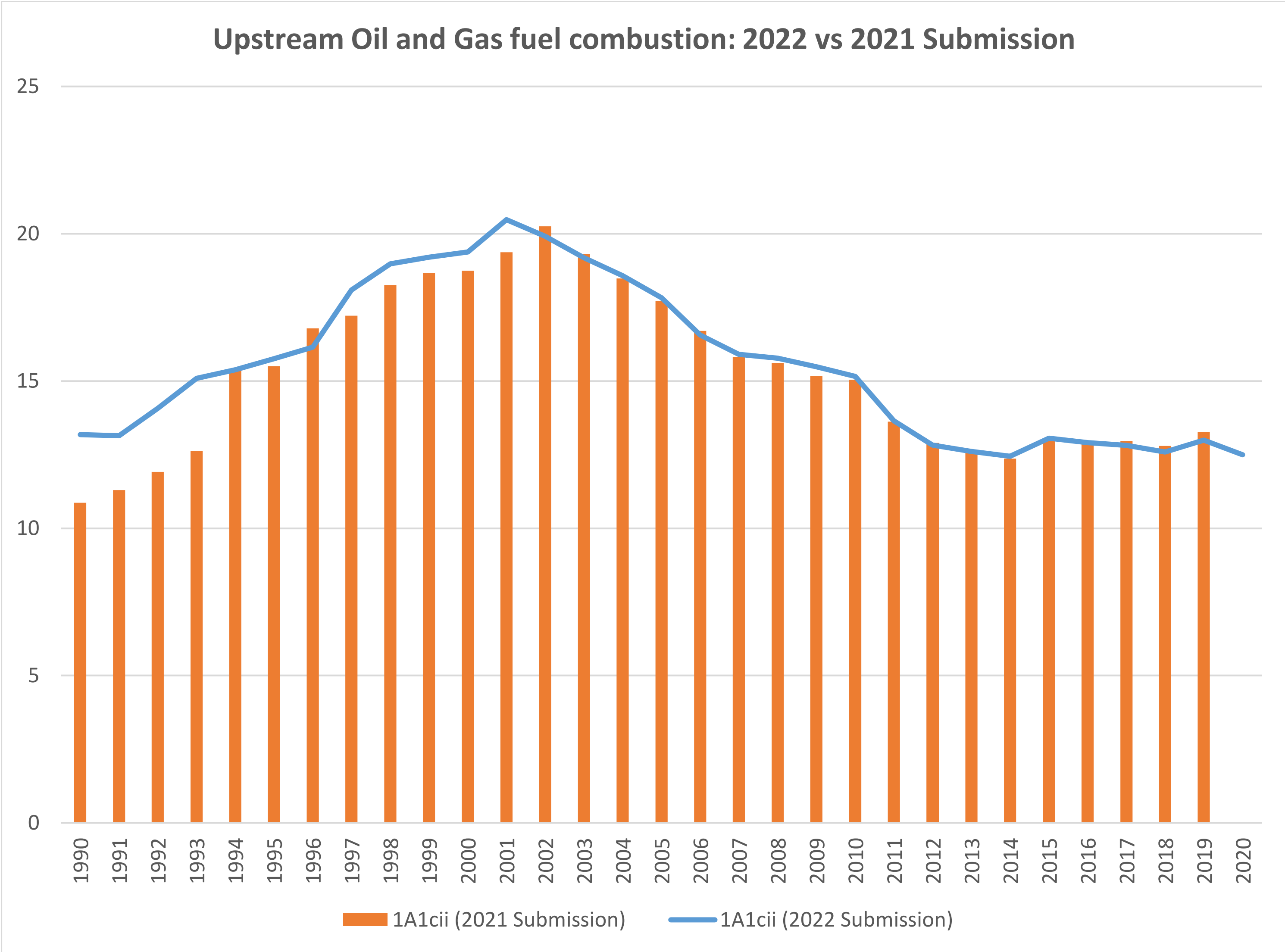
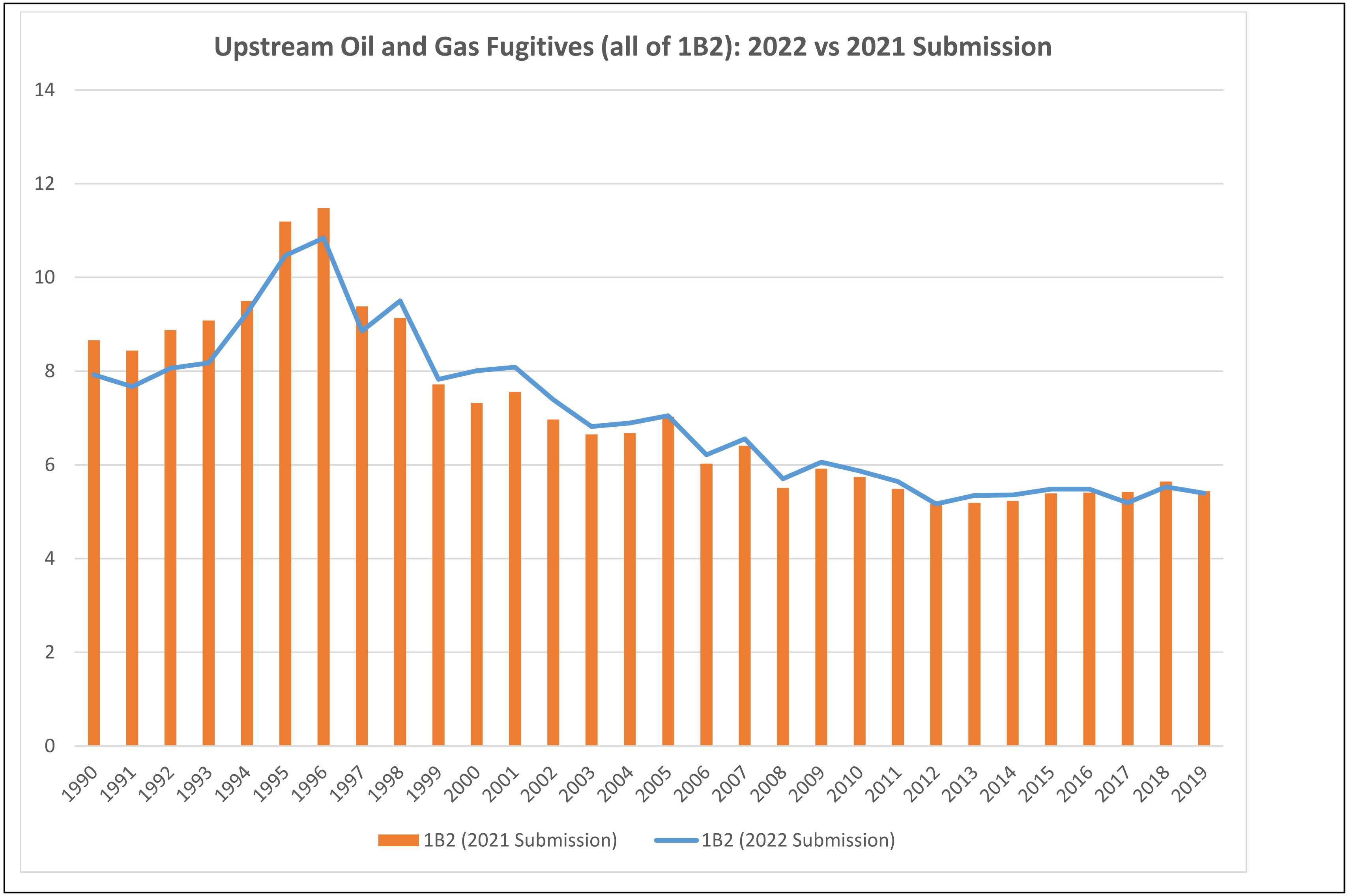


Figure 4.3.4 Recalculations to Upstream Oil and Gas Fugitives, 1B2



4.3.2 Carbon Dioxide

Across all of the upstream oil and gas source categories, including 1A1cii and all 1B2, there are recalculations to the UK GHGI carbon dioxide emissions through the range of method improvements as part of this oil and gas research task; the total emissions in 1990 are around 1.56 MtCO_2e higher than in the 2021 submission (across the 1A1cii/1B2 total), whilst the 2019 emissions are lower by around 0.36 MtCO_2e.

- **1A1cii Upstream oil and gas fuel combustion.**
  - There is a notable increase in emissions from combustion and flaring across 1998 to 2003 due to the research to align previous data with the EUETS NAP data, which is available first for combustion only (NAP #1) and then for combustion and flaring (NAP #2). The changes vary across years according to the differences observed between the data submitted to the EEMS system by operators (which were used in the 2021 submission) and the data that were submitted later during the determination of allocations for EUETS, where operators had conducted more research and derived more accurate installation-specific CEFs and activity data. In a small number of cases, some installations were noted as missing from the previous EEMS data altogether.
  - 2001 data shows a large recalculation upwards, which reflects higher emissions reported in the NAP for that year compared to EEMS data for many sites, but most notably: Clipper, Piper Bravo, Forties Delta, Claymore, Clyde, Dunlin and Alwyn North. These are partly offset by a notably lower emission estimate for Armada, but overall the increase across the sector is ~0.9 Mt CO_2. *Similar instances of NAP data indicating higher emissions than EEMS for several installations also underpins the revised emission estimates from fuel use in 1998, 1999 and 2000, all of which are up 0.5-0.8 Mt CO_2 compared to the 2021 submission*.
    - Higher estimates for Theddlethorpe (1998, 1999), Teesside Gas Processing Plant (1998-2001), Mossmorran (1999, 2000), Flotta terminal (2000, 2001), Barrow North (1999).
    - Higher estimates (offshore) for: Alwyn N (2001), Anasuria (2001, 1998-99), Beryl A and B (1998), Bruce (2000), Claymore (1998-2001), Clyde (1999-2001), Cormorant A and N (1998-2001), Dunlin (1998-2001), Forties (1998, 1999, 2001), Harding (2001), Marnock (1998), Nelson (2001), Piper (2000,2001), Ross (2000), Schiehallion (1998-2001), Clipper (2000-2001), Tern (2000-2001), Viking (1998)
    - Lower estimates (offshore) for: Armada (1998-2001), Tern (1998), Saltire (2001), Ravenspurn N (1998-1999), Murchison (1999), Ivanhoe (1998, 1999, 2001), Hawkings (1999, 2000), Brae A (1998).
  - 2002 and 2003 fuel combustion estimates are slightly *lower* than the 2021 submission, by ~0.3 and ~0.2 Mt CO_2 respectively, due primarily to the identification and removal of duplicate emission estimates, which were included in the EEMS dataset in a period when operators frequently reverted to the oil or gas field name (rather than using the installation name), and time series consistency checks had previously not identified the duplicates. Lower estimates are now reported therefore for installations including Armada, Beryl Alpha and Bravo, Ivanhoe, Lomond (2002 only). Revisions due to the comparison against NAPs data also occurred in this period, with increased emission estimates (partly offsetting the reductions noted above) evident for: Schiehallion (2002), Rough (2003), Ross (2002,2003), Ravenspurn S (2002), Pierce (2002), Nelson (2002), Murchison (2002, 2003), Montrose (2003) and Balmoral (2002).
  - 2017 to 2019 data are slightly lower than the 2021 submission, by ~0.14 to ~0.25 Mt, primarily due to the revision of allocation of emissions for a new site, South Hook LNG terminal, to the downstream gas sector (i.e. included in emission estimates under 1A1ci). Other re-allocations that affect the time series are for Brechin, ConocoPhillips Seal Sands CHP and the GASSCO Easington terminal which receives gas via an international pipeline from Norwegian gas fields; fuel use is therefore for a downstream gas compressor site. Minor revisions to the estimates of emissions also are evident at

other sites such as Hound Point and Sullom Voe terminals (2017), Flotta and Frigg terminals (2018) and Barrow North terminal (2019).

- Fuel combustion emissions in the early part of the time series have been revised through a method improvement. The BEIS energy statistics team has previously noted that the collection of fuel gas use data from upstream facilities was incomplete during the 1990s, and the method in the UK GHGI for many years up to the 2021 submission was to uplift the reported energy statistics data on oil and gas "natural gas" use by an amount based on the analysis of industry data (from EEMS) and UK energy statistics data from 1998 to 2000. There was a systematically higher estimate of fuel gas use from the (EEMS) industry data, which over those three years was 114% of the UK energy statistics total, and hence all of the UK energy statistics data on natural gas use back to 1990 was uplifted by 14% in previous UK GHGI submissions. This method was regarded as a reasonable approach to estimate the actual activity and emissions in the base year. However, this study has revised the method due to the analysis of the EEMS data against NAP information, which shows that the EEMS data (used to inform the uplift in the previous method) under-reported emissions for numerous facilities. Therefore, the study team sought an alternative method to derive the fuel gas estimates during the 1990s. We have re-analysed the industry submission to the UK Government from 2005 (UKOOA, 2005), which presented an assessment of the full time series of emission estimates from 1990 to 2003, specifically to take account of the impacts of the additional measurements by the industry following the development of the NAPs to inform sector and installation allocations for the EUETS scheme. This analysis therefore updated previous studies to draw upon the best available carbon emission factors (for combustion and flaring) and updates to activity data per installation. It drew upon industry inventory studies from the early 1990s, and presented source-specific emission estimates separately for "offshore" and "onshore" facilities (i.e. aggregate data, not estimates per facility, and not for "oil" and "gas" separately) from 1995 onwards. The data for 1990-1994 within that submission to Government was less detailed, with a broader aggregation of inventory emission estimates, but again splitting out estimates separately for offshore and onshore, and for pollutants: CO_2, CH_4, N_2O, NO_X, NMVOC, CO and SO_2.
- The UKOOA 2005 dataset is considered to be the best available basis for the UK GHGI emission estimates to present time series consistent estimates as it is likely to be a more accurate representation of the trend of emissions through the 1990s, compared to a flat percentage increase of a dataset that is known to be incomplete. The data for 1990, 1991 and 1995 onwards are based on industry operator surveys, whilst 1992-1994 estimates were derived using production trends.

- **1B2a1 Upstream Oil Production: Exploration**
    - Recalculations 1990-1994, down ~0.4 to ~0.6 Mt, to well testing emissions due to a method improvement to back-cast the level of well testing emissions from 1995 to 1990, using the trend in OGA well drilling statistics as a proxy.
    - Recalculations 2017-2019, down ~0.01 to ~0.06 Mt, due to a method improvement to revert to using EEMS data for well testing estimates.
    - New minor source added across the time series to apply the 2019 Refinement method to estimate emissions from onshore oil well exploration, which also encompasses any onshore gas well drilling as there is only a combined dataset for onshore well drilling activity.
- **1B2a2 Upstream Oil Production: Processing**
    - Estimates of emissions from direct processes are lower in the 2022 submission primarily due to a re-allocation of one key installation, Elgin platform, which has been re-allocated to the gas sector (1B2b3), as it is a condensate site that primarily produces natural gas and NGLs.
    - Minor revisions across the time series due to a method improvement to better-represent the GHG emissions from onshore oil production. We have accessed a full time series of oil field-specific production statistics and re-analysed across the time series of reported emissions (which is incomplete per pollutant across the time series

as the reporting thresholds are such that a lot of the smaller well sites do not report any emissions annually). The method is therefore now a hybrid of using reported emissions where they are available, and gap-filling using the average EF from UK operators (that do report for larger well sites) to derive estimates for the remaining smaller-producing onshore well sites.

- **1B2a3 Upstream Oil Production: Transport**
  - Very minor new estimates across the time series have been added to the UK GHGI, to reflect the CO_2 EFs in the 2019 IPCC Refinement. The onshore oil production from all bar one onshore well site are transported to terminals using road and rail tanker trucks, and there are EFs in the 2019 Refinement that cover any CO_2 released; further there is an EF for CO_2 from pipeline transport, which is applied to the production from Wytch Farm, which is transferred via onshore pipeline to Hamble terminal.
- **1B2b1 Upstream Gas Production: Exploration[8]**
  - Recalculations 1990-1994, down ~0.3 to ~0.5 Mt, to well testing emissions due to a method improvement to back-cast the level of well testing emissions from 1995 to 1990, using the trend in OGA well drilling statistics as a proxy.
  - Recalculations 2017-2019, down ~0.09 to ~0.13 Mt due to a method change to revert to using EEMS data for well testing estimates.
- **1B2b2 Natural Gas Production**
  - New minor sources have been added across the time series to implement the 2019 Refinement methods for onshore gas production and gas gathering, to reflect the time series now available from PPRS and the DTI Brown Book for onshore dry gas field annual production. In the UK there are very few such fields and annual production is historically very low, and these well sites do not report any annual emission estimates to the Regulator Inventories. Hence, we have applied the 2019 Refinement Tier 1 methods, as a proportionate approach to ensure completeness in the UK GHGI.
- **1B2b3 Natural Gas Processing**
  - The estimates for emissions from gas processing have been revised across the time series due to review of the data from operator-reporting, including revisions to allocations for specific sites to either the "oil" or "gas" upstream sectors. For onshore installations, the reporting of pollutant emissions to Regulator Inventories is not source-specific and therefore the allocation of these emissions to IPCC sub-categories is somewhat uncertain. Across the time series, for gas installations, whilst estimates of emissions from combustion or flaring are well understood and documented (within EUETS), the allocation of residual emissions to "venting" or "fugitive" or "process sources" is indicative, as source-specific data from individual sites / operators are scarce. The total emissions per pollutant per installation are a mandatory reporting requirement to the Regulator Inventories, and these data are verified by the regulators. Hence there is less uncertainty for total emissions across the GHGI and some changes in allocations have been made in this research.
  - In later years of the time series, the main recalculation is an increase in gas process emissions due to the re-allocation of the Elgin platform (a condensate site) from "oil" to "gas", and hence is just a re-allocation (from 1B2a2) and not a change in overall reported UK emissions.
- **1B2c1i Upstream Oil Venting; 1B2c1ii Upstream Gas Venting**
  - Across both oil and gas venting estimates there are only a few recalculations, with a handful of installations dominating the reported CO_2 estimates, typically where installations are managing CO_2-rich gas streams; for example, Shearwater gas platform has had to vent high quantities of high-CO_2 gas (that could not be flared) during 2017-2018. The re-allocation of the Elgin condensate platform from "oil" to "gas"

[8] Separate to this study, a new minor source has been added across the time series to add estimates of emissions from periodic onshore unconventional (shale) gas well exploration activity in the UK. There are very low levels of historic onshore dry gas production (conventional or unconventional) in the UK; all emissions from onshore associated gas production at oil wells is reported in 1B2a, and emissions from all onshore oil and gas well drilling are all estimated and reported under 1B2a1. However, during 2011, 2012, 2014, 2018 and 2019 there were activities to explore the viability of onshore shale gas development in a handful of locations. Emission estimates have been added to the UK GHGI for completeness, using site-level data on wells drilled, whether hydrocarbons were found or not, and any supplementary reporting of estimates of methane vented per site during the well development phase.

leads to equal and opposite recalculations between these two source categories, notably in 2015-2018 where CO_2 vented emissions at Elgin were around 6 to 8 ktCO_2.

- A further recalculation of estimates for oil venting in 2018 is due to revision to the allocation of emissions at the Flotta terminal. The total emissions from the site in both the previous and latest submission are aligned to the operator-reported SPRI total, but we have revised the allocation of emissions such that combustion and flaring totals align to the reported EUETS emissions, with the residual CO_2 emissions (to align to the SPRI total) now all allocated to venting, to reflect that the site historically has reported CO_2 vented when previously reporting source-specific estimates to EEMS.

- **1B2c2i Upstream Oil Flaring; 1B2c2ii Upstream Gas Flaring**
    - Recalculations in the early part of the time series are due to the method improvement to use the UKOOA 2005 data, leading to higher flaring estimates in 1990 by 0.41 Mt for 1B2c2i and 0.05 Mt for 1B2c2ii. UKOOA provides activity and emissions data for flaring for 1995-1997 at offshore and onshore installations separately. EEMS data from 1998 onwards and the UK production trends for oil and gas were used to derive separate estimates for "upstream oil" and "upstream gas" during 1995 to 1997. Flaring estimates for 1990 to 1994 were then back-cast using flaring per unit production and the IEFs for the upstream oil and upstream gas estimates in 1995. This leads to higher flaring emission estimates in 1990-1994, which is offset by the parallel improvement in time series consistency of emission estimates for well testing, reported under 1B2a1 and 1B2b1, where the previous submission had implausibly high allocations to well testing during 1990-1994, and lower allocations to flaring.
    - There are a number of revisions to data in the middle of the time series where analysis of the EUETS NAPs has indicated mis-reports and gaps in the original EEMS dataset. For example, the NAPs data has resolved some under-reporting where EEMS had omitted installation reports or had outlier low IEFs for: Claymore (2000, 2001), Clyde (2000, 2001, 2002), Flotta (2000, 2001), Guillemot/Triton (2000 – *previously missing from EEMS*). The analysis against NAPs also indicated where duplicate lines had been mis-reported in EEMS, including for Marnock ETAP (1999, 2000) and for Armada (1999, 2000, 2002).
    - In recent years, a few minor revisions to installation data were made, which led to a small (0.3%) reduction in total (i.e. oil and gas combined) flaring estimates in 2018 and a small (0.5%) increase in estimates for 2019. These included slightly higher flaring estimates for Barrow Terminal (2018, 2019) and Dunbar (2019), with slightly lower flaring estimates for Banff, Stella and Flotta terminal (all 2018) and Culzean (2019).

4.3.3 Methane

Across all of the upstream oil and gas source categories, including 1A1cii and all 1B2, the overall recalculations to the methane inventory through the range of method improvements as part of this oil and gas research task are relatively small; the total emissions in 1990 are around 0.02 MtCO_2e lower than in the 2021 submission (down 0.8% of the previous 1A1cii/1B2 total), whilst the 2019 emissions are higher by around 0.06 MtCO_2e (up by around 4.5%).

- **1A1cii Upstream oil and gas fuel combustion**
    - The recalculations of methane in 1A1cii follow the same pattern as for carbon dioxide as they are predominantly impacted by the same changes in underlying activity.
        - The base year estimates are slightly higher (~0.03 MtCO_2e) due to the method change to use the UKOOA 2005 dataset to inform fuel use data back to 1990;
        - There are increased estimates in the mid-time-series, 1998-2003, up between 0.01 to 0.04 MtCO_2e, due to the increase in estimated fuel gas combustion activity following analysis of the National Allocation Plans;
        - There is a very small reduction in estimates in 2019 (~0.002 MtCO_2e) due to the re-allocation of activity and emissions from a handful of installations identified as downstream gas / industry sites rather than upstream oil and gas.
- **1B2a1 Upstream Oil Production: Exploration & 1B2b1 Upstream Gas Production: Exploration**
    - The recalculations for methane follow a similar pattern to those for carbon dioxide:

        - Reductions in 1990-1994 are due to revisions to improve the time series consistency of well testing emission estimates. The method has been revised to now back-cast well testing emissions from 1995 data, using well drilling statistics.
        - Reductions in 2017-2019 are due to a method change to revert to using EEMS data for well testing estimates; overall the oil and gas well testing emissions (i.e. 1B2a1 and 1B2b1 combined) are down by ~0.05 $MtCO_2e$ in 2017 and 2018 and down ~0.04 $MtCO_2e$ in 2019. *Some drill rigs have been re-allocated between the oil and gas sector, and we will review that in the next submission as the distribution of methane across "oil" and "gas" now appears to be inconsistent, with too high an allocation to oil well testing in both 2017 and 2019. However, the total reported methane across 1B2a1 and 1B2b1 are consistent with EEMS operator reporting, so the UK GHGI total is correct.*
        - A new minor source (<1kt CO_2e, all years) has been added across the time series to apply the 2019 Refinement method for onshore oil well exploration, which also encompasses any onshore gas well drilling as there is only a combined dataset for onshore well drilling activity.
- **1B2a2 Upstream Oil Production: Processing**
    - There are recalculations in the early part of the time series due to the method improvement to use the UKOOA 2005 dataset to inform sector emissions of GHGs back to 1990. For both offshore oil production sites and onshore oil terminals, once methane estimates from fuel combustion and flaring are accounted for, the residual of the total reported emissions are allocated to oil processing source categories. This has led to an increase in methane allocation to 1B2a2 across the early 1990s, up 0.26 $MtCO_2e$ in 1990; the allocation is uncertain, but the alignment to the total sector emission reported by UKOOA is regarded as the most accurate overall approach for the UK GHGI.
    - A further recalculation across the time series is due to the implementation of a Tier 1 method from the 2019 IPCC Refinement to estimate methane emissions from onshore oil well sites. This method addresses a small completeness issue for the UK GHGI, as the UK onshore oil well sites, aside from Wytch Farm, are all small sites that do not report annual emission estimates to the PI/SPRI as they do not exceed the PPC reporting threshold. This additional small source adds ~0.02 $MtCO_2e$ methane in 1990, up to a peak of ~0.11 $MtCO_2e$ in 2011, and back down to ~0.02 $MtCO_2e$ in 2019 and 2020.
    - A further recalculation across the time series is due to the re-allocation of reported methane emissions from a number of chemical and petrochemical sites that are now reported under 2B10.
- **1B2a3 Upstream Oil Production: Transport**
    - There are recalculations across the time series due to a method improvement to address reporting inconsistencies from upstream operators of Offshore Tanker Loader (OTLs) installations. The new method has led to a more complete and time series consistent UK GHGI for this source, and this underpins the increase in reported emissions of ~0.025 $MtCO_2e$ in 2019, and a small decrease in emissions for 1990 of ~0.005 $MtCO_2e$.
    - The estimates for onshore oil loading methane emissions in the early part of the time series have been recalculated as part of the analysis and use of the UKOOA 2005 data for 1990-1997 estimates. The UKOOA data present estimates of methane from oil loading from 1995 onwards and these are used directly; for 1990 to 1994 the estimates have been derived by extrapolating back the 1995 % share of methane from total onshore methane emissions as a best estimate to deliver a time series consistent estimate for this source. This leads to a lower estimate of methane from onshore oil loading by ~0.026 to 0.023 $MtCO_2e$ across 1990 to 1994, and improved time series consistency.
    - In addition, there are very minor increases in methane estimates across the time series in 2019 (<0.5 $ktCO_2e$ per year) due to the addition of new estimates based on the 2019

IPCC Refinement methods for fugitive emissions from the onshore transport of produced oil via pipelines and road / rail tankers. This addresses a small completeness issue in the UK inventory, where the level of emissions typically is below the reporting threshold for regulated installations and hence there are no annual operator estimates of methane from most such sites.

- **1B2a6 Abandoned Wells**
  - New estimates have been added to the UK GHGI for the first time by applying the methods in the 2019 Refinement for abandoned wells onshore and offshore. This leads to very minor emissions added to the UK GHGI of around 0.5 kt CO_2e in 1990 and 0.6 kt CO_2e in 2019.
- **1B2b2 Natural Gas Production**
  - New methane estimates have been added to the UK GHGI across the time series due to the first implementation of the 2019 IPCC Refinement method for onshore gas production and gas gathering emissions. The impact is greatest in 2019, an increase of ~0.06 Mt CO_2e, reflecting that 2019 was a peak for UK onshore gas production, whilst the additional emissions in 1990 are ~0.01 Mt CO_2e. The UK production facilities tend to be small well sites that only report infrequently (or never) to the Regulatory Inventories (under IED/PPC) as their emissions fall below the reporting threshold. Hence to apply the 2019 IPCC Refinement method is justified to ensure completeness of the UK inventory.
- **1B2b3 Natural Gas Processing**
  - The oil and gas sector method improvement ensures that PI/SPRI residual methane emissions for onshore sites (once estimates for sources of known activity such as combustion and flaring are accounted for) are allocated to this source category. There is no notable recalculation in this source category in 2019.
  - As noted for CO_2 above, the estimates for emissions from gas processing have been revised across the time series due to review of the data from UKOOA for the early part of the time series and from operator-reporting in later years, including revisions to allocations for specific sites to either the “oil” or “gas” upstream sectors.
  - Estimates for fugitive methane emissions are allocated to 1B2b3, and in 1995 to 1997 are based on the reported industry data by UKOOA, with estimates back-cast to 1990 using the UK gas production time series and applying the IEF of fugitive emissions per unit gas production from 1995-1997.
  - Across 1990-1994 the method improvement to use the UKOOA 2005 dataset based on inventory surveys has led to an increase in methane allocated to 1B2b3 by around 0.43 $MtCO_2e$. The industry has reported methane totals for (i) total offshore methane emissions, and (ii) total onshore emissions in 1990-1994. The residual emissions (once estimates for other sources are accounted for, e.g. combustion, flaring, well testing) are reported as fugitives in 1B2b3. Whilst this allocation may be uncertain, the alignment to the total emission reported for the sector by UKOOA is regarded as the most accurate approach for the UK GHGI.
- **1B2c1i Upstream oil venting and 1B2c1ii Upstream gas venting**
  - There have been a small number of changes in allocation of individual installations between the oil and gas sector, which do not affect the overall emissions total and are reflected in equal and opposite recalculations between the two source categories across the time series. The overall recalculation in 2019 across oil and gas sites is only -4 $ktCO_2e$ following minor revisions to installation-level estimates and allocation of non-upstream oil and gas sites to other sectors.
  - Recalculations in the early years of the time series are due to the method change to align sector totals to the UKOOA industry estimates and an improvement in time series consistency of the method. The change in 1990 is around -0.5 $MtCO_2e$ across oil and gas venting. Estimates for methane emissions from venting in 1995 to 1997 are based on the UKOOA industry data, with estimates back-cast to 1990 using the UK gas production time series and applying the IEF of venting emissions per unit gas production from 1995-1997.
- **1B2c2i Upstream oil flaring and 1B2c2ii Upstream gas flaring**

  - There have been a small number of changes in allocation of individual installations between the oil and gas sector, which do not affect the overall emissions total and are reflected in equal and opposite recalculations between the two source categories across the time series. The overall recalculation in 2019 across oil and gas sites is only 4 ktCO_2e following minor revisions to installation-level estimates, including for: Flotta terminal, Teesside Gas Processing Plant and Dunbar platform.
  - Recalculations in the early years of the time series are due to the method change to align sector totals to the UKOOA industry estimates and an improvement in time series consistency of the method. The change in 1990 is around -0.2 MtCO_2e across oil and gas flaring. Estimates for methane emissions from flaring in 1995 to 1997 are based on the UKOOA industry data, with estimates back-cast to 1990 using the UK gas production time series and applying the IEF of flaring emissions per unit gas production from 1995-1997.

4.3.4 Nitrous Oxide

Across all of the upstream oil and gas source categories, including 1A1cii and all 1B2, the overall recalculations to the nitrous oxide inventory through the range of method improvements as part of this oil and gas research task are very small; the total emissions in 1990 are around 0.04 MtCO_2e higher than in the 2021 submission (across the 1A1cii, 1B2 total), whilst the 2019 emissions are lower by around 0.02 MtCO_2e.

- As noted for other pollutants, there is a notable increase in the estimated fuel gas combustion in 1990, due to the change in method to align to the UKOOA sector data; this is the key reason for the overall increase in nitrous oxide emissions in 1990, accounting for 0.035 MtCO_2e of the overall change. There are no significant recalculations in 1B2 in 1990, with minor increases due to new 2019 Refinement methods addressing completeness issues for sources including: onshore oil production, onshore gas production and gathering;
- The lower estimates in recent years including 2019 are due to re-allocation of emissions from a small number of installations such as the South Hook LNG terminal, to 1A1ci rather than to 1A1cii, partly offset by some revisions to flaring estimates due to gap-filling where operators had omitted N_2O estimates.

4.3.5 NMVOC

- **1B2a1 Upstream Oil Exploration; 1B2b1 Upstream Gas Exploration**
  - As across all pollutants, the NMVOC estimates from oil and gas well testing have been revised down in 2017 to 2019 as the method has been revised to revert to using the reported EEMS data; in 2019 the oil well testing emissions are now ~0.27kt NMVOC lower and gas well testing ~0.17 kt NMVOC lower.
- **1B2a2 Oil production processes**
  - In 2019 these are ~0.1kt NMVOC lower, and in 2005 these estimates are ~0.05kt NMVOC lower; this is primarily due to re-allocation of NMVOC emissions from a number of facilities that are not associated with upstream oil and gas and are now reported (more accurately) as chemical and petrochemical facilities, under 2B10 Chemical Industry (other). The sites moved from 1B2a2 (and a few from 1B2b2, Gas production process emissions) are primarily material storage and transfer sites servicing petrochemical production facilities rather than upstream oil and gas sites.
- **1B2a3 Upstream Oil Production: Transport**
  - The estimates of emissions from onshore oil loading throughout the 1990s have been significantly reduced to align with the reported total of onshore pollutant emissions within the UKOOA 2005 dataset. The NMVOC emissions total from these industry estimates was significantly lower than those presented in the 2021 submission, and hence in 1990 there is a recalculation of down ~131 kt NMVOC, which is by far the largest recalculation across the 1B2 sector for NMVOC.
  - There are minor increases in NMVOC estimates in 2019 (up ~0.08kt) and 2005 (up ~0.10 kt) due to the addition of new estimates based on the 2019 IPCC Refinement methods for fugitive emissions from the onshore transport of produced oil via pipelines and road / rail tankers. These address small completeness issues in the UK inventory,

where the level of emissions typically is below the reporting threshold for regulated installations.

- **1B2b2 Natural Gas Production**
  - NMVOC estimates have increased in most year in the time series due to the method improvement to implement the 2019 IPCC Refinement method for onshore gas production and gas gathering emissions. The impact is greatest in 2019, an increase of 0.62 kt NMVOC, reflecting that 2019 was a peak for UK onshore gas production, but emissions are also higher in 2005 by around 0.11 kt NMVOC. The UK production facilities tend to be small well sites that only report infrequently (or never) to the Regulatory Inventories (under IED/PPC) as their emissions would fall below the reporting threshold. Hence to apply the 2019 IPCC Refinement method is justified to ensure completeness of the UK inventory.
  - In some years (2011-2014) the re-allocation of reported RI emissions at installations that are chemical / petrochemical facilities to 2B10 out-weighs the impact of the new method noted above, leading to small reductions in NMVOC emissions reported in 1B2b2.
- **1B2b3 Natural Gas Processing**
  - The oil and gas sector method improvement ensures that RI residual NMVOC emissions for onshore sites (once estimates for sources of known activity such as combustion and flaring are accounted for) are allocated to this source category. In several years around the NMVOC base year, and including 2005, there are increased estimates of emissions from fugitive sources. 2005 NMVOC estimates are ~3kt higher than in the 2021 submission due to a high PI emission reported at Theddlethorpe terminal. In other years in the early 2000s, high emission reports at Shell Bacton terminal increase the inventory estimates. There is no notable recalculation in this source category in 2019.
- **1B2c1i Upstream oil venting and 1B2c1ii Upstream gas venting**
  - Consultation identified that Anasuria operator switched from reporting oil loading to "venting" from 2016 onwards. This was corrected to ensure time series consistency, leading to a lower allocation of emissions to venting of around 0.4 kt NMVOC per year 2016-2019;
  - There have been a small number of changes in allocation of individual installations between the oil and gas sector, which do not affect the overall emissions total and are reflected in equal and opposite recalculations between the two source categories across the time series.
- **1B2c2i Upstream oil flaring and 1B2c2ii Upstream gas flaring**
  - NMVOC estimates from flaring have been recalculated following a review of installation data. In 2019 emissions are higher than previously estimated due to the addition of estimates for Dunbar (which had not previously reported emissions but was still operating) and higher flaring estimates at the Flotta (oil) and Point of Ayr (gas) terminals. Overall, the NMVOC estimates were 0.14 kt NMVOC higher in 2019 across oil and gas flaring, compared to the 2021 submission. Conversely, the study team corrected a duplicate report of emissions in EEMS from the MacCulloch FPSO in 2005, leading to a small overall reduction of around 0.08 kt NMVOC.
  - There have been a small number of changes in allocation of individual installations between the oil and gas sector, which do not affect the overall emissions total and are reflected in equal and opposite recalculations between the two source categories across the time series.

4.4 Priorities for future research and development

As noted in section 4.2, there are a number of GHG sources where the existing evidence base is limited and are therefore priorities for further data gathering and research to improve accuracy and completeness of UK GHGI estimates.

- **Methane from flaring,** including (i) development of a system that enables more complete and consistent monitoring and reporting of unlit flares by operators across the UKCS, and (ii) the development of evidence from monitoring and reporting of flare emissions across different flare types, weather conditions, flare gas compositions, to inform the flaring combustion efficiency assumptions (i.e. 98% oxidation factor) that are currently applied within EUETS, EEMS and which underpin the UK GHGI estimates for flaring CO_2 and CH_4.
- **NMVOC and methane from oil loading**, primarily to gather evidence relating to EFs for methane and NMVOC emissions per unit crude oil transfers from platforms and FPSOs to shuttle tankers offshore, across a range of conditions (e.g. weather and sea conditions, shuttle tanker vapour recovery system design and operation, use of cover gases).

Consideration should be given to strengthening reporting systems in order to develop higher quality operator reporting for key activity and emissions data, i.e. systems that are assured in terms of completeness and accuracy, consistency in the use of methods and reporting systems. In particular to consider:

- Improvements to operator guidance and provision of updated methods and EFs, in order to improve the completeness and consistency of operator reporting to EEMS;
- Resource needs (IT, personnel) to enable regulatory oversight and scrutiny of PPRS and EEMS submissions and to implement more automated quality checks;
- Updates to onshore IED/PPC permits in order to generate annual pollutant emission estimates per source within the scope of the defined installations, i.e. to enhance the resolution of RI data reporting. This would enhance the evidence base for policy makers and regulators to monitor progress regarding monitoring and reporting to achieve BAT, e.g. for CH_4 and NMVOCs.

There may be opportunities to improve the design and alignment of data gathering and reporting systems across Government Departments and Agencies that may reap benefits across a range of applications: statistics, energy and emissions data reporting, development of policy and related evidence to foster a common understanding of challenges and opportunities to achieve common goals (across industry, Government) of e.g. zero routine flaring and net zero emissions. For example:

- OGA databases and systems for managing well data (drilling, abandonments) are not readily accessible to enable data queries to derive quantitative outputs that may help to inform emission estimates and track trends across the industry;
- OGA records of operator permits and consents that are required under the Energy Act and Petroleum Act to manage operations on the UKCS (e.g. Consent to Locate, Flaring Consents, Venting Consents) are not easily accessible and searchable. Development of these consent systems could provide an annual record of all mobile and fixed units in the UKCS to share with other data users.

5 Acknowledgements

This has been a complex project with many stakeholders that have contributed their time and energy to support the project team in identifying the best available data to help inform UK inventory estimates. Many thanks in particular to BEIS SICE, BEIS OPRED, BEIS DUKES, Defra, the OGA, the Environment Agency, the Scottish Environment Protection Agency and Oil and Gas UK.

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Appendices

Appendix 1: UKOOA 2005 Reference Data

Appendix 2: UK Upstream Fuel Gas Composition

Appendix 3: Inventory Source Category Methods

Appendix 1: UKOOA 2005 Reference Data

This appendix presents summary tables with the data provided by UKOOA to UK Government in February 2005 that has been used in this study to inform the UK GHGI inventory estimates during the 1990s. The tables below show the data for 1990-1994 and then for 1995 to 2000. Following the tables is an overview of how the data have been used to derive an inventory time series per source category.

Table A.1.1: UKOOA 2005 Data Submission to Defra: 1990 to 1994 Emissions Data
(All emissions data is in tonnes.)

Year	Activity	CO	NOx	SO2	CH4	VOC	CO2
1990	Drilling	5,140	10,113	7,310	7,201	3,098	1,352,461
1990	Production	31,152	46,855	2,023	67,372	47,029	14,263,066
1990	Loading	0	0	0	781	39,671	0
1990	Offshore total	36,293	56,969	9,333	75,354	89,798	15,615,527
1990	Onshore total	2,529	11,328	202	36,440	68,609	2,098,340
1990	Upsteam total	38,821	68,297	9,535	111,794	158,407	17,713,867

Year	Activity	CO	NOx	SO2	CH4	VOC	CO2
1991	Drilling	5,082	9,999	7,227	6,798	3,201	1,337,160
1991	Production	30,800	46,325	2,000	63,600	48,600	14,101,700
1991	Loading	0	0	0	737	40,996	0
1991	Offshore total	35,882	56,324	9,227	71,135	92,797	15,438,860
1991	Onshore total	2,500	11,200	200	34,400	70,900	2,074,600
1991	Upsteam total	38,382	67,524	9,427	105,535	163,697	17,513,460

Year	Activity	CO	NOx	SO2	CH4	VOC	CO2
1992	Drilling	5,302	9,975	7,434	6,813	3,259	1,434,645
1992	Production	32,131	46,214	2,057	63,739	49,484	15,129,775
1992	Loading	0	0	0	739	41,742	0
1992	Offshore total	37,433	56,189	9,491	71,290	94,485	16,564,419
1992	Onshore total	2,608	11,173	206	34,475	72,190	2,225,847
1992	Upsteam total	40,041	67,362	9,697	116,089	166,675	18,790,267

Year	Activity	CO	NOx	SO2	CH4	VOC	CO2
1993	Drilling	5,521	9,951	7,641	6,221	3,317	1,532,129
1993	Production	33,463	46,103	2,114	58,197	50,368	16,157,849
1993	Loading	0	0	0	674	42,488	0
1993	Offshore total	38,984	56,054	9,755	65,092	96,174	17,689,979
1993	Onshore total	2,716	11,146	211	31,478	73,480	2,377,095
1993	Upsteam total	41,700	67,201	9,967	105,996	169,654	20,067,074

Year	Activity	CO	NOx	SO2	CH4	VOC	CO2
1994	Drilling	5,741	9,927	7,847	6,234	3,376	1,629,614
1994	Production	34,794	45,992	2,172	58,324	51,253	17,185,924
1994	Loading	0	0	0	676	43,234	0
1994	Offshore total	40,535	55,919	10,019	65,233	97,862	18,815,538
1994	Onshore total	2,824	11,120	217	31,546	74,770	2,528,342
1994	Upsteam total	43,359	67,039	10,236	106,226	172,632	21,343,880

Note that the methane totals for 1992, 1993 and 1994 are not internally consistent. The "Upstream total" line is less than the sum of the "Offshore total" and "Onshore total". In the UK GHGI, we have applied the individual data for offshore and onshore totals and disregarded the "Upstream total" line. We note that these are not critical years in the UK GHGI anyway, as they are not a base year for any pollutant.

Table A.1.2: UKOOA 2005 Data Submission to Defra: 1995 to 2000 Emissions Data

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1995	Offshore	Drilling Diesel Consumption	246,951	790,243	9,804	55	2,593	1,482	27	321
1995	Offshore	Drilling Well Testing	200,000	591,369	520	16	2,670	6,001	7,000	3,000
1995	Offshore	Flaring	2,020,782	5,354,615	3,031	162	17,581	173	20,400	20,016
1995	Offshore	Fuel <20MW facilities	139,467	407,540	1,684	31	508	319	39	57
1995	Offshore	Fuel >20MW facilities	4,038,195	10,926,151	33,293	864	12,289	1,934	1,613	485
1995	Offshore	Fugitive Emissions	8,254	0	0	0	0	0	5,942	3,727
1995	Offshore	Gas Venting	38,134	2,741	0	0	0	0	23,438	14,696
1995	Offshore	Oil Loading	20,554,999	0	0	0	0	0	740	41,110
1995	Offshore	Other Gases	1,122,135	1,095,864	6,849	0	2,854	244	9,817	6,507
1995	Offshore	Total	28,368,918	19,168,523	55,181	1,129	38,495	10,154	69,016	89,918

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1995	Onshore	Flaring	250,728	618,990	854	55	2,209	26	2,787	2,228
1995	Onshore	Fuel <20MW facilities	26,615	70,961	83	6	21	15	2	17
1995	Onshore	Fuel >20MW facilities	677,204	1,775,221	7,532	149	2,702	305	494	150
1995	Onshore	Fugitive Emissions	2,912	0	0	0	0	0	2,740	411
1995	Onshore	Gas Venting	13,032	997	0	3	0	0	9,592	3,440
1995	Onshore	Oil Loading	89,065,629	0	0	0	0	0	1,608	75,493
1995	Onshore	Other Gases	1,084,142	1,056,636	3,302	0	1,609	21	20,249	2,325
1995	Onshore	Storage Tanks	12,514,460	0	0	0	0	0	2	21
1995	Onshore	Total	103,634,722	3,522,806	11,771	213	6,542	367	37,473	84,084

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1996	Offshore	Drilling Diesel Consumption	268,560	859,392	11,936	60	3,177	1,611	31	374
1996	Offshore	Drilling Well Testing	221,562	618,299	576	18	2,958	6,648	7,755	3,323
1996	Offshore	Flaring	2,054,542	5,395,941	3,082	165	17,875	34	21,298	19,793
1996	Offshore	Fuel <20MW facilities	119,903	346,809	976	26	311	236	36	38
1996	Offshore	Fuel >20MW facilities	4,186,471	11,291,744	34,605	896	12,758	1,667	1,671	506
1996	Offshore	Fugitive Emissions	10,990	0	0	0	0	0	7,455	3,534
1996	Offshore	Gas Venting	46,697	3,046	0	0	0	0	29,340	17,279
1996	Offshore	Oil Loading	24,054,521	0	0	0	0	0	847	47,043
1996	Offshore	Other Gases	761,896	746,732	4,061	0	1,686	133	5,642	3,642
1996	Offshore	Total	31,725,141	19,261,963	55,236	1,165	38,764	10,329	74,075	95,533

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1996	Onshore	Flaring	253,686	626,232	381	56	2,207	5	2,682	2,392
1996	Onshore	Fuel <20MW facilities	26,615	70,961	83	6	21	15	2	17
1996	Onshore	Fuel >20MW facilities	667,348	1,767,780	4,680	147	1,565	201	448	174
1996	Onshore	Fugitive Emissions	6,852	0	0	0	0	0	5,049	1,803
1996	Onshore	Gas Venting	4,364	298	0	1	0	0	3,198	1,166
1996	Onshore	Oil Loading	85,748,128	0	0	0	0	0	208	73,002
1996	Onshore	Other Gases	1,898,831	1,880,837	3,138	0	1,232	30	12,384	1,211
1996	Onshore	Storage Tanks	11,372,438	0	0	0	0	0	2	16
1996	Onshore	Total	99,978,262	4,346,109	8,282	209	5,025	251	23,971	79,781

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1997	Offshore	Drilling Diesel Consumption	257,592	824,294	10,796	57	2,865	1,546	29	346
1997	Offshore	Drilling Well Testing	209,682	619,713	545	17	2,799	6,292	7,339	3,145
1997	Offshore	Flaring	1,859,027	5,015,393	2,778	149	16,073	822	19,234	18,053
1997	Offshore	Fuel <20MW facilities	140,240	405,116	1,643	31	510	229	56	50
1997	Offshore	Fuel >20MW facilities	4,486,736	12,396,246	42,113	960	14,668	4,257	2,662	697
1997	Offshore	Fugitive Emissions	9,600	0	0	0	0	0	6,164	3,436
1997	Offshore	Gas Venting	46,392	2,817	0	0	0	0	31,226	14,908
1997	Offshore	Oil Loading	29,072,962	0	0	0	0	0	1,035	57,511
1997	Offshore	Other Gases	257,179	254,462	620	0	249	757	772	319
1997	Offshore	Total	36,339,410	19,518,040	58,496	1,215	37,164	13,902	68,519	98,465

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1997	Onshore	Flaring	182,586	504,605	598	40	1,608	4	2,529	1,731
1997	Onshore	Fuel <20MW facilities	20,882	50,578	65	5	17	10	1	13
1997	Onshore	Fuel >20MW facilities	916,131	2,556,287	5,925	202	2,579	211	613	210
1997	Onshore	Fugitive Emissions	7,122	0	0	0	0	0	5,299	1,823
1997	Onshore	Gas Venting	6,073	255	0	1	0	0	4,859	1,119
1997	Onshore	Oil Loading	79,612,227	0	0	0	0	0	304	71,548
1997	Onshore	Other Gases	491,535	489,433	143	0	118	63	1,777	0
1997	Onshore	Storage Tanks	45,516,421	0	0	0	0	0	58	1,893
1997	Onshore	Total	126,752,976	3,601,158	6,732	247	4,322	287	15,440	78,337

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1998	Offshore	Drilling Diesel Consumption	259,920	831,743	18,018	58	4,889	1,514	36	490
1998	Offshore	Drilling Well Testing	214,434	631,097	558	17	2,863	6,061	7,344	3,046
1998	Offshore	Flaring	1,886,572	5,077,343	2,758	152	15,708	666	19,699	16,978
1998	Offshore	Fuel <20MW facilities	140,117	392,506	1,675	31	547	87	72	37
1998	Offshore	Fuel >20MW facilities	5,050,946	13,028,492	43,714	1,081	15,290	2,376	2,204	654
1998	Offshore	Fugitive Emissions	9,716	0	0	0	0	0	6,222	3,494
1998	Offshore	Gas Venting	47,437	2,794	0	0	0	0	34,062	10,835
1998	Offshore	Oil Loading	30,638,811	0	0	0	0	0	1,321	44,126
1998	Offshore	Other Gases	38,061	36,410	10	0	55	846	382	358
1998	Offshore	Total	38,286,014	20,000,385	66,731	1,339	39,353	11,550	71,342	80,019

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1998	Onshore	Flaring	169,177	463,001	469	37	1,487	4	2,240	1,546
1998	Onshore	Fuel <20MW facilities	13,705	33,361	43	3	11	6	1	9
1998	Onshore	Fuel >20MW facilities	991,391	2,866,817	6,369	218	2,486	309	579	219
1998	Onshore	Fugitive Emissions	7,567	0	0	0	0	0	5,699	1,868
1998	Onshore	Gas Venting	5,059	49	0	1	0	0	4,058	932
1998	Onshore	Oil Loading	105,203,268	0	0	0	0	0	1,336	98,133
1998	Onshore	Other Gases	586,861	584,757	321	0	0	236	1,547	0
1998	Onshore	Storage Tanks	72,034,691	0	0	0	0	0	176	1,710
1998	Onshore	Total	179,011,720	3,947,985	7,202	259	3,984	555	15,637	104,416

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1999	Offshore	Drilling Diesel Consumption	121,127	387,608	7,256	27	1,931	343	20	231
1999	Offshore	Drilling Well Testing	70,361	211,907	178	6	892	1	2,421	1,097
1999	Offshore	Flaring	1,934,442	5,140,414	2,324	155	12,973	3,300	20,223	15,378
1999	Offshore	Fuel <20MW facilities	129,660	360,036	1,897	29	557	417	213	54
1999	Offshore	Fuel >20MW facilities	5,224,232	13,251,233	43,534	1,118	16,278	4,842	6,413	767
1999	Offshore	Fugitive Emissions	3,399	0	0	0	0	0	3,361	1,495
1999	Offshore	Gas Venting	52,150	11,300	0	0	0	0	30,012	9,720
1999	Offshore	Oil Loading	37,646,811	0	0	0	0	0	2,686	52,042
1999	Offshore	Other Gases	124,068	121,615	229	0	135	786	1,124	180
1999	Offshore	Total	45,306,248	19,484,113	55,418	1,335	32,766	9,689	66,474	80,965

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
1999	Onshore	Flaring	178,246	480,739	354	9	1,539	247	1,498	1,919
1999	Onshore	Fuel <20MW facilities	12,542	29,952	21	3	8	8	1	0
1999	Onshore	Fuel >20MW facilities	1,114,515	2,854,980	7,804	211	2,855	427	1,045	193
1999	Onshore	Fugitive Emissions	1,026	0	0	0	0	0	1,199	4,840
1999	Onshore	Gas Venting	2,869	56	0	0	0	0	2,079	654
1999	Onshore	Oil Loading	102,395,302	0	0	0	0	0	658	85,179
1999	Onshore	Other Gases	549,165	539,121	823	0	22	409	990	7,800
1999	Onshore	Storage Tanks	103,985,206	0	0	0	0	0	64	1,399
1999	Onshore	Total	208,238,871	3,904,848	9,003	223	4,424	1,091	7,534	101,985

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
2000	Offshore	Drilling Diesel Consumption	109,560	350,594	6,508	24	1,720	349	20	331
2000	Offshore	Drilling Well Testing	44,659	138,010	135	4	666	1	1,361	872
2000	Offshore	Flaring	1,711,814	4,363,285	2,057	137	11,484	1,775	19,260	11,071
2000	Offshore	Fuel <20MW facilities	126,749	361,776	1,874	28	524	59	322	60
2000	Offshore	Fuel >20MW facilities	5,113,427	13,855,459	41,053	1,093	16,066	3,868	6,561	806
2000	Offshore	Fugitive Emissions	3,752	2	0	0	0	0	3,600	1,530
2000	Offshore	Gas Venting	37,389	3,613	0	0	0	0	23,768	8,436
2000	Offshore	Oil Loading	33,610,348	0	0	0	0	0	3,713	56,968
2000	Offshore	Other Gases	0	0	0	0	0	0	0	0
2000	Offshore	Total	40,757,699	19,072,740	51,627	1,285	30,461	6,052	58,604	80,076

Year	Area	Source	Activity (t)	t CO_2	t NO_X	t N_2O	t CO	t SO_2	t CH_4	t VOC
2000	Onshore	Flaring	274,719	698,684	270	17	1,368	107	2,354	1,679
2000	Onshore	Fuel <20MW facilities	6,806	16,278	17	1	4	4	1	0
2000	Onshore	Fuel >20MW facilities	1,290,767	3,476,874	7,459	273	2,839	319	959	116
2000	Onshore	Fugitive Emissions	949	1	0	0	0	0	2,622	13,313
2000	Onshore	Gas Venting	4,620	104	0	0	0	0	2,803	1,621
2000	Onshore	Oil Loading	93,321,395	0	0	0	0	0	1,103	81,467
2000	Onshore	Other Gases	536,576	535,357	523	0	0	471	0	225
2000	Onshore	Storage Tanks	134,908,528	10,429	0	0	0	0	110	10,996
2000	Onshore	Total	230,344,359	4,737,727	8,269	291	4,211	900	9,952	109,416

A1.1 Method Development Per Source, using the UKOOA 2005 dataset

To develop time series consistent estimates, we have applied a range of proxy data to estimate the 1990 onwards emission totals per emission source per pollutant. The general approach is that the sum of the estimates will align with the UKOOA 2005 totals per pollutant, except where data outliers or gaps have been identified, such as the inconsistent use of N_2O EFs and the incomplete reporting of oil loading emissions evident in EEMS.

The parameters used to inform trends are the DTI Brown Book data on UK oil production and gas production, as well as the OGA Well Operations Notification System records of wells drilled per year:

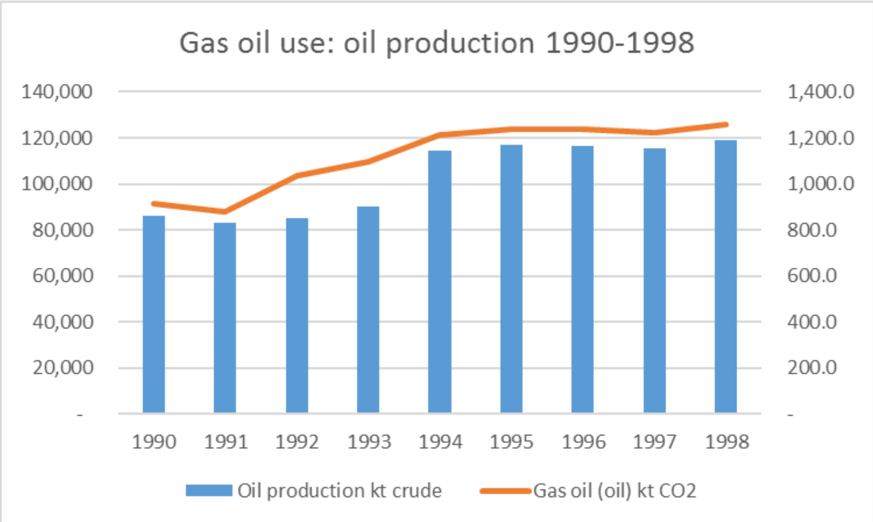
Table A.1.3 Parameters used to inform 1990-1998 time series per source

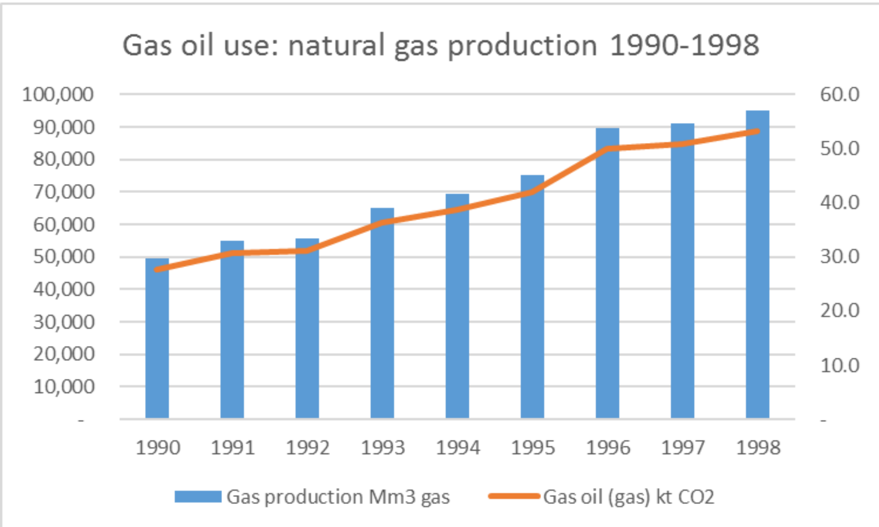
Parameter	Units	1990	1991	1992	1993	1994	1995	1996	1997	1998
Crude oil	kt/yr	86,234	83,129	85,222	90,213	114,383	116,743	116,679	115,340	118,919
Natural Gas	Mm^3/yr	49,506	55,051	55,738	65,109	69,343	75,158	89,514	91,170	95,171
∑ wells drilled	#wells	348	331	302	280	308	360	396	350	367

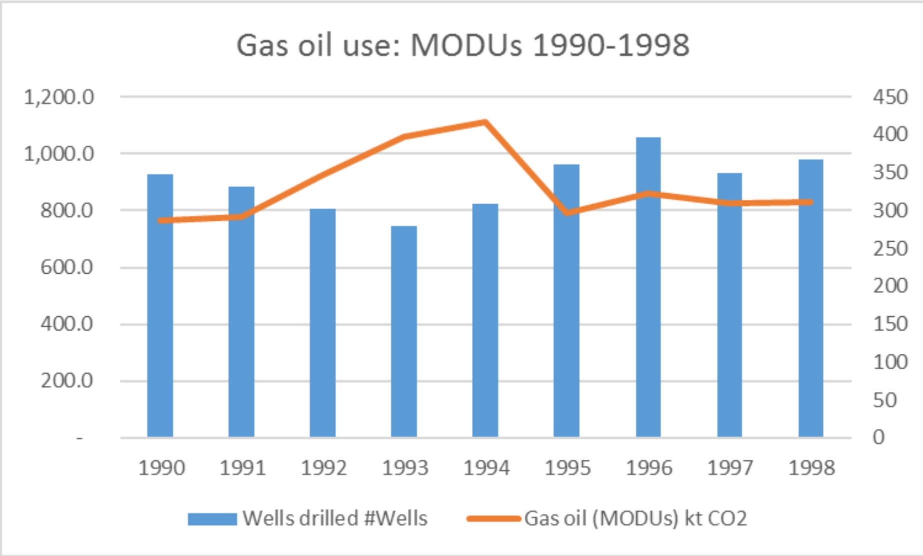
A1.1.1. Gas oil consumption

Gas oil consumption at stationary installations producing crude oil are estimated using the time series of crude oil production, assuming the same IEF of CO_2 emissions per unit production from EEMS data (1998-). Gas oil consumption at stationary installations producing natural gas are estimated using the time series of natural gas production, assuming the same IEF of CO_2 emissions per unit production from EEMS data (1998-). Gas oil consumption in Mobile Drilling Units is derived by difference:

UKOOA Total drilling emissions = Well Testing emissions + Gas oil use by MODUs

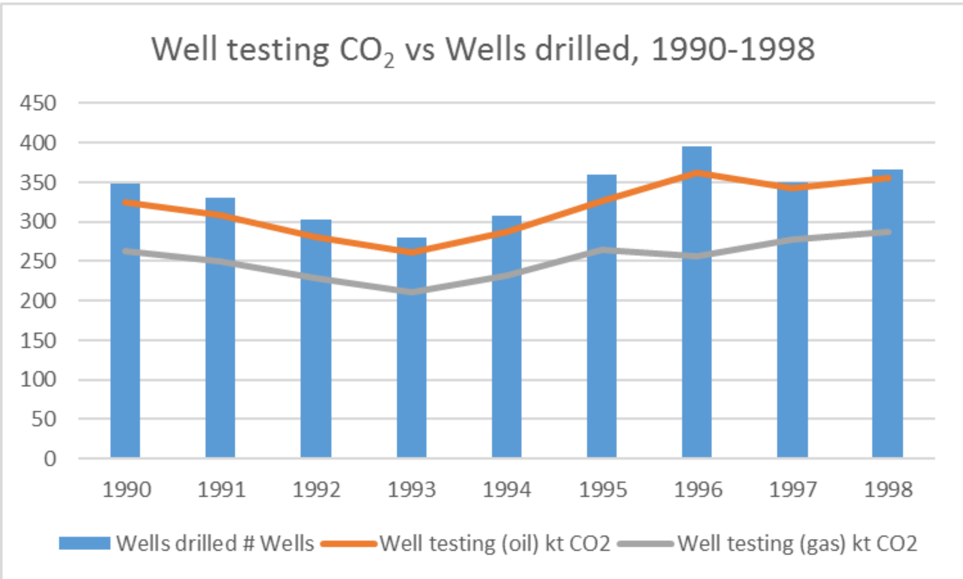






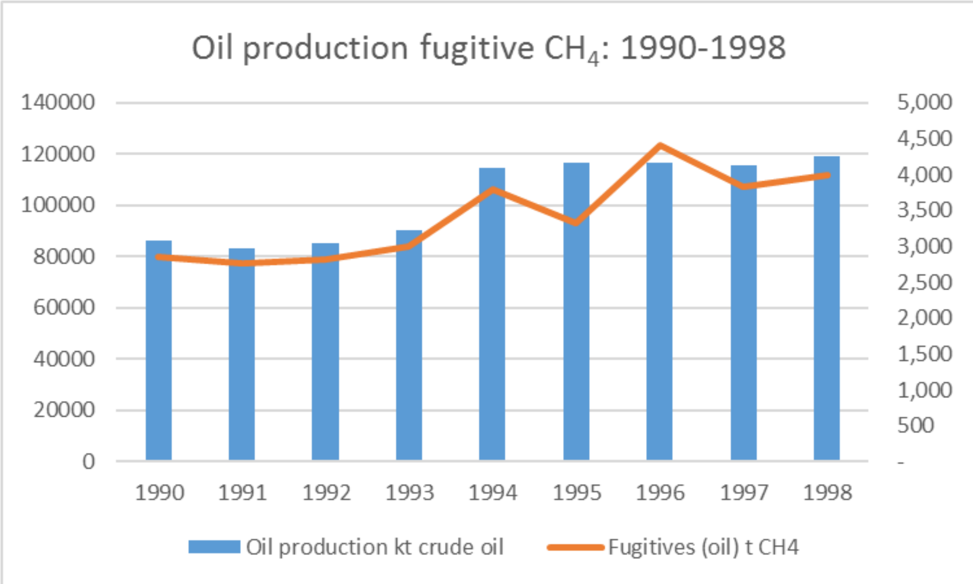
A1.1.2 Well Testing

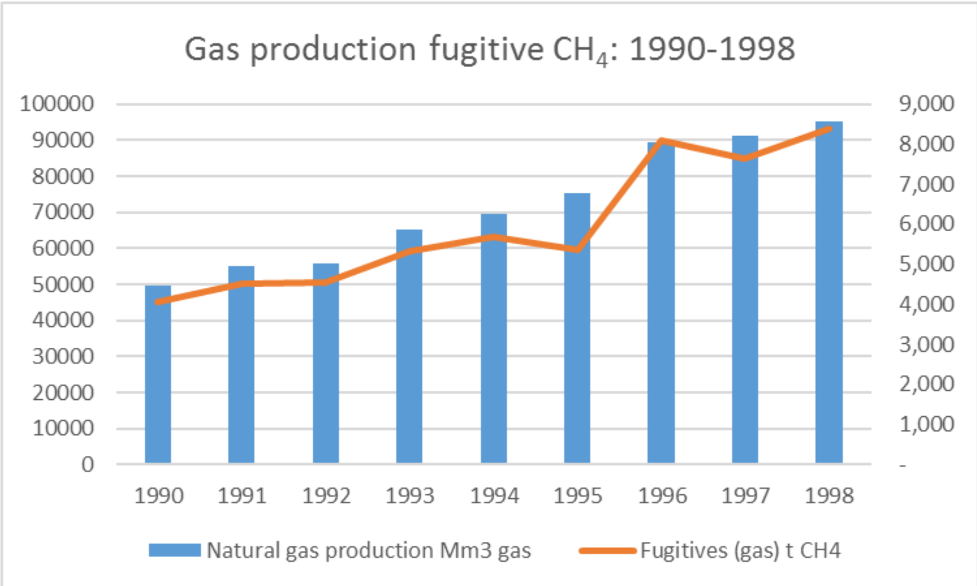
Well testing (oil) and well testing (gas) emissions are estimated using the OGA data on total wells drilled (including exploration, appraisal and development wells), assuming the same level of well testing activity and emissions per # wells tested from EEMS data (1998-). The total emissions from 1995 onwards are aligned to the UKOOA 2005 estimates for well drilling emissions, which leads to a low outlier in 1996 (see graph below). Note that the OGA data (1990-1998) does not distinguish between wells drilled for oil or gas exploration.



A1.1.3 Fugitives

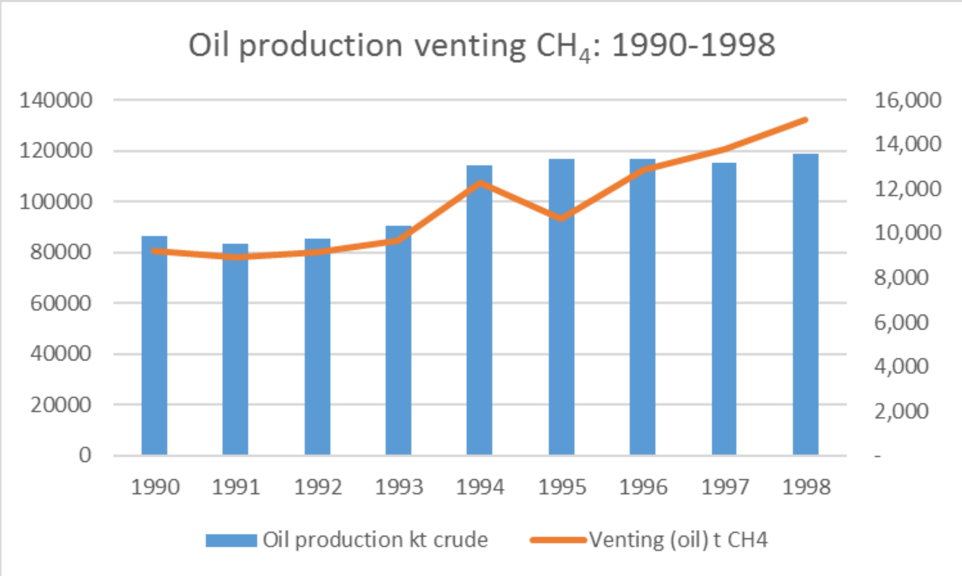
Total emissions from 1995 to 1997 across the oil and gas sector are aligned to the total data reported in UKOOA 2005. The split of those total emissions across “oil” and “gas” in 1995-1997 assume the same split between oil and gas as in the EEMS dataset (1998-). Then the estimates for 1990-1994 are back-cast from 1995 using the oil production and natural gas production trends. The graphs below illustrate the overall trend in emissions (for methane) versus the oil and gas production data.

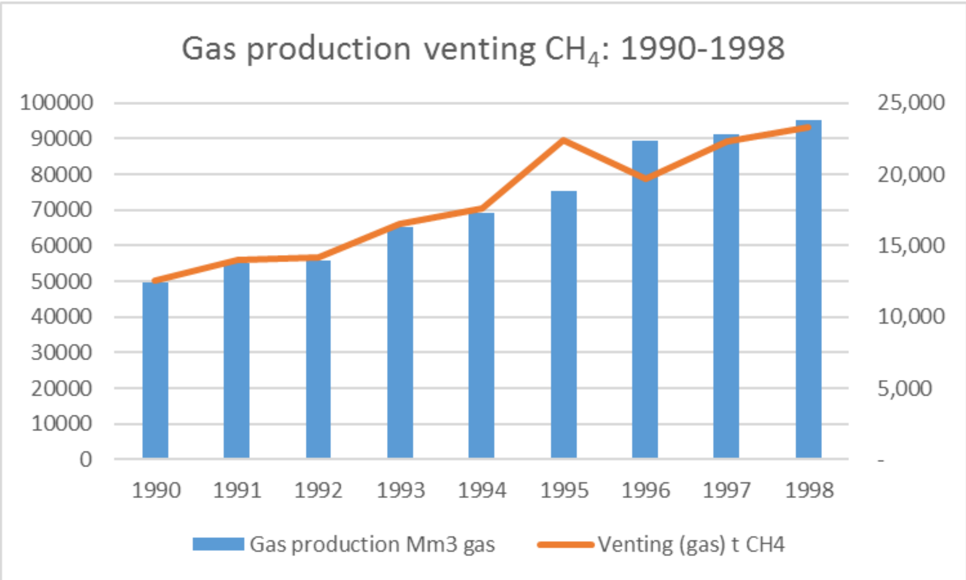




A1.1.4 Venting

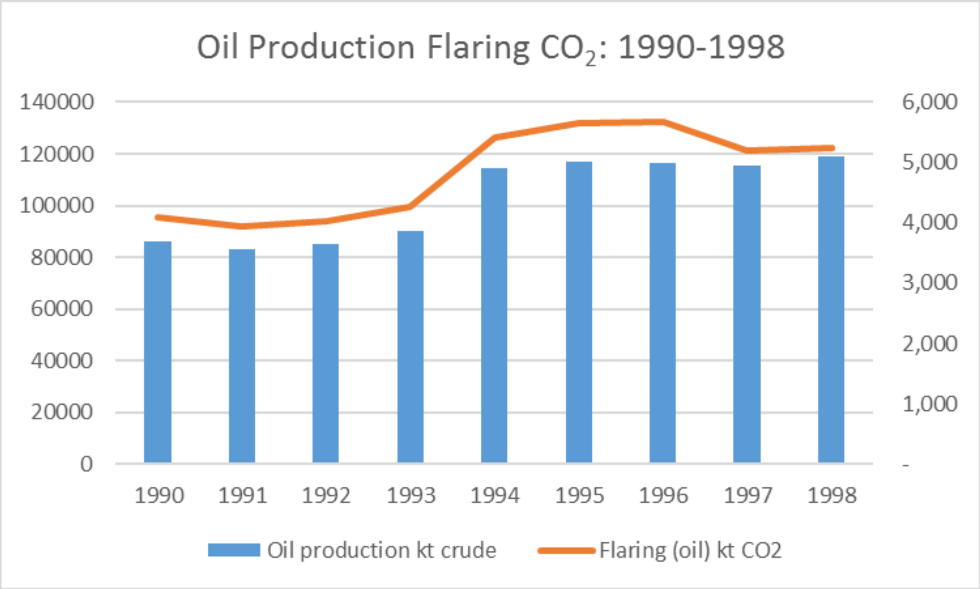
Total emissions from 1995 to 1997 across the oil and gas sector are aligned to the total data reported in UKOOA 2005. The split of those total emissions across “oil” and “gas” in 1995-1997 assume the same split between oil and gas as in the EEMS dataset (1998-). Then the estimates for 1990-1994 are back-cast from 1995 using the oil production and natural gas production trends. The graphs below illustrate the overall trend in emissions (for methane) versus the oil and gas production data.

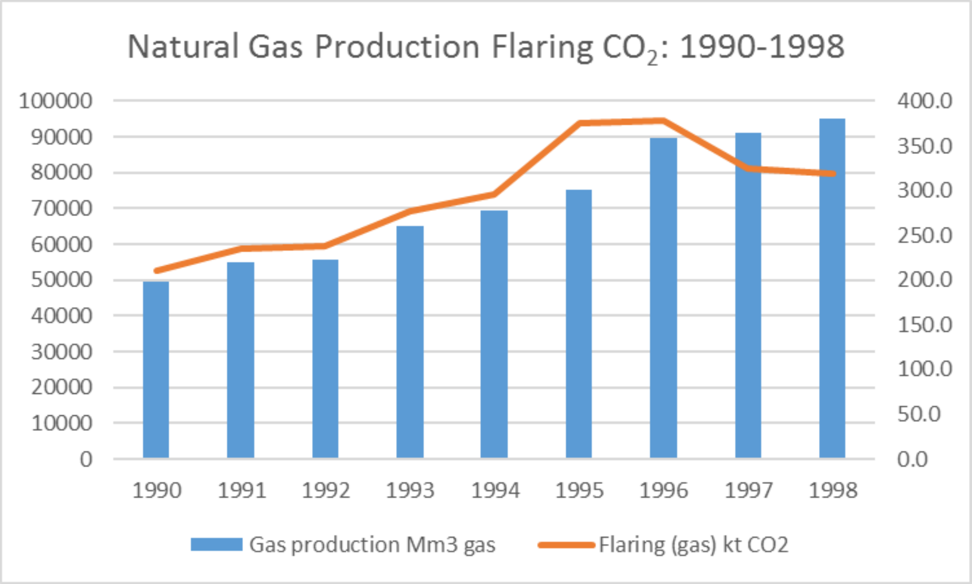




A1.1.5 Flaring

Total emissions from 1995 to 1997 across the oil and gas sector are aligned to the total data reported in UKOOA 2005. The split of those total emissions across “oil” and “gas” in 1995-1997 assume the same split between oil and gas as in the EEMS dataset (1998-). Then the estimates for 1990-1994 are back-cast from 1995 using the oil production and natural gas production trends. The graphs below illustrate the overall trend in emissions (for CO_2) versus the oil and gas production data.





A1.1.6 Direct Processes

The estimates of emissions from direct processes are based on a series of assumptions and are in part a "residual" category for GHG emissions, to align the sum of source estimates across 1A1cii and 1B2 with the UKOOA 2005 dataset.

First, the installation-level reporting of direct process CO_2 emissions within the EEMS data from 1998 are dominated by a small number of installations: Tartan Alpha (offshore oil), SAGE-St Fergus gas terminal and Kinneil oil terminal. For all three installations we have a time series of production (Tartan A: crude oil) or throughput (SAGE St Fergus: natural gas; Kinneil: crude oil) back to 1990. Taking the IEF (emissions per unit production or throughout) across 1998-2000 as representative, direct process emissions have been estimated for these installations back to 1990 for Tartan and Kinneil, and to 1992 for SAGE-St Fergus (when the terminal was commissioned).

In the years 1992 and 1993, several offshore oil and gas fields started production via two new associated gas terminals: SAGE-St Fergus (in 1992) and CATS (in 1993). To reflect emissions from process upsets / commissioning from the start-up of these platforms and terminals, we have estimated one-off direct process emissions in these years which we note are uncertain but do not affect inventory base year estimates.

Across the time series, the direct process source is used as a residual to align to the UKOOA 2005 data totals, calculated by difference from the sum of other sources.

The allocation of residual emissions to align to the UKOOA 2005 totals leads to variable estimates across the time series, e.g. high CO_2 emissions from oil production in 1995 and 1996. For NMVOC and methane, residual emissions are calculated for the offshore and onshore components:

Direct process = UKOOA (excl. loading) - ∑ (gas oil, fuel gas, flaring, fugitives, venting, well testing)

The allocation to "oil" and "gas" from these derived residuals is based on an assumption derived from historic reporting of methane and NMVOC from all sources aggregated, which indicates that methane emissions are around ~63% gas sector and ~37% oil sector, whilst NMVOC emissions are around ~21% gas sector, ~79% oil sector. The direct process estimates per source are thus derived by applying these %s and are subject to high uncertainty, but overall the totals align to the industry totals.

A1.1.7 Fuel Gas Combustion

The CO_2 emission estimates from fuel gas use are reported within the UKOOA 2005 dataset for 1995 to 1997, aggregated across oil and gas. For 1990-1994 the fuel gas estimates are derived by difference from the UKOOA 2005 emission totals from production sources, for both offshore and onshore sites:

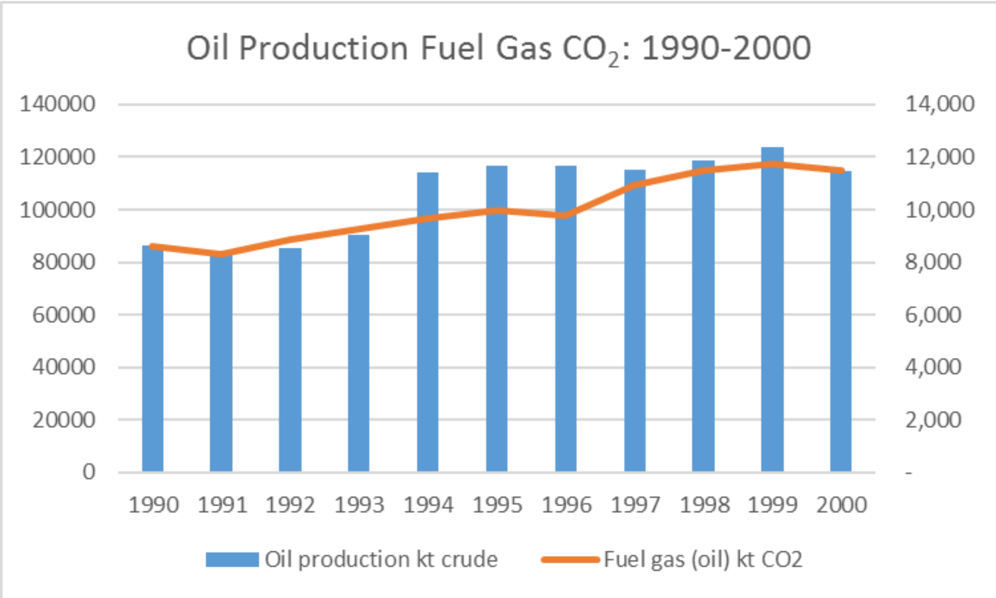
Fuel gas use = UKOOA (production) - ∑ (gas oil *not drilling*, gas flaring, venting, direct processes)

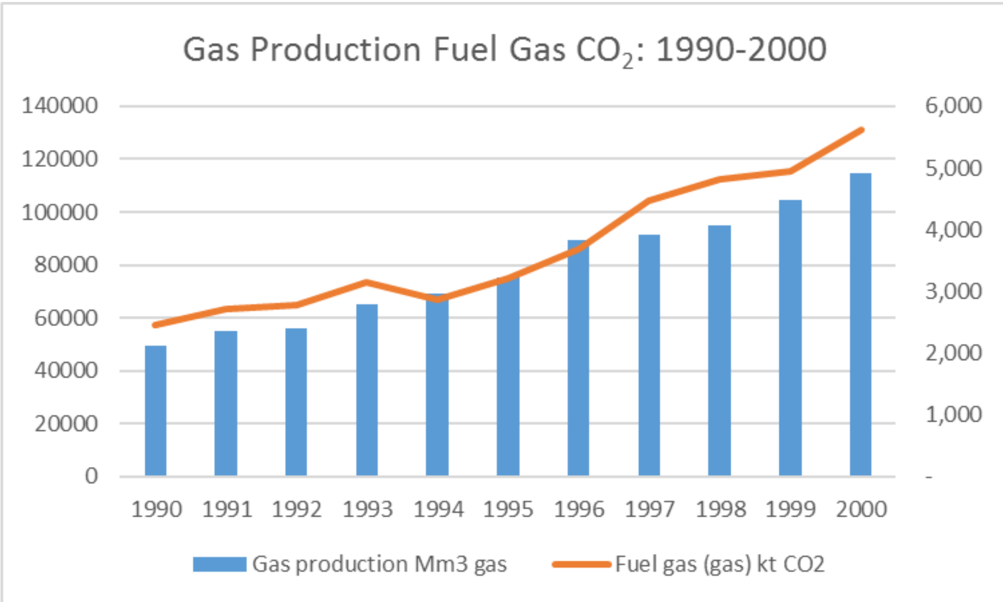
The total fuel gas emissions of CO_2 across oil and gas installations are then divided between "oil" and "gas" sectors by extrapolating back an estimate from the EEMS data (1998-) and using the production trends for crude oil and natural gas, and then aligning the derived interim estimates to the calculated "oil and gas" fuel gas total. This approach therefore seeks to reflect both the UKOOA 2005 CO_2 emissions total *and* the trends in oil and gas production.

The outputs from these calculations are illustrated in the graphs below. Analysis of the IEF of CO_2 per unit production gives an *indication* of the likely representativeness of these estimates. The 1990-1991 oil production IEF of ~100 tCO_2 per kt crude oil is comparable to the IEF towards the end of the 1990s, after which the IEF increases to a range 107-115 from 2001 onwards. During the 1990s, there is a short-term increase in IEF around 1992-1993 (IEF of ~103) which coincides with the period that many new platforms and a number of terminals were being brought into production, and then a few years where the IEF is lower (IEF of ~85 during 1994-1996), before reverting to ~95-100 during 1997-2000 and then rising to >107 from 2001 onwards.

Similarly for natural gas production, the IEF of ~49 tCO_2 per Mm^3 natural gas produced is comparable to the IEFs in the late 1990s before the emissions intensity increases from 2001 onwards to a range of 56-58. Similar trends are evident across the 1990s, with an IEF of ~49 across 1990-1993, a period of lower IEFs (IEFs ~41,42 in 1994-1996), then back to an IEF ~47-51 across 1997-2000, before increasing from 2001 onwards to >56.

The limited data resolution for 1990-1994 in particular leads to uncertainty over the allocation of emissions across 1A1cii and 1B2 sources, but these trends in IEF per unit production do indicate that the 1990 estimates for fuel gas combustion emissions are within the range of typical UKCS production.





Appendix 2: UK Upstream Fuel Gas Composition

The tables below present the fuel quality data that have been derived from PPRS, EUETS and EEMS data across the time series, including the CO_2 EF per TJ (net), NCV and density of fuel gas in four sub-sectors: offshore oil installations, offshore gas installations, oil terminals and gas terminals. The variable fuel gas composition across the different sub-sectors of the industry is based on the annual weighted averages of operator-reported data from each UK installation and reflects the different composition of the untreated fuel gases that are encountered at the different stages of upstream oil and gas production.

Table A.2.1: UK Upstream Fuel Gas Carbon Dioxide EF per Source, 1990-2020

Installation	Units	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Oil field	tCO_2/Tjnet	64.5	64.5	64.5	64.5	64.5	65.1	64.8	66.4	65.3	64.1
Gas field	tCO_2/Tjnet	59.0	59.0	59.0	59.0	59.0	59.5	59.3	60.7	60.0	58.2
Oil terminal	tCO_2/Tjnet	65.7	65.7	65.7	65.7	65.7	63.4	64.1	67.3	67.6	66.7
Gas terminal	tCO_2/Tjnet	58.6	58.6	58.6	58.6	58.6	56.5	57.1	60.0	59.7	58.5

Installation	Units	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Oil field	tCO_2/Tjnet	64.2	63.4	63.8	64.4	64.1	63.1	62.9	63.6	63.4	64.0
Gas field	tCO_2/Tjnet	58.6	58.3	57.4	58.1	58.1	59.0	58.1	58.1	58.0	57.2
Oil terminal	tCO_2/Tjnet	66.6	68.8	67.5	67.8	67.4	67.4	67.3	67.2	64.5	65.2
Gas terminal	tCO_2/Tjnet	57.6	57.4	57.3	57.6	56.8	57.0	56.5	58.8	57.6	57.5

Installation	Units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil field	tCO_2/Tjnet	63.2	65.4	64.0	62.9	65.3	64.5	63.9	63.7	64.1	63.0	63.2
Gas field	tCO_2/Tjnet	57.5	58.2	60.4	62.0	58.3	59.1	59.3	57.4	58.3	58.5	59.6
Oil terminal	tCO_2/Tjnet	67.2	70.2	68.7	66.5	68.3	67.9	66.9	67.3	67.3	66.6	66.3
Gas terminal	tCO_2/Tjnet	57.2	57.9	59.5	57.6	57.1	57.2	57.5	57.9	58.1	57.3	56.2

Table A.2.2: UK Upstream Fuel Gas Net Calorific Value per Source, 1990-2020

Installation	Units	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Oil field	GJ/tonne	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7
Gas field	GJ/tonne	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7
Oil terminal	GJ/tonne	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7
Gas terminal	GJ/tonne	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1

Installation	Units	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Oil field	GJ/tonne	41.7	42.1	41.5	41.3	41.5	41.7	41.7	41.5	41.7	41.5
Gas field	GJ/tonne	45.7	46.1	45.8	45.8	46.0	45.1	45.6	45.4	45.2	46.0
Oil terminal	GJ/tonne	41.7	42.1	41.5	41.3	41.5	41.7	41.7	41.5	41.7	41.5
Gas terminal	GJ/tonne	46.1	46.8	46.2	45.9	46.1	45.5	46.1	46.3	45.9	46.2

Installation	Units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil field	GJ/tonne	41.9	40.6	41.2	41.8	40.8	41.0	41.7	41.6	41.4	41.9	42.1
Gas field	GJ/tonne	46.2	45.6	44.2	45.6	45.8	45.3	45.2	46.4	45.8	45.5	45.2
Oil terminal	GJ/tonne	41.9	40.6	41.2	41.8	40.8	41.0	41.7	41.6	41.4	41.9	42.1
Gas terminal	GJ/tonne	46.4	45.9	44.7	46.0	46.2	46.3	46.5	46.4	45.7	46.0	46.2

Table A.2.3: UK Upstream Fuel Gas Density per Source, 1990-2020

Installation	Units	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Oil field	kg/sm^3	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Gas field	kg/sm^3	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Oil terminal	kg/sm^3	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Gas terminal	kg/sm^3	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76

Installation	Units	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Oil field	kg/sm^3	0.86	0.86	0.86	0.86	0.85	0.86	0.85	0.86	0.85	0.85
Gas field	kg/sm^3	0.76	0.75	0.76	0.76	0.75	0.77	0.76	0.75	0.76	0.75
Oil terminal	kg/sm^3	0.86	0.86	0.86	0.86	0.85	0.86	0.85	0.86	0.85	0.85
Gas terminal	kg/sm^3	0.76	0.75	0.76	0.76	0.75	0.77	0.76	0.75	0.76	0.75

Installation	Units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil field	kg/sm^3	0.84	0.86	0.85	0.85	0.86	0.85	0.85	0.84	0.85	0.85	0.85
Gas field	kg/sm^3	0.75	0.76	0.78	0.76	0.75	0.76	0.75	0.75	0.75	0.76	0.76
Oil terminal	kg/sm^3	0.84	0.86	0.85	0.85	0.86	0.85	0.85	0.84	0.85	0.85	0.85
Gas terminal	kg/sm^3	0.75	0.76	0.78	0.76	0.75	0.76	0.75	0.75	0.75	0.76	0.76

Appendix 3: Inventory Source Category Methods

1A1cii: Stationary combustion in upstream oil and gas production

Emission Sources

- Upstream oil production: fuel combustion
- Oil terminal: fuel combustion
- Upstream gas production: fuel combustion
- Gas terminal: fuel combustion

This source category comprises emissions from the combustion of all fuels (excluding fuel used for vessel propulsion) including own fuel gas and purchased fuels such as diesel, through all phases of exploration, development, production and decommissioning for all upstream oil and gas installations on the UKCS and onshore, i.e. including at offshore assets (platforms, FPSOs, MODUs), at onshore terminals and at onshore production sites.

The UK has been producing oil and gas, predominantly offshore in the North Sea, for decades, and there are several hundred oil and gas platforms that have been operating across the time series. As they have high power demands to run the exploration and production operations, most platforms include large gas turbines that are run off a proportion of the fuel gas produced on-site, with smaller supplementary engines, heaters and other units that may burn fuel gas and/or diesel; occasionally there are reports of use of fuel oil.

We have developed methods to derive separate estimates for:

(i) onshore terminals; and

(ii) offshore platforms, FPSOs and MODUs.

This separation reflects that the source datasets differ between onshore and offshore facilities due to different regulatory systems in the UK for onshore and offshore facilities. Each installation is allocated to either *upstream oil* or *upstream gas* production according to the OGA definitions of the fields/terminals producing/treating the oil or gas.

Pollutants Reported

- Carbon dioxide, methane, nitrous oxide, oxides of nitrogen, carbon monoxide, sulphur dioxide, NMVOCs, particulate matter

Method Summary

From 1998, the method is to aggregate installation-level activity and emission estimates, i.e. Tier 3. Emission estimates for 1990-1997 are based on lower resolution source data but are still a Tier 2 method, using industry-wide estimates that are derived from operator surveys through the 1990s.

As noted in section 3, across all years of the time series, the fuel use estimates presented in DUKES are incomplete and hence operator data are used to deliver a complete inventory estimate. The key activity and emissions datasets used across the time series are:

- **1990-1997**: Inventory agency estimate derived from the UKOOA 2005 aggregated estimates of GHG emissions presented for all offshore and onshore production emissions. Activity data estimated from the emissions data, assuming that the sector-wide carbon emission factors from 1998 were representative for earlier years for all fuels (diesel, fuel gas);
- **1998-2003**: EEMS operator-reported fuel combustion emission and activity estimates per installation, from all offshore mobile and fixed installations and all onshore terminals, supplemented by analysis of the EUETS NAP data (see section 3.1.3.3);
- **2004**: EEMS operator-reported fuel combustion emission and activity estimates per installation, offshore and onshore;
- **2005-2010**: EUETS (CO_2) and EEMS (all GHGs) operator-reported fuel combustion emission and activity estimates per fixed installation, offshore and onshore. EEMS data for all mobile offshore units;

- **2010-2020**: EUETS (CO_2) and EEMS operator-reported fuel combustion emission and activity estimates per fixed offshore installation; EEMS data for all mobile offshore units; EUETS (CO_2) operator-reported fuel combustion emission and activity estimates per onshore terminal.

Note that where the fuel combustion emissions are reported for an installation via both EEMS and EUETS, the EUETS data are regarded as better quality as they are subject to Third Party verification, as part of the requirements of the trading scheme. However, the scope of reporting under EUETS is not as complete as EEMS; mobile offshore units (e.g. drilling units) do not fall within EUETS scope and a number of smaller offshore platforms also report only to EEMS as they do not meet the EUETS threshold for combustion unit capacity.

Onshore oil and gas terminal operators reported fuel combustion estimates via EEMS from 1998 to 2010. Since 2010, terminal operators are not mandated to report to EEMS and most have ceased to do so, as they are already required to report installation-wide annual emission estimates under the IED/PPC reporting systems to onshore regulators. The EUETS data provide complete estimates for fuel use at all onshore oil and gas terminals from 2005 onwards.

The EUETS CO_2 data for high emitting source streams are based on source-stream-specific fuel analysis (i.e. compositional analysis to derive carbon content, NCV) and the assumption that the fuel is 100% oxidised; for example on most oil and gas platforms the estimates of emissions from fuel gas use within turbines, engines, heaters and other units are based on sampling and analysis of the carbon content of the fuel gas. As such the EUETS data are considered highly accurate; they provide a rich and detailed dataset that exhibits a range of variability in the fuel gas across installations.

The activity data reported in the UK GHGI for gas oil use are in net energy units (Terajoules net, gas oil) and are based on DUKES (BEIS, 2021) data for 2005-latest year, and the sum of operator-reported data for earlier years (EEMS, UKOOA). The fuel gas activity data are derived from operator-reporting to EEMS, EUETS and PPRS; the operator-reporting of emissions to EEMS and EUETS are accompanied by activity data in mass units (tonnes). These data are converted to energy units for the purposes of CRF reporting, and hence comparability against other reporting parties. To do this, the inventory agency uses the time series of gas density and calorific values from the PPRS dataset; these conversions are conducted at the source category level to reflect that the different sections of the upstream oil and gas production sector utilise fuel gas which varies in composition per source category. Across all installations, from dry gas production sites and terminals, through associated gas use and to the fuel gas derived at oil terminals, the fuel gas will comprise predominantly of methane but with varying quantities of other higher-chain hydrocarbons. The PPRS data reporting is used to inform the one data point presented in DUKES for the calorific value of all “produced natural gas”, but the ability to use the CVs for different sub-sections of the industry from PPRS improves the accuracy of the derived energy data that are reported in the UK inventory. The fuel quality data from PPRS for 2020 are as follows:

- Offshore gas production installations: GCV of 38.0 MJ/m^3; density of 0.76 kg/m^3
- Offshore oil production installations: GCV of 39.6 MJ/m^3; density of 0.85 kg/m^3
- Onshore gas terminals: GCV of 38.8 MJ/m^3; density of 0.76 kg/m^3
- Onshore oil terminals: GCV of GCV of 39.6 MJ/m^3; density of 0.85 kg/m^3

The time series of fuel gas densities, NCVs and CO_2 EFs are presented in Appendix 2.

The fuel combustion in the sector is a minor source of emissions of methane and nitrous oxide. Operators report estimates to EEMS, predominantly applying defaults from operator guidance for gas combustion or gas oil combustion. The inventory estimates are based on the operator-reported estimates from EEMS for 1998 onwards; the estimates in 1990-1997 are based on EFs rolled back from EEMS 1998- data.

Method Assumptions and Observations

- Emissions from OTs and CDs are ‘Not Estimated’ for this source. There is no oil or gas production in any of the OTs and CDs, and only limited well drilling and initial exploration activity (i.e. well testing) in waters around the Falklands Islands in 1998, in 2010, 2012 and 2015. There are no fuel use estimates specific to those exploration activities; it is assumed that any fuel use is accounted for within the Falklands energy balance data.
- Emission factors for nitrous oxide for 1A1cii are higher than the IPCC default range, as noted in previous UNFCCC reviews. The factors applied in the UK inventory are based on operator-reported data from predominantly offshore oil & gas facilities using fuel gas, which is mainly

natural gas or associated gas from oil production. These operator data are considered to be more representative of combustion emissions at UK installations than the IPCC defaults.

- **Completeness**: In the UK there are no known omissions, the scope of reporting is complete. We note that the scope of UK energy statistics is incomplete for the fuel gas combustion source (all years) and for gas oil combustion (1990 to 2004). The inventory agency draws upon a range of data sources to ensure completeness (and accuracy), using EUETS for most high emitting sites supplemented by EEMS data for mobile and smaller (sub-EUETS threshold) installations.
- **Accuracy**: The method is Tier 2/3 across the time series, using the best available data from operator reporting throughout. In the UK there has been a high level of fuel gas compositional analysis to inform EUETS allocations (from the National Allocation Plans from 1998 onwards) and subsequently in all operator submissions to EUETS; the emissions from fuel gas use within EUETS is by far the largest share of total GHGs from the sector as a whole and this gives confidence that this key category is highly accurate in the UK GHGI. The 1990-1997 data are based on the UKOOA 2005 report to UK Government, which took account of the work in the National Allocation Plans to derive better installation-level carbon emission factors but are based on more limited industry surveys from the early 1990s and hence are associated with higher uncertainty than the later data.
- **Time Series Consistency:** The method is compromised by the lack of fully detailed data for the 1990-1997 period, where only aggregate emissions data across all sources in 1A1cii and 1B2 are available from the industry submissions to UK Government; this coincides with a period where it is known that the UK energy statistics were not gathering complete data for all oil and gas terminals. Therefore, the study team has selected industry-reported data and applied IPCC good practice gap-filling methods to ensure that the time series consistency is as good as practicable given the available data.
- Extensive consultation with the BEIS energy statistics team has enabled the study team to clarify areas of the DUKES data that are incomplete for the upstream oil and gas sector, and to identify the best data to address these gaps. Wherever possible the Inventory Agency has filled data gaps with operator-reported estimates; this is possible as there are a defined number of installations that are active in this sector and their activities (and emissions) are generally well documented with gaps in data being relatively minor.
- In order to validate the data estimates, the inventory agency has derived estimates of *fuel gas use per unit production* for oil production and gas production back to 1990. There is a general trend to higher fuel gas use per unit production across the time series, reflecting the higher energy demands to extract materials from increasingly depleted oil and gas fields, although this trend is not always continuous year to year as some fields cease production and others come on stream. The total fuel gas use is 1.54 TJ net per kt crude oil production and 0.841 TJ net per Mm^3 gas production in 1990 whereas by the end of the 1990s the figures are 1.56 and 0.842 in 2000, with increases evident to over 1.60 and around 1.00 by 2002. These figures can only be regarded as indicative given the variability in emissions intensity production evident across the UKCS and limited data resolution in the early 1990s, but they do indicate that the derived estimates of fuel use for 1990 are lower than data for later years and of a similar order of magnitude, which is as expected.
- We further note that whilst the emission estimates specific to fuel combustion in 1990 are quite uncertain, that the total emissions across all upstream oil and gas sources (∑1A1cii, 1B2) in the UK GHGI are aligned with the industry submissions to UK Government (UKOOA, 2005) and hence are regarded as the most accurate data available.

QA/QC

Specific QA/QC and validation exercises relevant to these source categories include:

- Comparison of EEMS, EU ETS and DUKES activity data for fuel (natural) gas combustion. The data underpinning DUKES estimates are gathered via the PPRS which presents facility-level activity data that are compared against EEMS and EUETS to identify and reconcile any data inconsistencies;
- Comparisons between EEMS and EUETS, to review installation-specific activity data and emissions data (and hence implied IEFs for each site and source) to identify any possible gaps in the EEMS dataset, using EUETS as a de-minimis. The EUETS data typically covers a smaller scope of activities on a given installation, but the data quality (AD, EFs) are third-party verified,

whereas the EEMS dataset should be a comprehensive record of all combustion activities on upstream oil and gas installations but the data are subject to less rigorous QC;

- Comparisons of total emissions data reported by each onshore oil and gas installation via the Pollution Inventory/Scottish Pollutant Release Inventory/Welsh Emissions Inventory to assess time-series consistency and completeness of reporting, comparing CO_2 emissions data against those presented in EUETS (and EEMS if the terminal reports to EEMS also).
- The energy AD used in these estimates that come from DUKES are subject to the UK Statistics Authority's *Code of Practice for Statistics**Error! Bookmark not defined.***. EU ETS data is subject to its own QA processes.

Scope for future research and improvement

Improvements could be achieved if it becomes possible to obtain more resolved data on fuel gas quality per installation, to improve the assumptions for NCVs and density of fuel gas in particular. The current method applies the best available data from PPRS but this is a separate data reporting mechanism to the EEMS and EUETS datasets. If it was possible to obtain a more comprehensive NCV dataset directly from e.g. the EUETS data reporting, this would improve data quality. However, we note that this would not alter the emissions totals, but it would slightly improve the accuracy of the AD and EFs.

We note that this project has fully explored all available data for the early part of the time series and we see no practicable opportunity to improve the estimates for the 1990s.

Uncertainties

Uncertainties for both activity and emission factors are based on expert judgement, informed by the understanding of the available data, the level of uncertainty that is accepted within the reporting systems (e.g. EUETS) and the likelihood of error compensation across the UK installations.

In the latest year of the time series, the AD uncertainty for gas oil and fuel oil are estimated to be ±5% and the CO_2 EF uncertainty to be ±2% whilst the AD and CO_2 EF uncertainty for fuel gas are both estimated to be ±2%. In the Base Year the CO_2 EF uncertainties are all estimated to be ±2% whilst the AD uncertainty is assumed to be ±20% for all fuels due to the limited information from the industry surveys. Due to the limited measurement data and predominant use of UK industry-wide defaults for the estimation and reporting of methane and nitrous oxide, the uncertainties for the methane EFs (all years) is estimated at ±50% whilst for nitrous oxide the EF uncertainty is ±100% in all years.

Uncertainties in fuel use statistics are typically low. However, we note (as outlined above) that there are known data gaps in national statistics across the time-series and less detailed emissions data available for the 1990-1997 period, and hence uncertainties for the estimates in 1990 are higher than for recent years where much more detailed and complete operator-reporting of activity and emissions are evident. The carbon emission factors are based on UK specific data. Since there is a direct link between the carbon emitted and the carbon content of the fuel, it is possible to estimate CO_2 emissions accurately. Non-CO_2 emissions are dependent on a greater number of parameters and are largely based on defaults. As such, the uncertainties are higher, but since the emissions are smaller, this does not have a significant impact on the overall uncertainty of total GHG emissions.

1B2a1: Oil Exploration; 1B2b1: Gas Exploration

Emission Sources

- Offshore oil well testing
- Onshore conventional oil well exploration
- Offshore gas well testing
- [Onshore unconventional gas well exploration]

The initial phases of exploration for oil and gas resources lead to fugitive emissions of GHGs; these sources occur prior to production, including prospecting, exploratory well drilling, well testing, completion, field and well development.

In the UK the main emission source is in the well testing phase offshore, where wells are drilled and tested to assess the available resources, the field depth, pressure and so on to assess the feasibility of extracting the oil or gas. During the well tests, the produced fluids are separated, water and oil collected, and the gases are flared. These activities may be conducted directly from existing platforms, or from Mobile Drilling Units (MODUs), and all UK operators report their well testing emission estimates to EEMS. The 2019 Refinement (Energy Volume, Fugitives Chapter page 4.48) notes that there are no EFs for offshore well drilling / exploration activities and that these emissions "*are thought to be negligible*"; we interpret this to mean that the fugitive leaks from the initial phases of well drilling may be assumed to be negligible and/or dissolve in the water column.

The well commissioning phase may also include flaring and venting, however the UK reporting systems do not define at which phase of a project any flaring or venting is conducted. Any reporting of flaring (EEMS, EUETS, PPRS) and venting (EEMS, PPRS) does specify whether well commissioning was the reason, and hence this component of exploration emissions will be reported under 1B2c.

There are a small number of onshore oil wells in the UK; there are limited emissions data reported by operators within the IED/PPC regulatory inventories as often the level of annual emissions of GHGs from these well sites fall below the reporting threshold. The OGA Well Operations Notification System (WONS) includes reports on annual well drilling activity, and these data can be used to derive GHG emission estimates from the exploration phase, using the method set out in the 2019 Refinement.

A separate research report has estimated the GHG emissions from unconventional gas well drilling; there has been no subsequent gas production but very minor emissions of methane are reported in 1B2b1 from the exploratory drilling conducted in the UK.

Pollutants Reported

- Carbon dioxide, methane, nitrous oxide, oxides of nitrogen, carbon monoxide, sulphur dioxide, NMVOCs, particulate matter

Method Summary

Onshore oil well exploration

- IPCC 2019 Refinement Tier 1 method: *Emission = AD x Default EF*
- Activity data: Number of conventional oil wells drilled per year. These data on wells drilled onshore area available across the time series:
    - 1990 to 1993: DTI Brown Book 2001, Appendix 4;
    - 1994 to 1999 data from DTI Brown Book 2004; and
    - 2000 onwards from the OGA Well Operations Notification System (WONS)[9] annual reports on drilling activity
- Emission Factor(s): Default (D) EFs from IPCC. EF units are mass of pollutant emitted per conventional oil well drilled: *IPCC Refinement 2019 Table 4.2.4: Tier 1 EFs for Oil Exploration*.

Offshore Oil Well Testing and Offshore Gas Well testing

- UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 onwards, the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of well testing

[9] https://www.ogauthority.co.uk/data-centre/data-downloads-and-publications/well-data/

activity for 1990-1994 through extrapolation back from 1995 using well drilling statistics. The EEMS dataset specifies if the well test was for oil or gas.

- The EEMS data (BEIS, 2021a) present the AD in tonnes (of gases flared) and the emissions of individual gases including: CO_2, CH_4, N_2O, NO_X, NMVOC, CO, SO_2.
- UK GHGI emissions = ∑ operator emissions data per pollutant
- Emission factors for each pollutant are derived: EF = ∑ operator emissions / ∑ activity data

[The methods for unconventional onshore gas exploration are not reported here, as they were the subject of separate research, reported to BEIS in March 2021. They are noted here for completeness.]

Method Assumptions and Observations

- There is no unconventional oil exploration and production in the UK. The method applied to the onshore conventional oil sector is taken from the 2019 Refinement and addresses a minor gap in UK regulatory reporting, as the well operators onshore seldom exceed the reporting threshold for IED/PPC reporting during the exploration phase. There is a small risk of a minor double-count if for some of the larger well sites the operators have included some well drilling/exploration emission estimates in their annual submissions to regulators (which are used in the method outlined below for onshore oil production emissions).
- Well testing emission estimates on an installation-specific basis are included within the EEMS datasets from 1998 onwards at all sites of offshore exploration activities within UK's territorial waters, including data on both activity and emission factors of excess gas that is flared or released to the atmosphere. Emissions released at the seabed are not included in estimates; it is assumed that any such releases will dissolve in the water column without subsequent release to the atmosphere. Following a change of reporting systems used by the regulators in 2017, the inventory team noted a step-change (down) in reported oil and gas well testing emissions; it was assumed that the change in reporting system had led to the step-change and hence higher well testing estimates were reported within the 2021 submission. This research project has enabled further consultation with the BEIS OPRED team; it has been confirmed that the EEMS data are complete and hence in the 2022 submission we have corrected the previous over-report for estimates from 2017 onwards.
- In the EEMS dataset there is no separate reporting of emissions from well drilling, completions and testing; it is assumed that any releases of gases at the seabed during drilling or completions will dissolve in the water column, whereas any fugitive releases on the rigs are reported within EEMS. The Inventory Agency has consulted with the Co-ordinating Lead Author of the 2019 IPCC Refinement, Energy Fugitives, and national expert in oil and gas emissions inventory reporting, and confirmed that there are no default data to estimate well drilling and completion emissions in offshore production; therefore, the UK inventory estimates are considered to be accurate as they based on the best available operator-reported data, complete and consistent with the IPCC Guidelines.
- **Completeness**: In the UK there are no known omissions. The addition of estimates for onshore oil well exploration address a minor gap in previous UK submissions. There is a risk that operators offshore may not report their oil or gas well testing activity to EEMS; mobile drilling units by their nature are deployed across different production regions of the world and hence they may appear and disappear from the EEMS reporting year to year, which makes it difficult to evaluate the completeness of EEMS over the time series. However, we have no evidence that under-reporting occurs.
- **Accuracy**: The onshore oil production method is Tier 1, applying default EFs from the 2019 IPCC Refinement which are associated with high uncertainty (cited as -12.5% to +800%). It is a minor source in the UK context and hence does not impact significantly on overall inventory uncertainty. The oil and gas well testing EFs that operators typically apply in their EEMS returns are taken from operator guidance that was last updated for this source in 2008, based on UK industry research. There is some uncertainty that the carbon emission factors from that research are representative of the carbon content of the eluted gases from all oil and gas wells across the UKCS, given the range in crude oil, associated gas and dry gas compositional analysis that is noted from different installations reporting from different production areas on the UKCS. However, the data are UK-specific EFs, derived from analysis of fluids from UKCS production historically.

- **Time Series Consistency:** The underlying data (well drilling numbers) for the onshore oil exploration source is time series consistent. The offshore oil and gas well testing reporting by operators has been to a consistent reporting mechanism since ~1995. The 1990-1994 data are extrapolated using IPCC good practice methods, i.e. proxy data on well drilling to deliver a time series consistent dataset as far as is practicable. This research has significantly improved this time series, noting that in the 2021 submission there was a large step-down in well testing emissions between 1994 and 1995 that is not consistent with the trend in well drilling statistics.

Scope for future research and improvement

- To conduct drilling activities, offshore operators are required to report to OGA under the Energy Act / Petroleum Act, request drilling consents, submit data to the OGA WONS portal and also apply for Consent to Locate to a given oil or gas field. Through analysis of information on Consent to Locate and PETS EIA directions, it may be feasible to check on the completeness of reporting to EEMS by MODUs, i.e. to ensure that all operating MODUs have reported to EEMS, and to gap-fill where needed. However, operators are only required to obtain an OGA flaring consent and an EIA Direction for *extended* well tests (i.e. well tests scheduled to run for longer than 96 hours) and not for standard well tests and hence there may not be a complete list from OGA to use to validate the completeness of EEMS.
- The EFs applied in the EEMS system for oil and gas well testing have not been reviewed by the industry for >10 years; they may or may not be accurate and representative for the well testing practices and drilling activities in new production areas of the UKCS in recent years. To improve accuracy and ensure that the UK estimates are based on current EFs, new research and/or monitoring would need to be conducted.

Uncertainties

As noted above, the EFs applied for onshore oil exploration are associated with high uncertainty; the 2019 Refinement cites a range of -12.5% to +800% of the stated EF.

The oil and gas well testing EFs, whilst based on research from ~15 years ago, are based on UK industry research. The GHG emissions are dominated by CO_2, which is closely linked to the carbon content of the flared gases. Based on many years of EEMS and EUETS reporting of combustion of gas from the UKCS, the gas content can vary considerably, but the overall average CEF is quite stable. The uncertainty of the well testing EFs is therefore considered to be quite low, estimated at ±10%.

1B2a2: Oil Production & Upgrading

Emission Sources

- Offshore oil production: Direct Processes
- Offshore oil production: Other fugitives
- Oil terminals: Direct processes
- Oil terminals: Other fugitives
- Onshore conventional oil production

These emission sources cover the release of fugitive gases from the processing units on upstream facilities, where the produced fluids are extracted, treated (e.g. to remove acid gases), separated to allow the onwards delivery or use of liquids (crude oil, condensate) and gases. The emissions arise from leaks on the platform / FPSO / terminal infrastructure, from pipes, flanges, connectors, compressors, dehydrators, separators and other units. In the UK the reporting of fugitive releases by operators tends to fall into two categories: (i) several installations report "direct process" emissions that are usually due to the treatment of acid gases which are processed or flared / incinerated leading (usually) to additional releases of CO_2 and other gases such as SO_2 (e.g. Tartan Alpha, Piper Bravo, Kinneil Terminal); and (ii) all offshore facilities and oil terminals report operational fugitive releases from leaking infrastructure, which are usually estimated based on an inventory of all of the equipment on the facility (i.e. counts of flanges, pipelines, connectors, compressors and so on) and UK industry EFs (from EEMS) on leaks per year per piece of equipment.

Onshore oil production sites also exhibit similar fugitive releases but for most sites the level of annual emissions is below the reporting threshold for IED/PPD regulatory inventories, and hence an alternative method is needed to address that reporting gap.

Pollutants Reported

- Carbon dioxide, methane, nitrous oxide, oxides of nitrogen, carbon monoxide, sulphur dioxide, NMVOCs

Method Summary

<u>Onshore oil production</u>

- For CH_4 and NMVOC, a hybrid method that uses UK operator data where they are reported and gap-filling for sites that do not report. For CO_2 and N_2O there is no operator reporting of any emissions data and hence an IPCC Tier 1 method is applied: *Emission = AD x Default EF*
- <u>Activity data</u>: Over the time series there are 47 oil well sites active, and for each we have an annual volume of crude oil produced from industry reporting to OGA and its predecessors:
    - 1990 to 2003: DTI Brown Book 2004;
    - 2004 onwards from the PPRS system of monthly reporting.
- <u>Emission Factor(s)</u>: For the larger sites, such as Wytch Farm, Scampton North, Singleton and Cold Hanworth, there are operator reported estimates of CH_4 and NMVOC available from the PI, and these are used directly. For the remaining sites, CH_4 and NMVOC estimates are gap-filled using their reported production data and the weighted-average EF from the reporting sites, i.e. derived by dividing the sum of reported emissions by the sum of production at sites that reported emissions. This is effectively a Tier 2 method, applying UK-specific EFs.

  For CO_2 and N_2O, for all sites the method uses the IPCC default EFs from the 2019 Refinement for sites with high emitting technologies and practices; this EF is selected on the basis that whilst there is a regulatory system in place in the UK, these are small producing sites where implementing mitigation techniques are unlikely to be economic to apply. We further note that these are very small producers and the impact on the UK GHGI totals of the choice of default EF is almost negligible; if they were significant emitters they would report to the PI/SPRI.

<u>Offshore Oil Direct Processes and Fugitives</u>

- UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 onwards, the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of direct process and fugitive emissions for 1990-1994 through extrapolation back from 1995 using crude oil production statistics. A small number of installations account for the direct process sources and in those cases the time series of their estimated annual oil production or throughput was used to estimate the process emissions.

- The EEMS data (BEIS, 2021a) present the AD in tonnes (of all gases released) and the emissions of individual gases including: CO_2, CH_4, N_2O, NO_X, NMVOC, CO, SO_2. Emissions of fugitives (rather than direct process emissions) are dominated by CH_4 and NMVOC, with some reporting of CO_2 also evident.
- UK GHGI emissions = ∑ operator emissions data per pollutant

Oil Terminal Direct Processes and Fugitives

- The method is as described for offshore units above, i.e. a UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 to 2010 (when most terminals ceased reporting to EEMS), the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of direct process and fugitive emissions for 1990-1994 through extrapolation back from 1995 using crude oil production statistics.
- For onshore terminals, the annual submissions to the PI/SPRI are verified by the regulatory agency, whereas EEMS data are not. Therefore, to align the inventory totals to these verified data, across all years where PI/SPRI > EEMS totals per pollutant, the inventory method allocates the residual emissions to this source category. Further, for 2011 onwards, where the *only* data reported are from the PI/SPRI, the inventory method across all sources aligns to the total reported to the PI/SPRI and estimates of direct process and fugitive emissions are modelled based on previously reported source estimates and the trend in annual emissions per pollutant, per installations.
- This source category is also used for residual emissions once all other source estimates have been made, for the 1990-1997 dataset. The UKOOA 2005 dataset provides source-specific estimates back to 1995, and the 1990-1994 estimates per source are modelled (see other method descriptions across 1A1cii and 1B2) using proxy data. CO_2 and N_2O arise primarily from fuel combustion and gas flaring. For methane and NMVOC, the allocation of emissions across a range of sources is especially uncertain for 1990-1994; it is unknown whether the reported emissions from industry were from process sources, fugitive leaks, material storage or from venting. Our approach is to estimate specific allocations of methane and NMVOC from direct processes, storage and venting, and allocate the rest to "other fugitives" and report them here.

Method Assumptions and Observations

- For process and fugitive sources where the EEMS emissions data are provided without any underlying AD and EF information, the UK inventory method is to aggregate those operator-reported data and conduct QC against other reported data (such as production data to identify when installations start and cease production) to ensure completeness.
- Fugitive emissions reported within EEMS are typically aggregated for each installation, without any further information on the specific source/unit. Similarly, emissions reported under IED/PPC to the PI/SPRI by terminal operators are aggregated across all sources on the defined installation. These national circumstances of data availability mean that the UK inventory data cannot be disaggregated to separate fugitive emissions from oil and gas processing units, from other fugitives, such as acid gas removal units (except where these are specifically identified as "direct process" sources), other connectors, flanges and pipeline infrastructure. The transparency of the underlying operator calculations is limited, and QC of the data focuses on time series consistency per installation.
- The time series of estimates is heavily influenced by reported data from a relatively small number of installations. As noted in the method overview, a number of sites have additional processing requirements due to, for example, the incidence of acid gases from the upstream oil fields. The UK GHGI trend is therefore influenced significantly by the production trends at those installations. As with all sources, there is greater uncertainty regarding the estimates at the start of the time series due to the limited data resolution in the UKOOA 2005 dataset, but IPCC good practice gap-filling techniques have been used to deliver a plausible time series per source.
- The CH_4 and NMVOC method for onshore oil well sites uses operator reported emissions for larger sites and then applies an assumption that the smaller non-reporting sites operate at a similar EF of emissions per unit production.

Scope for future research and improvement

- The method is reliant on the operator reporting to EEMS; in order to test against an IPCC default or other methodology (such as the fugitives methodology developed through research in Norway in recent years) would require significant investment to gathering more detailed data about the infrastructure on UK platforms, FPSOs and terminals. To develop a more comprehensive Tier 2 method would require UK regulators and industry to generate more detailed activity and emissions data through either annual submissions or periodic research.
- For terminals there is an opportunity to update the requirements within IED/PPC permits (e.g. in response to the latest BREF notes) to include additional operator reporting (annual or periodic) of source-specific estimates, to supplement the installation-wide emission estimates that are currently reported to the PI/SPRI. Additional data (including AD or contextual info on e.g. production) would provide transparency of the source-specific emissions, and remove the need for assumptions to be applied to estimate the allocation of total emissions across fugitives, venting, storage, combustion etc, improving accuracy and opportunities to conduct QC.

Uncertainties

- The EFs applied for onshore oil production are associated with high uncertainty; the 2019 Refinement indicates that CO_2 EF uncertainties are around ±30%, whilst the range for N_2O is -10% to +1000%.
- In the latest year and considering the relative contributions to emission estimates per pollutant and the underlying methods and EFs, our expert judgement is that the activity data uncertainty is around 5 to 10% and the EF uncertainties are around 30% for CO_2, 50% for CH_4 and 200% for N_2O. Some of the EF uncertainties are *higher* than previously considered in the 2021 submission; the research has not reduced the inventory uncertainty, although the data and method selection across the time series has minimised it, but we better *understand* the sources of uncertainty in the data and have revised the uncertainty parameters accordingly.

1B2a3: Oil Transport

Emission Sources

- Offshore oil loading
- Onshore oil loading
- Oil transport fugitives: pipeline (onshore)
- Oil transport fugitives: road and rail tankers

The transfer of oil from the upstream production installations to refineries and terminals leads to fugitive emissions of hydrocarbons due to venting and leakage from pipelines, marine tankers, rail and road tankers. In the UK, these emissions arise from:

(i) crude oil production and offshore loading from OTLs to shuttle tankers;
(ii) off-loading of crude oil from oil tankers to onshore terminals and refineries;
(iii) transfer of crude oil via pipelines from offshore platforms and FPSOs to onshore terminals;
(iv) onshore loading of crude oil to road or rail tankers at onshore well sites; and
(v) the subsequent oil unloading from road/rail tankers at onshore terminals.

Under the IED/PPC reporting scope for onshore terminals, the items (ii), (v) and the onshore pipeline component of (iii) are already accounted for, and further any fugitives from the offshore end of oil pipelines under (iii) are covered within the scope of operator reporting of fugitive releases to EEMS.

The 2019 Refinement presents new guidance and EFs (Table 4.2.4B) for pipeline transfers, and two sets of EFs for shuttle tanker ships to account for those operating abatement equipment ("VRU") and those that do not. These EFs are based on Norwegian research; information from the industry indicates that North Sea shuttle tankers operate across the UK and Norwegian Continental Shelf production area, and hence the 2019 IPCC Refinement EFs are regarded as representative of UK circumstances.

Loading emissions are influenced by many contributing factors including: the composition and temperature of the crude oil; the design and operation of the loading system; whether the vessel cargo tanks contain HC gases, inert gases or a mixture of these when the loading operation starts; and (for offshore loading) the wave heights and weather conditions during loading.

Pollutants Reported

- Methane, NMVOC and carbon dioxide

Method Summary

<u>Offshore Oil Loading</u>

- IPCC 2019 Refinement Tier 1 method: *Emission = AD x Default EF*
- <u>Activity data</u>: Over the time series there are 33 offshore installations that service the crude oil from oil fields that are OTLs, and for each we can derive an annual volume of crude oil produced across the time series, from industry reports to OGA and DTI, and the field-installation mapping:
  - 1990 to 2003: DTI Brown Book. [1990-1994, BB 1995 Annex 6; 1995-1997, BB 2000 Appendix 9; 1998-2000, BB 2001 Appendix 9; 2001 to 2003, BB 2004 Appendix 9.]
  - 2004 onwards from the PPRS system of monthly reporting per field, aggregated across all fields and months per installation.
- <u>Emission Factor(s)</u>: Default (D) EFs from IPCC. EF units are mass of pollutant emitted per 1000m^3 of oil produced: *IPCC Refinement 2019 Table 4.2.4B: Tier 1 EFs for Oil Transport*.
  - Shuttle tankers (no VRU): 0.065 t CH_4 /1000 m^3; 1.10 t NMVOC /1000 m^3

<u>Onshore Oil Loading</u>

- UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 to 2010 (when most terminals ceased reporting to EEMS), the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of onshore oil loading emissions for 1990-1994 through extrapolation back from 1995 using crude oil production statistics.
- The EEMS data (BEIS, 2021a) present the AD in tonnes of crude oil received from shuttle tankers at the terminal and the emissions of individual gases in tonnes, including: CH_4 and NMVOC.
- UK GHGI emissions = $\sum$ operator emissions per pollutant

- For 2011 onwards, where installations continued to report to EEMS (e.g. Nigg, Flotta reported to 2014) then these data are used. For other sites where the only data reported are from the Pollution Inventory (PI) or the Scottish Pollutant Release Inventory (SPRI), there is no source resolution of reported emissions, only a total per pollutant per year per site is reported. The inventory method across all sources aligns to the total reported to the PI/SPRI and an estimate of oil loading emissions has been modelled based on previously reported source estimates and site total. These estimates have been augmented through operator consultation, for example with the ConocoPhillips Seal Sands oil terminal environmental manager (ConocoPhillips, 2019. Personal Communication) who provided a breakdown of total reported NMVOC emissions.

<u>Oil transport fugitives: pipeline (onshore)</u>

- IPCC 2019 Refinement Tier 1 method: *Emission = AD x Default EF*
- <u>Activity data</u>: There is only one onshore production site where the level of annual production warrants the investment in a pipeline to a nearby terminal, and that is the 91 km 16" diameter pipeline from Wytch Farm to Hamble terminal, via Fawley refinery. The annual production of crude oil at Wytch Farm is published via the historic DTI Brown Book, and now via the PPRS:
    - 1990 to 2003: DTI Brown Book. [1990-1992, BB 1995 Annex 6; 1993-1994, BB 2008 Annex 6; 1995-1997, BB 2000 Appendix 9; 1998-2000, BB 2001 Appendix 9; 2001 to 2003, BB 2004 Appendix 9.]
    - 2004 onwards from the PPRS, through annual aggregation of monthly reported data.
- <u>Emission Factor(s)</u>: Default (D) EFs from IPCC. EF units are mass of pollutant emitted per 1000m^3 of oil transported by pipeline: *IPCC Refinement 2019 Table 4.2.4B: Tier 1 EFs for Oil Transport*.
    - 0.0054 t CH_4 /1000 m^3; 0.00049 t CO_2 /1000 m^3; 0.054 t NMVOC /1000 m^3

<u>Oil transport fugitives: road and rail tankers (onshore)</u>

- IPCC 2019 Refinement Tier 1 method: *Emission = AD x Default EF*
- <u>Activity data</u>: The annual production of crude oil at all onshore well-sites is published via the historic DTI Brown Book, and now via the PPRS. The AD here is the total for all onshore fields less that for Wytch Farm, where the product is transferred via pipeline (*see above*):
    - 1990 to 2003: DTI Brown Book. [1990-1992, BB 1995 Annex 6; 1993-1994, BB 2008 Annex 6; 1995-1997, BB 2000 Appendix 9; 1998-2000, BB 2001 Appendix 9; 2001 to 2003, BB 2004 Appendix 9.]
    - 2004 onwards from the PPRS, through annual aggregation of monthly reported data.
- <u>Emission Factor(s)</u>: Default (D) EFs from IPCC. EF units are mass of pollutant emitted per 1000m^3 of oil transported by pipeline: *IPCC Refinement 2019 Table 4.2.4B: Tier 1 EFs for Oil Transport*.
    - 0.025 t CH_4 /1000 m^3; 0.0023 t CO_2 /1000 m^3; 0.25 t NMVOC /1000 m^3

Method Assumptions and Observations

- Offshore loading of crude oil is a key source category for NMVOCs in the UK inventory, and therefore a higher-Tier approach has been sought. We note that operators do report emission estimates from oil loading at offshore assets in EEMS, but that the data show significant inter-annual variability in scope with some installations only reporting periodically and other known OTLs not reporting at all, indicating that EEMS data for this source are not complete.
- The activity data required for estimates of emissions of hydrocarbons from oil loading offshore is the annual mass of crude oil production at UKCS platforms or FPSOs that are not connected to oil pipelines and hence the crude oil is transported to shore using shuttle tankers. The operator reporting in EEMS includes activity data for the mass of crude oil transferred per year. However, the OGA PPRS data for Offshore Tanker Loaders (OTLs) provides an alternative dataset via the monthly returns per OTL field on crude oil production which can be aggregated to the installation (i.e. platform or FPSO) level using the field to installation mapping. We note that the PPRS data are underpinned by statutory reporting obligations whilst EEMS is a voluntary reporting system for the oil loading source. As noted above, comparison of EEMS against PPRS and subsequent consultation with operators via the BEIS OPRED team confirmed that the EEMS-reported data by offshore operators are incomplete.

- Another alterative dataset is presented within DUKES Table F.1 *Crude Oil and Natural Gas Liquids production*, which reports an aggregated time series of mass (in kt) of crude oil production at OTLs per year. The DUKES data is derived from the OGA PPRS data and shows close consistency in most recent years. However, the DUKES data is derived based on a calculation method that considers disposals and stock changes month to month within the tankers; our analysis indicates that in most years this provides very similar estimates to a direct aggregation of the reported mass of production per month per OTL field in PPRS. For several years in the 2000s however, the DUKES Table F.1 indicates a much lower level of OTL production when compared against the aggregate of crude oil production data in the PPRS dataset; comparison of the PPRS vs. DUKES data at the field and installation level, shared with the BEIS energy statistics team, shows that production at three BP oil fields West of Shetland are significantly under-reported in the DUKES time series. Hence to deviate from the UK energy statistics in these mid-time-series years to use the higher PPRS data is justified and was agreed with BEIS; this is important to ensure that the 2005 Base Year for NMVOC reporting is accurate.
- The outcome of this analysis indicates that the **PPRS activity data are the most complete** and accurate dataset for the UK inventory method, rather than the EEMS or DUKES Table F.1 data. For the data back to 1990, we have the Brown Book production data per field, and we have identified which oil fields are OTLs and can hence derive an aggregate total; the overlap years (2000-2003) between the Brown Book and the PPRS show very close consistency and hence we are confident that the UK inventory method has a **time series consistent** activity data time series, using the Brown Book and PPRS data together from 1990 to latest year.
- The scope of reporting of fugitive emissions at offshore installations addresses any leaks at the offshore end of oil pipelines, whilst leaks under-sea we assume to be dissolved in the water column and any leaks at the onshore terminal receiving end of the pipelines will be reported under the scope of PPC/IED annual returns. Hence, we do not consider that the 2019 Refinement method for fugitive emissions from oil transport via pipelines is appropriate for the UK GHGI as it would introduce a double-count. We note that there is a risk that applying the pipelines method to the onshore production at Wytch Farm may introduce a small double count where fugitive leaks occur at Wytch Farm or at Hamble terminal and are already included within their annual reported emissions to the PI; however, the pipeline is on land rather than under-sea and hence any leaks at connections, compressors on the route are otherwise a gap in the UK GHGI. Hence the estimates are likely conservative but address a minor completeness issue.
- Across all of these transport fugitive sources, there is scarce data from UK sources to inform a country-specific EF; further, the many parameters that influence actual emissions (e.g. sea and weather conditions) make the accurate characterisation of this emission source highly uncertain. For the offshore loading source, there is the EEMS 2008 operator guidance which presents EFs that are derived from research in the UK in the 1990s; however we note that the 2019 Refinement EFs are derived primarily from research in the North Sea production area by the Norwegian authorities. The fleet of shuttle tankers that service the Norwegian sector also service UK installations and hence we consider that the 2019 Refinement EFs are the more recent data, based on circumstances similar to the UK and hence are the best available option.
- In deriving the offshore loading OTL activity data, we note that the crude oil production in the UK share of the median-line oil field, Statfjord, is processed and exported from a platform in Norwegian waters, and hence we have omitted the Statfjord production data in the UK GHGI activity data across the time series, as the emissions arise in Norwegian waters.
- The method described above is the recommended approach to derive both CH_4 and NMVOC emissions from these emission sources, but we note that to apply the new methods for NMVOCs is a decision for Defra.
- The onshore loading emissions dataset from EEMS for the small number of UK oil terminals shows clear step-changes in the NMVOC EFs applied by individual operators, which reflect the deployment of mitigation at each site over the years. Step-changes down are notable for NMVOC from: Kinneil Terminal (2003-4); Sullom Voe (2008-9); Flotta (2010-11); Seal Sands (2009-10). The default EFs in EEMS are hence not representative for onshore loading at oil terminals, where more stringent controls are now in place, due to the risk to local receptors of high NMVOC emissions at terminal ports and oil storage tank farms.

Scope for future research and improvement

- There is scope for UK research into the EFs applied for all sources in this section of the industry. We note that, for example, in the update of onshore facility permits to operate under PPC/IED that the onshore regulators (EA and SEPA) have the opportunity to request that plant operators provide further insight into the source-specific estimates of pollutants within the boundary of the defined installation. This would be especially helpful to improve the evidence base for the origin of fugitive NMVOC and CH_4 emissions, not only for oil loading but across all sources. This type of data is likely to be gathered already by operators; however, we note that there are a range of measurement options available to operators to estimate fugitive hydrocarbons, and a standard method applied across all UK installations would be needed to generate a more accurate and comprehensive dataset.

Uncertainties

- As noted above, the EFs are associated with high uncertainty; the 2019 Refinement cites a range of ±100% of the EFs for CH_4 and CO_2 from oil transport by pipelines, and -50% to +200% for NMVOC. The uncertainty range for oil transport by road and rail tankers is similar with a range of ±50% of the EFs for CH_4 and CO_2 and -50% to +200% for NMVOC. For offshore oil loading to shuttle tankers with or without VRUs the uncertainty range for CH_4 is cited as ±50%; no data are provided for NMVOC for that source.
- Noting the IPCC default uncertainty ranges above and the data limitations as regards no source-specific data reported by onshore terminal operators, our expert judgement is that overall the uncertainties for this group of sources is ±50% for methane, which is the only significant GHG emission, and similar for other gases.

1B2a4: Refining / Storage; 1B2b4: Natural Gas Transmission and Storage

Emission Sources

- Oil terminal storage
- Gas terminal storage

The storage of oil in onshore terminal tank farms leads to relatively low releases of hydrocarbons as the tanks breathe and minor fugitive releases occur. In the UK the regulation of NMVOC emissions in particular has led to mitigation of such sources through closed-loop tank filling and storage systems, floating roofs and so on.

There are similar, even less significant, fugitive emission sources for hydrocarbons from storage of fluids at many UK gas terminals, which also lead to NMVOC emissions and very low releases of CH_4.

Emissions from oil and gas terminals are reported under the scope of IED/PPC annual returns to UK regulators (EA and SEPA), but as with other sources there are no source-specific estimates available.

[This research does not cover downstream sources such as fugitives from refining of mineral oil or from gas transmission networks.]

Pollutants Reported

- Methane, NMVOC

Method Summary

Oil Terminal Storage and Gas Terminal Storage

- UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 to 2010 (when most terminals ceased reporting to EEMS), the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005). Estimates of oil terminal storage emissions for 1990-1994 are derived through extrapolation back from 1995 using crude oil production statistics; a similar method is used to estimate gas terminal storage using gas production statistics as a proxy.
- The EEMS data (BEIS, 2021a) present the AD in tonnes of fluids stored at the oil or gas terminal and the emissions of individual gases in tonnes, including: CH_4 and NMVOC.
- UK GHGI emissions = $\sum$ operator emissions per pollutant
- For 2011 onwards where the only data reported are to the PI/SPRI, there is no source resolution of reported emissions; only a total per pollutant per year per oil or gas terminal is reported. The inventory method across all sources aligns to the total reported to the PI/SPRI and an estimate of storage emissions has been modelled based on previously reported source estimates and the trend in annual site emission totals.
- Oil terminals that report storage emissions in EEMS include: Flotta, Sullom Voe, Nigg, Kinneil, Seal Sands.
- Gas terminals that report storage emissions in EEMS include: Barrow North, Theddlethorpe, Dimlington, Easington.

Method Assumptions and Observations

- There is a very limited dataset to inform estimates from these minor sources across both oil and gas terminals, but the historic EEMS data do consistently show that total emissions of CH_4 are almost negligible; NMVOC emissions are slightly more significant.

Scope for future research and improvement

- There is scope for UK research into the EFs applied for all sources in this section of the industry, but we note that given the relative insignificance of these sources that this is not a priority for improvement in future.

Uncertainties

- Noting the data limitations as regards no source-specific data reported by onshore terminal operators, our expert judgement is that overall the uncertainty for this source is ±50% for CH_4 and NMVOC. In the context of sector inventory uncertainties, these sources are immaterial.

1B2a6: Additional/Other Oil Fugitives

Emission Sources

- Abandoned Oil Wells (onshore)
- Abandoned Oil Wells (offshore)

Pollutants Reported

- Methane

Method Summary

- IPCC 2019 Refinement Tier 1 method: AD x Default EF = Emission
- Activity data: Number of wells abandoned per year (cumulative), derived from the OGA public wellbore search facility, at: https://itportal.ogauthority.co.uk/edufox5live/fox/edu/
- Emission Factor(s): Default (D) EFs from IPCC. EF units are mass of pollutant emitted per well abandoned per year. IPCC Refinement 2019 provides Tier 1 emissions factors for plugged, unplugged and both types for onshore and offshore oil wells.

Method Assumptions and Observations

- That each well, once abandoned, continues to emit low levels of hydrocarbons in each subsequent year, and that the IPCC default EFs are representative of UK circumstances.
- Over the history of onshore oil and gas production in the UK, there has been an evolution of post-operational practices as regulation has increased; older wells are unlikely to have been capped, whereas more recently all wells abandoned are required to be capped to minimise risk of hydrocarbon leakage.
- The OGA has not been able to provide analysis of the wells dataset to present the specific information on the year in which each well was abandoned. The OGA well status is listed according to when the well was drilled. Therefore, we have assumed, given the large number of wells drilled and abandoned over time, that the records of wells drilled that are subsequently abandoned (in any future year) is a good proxy for the actual number of wells abandoned in a given year.
- *(Inherent in the IPCC method)* The emissions of hydrocarbons for offshore wells that are abandoned is estimated to be only 2% that compared to onshore wells, as the IPCC Refinement Tier 1 method states that it is assumed that 98% of hydrocarbons released will dissolve in the water column and not be emitted to atmosphere.
- As the activity dataset is available only for all *oil and gas* wells aggregated, the method applies the same EFs to the full estimate of all abandoned *oil and gas* wells; hence emissions that ideally ought to be reported under 1B2b for leaks from abandoned *gas* wells are included here. The EF for oil wells is assumed to be applicable for gas wells also.
- This is a minor source and **not a key category** for methane emissions and hence a Tier 1 method is proportionate. The UK regulatory system for mining and oil production and after-care requirements for former production sites is such that only low levels of seepage of hydrocarbons is expected. We note that whilst there are academic studies in the UK to research the rate of leakage of methane from individual abandoned oil and gas well sites, there are no country specific EFs available and hence no Tier 2 method option. Therefore to apply the IPCC 2019 Refinement default is the best available dataset to address what would otherwise be a minor completeness issue in the UK GHGI.
- **Completeness**: In the UK there are no known omissions, the scope of reporting is complete. We note that there are no EFs for NMVOC from UK research nor IPCC or EMEP/EEA inventory guidance; NMVOC emissions my occur from these sources, notably from abandoned onshore oil wells. There is no known activity as no previous history of oil production in any OT or CD. There have been a small number of exploratory drilling campaigns offshore in the waters around the Falkland Islands, but no subsequent production and well abandonment.
- **Accuracy**: The method is Tier 1 using detailed AD for the UK and methods from the 2019 IPCC Refinement. The EFs are associated with high uncertainty (as high as -99 to 150% of the stated emission factor).

- **Time Series Consistency:** Annual OGA data on oil wells drilled and their current status is available across the time series, including whether wells are suspended or abandoned, via the public wellbore status search facility of the OGA. The method is therefore time series consistent.

Scope for future research and improvement

- We continue to engage with OGA to seek a solution that may enable us to derive a time series of wells abandoned in each year.
- Research to improve the understanding of when / how many wells abandoned have/have not been capped would enable an improvement to the method to apply the IPCC default EFs (or other EFs) that are specific to (i) capped wells and (ii) uncapped wells, rather than the (iii) “we don’t know if capped or uncapped” default EF that is currently applied to the full activity data.
- There are no default EFs for NMVOC or specific hydrocarbons (e.g. benzene) in either IPCC nor EMEP-EEA guidebooks, but there may be suitable EFs in other literature sources.

Uncertainties

- As noted above, the EFs are associated with high uncertainty; the 2019 Refinement cites a range of -99 to 150% of the stated EFs. The tier 1 method involves large uncertainties both in factor selection and also in determining whether an abandoned well has been plugged or not after decommissioning due to data limitations.
- The method complies with IPCC 2019 guideline for fugitive emissions from abandoned offshore and onshore oil wells. The Tier 1 approach has been applied as Tier 2 or 3 approaches are not available. We note that EFs for abandoned wells have high uncertainty. Activity data for this source are counts of total abandoned onshore and offshore wells in each year of the time series.
- Available information on abandoned wells do not indicate a clear distinction between abandoned oil and abandoned gas wells regarding practices or emission rates. Thus, all the EFs for 1.B.2.A/B.VII in IPCC 2019 are developed from data for both abandoned oil and gas wells. The EFs of abandoned wells are split into either “plugged” (or, properly decommissioned per regulations) and “unplugged” well sub-segments. If insufficient data on plugging practices is available to disaggregate activity data in such a way, the default EF for all type wells is to be used. More limited data are available on offshore wells and disaggregated (i.e. plugged versus unplugged) factors for offshore abandoned wells are developed in IPCC 2019 from onshore wells data considering that most methane (around 98 percent) from offshore abandoned wells is dissolved in marine water.

1B2b2: Natural Gas Production

Emission Sources

- Onshore natural gas production (conventional)
- Onshore natural gas gathering

These emission sources cover the release of fugitive gases from sources from the gas wellhead through to the delivery of gas to processing plants (where necessary), or to the connections to the National Transmission System. UK gas production onshore is limited to a small number of well sites, all conventional (i.e. no fracturing) and hence fugitives arise mainly from any leaks around the wellhead and through infrastructure (pipes, connectors, dehydrators, compressors).

Pollutants Reported

- Carbon dioxide, methane, nitrous oxide and NMVOC

Method Summary

Onshore natural gas production (conventional)

- IPCC Tier 1 method: *Emission = AD x Default EF*
- Activity data: Annual volume of natural gas (million m^3) produced, obtained from industry reporting to OGA, BEIS and their predecessors (DTI, DECC):
  - **1990 to 1998**: DTI Brown Book. [1990, BB 1995 Appendix 7; 1991-1992, BB 1996 Annex 7; 1993-1995 BB 1998 Appendix 7; 1996-1998 BB 2001 Appendix 10; 1999 onwards is from DUKES Annex F2
  - **1999 onwards** from DUKES Annex F.2.
- Emission Factor(s): Default (D) EFs from IPCC. EF units are mass of pollutant emitted per million m^3 of natural gas produced onshore: *IPCC Refinement 2019 Table 4.2.4G: Tier 1 EFs for Natural Gas Production Segment, 1B2b2*. Onshore activities occurring with higher-emitting technologies and practices.
  - 4.09 t CH_4 / Mm^3; 1.45 t CO_2 / Mm^3; 0.98 t NMVOC / Mm^3; 0.000025 t N_2O / Mm^3

Onshore natural gas gathering

- Method identical to the method presented above for onshore natural gas production (conventional), but applying the following EFs from IPCC *Refinement 2019 Table 4.2.4G: Tier 1 EFs for Natural Gas Production Segment, 1B2b2*. Onshore activities occurring with higher-emitting technologies and practices.
  - 3.20 t CH_4 / Mm^3; 0.35 t CO_2 / Mm^3; 0.77 t NMVOC / Mm^3; 0.000006 t N_2O / Mm^3

Method Assumptions and Observations

- There is a very limited dataset to inform estimates from these minor sources from the UK onshore gas production sector, as there are no reported data to the Pollution Inventory.
- The annual level of fugitive releases per well site is below the reporting threshold for IED/PPC regulatory inventories, and the UK industry does not produce any country specific EFs or estimates of fugitive leaks; hence to apply the IPCC 2019 Refinement Tier 1 default method is proportionate to address what would otherwise be a minor completeness issue in the UK GHGI.
- **Completeness**: In the UK there are no known omissions, the scope of reporting is complete. We note that there are no EFs for GHG nor NMVOC from UK research or the industry.
- **Accuracy**: The method is Tier 1 using detailed AD for the UK and methods from the 2019 IPCC Refinement; hence uncertainties are high %s of very small emission estimates.
- **Time Series Consistency:** Annual natural gas production onshore data is available across the time series, via the UK energy statistics and previous annual statistics publications (DTI Brown Book). The method is therefore time series consistent.

Scope for future research and improvement

- There is scope for UK research into the EFs applied for all sources in this section of the industry, but we note that given the relative insignificance of these sources that this is not a priority for improvement in future.

Uncertainties

- The EFs applied for onshore natural gas production are associated with high uncertainty; the 2019 Refinement indicates that CH_4 and CO_2 EF uncertainties are around ±20%, whilst the range for N_2O is -10% to +1000% and for NMVOC is -75% to +250%.
- The EFs applied for onshore natural gas gathering are associated with high uncertainty; the 2019 Refinement indicates that CH_4 and CO_2 EF uncertainties are around ±10%, whilst the range for N_2O is -10% to +1000% and for NMVOC is -75% to +250%.

1B2b3: Natural Gas Processing

Emission Sources

- Offshore gas production: Direct Processes
- Offshore gas production: Other fugitives
- Gas terminals: Direct processes
- Gas terminals: Other fugitives

These emission sources cover the release of fugitive gases from the processing units on upstream facilities, where the produced fluids are extracted, treated (e.g. to remove acid gases), separated to allow the onwards delivery or use of gas and condensate. The emissions arise from leaks on the platform / FPSO / terminal infrastructure, from pipes, flanges, connectors, compressors, dehydrators, separators and other units. In the UK the reporting of fugitive releases by operators tends to fall into two categories: (i) several installations report "direct process" emissions that are usually due to the treatment of acid gases which are processed or flared / incinerated leading (usually) to additional releases of CO_2 and other gases such as SO_2 (e.g. platforms: Elgin, Rough BD, Markham, and gas terminals: SAGE-St Fergus, Barrow, CATS, Point of Ayr, Theddlethorpe); and (ii) all offshore facilities and gas terminals report operational fugitive releases from leaking infrastructure, which are usually estimated based on an inventory of all of the equipment on the facility (i.e. counts of flanges, pipelines, connectors, compressors and so on) and UK industry EFs (from EEMS) on leaks per year per piece of equipment.

Pollutants Reported

- Carbon dioxide, methane, nitrous oxide, oxides of nitrogen, sulphur dioxide, carbon monoxide and NMVOC

Method Summary

<u>Offshore Gas Direct Processes and Fugitives</u>[10]

- UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 onwards, the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of direct process and fugitive emissions for 1990-1994 through extrapolation back from 1995 using natural gas production statistics. A small number of installations account for the direct process sources; emissions are dominated by CO_2 arising from sour gas treatment/venting and amine regeneration at the Elgin platform and from Rough BD platform. The time series of the annual gas production at each installation was used to estimate process emissions in pre-EEMS years.
- The EEMS data (BEIS, 2021a) present the AD in tonnes (of all gases released) and the emissions of individual gases including: CO_2, CH_4, N_2O, NO_X, NMVOC, CO, SO_2. Emissions of fugitives (rather than direct process emissions) are dominated by CH_4 and NMVOC, with some reporting of CO_2 also evident.
- UK GHGI emissions = $\sum$ operator emissions data per pollutant

<u>Gas Terminal Direct Processes and Fugitives</u>

- The method is as described for offshore units above, i.e. a UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 to 2010 (when most terminals ceased reporting to EEMS), the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of direct process and fugitive emissions for 1990-1994 through extrapolation back from 1995 using natural gas production statistics. The installations at SAGE-St Fergus and CATS terminals opened in 1992 and 1993 respectively; the inventory agency has estimated process releases back to those years (and zero emissions in 1990).
- For onshore terminals, the annual submissions to the PI/SPRI are verified by the regulatory agency, whereas EEMS data are not. Therefore, to align the inventory totals to these verified data, across all years where PI/SPRI > EEMS totals per pollutant, the inventory method allocates the residual emissions to this source category. Further, for 2011 onwards, where the *only* data reported are from the PI/SPRI, the inventory method across all sources aligns to the total reported to the PI/SPRI and estimates of direct process and fugitive emissions are

[10] An additional source reported in the UK GHGI as a fugitive emission is the emissions from the 2012 Elgin blow-out. A country-specific method was applied here, based on reported daily methane flow-rate observations taken on 5 days over the blow-out period. [This method was developed in previous research and is noted here for completeness.]

modelled based on previously reported source estimates and the trend in annual emissions per pollutant, per installations.

- This source category is also used for residual emissions once all other source estimates have been made, for the 1990-1997 dataset. The UKOOA 2005 dataset provides source-specific estimates back to 1995, and the 1990-1994 estimates per source are modelled (see other method descriptions across 1A1cii and 1B2) using proxy data. CO_2 and N_2O arise primarily from fuel combustion and gas flaring. For methane and NMVOC, the allocation of emissions across a range of sources is especially uncertain for 1990-1994; it is unknown whether the reported emissions from industry were from process sources, fugitive leaks, material storage or from venting. Our approach is to estimate specific allocations of methane and NMVOC from direct processes, storage and venting, and allocate the rest to “other fugitives” and report them here.

Method Assumptions and Observations

- For process and fugitive sources where the EEMS emissions data are provided without any underlying AD and EF information, the UK inventory method is to aggregate those operator-reported data and conduct QC against other reported data (such as production data to identify when installations start and cease production) to ensure completeness.
- Fugitive emissions reported within EEMS are typically aggregated for each installation, without any further information on the specific source/unit. Similarly, emissions reported under IED/PPC to the PI/SPRI by terminal operators are aggregated across all sources on the defined installation. These national circumstances of data availability mean that the UK inventory data cannot be disaggregated to separate fugitive emissions from oil and gas processing units, from other fugitives, such as acid gas removal units (except where these are specifically identified as “direct process” sources), other connectors, flanges and pipeline infrastructure. The transparency of the underlying operator calculations is limited, and QC of the data focuses on time series consistency per installation.
- The time series of estimates is heavily influenced by reported data from a relatively small number of installations. As noted in the method overview, a number of sites have additional processing requirements due to, for example, the incidence of acid gases from the upstream gas / condensate fields. The UK GHGI trend is therefore influenced significantly by the production trends at those installations. As with all sources, there is greater uncertainty regarding the estimates at the start of the time series due to the limited data resolution in the UKOOA 2005 dataset, but IPCC good practice gap-filling techniques have been used to deliver a plausible time series per source.

Scope for future research and improvement

- The method is reliant on the operator reporting to EEMS; in order to test against an IPCC default or other methodology (such as the fugitives methodology developed through research in Norway in recent years) would require significant investment to gathering more detailed data about the infrastructure on UK platforms, FPSOs and terminals. To develop a more comprehensive Tier 2 method would require UK regulators and industry to generate more detailed activity and emissions data through either annual submissions or periodic research.
- For terminals there is an opportunity to update the requirements within IED/PPC permits (e.g. in response to the latest BREF notes) to include additional operator reporting (annual or periodic) of source-specific estimates, to supplement the installation-wide emission estimates that are currently reported to the PI/SPRI. Additional data (including AD or contextual info on e.g. production) would provide transparency of the source-specific emissions, and remove the need for assumptions to be applied to estimate the allocation of total emissions across fugitives, venting, storage, combustion etc, improving accuracy and opportunities to conduct QC.

Uncertainties

- In the latest year and considering the relative contributions to emission estimates per pollutant and the underlying methods and EFs, our expert judgement is that the activity data uncertainty is ~2-5% and the EF uncertainties are ~10% for CO_2, 50% for CH_4 and 100% for N_2O. Some of the EF uncertainties are *higher* than previously considered in the 2021 submission; the research has not reduced the inventory uncertainty, although the data and method selection across the time series has minimised it, but we better *understand* the sources of uncertainty in the data and have revised the uncertainty parameters accordingly.

1B2c1i: Upstream Oil Production, Venting; 1B2c1ii Upstream Gas Production, Venting

Emission Sources

- Upstream oil production: venting
- Oil terminal: venting
- Upstream gas production: venting
- Gas terminal: venting

This source category comprises emissions from the venting of waste gases that arise through production activities for all upstream oil and gas installations on the UK Continental Shelf (UKCS) and onshore, i.e. including at offshore assets (platforms and FPSOs) and at onshore terminals. Venting releases comprise discharges of waste gas streams and process by-products, either through intentional releases or in emergencies; operators report a wide range of emissions as venting such as solution gas emissions from storage tanks, purging and blowdowns, pressure relief releases and disposal of waste gases or off-specification products where there is no option to flare. In operator reporting via EEMS, venting sub-sources include: emergency, maintenance and operational.

Pollutants Reported

- Carbon dioxide, methane, NMVOC and (rarely) nitrous oxide

Method Summary

Offshore oil production: Venting and Offshore gas production: Venting

- UK industry Tier 2/3 method, utilising the facility-level EEMS data for 1998 onwards, the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of gas venting emissions for 1990-1994 through extrapolation back from 1995 using crude oil (for oil sites) or natural gas (for gas sites) production statistics.
- The EEMS data (BEIS, 2021a) present the emissions of individual gases including: CO_2, CH_4, and NMVOC with occasional reporting of other gases such as N_2O, NO_X and CO. The EEMS reporting of activity data is inconsistent; in most cases the EEMS AD are the sum of the mass of the individual gases, but in others no AD are reported. In the UK GHG inventory model and reporting outputs, we simply aggregate the emissions data per pollutant across all sites and report that as the emission and the EF, with AD = 1.
- UK GHGI emissions = $\sum$ operator emissions per pollutant = EF ; AD = 1

Oil Terminals: Venting and Gas Terminals: Venting

- The method is as above, except that most terminals ceased to report emissions to EEMS beyond 2010 and hence for 2011 onwards, where the only data reported are from the PI or SPRI, there is no source resolution of reported emissions, only a total per pollutant per year per site. The inventory method for 2011 onwards therefore aligns to the total reported to the PI/SPRI across all sources, and an estimate of venting emissions has been modelled based on previously reported source estimates and the trend in annual site emission totals.

Method Assumptions and Observations

- EEMS data for venting are provided as emissions data without any underlying activity and emission factor information. The UK inventory method is to aggregate those operator-reported data and conduct QC against other reported data (such as production data to identify when installations start and cease production) to ensure completeness of reporting. In a small number of cases, operators may report gases other than CO_2, CH_4 and NMVOC under venting in EEMS; where there are reports of small amounts of N_2O, NO_X and CO reported as venting in EEMS, these data are included in the inventory, assuming that there are some waste combustion gases recorded as vented, e.g. from maintenance activities. This happens rarely and the mass of these gases is always very low; they may be misallocated, but it is a minor issue.
- **Completeness**: In the UK there are no known omissions, the scope of reporting is complete. Time-series checks by the inventory agency are used to assess the completeness of reporting each year; there are a small number of terminals that regularly report notable venting emissions, whilst offshore there are tens of installations that report notable venting of hydrocarbons (methane and NMVOC), and a small number (Elgin, Shearwater, Brae only in recent years) that

report venting of CO_2. Onshore terminals that routinely report notable venting emissions include: Flotta, Theddlethorpe, SAGE-St. Fergus, Shell-St Fergus, Barrow and Bacton.

- **Accuracy**: The method is Tier 2/3 across the time series, using the best available data from operator reporting throughout. Noting that in many cases the operator estimates are not presented via an "activity" and "emission factor" but rather are direct estimates of the gases vented from monitoring of the gas throughput and an assumed gas composition, the accuracy is hard to evaluate. Where there are installation-specific processes (e.g. acid gas stripping) that lead to high emissions of vented gases (e.g. Shearwater and Elgin often encounter high-CO_2 produced gases that cannot be flared; several terminals vent the process gases from fuel gas treatment facilities) the composition of the gases is monitored by operators. Smaller-scale vented emissions may be estimated through engineering calculations and default data on gas composition.
- **Time Series Consistency:** The method is compromised by the lack of fully detailed data for the 1990-1997 period, where only aggregate emissions data across all sources in 1A1cii and 1B2 are available from the industry submissions to UK Government. Therefore, the time series consistency is "as good as possible" given the limitations of the available data.

Scope for future research and improvement

- The method is reliant on the operator reporting to EEMS. The PPRS monthly reports also include data on venting. Comparisons of PPRS and EEMS data during this project have indicated that for many sites there is good correlation between EEMS and PPRS, whilst for other sites there are gaps in the PPRS data where EEMS includes venting estimates. This indicates that PPRS is not always reliable for QC of EEMS and/or to inform better estimates. The OGA has recently begun to consider revisions to the system of flare and vent consents, and there may be scope to establish better quality routine reporting of gas venting through the PPRS system, which could then provide an additional data source or QC step for the inventory.

Uncertainties

- Uncertainties of emissions reported are based on expert judgement, informed by the understanding of the available data and the likelihood of error compensation across all UK installations.
- In the latest year of the time series, the uncertainty for venting is estimated to be ±5% for CO_2, 100% for CH_4, whilst in the Base Year (1990) the uncertainty is assumed to be ±20% for CO_2 and 100% for CH_4 due to the more limited information available from industry and assumptions applied to estimate venting emissions.
- The limited alternative data against which the EEMS data can be validated undermines confidence in the accuracy and completeness of the venting estimates.

1B2c2i: Upstream Oil Production, Gas Flaring; 1B2c2ii Upstream Gas Production, Gas Flaring

Emission Sources

- Upstream oil production: gas flaring
- Oil terminal: gas flaring
- Onshore oil production: gas flaring
- Upstream gas production: gas flaring
- Gas terminal: gas flaring

This source category comprises emissions from the flaring of waste gases that arise through production activities for all upstream oil and gas installations on the UK Continental Shelf (UKCS) and onshore, i.e. including at offshore assets (platforms, FPSOs, MODUs), at onshore terminals and at onshore production sites. The gases may need to be flared to address operational issues (e.g. excess gas supply), structural issues (e.g. some platforms/FPSOs that produce crude oil and associated gas do not have any gas export line), safety issues. In operator reporting by offshore operators to BEIS OPRED, via EEMS, flaring sub-sources include: routine operations, gross, maintenance, upsets / other. Flaring of gases is also conducted at oil and gas terminals, again to manage waste gas and maintain operational and safety standards across the sites. For all offshore production sites and terminals, gas flaring emissions are reported by operators under EUETS since 2008 (i.e. from EUETS Phase 2 onwards), and within EEMS from 1998 onwards.

Onshore oil well sites are smaller production sites in the UK context but do still conduct a small amount of gas flaring during production; separate flaring estimates are made for these sites, for completeness.

The flaring of waste gases during well exploration and testing is reported separately under the 1B2a1 and 1B2b1 IPCC source categories for oil and gas well testing respectively. This enables a distinction to be made between emissions from exploration activities, and emissions from production activities.

Pollutants Reported

- Carbon dioxide, methane, nitrous oxide, oxides of nitrogen, carbon monoxide, sulphur dioxide, non-methane volatile organic compounds (NMVOCs)

Method Summary

The emission estimates across the time series are based on the sum of the best available data from upstream oil and gas operators, onshore and offshore. The method since 1998 is essentially a Tier 3 method, aggregating installation-level activity and emission estimates; estimates for 1990-1997 are based on lower resolution source data but are still a Tier 2 method, using industry-wide estimates from the trade association (UKOOA 2005) which are derived from operator surveys through the 1990s and assuming that carbon emission factors from gas flaring from 1998 are representative for earlier years.

Offshore oil production: Gas Flaring and Offshore gas production: Gas Flaring and

Oil Terminals: Gas Flaring and Gas Terminals: Gas Flaring

- UK industry Tier 2/3 method, utilising the facility-level EUETS data for 2008 onwards and EEMS data for 1998-2007, the industry-wide sector estimates for 1995 to 1997 (UKOOA 2005) and an estimate of gas flaring emissions for 1990-1994 through extrapolation back from 1995 using crude oil (for oil sites) or natural gas (for gas sites) production statistics.
- The EEMS data (BEIS, 2021a) present the AD of gas flaring in tonnes and the emissions of individual gases including: CO_2, CH_4, N_2O, NO_X, NMVOC, CO, SO_2. The EUETS data (BEIS, 2021c) provide the AD of gas flared in tonnes together with the carbon emission factor and verified CO_2 emissions total per flaring source per installation. As such the EUETS data are considered highly accurate; they provide a rich and detailed dataset that exhibits a range of variability in the flared gas composition across installations. Reporting to both EEMS and EUETS is underpinned by the sector-wide assumption of 98% oxidation of flared gas.
- UK GHGI emissions = ∑ operator emissions data per pollutant
- Activity data = ∑ operator activity data (tonnes): IEF = Emissions / AD

Onshore oil production: Gas Flaring

- IPCC Tier 2 method: *Emission = AD x Country Specific EF*
- Activity data: Annual mass of gas flared at onshore oil production facilities, obtained from industry reporting to OGA, BEIS and their predecessors (DTI, DECC):
  - **1990 to 1999**: Estimates of mass flared derived from the reported volumes of gas flared by DTI at onshore fields, scaled according to the mass and volume data for flaring at offshore fields, i.e. assuming similar gas density;
  - **2000 onwards** from monthly returns under PPRS for onshore loader fields.
- Emission Factor(s): The EF derived for offshore oil production per year is applied to the onshore flaring AD, as the best estimate of emissions per unit mass gas flared, as there are no operator-reported emissions data nor EFs from these smaller onshore well sites.

Method Assumptions and Observations

- Note that where the gas flaring emissions are reported for an installation via both EEMS and EUETS, the EUETS data are regarded as better quality as they are subject to Third Party verification, as part of the requirements of the trading scheme.
- The estimates of methane emissions from gas flaring are amongst the most uncertain of all estimates of GHGs from the upstream oil and gas sector. The EEMS operator guidance methane EF and the accepted EUETS sector-wide methodology (to estimate CO_2 emissions under EUETS) are based on a sector-wide assumption that the oxidation of flared gases is 98%. There is no routine monitoring and reporting of the performance of flares to industry regulators. Consultation with operators and regulators indicates that there is a variable approach by operators to track, monitor and resolve issues such as unlit flares, which will instead be cold venting flare gases. During such events, methane emissions will be much higher and carbon dioxide emissions much lower than the estimates reported based on the measurement of the amount of gas to flare and applying the 98% oxidation factor assumption. Aside from the issue of unlit flares, there is no routine industry monitoring of flare oxidation efficiency, and we note that just a small under-performance in flare efficiency, below the 98% industry assumption, will lead to a significant under-report in the methane estimates (e.g. a 96% flare efficiency equates to double the reported methane emissions).
- Gas flaring a minor source of emissions of nitrous oxide. Operators report estimates to EEMS, predominantly applying defaults from operator guidance, and hence this is essentially a Tier 2 approach; the inventory agency gap-fills reported data where necessary, using the default EF.
- The gas flaring an onshore well sites is a small component of total flaring emissions, e.g. in 2020 it is estimated to account for 0.6% of total flaring GHG emissions. The available data for this source is limited to activity data across the time series, with assumptions applied to use the EF from offshore oil production facilities and to derive the AD in the early part of the time series. This component of the gas flaring estimates is therefore subject to greater uncertainty than the well-documented other sources (offshore and at terminals).
- **Completeness**: In the UK there are no known omissions, the scope of reporting is complete. The inventory agency draws upon a range of data sources to ensure completeness (and accuracy), using EUETS supplemented by EEMS data for smaller installations that fall below the EUETS reporting threshold.
- **Accuracy**: The method is Tier 2/3 across the time series, using the best available data from operator reporting throughout. In the UK there has been a high level of flare gas compositional analysis to inform EUETS allocations (from the National Allocation Plans from 1998 onwards) and subsequently in all operator submissions to EUETS. Further, the stringent monitoring and reporting and other QAQC requirements of the EUETS system gives confidence that the reported mass of flare gas sent to flare per installation per year is highly accurate. As noted above, the biggest source of potential inaccuracy in GHG estimates is the assumption across all operator reporting that flare oxidation efficiency is 98%; deviation from that assumed level of oxidation will impact both the methane and carbon dioxide estimates.
- The 1990-1997 data are based on the UKOOA 2005 report to UK Government, which took account of the work in the National Allocation Plans to derive better installation-level carbon emission factors but are based on more limited industry surveys from the early 1990s and hence are associated with higher uncertainty than the later data.

- **Time Series Consistency:** The method is compromised by the lack of fully detailed data for the 1990-1997 period, where only aggregate emissions data across all sources in 1A1cii and 1B2 are available from the industry submissions to UK Government. Therefore, the time series consistency is "as good as possible" given the limitations of the available data.

QA/QC

Specific QA/QC and validation exercises relevant to these source categories include:

- Comparisons between EEMS and EUETS, to review installation-specific activity data and CO_2 emissions data (and hence implied IEFs for each site and source) to identify any possible gaps in the EEMS dataset, using EUETS as a de-minimis. The EUETS data quality (AD, EFs) are third-party verified and hence regarded as the more accurate dataset;

- Comparisons of total emissions data reported by each onshore oil and gas installation via the Pollution Inventory/Scottish Pollutant Release Inventory/Welsh Emissions Inventory to assess time-series consistency and completeness of reporting, comparing CO_2 emissions data against those presented in EUETS (and EEMS if the terminal reports to EEMS also).

Scope for future research and improvement

- A high priority for further research is to develop a more rigorous and comprehensive evidence base for flare performance at all upstream installations, especially for those that operate offshore in potentially harsh conditions and with more limited opportunities for flare stack maintenance. Priorities are to seek more measurement data on the performance of different flare stack types (enclosed or open flare designs etc.) and to develop more rigorous and consistent operator monitoring and reporting systems to track when flares are operational, when they are unlit, and the volume/mass of flare gas passed to the flare stack during these different periods of operation.

Uncertainties

- Uncertainties for both AD and EFs are based on expert judgement, informed by the understanding of the available data, the level of uncertainty that is accepted within the reporting systems (e.g. EUETS) and the likelihood of error compensation across all UK installations.
- In the latest year of the time series, the AD uncertainty for gas flaring is estimated to be ±5%, whilst in the Base Year (1990) the AD uncertainty is assumed to be ±20% due to the more limited information available from industry and assumptions applied to estimate flaring activity.
- Across the time series, the CO_2 EF uncertainty is estimated to be ±5% whilst the uncertainty in the EFs for both methane and nitrous oxide are estimated to be ±100% across all installations, reflecting the uncertainty in oxidation factor assumption (for methane) and the widespread use of a default EF (for nitrous oxide).
- Uncertainties in flaring AD are typically low. However, we note (as outlined above) that there are different operator flare stack monitoring (lit/unlit) practices evident (across the time series) and also that there are less detailed activity and emissions data available for the 1990-1997 period. Hence uncertainties for the estimates in 1990 are higher than for recent years where much more detailed and complete operator-reporting of activity and emissions are evident.
- The CO_2 EFs are based on UK-specific data, from sampling and compositional analysis of gas sent to flare. Despite the uncertainty regarding the assumed gas flaring oxidation factor, across the sector the uncertainty of the CO_2 EF is still expected to be low, however the uncertainty of the CH_4 EF is considered to be high.

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